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Clean Energy Standard White Paper – Cost Study

April 8, 2016

This Study is issued by the New York State Department of Public Service (DPS).

The supporting analysis in this Study was led by the New York State Energy Research and Development Authority (NYSERDA) working in collaboration with DPS. NYSERDA and DPS acknowledge the contributions of Sustainable Energy Advantage, LLC (SEA) and SEA's subcontracting consultants AWS Truepower, Antares Group, and Daymark Energy Advisors for their primary analytical role in the development of the analysis for Tier 1 and Tier 2 in this Study.

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Executive Summary

The Clean Energy Standard Cost Study (Study) complements and advances the Clean Energy Standard (CES) Staff White Paper (White Paper)(1). The White Paper was published on January 25, 2016 and proposes the CES as New York's policy to deliver the goals of generating 50% of our electricity from renewable resources like solar, wind, and hydro renewable electricity by 2030, while also ensuring that upstate nuclear plants continue to generate so that the carbon savings provided by these plants are maintained. The CES builds on the State's nationally leading efforts to reduce greenhouse gas emissions 40% by 2030 and 80% by 2050, protect the health and safety of New Yorkers, and stimulate economic growth, including the Reforming the Energy Vision initiative, Clean Energy Fund administered by NYSERDA, Regional Greenhouse Gas Initiative, and plans to eliminate coal generation by 2020.

A benefit-cost analysis of the CES is required to support the Public Service Commission's (PSC) obligation to ensure electric prices are just and reasonable. The Study examines the impact that key cost drivers can have on overall consumer bills, and will assist the PSC to design and implement a cost-effective CES. **The Study estimates that, even in this period of lower electricity prices due to historically low natural gas prices, New York can meet its clean energy targets with less than a 1% impact on electricity bills (or less than $1 per month for the typical residential customer) in the near term and shows net positive benefit of $1.8 billion by 2023**.

(1) Case 15-E-0302. Reference is also made to the analysis provided in the Draft Supplemental Environmental Impact Statement (EIS) published on February 23, 2016, see: http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=154829&MatterSeq=48235

The implementation of the CES is aligned with Reforming the Energy Vision (REV) and the Clean Energy Fund(1), which will reduce ratepayer collections over time and reduce the costs of clean energy technologies such as solar, wind, and energy efficiency through programs like NY-Sun, the Green Bank, and Research & Development. All of these investments will help to lower the cost of achieving the 50% renewables goal.

This Study provides analysis examining the cost impact of variations in key cost driver assumptions. A "base case" scenario – which reflects mid-point assumptions for each key factor – is used as a reference point for comparison. The conclusions presented in this study are based on analysis covering the period to 2023. This coincides with the timing of periodic reviews of the CES by the PSC as proposed in the White Paper, and recognizes that any projection extending to 2030 (and the decades that follow) is subject to significant uncertainty.

The net benefits of the CES to 2023 of $1.8 billion reflect program costs and the benefits associated with lower carbon emissions. The CES forms a crucial component of efforts to deliver the New York State targets of reducing carbon emissions by 40% by 2030, and 80% by 2050, both by maintaining emission reductions from existing nuclear and renewable energy facilities, and achieving further carbon reductions through new renewable energy deployment. The Study quantifies these carbon benefits using the "social cost of carbon" as published by the U.S. Environmental Protection Agency.

(1) Case 14-M-0094, Proceeding on Motion of the Commission to Consider a Clean Energy Fund, January 21, 2016, www.nyserda.ny.gov/About/Clean-Energy-Fund

REV and the CES will promote each other's achievement. REV will cause an expansion of distributed resources and enable their integration with the electric grid in a way that decreases system costs and facilitates renewable generation. The CES, by clearly stating both an absolute mandate and interim targets, will support the development of a vibrant clean energy market and provide the scale and certainty necessary for broad competition that encourages private investment and reduces costs.

In addition to the cost and benefits quantified in this Study, there are significant economic development benefits identified – for example, the proposal to provide new support for upstate nuclear plants would protect 25,000 direct and indirect jobs, $3 billion in direct and indirect economic activity, and $145 million in State tax revenue.

Nonetheless, in the near term achieving the 50% renewables mandate requires New York State to make investments into the future. As noted, the extent of these costs depends on a number of key drivers, some of which can be influenced by New York State policy while others are external:

- The Study examines the cost differences between the main two procurement structures available to bring forward renewables – “bundled PPAs” (under which generators receive a fixed level of compensation per unit of energy for energy and capacity value, and the renewable attributes) and “REC only” (under which generators receive a fixed top-up payment for the renewable attributes, on top of the revenue they are able to secure from energy and capacity sales).

- Energy price and interest rate sensitivities illustrate the impact of variations in these two largely external factors.
- A technology cost sensitivity considers the possibility of less-than-expected reductions in the cost of land-based wind turbines.
- System load assumptions examine the impact of higher system-wide electricity use in New York State, which in turn would require greater amounts of renewables to meet the 50% goal.
- Tax credit scenarios demonstrate the value of the current federal tax credits (compared to not having federal tax credits), as well as the value that could be realized if such tax credits were to continue at current levels.

This Study **concludes** that the CES can be achieved in a manner that balances cost impact and results in net benefits, and several variables favor investment in renewable energy deployment. Specifically:

1. Two of the cost drivers that show significant upward or downward changes in overall cost under high and low cost scenarios are also factors that New York State can influence to a large extent: procurement structures and the total amount of energy use. This emphasizes the importance of ongoing work to determine the mix of procurement structures (as set out in the White Paper), as well as state energy efficiency programs, such as the Clean Energy Fund, to reduce electricity consumption.

2. Future developments in energy prices are uncertain, and are expected to be an important driver of the program cost of the CES. However, swings in CES program costs as a result of energy prices would be balanced by opposite effects on ratepayers' overall electricity bills. For example, lower-than-expected energy prices could increase the CES program costs, but this would be offset by a reduction in energy bills from lower wholesale energy prices.
3. While interest rates and technology costs also have an impact, the analysis indicates that – over the Study period to 2023 – it is smaller than that of the other drivers examined. This also suggests that a technology-neutral approach to structuring the CES Tiers is an appropriate design choice.
4. The current federal tax credits are an important contributor towards reducing the cost of renewables to New York State, and a further extension of the tax credits at their current level could result in a substantial further reduction of the costs.
5. The current combination of low energy prices, low interest rates and available tax credits presents a uniquely favorable environment for near-term investment into renewables as proposed by the White Paper. The benefits from these investments can be realized with less than a 1% near-term bill impact.
6. Using the standard Federal and State regulatory approach to valuing avoided carbon emission, the CES delivers a significant net benefit for all New Yorkers over the Study period.

Section 1 – Introduction

Introduction

The Clean Energy Standard Cost Study (Study) complements and advances the Clean Energy Standard (CES) Staff White Paper (White Paper)(1). The White Paper was published on January 25, 2016 and proposes the CES as New York's policy to deliver the goals of generating 50% of our electricity from renewable resources like solar, wind, and hydro renewable electricity by 2030, while also ensuring that upstate nuclear plants continue to generate so that the carbon savings provided by these plants are maintained. The CES builds on the State's nationally leading efforts to reduce greenhouse gas emissions 40% by 2030 and 80% by 2050, protect the health and safety of New Yorkers, and stimulate economic growth, including the Reforming the Energy Vision initiative, Clean Energy Fund administered by NYSERDA, Regional Greenhouse Gas Initiative, and plans to eliminate coal generation by 2020.

A benefit-cost analysis of the CES is required to support the Public Service Commission's (PSC) obligation to ensure electric prices are just and reasonable. The Study examines the impact that key cost drivers can have on overall consumer bills, and will assist the PSC to design and implement a cost-effective CES. **The Study estimates that, even in this period of lower electricity prices due to historically low natural gas prices, New York can meet its clean energy targets with less than a 1% impact on electricity bills (or less than $1 per month for the typical residential customer) in the near term and shows net positive benefit of $1.8 billion by 2023**.

(1) Case 15-E-0302. Reference is also made to the analysis provided in the Draft Supplemental Environmental Impact Statement (EIS) published on February 23, 2016, see: http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=154829&MatterSeq=48235

Introduction (cont'd)

The implementation of the CES is aligned with Reforming the Energy Vision (REV) and the Clean Energy Fund(1), which will reduce ratepayer collections over time and reduce the costs of clean energy technologies such as solar, wind, and energy efficiency through programs like NY-Sun, the Green Bank, and Research & Development. All of these investments will help to lower the cost of achieving the 50% renewables goal.

Overall costs and benefits depend on a number of key factors. Some of these are largely outside of New York State's control, such as wholesale electricity prices (driven by natural gas prices), interest rates and federal tax credits; others can be directly influenced by New York State, such as the structures used to procure renewable energy resources; while others are a combination, such as installed costs of technology (which are driven by global market scale and in-state soft cost reductions) and total energy consumption (which is driven by long-term societal or behavioral trends as well as state energy efficiency and similar programs). The impact of each of these factors is examined throughout this Study.

(1) Case 14-M-0094, Proceeding on Motion of the Commission to Consider a Clean Energy Fund, January 21, 2016, www.nyserda.ny.gov/About/Clean-Energy-Fund

Introduction (cont'd)

Any projection extending to 2030 (as well as the decades following 2030, once the full lifetime of installations deployed until 2030 is taken into account) is subject to uncertainty. Forecasts can be provided with a comparatively high degree of confidence for the near term, but as estimates are extended further in time, input assumptions (such as technology cost assumptions) become increasingly uncertain, and long-term analysis could suggest a false sense of precision. The conclusions presented in this Study are therefore based on analysis covering the period to 2023. This coincides with the timing of periodic reviews of the CES by the PSC as proposed in the White Paper. The time horizon of this Study provides the PSC with analysis covering the period until the second such review.

Forecasting the cost of achieving the entire 2030 target is deemed highly speculative at this point. However, the Study also provides an appendix with 2030 estimates that indicate modest bill impacts for reaching the full 50% mandate.

Structure of This Study

This **Section 1** provides an overview of the methodology used for this Study.

The CES obligation is divided into proposed "tiers" with differing purpose, eligibility, targets and Alternative Compliance Payment levels:

- Tier 1 – increasing targets for new renewable supply sources, aimed at bringing forward the growth in renewable electricity needed to achieve the 2030 50% renewable electricity target,
- Tier 2 – targets to maintain the supply of existing renewable supply sources to New York,
- Tier 3 – maintenance of nuclear facilities.

Sections 2-7 focus on **Tier 1** of the CES by analyzing each of the key factors that are likely to influence cost and deployment of new renewables throughout the first two review periods of the CES (to 2023):

- Procurement structures for new renewables, in particular solicitation mechanisms (Section 2);
- Energy prices (Section 3);
- Interest rates, and their impact on the finance costs experienced by renewable energy projects (Section 4);
- Future technology installation costs and cost reductions (Section 5);

Structure of This Study (cont'd)

- System load – the overall level of electricity consumption in New York (Section 6); and
- Federal tax credits and their impact on reducing the costs to New York State (Section 7).

Section 8 puts forward analysis for the remaining tiers of the CES – **Tiers 2A, 2B and 3**.

Section 9 examines impacts on customers' electricity bills.

While the Study focuses on the program costs of the CES, **Section 10** discusses some important related costs and benefits, such as macroeconomic impacts and impacts on wholesale prices.

Appendices A and B contain detailed information on the methodology and input assumptions used to derive the analysis presented in this Study.

Appendix C contains supporting analytical results for the period to 2030, subject to significantly higher levels of uncertainty than those presented in Sections 2 through 9.

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Cost Indicators

The Study provides two main cost indicators:

- **Gross program costs** reflect the estimated additional payments (above energy and capacity value revenue) which developers would require to receive in order for projects to be commercially viable.
- In addition, **net program costs** are presented, which are defined as the gross program costs reduced by the **societal value of the avoided CO2 emissions** (in excess of the carbon value already included in the electricity price as a result of the Regional Greenhouse Gas Initiative (RGGI)).

The CES forms a crucial component of efforts to deliver the New York State targets of reducing carbon emissions by 40% by 2030, and 80% by 2050, both by maintaining emission reductions from existing nuclear and renewable energy facilities, and achieving further carbon reductions through new renewable energy deployment. The Study quantifies these carbon benefits using the “social cost of carbon” as published by the Environmental Protection Agency. The analysis shows that when these benefits are accounted for, the CES is a net positive benefit of $1.8 billion for New Yorkers over the period to 2023.

CES Carbon Benefits

Figure 1.1: Tons of avoided carbon

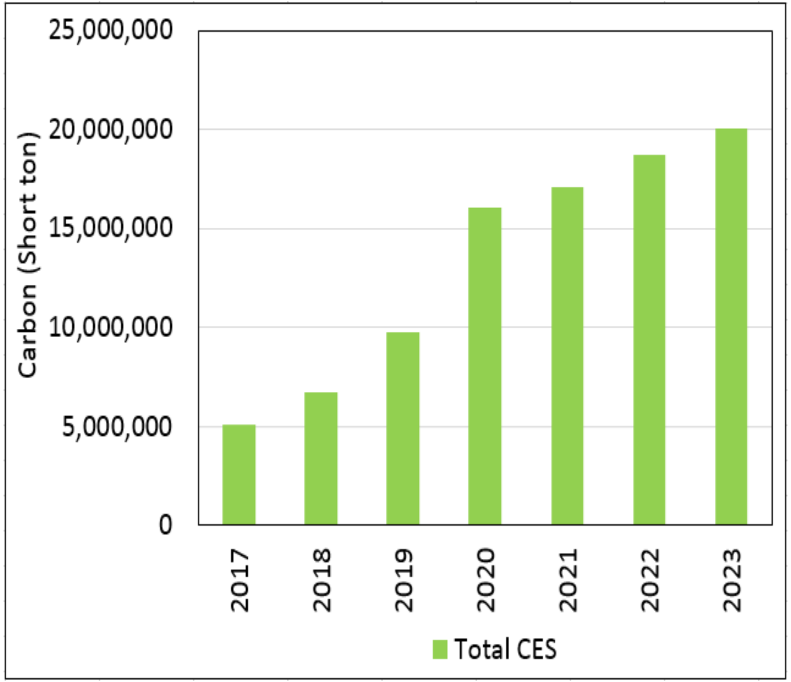
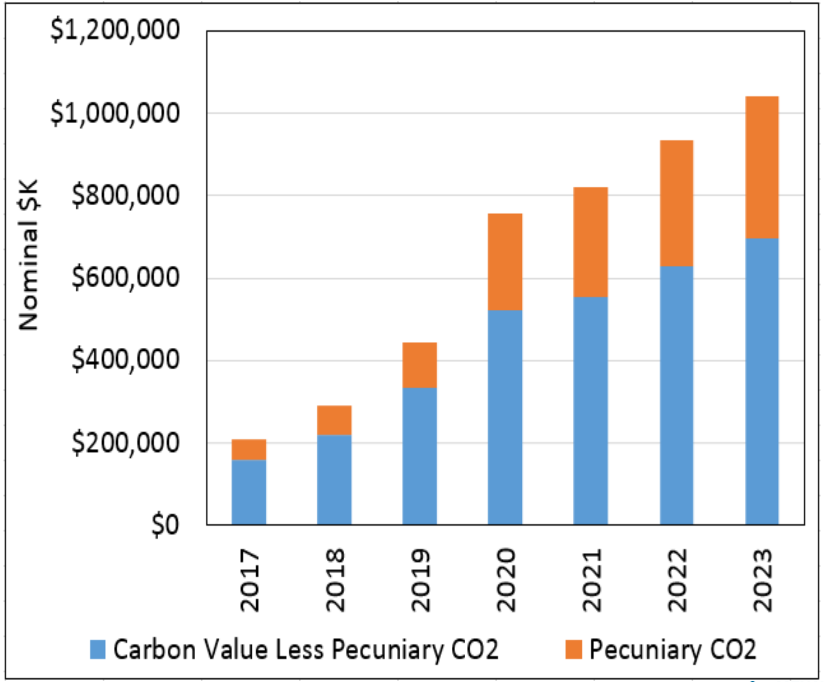


Figure 1.2: Value of avoided carbon



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Cost Indicators (cont'd)

Gross and net program costs (benefits) are presented throughout the Study as nominal annual costs. Annual costs represent the (effective) program payments made in each year to all generators in that year (regardless whether the installations were constructed in that year or earlier).

Two further cost indicators are provided:

- The **lifetime net present value cost**, reflecting the total program cost until all installations have reached the end of their program payment entitlement, discounted to net present value in 2015 (1) at a real 5.5% discount rate;
- The **percentage electricity bill impact** in 2023 (being the peak cost year for the time horizon examined in Sections 2-9), calculated as the total gross program cost in 2023 divided by the most recently reported (2014) total statewide electricity bill spend.

(1) All real terms net present value numbers in this Study are provided in 2015 $ as being the most recent year for which actual inflation data is available.

Cost Indicators (cont'd)

Throughout this Study, statewide cost estimates are shown. The jurisdictional load-serving entities (LSEs) are expected to be responsible for approximately 73% of the total costs (commensurate with their share of statewide load).

For Tier 1, costs are estimated for the full assumed project lifetime of 20 years. This means that the Tier 1 analysis to 2023 includes associated costs through 2042. For Tiers 2 and 3 – which cover existing installations – no assumption has been made regarding remaining useful life, thus costs are not assessed beyond the specified time horizon (2023).

Analysis shown in this Study reflects an update of the analysis contained in the Draft Supplemental Environmental Impact Statement Issued February 23, 2016 (chapter 9) due to further refinements in assumptions and approach.

Tier 1 – Methodology

Analysis for Tier 1 was carried out as follows:

- Extensive research was conducted to build a detailed and up-to-date supply curve of available renewable energy technology cost, resource availability and resource constraints in New York:
  - Robust bottom-up analysis on land-based wind, utility-scale solar and bioenergy;
  - Detailed modeling of small hydro based on publicly available data;
  - Results of recent NYSERDA-funded analyses regarding potential future offshore wind costs as delivered to Downstate New York;
  - An indicative analysis estimating the cost and quantity of the of most likely import potential from territories adjoining New York State.
- The supply curve analysis was developed on the basis of previous similar work carried out for the RPS Main Tier program (1), and thus follows vetted and well-understood methodology.

(1) www.nyserda.ny.gov/All-Programs/Programs/Main-Tier/Documents

Tier 1 – Methodology (cont'd)

As noted above, the estimates presented in this Study are subject to uncertain future developments of key assumptions. Accordingly, this Study does not stipulate a single scenario that would represent a best available forecast. Instead, the Study identifies a number of key drivers of overall cost, and explores the impact of each. Each of these key factors is compared to a base case scenario. The base case scenario represents central assumptions for each cost driver:

- Procurement structures: the 2015 LSR Options Paper (Case 15-E-0302) explored a range of policies for procuring LSR resources. These in turn were reflected in the Staff White Paper (Section II.C). The main procurement options are by means of bundled PPA contracts (whereby generators receive a fixed total compensation level per unit of energy) or through fixed-REC contracts (whereby generators receive a fixed payment on top of the proceeds from commodity sales). The Study base case assumes a mix of 50% PPA and 50% REC prices.
- Base case settings for other cost drivers – energy prices, technology costs, interest rates, system load, tax credits – reflect best available data.

Tier 1 – Methodology (cont'd)

Some modeling simplifications yield a likely conservative approach:

- Procurement of utility-owned generation (UOG) is not modeled explicitly. A full analysis of relative differences between UOG and PPA was the subject of the LSR Options Paper, filed by NYSERDA on June 1, 2015 under Case Order 15-E-0302, which compares overall and temporal costs obtained under each procurement model for a representative 100 MW wind farm. To the extent that UOG is allowed to participate (the White Paper proposes limited circumstances with UOG eligibility), and if such UOG has a lower cost of capital than that modeled, then overall costs may be reduced.
- Delivery of energy from potential imports of eligible renewables from neighboring control areas (Quebec, Ontario, PJM, New England) has been modeled through a number of restrictive assumptions.
- Some resources were not modeled, either because of currently higher costs, relatively small quantities available over the study period, or analytical prioritization. Examples include anaerobic digesters (other than at wastewater treatment plants), geothermal, tidal, wave, fuel cells using any fuel, and biomass combined heat and power (CHP). To the extent that such technologies may be able to compete cost-effectively, the projected costs could be reduced.

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Tier 1 – Targets

The White Paper provides illustrative new renewables (Tier 1) targets through 2020 (subject to adoption of final targets by the Commission). These annual figures to 2020 as well as an illustrative trajectory to 2023 and the final 2030 50% renewable electricity target were used as the basis for this Study.

Table 1.1

Year	Cumulative new GWh
2017	1,536
2018	2,446
2019	3,465
2020	5,465
2023	12,365
2030	33,700

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Tier 1 – Other Programs

The Tier 1 analysis presented in this Study depends on assumptions made as regards a number of other programs:

- As set out in the Staff White Paper, certain assumptions have been made in terms of reducing the amount of electricity consumed in New York State.
- Part of the CES goal is already being delivered by existing policies, in particular NY-Sun for behind-the-meter generation, and RPS Main Tier solicitations for large-scale projects. Project developed under these policies that reach commercial operation in 2015 or later would count towards fulfilment of the CES.(1)
  - Distributed energy resources (DER) were included in the analysis in this Study as delivering the 3 GW of behind-the-meter (BTM) solar PV that constitute the target for the **NY-Sun** program. No further modeling of these resources was carried out given current incomplete knowledge of the full value of DER as well as the future policy framework to be made available to DER resources. These matters are addressed through Case 15-E-0751 (In the Matter of the Value of Distributed Energy Resources).

(1) Note that, as discussed in the White Paper, installations prior to 2015 are treated as part of the baseline so long as the RECs relating to such projections are controlled by New York State, and as Tier 2 supply thereafter.

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Tier 1 – Other Programs (cont’d)

Depending on the outcome of ongoing proceedings relating to BTM resources, such resources could be expected to deliver a greater level of penetration than reflected in this Study and would in this case displace some of the large-scale renewables (LSR) resources. These outcomes can be analyzed as part of and following the ongoing proceedings relating to BTM resources.

- Past **Main Tier solicitations** as well as the Main Tier solicitation planned to take place in 2016, together with delivery of BTM solar PV as discussed above, were assumed to deliver the proposed CES targets up to 2019.
- As a result, the costs of the CES are shown in this Study as the costs of the new renewables needed in addition to Main Tier and NY-Sun deployment in order to deliver the CES targets, starting in 2020. Part of the costs of the Main Tier and NY-Sun programs could nevertheless be borne by LSE customers. The RECs from Main Tier and NY-Sun projects currently accrue to NYSERDA. The net present value lifetime program costs for NY-Sun and the Main Tier solicitations (from 2015) are estimated to be $989.3M (1). The extent to which costs for these programs would be shifted to the CES and to LSEs will depend on decisions on the means by which the RECs from these projects would be made available for Tier 1 compliance.

(1) Net present value in 2015 $ using a 5.5% real discount rate.

Tier 1 – Total Annual Generation by Program

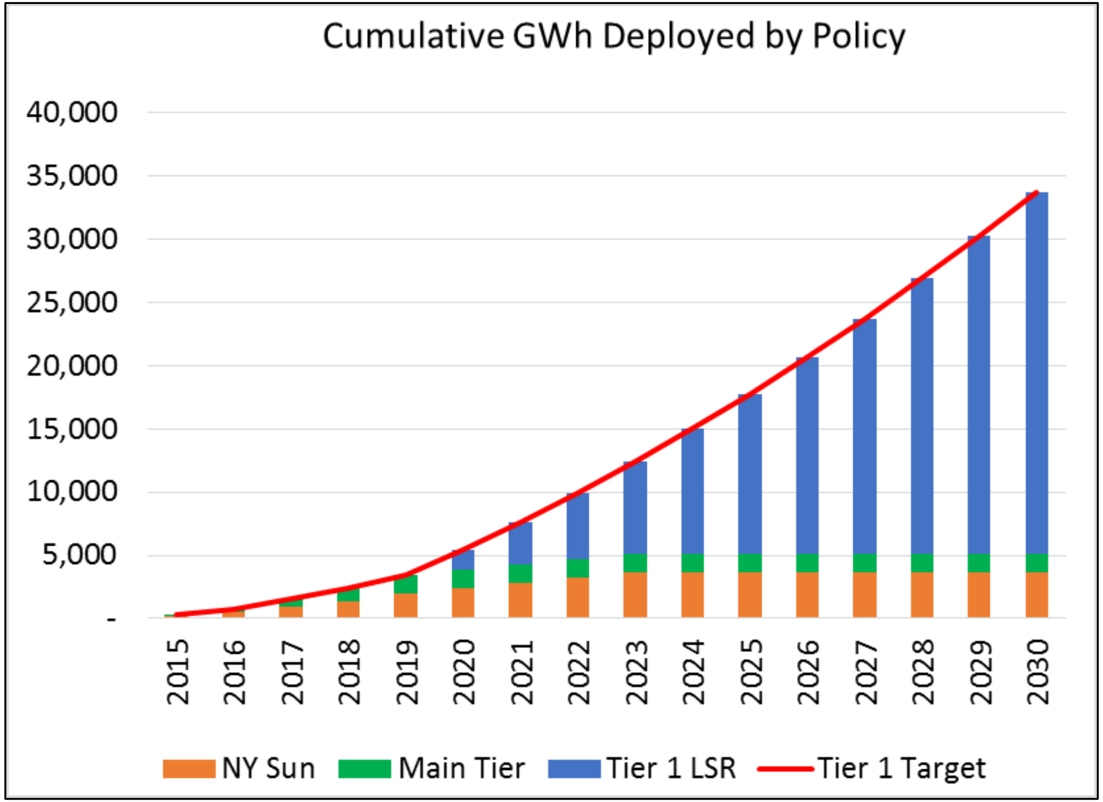

Figure 1.3: Annual Tier 1 target levels from 2021-2029 are based on interpolation between the published proposed targets up to 2020 and the 2030 target. They should be taken as illustrative.

All data reflects modeling estimates. See Appendix A for methodology.

Tiers 2 and 3 – Methodology

Tier 2A addresses existing renewable electricity installations in New York State that are not, or will no longer be, covered by Main Tier solicitation contracts, and would have the opportunity to export their generation to other territories. The costs of Tier 2A are estimated based on breakeven payments required to make New York attractive relative to export to such other territories, particularly New England.

Tier 2B regards existing renewable electricity generation which only has limited export opportunities. Costs are estimated based on pricing levels observed for comparable resources in Northeast RPS programs.

Tier 3 functions as a bridge to the low-carbon portfolio of 2030 by preserving the carbon reductions achieved through certain nuclear generation to date. The program costs for Tier 3 are expected to be based on the difference between expected costs and commodity sale revenues. Tier 3 program costs are provided in this Study as a broad range of lifetime program costs (reflecting high/low energy price and high/low nuclear operating cost assumptions) so as not prejudice negotiations with operators of the nuclear facilities in question regarding the level of Tier 3 Zero Emission Credit (ZEC) payments to be provided.

Other Costs and Benefits

The Study focuses on the cost of the CES as the program payments made to generators. In addition, net program costs are provided which take into account societal carbon benefits. Some other costs and benefits are noted:

- **Economic impacts**: this Study does not provide a macroeconomic assessment of the CES. However, considerations of economic benefits of renewable energy investment are discussed in Section 10, based on existing relevant studies.
- **Impact on electricity wholesale prices**: prices may be affected depending on the level of nuclear generation being maintained and new renewable electricity deployment achieved. See Section 10 for further discussion.
- **Grid infrastructure and grid integration costs and benefits**: the analysis includes some assessment of grid-related costs to the extent they are borne by project developers (see Appendix A for details), but wider grid integration costs or benefits of renewables are not quantified in this Study. The Department of Public Service (DPS) has initiated a State Resource Planning (SRP) study to examine the effects of various public policies on the State's bulk power system, which will present findings over the coming months.

Other Costs and Benefits (cont'd)

- **Environmental impacts:** while the analysis carried out for this Study reflects environmental constraints to some extent (see Appendix A.2 and A.7), environmental costs and other impacts are not included. See the analysis provided in the EIS.(1)
- The establishment and operation of the CES REC market will entail certain **administrative and transactional costs** both for government and market participants. These are not assessed in this Study.

(1) http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=154829&MatterSeq=48235

Section 2 – Tier 1: Procurement Structures

Introduction

This Section discusses the impact of possible renewable electricity procurement structures on the overall Tier 1 cost for deployment until 2023. It analyzes the following procurement options:

- **Bundled PPA structures.** Under this approach, the total payment per MWh (encompassing the entirety of the generator's revenue stream including compensation for energy and capacity) is set at the start of the project; the program cost per MWh shown in this Section is calculated as the difference between this amount and the energy/capacity value in any year, as forecast under the price projections set out in Appendix A.3, and reflecting the zonal price into which the generator sells its output and the project's expected production profile. Where at any point in time the value of energy/capacity exceeds the contracted PPA amount, the program cost per MWh becomes negative (i.e., LSE customers benefit from paying the renewable electricity generator less than the market value of energy and capacity).

- **Fixed-price RECs.** Under this approach, the program cost per MWh is the fixed nominal REC price per MWh set at the start of project operation, which then remains unchanged throughout the period for which RECs are paid. The generator is exposed to fluctuations in commodity value (energy and capacity revenue).

Introduction (cont'd)

The analytical distinction between bundled PPA and fixed REC contains some simplifications.

- No analysis of spot market REC prices has been conducted for any generation that is not procured through either long-term PPAs or fixed RECs. Spot REC prices will likely be volatile based on short-term market supply and demand and related dynamics, and on average, could be higher or lower than the prices assumed based on both policy design and market factors that cannot be known at this time. In the long term, spot prices would be expected to approach the long-term technology costs assessed in this Study, reflecting finance costs commensurate with the risk profile of exposure both to commodity and REC price fluctuation.
- With regard to PPA modeling, no distinction is made in the analysis between “mandatory” or “self-initiated” PPAs as discussed in the White Paper since, from an analytical perspective, either would achieve a similar cost result.
- Procurement of utility-owned generation (UOG) is not modeled explicitly. A full analysis of relative differences between UOG and PPA was the subject of the LSR Options Paper, filed by NYSERDA on June 1, 2015 under Case Order 15-E-0302, which compares overall and temporal costs obtained under each procurement model for a representative 100 MW wind farm.

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Introduction (cont'd)

The following three scenarios are presented:

- A "base case" which reflects a mix of 50% bundled PPA projects and 50% fixed REC projects;
- A sensitivity of 100% bundled PPA installations;
- A sensitivity of 100% fixed REC installations.

As noted in Section 1, cost estimates are provided as:

- The **gross program costs** (to be borne by LSE customers), reflecting payments made to generators under the program above the energy and capacity value, and
- The **net program costs**, defined as the program costs adjusted for the societal value of carbon emissions.

In addition to cost indicators, this Section also presents projections on the potential mix of technologies resulting from the base case. These are shown as the renewable capacity (in MW) deployed each year and the resulting additional renewable generation (in GWh) each year.

See Appendix A for details on methodology.

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Tier 1 Cumulative Capacity Deployed

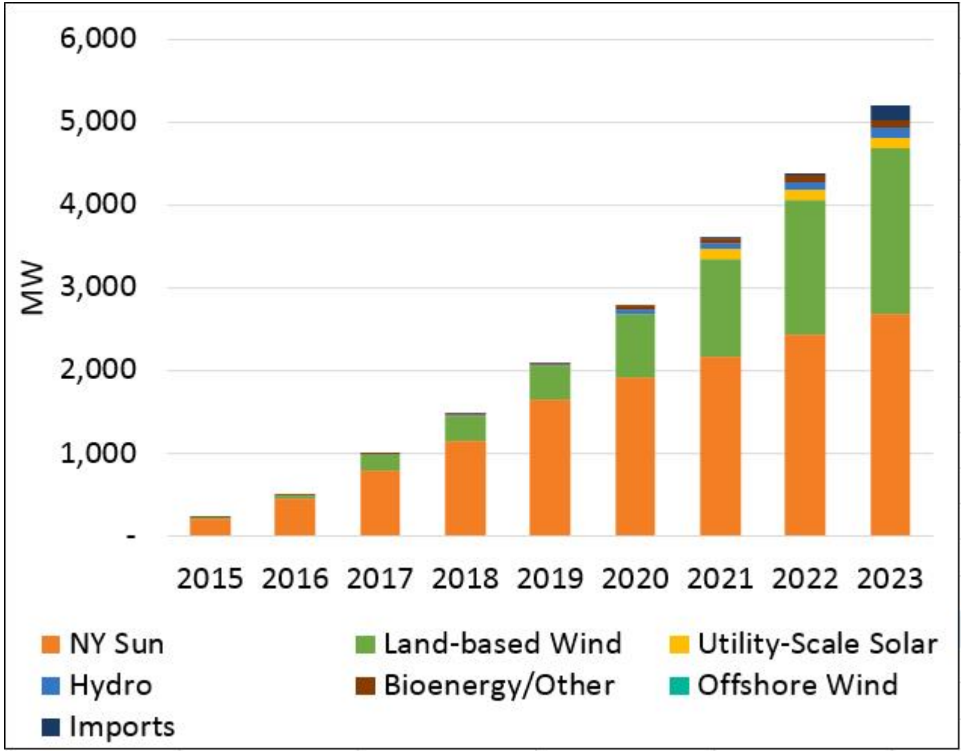

Figure 2.1. This graph shows the base case projection for all installed capacity eligible for Tier 1 of the CES. It includes NY-Sun/ behind-the-meter installations as well as installations from the Main Tier solicitation program, in each case from 2015.

Data reflects an adoption scenario, not a commitment to a particular technology mix. See Appendix A for methodology.

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Tier 1 Capacity Installed

Purple: past Main Tier solicitations

Blue: upcoming 2016 Main Tier solicitation

Table 2.1 - Incremental

MW	2015	2016	2017	2018	2019	2020	2021	2022	2023
NY-Sun	208	249	330	369	500	258	258	258	258
Land-based Wind	18	23	155	100	106	370	408	448	359
Utility-Scale Solar					-	-	109	14	-
Hydro	-	-	0	12	15	23	23	22	39
Bioenergy/other	1	3	-	10	-	33	7	31	5
Offshore Wind					-	-	-	-	-
Imports							4	4	165

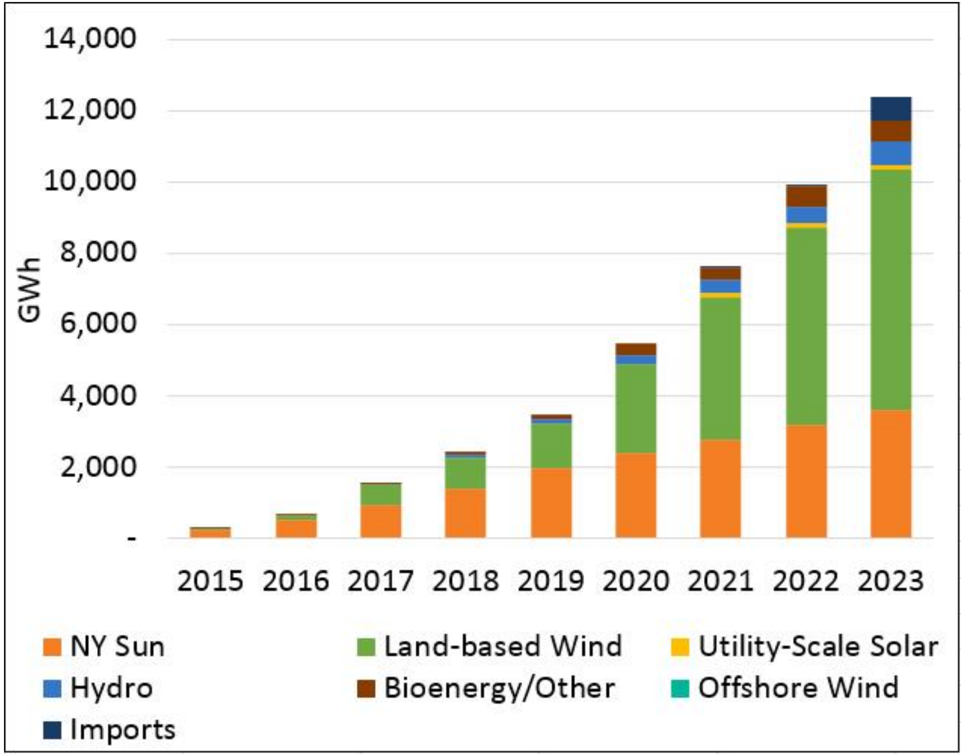
Pre-2015 deployment is not shown, (eg for this reason NY-Sun deployment shown is less than the full 3 GW NY-Sun target)

Table 2.1 - Cumulative

MW	2015	2016	2017	2018	2019	2020	2021	2022	2023
NY-Sun	208	457	787	1,156	1,656	1,914	2,172	2,430	2,688
Land-based Wind	18	40	196	296	402	771	1,180	1,628	1,987
Utility-Scale Solar	-	-	-	-	-	-	109	124	124
Hydro	-	-	0	12	28	51	74	96	135
Bioenergy/other	1	5	5	14	14	47	54	85	89
Offshore Wind	-	-	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	4	8	173

Data reflects an adoption scenario, not a commitment to a particular technology mix. See Appendix A for methodology.

Tier 1 Cumulative Generation



Data reflects an adoption scenario, not a commitment to a particular technology mix. See Appendix A for methodology.

Figure 2.2. This graph shows the base case projection for generation from the installed capacity shown in Figure 2.1.

Note that there is no linear correlation across the range of technologies between the GWh figures shown here and the MW capacity in Figure 2.1, because capacity factors differ for each technology. For instance, the lower capacity factor of solar PV compared to other technologies explains why the proportion of solar PV production is less than its proportion of total capacity, relative to the other technologies.

Tier 1 Generation

Purple: past Main Tier solicitations

Blue: upcoming 2016 Main Tier solicitation

Table 2.2 - Incremental

GWh	2015	2016	2017	2018	2019	2020	2021	2022	2023
NY-Sun	218	306	391	469	578	408	408	408	408
Land-based Wind	55	72	459	293	362	1,290	1,448	1,540	1,214
Utility-Scale Solar					-	-	133	17	-
Hydro	-	-	5	72	80	101	96	99	188
Bioenergy/other	9	21	-	76	-	200	43	214	28
Offshore Wind					-	-	-	-	-
Imports					-	-	22	21	611

Pre-2015 deployment is not shown

Table 2.2 - Cumulative

GWh	2015	2016	2017	2018	2019	2020	2021	2022	2023
NY-Sun	218	524	915	1,384	1,962	2,370	2,778	3,186	3,594
Land-based Wind	55	127	586	880	1,241	2,531	3,979	5,519	6,733
Utility-Scale Solar	-	-	-	-	-	-	133	151	151
Hydro	-	-	5	77	156	258	354	453	641
Bioenergy/other	9	30	30	106	106	306	349	563	590
Offshore Wind	-	-	-	-	-	-	-	-	-
Imports	-	-	-	-	-	-	22	43	654

Data reflects an adoption scenario, not a commitment to a particular technology mix. See Appendix A for methodology.

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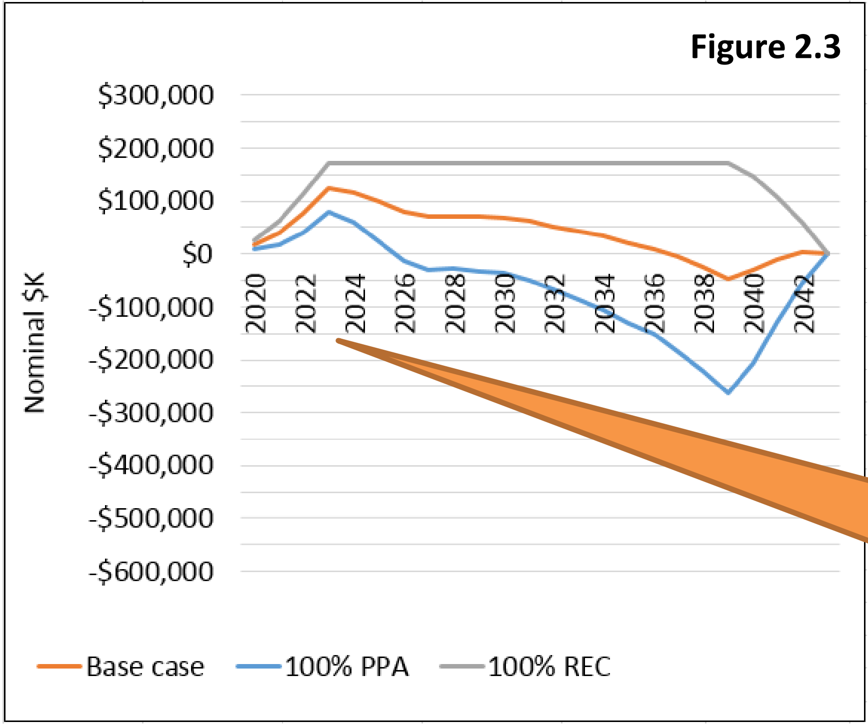
Tier 1 Gross Program Costs to 2023 – Procurement Structures

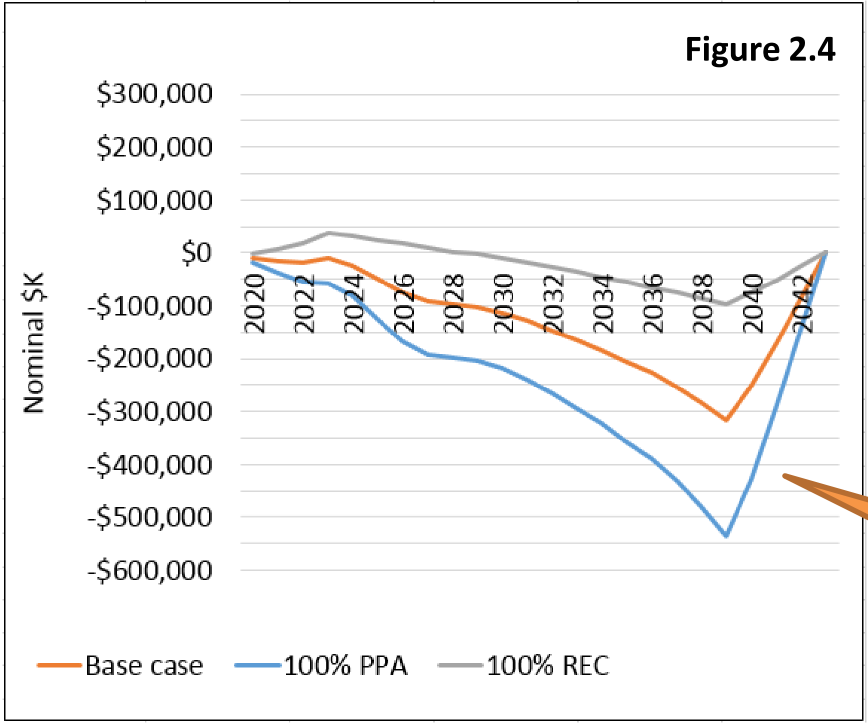


	Net present value	Bill impact in 2023
100% PPA	$269 M benefit	0.28%
Base case	**$453 M cost**	**0.45%**
100% REC	$1.18 B cost	0.62%

Data shows deployment until 2023. Under 100% REC, costs stay constant thereafter because REC prices are fixed, while effective PPA cost (net of energy/capacity value) declines as energy prices are projected to rise. The base case shows a mix between PPA and REC.

All data reflects modeling estimates. Only incremental CES generation (2020-2023) is shown. See Appendix A for methodology.

Tier 1 Net Program Costs to 2023 – Procurement Structures



	Net present value
100% PPA	$1.51 B benefit
Base case (50%/50%)	**$787 M benefit**
100% REC	$65 M benefit

Benefits reduce as installations deployed to 2023 reach the end of their life

Carbon benefits turn costs into net benefits in all three scenarios

All data reflects modeling estimates. Only incremental CES generation (2020-2023) is shown. See Appendix A for methodology.

Procurement Structures: Observations

The following high-level observations are presented:

1. For completeness, the technology mix results are provided for all resources that count towards Tier 1, i.e., including NY-Sun and Main Tier installations from 2015. As regards cost projections, all installations deployed until 2019 are expected to result from existing programs (Main Tier solicitations and NY-Sun) and thus not reflected in the cost projections. 2020 represents the first year of deployment under the new CES.
2. The base case technology mix scenario indicates that land-based wind continues to be the dominant large-scale technology throughout the period to 2023 considered here. As noted earlier, behind-the-meter uptake is presented as the level of deployment currently targeted under NY-Sun. Hydro, utility-scale solar PV and biomass are all expected to make smaller contributions. The analysis does not see offshore wind (OSW) deploying within the 2023 timeframe – see Appendix A.2 for discussion of the OSW analysis, and Appendix C for longer-term deployment estimates.
3. Consistent with the analysis presented in the 2015 LSR Options Paper, the greater revenue certainty of PPAs (resulting in reduced investor exposure to commodity market price risk), allows projects to come forward at a lower expected gross program cost than a fixed-price REC approach. In the analysis, this is modeled through higher investor hurdle rates in the fixed-REC scenario than the PPA scenario. The result is shown as lower costs in the initial years.

Procurement Structures: Observations (cont'd)

4. The analysis presented here reflects deployment until 2023. Under the REC scenario, gross program costs remain constant thereafter, consistent with the fact that REC payments are fixed. Under the PPA scenario, costs decline in future years as energy prices are expected to rise, and effective program payments to generators only need to compensate for an increasingly small gap between energy prices and the fixed total revenue level. As energy prices are projected to increase further, this results in effective payments becoming negative, as energy prices start to exceed the fixed PPA compensation level. The result is a negative gross program cost, or a benefit, for the PPA scenario.
5. The same effects are shown after application of the societal carbon benefit. The net effect is shown to be a net program benefit rather than a cost to society. Since these carbon benefits are projected to increase year-over-year, the net benefit to society also increases as the years progress.

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Section 3 – Tier 1: Energy Prices

Introduction

This Section examines the impact of uncertainty in regard to future energy prices on the overall Tier 1 cost for deployment until 2023.

- **The central energy prices forecast** used in the Study is based on an adjusted version of the NYISO CARIS forecast until 2024. After 2024, it reflects a mix of expected inflation and natural gas price increases.
- **The "low" energy prices scenario** assumes that energy prices are 10% lower in each year than assumed under the base case.
- **The "high" scenario** assumed that energy prices are 15% higher in each year than assumed under the base case. The asymmetric approach between low and high case reflects the view that the base case forecast is comparatively conservative, and thus arguably leaves more room for higher price rises.
- **Capacity prices** are at central forecast levels in all scenarios.

Further details are provided in Figures 3.1 to 3.3 below. See also Appendix A for details on methodology.

Wholesale Energy Price Base Case

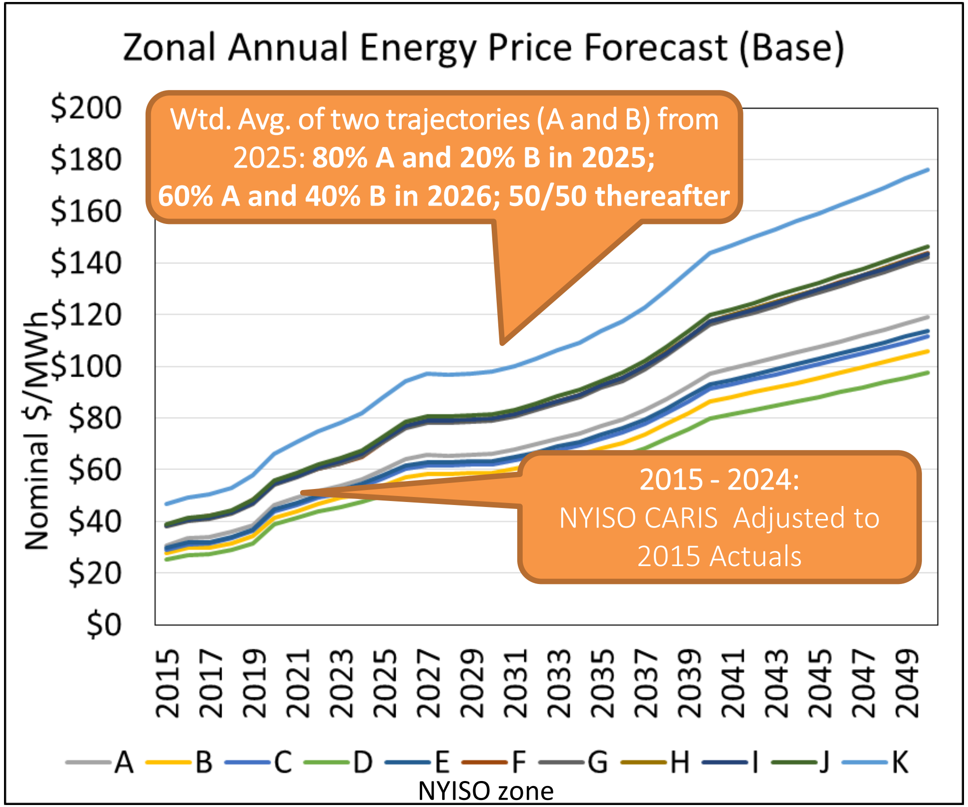

Figure 3.1. For this analysis, the 2015 NYISO CARIS energy price forecast trend, adjusted downward to align with actual energy prices in 2015, was used as the "Base" energy price forecast through 2024. Thereafter, the energy price is the weighted average of two trajectories:

- **A. Constant Real Index**: Constant in real dollar terms at the 2024 level, i.e., continuing to increase with inflation annually (in nominal terms); and
- **B. AEO 2015 Natural Gas Price Index**: Indexed the 2024 forecast to trend at the annual rate of change for the 2015 EIA AEO Reference Case natural gas price forecast

An avoided cost of carbon policy compliance is embedded in the NYISO CARIS energy price forecast. By virtue of the adjustment method described above, the monetized cost of carbon was implicitly assumed to be adjusted and extrapolated in proportion to the Base energy price forecast in this analysis.

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Energy Price Forecast Sensitivities

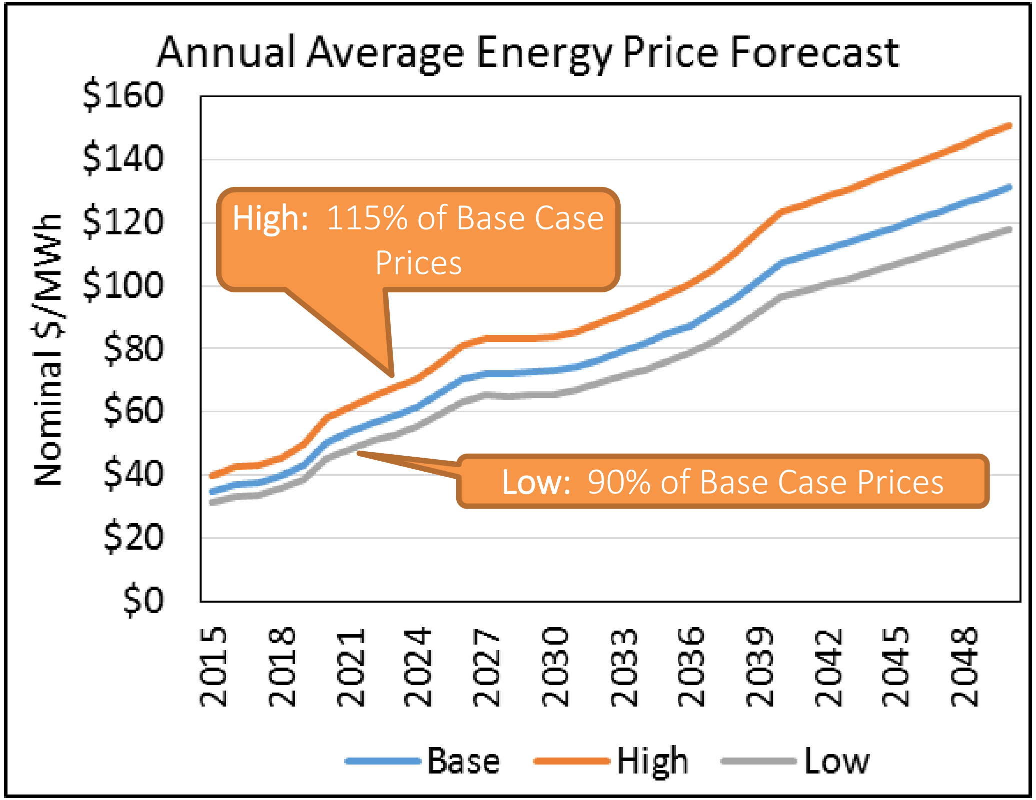


Figure 3.2. Two alternative energy market price futures were developed to test the sensitivity of program costs to energy market values.

The "**High**" energy price forecast represents 115% of the "Base" case in any given year.

The "**Low**" energy price forecast represents 90% of the "Base" case in any given year.

Capacity prices

Capacity price forecast developed by Staff as part of the BCA Order through 2035; translated to UCAP; held constant at 2035 levels in real $ terms in 2036 and thereafter.

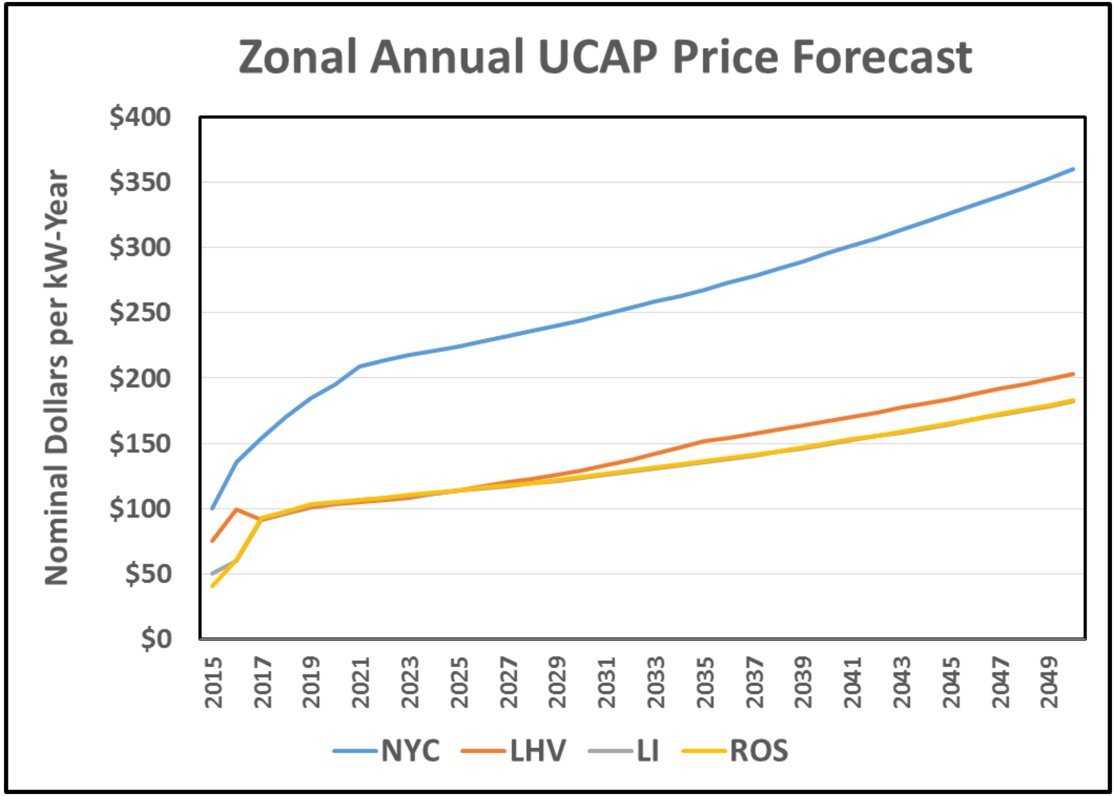
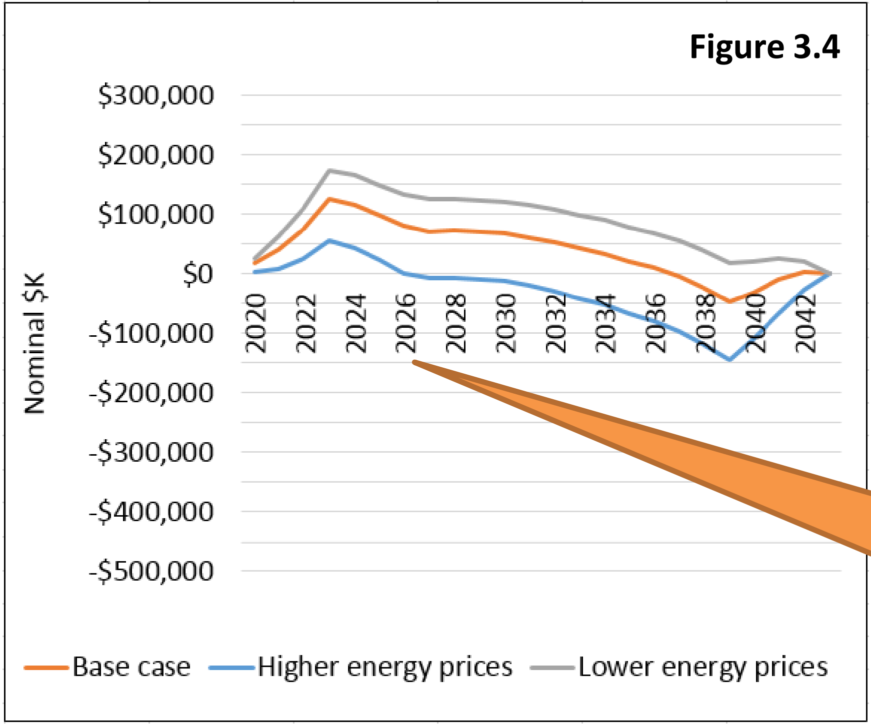


Figure 3.3

Tier 1 Gross Program Costs to 2023 – Energy Prices



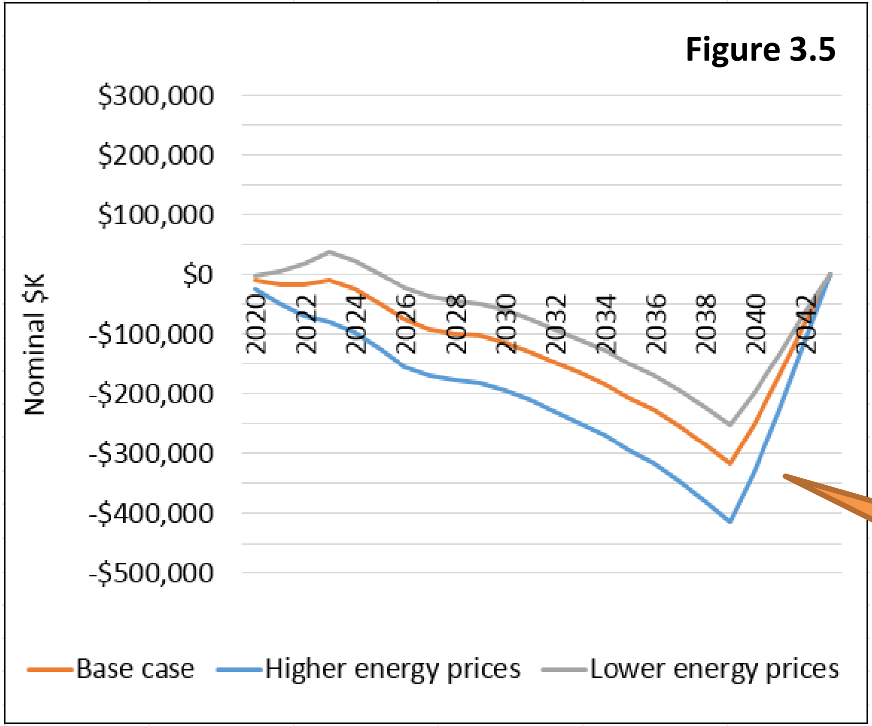
	Net present value	Bill impact in 2023
Higher energy prices	$102 M benefit	0.20%
Base case	**$453 M cost**	**0.45%**
Lower energy prices	$823 M cost	0.62%

If energy prices rise by more than expected in the (conservative) base case assumptions, upfront costs are lower in the early years, and costs turn into benefits for consumers by the mid-2020s, resulting in an overall lifetime benefit even before carbon or other benefits are considered.

All data reflects modeling estimates. Only incremental CES generation (2020-2023) is shown. See Appendix A for methodology.

NEW YORK STATE OF OPPORTUNITY.

Tier 1 Net Program Costs to 2023 – Energy Prices



	Net present value
Higher energy prices	$1.34 B benefit
Base case	**$787 M benefit**
Lower energy prices	$418 M benefit

Benefits reduce as installations deployed to 2023 reach the end of their life

Carbon benefits turn costs into net benefits in all three scenarios

All data reflects modeling estimates. Only incremental CES generation (2020-2023) is shown. See Appendix A for methodology.

Energy Prices: Observations

The following high-level observations are presented:

1. Higher energy prices are expected to result in lower Tier 1 program costs, since program payments would need to compensate for a smaller revenue gap between commodity revenue and required project returns. Equally, lower energy prices would translate to higher program costs. This would certainly be the case for PPA structures, where generators receive a fixed total amount of compensation per unit of energy: the risk of energy price fluctuations is borne by LSE customers, who therefore are exposed to both the upside of higher energy prices (in terms of lower CES costs) and the downside of lower energy prices (in terms of higher CES costs).
2. This outcome would be somewhat less predictable for fixed-REC procurement structures. While LSE customers do not bear any energy price risk for an individual fixed-REC project (the project developer does), any long-term deviation in energy prices from the initial forecast does also translate into a change in program cost if fixed RECs are used: for instance, if energy prices are lower than initially forecast over a prolonged period of time, investors will likely lower their energy price expectations, and will thus start bidding new projects at a higher REC price than they would have done under the original price forecast; accordingly, program costs would end up higher than initially forecast.

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Energy Prices: Observations (cont'd)

3. It should be stressed that while PPA structures may expose LSE customers to a greater level of commodity price risk, they do provide access to lower finance costs; this cost advantage provides LSE customers with significant cost savings that would be realized in all energy price scenarios, and thus act as a "buffer" against greater exposure to energy prices.
4. Finally, it should be noted that the impact of energy prices on CES costs should not be seen in isolation from the impact of energy prices on customers' total bills. While lower energy prices would result in higher CES costs, this would be offset by the benefit customers would see as a result of lower wholesale prices. This effect is explored further in Section 9.

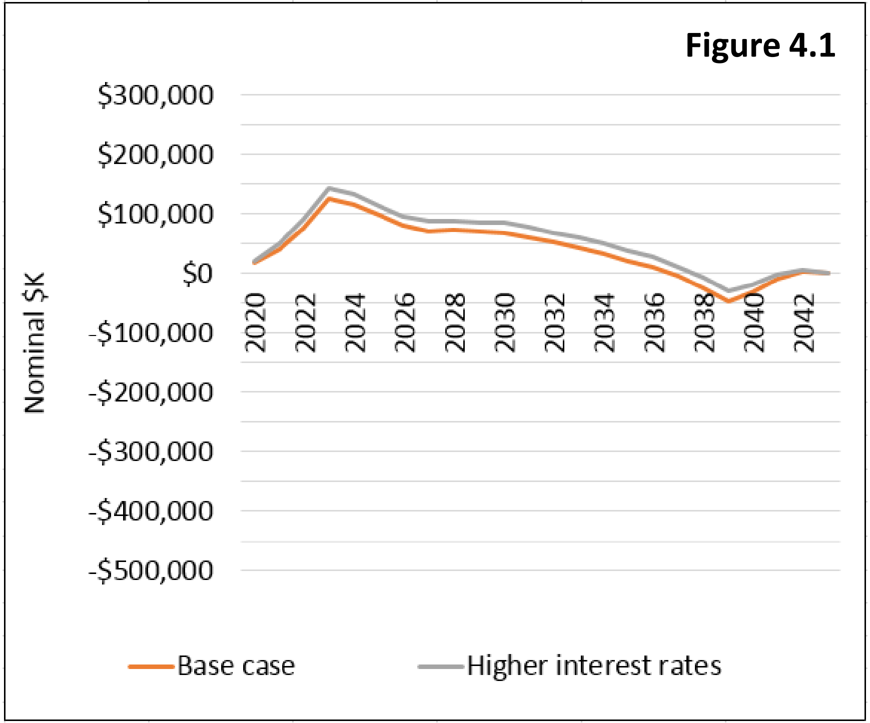
Section 4 – Tier 1: Interest Rates

Introduction

With little or no fuel costs to account for, renewable energy project finance is dominated by determining the structure and cost of long-term financing for the initial capital requirement. The analysis assumes that around 35-70% of the cost of a renewables project (depending on the technology) is financed with debt. The cost of debt in turn depends on interest rates. With interest rates currently at historic lows, the Study assesses a sensitivity where interest rates are assumed to be 1.25% (125 base points) above current levels.

See Appendix A.4 for further details on finance assumptions.

Tier 1 Gross Program Costs to 2023 – Interest Rates

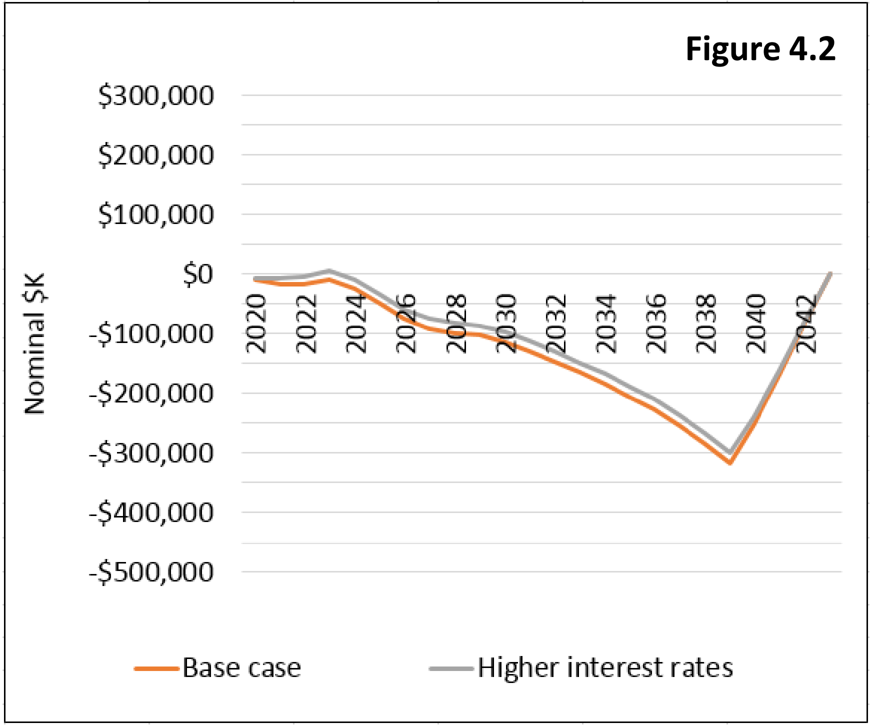


	Net present value	Bill impact in 2023
Base case	**$453 M cost**	**0.45%**
Higher interest rates	$570 M cost	0.51%

The impact of a higher interest rate assumption appears relatively limited.

All data reflects modeling estimates. Only incremental CES generation (2020-2023) is shown. See Appendix A for methodology.

Tier 1 Net Program Costs to 2023 – Interest Rates



	Net present value
Base case	**$787 M benefit**
Higher interest rates	$671 M benefit

The impact of a higher interest rate assumption appears relatively limited.

All data reflects modeling estimates. Only incremental CES generation (2020-2023) is shown. See Appendix A for methodology.

Interest Rates: Observations

The following high-level observation is presented:

1. Although the interest rate sensitivity examined here assumes a significant increase in interest rates of 1.25 percentage points, the analysis suggests that the effect on overall cost is relatively moderate. Debt finance constitutes only a proportion of overall project finance, and when taken in combination with other relevant factors, such as the cost of equity finance and overall technology cost, the impact of an increase in debt cost is diluted.

Section 5 – Tier 1: Technology Costs

Introduction

The base case projection as discussed in Section 2 suggests that the main large-scale technology to be deployed between now and 2023 continues to be land-based wind. This Section tests this result by applying a sensitivity that assumes fewer reductions in the cost of land-based wind installations than expected in the base case.

Under this "higher cost" scenario, it was assumed that:

- Average hub heights of wind turbines increase less in future years than assumed in the base case, and
- No other technological advancement that could reduce costs takes place (whereas the base case does assume some further technological advancement).

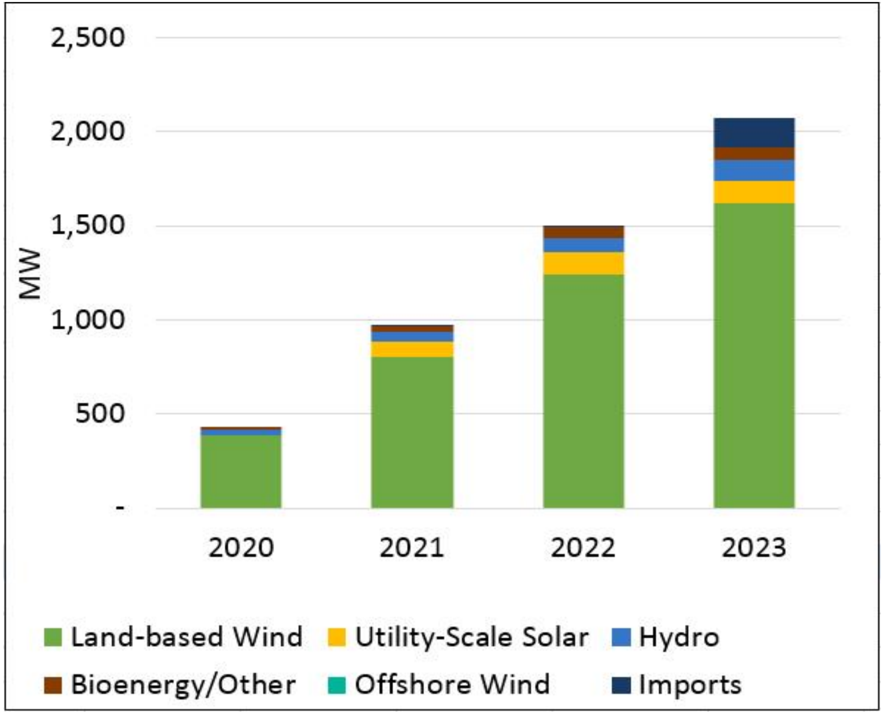
Both the base and the sensitivity assumptions are described in more detail in Appendix A.2.

This Section illustrates the possible impact on both technology mix and costs resulting from a higher technology cost assumption for land-based wind.

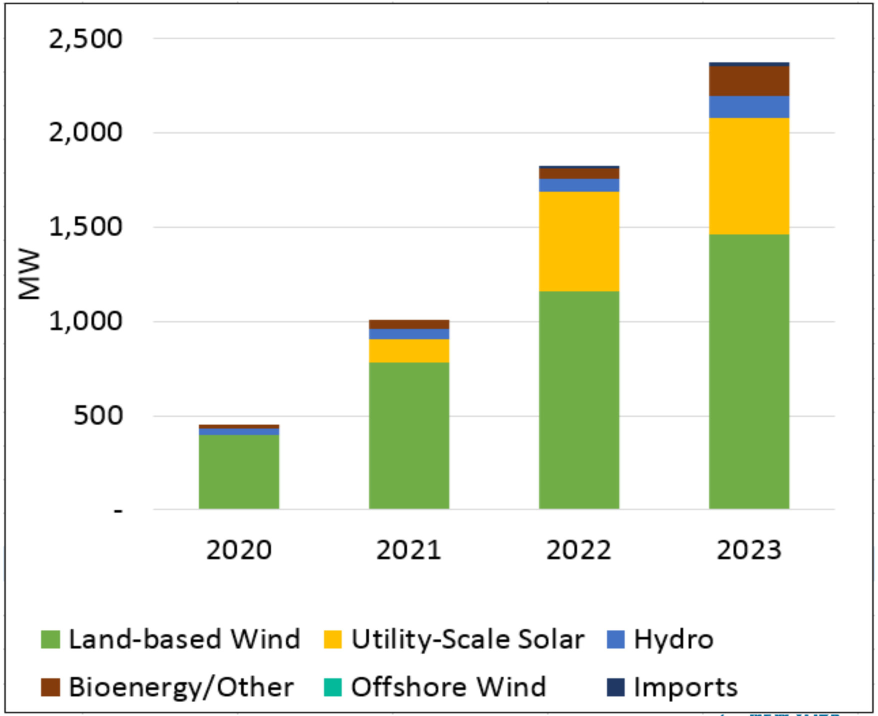
Capacity Deployed – Technology Cost

Figure 5.1

Base



Higher LBW



Data reflects adoption scenarios, not a commitment to a particular technology mix. Only incremental CES uptake (2020-2023) is shown. See Appendix A for methodology.

NEW YORK STATE OF OPPORTUNITY.

Capacity Deployed – Technology Cost

Table 5.1

Base

Incremental

MW	2020	2021	2022	2023
Land-based Wind	383	418	438	377
Utility-Scale Solar	-	86	38	-
Hydro	31	21	22	39
Bioenergy/other	20	6	31	5
Offshore Wind	-	-	-	-
Imports	-	4	4	152

Cumulative

MW	2020	2021	2022	2023
Land-based Wind	383	802	1,240	1,617
Utility-Scale Solar	-	86	124	124
Hydro	31	51	73	112
Bioenergy/other	20	25	56	61
Offshore Wind	-	-	-	-
Imports	-	4	8	159

Higher LBW

Incremental

MW	2020	2021	2022	2023
Land-based Wind	398	386	377	303
Utility-Scale Solar	-	124	400	94
Hydro	34	15	22	40
Bioenergy/other	18	34	6	99
Offshore Wind	-	-	-	-
Imports	-	-	10	11

Cumulative

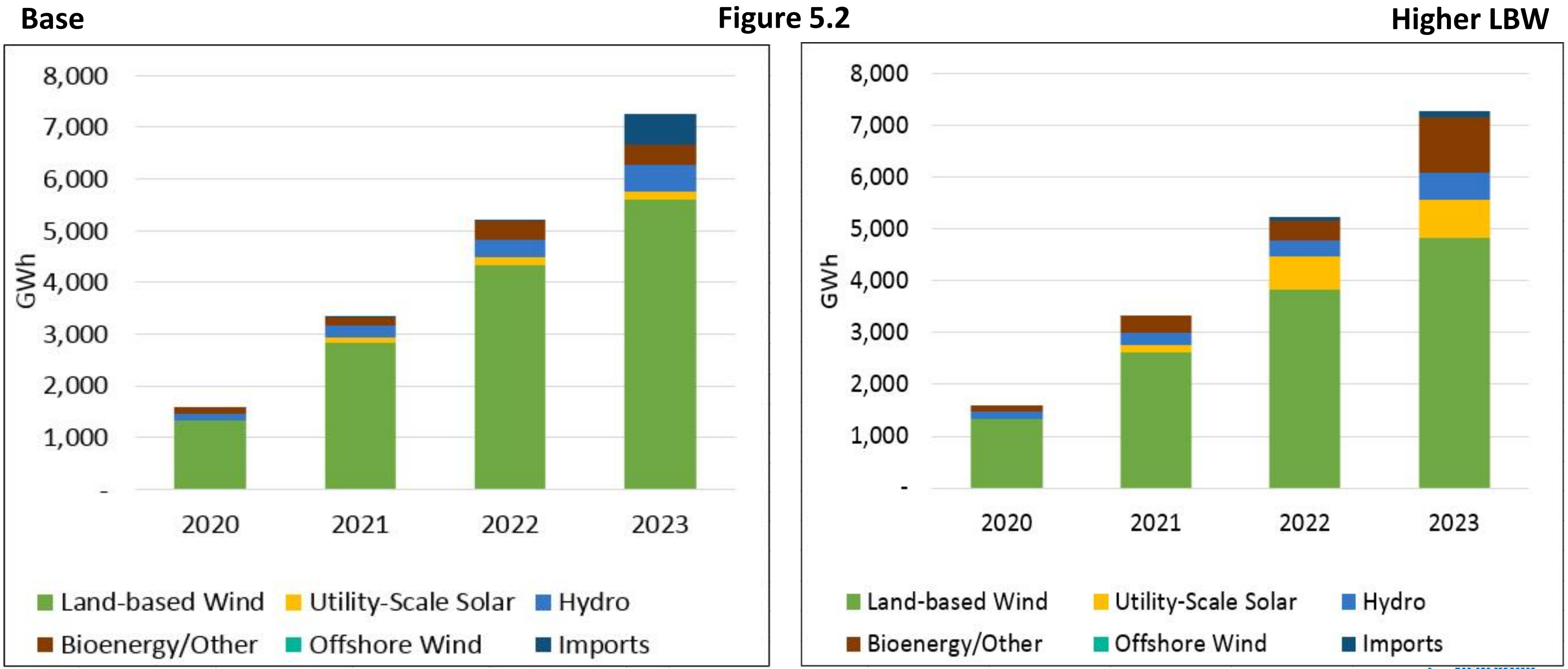
MW	2020	2021	2022	2023
Land-based Wind	398	784	1,161	1,464
Utility-Scale Solar	-	124	524	619
Hydro	34	50	71	112
Bioenergy/other	18	52	58	157
Offshore Wind	-	-	-	-
Imports	-	-	10	21

Base case figures may differ somewhat from those in Section 2 because only incremental CES uptake (from 2020) is reflected. Data reflects adoption scenarios, not a commitment to a particular technology mix. See Appendix A for methodology.

NEW YORK STATE OF OPPORTUNITY.

Generation – Technology Cost

Figure 5.2



Data reflects adoption scenarios, not a commitment to a particular technology mix. Only incremental CES uptake (2020-2023) is shown. See Appendix A for methodology.

NEW YORK STATE OF OPPORTUNITY.

Generation – Technology Cost

Table 5.2

Incremental

Base

GWh	2020	2021	2022	2023
Land-based Wind	1,333	1,487	1,510	1,272
Utility-Scale Solar	-	105	46	-
Hydro	138	93	100	180
Bioenergy/other	121	35	214	28
Offshore Wind	-	-	-	-
Imports	-	22	21	562

Higher LBW

GWh	2020	2021	2022	2023
Land-based Wind	1,333	1,279	1,219	993
Utility-Scale Solar	-	151	483	115
Hydro	150	77	100	185
Bioenergy/other	109	235	34	690
Offshore Wind	-	-	-	-
Imports	-	-	56	58

Cumulative

Base

GWh	2020	2021	2022	2023
Land-based Wind	1,333	2,819	4,330	5,601
Utility-Scale Solar	-	105	150	150
Hydro	138	231	332	512
Bioenergy/other	121	156	370	398
Offshore Wind	-	-	-	-
Imports	-	22	43	605

Higher LBW

GWh	2020	2021	2022	2023
Land-based Wind	1,333	2,612	3,831	4,824
Utility-Scale Solar	-	151	634	749
Hydro	150	226	326	512
Bioenergy/other	109	344	378	1,068
Offshore Wind	-	-	-	-
Imports	-	-	56	114

Base case figures may differ somewhat from those in Section 2 because only incremental CES uptake (from 2020) is reflected. Data reflects adoption scenarios, not a commitment to a particular technology mix. See Appendix A for methodology.

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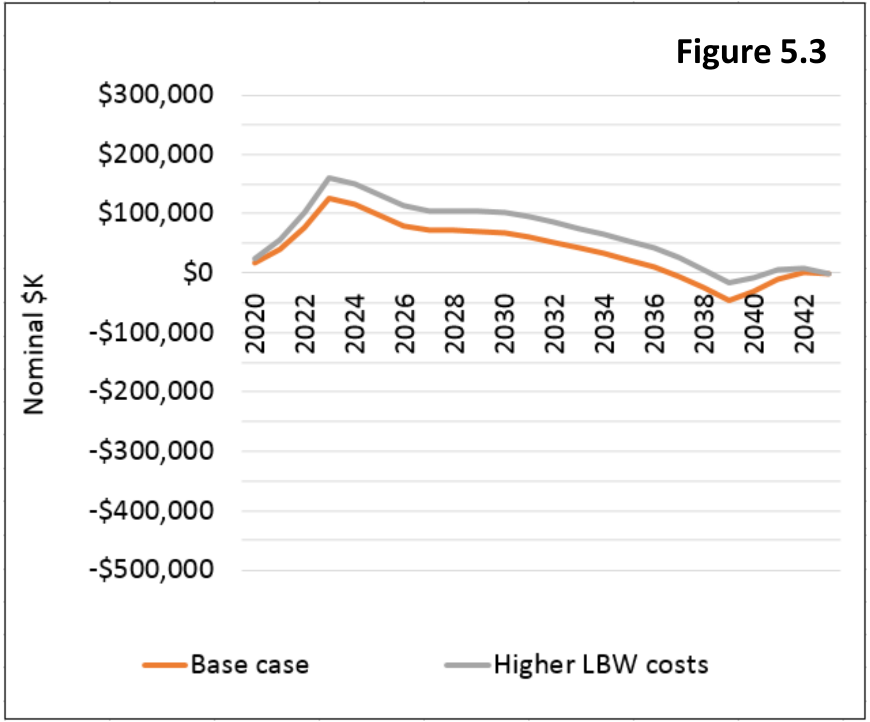
Tier 1 Gross Program Costs to 2023 – Technology Cost

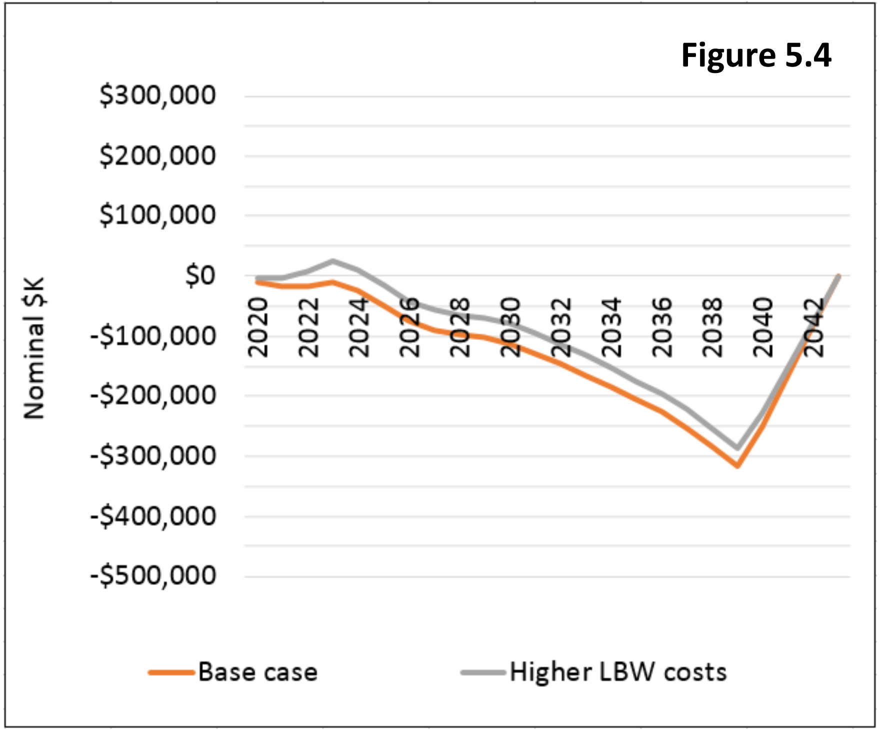


All data reflects modeling estimates. Only incremental CES uptake (2020-2023) is shown. See Appendix A for methodology.

	Net present value	Bill impact in 2023
Base case	**$453 M cost**	**0.45%**
Higher LBW cost	$684 M cost	0.58%

As expected, overall costs increase if LBW technology costs do not reduce as much as expected over the coming years. However, the analysis suggests that the costs of other technologies, in particular utility-scale solar, are close to those of LBW, which helps to contain costs by allowing more solar to be deployed.

Tier 1 Net Program Costs to 2023 – Technology Cost



All data reflects modeling estimates. Only incremental CES uptake (2020-2023) is shown. See Appendix A for methodology.

	Net present value
Base case	**$787 M benefit**
Higher LBW cost	$556 M benefit

Technology Cost: Observations

The following high-level observations are presented:

1. Over the period to 2023, land-based wind constitutes the dominant technology under base case assumptions. However, when assuming a lower degree of technology cost improvements for land-based wind, the analysis suggests that the cost of in particular utility-scale solar PV is rapidly approaching that of wind turbines: the “High-LBW” sensitivity sees a significant shift from wind to solar deployment, with only a moderate increase in overall cost.
2. This suggests that a technology-neutral approach to designing Tier 1, as proposed, will allow a portfolio of large-scale renewables technologies to compete effectively, ensuring both that any risk of over-reliance on a single technology is mitigated, and that competition between technologies will help deliver the 2030 target in the most cost-effective way.

Section 6 – Tier 1: System Load

NEW YORK STATE OF OPPORTUNITY.

Introduction

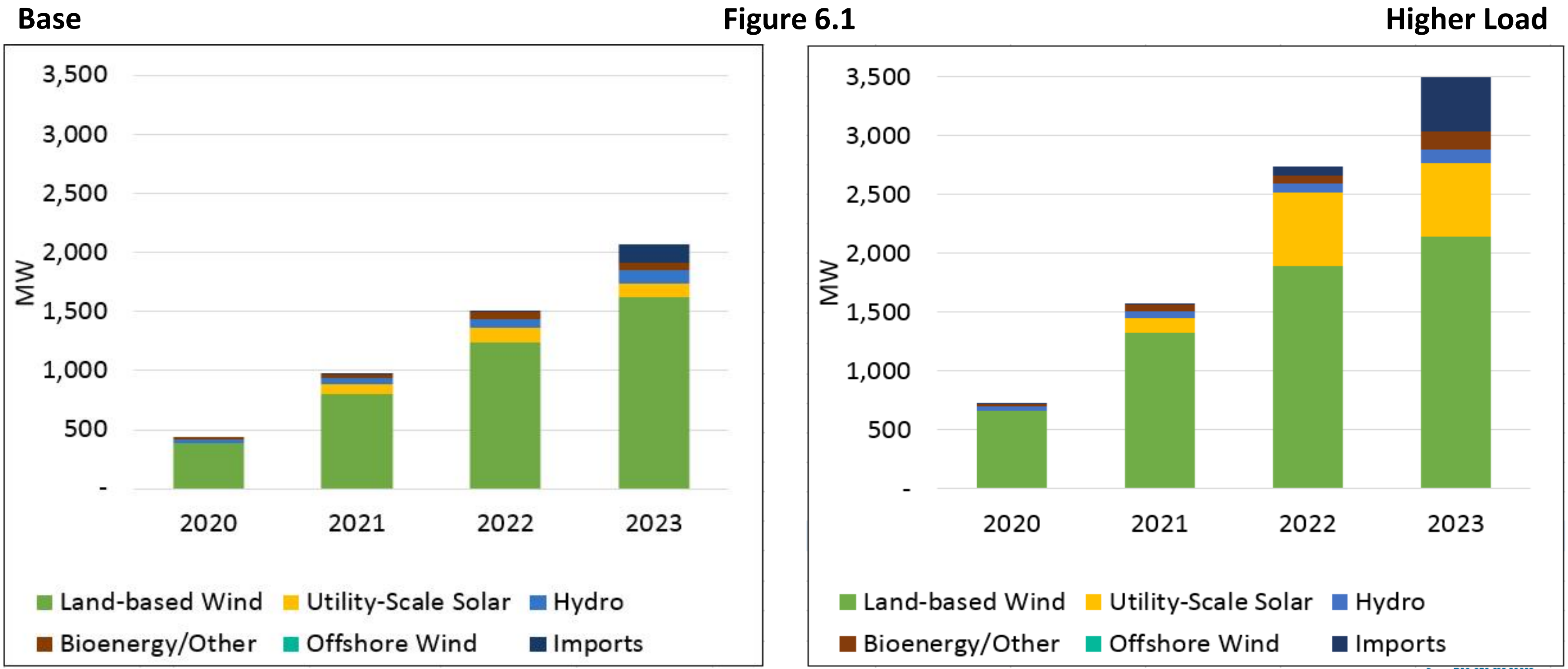
The high load sensitivity presented here assumes that total electricity generation (“load”) in 2030 is around 22,000 GWh higher than in the base case, resulting in an additional level of renewable electricity needed of around 11,000 GWh in order to reach the 2030 50% renewable electricity target. No assumption is made as to the drivers behind a different system load – this could be as a result of higher electricity consumption, for instance for electric vehicles or heat pumps, or lower levels of energy efficiency than assumed in the base case, or other long-term behavioral changes.

For the purpose of the sensitivity presented here, this translates to an additional level of incremental renewable electricity of around 1,000 GWh in each of the years from 2020.

The following pages show a comparison of the modeled mix of technologies and annual costs between the base case and the high load case.

Capacity Deployed – System Load

Figure 6.1



Data reflects adoption scenarios, not a commitment to a particular technology mix. Only incremental CES uptake (2020-2023) is shown. See Appendix A for methodology.

Capacity Deployed – System Load

Table 6.1

Incremental

Base

MW	2020	2021	2022	2023
Land-based Wind	383	418	438	377
Utility-Scale Solar	-	86	38	-
Hydro	31	21	22	39
Bioenergy/other	20	6	31	5
Offshore Wind	-	-	-	-
Imports	-	4	4	152

Higher system load

MW	2020	2021	2022	2023
Land-based Wind	664	663	562	250
Utility-Scale Solar	-	126	507	-
Hydro	37	19	19	41
Bioenergy/other	22	35	6	83
Offshore Wind	-	-	-	-
Imports	4	-	77	382

Cumulative

Base

MW	2020	2021	2022	2023
Land-based Wind	383	802	1,240	1,617
Utility-Scale Solar	-	86	124	124
Hydro	31	51	73	112
Bioenergy/other	20	25	56	61
Offshore Wind	-	-	-	-
Imports	-	4	8	159

Higher system load

MW	2020	2021	2022	2023
Land-based Wind	664	1,327	1,889	2,139
Utility-Scale Solar	-	126	632	632
Hydro	37	55	74	115
Bioenergy/other	22	56	62	145
Offshore Wind	-	-	-	-
Imports	4	4	81	463

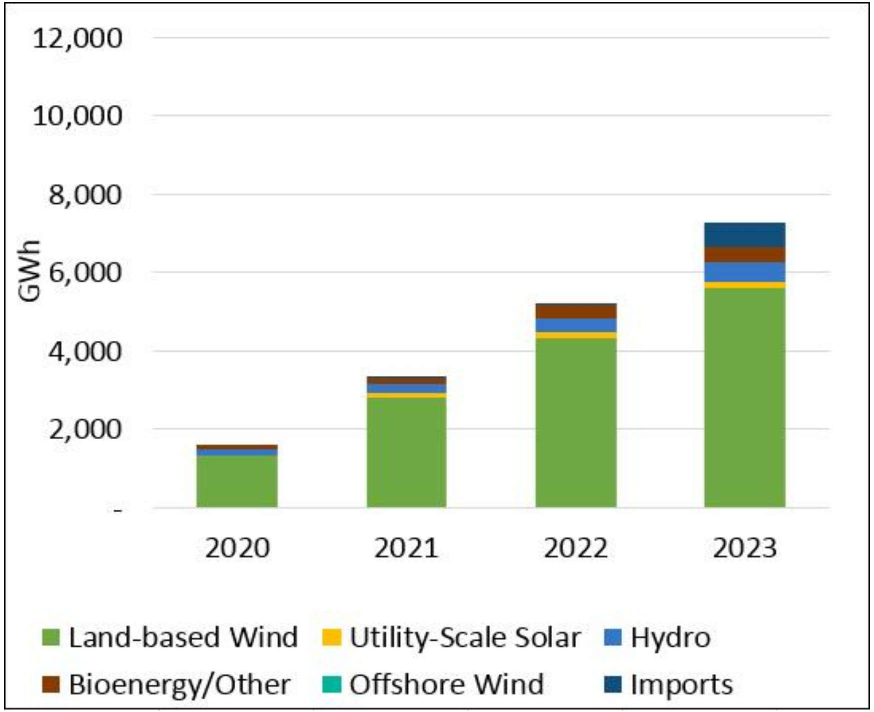
Base case figures may differ somewhat from those in Section 2 because only incremental CES uptake (from 2020) is reflected. Data reflects adoption scenarios, not a commitment to a particular technology mix. See Appendix A for methodology.

NEW YORK STATE OF OPPORTUNITY.

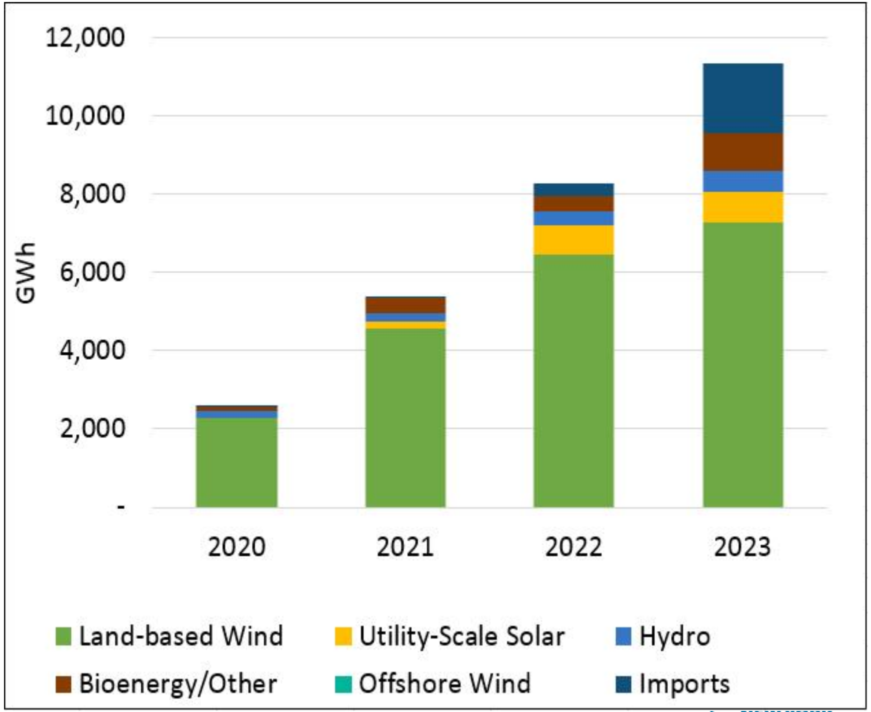
Generation – System Load

Figure 6.2

Base



Higher Load



Data reflects adoption scenarios, not a commitment to a particular technology mix. Only incremental CES uptake (2020-2023) is shown. See Appendix A for methodology.

NEW YORK STATE OF OPPORTUNITY.

Generation – System Load

Base **Table 6.2** **Higher Load**

Incremental

Base:

GWh	2020	2021	2022	2023
Land-based Wind	1,333	1,487	1,510	1,272
Utility-Scale Solar	-	105	46	-
Hydro	138	93	100	180
Bioenergy/other	121	35	214	28
Offshore Wind	-	-	-	-
Imports	-	22	21	562

Higher Load:

GWh	2020	2021	2022	2023
Land-based Wind	2,298	2,280	1,878	836
Utility-Scale Solar	-	153	613	-
Hydro	157	88	91	189
Bioenergy/other	132	238	34	580
Offshore Wind	-	-	-	-
Imports	22	-	292	1,455

Cumulative

Base:

GWh	2020	2021	2022	2023
Land-based Wind	1,333	2,819	4,330	5,601
Utility-Scale Solar	-	105	150	150
Hydro	138	231	332	512
Bioenergy/other	121	156	370	398
Offshore Wind	-	-	-	-
Imports	-	22	43	605

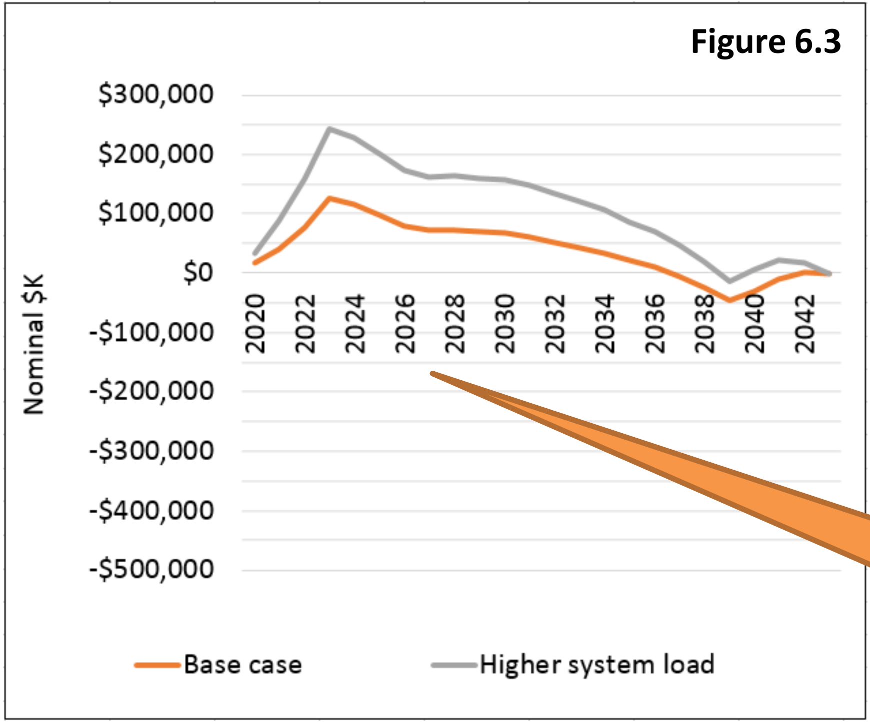
Higher Load:

GWh	2020	2021	2022	2023
Land-based Wind	2,298	4,578	6,457	7,293
Utility-Scale Solar	-	153	766	766
Hydro	157	245	336	525
Bioenergy/other	132	371	405	985
Offshore Wind	-	-	-	-
Imports	22	22	314	1,769

Base case figures may differ somewhat from those in Section 2 because only incremental CES uptake (from 2020) is reflected. Data reflects adoption scenarios, not a commitment to a particular technology mix. See Appendix A for methodology.

NEW YORK STATE OF OPPORTUNITY.

Tier 1 Gross Program Costs to 2023 – System Load



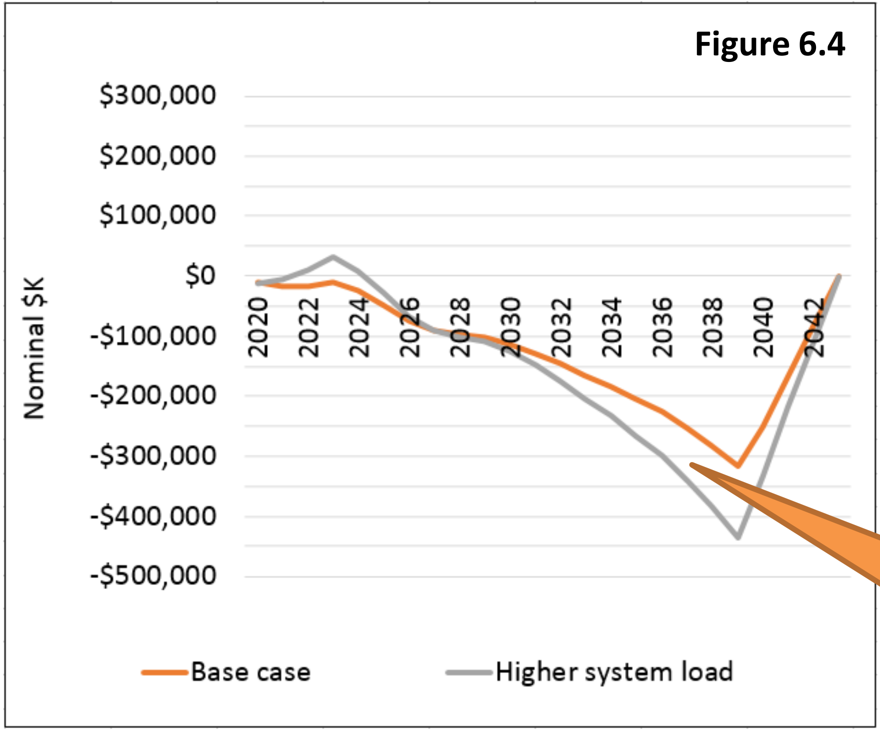
	Net present value	Bill impact in 2023
Base case	**$453 M cost**	**0.45%**
Higher system load	$1.07 B cost	0.87%

While installing more renewables would also result in higher upfront costs, it would also deliver higher environmental (carbon) benefits, as shown on the next page.

All data reflects modeling estimates. Only incremental CES uptake (2020-2023) is shown. See Appendix A for methodology.

NEW YORK STATE OF OPPORTUNITY.

Tier 1 Net Program Costs to 2023 – System Load



All data reflects modeling estimates. Only incremental CES uptake (2020-2023) is shown. See Appendix A for methodology.

	Net present value
Base case	**$787 M benefit**
Higher system load	$872 M benefit

As gross program costs decline during later years (mainly as a result of rising energy prices) and carbon benefits increase, the net benefits increase as well. This effect is amplified in the high load case where more renewables are installed.

System Load: Observations

The following high-level observations are presented:

1. Under the high load scenario, significant increases in deployment are observed in particular for land-based wind and utility-scale solar. In addition, a greater amount of imported renewables is added to the mix.
2. The high load sensitivity shows significantly higher costs: lifetime gross program costs (NPV) double from less than half a billion dollars to over a billion over lifetime of deployment to 2023. This emphasizes the importance of reducing the system load as a way of managing the overall cost of the CES.

Section 7 –
Tier 1: Federal Tax Credits

Introduction

Federal renewable energy tax incentive programs, including the Production Tax Credit (PTC) and the Investment Tax Credit (ITC) reduce the revenue required to meet investor hurdle rates of return. The PTC represents a 10-year production incentive realized as a tax credit for each MWh of generation. ITC represents a tax credit which is calculated as a percentage of eligible investment.

The eligibility requirements for PTC and ITC in this analysis were modeled based on the recently enacted Protecting Americans from Tax Hikes Act of 2015 (PATH) and the Consolidated Appropriations Act of 2016 (CAA).

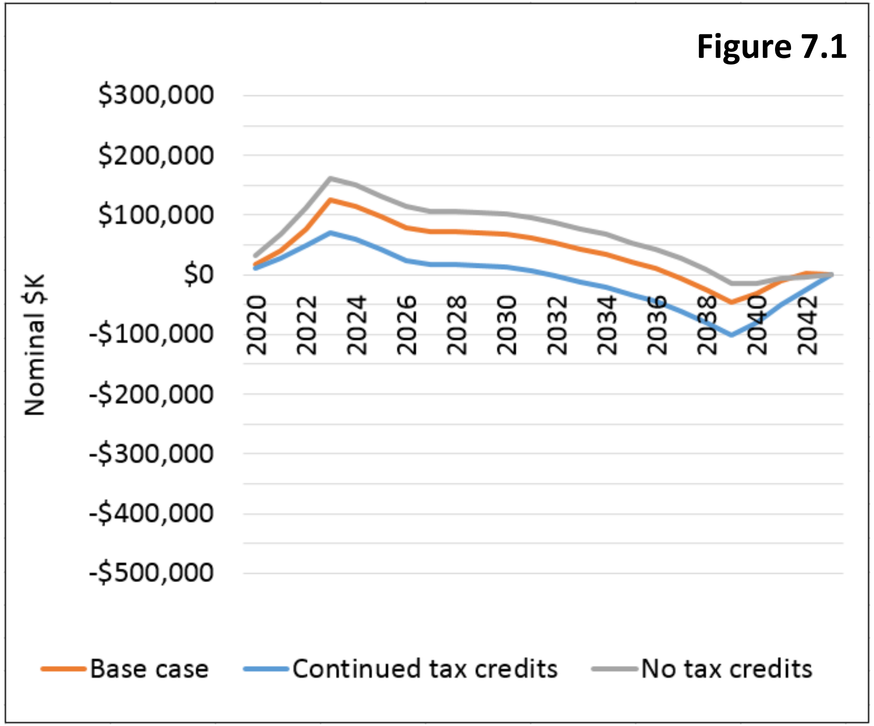
- For non-wind resources, the PTC was extended by a year to December 31, 2016.
- For wind resources, the PTC was extended through 2016, followed by a phase-out to 80% of the credit value for 2017, 60% for 2018 and 40% for 2019, and 0% thereafter, for all wind resources commencing construction before January 1, 2020. The CAA also extended the ability of wind facility owners to elect the Investment Tax Credit in lieu of PTC under current law.
- For utility-scale solar PV, the full 30% ITC was extended from December 31, 2016 to December 31, 2019, followed by a phase-out pathway to 26% in 2020 and 22% in 2021. Thereafter, the ITC would revert to the current statutory levels of 10% for corporate taxpayers and 0% for individuals.

Introduction (cont'd)

Base case scenarios in this Study reflect the current federal tax credits regime as outlined above. This Section compares the base case to two scenarios:

- The "No tax credits" scenario analyzes hypothetical costs if the tax credits were absent.
- The "Continued tax credits" scenario assumes that PTC and ITC are available until 2023 at their current peak level instead of phasing down.

Tier 1 Gross Program Costs to 2023 – Federal Tax Credits



	Net present value	Bill impact in 2023
Continued tax credits	$87 M cost	0.25%
Base case	**$453 M cost**	**0.45%**
No tax credits	$704 M cost	0.58%

The availability of the latest round of federal tax credits offers NYS the opportunity to realize a $250 M savings (NPV) on CES deployment until 2023

If tax credits were to remain in place at the current level until 2023, the savings would be even more significant

All data reflects modeling estimates. Only incremental CES generation (2020-2023) is shown. See Appendix A for methodology.

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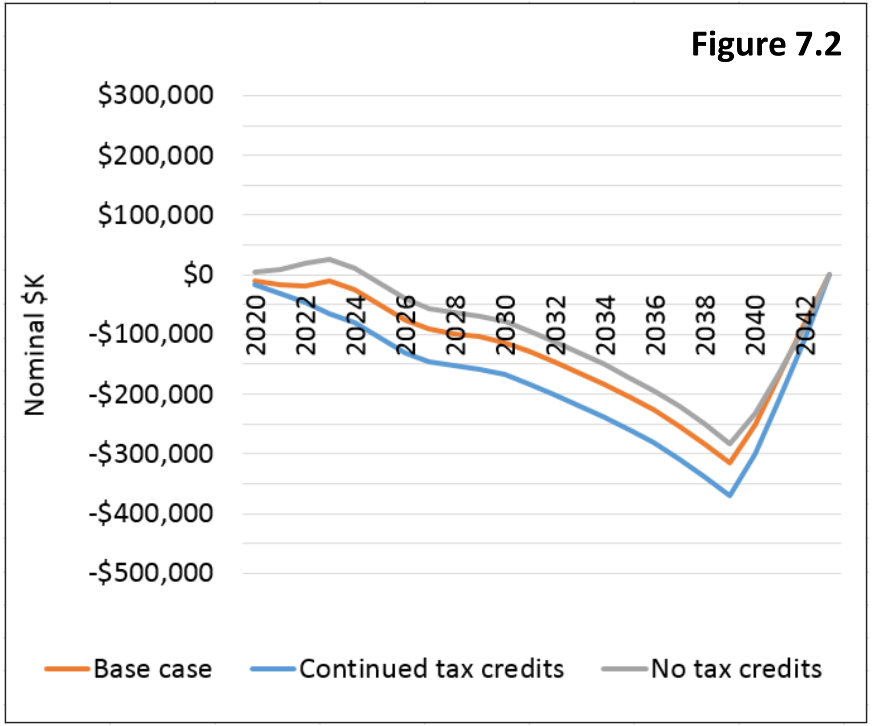
Tier 1 Net Program Costs to 2023 – Federal Tax Credits



	Net present value
Continued tax credits	$1.15 B benefit
Base case	**$787 M benefit**
No tax credits	$537 M benefit

All data reflects modeling estimates. Only incremental CES generation (2020-2023) is shown. See Appendix A for methodology.

Federal Tax Credits: Observations

The following high-level observations are presented:

1. The “no tax credits” scenario is a hypothetical one, since there the availability of tax credits until 2023 represents a legal commitment. However, it demonstrates the significance of these tax credits, and adds another argument to the urgency of taking forward the CES program in the near term while the tax credits continue to be available.
2. While the tax credits are currently designed to ramp down over the period to 2023, the “continued tax credits” scenario illustrates that significant additional value would be available if tax credits were maintained at current levels.

Section 8 – Tiers 2 and 3

Introduction – Tier 2

Under current arrangements, RECs from existing renewable electricity generation accrue to New York State and thus count towards New York State's renewable energy targets while covered by RPS Main Tier contracts. As projects reach the end of these contracts, they would be at liberty to export generation to other markets depending on the revenue opportunities available elsewhere. The Staff White Paper proposes Tier 2 as a policy to ensure that existing renewable energy generation continues to be made available within New York State, thus counting towards delivery of the 2030 50% target.

Tier 2A focuses on such renewable energy generation that would be eligible towards RPS mandates outside New York State. Tier 2B covers generation that may not be eligible in other territories or otherwise has limited export opportunities.

Estimated Tier 2A and 2B quantity levels are shown in Figure 8.1. While the Tier 2B quantity is not expected to change over time, the Tier 2A generation levels would increase as further Main Tier contracts reach the end of their term.

As throughout this Study, estimates are provided through to 2023. Longer-term projections to 2030 are included in Appendix C.

Introduction – Tier 2 (cont'd)

Program costs for Tier 2A have been estimated on the basis of payments that would be required to bring revenue opportunities within New York State for Tier 2A generators on a level playing field with those that would be available by exporting. Specifically, the analysis estimates available revenue in New England, as being the most likely export market. Revenue in such other territories is adjusted for any cost and risk differences associated with export.

The analysis assumes that revenue outside New York State would be available on a spot market basis. Program costs have been assessed using two approaches:

- The first approach assumes a similar spot market revenue arrangement within Tier 2A in New York State, thus providing a similar level of revenue risk as would be attached to export; or
- Tier 2A revenue is made available through PPA arrangements, thus providing a lower level of revenue risk. The duration of all PPAs is assumed to end in 2030, thus covering a decreasing length of time for each successive vintage.

Base case program cost estimates are provided based on a 50%/50% mix of the two approaches, with scenarios reflecting 100% spot price or 100% PPA provided as sensitivities. Energy price sensitivities are provided as well.

Introduction – Tier 2 (cont'd)

For Tier 2B program costs have been estimated based on a range of costs informed by experience in other states for similar resource classes, resulting in an assumed range of payments **$1.50-$3.00** (nominal) per MWh. Again, the base case reflects the mid-point (or **$2.25** per MWh) of the range of costs.

For Tier 2A, program costs are also shown after application of the societal carbon benefit of Tier 2A generation. As regards Tier 2B, Appendix A of the White Paper explains the uncertainties around the extent to which Tier 2B installations may currently or in future have access to realistic export opportunities. Given these uncertainties, the conservative approach was taken not to present the carbon value associated with generation from these installations as a CES benefit. Nevertheless, it is important to note that the Tier 2B policy will contribute towards continuing to avoid all or part of these carbon emissions in New York State, estimated at approximately **8.3 million tons of carbon avoided** per year, with a carbon value of around **$340M** (in 2017).

See Appendix B for further details about the Tier 2 methodology and Appendix A.7 for notes about carbon value methodology.

Tier 3

The White Paper proposes Tier 3 as a policy to ensure that existing nuclear facilities continue to operate despite current low electricity prices, using "Zero Emission Credit" (ZEC) payments. The likely costs associated with ZEC payments for nuclear installations have been analyzed based on low and high assumptions of the cost of generation of nuclear power and future energy prices. The analysis estimates costs in the following ranges:

Lifetime NPV	To 2023 – Gross Program Costs	To 2023 – Net Program Costs
Tier 3	**Cost** of $59 M - $658 M	**Benefit** of $928 M - $1.08 B

The above cost estimates are intentionally provided as broad ranges. As stated in the White Paper, ZEC premium levels will be determined based on "open book" assessment of the costs of nuclear generation, working with the operators of the nuclear facilities in question. This Study refrains from publishing detailed estimates of annual costs or payments per unit of energy to avoid prejudicing this process.

See Section 10 for notes in respect of the economic benefits of maintaining the nuclear facilities eligible for Tier 3.

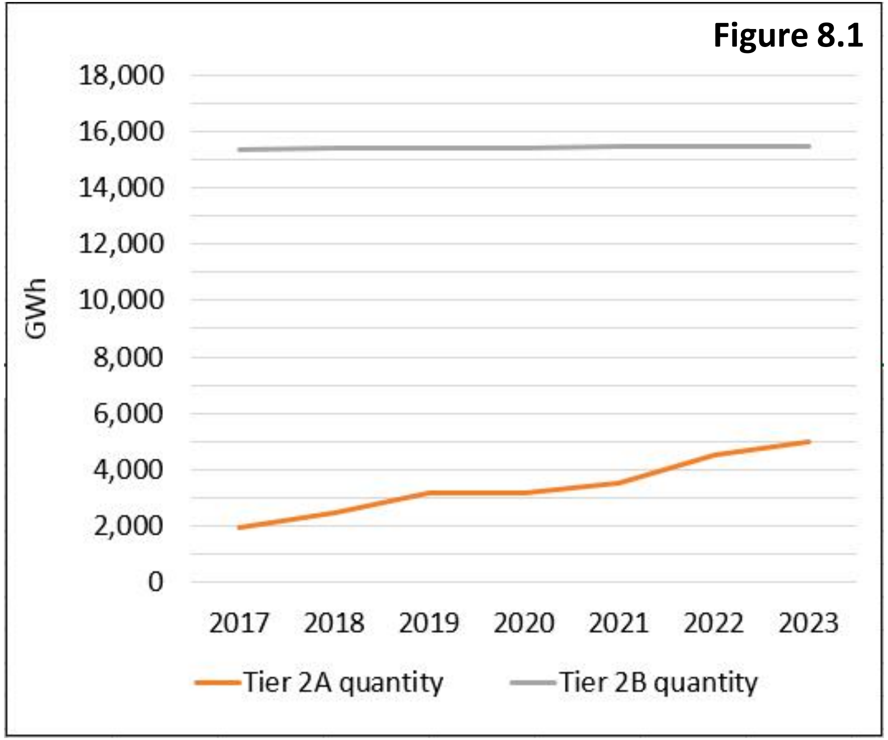
Tiers 2 and 3 - Sensitivities

The analysis for Tiers 2A, 2B and 3 includes the following range of scenarios:

- For Tier 2A, the range of scenarios includes:
  - A range of procurement costs, set at 100% PPA, 100% spot price, and a 50%/50% mix between the two (as the base case); and
  - High and low energy price sensitivities (see Appendix A.3 for details).
- For Tier 2B, the scenarios include the upper and lower bounds of the assumed compensation levels, and a mid point as the base case.
- Tier 3 has been examined under:
  - Procurement cost scenarios, covering a high cost and a low cost assumption, as well as the mid point as the base case; and
  - Energy price scenarios (see Appendix A.3).

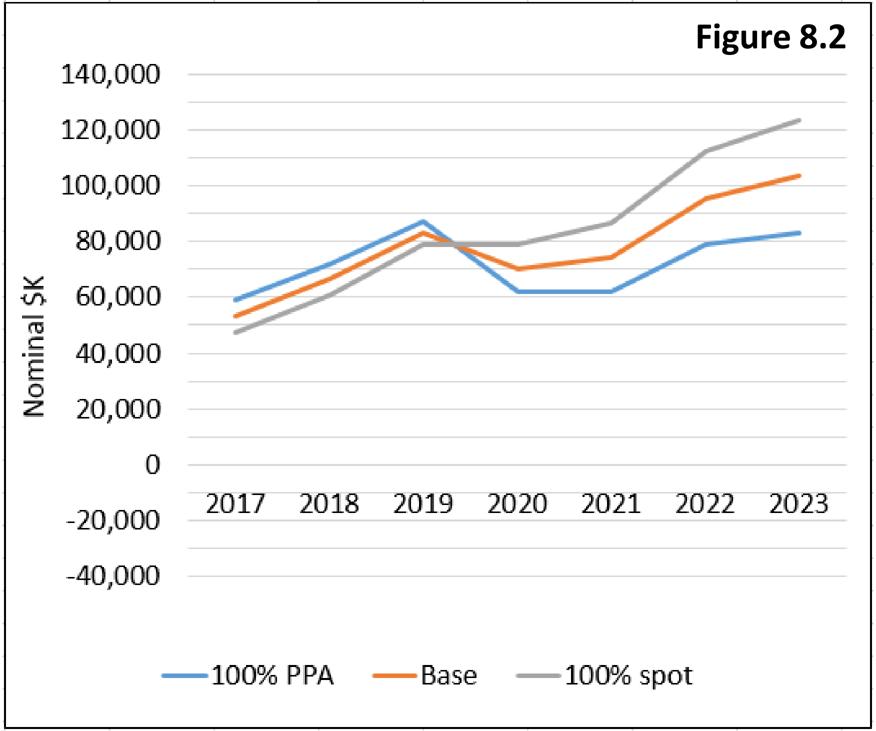
As discussed throughout the preceding Sections, the analysis for Tier 1 includes examination of a number of other cost drivers: interest rates, system load, technology cost and federal tax credits. These factors apply to new-build installations and thus are not relevant to the analysis of Tiers 2 and 3. Where the impact of these cost drivers is examined across the total CES costs in this Study, Tier 2 and 3 components of such cost indicators reflect base case assumptions.

Tier 2 Target Levels



All data reflects modeling estimates. See Appendix B for methodology.

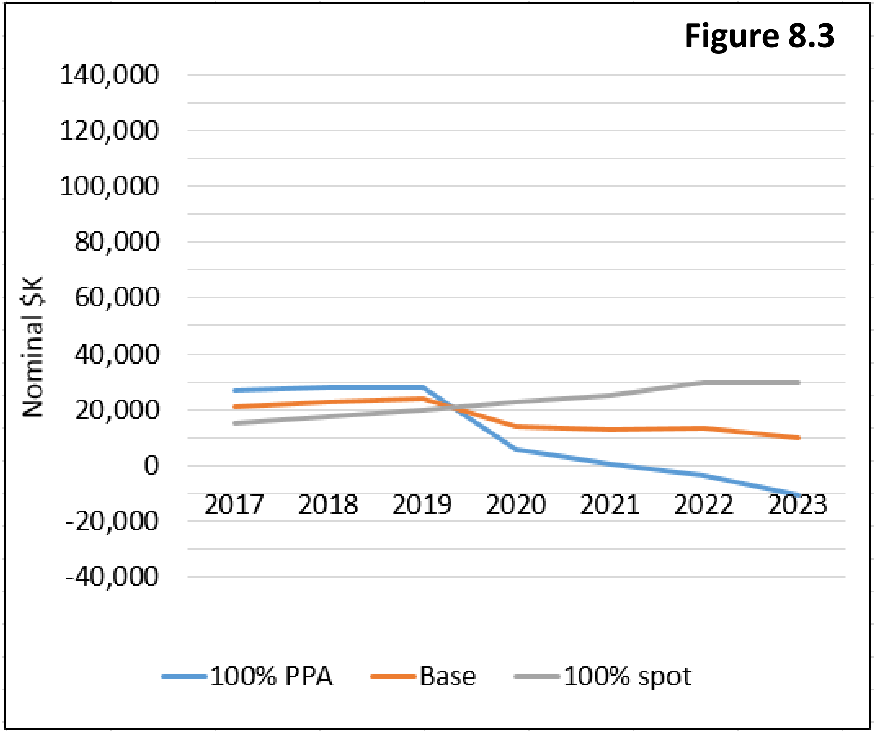
Tier 2A Gross Program Costs to 2023 – Procurement Structures



	Net present value	Bill impact in 2023
100% PPA	$353 M cost	0.30%
Base case	**$376 M cost**	**0.37%**
100% spot	$399 M cost	0.44%

All data reflects modeling estimates. See Appendix B for methodology.

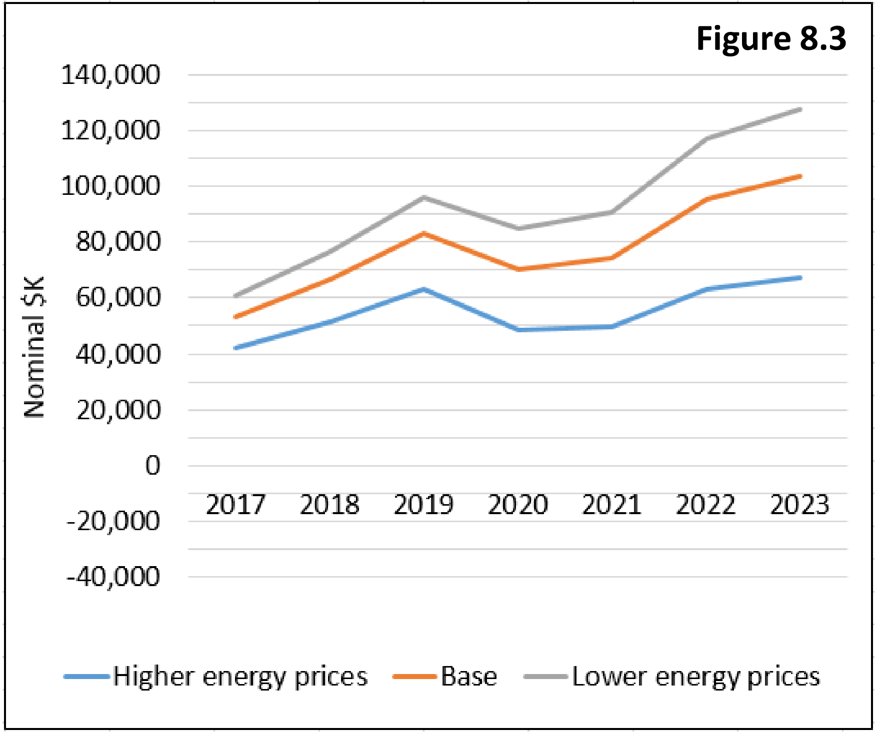
Tier 2A Net Program Costs to 2023 – Procurement Structures



	Net present value
100% PPA	$63 M cost
Base case	**$86 M cost**
100% spot	$109 M cost

All data reflects modeling estimates. See Appendix B for methodology.

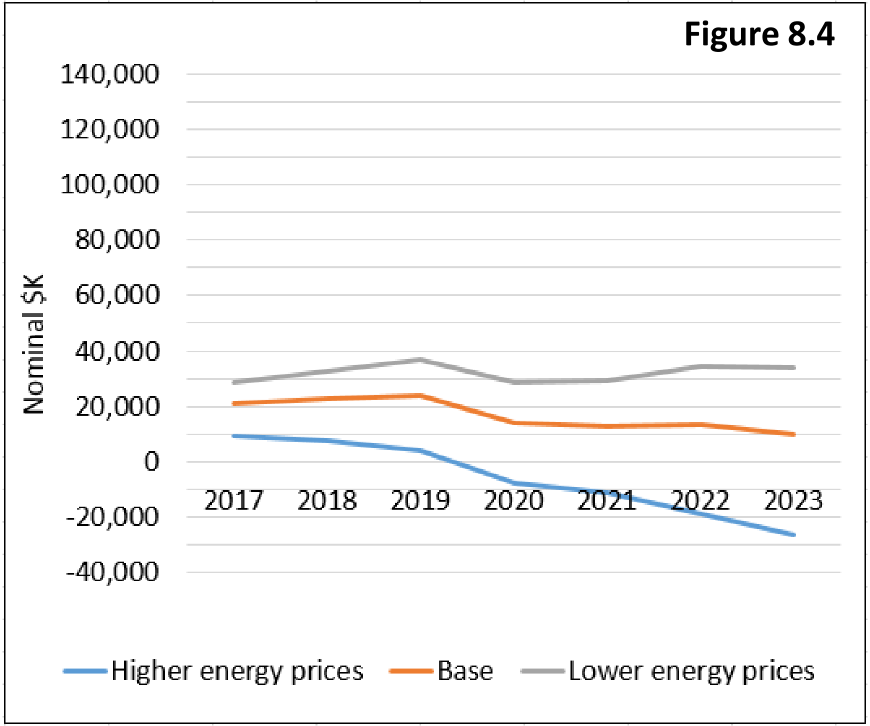
Tier 2A Gross Program Costs to 2023 – Energy Prices



	Net present value	Bill impact in 2023
Higher energy prices	$268 M cost	0.24%
Base case	**$376 M cost**	**0.37%**
Lower energy prices	$447 M cost	0.46%

All data reflects modeling estimates. See Appendix B for methodology.

Tier 2A Net Program Costs to 2023 – Energy Prices

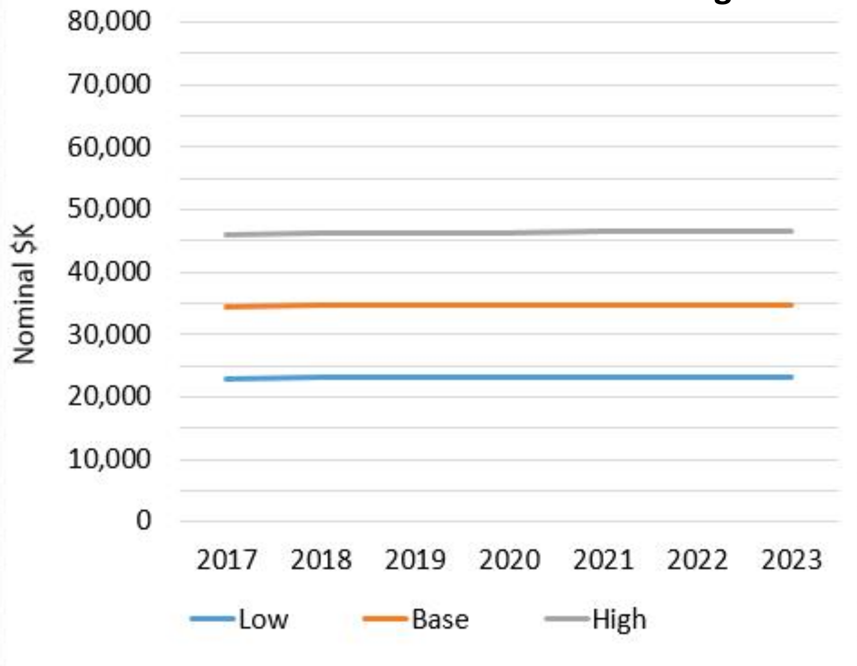


	Net present value
Higher energy prices	$21 M benefit
Base case	**$86 M cost**
Lower energy prices	$158 M cost

All data reflects modeling estimates. See Appendix B for methodology.

Tier 2B Gross Program Costs to 2023

Figure 8.5



	Net present value	Bill impact in 2023
Low case (PPA)	$114 M cost	0.08%
Base case	**$171 M cost**	**0.13%**
High case (spot)	$229 M cost	0.17%

As noted above, a conservative approach is taken by not presenting Tier 2B carbon savings as a specific CES benefit, and thus no net program costs are provided.

All data reflects modeling estimates. See Appendix B for methodology.

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Observations

The following high-level observations are presented:

1. As observed in Section 2 and following for Tier 1, both procurement structures and future energy prices can have a significant impact on overall costs for Tier 2A.
2. Tier 2 is applicable to existing installations. Other cost drivers examined for Tier 1, in particular interest rates, system load, technology cost and federal tax credits, are mainly relevant to new installations, and are thus not expected to impact significantly on the cost of Tier 2.
3. The analysis confirms the importance of maintaining the carbon emission reductions from nuclear plants by indicating that moderate gross program costs for Tier 3 allow the very significant carbon savings from these installations to be preserved.

Section 9 – Bill Impacts

Bill Impacts Methodology

Bill impacts were analyzed focusing on the year 2023. Estimates for later years were considered too uncertain given the uncertainties in the program cost projections developed in this Study combined with further uncertainties as to customer energy consumption patterns as well as energy delivery charge projections.

Bill impacts are assessed for the estimated program costs of the total CES, encompassing Tiers 1, 2A, 2B and 3.

Bill impact analysis was carried out using three methods:

1. Impacts were calculated for typical individual customers:
   - Two typical groups of residential customers were examined: for Con Edison, usage of 300 kWh per month was assumed due to the high percentage of low-use customers; for upstate, usage of 600 kWh per month was assumed.
   - Bill impacts for large commercial and industrial (C&I) customers were calculated on the basis of a hypothetical customer for all utilities. C&I customers vary considerably in their size and electricity usage, so the results are only illustrative.

   For the upstate utilities, the impact varies greatly due to tariff differences. The upstate results shown here reflect an average across different tariffs.

Bill Impacts Methodology

2. As an alternative approach, impacts were calculated by dividing the total CES gross program costs in 2023 by the total 2014 statewide spend on electricity.
3. Finally, projected total CES gross program cost was compared to projected wholesale electricity prices under the base, low and high energy price forecasts used throughout this Study. The result is shown in Figure 9.1.

Note that no forecast of total retail bills is available. Bill impact indicators as a percentage of retail bills are calculated as a percentage of 2014 bills; the comparison of CES costs to forecast energy prices is based on forecast wholesale prices.

Bill Impacts – Residential and C&I Bills

The following table summarizes estimated bill impacts from Tiers 1, 2 and 3 of the CES under the base case. Bill impacts are shown in the year 2023, in real dollars (2015).

Table 9.1

		Bill impacts in 2023
Residential	Con Edison	$0.48/month (0.5% of bill)
	Upstate	$0.96/month (1.0% of bill)
Large C&I	Con Edison	$1,154/month (0.8% of bill)
	Upstate	$1,154/month (1.4% of bill)

2014 Upstate Residential Utilities' bill based on weighted average number of customers; 2014 Upstate Large Commercial and Industrial Utilities' bill based on straight average of bills.

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Bill Impacts - Sensitivities

Impacts are shown as the total gross program costs of the CES in 2023 are expressed as a percentage of 2014 statewide spend on electricity. Data is provided for the base case and the range of sensitivity variations of the various cost drivers examined in this Study. All sensitivities are provided relative to the base case. See Appendix A for details of the inputs settings for the various sensitivities.

- The **base case** impact is forecast at **0.95%.**
- **Procurement structures**. Under 100% PPA procurement this drops to **0.66%**; under 100% fixed-REC procurement this is projected at **1.23%.**
- **Energy prices**. Lower and higher energy price assumptions are forecast to change base case impacts to **1.22%** and **0.57%**, respectively.
- **Interest rates**. Using a higher interest rate assumption, the impact increases moderately to **1.01%**.
- **Technology cost**. A higher cost assumption for land-based wind turbines is forecast to increase the bill impact moderately to **1.07%.**
- **System Load**. A higher assumption on the amount electricity consumed in New York State over the program period results in a significant impact on cost, increasing projected average bill impacts to **1.37%**.
- **Tax credits**. If no federal tax credits were in place, bill impacts would be projected to rise to **1.07%**. If the federal tax credits were to remain in place until 2023 at their current peak level (instead of being phased down over time), the resulting benefit would reduce bill impacts to **0.75%**.

Comparison with Forecast Wholesale Prices

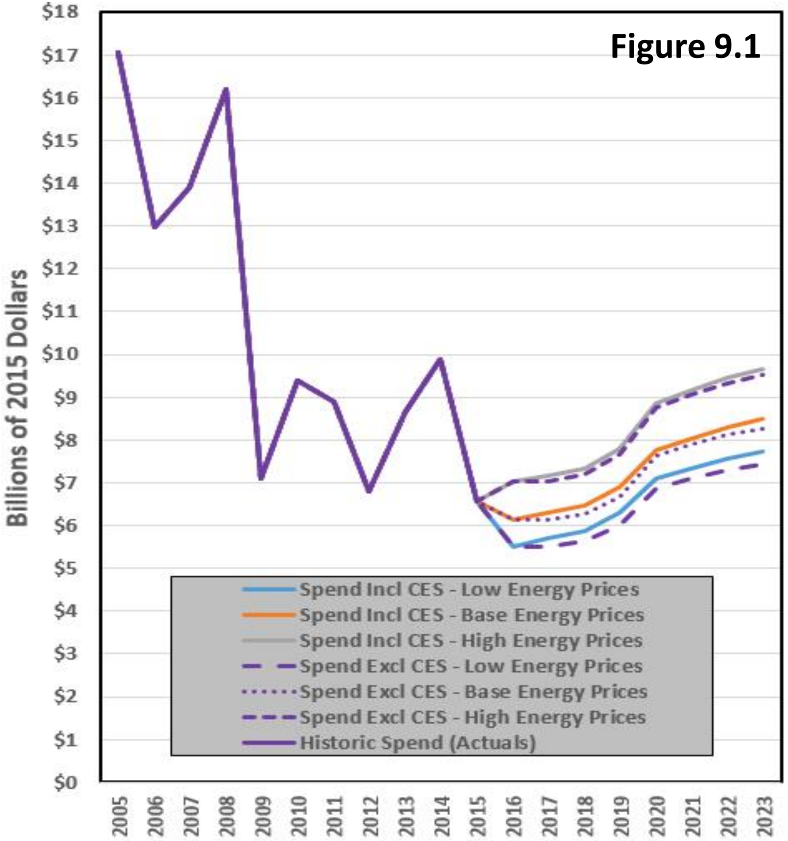

Figure 9.1 illustrates projected CES gross program costs relative to total historic and projected statewide wholesale electricity spend. As an example, in the base case the maximum cost impact of the CES until 2023 on typical monthly residential electricity bills is estimated to be less than $1 in real terms(1).

While CES program costs would be higher under low energy prices, this would be outweighed by customers' savings on their overall energy bills due to lower energy prices.

(1) Based on 600 kWh of monthly electricity use.

Observations

The following high-level observations are presented:

1. Two of the cost drivers that show significant upward or downward changes in overall cost under high and low cost scenarios are also factors that New York State can influence to a large extent: procurement structures and the total amount of energy use. This emphasizes the importance of ongoing work to determine the mix of procurement structures (as set out in the White Paper), as well as state energy efficiency programs to reduce electricity consumption.
2. Future developments in energy prices are uncertain, and are expected to be an important driver of the effective program cost of the CES. However, swings in CES program costs as a result of energy prices would be balanced by opposite effects on ratepayers' overall electricity bills. For example, lower-than-expected energy prices could increase the CES program costs, but this would be offset by a reduction in energy bills from lower wholesale energy prices.
3. While interest rates and technology costs also have an impact, the analysis suggests that – over the main Study period to 2023 – it is smaller than that of the other drivers examined.
4. The current federal tax credits are an important contributor towards containing the cost of renewables, and a further extension of the tax credits at their current level could result in a substantial further reduction of the costs.

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Observations (cont'd)

5. The CES represents a reinvestment of a small portion of savings from recent reductions in wholesale energy costs into decarbonizing the supply portfolio. Current low energy prices present an opportunity to invest in a clean energy future – Load-Serving Entities' (LSE) customers will continue to save money compared to historic prices.

Section 10 – Economic and Price Impacts

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Economic Impacts of the CES

While no specific analysis of economic benefits was carried out as part of this Study, recently-completed studies, which measured the economic benefits of clean energy technologies, can provide reasonable indicators of economic benefits if such technologies received support by the CES. These analyses each focus on one or more technologies to be supported by the CES, and have assessed the economic impacts from direct support of such technology. In the case of renewable technologies, the economic benefits were assessed based on support received/projected from publicly-funded activities. In the case of Upstate nuclear facilities, the current economic contributions to local economies has been measured, indicating the possible loss of such economic activity should the facilities close.

This regards the following studies:

1. November 2015 Brattle draft report: *New York's Upstate Nuclear Power Plants' Contribution to the State Economy*
2. January 2012 NYSERDA report: *New York Solar Study*
3. September 2013 NYSERDA report: *NYSERDA Renewable Portfolio Standard Main Tier 2013 Program Review*
4. 2014 National Renewable Energy Laboratory (NREL) study: *A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards*

Economic Impacts of the CES (cont'd)

In November 2015, Brattle released a draft report entitled, *New York's Upstate Nuclear Power Plants' Contribution to the State Economy.(1)* The draft report concluded that the continued operation of nuclear facilities will bring about or maintain significant short and long-term benefits to New York State. More specifically, the draft analysis estimated that the upstate nuclear facilities (Ginna, FitzPatrick, and Nine Mile) will contribute, on a net basis, the following benefits annually (between 2015 and 2024) to the New York State economy:

- 24,800 direct or secondary jobs.
- $3.16 billion in direct or secondary GDP.
- $144 million in direct or secondary State tax revenues.

Similar economic impacts from the closure of nuclear facilities, including direct and secondary job impacts and local tax revenue impacts, has been noted in separate studies.(2)

(1) http://www.brattle.com/system/publications/pdfs/000/005/229/original/New_York's_Upstate_Nuclear_Power_Plants'_Contribution_to_the_State_Economy.pdf?1449526735

(2) See Cooper, Jonathan, The Pilgrim Nuclear Power Station Study (Univ. of Massachusetts Amherst, 2014); Mullen and Kotval, The Closing of the Yankee Rowe Nuclear Power Plant: The Impact on a New England Community (1997).

Economic Impacts of the CES (cont'd)

In January 2012, NYSERDA released a report entitled, *New York Solar Study* (1). The study was conducted in response to The Power New York Act of 2011, which directed NYSERDA to prepare a study to evaluate the costs and benefits of increasing the use of solar photovoltaics (PV) in New York State to 5,000 MW by 2025. One component of the study involved examining the macroeconomic impacts. Since the "Low Cost Case" cost projections in that study are now more in-line with current cost projections than the study's Base Case cost projections, key findings for the "Low Cost Case" are shown below.

- Over the entire analysis interval (2013 through 2049), the average annual job impact was a gain of approximately 700 net jobs.
- The net present value (NPV) of the cumulative gross state product (GSP) impact was a net increase of approximately $3 billion.

(1) http://www.nyserda.ny.gov/About/Publications/Solar-Study

Economic Impacts of the CES (cont'd)

In September 2013, NYSERDA released a report entitled, *NYSERDA Renewable Portfolio Standard Main Tier 2013 Program Review. (1)* A macroeconomic analysis conducted as part of the review examined the RPS Main Tier Current Portfolio commitments that resulted in approximately 1,800 MW of New York State renewable capacity in place or under construction through the end of 2012. Key findings over the analysis period (2002-2037) are shown below.

- On average, there were expected to be approximately 668 more net jobs in the New York State economy (inclusive of multiplier effects) in each year.
- The cumulative net GSP gain was expected to be approximately $2.0 billion, with a NPV of $921 million.
- For every $1 spent on the acquisition of RPS Attributes for the Current Portfolio of RPS Main Tier projects under contract with NYSERDA, the State will capture on average approximately $3 in direct investments associated with project spending over the project lifetime. Based on these findings, it is possible to estimate the magnitude of potential near-term direct investments associated with the illustrative CES renewable resource deployment scenario. The base case near-term (deployment between 2015-2020) direct investments are estimated to be greater than a billion dollars.

(1) NYSERDA. 2013. Renewable Portfolio Standard Main Tier 2013 Program Review. Direct Investments in New York State. Final Report. Prepared by Sustainable Energy Advantage, LLC and Economic Development Research Group Inc. for NYSERDA.

Economic Impacts of the CES (cont'd)

In 2014, the National Renewable Energy Laboratory (NREL) conducted a study, *A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards (1)*, wherein NREL identified six state renewable portfolio standard programs, comparing the quantified economic impacts of those programs, including jobs impacts, support for local tax base, and secondary impacts. That study found that a number of the studies examined economic development benefits annually or over the lifespan of the renewable energy projects, with benefits on the order of $1-$6 billion, or $22-30/MWh of renewable generation.

(1) http://www.nrel.gov/docs/fy14osti/61042.pdf

Wholesale Price Impacts of the CES

As noted in the recent Order Establishing the Benefit Cost Analysis Framework (Case 14-M-0101, January 21, 2016), wholesale price impacts are not resource or societal benefits, but transfers from one subset of society to another. Further, they are difficult to estimate accurately, and, most likely, only temporary.

However, as also noted, such market price impacts will certainly have a temporary impact on ratepayers' bills.

Thus, any market price reductions caused by adopting the CES should not be considered a societal "benefit" produced by the policy.

However, when bill impacts are estimated, it is appropriate to acknowledge that such price reductions will temporarily reduce or eliminate these impacts.

The size and duration of such price impacts will depend on many factors. The most important of these are: (1) the quantitative impact the CES has on MW and MWh market supply and demand; (2) the time period over which these impacts occur; (3) the extent to which the policy change is clearly described in advance, and considered likely to materialize by market participants; and (4) whether the CES will have any long-run effect on the cost of the long run marginal resource that is added when the system is in need of new market-based capacity.

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Appendix A – Tier 1 Methodology

Appendix A.1 – Modeling Overview

Overview of Supply Curve Analysis

A supply curve model was developed for NYSERDA by Sustainable Energy Advantage, LLC to support analysis of resource deployment and cost impacts of potential large-scale renewables (LSR) policy and procurement/ financing options. Material contributions to input data and resource assumptions were provided by Sustainable Energy Advantage's subcontractors AWS Truepower, Antares Group, and Daymark Energy Advisors.

The model was adapted to examine the Clean Energy Standard Tier 1 proposal aimed at delivering New York's 50% by 2030 renewable electricity goal.

The supply curve characterizes the costs of newly constructed LSRs available to meet annual incremental demand in New York under long-term contracts with assumed financing structures and costs consistent with the risk allocation between investors and customers. Financing cost assumptions reflect the differences between the two main procurement approaches modeled and presented in this Study:

- Under a **fixed-price REC** approach, generators receive a fixed compensation amount per MWh, on top of revenue from energy and capacity sales. The REC price set at the start of project operation, and remains unchanged throughout the period for which RECs are paid.

Overview of Supply Curve Analysis (cont'd)

- Under a **bundled PPA** approach, the generator receives a total fixed payment per MWh, encompassing the entirety of the generator's revenue stream including compensation for energy and capacity. This bundled amount is set at the start of the project, and remains unchanged throughout the period for which RECs are paid.

Supply sources are sorted from least to highest 'premium', being the difference between the levelized cost of energy (LCOE) and levelized projected commodity market energy and capacity revenues.

Where this Study presents results reflecting a mix of fixed REC and bundled PPA procurement, these were derived by carrying out the analysis separately under PPA and fixed REC assumptions, and blending (averaging) the results.

LSR Supply Curve: Key Analysis Parameters

The supply curve consists of a subset of LSR resources which both meet the eligibility criteria of the existing RPS Main Tier program and are most likely to contribute substantially to meeting demand. As an analysis simplification, some resources were not modeled, either because of currently higher costs, relatively small quantities available over the study period, or analytical prioritization. Examples include anaerobic digesters (other than at wastewater treatment plants), geothermal, tidal, wave, fuel cells using any fuel, and biomass combined heat and power (CHP). If such technologies were deployed, the projected costs could be reduced.

In addition to supply within New York State, imports from adjacent control areas are assumed to be eligible if their energy is delivered to NYISO on an hourly-matching basis with transmission, and capacity not committed in their source control areas. The analysis includes estimated cost and quantity of the most likely resources from PJM (wind), Ontario (wind and small hydro) and Quebec (wind) available to and deliverable to New York.

LSR Supply Curve: Temporal Factors

The analysis time horizon spans commencement of commercial operation years from 2017 through 2030, and calculates policy payments for production in years 2017 through 2049 when the last tranche of 20-year LSR contracts expire.

When used to model a load-serving entity Tier 1 LSR obligation in a particular year, the model assumes that production commences on January 1 of the first year of commercial operation, on the basis of procurement and financing a number of years prior to such date consistent with the typical construction and development lag times for the applicable technology. See Table A.1.

Each project is assumed to be contracted for a duration of 20 years.

Payments and production are tracked in the model through the life of 20-year contracts.

Residual control of RECs beyond the 20-year contract may be accomplished through contractual provisions or utility ownership, for example, but these issues fall outside of the model framework, and possible associated costs of such provisions are not included in this analysis.

Assumed Lag from Contract to Operation

Table A.1

Resource	Contract to Operation Lag	
	Quarters	Years
LBW (10-30 MW)	6	2
LBW (30-100 MW)	7.5	2
LBW (100-200 MW)	7.5	2
LBW (>200 MW)	7.5	2
Utility-Scale Solar	4.5	1
Hydro (Upgrades)	13.5	3
Hydro (NPD)	13.5	3
Biomass Co-Firing	6	2
Biomass CHP - Existing <5 MW	13.5	3
Biomass CHP - Existing <25 MW	13.5	3
Biomass CHP - New <5 MW	13.5	3
Biomass CHP - New <25 MW	13.5	3
Biomass Repower - Retired Units	13.5	3
Biomass Repower - Operating Units	13.5	3
Biomass - IGCC	13.5	3
Anaerobic Digestion	10.5	3
Offshore Wind	12	3

For the purpose of determining a project's date of commercial operation, a technology-specific built-in lag time was included between the time of contracting and commercial operation.

The calendar quarters assumed for typical lag between contracting and commercial operation are rounded to the nearest year to fit the annual model.

While costs are defined based on the first year of commercial operation (so no adjustment is made for lag), the eligibility for Federal Incentives (described further in Appendix A.5) is based on what a bidder would presume for eligibility at the time of the bid.

LSR Model Flow Chart

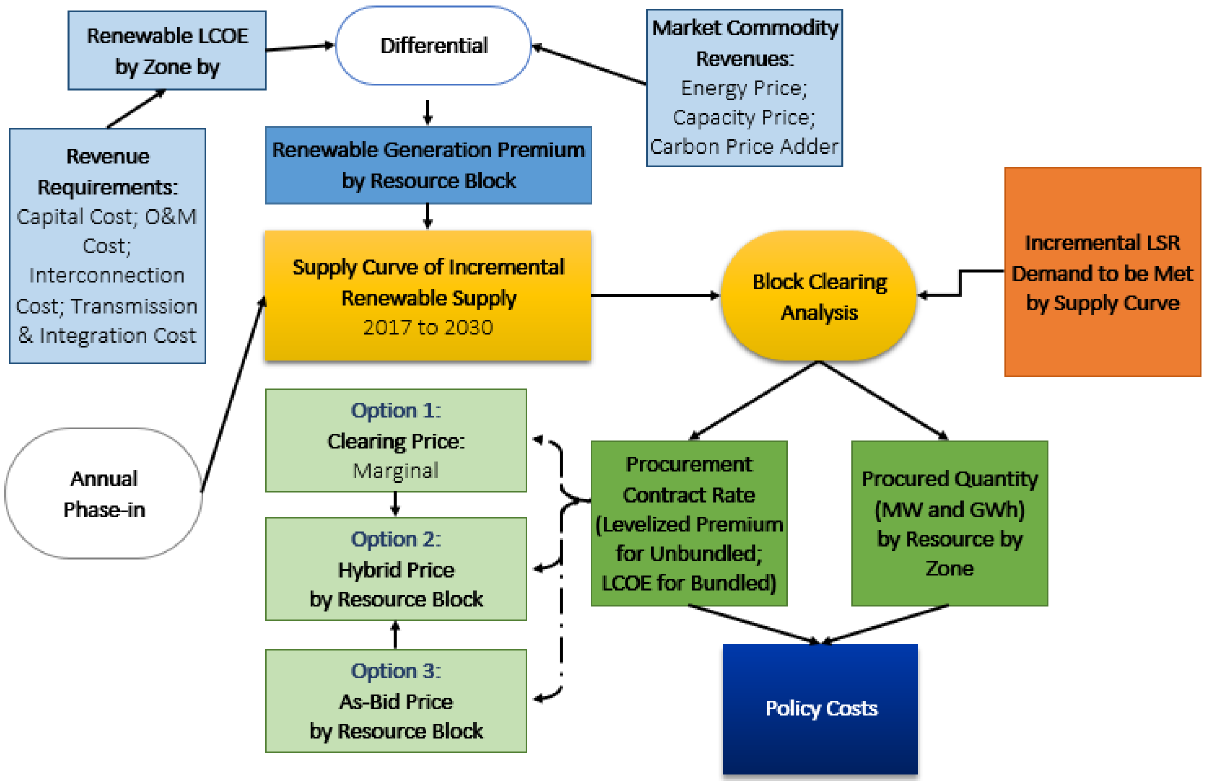

Figure A.1. The model builds a resource supply curve, stacks it from least to highest premium in each year, and (subject to certain deployment constraints) adopts the cheapest portfolio of resources needed to fulfill either budget targets or, in this analysis, target demand quantities.

Incremental LSR supply for each technology is a function of projected resource potential, performance, and siting factors.

LSR Supply Curve: Other Modeling Protocols

Bid prices for contracts are based on the LCOE required in the year of commercial operation, and assume contract payments for 100% of generation over a 20-year project lifespan.

Federal incentive eligibility (PTC, ITC) is based on the value in the year of the qualifying event (start of construction) with a maximum lag period between the start of construction and commercial operation assumed to be allowed by the Internal Revenue Service (see Appendix A.5).

As a modeling simplification, no production degradation over time is explicitly modeled. However, solar PV degradation is accounted for in adjusting a levelized capacity factor.

While some contract attrition is implied and could ultimately be addressed through procurement targets, the quantity modeled is assumed to be net of any attrition of amounts contracted.

The maximum resource potential is derived from geospatial analyses of resource or fuel availability at resources sites and literature review of technology characteristics and trends. The maximum resource potential is gradually made available in the supply curve ("phased in") to recognize practical constraints on build-out due to evolving market barriers, supply chain constraints (delivery, manufacturing and installation infrastructure limitations), development lead time, permitting constraints, market acceptance, technology availability, etc.

LSR Supply Curve: Resource Blocks

The supply curve is comprised of “Resource Blocks” representing the available LSR potential of a particular technology (and associated differentiating characteristics) and uniform cost within each NYISO zone. The objective is to represent the diversity of supply factors (e.g. cost, production profile) and different market values concisely; as a result, in many cases, supply potential of similar characteristics are combined into a single block. Based on the nature of the resource, multiple different resource blocks are defined, e.g. LBW cost is a strong function of wind speed, scale and distance from transmission. As a result, each LBW resource block represents a site with different features.

The model takes a probabilistic approach to the raw data, assigning “de-rating factors” to account for permitting and other factors impacting probability of success. As a result, the model does not explicitly predict the development of a particular site in a particular location. For example, if two 100 MW LBW sites of similar characteristics are de-rated by 50%, the selection of that potential is representative of either one or the other site being developed, or a 50 MW project being built at each.

Key Characteristics of Resource Blocks

Resource blocks are defined by the following characteristics:

- The block's location (NYISO zone) within New York (or delivery zone, for imports);
- The maximum potential developable quantity (in MW);
- The capacity factor (in %);
- The capital expenditures (CAPEX) less interconnection cost (in $/kW), and (separately) the interconnection cost (in $/kW);
- Operations and maintenance (O&M, or OPEX) costs (fixed in $/kW, variable in $/MWh);
- For biomass, the technology's heat rate (conversion efficiency) and fuel cost;
- A carrying charge (in % of CAPEX) encompassing all financing assumptions;
- The levelized cost of energy (LCOE, in $/MWh) as calculated by the model (see Figure A.2);
- Capacity value (stated as the annual average UCAP as % of nameplate capacity);
- The levelized market value (in $/MWh) of energy and capacity over the contract duration; and
- The levelized cost premium (in $/MWh), derived as the difference between LCOE and levelized market value.

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Capital Expenditures (CAPEX)

Up-front capital expenditures are defined using the definition used in NREL's 2015 Annual Technology Baseline (ATB) and Standard Scenarios, as the "Total capital expenditure required to reach commercial operation of a plant".

This can be thought of as the full set of costs subject to permanent financing, including all development, installation and transaction costs, including but not limited to:

- Installed costs of generator hardware
- Interconnection costs
- Labor
- Reserves
- Financing-related transaction costs

Operational Expenditures (OPEX)

Operating expenditures (OPEX) comprise the ongoing costs borne by generation projects over time for all manner of operations and maintenance (O&M) and administrative expenses, commonly grouped into categories of "fixed" O&M (stated in $/kW-yr), which are insensitive to the volume of energy production; or "variable" O&M (stated in $/MWh) which includes costs that are either sensitive to energy production, or projected on a per-MWh basis.

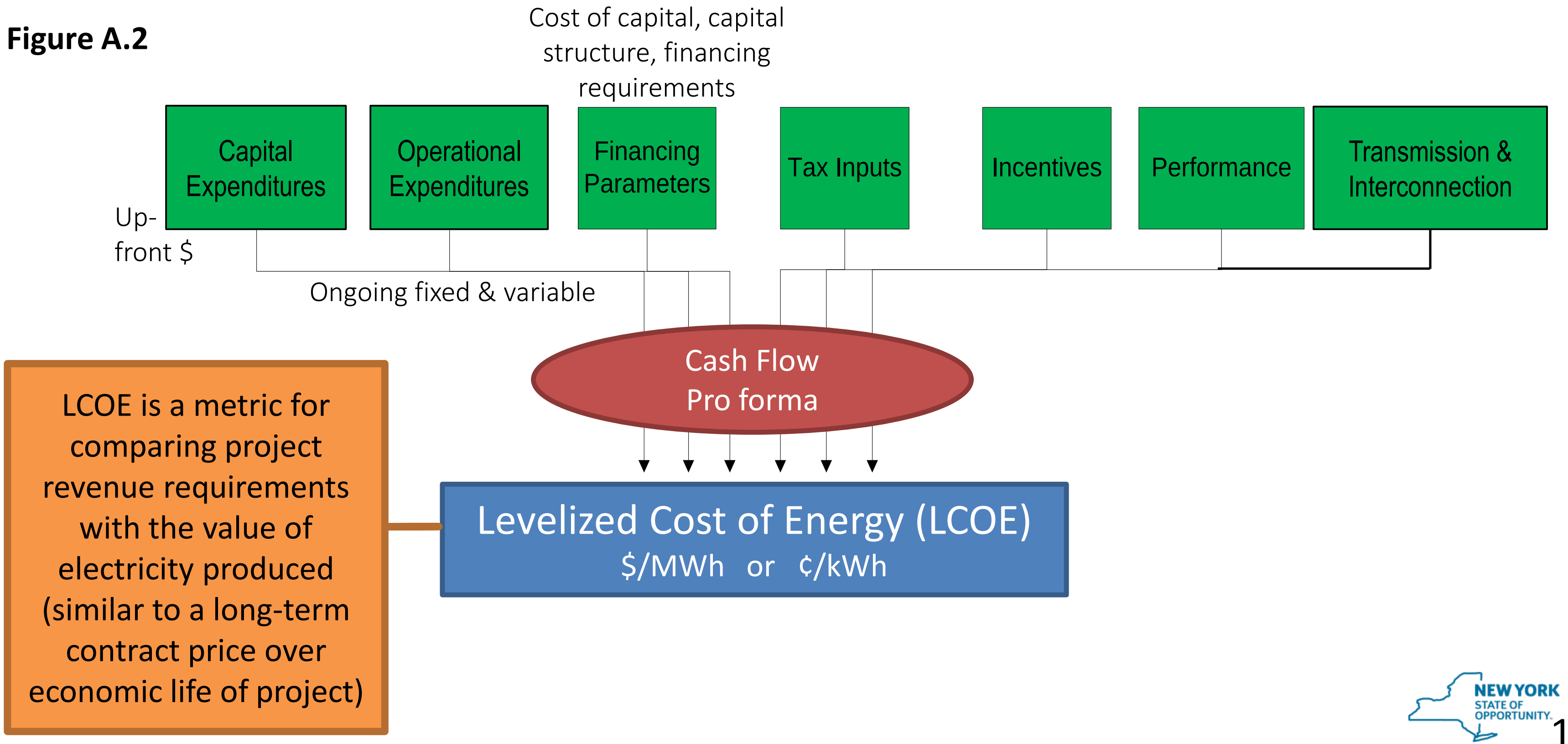
OPEX includes (but is not limited to):

- Cost of labor and parts
- Insurance
- Land costs (leases, royalties, etc.)
- Management and administrative fees
- Taxes or payments in lieu of tax (PILOTS)

Capital replacements and overhauls during the operation life of a project are also included in OPEX, modeled as spread evenly over the contract duration for the purposes of this analysis.

Levelized Cost of Energy

Figure A.2



Benchmarking

An LCOE benchmarking analysis between the supply curve analysis for this Study and the modeling underpinning the 2015 LSR Options Paper (Case 15-E-0302) was conducted by comparing the 100 MW reference installation used in the Options Paper analysis with a representative 100 MW project in the current Study. LCOEs were found to fall within a similar range, after adjusting for relative differences such as more granular approach to topography in this Study and differences in energy and capacity value assumptions.

Appendix A.2:

LSR Technology Cost & Quantity

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Appendix A.2.1 – Land-Based Wind

Overview of Approach

The costs and performance characteristics of land-based wind (LBW) are very site-specific. Resource potential is specific to wind speed, further constrained by permitting limitations that have historically been more challenging than for some other technologies. Cost is strongly tied to such factors as project scale, topography, distance from interconnection, and accessibility to roads. Production is also influenced by hub height and technology choices. A detailed geospatial approach intended to reflect the site-specific nature of LBW development with respect to resource potential and project cost was used in this analysis.

The geospatial study identified and characterized potential land-based wind sites in New York (and in adjacent importing regions, discussed further in Appendix A.2.7). De-rates to raw windy land area results were applied to LBW sites to differentiate the likelihood of permitting based on a site-by-site screening of the presence and proximity of potential neighbors and land-use conflicts. Cost functions were developed to represent development cost variations associated with site characteristics.

While a geospatial approach was used for determining LBW resource potential, it is applied as a probabilistic analysis. Model results do not depict, and should not be used to define site locations, deployment timing, and costs for actual individual projects.

LBW Capital Expenditures

(not including Transmission and Interconnection Cost)

A “starting point CAPEX” of $1,692/kW (in 2013 $), representative of a 200-MW project located in an idealized (for permitting and installation) central US plains location, was selected based on the 2015 NREL ATB. Transmission and interconnection costs are developed separately on a site-specific basis.

A series of adjustments, developed based on public studies, past LSR analyses and interviews with developers active in New York and the rest of the nation, was applied to reflect cost differences between land-based wind development in New York and an idealized central US plains location, as well as cost variations associated with key parameters that characterize land-based wind development cost.

These adjustments included locational adjustments (Table A.2), project size adjustments (Table A.3), and topography adjustments (Table A.4).

LBW CAPEX Adjustments

Table A.2. Locational adjustments:
The 'Regional factor' represents the difference between national average costs and those specific to Upstate NY and Long Island. The 'Siting factor' reflects siting and soft cost difference from the idealized (central plains) site.

NY Region	NYISO Zones	EIA Regional Factor	Siting Factor	Final Adjustment Factor
Upstate	Rest of state	1.01	1.06	1.07
NYC	Zone J	N/A	N/A	N/A
LI	Zone K	1.25	1.10	1.38

Table A.3 Size adjustment:
The size adjustment reflects diseconomy of scale compared to resources in size categories smaller than the 200 MW baseline.

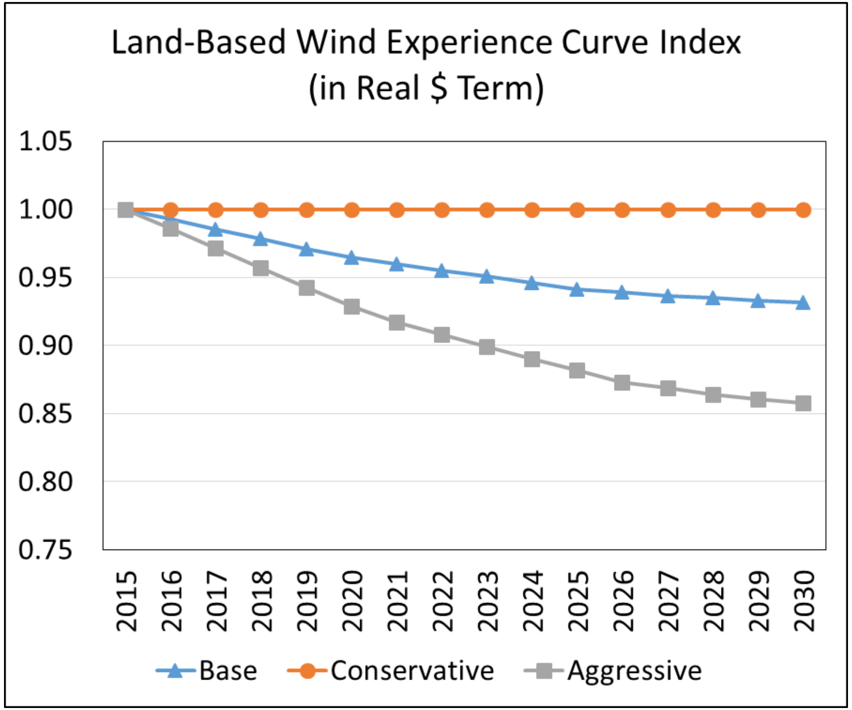
Technology Size Category	Adjustment Factor
LBW 10-30 MW	1.30
LBW 30-100 MW	1.15
LBW 10-30 MW	1.02
LBW >200 MW	1

Table A.4 Topography adjustment:
The adjustment for the site topography reflects cost differences in site topography (slopes) and access to roads.

Land Type		Definition	Min. Elevation (m)	Min. Elevation Difference vs. Surroundings (m)	Adjustment Factor
Plain	1	Slope = 0 – 5%, Not 3 or 4	N/A	N/A	1.00
Rolling Hills (Accessible)	2	Slope = >5 – 15%, Not 1,3 or 4	N/A	N/A	1.07
Rolling Hills (Remote)	3	Slope = 8 – 12%, Not 4	300	100	1.12
Mountainous	4	Slope = >10 – 20%	500	N/A	1.22

LBW CAPEX Experience Curves

Figure A.3



Graph shows relative cost change compared to start year.

Experience curves were developed to represent technology cost decline (in real dollar terms) on a $/kW basis over the span of the study period. Three experience curve cases (Low, Mid and High) were derived by indexing the Low, Mid and High NREL ATB CAPEX forecasts for NREL's 'techno-resource group (TRG) 2'. (TRGs 2 and 3 are most consistent with conditions with the majority of sites in New York).

Since the projected rates of cost decline for all three cost trajectories are slower than the rate of inflation, land-based wind CAPEX would increase over time in nominal dollar terms at a slower-than-inflation rate, depending on the trajectory selected.

The Base trajectory was used in all scenarios studied in this analysis.

LBW OPEX (O&M)

Interviews with active, experienced wind developers yielded the finding that market participants typically model wind project economics based on the build-up of annual fixed O&M expenses. None of the market participants interviewed forecast wind project economics using Variable O&M expenses. As a result, no variable expenses were modeled in this analysis.

A nominal levelized 2015 baseline fixed O&M cost was set at $70.00/kW-yr based on O&M cost data from past LSR analyses, interviews with developers and publicly available sources.

The fixed O&M cost in this analysis includes the amortized cost of all equipment repairs and replacements (including provisions for capitalized expenditures); all operations, maintenance, repair and replacement labor; insurance expense; project management and administrative expense; land lease or royalty payments; and property taxes (or payments in lieu thereof). A New York-specific Payment in Lieu of Taxes (PILOT) of $8,000 per kW was assumed for all project sizes.

A labor cost adjustment factor of 1.1, intended to represent regional labor cost differences, was applied. This factor was derived by taking the ratio of the New York annual mean wage for the "Installation, Maintenance and Repair Occupations" category in New York ($49,750) to the national mean ($45,220). After accounting for this regional labor adjustment, the final fixed, nominal levelized O&M cost was $77/kW-yr.

The levelized fixed O&M costs are held at constant in real $ terms.

LBW Resource Potential

A geospatial approach was taken for determining technical resource potential and performance for land-based wind in New York and adjacent importing regions. Two types of constraints were established in this analysis:

- Primary constraint (excluded areas): These land uses were completely excluded from the analysis.
- Secondary constraint: For these land uses, probability de-rates (as % of site capacities) can be applied to sites intersecting these areas.

Each continuous area (after the exclusion of primary constraints) capable of hosting a wind project of at least 10 MW in size was defined as a project site, and was associated with a NYISO load zone and wind resource data, including:

- Land area and power density (measured in MW/km2), together derive the site capacity (MW). Power density varied according to site characteristics and was site-specific, as modeled by AWS Truepower.
- Wind speeds were modeled at four potential hub heights (80m, 100m, 120m and 140m).
- Average slope and elevation, which inform the characterization of topography (flat, rolling hills and mountainous), and
- Distance to existing 23-45kV, 69kV, 115-150kV, 230kV and 340kV transmission lines and substations.

LBW Primary and Secondary Constraints

Primary Constraints - Excluded Areas	Buffer
Adirondack and Catskill Parks	100 ft.
National Historic Preserves / Sites / Parks	100 ft.
Wildlife Management Areas	100 ft.
State Unique Area	100 ft.
State and Local Parks	100 ft.
National Monuments	100 ft.
National Wildlife Refuges	100 ft.
National Park Service Land	100 ft.
Fish and Wildlife Service Lands	100 ft.
American Indian Lands	100 ft.
GAP Status 1 & 2 Lands (Protected Lands)	100 ft.
Urban Areas	Class (22) – 200 m; Class (23) & (24) – 500 m
Wetlands & Waterbodies	100 ft.
Large Airports	20,000 ft.
Small / Medium Airports	10,000 ft.
Proposed Wind Farms	3 km
Existing Wind Farms	3 km
Slopes > 20%	N/A
Appalachian Trail	3 km

Table A.5 describes the primary constraints excluded from the geospatial analysis. The supply curve model also has the functionality to apply probability de-rates to sites intersecting the following secondary constraint areas to represent a higher hurdle to permitting success. All scenarios studied in this analysis assumed no secondary constraint de-rates. This approach allows for analysis of whether secondary constraints are a constraining factor on LBW development, which is a later phase of the analysis.

Secondary constraint areas include:

- Department of Defense Lands
- Forest Service lands
- State forest lands
- Modeled rare species distributions
- Modeled migratory bird stopovers
- Bat distributions/locations/travel zones
- Terrestrial connectivity and resilience

LBW Housing Density/ Proximity Derating

The presence and density of dwellings within a site footprint, or nearby, were assumed to be an (imperfect) proxy for the ability to successfully permit a site. However, there are no geospatial 'layers' available which show individual dwellings and allow an automated assessment of setbacks from existing dwellings statewide.

An additional manual site characterization step, using Google Earth, was employed to individually screen each site to assess potential siting conflicts due to the presence or proximity of dwellings and roads. A total of 433 sites surviving the primary screening were examined in this manner and sorted into five categories of housing density (substantial, high, medium, low and none).

Sites with "substantial" housing density were excluded outright. A total of 370 sites remained after this step. De-rates (as % of site capacity) were applied to reduce the available land areas associated with the remaining categories, as follows:

- High: 95% (i.e., only 5% of the land area was modeled to be developable)
- Medium: 75%
- Low: 30%
- None: 5%

Distribution of Potential LBW Sites

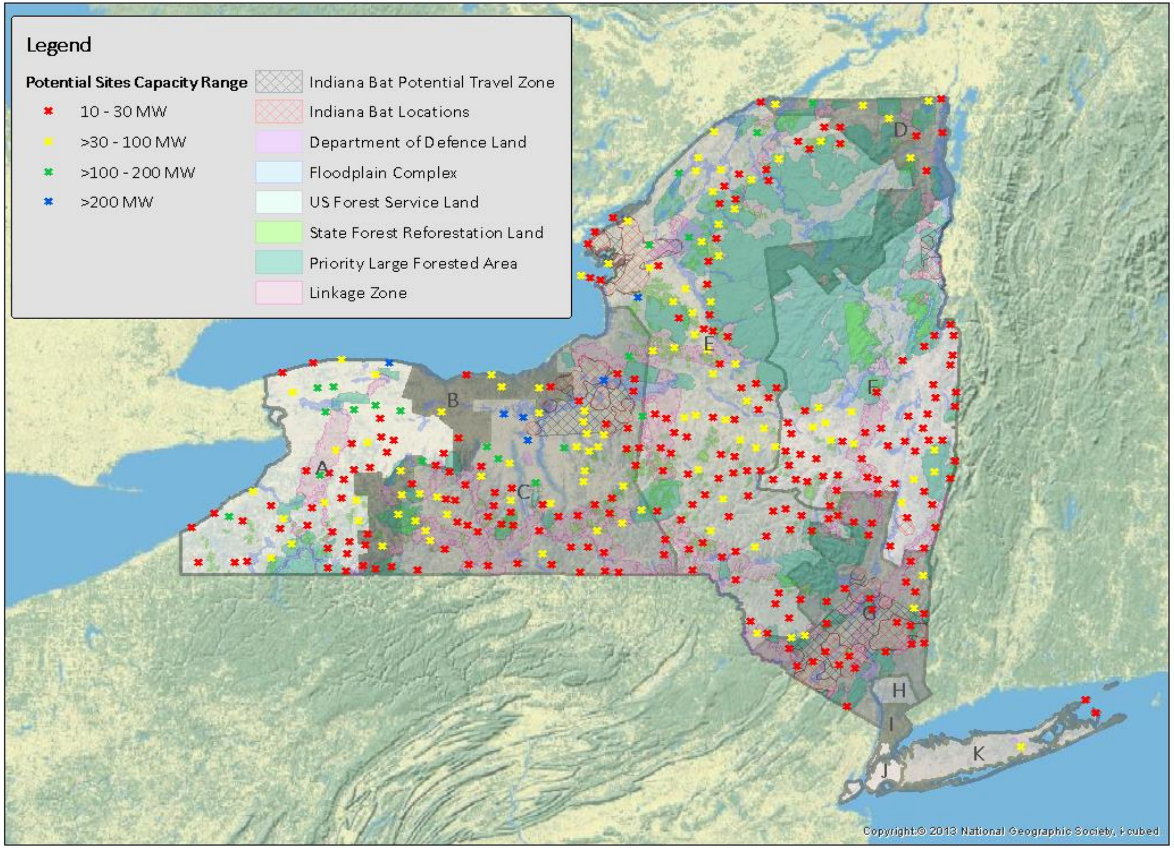


Figure A.4 depicts the 370 New York LBW sites included in the supply curve. As noted above, this is the result of probabilistic geospatial analysis and should not be interpreted as defining actual project sites.

LBW Capacity Factors

Capacity factors based on current technology were estimated for each of the 370 identified sites at four hub heights (80m, 100m, 120m and 140m). To calculate capacity factors, a scalable wind turbine power curve (representing the composite of several leading turbine models) was first developed to represent current, commercially-available technology.

Wind speed and air density data from each site were applied to the composite power curve to determine the gross hourly energy production at the selected hub height for a typical year. The resulting net energy production, after accounting for varying loss factors, was compared with the maximum possible energy output (i.e., operating at nameplate capacity in all hours) to produce a typical hourly capacity factor database.

Evolution of capacity factors over time was modeled based on two parameters:

- Average fleet hub height evolution; and
- Technology advancement at a constant hub height.

LBW Hub Height Evolution

While many parameters collectively determine capacity factor expected for a particular wind regime, to simplify the model, hub heights were used as a proxy for a combination of blade length (rotor swept area) and hub height.

This analysis assumed that hub heights would continue the recent increasing trend over the span of the study.

This analysis also assumed that wind speed is the primary driver dictating the selection of hub heights, e.g., deployment of higher hub heights is more important for low-wind speed sites, where going higher allows a project to access an economically viable wind regime. In contrast, higher towers and larger blades may not be well-suited to the windiest sites due to logistical challenges in getting larger components to the site.

To model average hub height fleet evolution, LBW sites were divided into 3 Hub Height Groups as a function of site wind speed measured at 80 m: Group 1: >8.0 m/s; Group 2: 6.5-8.0 m/s; Group 3: <6.5 m/s.

An initial fleet average hub height in 2017 was identified for each Group based on understanding of current trends. Three sets of hub height evolution scenarios were developed by AWS Truepower for each grouping to reflect expected changes in average hub heights over time for each group.

Interpolation between the 80, 100, 120 and 140 meter capacity factor modeling results was used to derive the capacity factor for a specific site at the fleet average hub height for a specific year.

The results are shown in Table A.6.

LBW Hub Height Evolution

Table A.6

(Meters)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base														
Group 1	80	82	84	86	88	90	92	94	96	98	100	102	104	106
Group 2	92	94	96	98	100	102	104	106	108	110	112	114	116	118
Group 3	100	102	104	106	108	110	112	114	116	118	120	122	124	126
Conservative														
Group 1	80	81	82	83	84	85	86	87	88	89	90	91	92	93
Group 2	85	86	87	88	89	90	91	92	93	94	95	96	97	98
Group 3	95	96	97	98	99	100	102	104	106	108	110	112	114	116
Optimistic														
Group 1	85	87	89	91	93	95	97	99	101	103	105	107	109	111
Group 2	95	97	99	101	104	107	110	113	116	119	122	125	128	131
Group 3	100	103	106	109	112	115	118	121	124	127	130	133	136	139

The "Base" case was selected for use in all scenarios except the High LBW Cost sensitivity in this analysis. In the High LBW Cost sensitivity scenario, the "Conservative" case was used.

LBW Technology Advancement Factors

Additional technological improvement, represented by capacity factor at a given hub height, was assumed. Since the NREL ATB figures account for both technological advance and increases in hub height, the NREL ATB rate of change figures were reduced 50% to eliminate potential double counting. High, mid and low (no change) trends from 2015 NREL ATB (for TRG 3), net of the hub height increase adjustment, were used to create three series of Technology Advancement Factor (TAF) multipliers, as follows.

Table A.7

Case	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Aggressive	1.00	1.02	1.03	1.05	1.06	1.07	1.08	1.09	1.10	1.10	1.11	1.11	1.12	1.12
Base	1.00	1.01	1.02	1.02	1.03	1.04	1.05	1.05	1.06	1.06	1.07	1.07	1.08	1.08
Conservative	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

The “Base” case was selected for use in all scenarios except the High LBW Cost sensitivity in this analysis. In the High LBW Cost sensitivity scenario, the “Conservative” case was used.

LBW Annual Resource Availability (Phase-In)

An assumption for the maximum annual land-based wind build rate (MW per year) was developed based (i) in the near-term pipeline on the quantity of supply under development (initially limited by supply in the NYISO interconnection queue, and thereafter based on a survey of additional projects under development that could be added to the queue in the near-term) and (ii) in the long-term, on supply chain and infrastructure constraints.

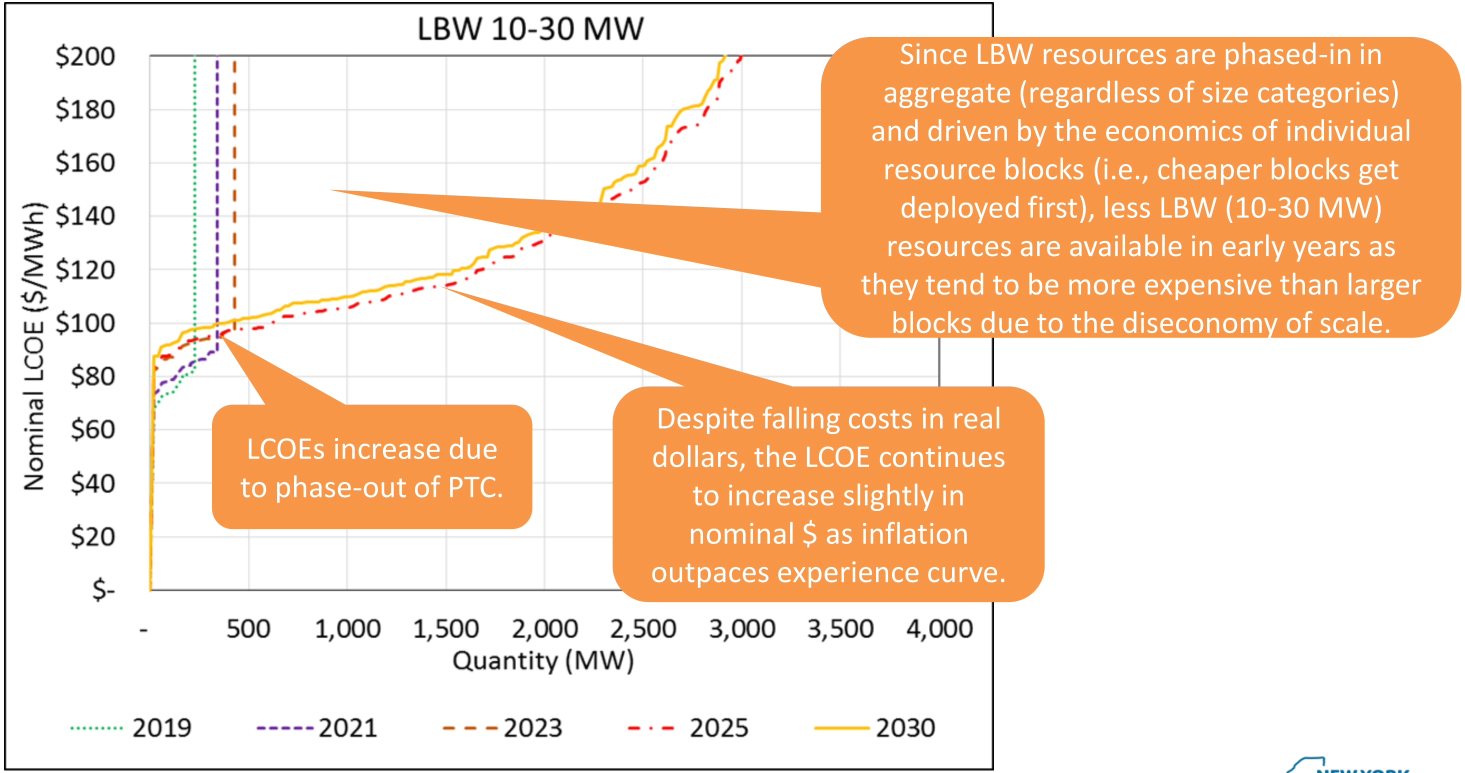
All land-based wind resource blocks were categorized into two phase-in categories as a function of the block's 2017 LCOE:

- The top two-third of blocks with lower LCOEs were assigned to the "LBW More Likely" category, which were made available (as % of maximum annual build rate) to be deployed in the supply curve first.
- The remaining third were assigned to the "LBW Less Likely" category. These resource blocks would not be available until the annual phase-in % for "LBW More Likely" reach 100% (i.e., all "LBW More Likely" blocks were made available, but not necessarily completely deployed).

The annual phase-in percentages were applied to derive an annual cap to the number of land-based wind blocks (sorted from least to highest premium) that would be made available for deployment. e.g., if the total resource potential for the "LBW More Likely" category is 2000 MW, and the annual phase-in % for 2018 is 10%, then first 200 MW of "LBW More Likely" blocks with the lowest premiums that have not been deployed in previous years would be available to be deployed in that year.

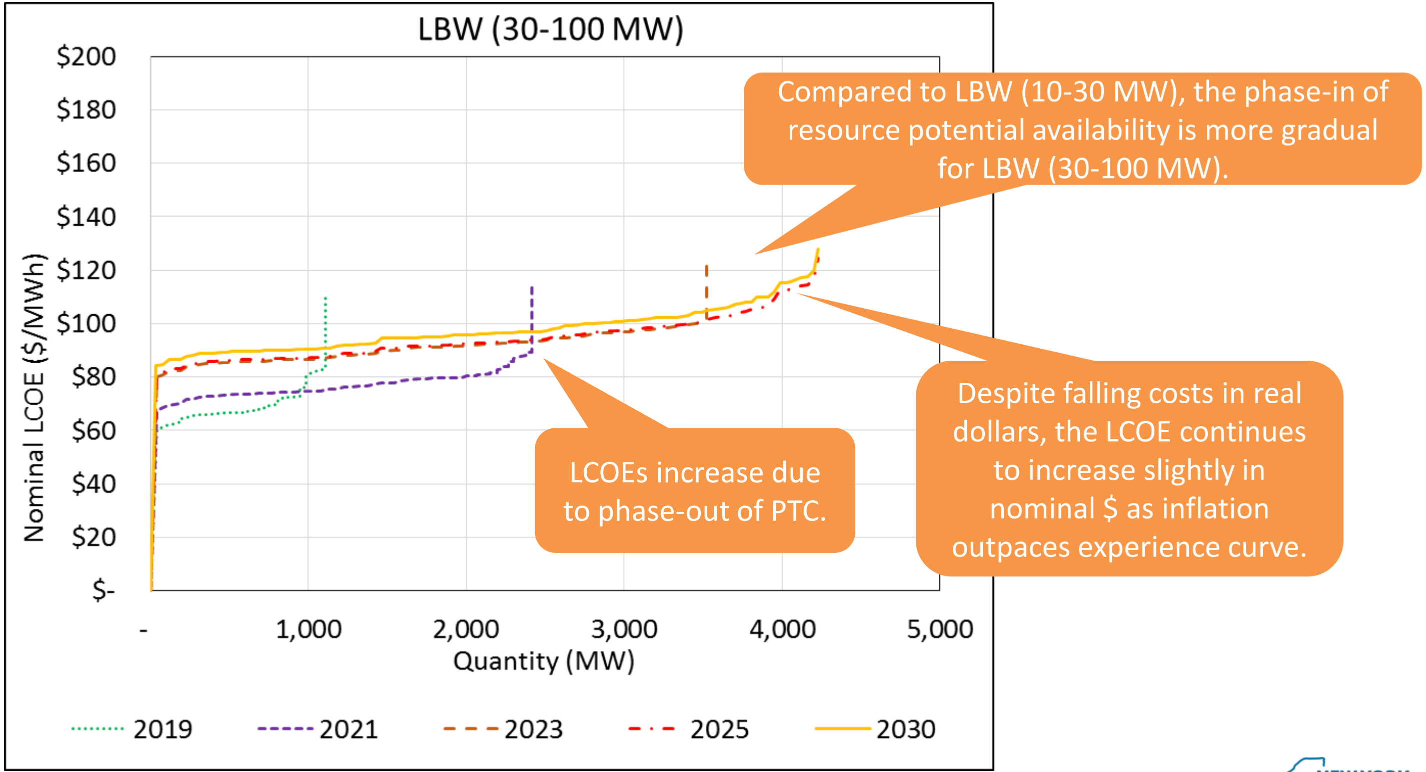
LCOE Supply Curves: LBW 10-30 MW

Figure A.5



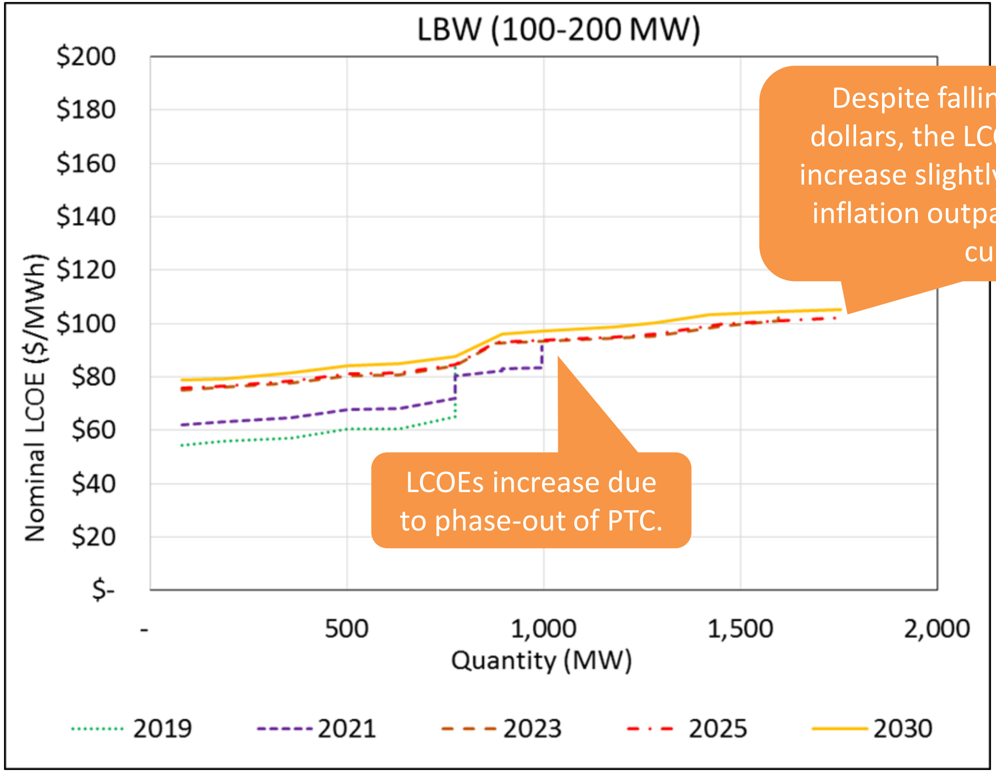
LCOE Supply Curves: LBW 30-100 MW

Figure A.6



LCOE Supply Curves: LBW 100-200 MW

Figure A.7



Despite falling costs in real dollars, the LCOE continues to increase slightly in nominal $ as inflation outpaces experience curve.

Appendix A.2.2 – Offshore Wind

Offshore Wind: Overview of Approach

The "state of the art" for projected offshore wind (OSW) costs is evolving, with a number of ongoing studies underway to estimate the costs that may be achievable in the future within the U.S. based on very limited U.S. data, but accounting for technological progress, scale deployment, and the costs that may be realized if deployment at scale in the northeastern U.S. allowed for the development of a robust supply chain and associated amortization of fixed costs over a portfolio of projects. Such a committed deployment can be referred to as "market visibility".

In addition, OSW LCOEs are site specific: a function of distance to shore, water depth, wind speed, transmission and interconnection cost, and scale of deployment. Generic data may be poorly suited to apply to New York OSW potential.

OSW resource potential and projected costs were therefore based on the most recent data available and applicable to New York, but also considering global market advances, U.S. learning, and the cost reductions that might be realized in the presence of such "market visibility".

OSW Data and Methodology

As further described herein, the OSW analysis was based on:

(i) The March 2016 *Massachusetts Offshore Wind Future Cost Study* prepared by the University of Delaware Special Initiative on Offshore Wind ("SIOW 2016"), an update to SIOW's report for NYSERDA, the *New York Offshore Wind Cost Reduction Study*;

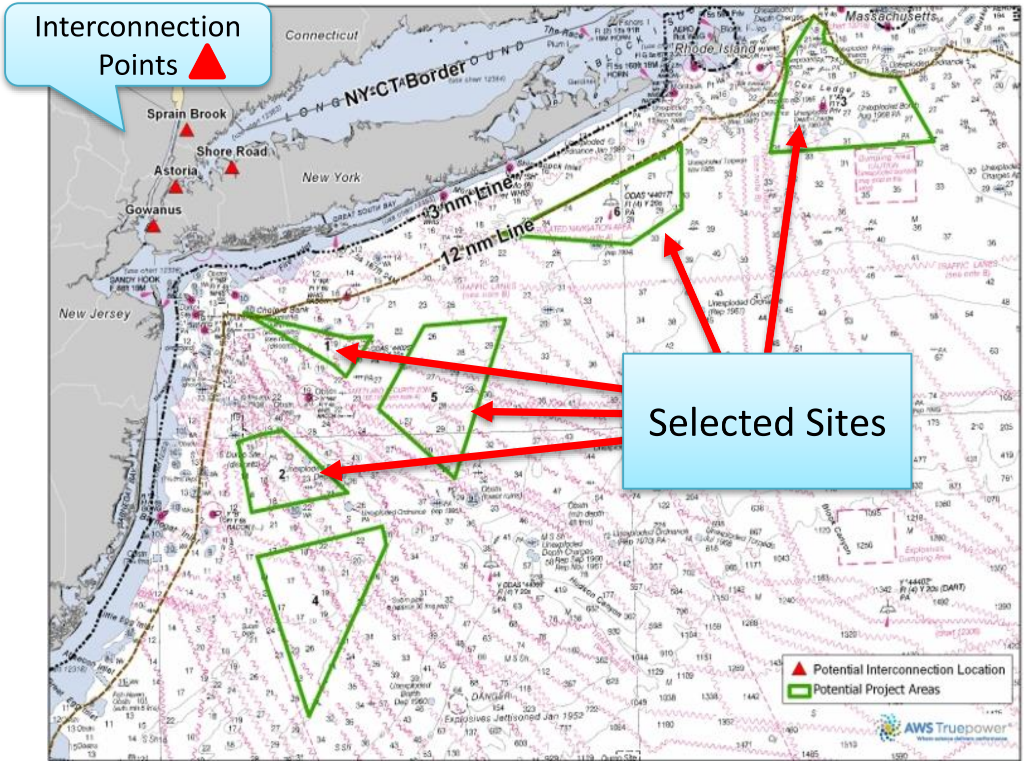
(ii) The 2015 NREL ATB; and

(iii) Earlier NYSERDA-internal analysis

This analysis used as its starting point the NYSERDA-internal cost and resource analysis , and used the SIOW 2016 and NREL ATB to adjust these NY-specific figures over time to reflect the confluence of several factors implicit in the latter studies, including: the latest European experience in cost reduction realized through market maturation, scale economies and industrialization of the OSW sector (global learning); continued scaling of turbines from 5 MW to 8 MW class turbines; U.S. learning and industry scaling; availability of long-term revenue certainty; and development of domestic supply chain, spreading of fixed costs, and increased competition consistent with a commitment to deploy OSW at scale in the eastern US through 2030.

OSW Resource Potential

Figure A.8



Of six potential offshore wind areas characterized, five were selected as the closest, most advanced and/or most representative of the resource potential reasonably available during the Study period, as shown in Table A.8 and Figure A.8.

Table A.8: OSW Wind Areas

Offshore Site	Area (km^2)	Build-Out Potential (MW)
1	285	855
2	663	1,989
3	1,521	4,563
5	1,372	4,116
6	1,027	3,081

OSW Resource Blocks

Five OSW resource blocks (sites 1, 2, 3, 5 and 6) were created. The portion of each block assumed to be available for deployment before 2030 (i.e., the size of each supply curve block as used in the model), the interconnection point and potential NYISO zone of interconnection, are shown in Table A.9. These blocks do not fill out the total wind area identified for each site in Table A.8.

Figure A.9

Resource Block	Annual Average Capacity (MW)	Point of Interconnection Assumed	NYISO Zone
1	791	Shore Road (LIPA)	K
2	1295	GowanusN (ConEd)	J
3	2594	Shore Road (LIPA)	K
5	2402	Astoria 345 (NYPA)	J
6	1869	Spainbrook (ConEd C)	J

Offshore Wind CAPEX and OPEX

The approach to projecting OSW costs effectively combines NY-specific data characterizing sites with the most recent available data on future OSW cost expectations, in a manner that reflects (or assumes) the expected impact of a regional commitment to OSW at scale and its impact on prices.

CAPEX assumptions from the NYSERDA-internal analysis were first adjusted to a common base year (i.e., assumed to reflect current costs for 5 MW-class turbines installed in NY in 2015). This data was compared to the most recent European cost data for the 5 MW turbine class, and found to be consistent. Next, CAPEX learning curve trends were derived, representing an expected decline in technology costs driven by continued scaling to larger class turbines, global cost reduction, U.S. learning and market visibility. These were derived using data derived from the 2015 NREL ATB (for Techno-Resource Group (TRG) 5 and 6) and the 2016 SIOW, as described in detail further below.

For OPEX, the 2015 NREL ATB OPEX forecast for TRG 5 and 6 was converted to nominal levelized dollars and then studied for each scenario.

TRG 5 and 6 represent offshore wind resources in mid-depth water with weighted average wind speeds of 9.1 m/s and 8.6 m/s respectively. These two TRG groups were selected as the most representative of five offshore wind project sites considered in this analysis.

Offshore Wind CAPEX Over Time

CAPEX trajectories were influenced by the annual rate of change in the 2015 NREL ATB and 2016 SIOW. Several learning curves were derived, each converted to an index (relative to the 2015 nominal value) which could be applied to the CAPEX 'starting point' derived from the NYSERDA-internal analysis.

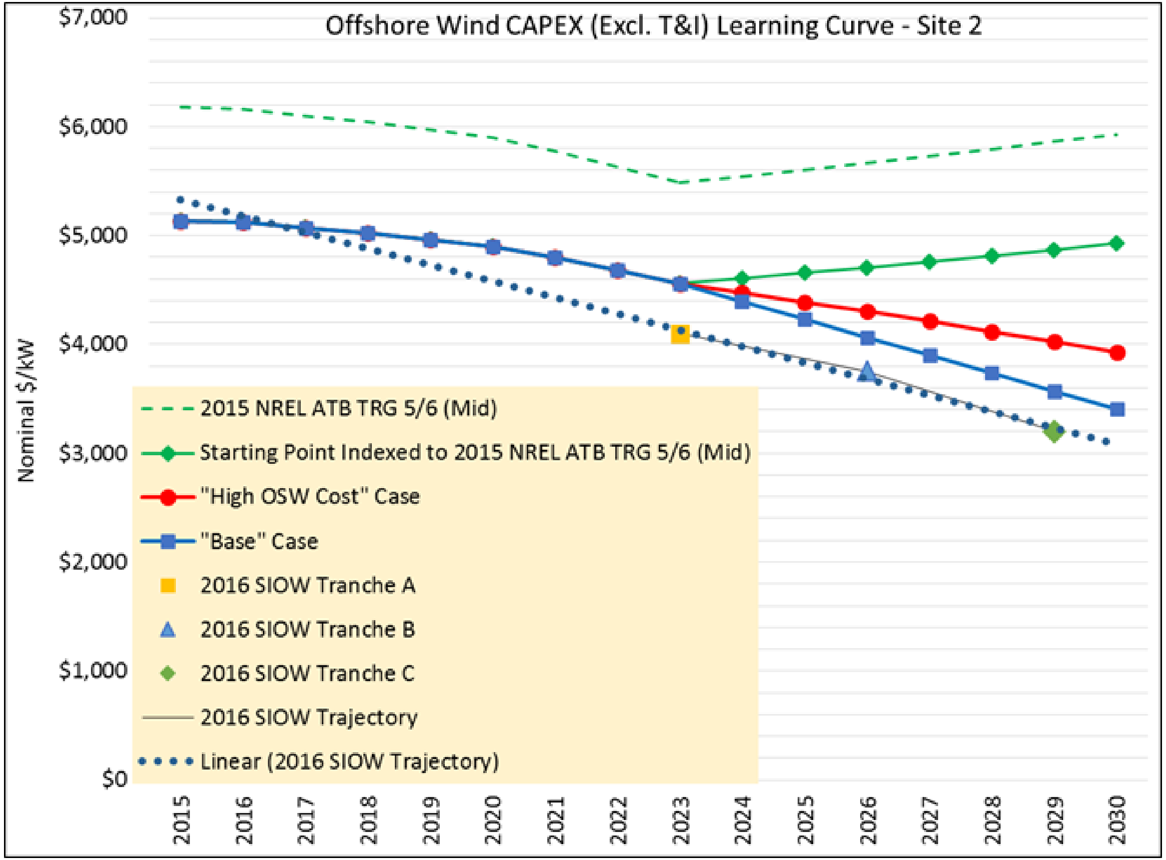
- An '2015 NREL ATB CAPEX trajectory' was developed using the 2015 NREL ATB CAPEX (Mid) trajectory, TRG 5/6. (the dotted green line in Figure A.9). From 2023 onward, this forecast trajectory increases markedly in nominal terms, and was deemed too conservative in comparison to more recent data.
- A '2016 SIOW CAPEX trajectory' was developed from trending the three OSW tranches analyzed therein (dotted blue line in Figure A.9).

The base case was derived by starting with the CAPEX from the NYSERDA-internal analysis, then trending it until 2023 with the index derived from the 2015 NREL ATB CAPEX (dotted green line), and trending it thereafter with the index derived from the 2016 SIOW CAPEX (dotted blue line). The resulting base case is shown as the blue solid line.

An alternative high cost OSW CAPEX trajectory was developed. This took the 2023 base case starting point, and trended it at an index developed as follows. A hybrid learning curve index was created for the period following 2023, based on a weighting of a '2015 NREL ATB CAPEX trajectory' index (30% weight) and a '2016 SIOW CAPEX trajectory' index (70% weight). The result is shown as the red solid line.

OSW CAPEX Trajectory

Figure A.9



OSW Transmission and Interconnection

NYSERDA's internal analysis developed transmission and interconnection (T&I) costs for interconnecting each phase to the associated interconnection points, for both Energy Resource Interconnection Service (ERIS) and Capacity Resource Interconnection Service (CRIS). In deriving these estimates, the following key assumptions were made: (i) The majority of the distance between OSW project and onshore interconnection point was assumed to be via undersea cable due to the lack of high voltage transmission infrastructure on Long Island and the expected difficulty of siting new high voltage lines there; (ii) A fraction of the T&I costs associated with a portion of onshore facilities were assumed to be owned by the interconnecting utility and charged back to the project owner (at lower cost of capital), while the remainder was assumed to be financed by the project owner at the same capital structure as generation facilities.

For this Study, T&I data ERIS costs from the NYSERDA-internal analysis were used, but OSW projects were assumed able to access capacity revenue. It was assumed that any additional upgrades necessary to yield capacity deliverability (i.e., incremental CRIS costs in excess of ERIS costs) would also yield substantial reliability co-benefits such that the cost of these incremental network upgrades were assumed to be socialized. Finally, over time, these T&I costs were held constant in real dollar terms through 2020. Thereafter, they were assumed to decrease by 1% per year in real dollar terms through 2030, consistent with expectations of evolving transmission and interconnection technology and strategy. These costs were added to the CAPEX derived as described above.

Technological Advancement

Net c.f.s were applied to a composite power curve for an 8-MW wind turbine. The CAPEX and OPEX figures from the prior slides reflect a technology evolution which includes both larger turbines at higher hub heights, and other technology advance. The 2017 starting point capacity factors for each site (assuming 100 m in hub height) are summarized in Table A.10.

Table A.10: OSW 2017 Starting Point Capacity Factors

	2017 c.f.
Site 1	43.6%
Site 2	44.0%
Site 3	44.8%
Site 5	44.5%
Site 6	44.5%

A technological advance index was developed by first taking the average of the capacity factor trajectories (Mid) for TRG 5 and TRG 6 in the 2015 NREL ATB, then converting the trajectory into an index with 2017 as the base year to represent gains in OSW turbine production as a result of technological advance and increases in hub height over time. (See Table A.11.)

Table A.11: OSW Index of Production Increase due to Technological Advancement

2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1.000	1.005	1.011	1.016	1.038	1.060	1.081	1.082	1.083	1.084	1.085	1.086	1.087	1.088

OSW Annual Resource Availability (Phase-In)

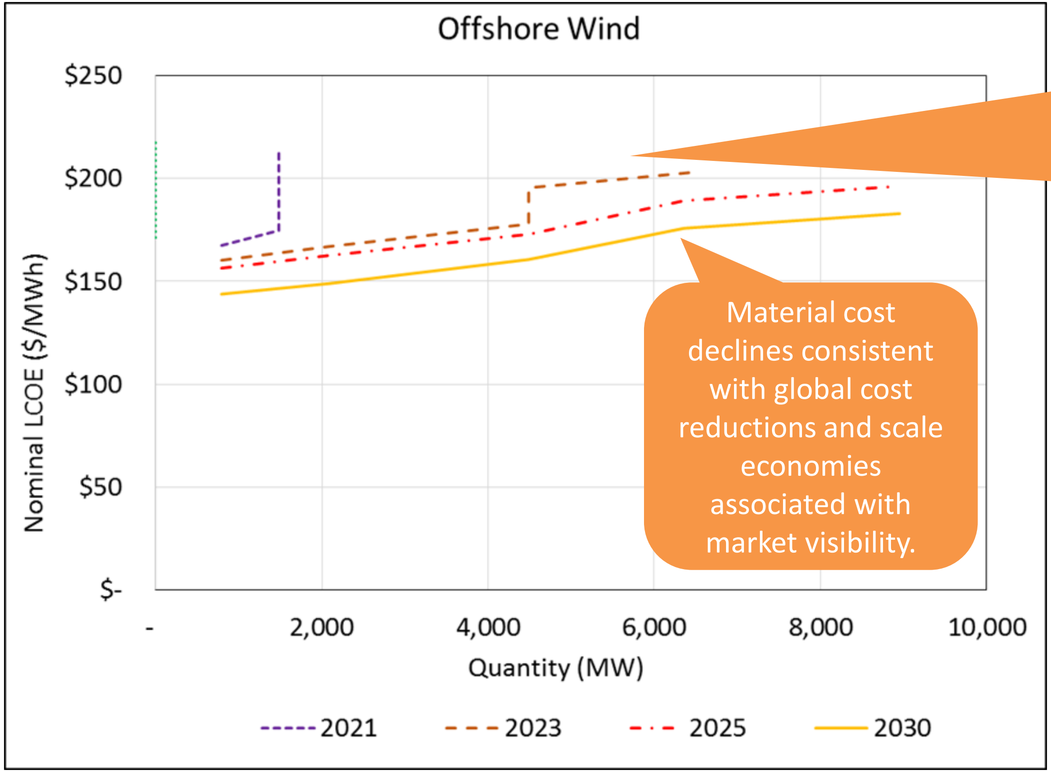
A dynamic approach was taken to derive the annual resource availability of OSW. First, the Year 1 maximum build rate for OSW was set to be 400 MW based on the NYSERDA-internal analysis, which also provided assumptions for increases in number of deployable turbines per year in subsequent years as a result of both learning effects and infrastructure/supply chain expansion. These annual deployment rates were extrapolated, and assumed to apply to 8 MW-class turbines. See Table A.12. The growth rate implicit in Table A.12 was applied dynamically to the OSW modeled in the analysis, i.e. each year the maximum would be last year's deployment plus the growth rate between last year and the current year.

Table A.12: Maximum OSW Build Rate

Site	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
Max Turbine Build Rate	50	60	72	86	102	120	140	162	186	212	240
Max Cumulative Turbines	50	110	182	268	370	490	630	792	978	1190	1430
Max. Cumulative Build (MW)	400	880	1456	2144	2960	3920	5040	6336	7824	9520	11440

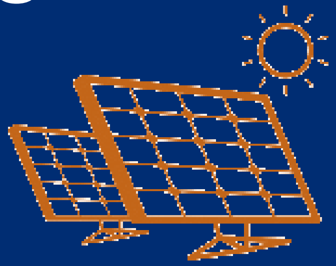
LCOE Supply Curves – Offshore Wind

Figure A.10



There is a rapid increase in resource availability in the later years, as the maximum incremental build rate from year to year continues to increase due to market maturation.

Appendix A.2.3 – Utility-Scale Solar PV



NEW YORK STATE OF OPPORTUNITY.

Utility Scale Solar Photovoltaic (PV): Overview of Approach

Utility-scale solar PV has yet to be cost competitive in the northeast RPS markets without explicit carve-outs or co-incentives, but this situation is expected to change in the near future as developers are actively developing larger-scale projects, and such installations are already competitive with the least cost LSRs in many other locations.

Distributed generation solar PV is assumed to be eligible for Tier 1, but for purposes of this analysis, was assumed to be driven by other programmatic activity, such as NY-Sun.

A geospatial analysis was conducted to estimate the total developable area after considering certain land-use types and constraints. Since the gross land area potentially available far exceeds the amount of utility-scale PV that would ever be deployed, the analysis was limited to sites near existing interconnection opportunities and roads, likely to have lowest cost. The analysis focused on installations in the 10-30 MW scale assumed likely to dominate this sector.

This geospatial analysis is less site-specific than the LBW analysis, as (other than interconnection cost) most sites would have similar costs and production. Therefore the results are more aggregated than in the LBW analysis, with resource blocks representing sites grouped by similar cost characteristics within each NYISO zone.

CAPEX

(not including Transmission and Interconnection Cost)

Utility-Scale Solar CAPEX baselines representing the capital expenditure of developing a 10-30 MW utility-scale solar project (Fixed-Tilt and 1-Axis Tracker) were derived based on an examination of publicly available sources, the consultant's past LSR analyses, and interviews with solar developers active (or planning to be active in this scale) in New York.

"Conservative" baselines assuming a lower degree of market maturation were also selected and used for the High PV Cost sensitivity scenario.

Two locational adjustments were applied to the Baselines to reflect regional cost differences in PV development among NY regions (Siting Factor), as well as cost differences of solar siting and permitting between different NY regions and the national average (EIA Regional Factor). See Table A.14.

The capacity and $/kW cost data (CAPEX and Fixed O&M) used in this analysis are expressed in DC.

CAPEX

(not including Transmission and Interconnection Cost)

Table A.13: Utility-Scale PV CAPEX Baseline

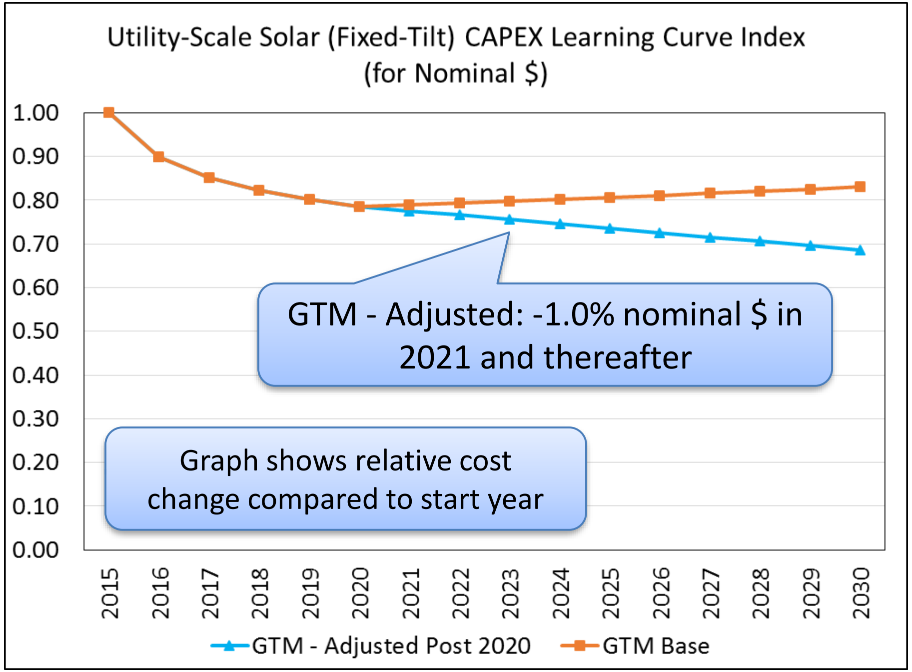
CAPEX Baseline (2014$/kW)	2014 CAPEX Baseline	
Technology & Size Category	Base	Conservative
Solar 10-30 MW, Fixed Tilt	$1,423	$1,503
Solar 10-30 MW, Single Axis	$1,843	$1,843

Table A.14: Utility-Scale PV CAPEX Adjustment Factors

NY Region	NYISO Zones	EIA Regional Factor	Siting Factor	Final Adjustment Factor
Upstate	A, thru I	0.98	1.00	0.98
NYC	J	1.25	1.02	1.28
LI	K	1.45	1.02	1.48

CAPEX Experience Curves (Fixed-Tilt)

Figure A.11: Utility-Scale Fixed-Tilt Cost Trend



An initial CAPEX trajectory (in real $ terms) was developed for fixed-tilt projects using the cost trend published by Greentech Media in November 2015 (1).

From 2020 onward, this forecast trajectory (which increases in nominal terms) was deemed too conservative.

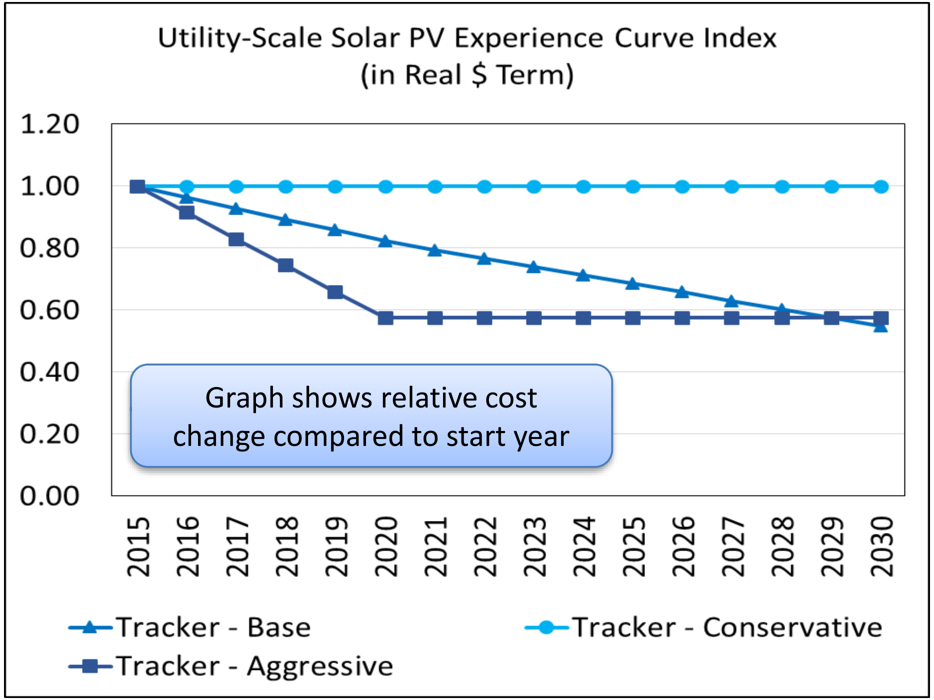
For the Base analysis, the GTM forecast was used through 2020 and thereafter the cost trajectory was assumed to decline by 1.0% in nominal dollar terms each year.

For the High PV Cost sensitivity analysis, the GTM forecast was used through 2030.

(1) GTM November 3, 2015 Presentation (http://www.greentechmedia.com/articles/read/Slideshow-Reaching-250-GW-The-Next-Order-of-Magnitude-in-US-Solar)

CAPEX Experience Curves (Tracker)

Figure A.12



CAPEX trajectories for single-axis tracker projects (in real $ terms) were taken from the 2015 NREL ATB. A Base trajectory and two alternative futures (aggressive and conservative) were developed.

Only the Base trajectory was used in this analysis.

OPEX (O&M)

Nominal levelized fixed O&M baselines were developed for fixed-tilt and single-axis tracker projects, based on an examination of publicly available sources and the consultant’s past LSR analyses. No variable O&M costs for utility-scale solar PV were modeled in this analysis.

After determining the baselines, a labor cost adjustment factor of 1.1 (derived as a ratio of the NY annual mean wage for “Installation, Maintenance and Repair” occupations to the national annual mean wage for the same category) was applied to the baselines in Table A.15 as a proxy of regional labor cost differences between New York and the national average.

The O&M costs were held constant in real dollar terms, increasing with inflation over time in nominal dollar terms.

Table A.15: Utility-Scale PV OPEX Baselines

Technology & Size Category	Fixed O&M Cost Baselines (Nominal $/kW-yr)
Solar 10-30 MW, Fixed Tilt	$30.00
Solar 10-30 MW, Single Axis Tracker	$40.00

Fixed-Tilt vs. Single Axis Tracker Projects

Both fixed-tilt and single-axis tracker solar projects could be developed on the same sites identified in the utility-scale solar resource potential analysis described on the next several pages.

Fixed-tilt and single-axis tracker solar facilities have different cost and production characteristics, with single-axis trackers producing more energy but at higher CAPEX and OPEX. To determine which technology option would be cost-optimal to deploy at a specific location in a given year based on the study assumptions, this Study assumed that developers would install whichever technology option would have a lower levelized revenue requirement at the time of solicitation.

Based on this assumption, alternative resource blocks were created for each zone, representing each technology option. The supply curve selects between alternative fixed-tilt or single-axis tracker solar resource blocks in each year by selecting the technology type with the lower levelized premium. The lower-cost technology would be made available to be deployed for that resource block in that particular year.

Resource Potential

A geospatial analysis for determining utility-scale PV resource potential was developed using a site screening approach based on a review of publicly available solar and renewable energy technical potential studies. Several simplifying assumptions were made in this analysis:

- A utility-scale solar PV project would connect at either 23-46 kV, 69 kV and 115 kV (voltages for which data was readily available in a GIS data layer)
- Given the ample land available and economic considerations, developers would choose to site utility-scale solar PV projects near existing substations instead of building new substations over the span of the study period. Hence, a utility-scale solar PV project would interconnect to an existing substation.

Similar to determining land-based wind resource potential, all primary constraint land areas (see Table A.16) were first excluded in the analysis. A secondary-level constraint was applied to exclude all areas beyond 2 miles of any roads and beyond 3 miles of any existing substations (at 23-46 kV, 69 kV and 115 kV).

The remaining contiguous areas were considered as potential project sites. A power density of 7.5 acres/MW was used to calculate the resource potential (in MW) at each site. Only sites with a capacity of 10 MW or higher were considered in this analysis.

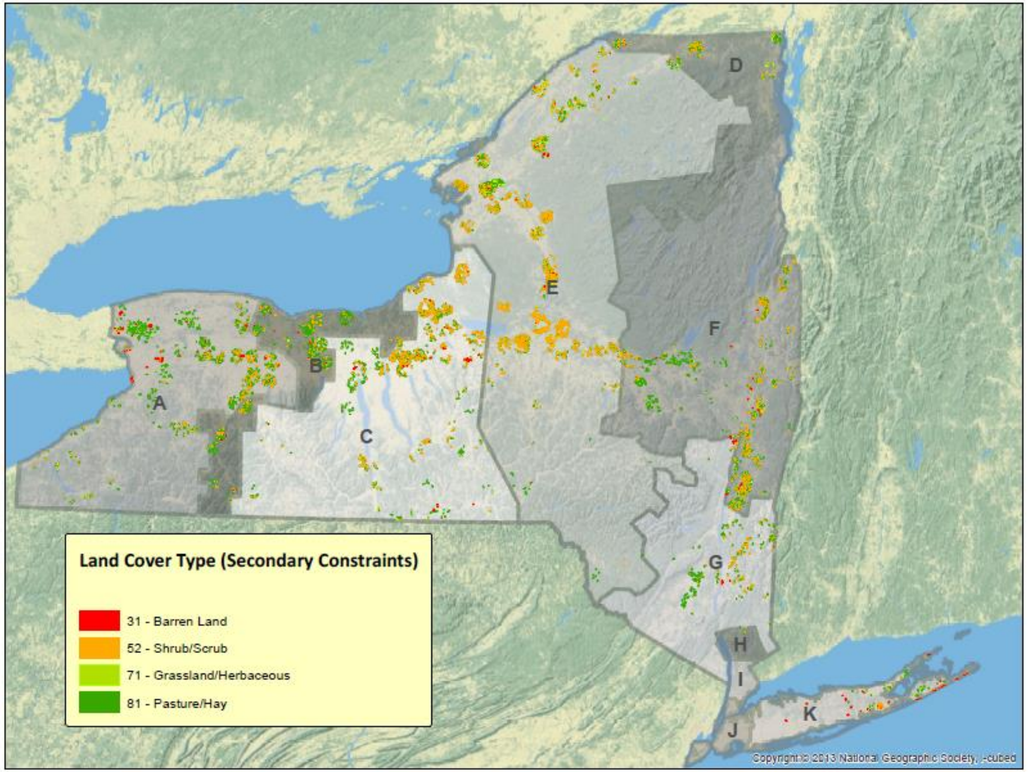
Table A.16

Utility-Scale PV Primary Constraints

Primary Constraints - Excluded Areas	Additional Buffer Beyond Excluded Area
Adirondack and Catskill Parks	100 ft.
National Historic Preserves/Sites/Parks	100 ft.
Wildlife Management Areas	100 ft.
State Unique Area	100 ft.
State and Local Parks	100 ft.
National Monuments	100 ft.
National Wildlife Refuges	100 ft.
National Park Service Land	100 ft.
Fish and Wildlife Service Lands	100 ft.
American Indian Lands	100 ft.
GAP Status 1 & 2 Lands (Protected Lands)	100 ft.
Urban Areas	25 ft.
Forests	0 ft.
Cultivated Crops	0 ft.
Wetlands & Waterbodies	100 ft.
Existing Roads and Highways	25 ft.
Airports	25 ft.
Slopes ≥ 5%	N/A

Probability De-rates by Land Cover Type

Figure A.13: Utility-Scale PV Potential Sites by Land Cover Type



Potential sites shown here are the result of probabilistic geospatial analysis and should not be interpreted as defining actual project sites.

The identified sites were spatially correlated with land cover types (Barren Land, Shrub/Scrub, Grassland/Herbaceous, Pasture/Hay).

A probability de-rate of 25% was applied to the pasture/hay area within a site to reflect a lower probability of permitting success (i.e., permittable area after de-rate = 100% of other land cover areas and 25% of pasture/hay area).

Grouping Sites into Resource Blocks

An economic optimization analysis, as described in Appendix A.6, was conducted to identify the least-cost interconnection configuration for each site.

Unlike LBW, utility-scale PV resource blocks were treated as an aggregation of sites with similar cost characteristics and market values. Since this analysis assumed little CAPEX variations among sites, the key driver of cost differences was interconnection cost. As a result, the sites were categorized by NYISO zones into four interconnection cost ranges:

- ≤$20/kW
- >$20 - $50/kW
- >$50 - $150/kW
- >$150/kW

Capacity Factors

Capacity factors (c.f.s) for utility-scale solar PV (fixed-tilt and single-axis tracker) were derived using 8760 hourly production data from PV Watts® Calculator at representative location for each NYISO zone using the following system information as inputs (with other inputs kept at default). Resulting Year 1 c.f. at each zone are shown in Table A.17.

Table A.18: Assumed PV System Characteristics

Inputs	Fixed	1-Axis
Modeled System Size (MW DC)	20	20
Module Type	Standard	Standard
Array Type	Fixed (Open Rack)	1-Axis Tracking
Array Tilt (Degree)	25	25
Array Azimuth (Degree)	180	180
DC to AC Size Ratio	1.22	1.22

Table A.17: Year 1 PV c.f. at each zone

Zone	Selected Location	Fixed	1-Axis
A	Buffalo	13.7%	16.2%
B	Rochester	13.9%	16.5%
C	Syracuse	14.2%	17.0%
D	Plattsburgh	14.6%	17.3%
E	Utica	12.7%	15.1%
F	Albany	14.6%	17.3%
G	Poughkeepsie	13.3%	15.7%
H	Millwood	14.4%	17.2%
I	Yonkers	15.1%	18.1%
J	New York City	15.4%	18.3%
K	Long Island	14.7%	17.6%

The Year 1 c.f. were then levelized to produce a single c.f. for each system in all years, to account for an annual production degradation of 0.5%.

NEW YORK STATE OF OPPORTUNITY.

Annual Resource Availability (Phase-In)

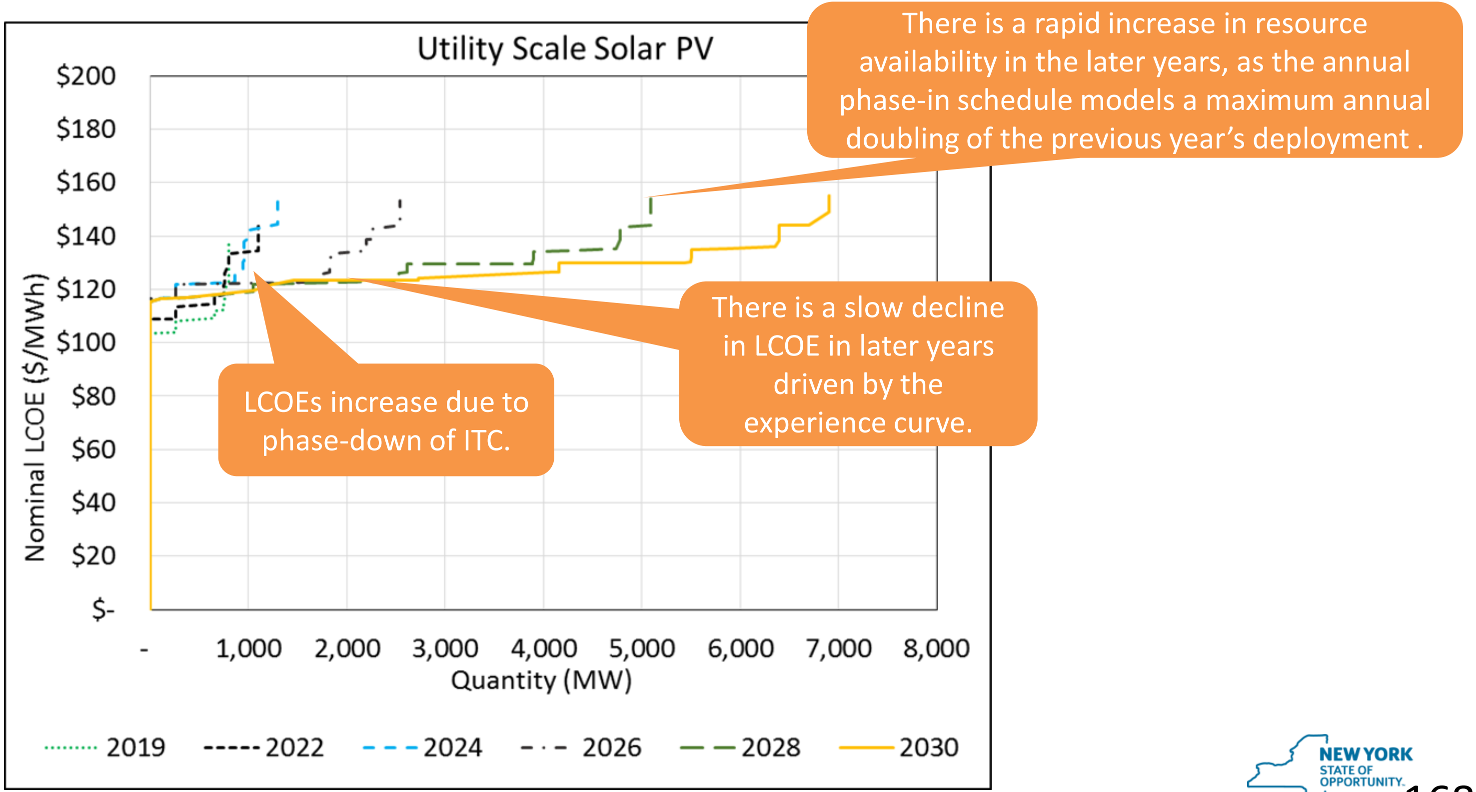
A dynamic approach was taken to derive the annual resource availability of utility-scale solar PV.

First, the 2017 maximum build rate for utility-scale solar was set to be 300 MW based on observations in other early-stage utility-scale markets.

Thereafter, the annual build rate was capped at no more than 200% of the previous year's installed quantity until 100% of resource potential is reached. e.g., if no utility-scale solar PV was deployed until 2024, the annual phase-in % would remain at 300 MW expressed as a % of the total resource potential during that period. If 250 MW of utility-scale solar was deployed in 2024, then the maximum amount deployable in 2025 would be 500 MW (expressed as a % of the total resource potential).

LCOE Supply Curves: Utility-Scale Solar PV

Figure A.14



Appendix A.2.4 – Small Hydroelectric

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Overview of Approach

Methodologies for determining CAPEX, OPEX, and resource potential were developed based on interviews with developers currently active in New York's hydro market and a literature review of publicly available data from the Idaho National Engineering and Environmental Laboratory (INL), Oak Ridge National Laboratory (ORNL), and the U.S. Department of Energy.

When considering the data from these publicly available studies, it is important to understand that the costs and potential of hydro resources are both extremely site-specific and (for costs) size-sensitive. The following cost and resource potential modeling exercises attempted to represent the central tendency of hydro development based on historical data. A comprehensive site screening exercise beyond the scope of this study would be required in order to accurately capture the true economics and hydro resource development potential in New York.

Hydro Resources Considered

The New York Main Tier RPS limits hydro eligibility to (i) upgrades to existing facilities and (ii) new power facilities less than 30 MW, run-of-river projects that do not involve the creation of new impoundments. Four types of small hydro resources potentially eligible under Main Tier RPS eligibility rules were examined at the initial phase of this analysis: upgrades, non-powered existing dams (NPD), repowering of existing dams, and run-of-river/in-stream hydro resources.

Based on a lack of data and interviews with developers, it was concluded that run-of-river/in-stream hydro without dams are not yet commercial, and likely will not be commercial over the span of this study.

While interviewed developers have indicated some development activities with the repowering of existing dams, the available aggregate public data sources did not provide any resource potential or cost data for New York for this category. Although not confirmed, this category may have been grouped into the upgrades or NPD categories in national studies used for this analysis. More granular and site-specific data may be available, but vetting such data would be beyond the scope of this analysis.

Based on the rationale above, only upgrades and NPD are included in this analysis.

Hydro CAPEX

(not including Transmission & Interconnection Costs)

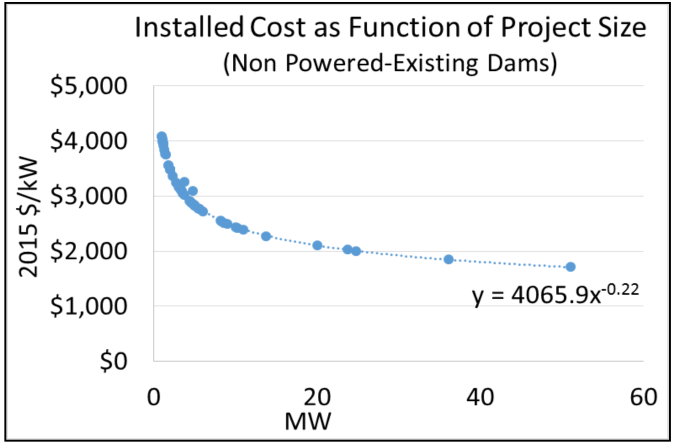
The baseline CAPEX for hydro upgrades and hydro non-powered dams were derived using data from the 2003 Idaho National Laboratory (INL) Hydropower Resource Economics Database as a basis.

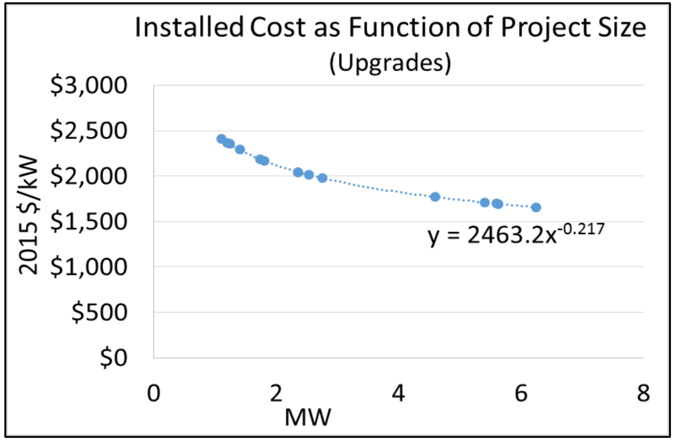
The INL database provides estimated project development and operation costs for 2,155 hydropower sites in the U.S. These costs were developed using estimation tools based on historic experience for similar facilities.

Installed cost as function of project scale, for different installation types, were derived based on a regression analysis of data points from the INL database (see Figure A.15).

The entire cost functions were then escalated to 2015 dollar terms using the Handy-Whitman Index (~1.5) for "Total Hydraulic Production Plant."

Figure A.15: Hydro Installed Cost as Function of Project Size





Hydro CAPEX

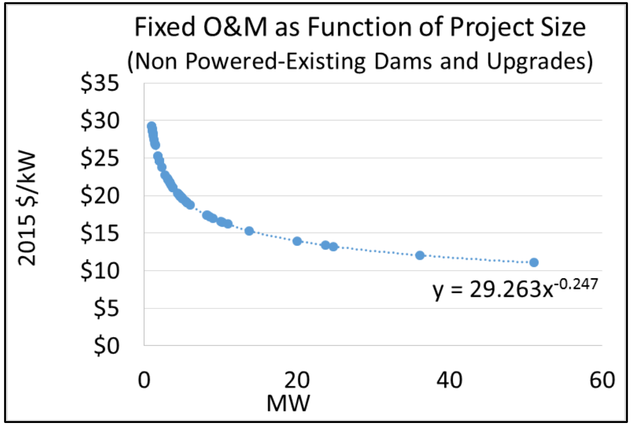
The INL definition of installed cost includes:

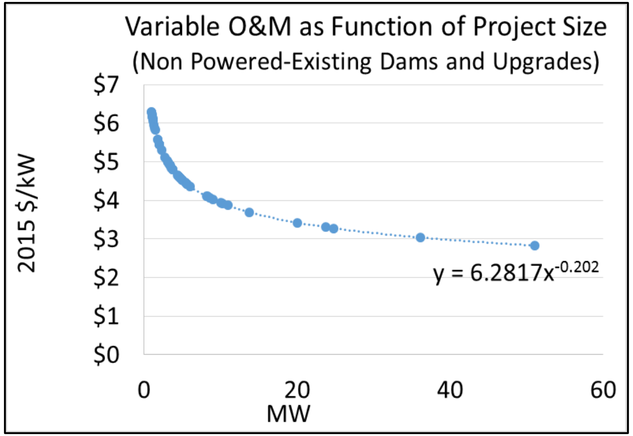
- Overnight development cost including soft costs; plus
- Total mitigation cost

However, it does not include construction financing. Using data from the 2015 NREL ATB, this analysis assumed that construction financing makes up 3.7% of CAPEX. Hence, the cost derived for each hydro site using the escalated INL cost functions was scaled upward by 3.7% to account for construction financing.

Because small hydro is a mature technology, this analysis assumed no experience curve (technological advance) in real dollar terms.

Figure A.16: Hydro Fixed & Variable O&M as Function of Project Size





Hydro OPEX

Similar to CAPEX, fixed and variable O&M costs as functions of project scales were derived based on a regression analysis of data points from the 2003 INL database, and then escalated to 2015 dollar terms using the EIA AEO 2015 GDP index.

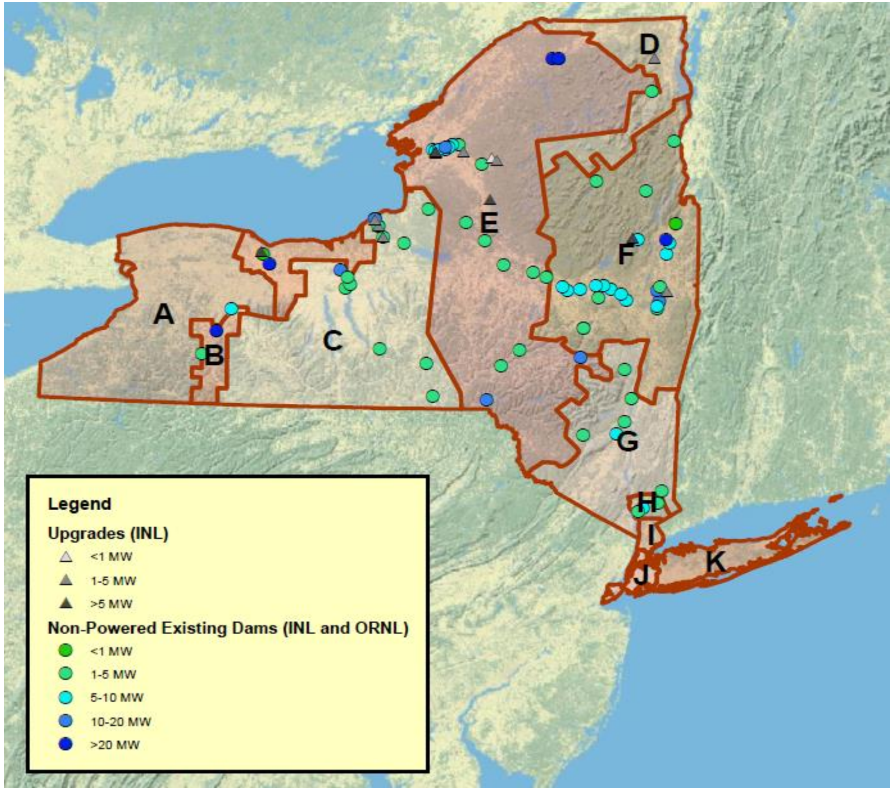
The INL definition of fixed O&M includes costs of operation supervision and engineering; maintenance supervision and engineering; maintenance of structures; maintenance of reservoirs, dams and waterways; maintenance of electric plant; and maintenance of miscellaneous hydraulic plant.

The INL definition of variable O&M includes cost of water for power; hydraulic expenses; electric expenses; miscellaneous hydraulic power expenses; and rents.

However, the INL does not account for local property tax rates for hydro projects. A proxy local property tax rate of $50/kW was applied for all projects in this analysis.

Hydro Resource Potential

Figure A.17: Distribution of Potential Hydro Sites



The 2003 INL study and 2012 ORNL include geographical coordinates for hydro upgrade and hydro NPD sites in New York state, along with site characteristics, such as estimated capacity and monthly production. As explained in more detail below, the source data may however not be a reliable indicator of actual available or suitable sites and is thus not presented as such in this Study.

Hydro sites that do not meet the existing Main Tier RPS eligibility requirements for hydro were excluded from this analysis.

Sites that are eligible were geospatially correlated with the eleven NYISO zones.

For NPD, the distance of each site from the nearest existing substations (at 23-46 kV, 69 kV and 115 kV) was defined for interconnection cost calculations. Upgrades were assumed to already be interconnected and to require minimum if any additional interconnection cost.

Hydro Resource Potential Adjustments

Interviews with several hydro developers active in NY indicated that national-level hydro resource potential studies like the INL and ORNL studies used for this analysis may be less than fully adequate for purposes of this study in several respects. For example:

- As regards the viable **generation per site**, they tend to model idealized (unrealistically high) resource potential (site capacity and/or energy production) based on the total measured total water flow; they also do not accurately account for economic and operational considerations that can dictate project viability and scale, and thereby frequently overstate economically developable production.
- As regards the **number of available sites**, earlier site surveys (which do not screen for permittability under modern standards) list a materially greater number of sites than were characterized in these national studies, suggesting that the national studies may understate the total population of developable sites.

Hydro Resource Potential Adjustments (cont’d)

A more thorough analysis would require site-by-site screening, well beyond the study scope. In the face of incomplete (with respect to the total list of potential sites) and potentially overstated production, the following adjustments were made to the effective potential of each hydro site:

- The resource potential for each resource block was tripled (which has the effect of tripling the number of potential sites, but not the size of the site itself) to align the total hydro resource potential number with a much older but more comprehensive survey commissioned by NYSERDA that has granular hydro site data for New York state.
- For the development of hydro upgrade projects, existing owners of the dams are required to open up their FERC licenses, which would expose them to the risk of losing said licenses. Interviewed developers observed that many technically-feasible upgrade projects may not get developed because of this concern. Further, as noted above, the comprehensive survey data did not account for meeting modern permitting criteria, which later studies by INL and ORNL account for. Therefore, a 50% probability de-rate was applied to the resource potential of each block (again, does not affect modeled size of individual site) to represent this “license lock-in” constraint and potential federal permitting challenges.
- Capacity factors were adjusted, as discussed below.

Hydro Capacity Factors

The INL and ORNL databases provide monthly production data, as well as the nameplate capacity for each identified hydro site. This data was used as the basis for calculating capacity factors for each site in this analysis.

The monthly production data from INL and ORNL is modeled based on water flow measurements. Developers noted that this type of modeling exercise will likely overestimate production since, in reality, hydro facilities cannot capture every single drop of water flow. For comparison, a typical small hydro project in New York may have capacity factor of around 60%, whereas most capacity factors calculated using the monthly production data and site capacity data from the INL and ORNL studies were in the 70 – 80% range, with a few sites yielding capacity factors greater than 100% in some months.

To avoid overestimating the production of hydro resources, the monthly production data was capped at a maximum 60% annual capacity factor.

According to developers interviewed, upgrades projects would usually yield less production than a typical baseload project. To reflect this observation, the calculated capacity factors for hydro upgrades were then further capped at 35%.

Annual Resource Availability (Phase-In)

Unlike land-based wind and utility-scale solar PV, hydro resources are not subject to the same type of supply chain constraints or other limitations as less commercially mature technologies with much larger incremental resource potential.

Instead, the build-out rates of hydro resources are much more likely to be affected by federal permitting challenges and lead times (and consistent with the modest level of activity seen under the Main Tier RPS to date).

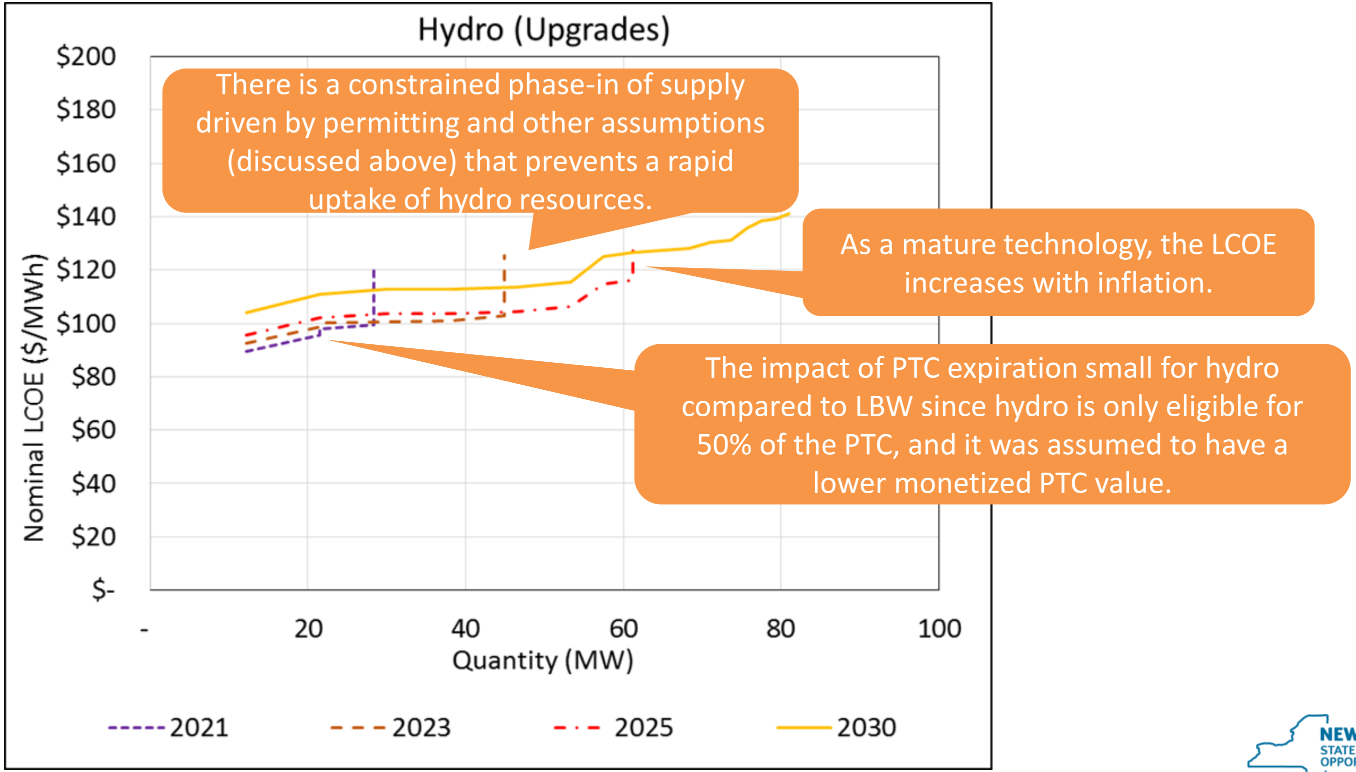
This analysis assumed a relatively slow build-out rate for hydro resources to reflect permitting-related barriers, as shown in Table A.19.

Table A.19: Annual Phase-In Rate for Hydro (Upgrades) and Hydro (NPD)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Upgrades	5%	10%	15%	20%	30%	40%	50%	60%	75%	90%	100%	100%	100%	100%
NPD	0%	0%	2.5%	5%	8%	10%	15%	25%	45%	55%	70%	80%	90%	100%

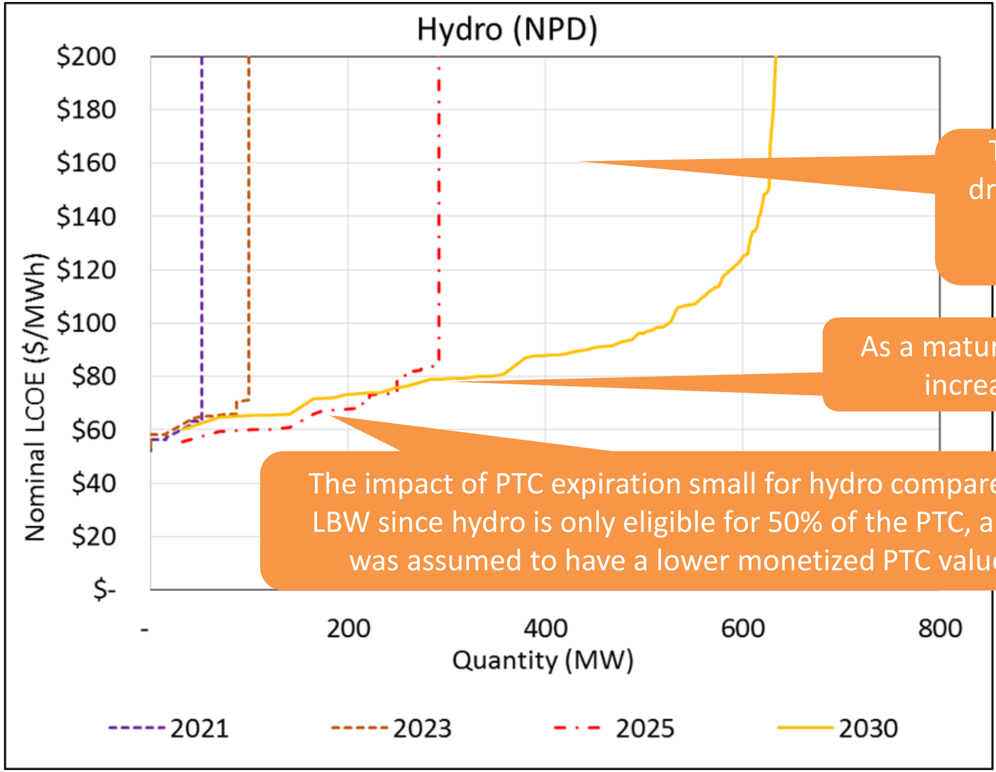
LCOE Supply Curves – Hydro Upgrades

Figure A.18



LCOE Supply Curves – Small Hydro at Non-Powered Dams

Figure A.19



There is a constrained phase-in of supply driven by permitting and other assumptions (discussed above) that prevents a rapid uptake of hydro resources.

As a mature technology, the LCOE increases with inflation.

The impact of PTC expiration small for hydro compared to LBW since hydro is only eligible for 50% of the PTC, and it was assumed to have a lower monetized PTC value.

Appendix A.2.5 – Woody Biomass

Overview of Approach

Incremental biomass-to-electricity is a complex and multifaceted potential source of LSR supply for two reasons. First, it can be produced by a variety of technologies and applications, including new facilities, repowering of existing facilities not currently burning biomass, and substituting fuel in existing fossil fueled generators. In addition, biomass is the only LSR that requires fuel, and the fuel sources are varied in their geographic availability and cost (thus having their own fuel supply curve).

Woody biomass resources examined include (i) Fossil-fired generators (both retired and operating) repowered as dedicated biomass-to-energy generators, and (ii) Greenfield dedicated biomass integrated gasification combined cycle (IGCC). Other potential sources were excluded from this analysis, including:

- Direct fire or fluidized bed biomass, due to the low likelihood that such resources would be both permittable and economic to deploy.
- Co-firing of existing coal-fired plants with biomass fuel, as a result of Gov. Cuomo's recent announcement of intent to retire all coal-fired plants in NY.
- Combined heat and power (CHP), including conversion of existing CHP applications from fossil fueled to biomass, as well as new CHP applications.

Resource Costs and Technology Assumptions

Resource cost assumptions, capacity factors and heat rates used for woody biomass resources in this analysis were first developed based on past LSR analyses and available public studies. These assumptions were then reviewed and finalized by Antares Group, Inc. to align with market trends.

To determine the resource potential for biomass repowering (retired and operating) units, available retired or operating fossil-fueled generators in New York were identified and screened for units that might potentially be repowered as dedicated biomass generation units. The identified units were aggregated by NYISO zones into resource blocks.

As noted, the study assumed that new dedicated direct-fired or fluidized bed facilities would not be broadly viable. Instead, greenfield dedicated biomass integrated gasification combined cycle (IGCC) resources were modeled in the Supply Curve. The resource potential for IGCC biomass is limited by the availability of fuel from the fuel supply allocation modeling (discussed below). One cost advantage of IGCC technology is that it could allow access to a broader set of low-cost fuels not otherwise eligible if directly combusted under Main Tier RPS rules (which were assumed to apply under the CES).

Biomass technologies and their resource potential and other characteristics are shown in Table A.20.

Woody Biomass Assumptions

Table A.20

Biomass Resource Category	Zone	Capacity (MW)	Capacity Adjustment	Adjusted Capacity (MW)	c.f.	Heat Rate (BTU/kWh)	2017 Cost (2015 $)			
							Installed Cost ($/MWh)	Interconnection Cost ($/MWh)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Biomass Repower - Retired Units	A	310.80	50%	155.40	80%	13500	$1,682	-	$111	$5
	B	239.00	50%	119.50	80%	13500	$1,682	-	$111	$5
	C	277.00	50%	138.50	80%	13500	$1,682	-	$111	$5
Biomass Repower - Operating Units	A	118.80	50%	59.40	80%	13500	$1,682	-	$111	$5
Biomass - IGCC	A	Fuel-Limited	100%	Fuel-Limited	90%	11500	$4,112	$74	$111	$5
	B	Fuel-Limited	100%	Fuel-Limited	90%	11500	$4,112	$74	$111	$5
	C	Fuel-Limited	100%	Fuel-Limited	90%	11500	$4,112	$74	$111	$5
	E	Fuel-Limited	100%	Fuel-Limited	90%	11500	$4,112	$74	$111	$5
	D	Fuel-Limited	100%	Fuel-Limited	90%	11500	$4,112	$74	$111	$5
	F	Fuel-Limited	100%	Fuel-Limited	90%	11500	$4,112	$74	$111	$5
	G	Fuel-Limited	100%	Fuel-Limited	90%	11500	$4,112	$74	$111	$5
	H	Fuel-Limited	100%	Fuel-Limited	90%	11500	$4,112	$74	$111	$5

Capacity of some resources adjusted downward to reflect probability of success driven by siting and permitting constraints; based on revised assumptions from 2008 RPS study

Woody Biomass Fuel Supply

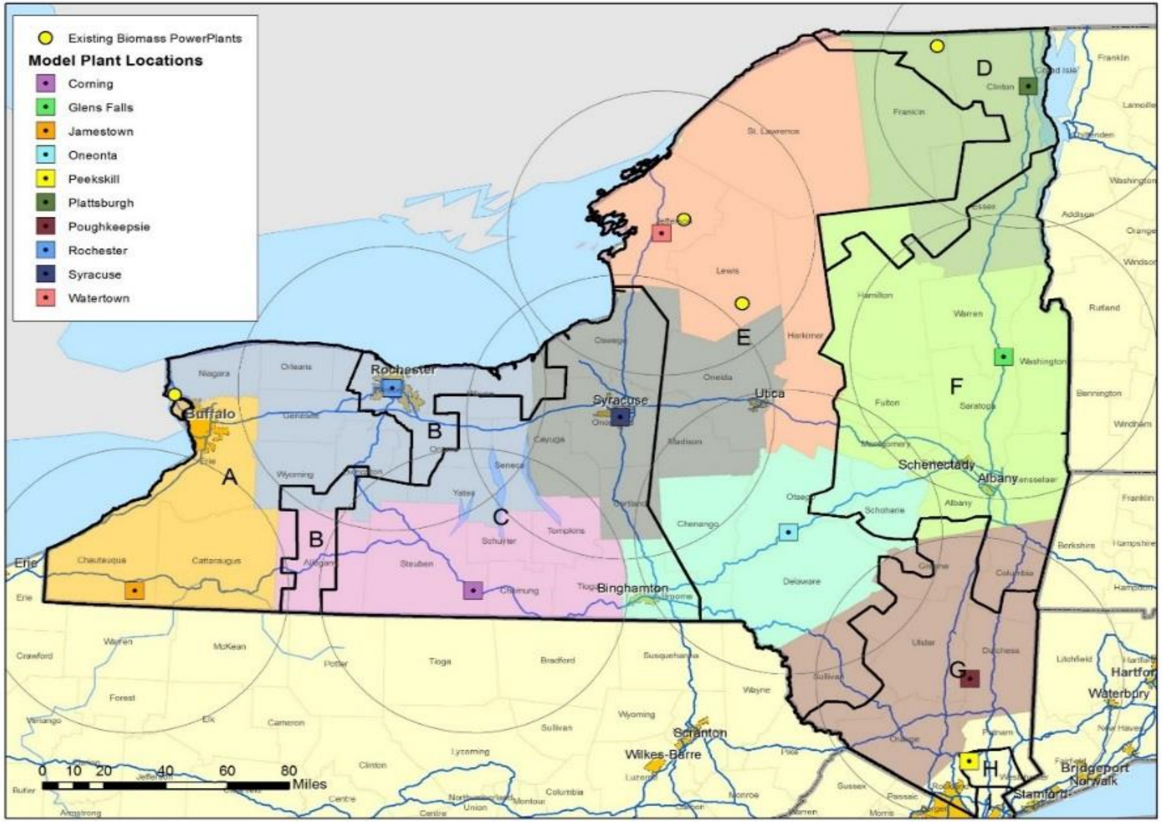
In addition to the availability of existing units (in the case of biomass repowering), biomass resource potential is dictated by the quantity of fuel economically available, which is in turn dictated by physical accessibility and cost. A material cost component of biomass fuel is the cost to transport it to the power plant, limiting the viable 'fuel basket' for each potential plant.

Representative bioenergy project locations were identified within each zone in order to realistically account for both fuel availability to plants within that zone, taking into account associated transportation costs. These potential locations were selected to be a reasonable proxy for a bioenergy project, with nearby access to electric infrastructure, proximity to population centers (representing workforce availability and by proxy water supply infrastructure), and highway/rail access (see Figure A.20).

To model the availability of biomass fuel supply and associated costs, Antares Group conducted a geospatial analysis (based in part on prior work for the Renewable Fuels Roadmap and Sustainable Biomass Feedstock Supply for New York, Annual Update #2 (2012) published in January 2013) to estimate the total quantity of biomass available at different delivered price points within each of the NYISO Zones. Biomass resources considered include forest and urban resources by county, including (i) forest based biomass; (ii) willow; and (iii) construction and demolition (C&D) wood. C&D was assumed to only be available if combusted in an IGCC configuration. The resulting biomass fuel supply curves are shown in Figures A.21.

Model Plant Locations and Zones

Figure A.20



Woody Biomass Fuel Supply Curves

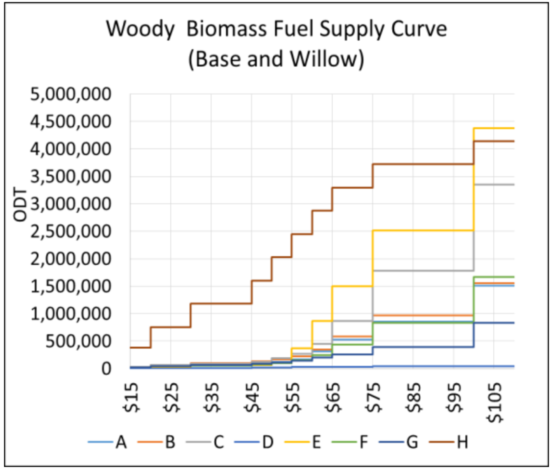
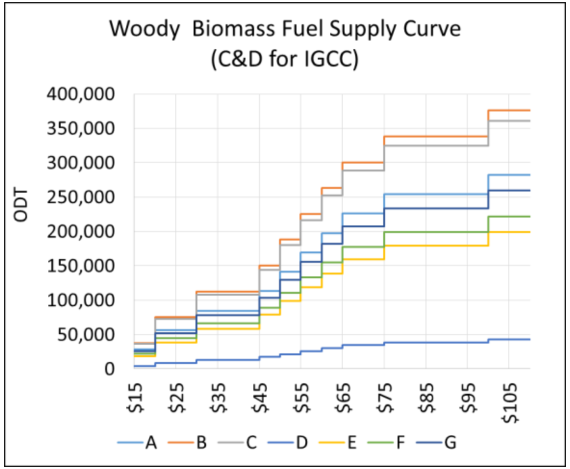
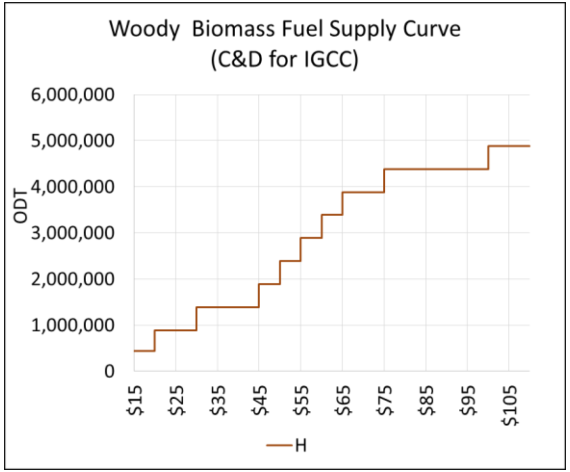


Figure A.21





Allocation of Biomass Fuel to Specific Plants

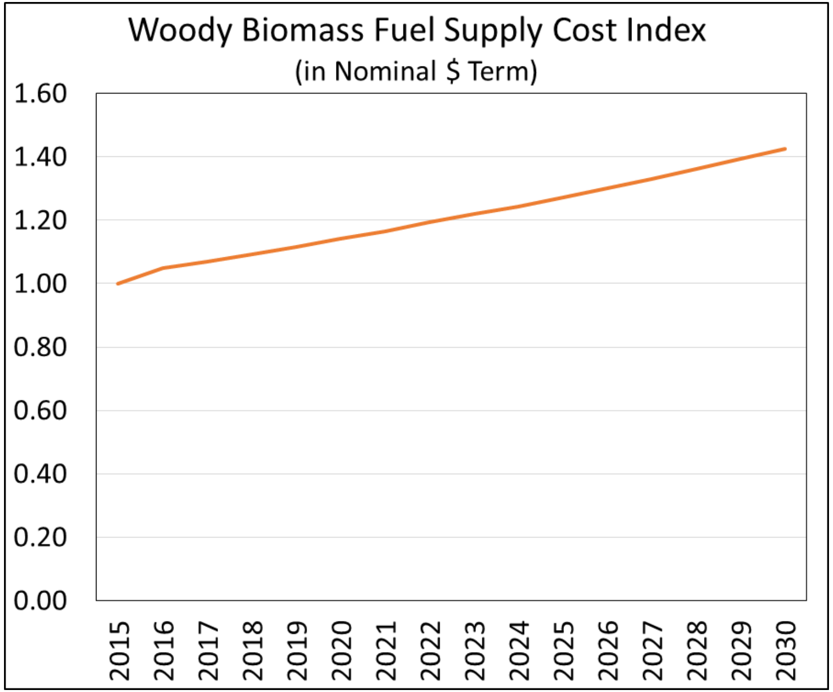
Within each NYISO zone, the available woody biomass fuel supply was allocated to the resource blocks listed in Table A.20 from least to highest cost based on each block's 2017 LCOEs (not including biomass fuel cost).

The available fuel supply was first allocated to the resource block with the lowest LCOE resource block up the supply curve, until the block's maximum fuel requirement was fully satisfied. The remaining fuel supply would be allocated to next cheapest block, and so forth until all available supply was been fully allocated. The marginal resource block (the last resource block receiving fuel supply) was allocated the remaining quantity. Its resource potential would be reduced to the MW-equivalent of the allocated fuel supply. Resource blocks that are more expensive than the marginal block would receive no fuel supply and thereby would appear to have zero resource potential in the supply curve.

In addition to forest based biomass and willow, C&D wood supply was also assumed to be available for Biomass IGCC resources. Biomass IGCC blocks were modeled to receive C&D wood supply first. They would then compete head-to-head with other biomass resources for available "Base and Willow" supply. The sum of the C&D wood supply and "Base and Willow" supply was the total resource potential for Biomass IGCC.

Woody Biomass Fuel Supply Cost

Figure A.22: Woody Biomass Fuel Supply Cost Index



The weighted average $/MMBTU cost of all supply allocated to a resource block would set the Year 1 fuel supply cost baseline for that block.

In this analysis, a nominal levelized fuel supply cost (assumed to be the Year 1 fuel supply cost baseline adjusted by a 10% discount rate) was used.

Since transportation cost is a key driver of biomass supply cost, the nominal levelized fuel supply cost was assumed to escalate at a hybrid cost trajectory (in nominal dollar terms) comprising of the 2015 EIA AEO "Transportation Diesel Fuel" index for the Mid-Atlantic region (accounting for 25% of escalation) and the 2015 EIA AEO GDP Chain-type Price Index (accounting for 75% of escalation).

Annual Resource Availability (Phase-In)

The annual maximum biomass build-out rate (shown in Table A.21) was assumed to be predominantly driven by development timing.

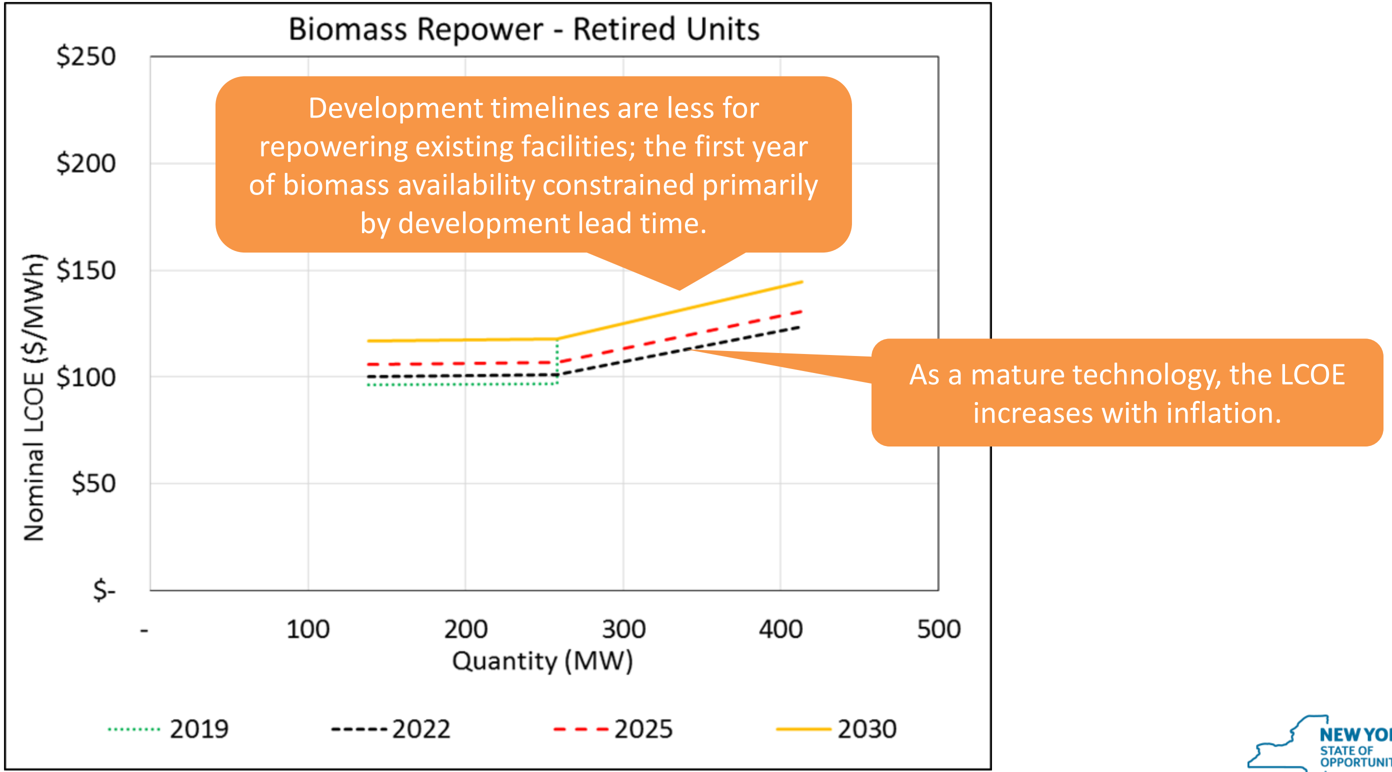
The analysis assumed that biomass repowering resources would have a relatively quick uptake limited primarily by development lead times. For Biomass IGCC, the analysis assumed that several years must pass before the technology is fully commercially available in the U.S. and able to compete in the market with other LSR considered in the supply curve.

Table A.21: Annual Phase-In rate for Woody Biomass Resources

	2017	2018	2019	2020	2021	2022	2023 and thereafter
Biomass Repower - Retired Units	0%	0%	50%	100%	100%	100%	100%
Biomass Repower - Operating Units	0%	0%	50%	100%	100%	100%	100%
Biomass - IGCC	0%	0%	0%	0%	0%	100%	100%

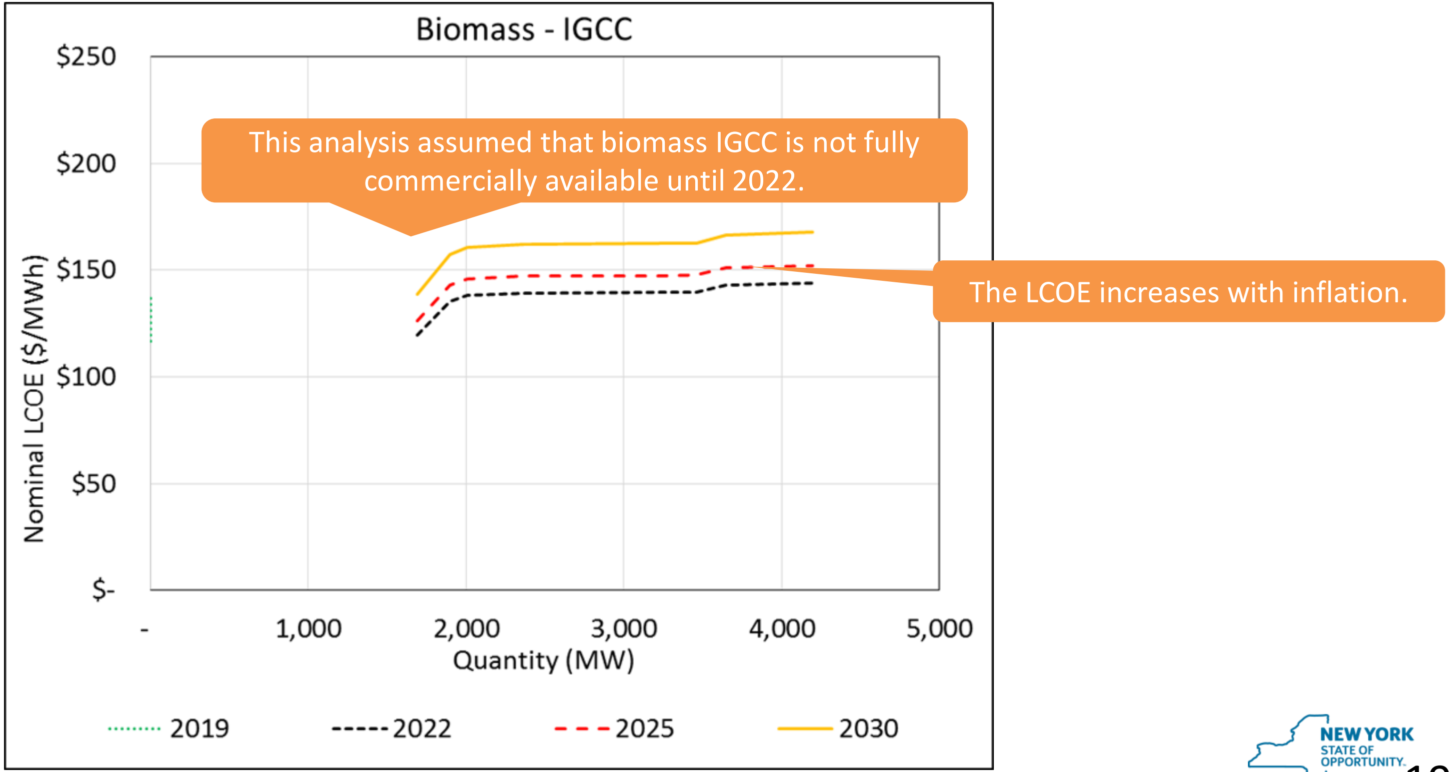
LCOE Supply Curves: Biomass

Figure A.23



LCOE Supply Curves – Biomass IGCC

Figure A.24



Appendix A.2.6 – Biogas

Overview of Approach

This analysis focused on anaerobic digestion at waste water treatment plants (WWTPs). While other sources of biogas – landfill gas and manure – are available and are assumed eligible for the LSR policy, they were not modeled in the SC due to a combination of higher costs (preventing the resources from being competitive against other resources), relatively small quantities available over the study period, or technologies not yet fully commercial.

There are 585 WWTP facilities throughout the state, with throughputs ranging from less than 0.1 million gallons per day (MGD) to more than 300 MGD. This study focused on facilities with design flows of 20 MGD and higher, as these have the potential for higher quantities of biogas production from anaerobic digestion (AD) and larger electric generation capacities. There are a total of 34 facilities meeting such criteria, with a total design flow of nearly 2,900 MGD, equivalent to 79% of the treatment capacity in the state.

Resource Potential

Table A.22:
Resource Potential of Biogas at WWTP

Zone	Biogas Production (million cf/yr)	Potential Electric Output (MWh/yr)	Electric Capacity (MW)
A	775	37,477	4.8
B	715	34,582	4.4
C	403	19,500	2.5
D	0	0	0.0
E	63	3,047	0.4
F	332	16,042	2.0
G	91	4,403	0.6
H	0	0	0.0
I	522	25,228	3.2
J	5,686	274,968	34.9
K	543	26,280	3.3
Total	9,130	441,527	56.0

Biogas generation potential can vary widely based on digester specifics and feedstock / substrate materials. The estimated biogas generation was calculated for each WWTP based on the design throughput and methane generation potential data from the Malcom Pirnie report as well as Antares Group's in-house data collected from previous work in this area.

It was assumed that the biogas generated has a methane content of 55%. Electric production capacity (kW) and generation (kWh) was then calculated assuming an electric conversion efficiency of biogas 25% and a capacity factor of 90%. The biogas and electric generation estimates were then summed for each NYISO Zone based on the location of the WWTP (see Table A.22).

Food waste and other organic materials are a potential feedstock resource that could be added to WWTP AD plants to increase biogas production and electricity generation. A resource potential screening was conducted for food waste and other organic materials. However, this category was not included in the supply curve analysis at this time.

Resource Cost and Capacity Factor Assumptions

Resource cost assumptions and capacity factors used in this analysis for biogas were first developed based on past LSR analyses and public studies. These assumptions were then reviewed and finalized by Antares Group to align with market trends.

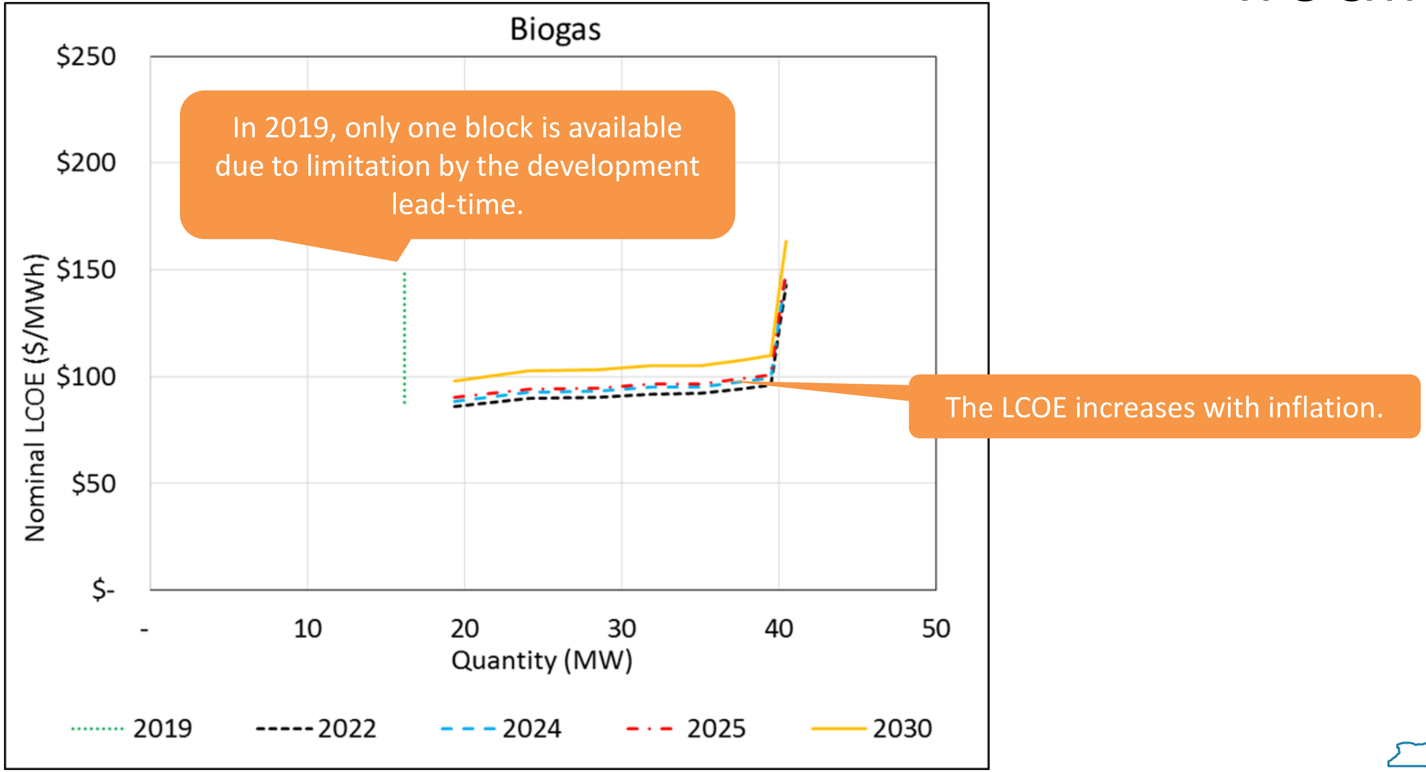
All feedstock material for ADG is assumed to be a zero cost resource. Any tipping fees that may apply are assumed to cover collection, sorting and transportation costs.

Table A.23: Biogas Resource Potential, Cost and Capacity Factor Summary

Zone	Block Capacity	Capacity Factor	2017 Cost (Nominal $)			
			Installed Cost	Interconnection Cost	Fixed O&M	Variable O&M
	MW	%	2015 $/kW	2015 $/kW	$2015 $/kW-yr	2015 $/MWh
A	4.8	70.0%	$3,422	$263	-	$22
B	4.4	70.0%	$3,422	$285	-	$22
C	2.5	70.0%	$3,422	$505	-	$22
E	0.4	70.0%	$3,422	$3,234	-	$22
F	2.0	70.0%	$3,422	$614	-	$22
G	0.6	70.0%	$3,422	$2,238	-	$22
I	3.2	70.0%	$3,422	$391	-	$22
J	34.9	70.0%	$3,422	$36	-	$22
K	3.3	70.0%	$3,422	$375	-	$22

LCOE Supply Curves – Biogas at Waste Water Treatment

Figure A.25



Appendix A.2.7 – Imports

Overview of Approach to LSR Imports

Resources from adjacent control areas were considered, to the extent LSR supply could be delivered to NYISO. Compared to the detailed supply curves developed for NY State, a more simplified approach was developed for neighboring control areas. Resource potential researched and analyzed was limited to those resource types listed in Table A.24 for each control area, deemed the most likely sources for export.

Potential LSR imports are limited by physical transmission inter-ties as well as competing usage of those ties and other transmission-related constraints. Existing ties were considered in the base case. The potential for increased imports was also examined as a potential sensitivity. Available space (or congestion) on the existing ties was assumed to be consistent with usage of the ties in the recent past. Together, these factors were used to estimate assumed practical transfer limits for PPA supply which would need to rely on high likelihood of delivery to support financing.

Competing native demands for LSRs as well as internal transmission constraints on moving supply in neighboring control areas were considered as limiting factors to supply available for export to NY. Additional factors considered in characterizing LSR imports included identifying the NYISO delivery zone (which dictates the energy revenue available to the facility), the potential transaction cost and risks of the export/import transaction, electrical losses, and the potential loss of the ability to monetize capacity revenue in either the exporting market or NYISO.

Resources Analyzed in Adjacent Control Areas

Table A.24

Exporting Region	Resource
ISO-NE	Land-based wind
PJM	Land-based wind
Ontario	Land-based wind, small hydroelectric (meeting current RPS eligibility requirements)
Quebec	Land-based wind, small hydroelectric (meeting current RPS eligibility requirements)

The resources examined to create supply curves for each exporting region are shown in Table A.24.

Geospatial analysis of LBW resources was performed, similar to the analysis described in Appendix A.2.1.

Potentially eligible incremental small hydro resource potential in Ontario was gleaned from a study of incremental potential. LCOEs were derived using the same cost curves applied to NY small hydro supply. Carrying charges were modified to reflect Canadian depreciation rules and Ontario tax rates.

Small hydro potential was sought for Quebec as well, but insufficient publically available data was found, so Quebec small hydro exports were ignored.

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Constraints on Out-of-State Resources for CES Tier 1 Supply Curve

Competing demands and transmission constraints for LSRs were identified in each exporting area.

A portion of the eastern PJM states' RPS demands were assumed to be met first from available supply. Furthermore, due to existing transmission limitations, all wind supply from Ohio westward was assumed to be inaccessible to the New York market due to west-to-east transmission constraints.

Announced Ontario procurement policy demands were assumed to be met first from available supply. Due to material internal transmission constraints, supply from much of the northern and western province was assumed unable to reach New York without additional transmission, and supply was further limited if located within or blocked from getting through the Toronto area.

Due to strong demands relative to supply, and consistent with substantial current and proposed flow of supply from New York towards New England, imports from New England to New York were deemed unlikely, so New England LSR supply was exclude from the supply curve.

Inter-tie Capacity and Usage

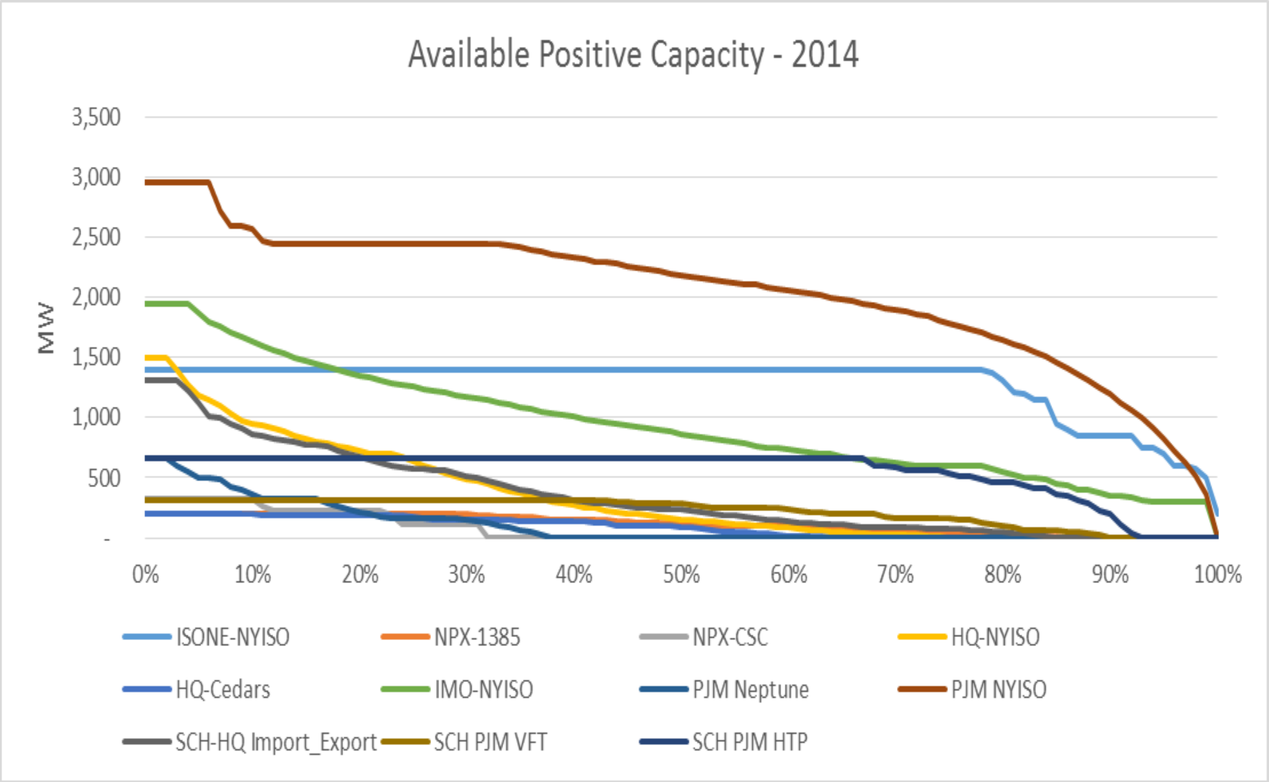
The amount of imports from adjacent control areas will be highly dependent on transmission availability into NYISO (as well as externally), as well as competition with the source territories for the same resource. As a result, the contribution of imports is less certain than projections for supply within New York, and there are circumstances under which the import contribution could be materially larger than shown here, with a resulting decrease in program costs.

Figures A.25 and A.26 show the importing traffic on all transmission ties to New York in 2014 and 2015, respectively.

In order to support project financing for a PPA, it was assumed that a project would need to be able to deliver at least 85% of the hours in a year to satisfy investors as to access to CES Tier 1 revenues. Therefore, the MW available for at least 85% of the hours in the year, based on 2014-2015 usage, was assumed to be the practical limit to imports. These results are shown in Table A.25.

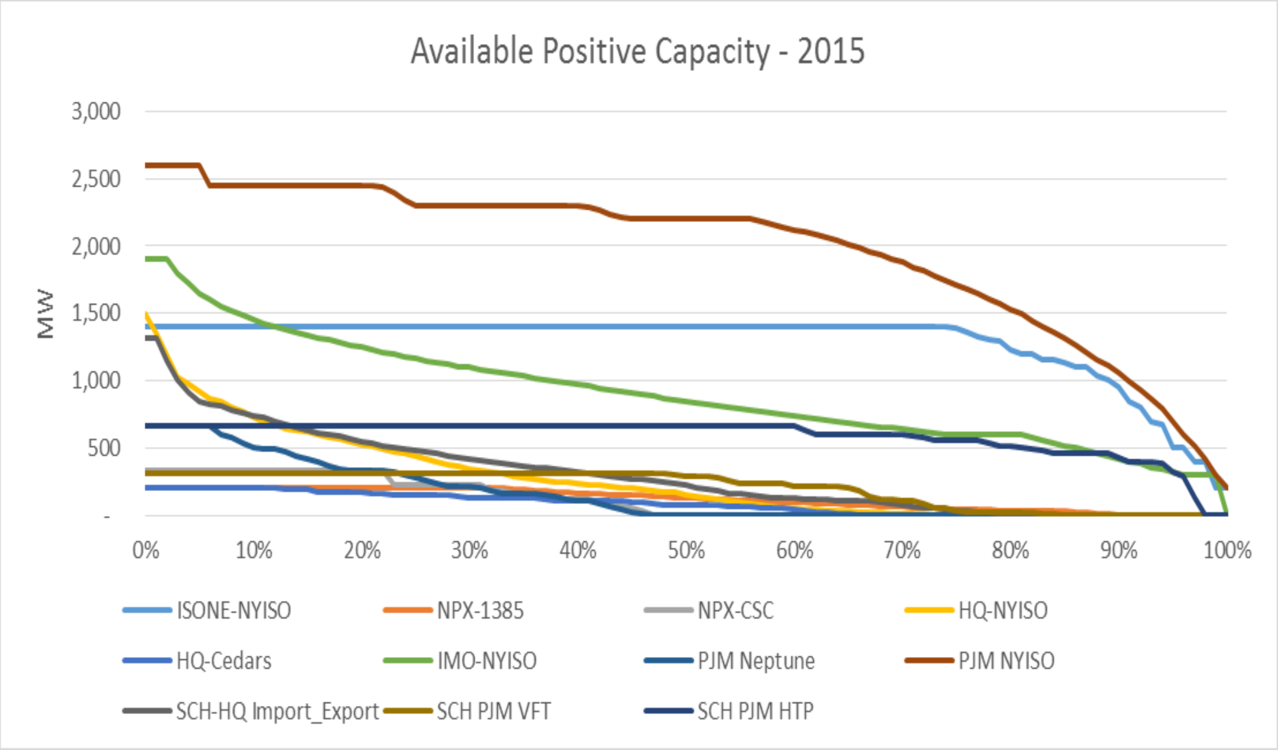
Inter-tie Usage Patterns, 2014

Figure A.26



Inter-tie Usage Patterns, 2015

Figure A.27



MW Available over NY Interties at least 85% of hours per year

Table A.25

	ISONE-NYISO	NPX-1385	NPX-CSC	HQ-NYISO	HQ-Cedars	IMO-NYISO	PJM Neptune	PJM NYISO	SCH-HQ Import Export	SCH PJM VFT	SCH PJM HTP
2014	950	8	-	-	-	453	-	1,460	5	65	360
2015	1,128	30	-	-	-	516	-	1,311	-	-	460
Average	1,039	19	-	-	-	485	-	1,385	3	33	410

Imports Analysis: Summary of Key Parameters

Table A.26 summarizes key parameters developed in deriving and building the LSR import supply curve. It shows the ties from each exporting area into NYISO, the assumed dominant NYISO delivery zone (used for valuing the energy revenues), the assumptions for available transfer limits and the resultant maximum amount of import supply (in MW).

The same table also shows the costs and assumed losses assessed to potential imported supply. The details behind the cost derivation are shown in Table A.27.

As can be seen, there are some cells in these tables which are incomplete. No costs are assumed for these parameters, although further research may reveal additional losses or costs that might be applied.

Key Import Analysis Assumptions

Table A.26

Source Market	Interface	Assumed NYISO Delivery Zone	Assume Practical Transfer Limit for PPA Supply (MW)	Market Adjustment Factor	Assumed Max Imports (MW)	Cost of Importing Power (2015 $/MWh)	Losses (to the extent applied outside of LMP pricing) (%)	Incremental Native Demand (MW)
ISO-NE	ISONE-NYISO	F	1,039.2	0%	-	$ 1.30	0.0%	all
	NPX-1385	K	19.0	0%	-		0.0%	all
	NPX-CSC	K	-	0%	-		0.0%	all
Quebec (HQ)	HQ-NYISO	D	-	0%	-	$12.50	?	0
	HQ-Cedars	D	-	0%	-	$12.50	?	0
	Champlain Hudson Power Express	F	1,000.0	100%	1,000	$10.20	??	0
Ontario (IMO)	IMO-NYISO	A	484.8	100%	480	$4.20	?	Yes
PJM	PJM Neptune	K	-	0%	-	$12.90	?	Eastern
	PJM NYISO	A, C	1,385.3	100%	1,390	$9.20	0.0%	Eastern
	SCH PJM VFT	J	32.5	0%	-	$9.20	2.5%	Eastern
	SCH PJM HTP	J	410.0	100%	410	$21.00	1.9%	Eastern

Preliminary Analysis of Cost of Importing LSRs, $/MWh

Table A.27

	Day Ahead to Real Time Risk	Transmission Tariff Charges for Export Transmission Service or Similar	Charges for Merchant TX Services	Ancillary Services and Other Charges Applicable to ETS Transactions	NYISO Schedule 1 Import costs	Losses (to the extent applied outside of LMP pricing)	Historical Price Differential	Total ($/MWh)
PJM-Neptune	$1	$0.00	$10.00	?	$ 0.26	?	$1.63	$12.90
PJM-Linden VFT	$1	$0.00	$6.00	?	$ 0.26	2.5%	$1.92	$9.20
PJM-Hudson	$1	$0.00	$10.00	?	$ 0.26	1.9%	$9.71	$21.00
NYISO-PJM	$1	$3.50	n/a	$ 2.50	$ 0.26	0.0%	$1.96	$9.20
ISO NE	$1	$0.00	n/a		$ 0.26	0.0%	$0.00	$1.30
Quebec - NYISO (existing ties)	$1	$8.96	n/a	?	$ 0.26	?	$2.32	$12.50
Quebec	$1	$8.96	Assume Socialized	?	$ 0.26	??		$10.20
Ontario	$1	$2.98	n/a	?	$ 0.26	?	$0.00	$4.20

Other Key Import Assumptions and Their Impact

A number of assumptions were made which, if relaxed, would likely result in lower CES ratepayer costs.

- Potential imports from ISO-NE are ignored, however substantial tie capacity is available to allow imports (1)
- The analysis assumes imported supply is unable to secure capacity revenues in either source or NYISO markets. If such revenues were available in either market, the premium associated with these resources would be reduced and additional cost-effective imports would be deployed, reducing ratepayer costs.

(1) The analysis does not currently assumed any additional exports to New England from generation not yet operating. If any proposals under New England Clean Energy RFP successfully secure PPAs in competition against New England and Canadian resources, it may be appropriate to remove a corresponding quantity of supply from NY supply curve.

Other Key Import Assumptions and Their Impact (cont'd)

- While inter-tie space is modeled as available from PJM, the model has not selected for deployment any PJM supply as cost-competitive. This result is dictated by assumptions of (i) transmission limitations prohibiting access to low-cost wind west of eastern PJM (i.e., PA, WV), (ii) the most cost-effective supply in eastern PJM is assumed to be deployed primarily to meet PJM RPS demand first, and (iii) material costs are assumed to wheel supply out of PJM and into NYISO. However, some or all PJM supply could potentially qualify for capacity revenues in New York, reducing the out-of-market costs. Alternatively, FERC's ongoing efforts to eliminate seams between wholesale markets could eliminate pancaking, reducing the costs of imports. Finally, new transmission ties from the Midwest into eastern PJM (as have been proposed) could dramatically add to low cost wind available to both eastern PJM and NYISO. Existing interties from Quebec are modeled as full and thus unavailable for additional imports. Exports from Ontario are modeled as limited due to transmission constraints. Additional ties into NY could allow substantial additional supply to enter.

High Imports Sensitivity

All base cases assume availability of out-of-state resources for import into New York State within the confines of current transmission line capacity.

Currently, ties carrying energy from Quebec into NYS are fully utilized in most hours, and ‘large hydro’ is not modeled as eligible for the CES in the base case.

A “High Imports” sensitivity is included to illustrate the potential impact of a new tie from Quebec to load centers in New York which would carry large hydro supply, should it be deemed CES eligible.

This sensitivity assumes (i) the 1,000 MW Central Hudson Power Express (CHPE) transmission line will be installed, with costs of the facility assumed 100% socialized; (ii) the line would ultimately be fully loaded, to carrying 1,000 MW of baseload hydroelectric, commencing in 2023 and entering the CES market as annual demand targets allow; and (iii) large hydro supply from Quebec would be priced at ‘market’ for a CES resource, i.e., the highest price possible which would allow it to compete successfully versus other resources in the supply curve.

To model the large hydro supply in the Supply Curve, a 1,000-MW large hydro supply curve block was created and assumed to be able to interconnect to NYISO Zone F with access to CRIS rights. LCOEs were imputed for the block such that all (or most) of the block would be deployed commencing in 2023, until fully deployed (the block is too large to be deployed in a single year).

Appendix A.3 – Energy and Capacity Market Value

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Introduction

The commodity market value of LSRs represents the revenue paid to a generation project from the NYISO wholesale energy and capacity markets for its products (energy and capacity; it is assumed that LSRs produce no ancillary services of material market value), or the equivalent value that it would be paid for these products in the spot market, if used to self-supply.

Commodity market value of each resource block is comprised of:

- The production-weighted zonal energy market price ($/MWh), which is based on a typical year hourly production profile. This is calculated by taking the ratio of the total energy revenues the project would have earned at zonal LBMPs over the last 2 years (average of Day-Ahead and Real-Time) , divided by the all-hours unweighted average LBMPs over the same period.
- The zonal capacity price ($/kW), adjusted by the capacity value (the season-weighted average UCAP as a % of nameplate capacity).

For the purpose of calculating the levelized renewable generation premium for sorting resource blocks and the fixed-price REC payment, 20-year levelized market value projections were used (using a discount rate of 10%).

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Wholesale Energy Price Base Case

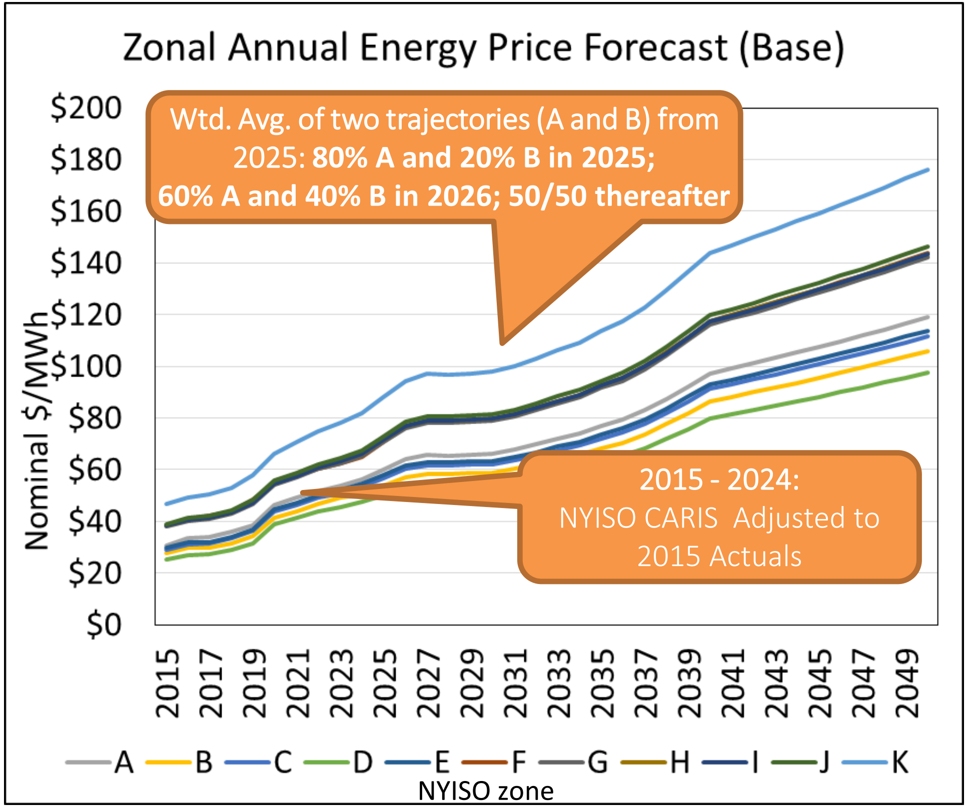

Figure A.28. For this analysis, the 2015 NYISO CARIS energy price forecast trend, adjusted downward by DPS to align with actual energy prices in 2015, was used as the "Base" energy price forecast through 2024. Thereafter, the energy price is the weighted average of two trajectories:

- **A. Constant Real Index**: Constant in real dollar terms at the 2024 level, i.e., continuing to increase with inflation annually (in nominal terms); and
- **B. AEO 2015 Natural Gas Price Index**: Indexed the 2024 forecast to trend at the annual rate of change for the 2015 EIA AEO Reference Case natural gas price forecast

An avoided cost of carbon policy compliance is embedded in the NYISO CARIS energy price forecast. By virtue of the adjustment method described above, the monetized cost of carbon was implicitly assumed to be adjusted and extrapolated in proportion to the Base energy price forecast in this analysis.

Energy Price Forecast Sensitivities

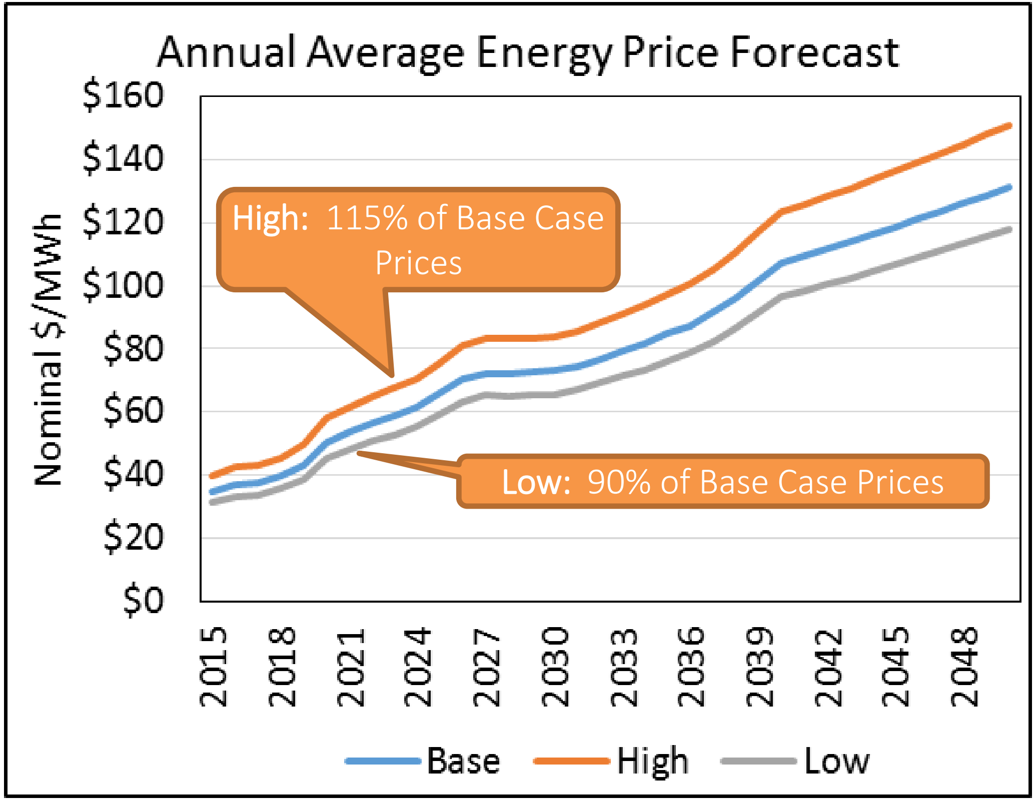

Figure A.29. Two alternative energy market price futures were developed to test the sensitivity of program costs to energy market values.

The "**High**" energy price forecast represents 115% of the "Base" case in any given year.

The "**Low**" energy price forecast represents 90% of the "Base" case in any given year.

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Capacity Price Forecast

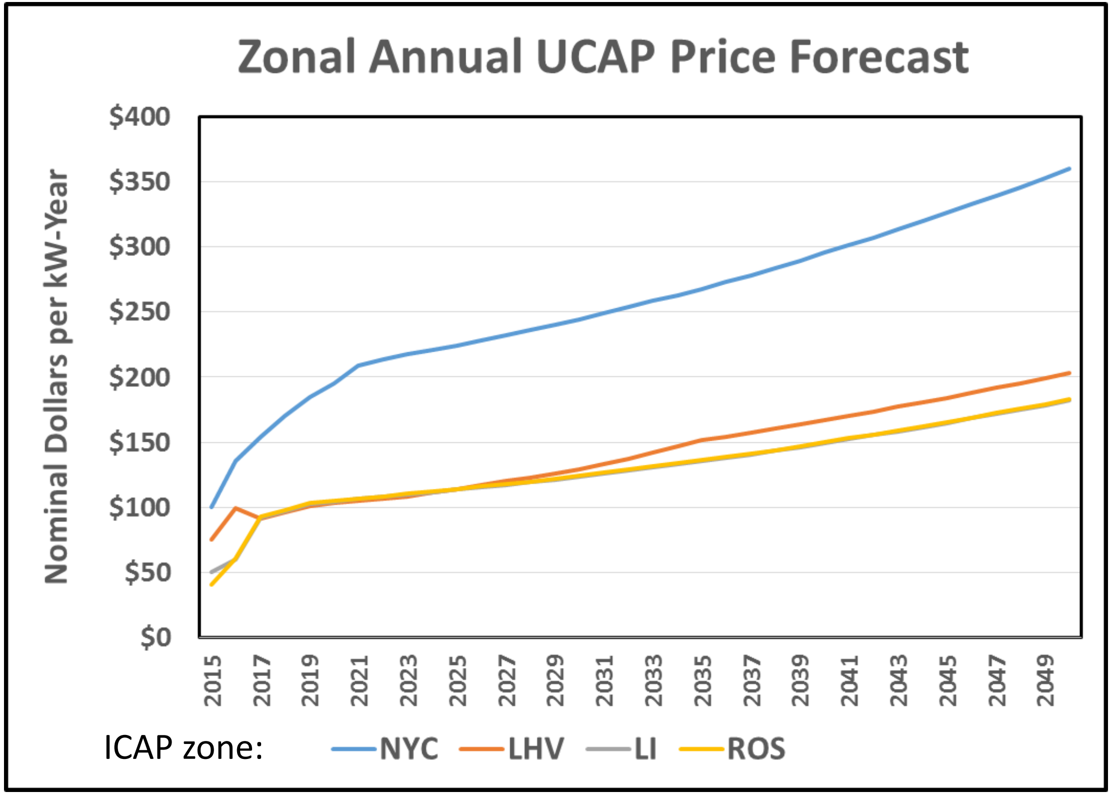
Zonal Summer and Winter ICAP generator prices as per the BCA (Order Establishing the Benefit Cost Analysis Framework, Case 14-M-0101, January 21, 2016) from 2015 to 2035 were translated to zonal average annual UCAP prices using the average of the zonal Summer 2015 and Winter 2015/16 translation factors. In 2036 and thereafter, the capacity prices were held constant at the 2035 level in real dollar terms (increasing with inflation in nominal dollar terms).

For the calculation of each resource block's commodity market value, the $/kW-yr capacity price was converted to $/MWh by dividing by the product (capacity factor * 8760 hours).

Actual capacity revenues credited to a generation project are contingent on its "reliable" capacity in Summer and Winter peaks. The portion of a project's nameplate capacity that is eligible for earning UCAP revenues was represented by the seasonal-weighted capacity value, state as a % of nameplate capacity, in this analysis (see below for a detailed description).

Capacity Price Forecast

Figure A.30



Production-Weighting Adjustment of Energy Market Values

The hourly energy market values credited to intermittent generation projects vary by time of production. Technologies that produce a greater proportion of their output during peak hours are worth more than those with a greater proportion of off-peak production. To reflect the seasonal and temporal variations while using an annual energy market price forecast, a production-time weighting adjustment approach was applied for this analysis.

Production time-weighting adjustment factors are intended to reflect the coincidence of the production profiles of intermittent LSR with zonal hourly LMP prices. No adjustment was applied to baseload LSR, such as biomass, which are assumed dispatchable or producing in a baseload configuration. The adjustment factors for each technology were calculated as the ratio of the weighted average of the 2-year historic 8760-hourly LMPs (using the 8760 typical hourly production profile for each technology sub-category for each NYISO load zone) to unweighted average of the 2-year historic 8760-hourly LMPs.

The actual $/MWh energy revenue credited to a generation project equals the product of the zonal energy price times the production time weighting adjustment factor for the corresponding technology sub-category and NYISO zone.

Production Time Weighting Adjustment: 8760 Hourly Production Profiles

The 8760 hourly production profiles for each intermittent LSR technology for applicable NYISO zones (as well as representative sites in neighboring control areas) were developed using data from the following sources:

- **Land-based Wind**: Power curves (provided by AWST) for a “typical site” with an average net capacity factor of 35%.
- **Offshore Wind**: Power curves (provided by AWST) for an 8-MW class wind turbine at hub heights of 110, 120, 130 and 140 meters; production profiles modeled to change over time with average fleet hub height described in Appendix A.2.2.
- **Utility-Scale Solar PV**: PVWatts® data for 20 MWDC projects at representative locations for each zone.
- **Hydro (Upgrades) and Hydro (NPD)**: Monthly river flow data provided by ORNL and INL for each site, truncated to reflect production de-rate assumptions discussed in Appendix A.2.4.

Capacity Value of a Generator

Capacity revenues are only credited to an LSR generator's "unforced" capacity. The unforced capacity represents the portion of the nameplate capacity that is expected to be available during Summer and Winter peaks based on historic operating data. In this analysis, the unforced capacity is modeled as a percentage of the nameplate capacity (referred to as the "capacity value").

For land-based wind, offshore wind and utility-scale solar PV, the capacity values were calculated using the straight average of the summer and winter unforced capacity percentages provided in the NYISO Installed Capacity manual as a basis.(1) For land-based wind and utility-scale solar PV, the average percentages were further adjusted by a weighting factor that is technology- and location-specific to approximate the seasonal-weighted capacity revenues available to each technology in each zone. For hydro upgrades and hydro NPD, site-specific capacity values were developed using adjusted monthly flow data provided by ORNL and INL. For baseload resources (biomass and biogas), the capacity values were assumed to be 90%, consistent with a ballpark unavailability (EFOR).

(1) http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

Analysis of Energy Price Sensitivities

Investors are exposed to energy price fluctuations in a fixed-REC procurement approach, but not in a bundled PPA approach. The difference in risk profile is reflected in the analysis through different investor hurdle rates for each approach. The analysis does not include differentiation between REC and PPA scenarios as regards how investors are expected to respond to different energy price scenarios. In both the REC and the PPA scenario, the higher energy price scenario examined in this Study leads to lower gross program costs (because projects require less additional revenue on top of commodity market sales in order to reach their hurdle rates), and vice versa.

However, the current analysis likely overstates this effect for fixed RECs, due to limitations in the methodology used. When calculating the bid price investors are putting forward, the model uses the energy price forecast provided for the sensitivity in question; the level of risk of actual future energy prices deviating from this forecast is reflected in the level of investor hurdle rates. The model does not assess the impact of actual prices deviating from the energy price forecast investors use to calculate their bid price.

For example: fixed-REC bidders developing “project A” will set their bid price based on their expectation of energy prices. If actual energy prices turn out to be lower than the forecast, developers of future projects may adjust their expectation of energy prices downwards, and if so this would translate to higher program costs, but the developers of project A would not be able to make any adjustments; the lower total revenue they receive for project A would translate to a lower program cost for project A. This effect is not captured by the analysis.

Appendix A.4 – Financing

Modeling LSR Financing: The Carrying Charge Approach

With little or no fuel costs to account for, renewable energy project finance is dominated by determining the structure and cost of long-term financing for the initial capital requirement. To support derivation of LCOE in every year for a very large number of resource blocks, the capital and financing cost are annualized and converted to levelized $/MWh. This is done through the use of a modified "carrying charge" – a constant percentage factor applied to the CAPEX intended to represent the portion of a project's initial investment and fixed costs recovered each year. While less precise than a discounted cash flow analysis due to the time-sensitive, tax-oriented nature of renewable energy investments, the carrying charge approach is effective for comparing a wide range of project technologies, sizes, locations and other characteristics within a single analysis.

The modified carrying charge is calculated using CREST (the Cost of Renewable Energy Spreadsheet Tool developed by Sustainable Energy Advantage, LLC for NREL) by removing all operating costs for an illustrative technology and determining the nominal levelized annual revenue per kW required to meet investor returns. This quantity is divided by the CAPEX to determine a percentage carrying charge which can then be applied to a resource block of the applicable technology. This approach is better able to reflect the consequences of taxation and depreciation than the conventional carrying charge formula, closely simulating the results that would be produced if CREST or a discounted cash flow model were used to model every resource block, but in a much less time-consuming way.

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Modeling LSR Financing: The Carrying Charge Approach (cont'd)

A carrying charge was calculated for each technology subcategory, taking into account that technology's useful life, financing structure and associated costs, and tax benefits and obligations. To this end, the percentage of equity and debt and associated rates of return impact the carrying charge – and therefore the cost of energy – for each technology subcategory. Estimated carrying charges for each technology were applied to all project capital costs, including the cost of transmission upgrades and interconnection.

Financing Assumptions

This analysis assumed an LSR long-term contract duration of 20 years for all technologies and cases. A federal tax rate of 35% and a state tax rate of 7.1% were applied to all technologies.

For each technology subcategory, carrying charges were calculated for two financing scenarios – “Base” and “High Interest” – representing different costs of debt with respect to different assumptions on interest rates.

For each financing scenario, carrying charges were calculated for two cases– “Bundled PPA” and “Fixed-Price REC” – representing the different levels of financing risks with respect to whether commodity market values are fully hedged.

For each case, carrying charges were calculated for a “with PTC” case and a “without PTC” case (or “with 30% ITC” and “with 10% ITC” for utility-scale solar and OSW). An interpolation of the carrying charges with and without (or reduced) federal incentives was done to derive the carrying charge values for years when tax credit values are phasing down.

More detailed financing assumptions regarding debt and equity ratios and costs, as well as debt term, used for calculating the carrying changes are summarized in Tables A.28 through A.35.

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Technology-Specific Financing Cost Assumptions

Table A.28a: Financing Cost Assumptions for LBW (10-30 MW) - Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	5.75%	18	50%	11.75%
Fixed-Price REC -- With PTC	45%	5.75%	18	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	65%	5.75%	18	35%	10.00%
Bundled, Perfect Hedge, IPP Finance, With PTC	55%	5.75%	18	45%	12.11%

Table A.28b: Financing Cost Assumptions for LBW (10-30 MW) – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	7.00%	18	50%	11.75%
Fixed-Price REC -- With PTC	45%	7.00%	18	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	65%	7.00%	18	35%	10.00%
Bundled, Perfect Hedge, IPP Finance, With PTC	55%	7.00%	18	45%	12.11%

Technology-Specific Financing Cost Assumptions (2)

Table A.29a: Financing Cost Assumptions for LBW (>30 MW) – Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	5.75%	18	50%	10.50%
Fixed-Price REC -- With PTC	45%	5.75%	18	55%	14.75%
Bundled, Perfect Hedge, IPP Finance, Without PTC	65%	5.75%	18	35%	8.75%
Bundled, Perfect Hedge, IPP Finance, With PTC	55%	5.75%	18	45%	10.86%

Table A.29b: Financing Cost Assumptions for LBW (>30 MW) – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	7.00%	18	50%	10.50%
Fixed-Price REC -- With PTC	45%	7.00%	18	55%	14.75%
Bundled, Perfect Hedge, IPP Finance, Without PTC	65%	7.00%	18	35%	8.75%
Bundled, Perfect Hedge, IPP Finance, With PTC	55%	7.00%	18	45%	10.86%

Technology-Specific Financing Cost Assumptions (3) Offshore Wind

This Study assumed that the financing risks (hence, equity IRR) for offshore wind would decrease over time as the market matures. Three intervals (starting point, mid-point, and end point) representing different phases of offshore wind financing market maturity were established. An ‘end point’ representing a fully mature financing market, equivalent to financing for land-based wind except for a modest differential reflective of the higher construction period and performance risk associated with operation in a far offshore environment. Each interval is correlated to an equity IRR percentage, as follows:

	Bundled				Fixed REC			
	Base		Faster Financing Maturation		Base		Faster Financing Maturation	
	IRR	Year	IRR	Year	IRR	Year	IRR	Year
Starting Point	11.50%	2017-2023	11.00%	2017-2023	13.25%	2017-2023	12.75%	2017-2023
Mid Point	11.00%	2024-2027	10.00%	2024-2026	12.75%	2024-2027	11.75%	2024-2026
End Point	10.50%	2028-2030	9.00%	2027-2030	12.25%	2028-2030	10.75%	2027-2030

Carrying charges correlated to four equity IRR percentages (11.5%, 11.0%, 10.5% and 9.0% for Bundled PPA) were developed. Linear interpolation between carrying charges at the four percentages was used to determine the carrying charge at a given IRR for each interval.

Technology-Specific Financing Cost Assumptions (4)

Table A.30a: Financing Cost Assumptions for OSW at 11.5% Equity IRR - Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	6.50%	18	50%	13.25%
Fixed-Price REC -- With PTC	45%	6.50%	18	55%	17.25%
Bundled, Perfect Hedge, IPP Finance, Without PTC	70%	6.50%	18	30%	11.50%
Bundled, Perfect Hedge, IPP Finance, With PTC	60%	6.50%	18	40%	13.36%

Table A.30b: Financing Cost Assumptions for OSW at 11.0% Equity IRR - Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC – With 10% ITC	50%	6.50%	18	50%	12.75%
Fixed-Price REC -- With 30% ITC	45%	6.50%	18	55%	16.75%
Bundled, Perfect Hedge, IPP Finance, With 10% ITC	70%	6.50%	18	30%	11.00%
Bundled, Perfect Hedge, IPP Finance, With 30% ITC	60%	6.50%	18	40%	12.86%

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Technology-Specific Financing Cost Assumptions (5)

Table A.30c: Financing Cost Assumptions for OSW at 10.5% Equity IRR - Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	6.50%	18	50%	12.25%
Fixed-Price REC -- With PTC	45%	6.50%	18	55%	16.25%
Bundled, Perfect Hedge, IPP Finance, Without PTC	70%	6.50%	18	30%	10.50%
Bundled, Perfect Hedge, IPP Finance, With PTC	60%	6.50%	18	40%	12.36%

Table A.30d: Financing Cost Assumptions for OSW at 9.0% Equity IRR - Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC – With 10% ITC	50%	6.50%	18	50%	10.75%
Fixed-Price REC -- With 30% ITC	45%	6.50%	18	55%	14.75%
Bundled, Perfect Hedge, IPP Finance, With 10% ITC	70%	6.50%	18	30%	9.00%
Bundled, Perfect Hedge, IPP Finance, With 30% ITC	60%	6.50%	18	40%	10.86%

Technology-Specific Financing Cost Assumptions (6)

Table A.30e: Financing Cost Assumptions for OSW at 11.5% Equity IRR – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	7.75%	18	50%	13.25%
Fixed-Price REC -- With PTC	45%	7.75%	18	55%	17.25%
Bundled, Perfect Hedge, IPP Finance, Without PTC	70%	7.75%	18	30%	11.50%
Bundled, Perfect Hedge, IPP Finance, With PTC	60%	7.75%	18	40%	13.36%

Table A.30f: Financing Cost Assumptions for OSW at 11.0% Equity IRR – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC – With 10% ITC	50%	7.75%	18	50%	12.75%
Fixed-Price REC -- With 30% ITC	45%	7.75%	18	55%	16.75%
Bundled, Perfect Hedge, IPP Finance, With 10% ITC	70%	7.75%	18	30%	11.00%
Bundled, Perfect Hedge, IPP Finance, With 30% ITC	60%	7.75%	18	40%	12.86%

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Technology-Specific Financing Cost Assumptions (7)

Table A.30g: Financing Cost Assumptions for OSW at 10.5% Equity IRR – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	7.75%	18	50%	12.25%
Fixed-Price REC -- With PTC	45%	7.75%	18	55%	16.25%
Bundled, Perfect Hedge, IPP Finance, Without PTC	70%	7.75%	18	30%	10.50%
Bundled, Perfect Hedge, IPP Finance, With PTC	60%	7.75%	18	40%	12.36%

Table A.30h: Financing Cost Assumptions for OSW at 9.0% Equity IRR – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC – With 10% ITC	50%	7.75%	18	50%	10.75%
Fixed-Price REC -- With 30% ITC	45%	7.75%	18	55%	14.75%
Bundled, Perfect Hedge, IPP Finance, With 10% ITC	70%	7.75%	18	30%	9.00%
Bundled, Perfect Hedge, IPP Finance, With 30% ITC	60%	7.75%	18	40%	10.86%

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Technology-Specific Financing Cost Assumptions (8)

Table A.31a: Financing Cost Assumptions for Utility-Scale Solar PV – Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	45%	5.75%	15	55%	11.50%
Fixed-Price REC -- With PTC	35%	5.75%	15	65%	12.50%
Bundled, Perfect Hedge, IPP Finance, Without PTC	45%	5.75%	15	55%	10.50%
Bundled, Perfect Hedge, IPP Finance, With PTC	35%	5.75%	15	65%	11.50%

Table A.31b: Financing Cost Assumptions for Utility-Scale Solar PV – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC – With 10% ITC	45%	7.00%	15	55%	11.50%
Fixed-Price REC -- With 30% ITC	35%	7.00%	15	65%	12.50%
Bundled, Perfect Hedge, IPP Finance, With 10% ITC	45%	7.00%	15	55%	10.50%
Bundled, Perfect Hedge, IPP Finance, With 30% ITC	35%	7.00%	15	65%	11.50%

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Technology-Specific Financing Cost Assumptions (9)

Table A.32a: Financing Cost Assumptions for Hydro – Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	6.50%	20	50%	11.75%
Fixed-Price REC -- With PTC	45%	6.50%	20	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	70%	6.50%	20	30%	10.00%
Bundled, Perfect Hedge, IPP Finance, With PTC	65%	6.50%	20	35%	12.11%

Table A.32b: Financing Cost Assumptions for Hydro – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	7.75%	20	50%	11.75%
Fixed-Price REC -- With PTC	45%	7.75%	20	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	70%	7.75%	20	30%	10.00%
Bundled, Perfect Hedge, IPP Finance, With PTC	65%	7.75%	20	35%	12.11%

Technology-Specific Financing Cost Assumptions (10)

Table A.33a: Financing Cost Assumptions for Biomass CHP – Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	7.50%	14	50%	11.75%
Fixed-Price REC -- With PTC	45%	7.50%	14	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	60%	7.50%	14	40%	10.00%
Bundled, Perfect Hedge, IPP Finance, With PTC	55%	7.50%	14	45%	12.11%

Table A.33b: Financing Cost Assumptions for Biomass CHP – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	8.75%	14	50%	11.75%
Fixed-Price REC -- With PTC	45%	8.75%	14	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	60%	8.75%	14	40%	10.00%
Bundled, Perfect Hedge, IPP Finance, With PTC	55%	8.75%	14	45%	12.11%

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Technology-Specific Financing Cost Assumptions (11)

Table A.34a: Financing Cost Assumptions for Biomass Repower – Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	7.50%	10	50%	13.25%
Fixed-Price REC -- With PTC	45%	7.50%	10	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	70%	7.50%	10	30%	11.50%
Bundled, Perfect Hedge, IPP Finance, With PTC	65%	7.50%	10	35%	12.00%

Table A.34b: Financing Cost Assumptions for Biomass Repower – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	8.75%	10	50%	13.25%
Fixed-Price REC -- With PTC	45%	8.75%	10	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	70%	8.75%	10	30%	11.50%
Bundled, Perfect Hedge, IPP Finance, With PTC	65%	8.75%	10	35%	12.00%

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Technology-Specific Financing Cost Assumptions (12)

Table A.35a: Financing Cost Assumptions for Biomass IGCC – Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	7.50%	14	50%	13.25%
Fixed-Price REC -- With PTC	45%	7.50%	14	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	70%	7.50%	14	30%	11.50%
Bundled, Perfect Hedge, IPP Finance, With PTC	65%	7.50%	14	35%	12.00%

Table A.35b: Financing Cost Assumptions for Biomass IGCC – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	8.75%	14	50%	13.25%
Fixed-Price REC -- With PTC	45%	8.75%	14	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	70%	8.75%	14	30%	11.50%
Bundled, Perfect Hedge, IPP Finance, With PTC	65%	8.75%	14	35%	12.00%

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Technology-Specific Financing Cost Assumptions (13)

Table A.35c: Financing Cost Assumptions for Biogas– Base

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	7.50%	18	50%	11.75%
Fixed-Price REC -- With PTC	45%	7.50%	18	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	60%	7.50%	18	40%	10.00%
Bundled, Perfect Hedge, IPP Finance, With PTC	55%	7.50%	18	45%	12.11%

Table A.35d: Financing Cost Assumptions for Biogas – High Interest

Procurement/Contracting Options	% Debt	Total Cost of Debt	Debt Term	% Equity	Total Cost of Equity
Fixed-Price REC -- Without PTC	50%	8.75%	18	50%	11.75%
Fixed-Price REC -- With PTC	45%	8.75%	18	55%	16.00%
Bundled, Perfect Hedge, IPP Finance, Without PTC	60%	8.75%	18	40%	10.00%
Bundled, Perfect Hedge, IPP Finance, With PTC	55%	8.75%	18	45%	12.11%

Calibration of Cost of Capital Assumptions

Costs of capital, and capital structures, as experienced in the market are not uniform, but rather vary widely among developers or owners of power plants. There is a range of reasonable assumptions that can be made to reflect market costs of capital for power plants under different contracting/revenue risk profiles. The methodology described was intended to place these assumptions in the middle of the aforementioned range.

Market data is available for the Bundled PPA scenario from recent PPA results outside New York, either perfectly hedged or imperfectly hedged (i.e., leaving some negative LBMP risk on seller) to calibrate the cost of capital assumptions for the Bundled PPA scenario to actual deals. As a result, there is comfort in these figures as representative of transactions in which seller is insulated from most or all of the commodity price risk.

For the Fixed-Price REC scenario, in establishing the preliminary assumption for higher cost of capital to reflect developer commodity market price risk, there was little or no market data to calibrate the preliminary estimate. Markets outside of New York do not have comparable contracting structures for 20 years REC transactions, and prior Main Tier REC contracts were of only 10-year duration.

Calibration of Cost of Capital Assumptions (cont’d)

However, the results of NYSERDA’s latest Main Tier procurements allows a calibration of the 20-year Fixed-Price REC-only contracting to actual comparable market data (under the base energy price forecast). These results suggest that an adjustment to the analysis inputs is appropriate in order to achieve a mix of energy price forecast inputs and finance charge inputs that reflects the reality investors are experiencing. This adjustment was implemented in the form of an increase in the cost of capital. As a result of this calibration exercise, the carrying charges shown for the Fixed-Price REC scenario were scaled up by a multiplier of **1.15**.

Appendix A.5 – Federal Incentives

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Federal Tax Credits: PTC & ITC

Federal renewable energy tax incentive programs, including the Production Tax Credit (PTC) and the Investment Tax Credit (ITC), reduce the LCOE by reducing the revenue required to meet investor hurdle rates of return. The PTC represents a 10-year production incentive realized as a tax credit for each MWh of production. ITC represents a tax credit which is calculated as a percentage of eligible investment.

The eligibility requirements for PTC and ITC in this analysis were modeled based on the recently enacted Protecting Americans from Tax Hikes Act of 2015 (PATH) and the Consolidated Appropriations Act of 2016 (CAA).

- For non-wind resources, the PTC was extended by a year to December 31, 2016.
- For wind resources, the PTC was extended through 2016, followed by a phase-out to 80% of the credit value for 2017, 60% for 2018 and 40% for 2019, and 0% thereafter, for all wind resources commencing construction before January 1, 2020. The CAA also extended the ability of wind facility owners to elect the Investment Tax Credit in lieu of PTC under current law.
- For utility-scale solar PV, the full 30% ITC was extended from December 31, 2016 to December 31, 2019, followed by a phase-out pathway to 26% in 2020, 22% in 2021. Thereafter, the ITC would revert to the current statutory levels of 10% for corporate taxpayers and 0% for individuals.

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Federal Tax Credits: PTC & ITC (cont'd)

The eligibility for PTC/ITC incentives is determined based on the assumed "begin construction" date of a resource block, which for this analysis was modeled as the commencement of operation date minus the "construction to operation lag" plus one year (to account for a full year of eligibility).

PTC value was calculated as the pre-tax value of PTC on an equivalent 20-year nominal levelized basis, and was deducted from the LCOE. The value of ITC was calculated as a percentage of ITC-eligible CAPEX.

To simplify, tor all PTC-eligible resource blocks other than OSW, it was assumed PTC would be taken by the owner (even if eligible for 30% ITC in lieu of PTC). In practice, in many instances use of ITC may be lower cost, so this assumption may tend to slightly overstate costs. For OSW, the LCOE was first analyzed using either PTC or ITC, and because ITC was always lower, ITC in lieu if PTC was always assumed for OSW.

ITC-eligible CAPEX was assumed to be 95% of the total CAPEX for utility-scale PV projects and 90% of the total CAPEX of an offshore wind project), and the ITC was deducted from the CAPEX.

Finally, due to increased scarcity of tax equity in the market commensurate with expansion of the incentives increasing the possibility that investors may not be able to fully monetize the value of tax credits (or roll the credit into subsequent years until it can be monetized, decreasing its effective value), the value of PTC was reduced to the percentage of 'face value', shown in Table A.36.

Federal Tax Credits Sensitivities

Three alternative federal tax incentive scenarios were developed to test the sensitivities of availability of federal tax revenues to program costs:

- The "No FTC" scenario assumed that PTC and ITC were absent through the entire span of the study.
- The "FTC Extension at Peak" scenario assumed that PTC and ITC would continue to be available at the peak credit value (i.e., 100% for PTC and 30% for utility-scale solar ITC). This sensitivity was applied to Study results for the period to 2023.
- The "FTC Extension at Tail" scenario assumed that PTC and ITC values were phased-down as currently legislated. Instead of expiring, PTC and ITC would continue to be available at the credit value of the last phase-down year throughout the remaining period of the study. This sensitivity was applied to Study results for the period to 2030.

Effective Monetization of Federal Tax Incentives

Table A.36

Technology	Equivalent % of Tax Credit Value Effectively Monetized
LBW (10-30 MW)	80.0%
LBW (30-100 MW)	90.0%
LBW (100-200 MW) (>200 MW)	90.0%
Utility-Scale Solar PV	90.0%
Hydro (Upgrades)	75.0%
Hydro (NPD)	75.0%
Woody Biomass	75.0%
Biogas	75.0%
Offshore Wind	90.0%

PTC and ITC Schedules

A project meeting the IRS requirements to 'commence construction' in a particular year may earn the value of the incentive shown in Figure A.30 for that year if in the year so long as it comes online within the timeframe allowed by law.

Examples are provided in Figure A.32. For example, wind is modeled as follows: a wind project reaching commercial operation by December 31 of the second year following commencement of construction, and producing its first full year of production in the following year, will be subsidized at the incentive level that applied in the year applicable when it commenced commences construction. So, as shown in Figure A.33, a wind project commencing construction before the end of 2018 and reaching commercial operation on December 31, 2020 and producing its first full year of production in in 2021 would earn 60% of the PTC value.

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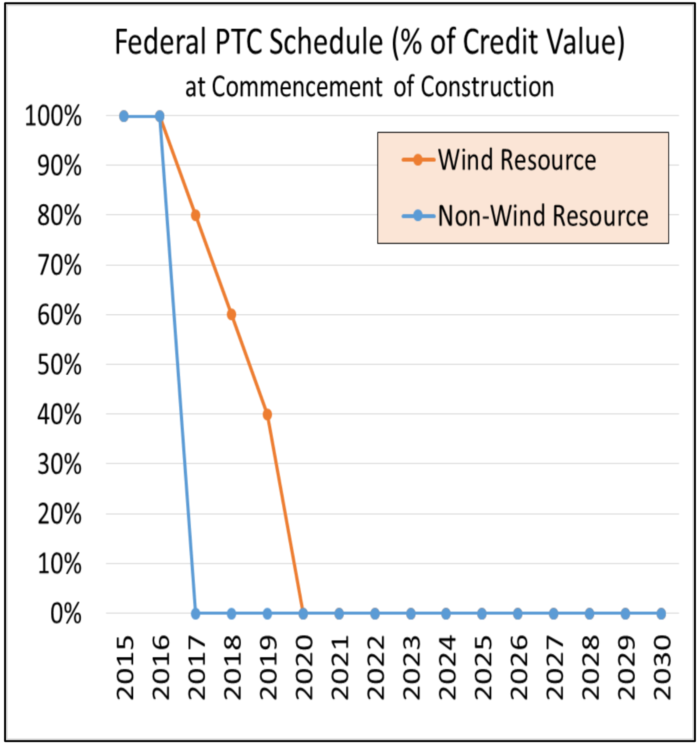
PTC and ITC Schedules



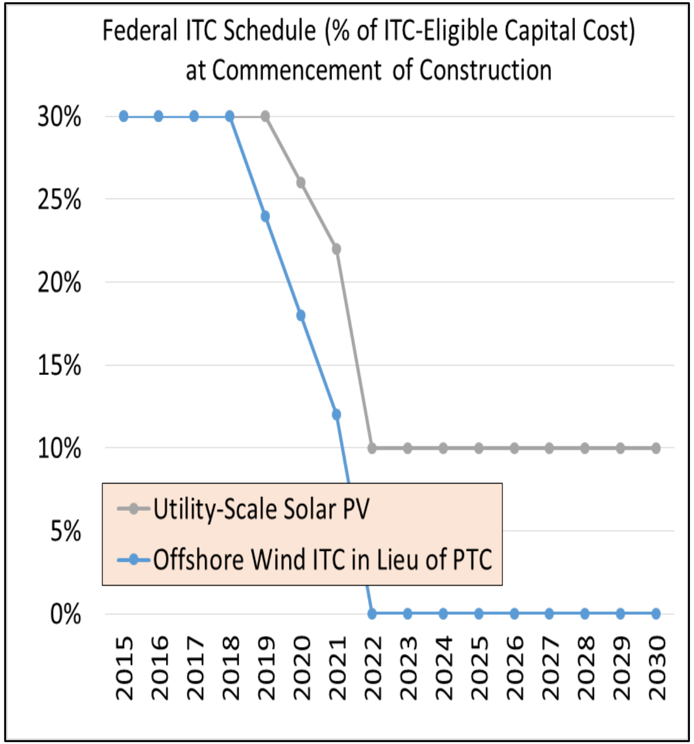


Figure A.31

PTC and ITC Schedules - Examples

E.g. For a Land-Based Wind Project Commencing Operation in 2021

E.g. For a Biomass Project Commencing Operation in 2019

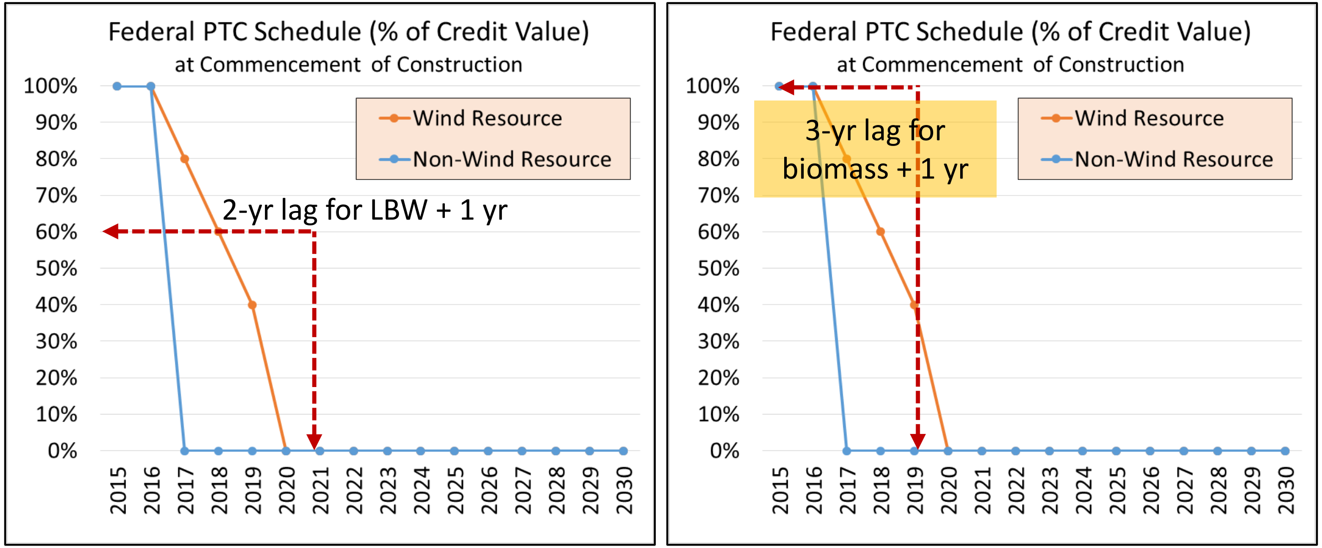


Figure A.32

Appendix A.6: Transmission and Interconnection

Cost of Grid Upgrades

The cost of interconnection born by incremental generators is considered as part of the total capital expenditures (CAPEX) to be financed, and is modeled as the sum to two components.

- The first component can be thought of as the cost of the 'extension cord' to plug into the existing transmission system, commonly referred to as the generator lead cost.
- The second component is the upstream non-reimbursed network upgrade costs that are determined by the NYISO (or interconnecting utility, if interconnecting to the distribution system or within a neighboring control area) and are charged to the generator through the interconnection process.

Socialized grid integration and upgrade costs are not examined in this Study. DPS has initiated a **State Resource Planning** (SRP) study to examine the effects of various public policies on the State's bulk power system. The SRP will examine potential reliability impacts to the State's bulk electric system given the addition of variable generation sources contemplated by the CES. It will Identify the reliability boundaries of the bulk power system and the upgrades that would be required to maintain a reliable system. The study is being performed in coordination NYSERDA, NYDEC, NYISO, NYDOS(UIU) and the New York Transmission Owners, with the assistance of two consultants, General Electric and ICF. Findings will be presented over the coming months.

Generator Lead Cost

The generator lead cost is modeled as consisting of two components: the cost of building new generator lead lines and the "non-line" cost of interconnecting that line to either an existing transmission line (via a new substation) or to an existing substation.

The cost of building new generator lead lines is the product of the unit capital cost (measured in $M/mile) of building a transmission line of a specified voltage and the distance between the project and the interconnecting infrastructure. The latter may include the cost of building a new substation, expanding an existing substation or installing a new breaker and other interconnection equipment.

This analysis considered five interconnection voltage ranges for which geospatial data was available and used in the analyses described in Appendix A.2: 23-46kV; 69kV; 115-150kV; 230kV and 345kV. Data from the Black & Veatch 2014 Capital Costs for Transmission and Substations study, and the Eastern Interconnection Planning Collaborative 2012 draft report on Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios, were used as a basis for developing the interconnection cost assumptions. Note that the Black & Veatch and EIPC studies only provided data on interconnection infrastructures with voltages of 230kV or above.

Generator Lead Cost (cont'd)

In consultation with an interconnection engineering expert, the aforementioned study data was refined, the appropriate interconnection configuration assumptions were defined for each infrastructure voltage range, and cost assumptions were adjusted to extrapolate to for 23-46 kV, 69-kV and 115-150 kV levels in a consistent manner. The data from these studies was also adjusted to better align interconnection cost experience in the Northeast. (See Table A.37)

A geospatial approach was taken to calculate the generator leads cost for land-based wind, utility-scale solar PV and hydro NPD resource blocks. Other interconnection assumptions were made for biomass and offshore wind. As described in previous Sections, straight-line distances of each identified project site from the nearest existing transmission lines and/or substations at different voltages were identified as outputs of the geospatial resource potential analyses. These distances were increased by 30% to reflect the practical constraints of building lines around geographic obstacles, and non-participating landowners, and within rights-of-way .

Using cost assumptions and capacity range constraints in Table A.37, the total cost of interconnecting to each compatible infrastructure for a project site was calculated. The least-cost option was chosen to be used as the modeled interconnection cost for that site in the supply curve. For utility-scale solar PV, the interconnection cost of a resource block was the weighted average interconnection cost for all sites within that block.

Generator Lead Cost Assumptions

Table A.37

Voltage (kV)	Compatible Project Capacity Range (MW)	Cost for Transmission Line ($M/Mile)	"Non-Line" Cost for Interconnecting to Existing Tx Line ($M)	"Non-Line" Cost for Interconnecting to Existing Substation ($M)
23-46	10-20	$0.50	$1.25	$0.75
69	20-60	$0.65	$2.50	$1.20
115-150	40-150	$1.43	$6.00	$1.80
230	120-230	$1.56	$9.50	$2.80
345	120-500	$3.57	$16.00	$4.20

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Network Upgrades

Projects can connect to the NYISO grid via either an Energy Resource Interconnection Service (ERIS) agreement, or, to access capacity market revenues, a Capacity Resource Interconnection Service (CRIS) agreement. This choice could have a significant impact on interconnection costs. Network upgrades may be required under each option, but in constrained areas of the grid, where additional upstream network investments are required to assure capacity deliverability, CRIS upgrades may be materially more costly.

In either case, the cost of network upgrades are not transparent, are extremely non-linear, and are therefore extremely difficult and costly to estimate with precision. For each project they are determined through the NYISO interconnection process, and are generally confidential in nature.   In constrained locations of the grid, such as the NYISO North zone (Zone D), network upgrade costs may be significantly higher than elsewhere. Conducting the necessary transmission studies to determine network upgrade costs is beyond the scope of this study. In addition, the allocation of major upgrades may have different cost allocations between projects as a matter of timing (NYISO may allocate costs between projects studies in a specific ‘class year’), and cost for specific network upgrades may have different cost allocation between generators and load as a function of evolving transmission planning process and policy.

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Modeling Network Upgrades

Project 11 from the September 2015 DPS "*Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives*" report was chosen as a proxy for developing an appropriate indicative network upgrade cost assumption for this analysis. The project was a $1.2 B upgrade project that was estimated to bring an additional 1000 MW capacity to the UPNY/SENY interface. Based on this data point, a $30/kW-yr value representing a transmission upgrade with a similar cost, used at a high capacity factor (such as might be the case if used by a combination of wind and large hydro), was selected as a proxy network upgrade cost adder.

This adder was divided into two categories: a $10/kW-yr ERIS adder that was applicable to all resources; and a $20/kW-yr CRIS adder that was applied to resources interconnecting via CRIS, except resources in Zones H, I, J and K, which were assumed not to be subject to network upgrade costs. Further, the analysis assumed that network upgrade costs would not be allocated evenly to all technologies. The applicability of this CRIS adder to each technology subcategory is shown in Table A.38.

Applicability of CRIS Adder by Technology

Table A.38

Resource Category	% of CRIS Adder Applied
LBW < 20 MW	50%
LBW ≥ 20 MW	100%
Utility-Scale Solar	10%
Hydro	0%
Woody Biomass	0%
Biomass - IGCC	100%
Biogas	0%
Offshore Wind*	0%

* ERIS and CRIS cost assumptions were embedded in CAPEX for offshore wind. This percentage does not have an impact on the calculation of LCOEs.

In all scenarios studied in this analysis, it was assumed that all resources (except offshore wind) in every zone would interconnect via CRIS. For offshore wind, an optimization analysis was conducted to determine the more economic configuration for each block in each year. 100% of the CRIS adder (subject to applicability adjustment by technology) was assumed to be born by developers through the entire span of the study.

Appendix A.7: Calculation of Results

Bidding Behavior: As-Bid vs. Clearing

Developer bidding behavior can be modeled based on two approaches. In the "**As-Bid Price**" approach, developers are assumed to bid at their revenue requirement based on threshold internal rates of return for the solicitation year. Alternatively, in the "**Clearing Price**" scenario, bidders prices would be paid based on the highest clearing bid, notwithstanding the individual generation project's revenue requirement. The cost under such an approach is modeled as the marginal cost of entry.

With recurring procurements, an increasing amount of market information becomes visible, allowing the lowest cost, sub-marginal bidders the opportunity to increase their bids above their threshold requirements and still be competitive. Over time, it is expected that bid prices will tend to increase under an as-bid structure with increased market experience, liquidity and transparency. For the studied period, it is expected that bid prices would likely fall within the spectrum between the individual as-bid price of a project and the marginal cost of entry. To model this bidding behavior, a "**Hybrid**" approach was taken. Under Fixed-Price REC modeling, this hybrid approach represents the weighted average of the as-bid premium of the resource block and the marginal premium for that solicitation year. Under PPA modeling, this approach represents the as-bid PPA payment, adjusted upward by the prorated marginal levelized premium. For all scenarios studied in this analysis, the as-bid price and the clearing price were given equal weighting (i.e., 50/50).

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Competing Demands

Other policies and markets both within New York and in adjacent regions could shop from the same pool of LSR resources as the CES Tier 1. Depending on the economics of the policies or markets, these competition could accelerate the depletion of lower-cost resources from the supply curve, pushing the Tier 1 policy cost upward.

In this analysis, the annual voluntary market demands and the annual Tier 1 LSR demands were aggregated, consistent with buyers shopping form the same pool of resources. Resources from the supply curve were deployed to meet the aggregated target each year. The supply from each resource block deployed was allocated to the Tier 1 policy and the voluntary demand market proportionally based on their respective demand for that year. Only supply allocated to the LSR policy was traced in the calculation of capacity deployed, generation and costs. The impact of voluntary demand is that Tier 1 LSR supply costs are slightly higher as the combined demand must reach a bit further up the supply curve.

Competition from neighboring markets was not modeled explicitly, i.e., it was assumed that the mechanisms made available through Tier 1 would suffice to encourage new installations to deliver into the New York market rather than export.

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Voluntary Demand

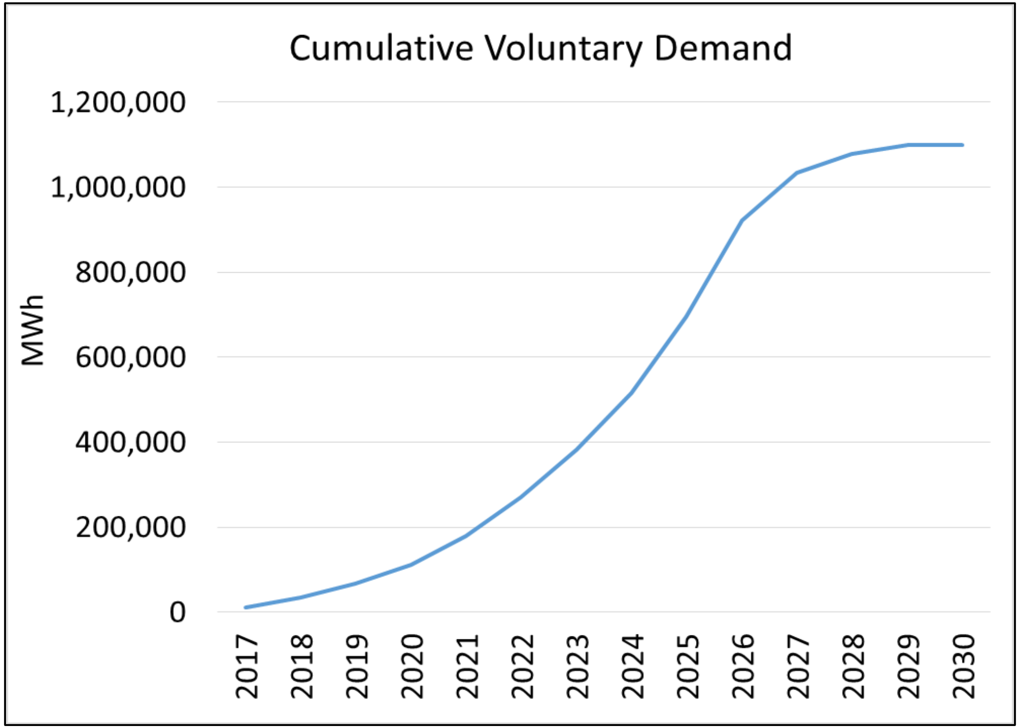


Figure A.33. All scenarios studied in this analysis assumed a cumulative voluntary market penetration of 1% of jurisdictional load by 2030.

The annual voluntary demand schedule was shaped to an "S" curve to represent typical policy adoption trend.

The impact of such voluntary demand in the analysis was to reduce the supply curve resource availability for the purpose of fulfilling Tier 1 targets.

Calculation of Results

As noted previously, the supply curve model sorts resource blocks from lowest to highest premium for each solicitation year (referred to as a procurement tranche) and deploys available blocks until the LSR target is met for each tranche (“block clearing”).

In practice, the cheapest resources may not always be deployed first, so this approach may under-estimate some costs in early years and over-estimate those costs in later years if some cheaper resource blocks are deployed later than modeled.

In addition, the model does not model any potential preference for deploying installations in locations with low environmental impact other than through the constraints set out in Appendix A.2 above. Any such effects could result in some cost increases above those modeled if cheaper sites being deployed in the model were either subject to additional costs or not utilized as a result. Analysis of environmental and social constraints by means of spatial mapping is ongoing within NYSERDA and will be published in due course.

From the block clearing exercise as described, the quantity (MW and GWh) deployed for each resource block and the $/MWh program cost for each block are identified. The production, annual policy payment, and annual market value (relevant in Bundled PPA modeling) for each resource block are tracked individually for the block’s entire 20-year contract duration in the model.

Calculation of Program Costs (cont'd)

- Under PPA modeling, the annual $/MWh program cost of a block represents the LCOE for the year the block was deployed, which is fixed throughout the contract life, minus the annual market value (expressed in $/MWh) credited to that block, which varies over time.
- Under fixed REC modeling, the annual $/MWh program cost of a block represents the weighted average of the clearing levelized premium and the as-bid premium for the year the block was deployed, which is fixed throughout the contract life.

The base case scenarios presented in this Study reflect a 50%/50% mix between fixed REC and bundled PPA procurement. These base case results were derived by carrying out the analysis separately under PPA and fixed REC assumptions, and blending (averaging) the results.

Carbon Value

Table A.39 shows the social cost of carbon (SCC) used in this Study (in dollars per MWh of generation), taken from EPA's Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015). The SCC values used in this Study are consistent with the PSC's January 21, 2016 Order, "Order Establishing the Benefit Cost Analysis Framework". Note, however, that the specific values used reflect a slight modification due a revision from EPA.

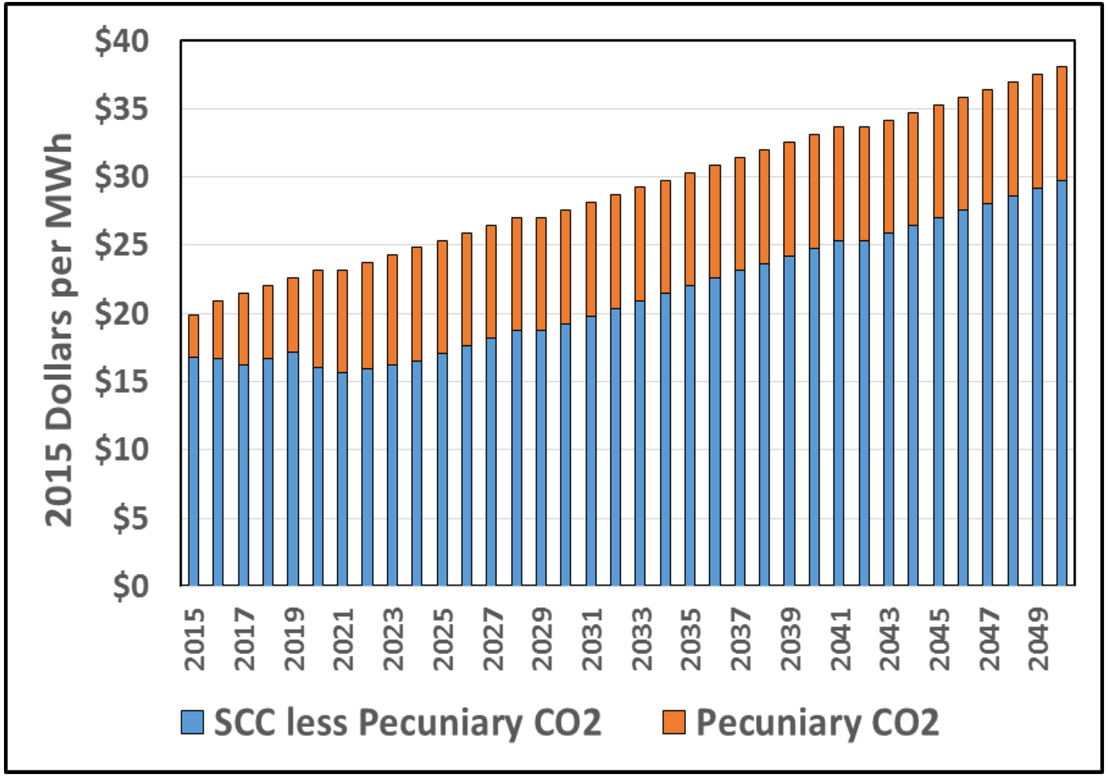
The avoided CO2 emission rate underlying the carbon value was assumed as an average marginal rate of around 1,077 pounds (0.538 short tons) per MWh (consistent with the 2015 Net Metering Study).(1)

Carbon benefits are reflected in the (gross) program costs to the extent they are internalized in the electricity price. Table A.39 notes this pecuniary value of CO2. The pecuniary value was taken from the 2015 NYISO CARIS 1 forecast of RGGI allowance prices (held constant in real terms after 2024). Net program costs presented in this Study are the gross program costs minus the non-pecuniary portion of the social cost of carbon (see Table A.39).

(1) An alternative approach would be to use a future expectation for system average natural gas emission rate; examination of recent SRP production cost model output indicates this rate to be approximately 900 pounds per MWh. Using this approach would reduce the overall tons avoided and hence carbon value by about 16%. By way of comparison, it should be noted that inclusion of Tier 2B carbon value (see Section 8) would more than offset any such reduction in value.

Carbon Value per MWh

Table A.39



Appendix B – Tier 2 and 3 Methodology

Tier 2: Analysis Overview

The Tier 2 analysis presented in this Study was carried out by NYSERDA's consultant, Sustainable Energy Advantage, LLC.

Modeling of the costs to supply Tier 2 is primarily based on assessment of opportunity cost.

By definition, Tier 2A resources have material revenue opportunities in surrounding markets – historically and currently in the New England Class I RPS markets; in the future, it is possible that PJM 'Tier 1' RPS market prices could become competitively attractive. The analysis attempts to identify a payment level that will successfully attract most or all such resources to sell their RECs for CES Tier 2A in New York State rather than exporting their energy to other markets.

Also by definition, Tier 2B resources have very limited revenue opportunities for their REC in other markets, likely lower than the cost of accessing those markets. The costs assumed to apply for purposes of this analysis are representative of those available to similar resources in nearby state RPS markets, and are assumed to be sufficiently above transactions costs to motivate a sale of RECs to CES obligated entities, but not much more.

Tier 2A Analysis Approach

Tier 2A addresses existing renewable electricity installations in New York State that are not, or no longer covered by Main Tier solicitation contracts, and would have the opportunity to export their generation to other territories. Targets levels are established initially at the contribution of eligible resources to the 2014 baseline (i.e., generation of such resources net of exports at that time), and increase as Main Tier RPS contracts reach the end of their term.

The costs of Tier 2A are estimated in several steps.

- First, an appropriate alternative compliance payment (ACP) level is estimated. The ACP represents the cap on spot REC prices in a Tier 2A market. The ACP provides the basis for estimating costs in the absence of long-term contracting. The cost is estimated at 98% of ACP (to reflect an approximate level of discount to price caps common in other markets, such discount needing to be sufficient to compensate a buyer for transactions costs not otherwise incurred in the simpler payment of ACP). In this case, the NY market revenue stream would provide a similar or slightly lower level of revenue risk as available in alternative markets.
- Alternatively, a payment level is estimated for the payments to Tier 2A generators under bundled PPAs of duration from the year generation first becomes eligible for Tier 2A, through 2030 (i.e., progressively decreasing contract duration). In this case, provision of long-term bundled PPAs could provide the necessary incentive for generation to stay in New York State at a lower cost due to the additional commodity market revenue certainty benefits of PPAs.

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Tier 2A Analysis Approach (cont'd)

- A final step is to craft alternative futures representing either of these all-spot or all-bundled PPA extremes, or some combination thereof.

In either the spot REC price or Bundled PPA scenarios, the projected costs are based on the breakeven payments required to make NY CES revenues sufficiently attractive, relative to export to such other markets (particularly New England) to retain most or all of the supply in New York. The difference is that the risk and rewards differ, and therefore the expected revenue streams can and should be valued differently.

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Derivation of Tier 2A ACP

The breakeven analysis centers on the following formula:

Levelized NY ACP = Levelized NE REC + Levelized NE Energy – (levelized transaction/risk adjustment for delivery into NE) - (Levelized NY energy + Levelized NY capacity)

It was assumed that exporting generation would be unable to monetize capacity revenue in either market.

Each component is described as follows.

- The **Levelized NE Spot REC Price** revenue based on a levelization of an annual projected Massachusetts Class I REC price forecast. A Massachusetts price is used as a proxy for other smaller Class I markets, most of which tend to have similar prices in most years. The forecast is based on an amalgamation of applicable scenarios from Sustainable Energy Advantage's proprietary recent New England Renewable Energy Market Outlook (REMO). Two forecasts were averaged and levelized. One (the higher of the two) assumes very limited exports of legacy NYSERDA contract LSR from New York to New England, and the other represents a moderate level of such exports. For each, the long-term trend assumed one standard deviation above an 'expected value' case to reflect that generators would forego greater upside in New England to sell RECs at or near a Tier 2A ACP in New York. The resulting levelized New England REC price from 2017 through 2030 is $30 per MWh.

Derivation of Tier 2A ACP (cont'd)

- For the **Levelized NE Energy revenue**, a forecast of ISO-NE Western Massachusetts (WMA) zone energy prices produced for the REMO analysis (1) was used, adjusted to reflect wind-production-weighting. For the levelized transaction/risk adjustment for delivery into New England, the value of Transaction Costs & Basis (NYISO Zone D to ISO-NE WMA) plus delivery risk (comprised of factors including basis risk, scheduling and curtailment risk) was assumed to be $8/MWh nominal levelized (2).
- The **Levelized NY Energy** was based on the NY Energy price forecast for Zone D as described in Appendix A.3, adjusted to reflect wind-production-weighting.
- Finally, the **Levelized NY Capacity** was based on the weighted average summer and winter price forecast for Zone D described in Appendix A.3, and converted to $/MWh at an assumed 34% c.f.

Notes:
1: to the extent that this was not developed in a consistent manner with NY energy price forecast, an adjustment upward or downward to align the forecasts would result in a corresponding adjustment downward or upward to the NE REC price, offsetting the adjustment. Therefore no adjustment was made.
2: Based on the consultant's past analysis, periodic benchmarking in interviews with market participants doing this type of transaction, reduced to reflect increased value of RECs which cannot be delivered to NE under CES compared to present.

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Derivation of Tier 2A ACP (cont'd)

For this analysis, different discount rates were applied in levelizing different revenue streams consistent with the commensurate risk associated with that revenue stream. Unhedged revenues (NE REC, NE energy, transaction) were discounted at 14.75%; Unbundled revenue streams (NY energy and capacity but RECs at ACP) were discounted at 12.28%. These discount rates represent the average of the associated (i) cost of equity, and (ii) weighted average cost of capital, applicable to wind, as derived for the supply curve analysis and described in Appendix A.4. Unhedged capacity revenue was further de-rated to 50% of the forecast value.

The calculated result for the ACP was $25.75 per MWh.

Derivation of Tier 2A Bundled PPA Price Premium

The analysis of levelized prices paid under Bundled PPAs to Tier 2A generators proceeds similarly to the derivation of the ACP described above. The primary difference is in the risk profiles of the various revenue streams, and therefore the discount rates used to assess them. The formula used is as follows:

> *Nominal NY Breakeven REC Revenue = Nominal NE REC price + Nominal NE Energy Price – (Nominal transaction Cost+Basis+Delivery Risk) – (Levelized NY energy and capacity revenue, year of PPA through 2030)*

The PPA price was calculated as the levelized effective program payment for PPAs beginning in each respective year and ending in 2030. The discount rates used for the bundled (and thus fully hedged) New York energy, capacity and REC revenue streams were based on the average of the 'bundled/perfect hedge' (i) cost of equity, and (ii) weighted average cost of capital, applicable to wind. This discount rate was 8.91%.

The PPA rates are of declining duration for each tranche of Tier 2A supply coming onto the market that enters contracts. This annual effective PPA program payment was then levelized and added to aforementioned levelized energy and capacity prices to determine the levelized PPA price. The cost premium was derived as the levelized PPA payment less the NYISO commodity market energy and capacity revenues. Total costs were calculated for each tranche of contracting on a volume weighted basis.

Tier 2B Analysis Approach

Tier 2B applies to existing renewable electricity generation which does not have export opportunities.

Tier 2B targets are set bases on the amount of LSR in the 2014 baseline that are not owned by NY State Entities, net of expired RPS Main tier contracts.

Tier 2B resources have very limited revenue opportunities for their REC in other markets, likely lower than the cost of accessing those markets. Thus a breakeven analysis as performed for Tier 2A is not feasible. Instead, the costs assumed to apply for purposes of this analysis are representative of those available to similar resources in nearby state RPS markets, and are assumed to be sufficiently above transactions costs to motivate a sale of RECs to CES obligated entities, but not much more. However, if the sum of market energy and capacity revenues plus a nominal revenue stream for RECs is insufficient to cover operating costs, it is possible that such generators might cease to operate without higher REC revenues or co-incentives. Such additional costs needed to keep every Tier 2B generator operating have not been included in the analysis.

Tier 3

The White Paper proposes Tier 3 as a policy to ensure that existing nuclear facilities continue to operate despite current low electricity prices, using “ZEC” payments. The likely costs associated with ZEC payments for nuclear installations have been analyzed over the periods to 2023 and 2030, based on low and high assumptions of the cost of generation of nuclear power and future energy prices.

The analysis produced a projection of low and high range costs per MWh of generating nuclear electricity over the Study period. This was set against the low and high range electricity revenue assumptions as well as the capacity revenue assumptions used throughout this Study (see Appendix A.3). In any year where this produced a shortfall, it was assumed that the Tier 3 payments would be set at the level required to cover this shortfall.

Neither the assumptions used for generation costs of nuclear electricity nor the resulting annual expected program costs for Tier 3 are published in this Study. As stated in the White Paper, ZEC premium levels will be determined based on “open book” assessment of the costs of nuclear generation, working with the operators of the nuclear facilities in question. This Study refrains from more detailed numbers in order to avoid prejudicing this process.

See Section 10 for notes in respect of the economic benefits of maintaining the nuclear facilities eligible for Tier 3.

Appendix C – Longer-term Projections

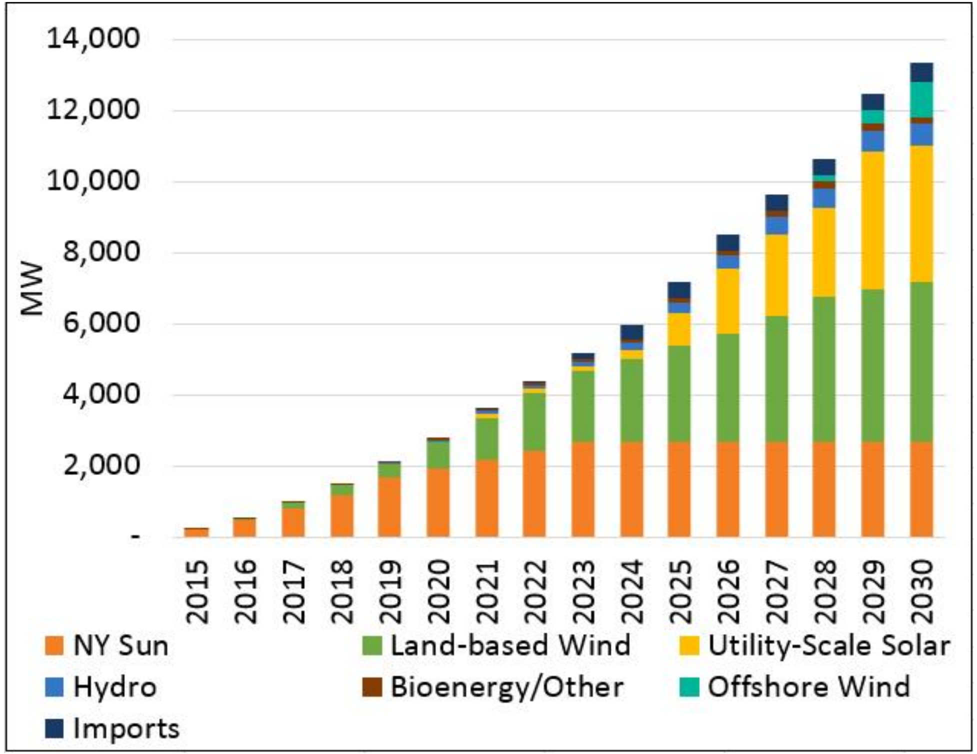
Introduction

This Appendix provides analysis covering the full CES program period to 2030 (extending to 2049 once the full 20-year contract period of installed renewables is taken into account). It complements the projections provided for the period to 2023 throughout this Study, noting that the estimates provided in this Appendix are considered to be significantly more uncertain than the 2023 analysis.

The following information is provided:

- Technology mix and quantity/target levels
- Gross and net program cost (in lifetime net present value) by CES Tier
- Carbon benefits
- Average bill impacts for the base case and variations for each of the cost drivers examined throughout this Study
- Comparison between CES costs and projected wholesale electricity costs
- Program costs per MWh.

Tier 1 Cumulative Capacity Deployed



Data reflects an adoption scenario, not a commitment to a particular technology mix. See Appendix A for methodology.

Figure C.1. This graph shows the base case projection until 2030 for all installed capacity eligible for Tier 1 of the CES. It includes NY-Sun/ behind-the-meter installations as well as installations from the Main Tier solicitation program, in each case from 2015.

Tier 1 Capacity Installed

Purple: past Main Tier solicitations

Blue: upcoming 2016 Main Tier solicitation

Table C.1. Incremental

MW	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NY-Sun	208	249	330	369	500	258	258	258	258							
Land-based Wind	18	23	155	100	106	370	408	448	359	322	382	326	520	552	204	190
Utility-Scale Solar					-	-	109	14	-	142	646	928	452	182	1,380	-
Hydro	-	-	0	12	15	23	23	22	39	62	126	61	99	68	45	3
Bioenergy/Other	1	3	-	10	-	33	7	31	5	-	2	53	44	1	-	-
Offshore Wind					-	-	-	-	-	-	-	-	-	197	194	608
Imports						-	4	4	165	261	19	3	-	-	-	60

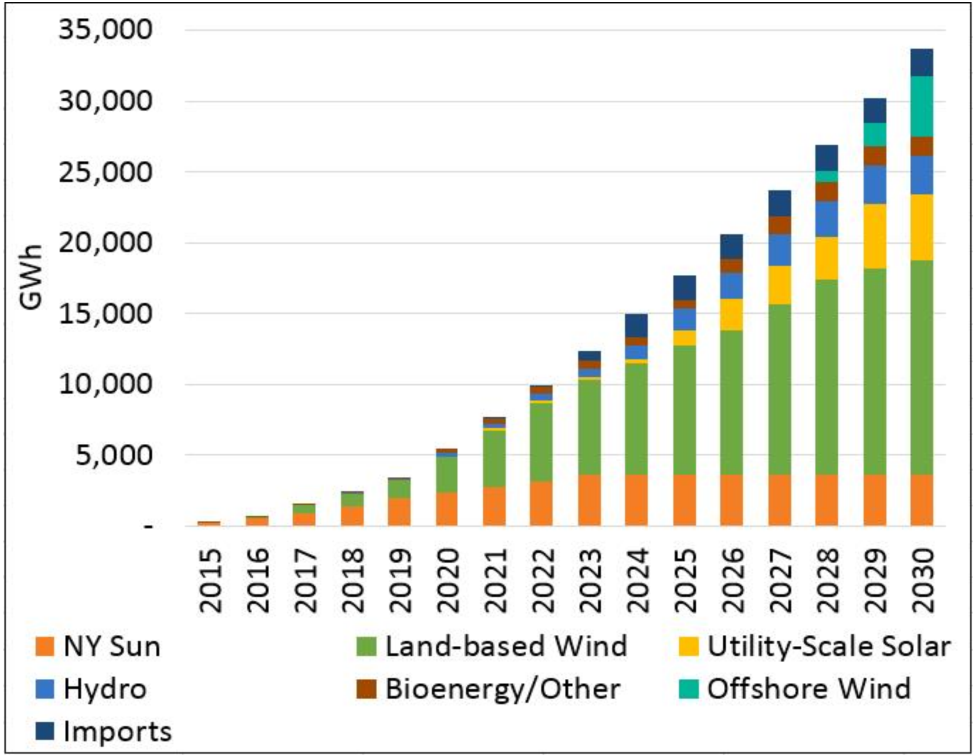
Pre-2015 deployment is not shown, (eg for this reason NY-Sun deployment shown is less than the full 3 GW NY-Sun target)

Table C.1. Cumulative

MW	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NY-Sun	208	457	787	1,156	1,656	1,914	2,172	2,430	2,688	2,688	2,688	2,688	2,688	2,688	2,688	2,688
Land-based Wind	18	40	196	296	402	771	1,180	1,628	1,987	2,309	2,691	3,018	3,537	4,089	4,294	4,483
Utility-Scale Solar	-	-	-	-	-	-	109	124	124	266	912	1,840	2,292	2,475	3,855	3,855
Hydro	-	-	0	12	28	51	74	96	135	197	323	384	483	551	597	600
Bioenergy/Other	1	5	5	14	14	47	54	85	89	89	91	144	188	189	189	189
Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	197	391	1,000
Imports	-	-	-	-	-	-	4	8	173	434	453	456	456	456	456	516

Data reflects an adoption scenario, not a commitment to a particular technology mix. See Appendix A for methodology.

Tier 1 Cumulative Generation



Data reflects an adoption scenario, not a commitment to a particular technology mix. See Appendix A for methodology.

Figure C.2. This graph shows the base case projection for generation from the installed capacity shown in Figure C.1.

Note that there is no linear correlation across the range of technologies between the GWh figures shown here and the MW capacity in Figure C.1, because capacity factors differ for each technology. For instance, the lower capacity factor of solar PV compared to other technologies explains why the proportion of solar PV production is less than its proportion of total capacity, relative to the other technologies.

Tier 1 Generation

Purple: past Main Tier solicitations

Blue: upcoming 2016 Main Tier solicitation

Table C.2 - Incremental

GWh	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NY-Sun	218	306	391	469	578	408	408	408	408							
Land-based Wind	55	72	459	293	362	1,290	1,448	1,540	1,214	1,117	1,266	1,115	1,792	1,830	686	668
Utility-Scale Solar					-	-	133	17	-	174	779	1,131	506	213	1,627	-
Hydro	-	-	5	72	80	101	96	99	188	297	617	271	445	307	206	12
Bioenergy/Other	9	21	-	76	-	200	43	214	28	-	13	368	307	7	-	-
Offshore Wind					-	-	-	-	-	-	-	-	-	843	831	2,602
Imports					-	-	22	21	611	1,013	75	15	-	-	-	215

Pre-2015 deployment is not shown

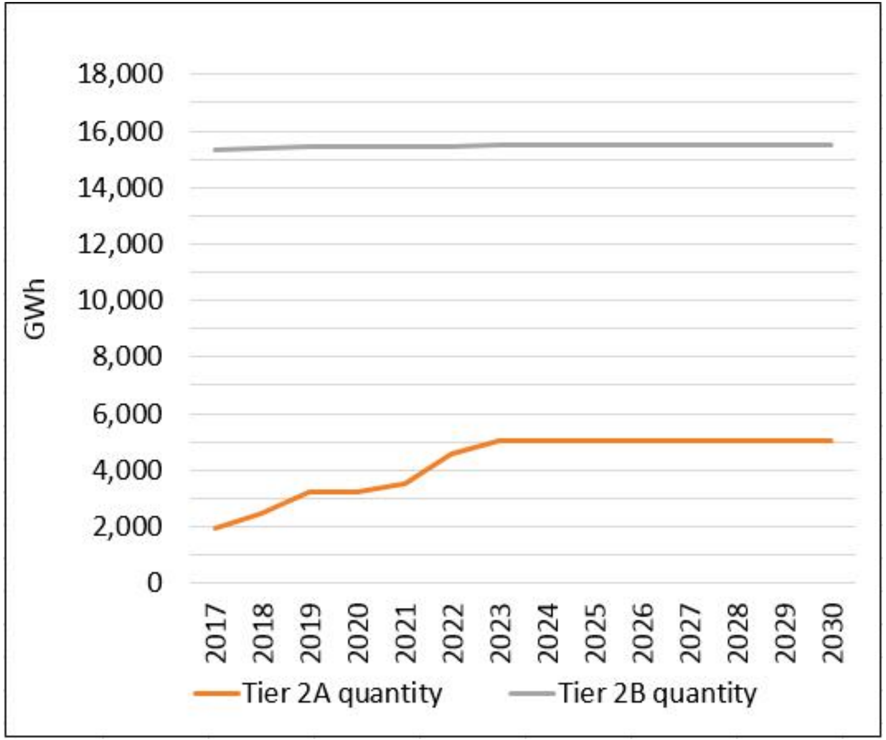
Table C.2 - Cumulative

GWh	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NY-Sun	218	524	915	1,384	1,962	2,370	2,778	3,186	3,594	3,594	3,594	3,594	3,594	3,594	3,594	3,594
Land-based Wind	55	127	586	880	1,241	2,531	3,979	5,519	6,733	7,849	9,115	10,231	12,022	13,852	14,538	15,206
Utility-Scale Solar	-	-	-	-	-	-	133	151	151	324	1,104	2,235	2,741	2,954	4,582	4,582
Hydro	-	-	5	77	156	258	354	453	641	938	1,556	1,827	2,271	2,578	2,784	2,796
Bioenergy/Other	9	30	30	106	106	306	349	563	590	590	603	971	1,278	1,285	1,285	1,285
Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	843	1,674	4,275
Imports	-	-	-	-	-	-	22	43	654	1,667	1,742	1,757	1,757	1,757	1,757	1,972

Data reflects an adoption scenario, not a commitment to a particular technology mix. See Appendix A for methodology.

Tier 2 Target Levels

Figure C.3



All data reflects modeling estimates. See Appendix B for methodology.

Program Cost by Tier

The calculations in this Study indicate that when taking account of the benefits resulting from reductions in harmful carbon emissions, the benefits of investing in renewables far outweigh the costs. The table below presents the program costs of the CES before ("gross") and after ("net") accounting for carbon benefits. These figures do not reflect economic benefits (see Section 10 for discussion of economic impacts).

2015 $ NPV	Gross Program Cost to 2030	Net Program Cost to 2030
Tier 1	$2.44 B cost	$1.88 B benefit
Tier 2A	$630 M cost	$8 M cost
Tier 2B	$277 M cost	$277 M cost
Tier 3	$270 M cost	$2.80 B benefit
Total	**$3.62 B cost**	**$4.39 B benefit**

The results reflect base case assumptions. Tier 1 is calculated as the full lifetime cost and benefit of installations (to 2049 for the 2030 time horizon). Tiers 2 and 3 reflect the period to 2030. Costs from existing programs (NY-Sun, Main Tier solicitations) are not shown. Lifetime NPV calculations use a discount rate of 5.5% (real). See Section 1 and the Appendices for further details on assumptions and methodology.

CES Carbon Benefits

Figure C.4: Tons of avoided carbon

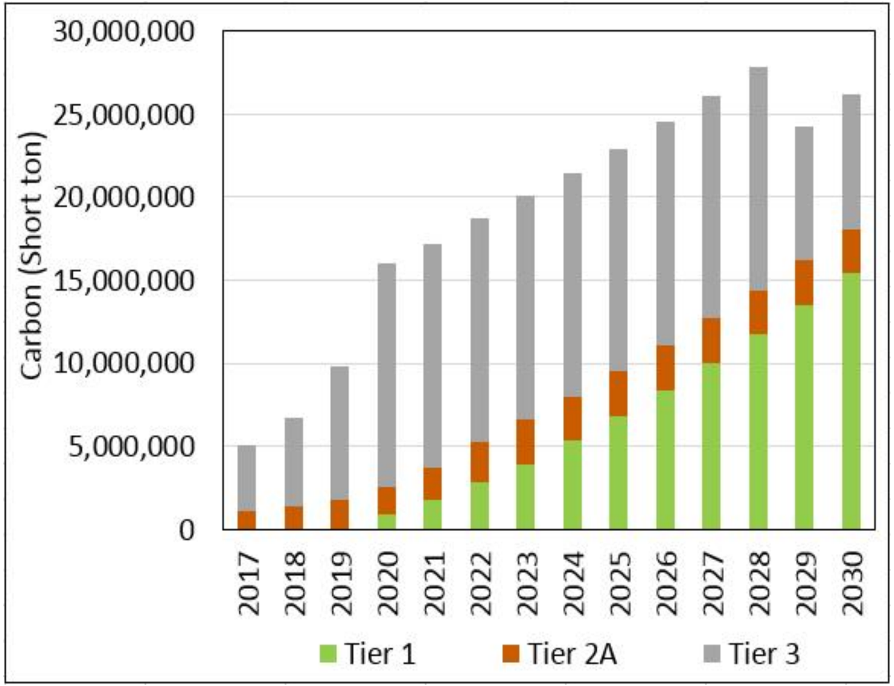
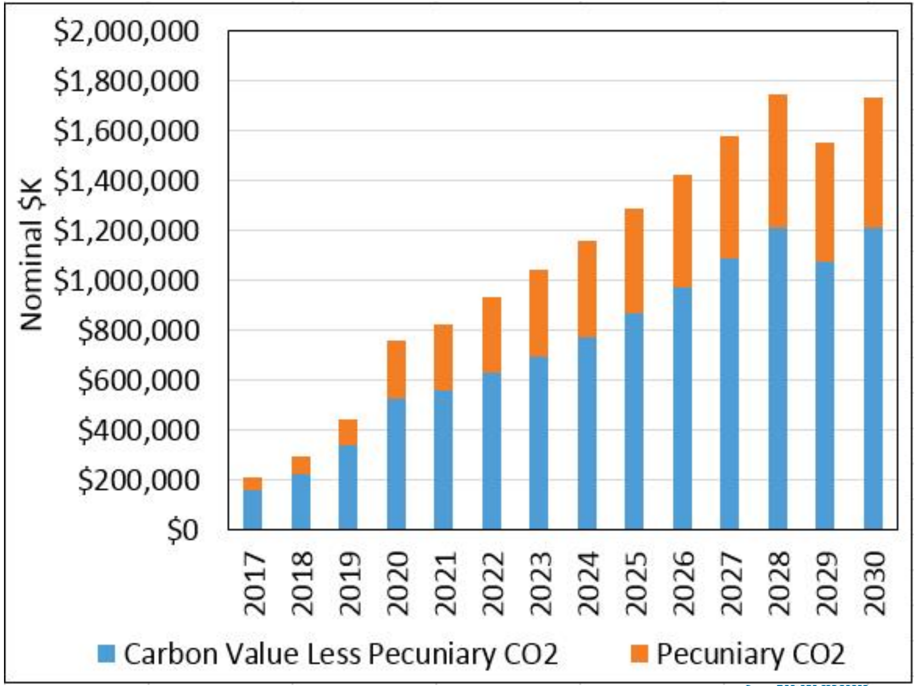


Figure C.5: Value of avoided carbon



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Bill Impacts

Impacts are shown as the average impact over the total program period (to 2049 when the last installations reach the end of their assumed 20-year contract period). They are expressed as the average CES gross program cost over the program period (in real terms) as a percentage of 2014 total statewide electricity bill spend. Data is provided for the base case and the range of sensitivity variations of the various cost drivers examined in this Study. All sensitivities are provided relative to the base case. See Appendix A for details of the inputs settings for the various sensitivities.

- The **base case** impact is forecast at **0.94%**
- **Procurement structures**. Under 100% PPA procurement this drops to a negligible level of **0.03%**; under 100% fixed-REC procurement this is projected at **1.84%.**
- **Energy prices**. Lower and higher energy price assumptions are forecast to change base case impacts to **1.43%** and **0.22%**, respectively.
- **Interest rates**. Using a higher interest rate assumption, the impact increases moderately to **1.08%**.
- **Technology cost**. The 2023 analysis set out in Section 5 tests a technology cost sensitivity for land-based wind only. In the analysis to 2030, technology sensitivities were additionally assessed for utility-scale solar and offshore wind. In each case the sensitivity reflects an increased cost assumption for the technology in question. Results are shown in Figure C.6 and Tables C.3-C.4 below.

Bill Impacts (cont'd)

The analysis suggests that variations in key technology cost assumptions lead to significant changes in the technology mix (shown in Figure C.6), but appear to result in only a relatively small change in total costs/ bill impacts (see Table C.4). Equally, this indicates that during the later part of the Study period a number of technologies are achieving similar cost levels and are thus able to compete effectively.

- **System Load**. A higher assumption on the amount of electricity consumed in New York State over the program period results in a significant impact on cost, increasing projected average bill impacts to **1.57%**.
- **Tax credits**. If the federal tax credits were to remain in place until 2030 at their final level before being phased out, the continued availability of tax credits is projected to reduce bill impacts to **0.72%**.
- **Imports**. A final sensitivity carried out in the 2030 analysis assumed the possibility of 1,000 MW of additional infrastructure capacity being available from 2023 to import hydro power from Canada. This was projected to reduce bill impacts significantly to **0.65%**.

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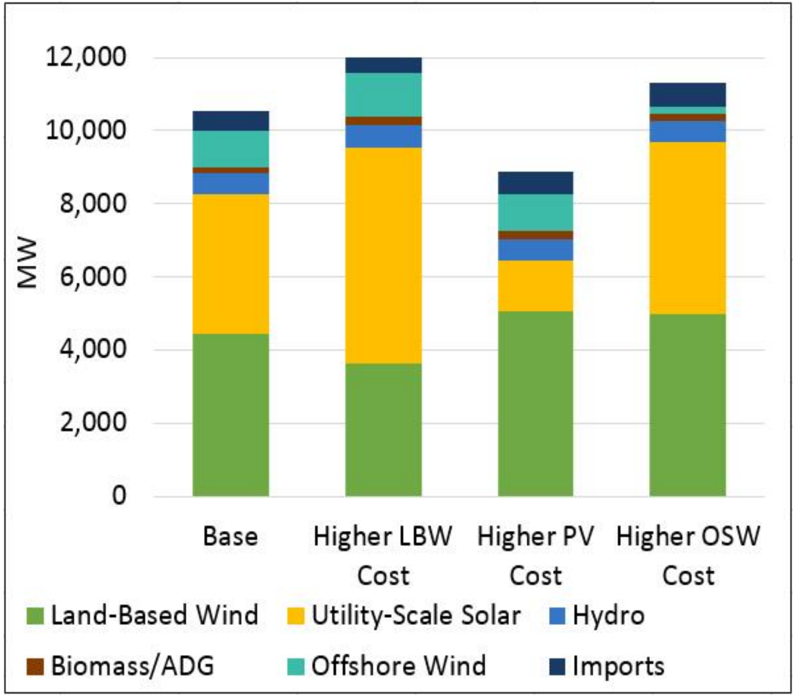
Technology Cost Sensitivities

Figure C.6: Total CES Tier 1 deployment by 2030



Data reflects adoption scenarios, not a commitment to a particular technology mix.

Table C.3: Total CES Tier 1 deployment by 2030

MW	Base	High LBW	High PV	High OSW
LBW	4,420	3,609	5,050	4,975
Solar PV	3,830	5,939	1,394	4,692
Hydro	577	597	593	600
Bioenergy	175	227	233	175
OSW	1,000	1,215	1,000	200
Imports	516	448	604	656

Table C.4

Case	Bill Impact
Base	0.94%
Higher LBW cost	1.16%
Higher PV cost	1.00%
Higher OSW cost	0.99%

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Comparison with Forecast Wholesale Prices

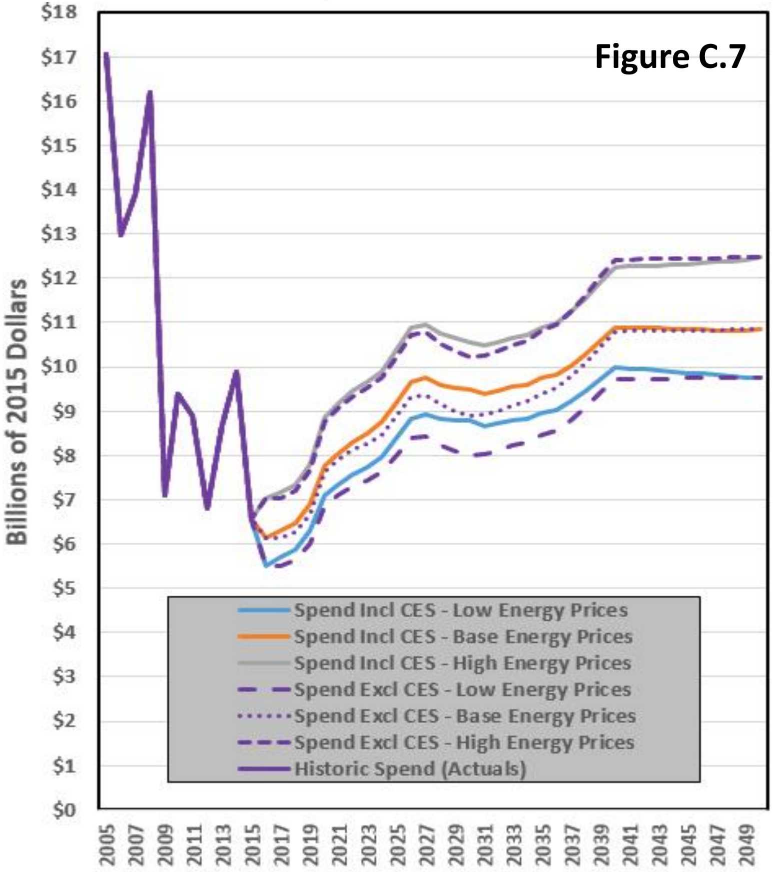

Figure C.7 summarizes the relationship between total annual CES gross program costs and total statewide annual spend on wholesale energy under base case, high or low energy price forecasts.

- If, going forward, energy prices rise from their current low levels by more than our central energy price forecast, customers could start seeing net savings from the investment in renewables.
- If energy prices stay at their current low level or rise only modestly, customers would continue to spend significantly less on energy than they did until recently, even after taking into account the costs of the CES.

Note that this graph compares CES to wholesale energy cost, not retail bills. CES costs are relatively lower when set against retail bills, as shown above.

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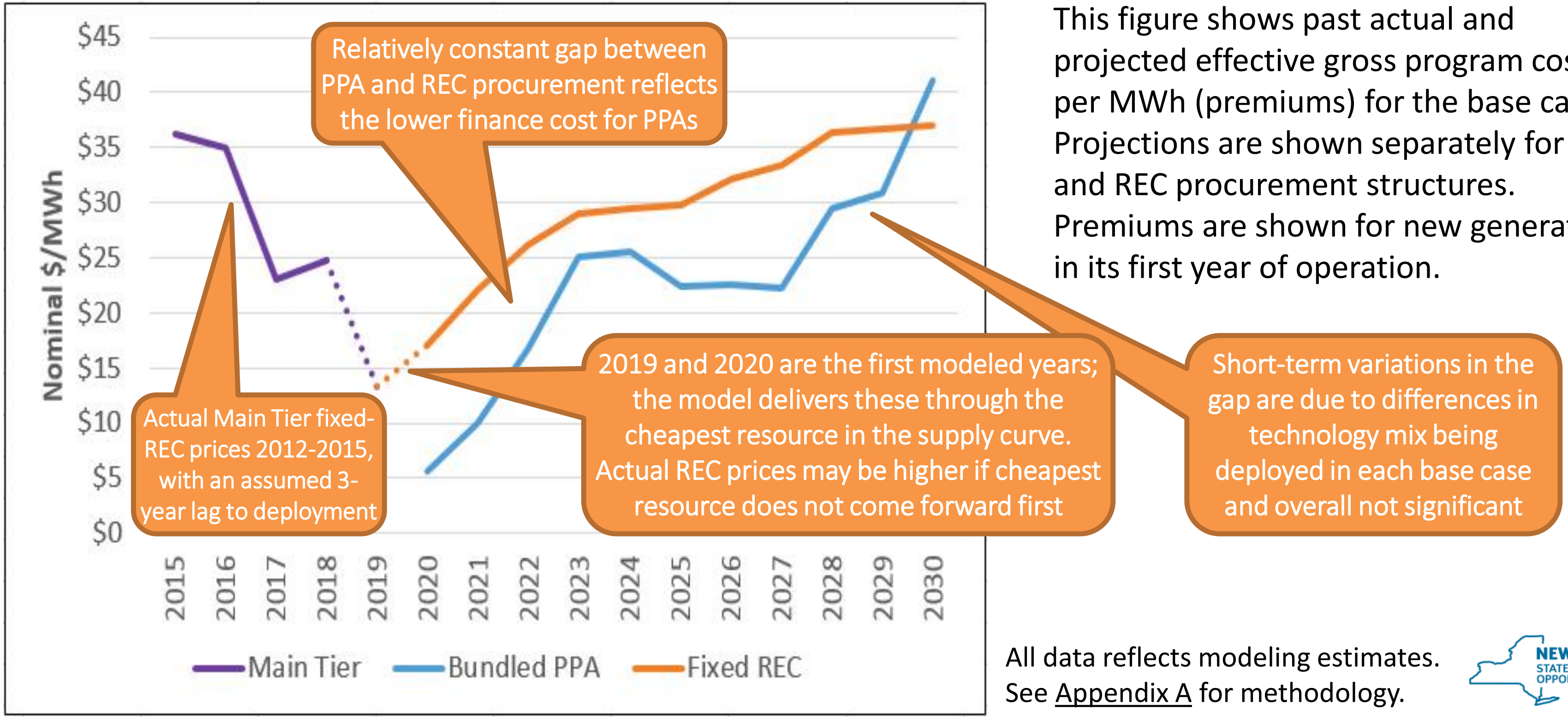
Tier 1 Program Cost per MWh

Figure C.8



This figure shows past actual and projected effective gross program costs per MWh (premiums) for the base case. Projections are shown separately for PPA and REC procurement structures. Premiums are shown for new generation in its first year of operation.

All data reflects modeling estimates.
See Appendix A for methodology.

Tier 2A Program Cost per MWh

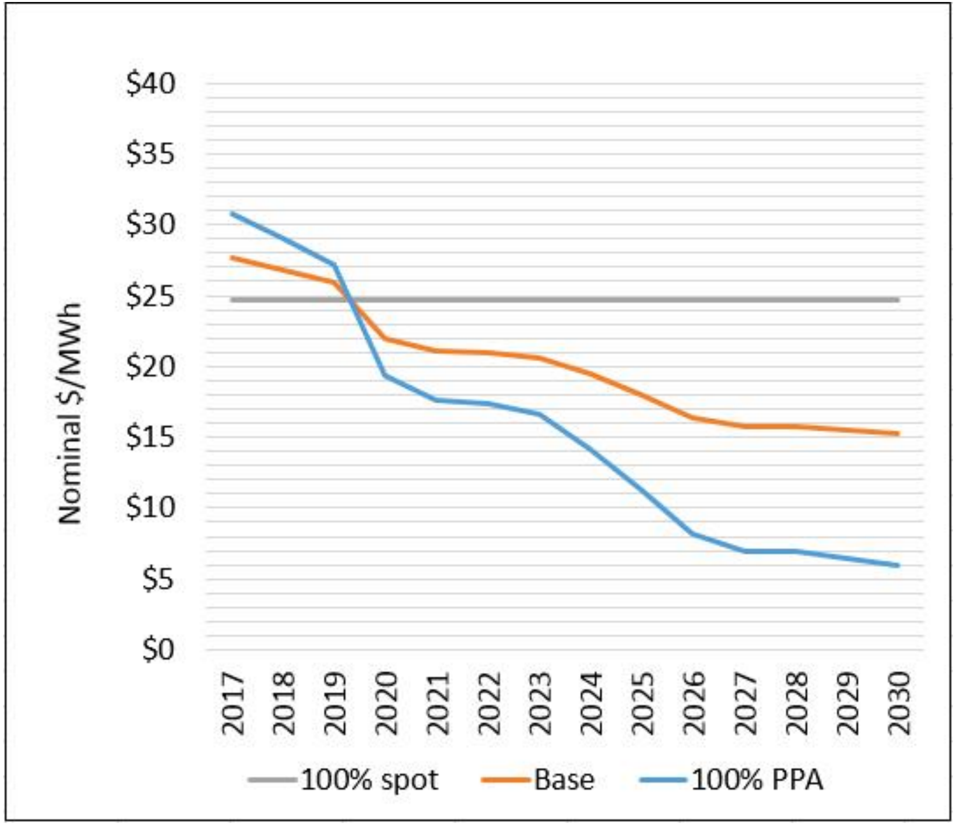


Figure C.8. This figure shows projected effective gross program costs per MWh (premiums) for the base case (50%/50% mix between spot price and PPA procurement), as well as the 100% and 100% REC scenarios.

Note that program costs per MWh for Tier 2B are discussed in Section 8. Section 8 also explains that no program costs per MWh are published for Tier 3 at this time.

All data reflects modeling estimates. See Appendix B for methodology.

Appendix D – Abbreviations

Abbreviations

Abbreviation	Stands for	Explanation
AD (or ADG)	Anaerobic digestion	Biogas technology application
ATB	Annual Technology Baseline	Modeling assumptions created by NREL for renewable energy modeling
BC	Base Case	
BCA	Benefit Cost Analysis	
BTM	Behind-the-meter	Distributed renewable electricity generation
C&D	Construction and Demolition Debris	A waste biomass fuel assumed to only be eligible if burned in a biomass IGCC configuration.
CAPEX	Capital Expenditure	
CARIS	NYISO Congestion Assessment and Resource Integration Study	
CES	Clean Energy Standard	
C.F.	Capacity Factor	
CHP	Combined heat and power	For this study, biomass combusted in a configuration to create both useful heat and electricity
CRIS	Capacity Resource Interconnection Service	NYISO term for interconnection service as a capacity resource

Abbreviations

Abbreviation	Stands for	Explanation
DOE	U.S. Department of Energy	
DPS	New York Department of Public Service	
EDC	Electric Distribution Company	Utilities serving in their role as distribution service provider
EFOR	Equivalent Forced Outage Rate	
EIS	Environmental Impact Statement	The Draft Supplemental Environmental Impact Statement published on February 23, 2016
ERIS	Energy Resource Interconnection Service	NYISO term for interconnection service as an energy resource only (not eligible to earn capacity revenues)
ESCO	Energy Service Company	Competitive supplier of electricity at retail
FTC	Federal tax credit	
GSP	Gross State Product	
GWh	Gigawatt-hour	
ICAP	Installed Capacity	NYISO ICAP market is based on the obligation placed on load serving entities (LSEs) to procure ICAP to meet minimum requirements.

Abbreviations

Abbreviation	Stands for	Explanation
IGCC	Integrated Gasification Combined Cycle	ICGG technology using woody biomass or C&D as fuel
INL	Idaho National Laboratory	
ITC	Investment Tax Credit	Federal tax credit incentive as a percentage of eligible CAPEX available to solar PV, and to projects eligible for PTC in lieu of the PTC.
kWh	Kilowatt-hour	
LBMP	Locational-Based Marginal Price	NYISO spot energy market price in $/MWh
LBNL	Lawrence Berkeley National Laboratory	
LBW	Land-based wind	
LCOE	Levelized cost of energy.	The levelized (or constant in each year) amount of revenue per MWh needed in order to make a RE installation commercially viable, based on its upfront cost, ongoing costs and investment hurdle rate. LCOE is only one comparative metric; it does not consider the differences in the value of a generator's production, which may result in generators with identical LCOE having different out-of-market costs. This study uses *nominal* LCOE, meaning the amount of revenue per MWh is the same in each year in nominal terms (some studies use *real* LCOE).

Abbreviations

Abbreviation	Stands for	Explanation
LSE	Load-Serving Entity	Entity supplying electricity at retail to end-use customers in New York including ESCOs, EDCs (operating in their capacity as suppliers of last resort)
LSR	Large-scale renewables	Term used to generally differentiate from distributed generators and BTM generators
MGD	Million Gallons per Day	Measure of throughput at WWTPs
MW	Megawatt	
MWh	Megawatt-hour	
NEM	Net metering	
NPD	Non-powered dams	Existing hydro dams not currently hosting electric generation facilities
NREL	National Renewable Energy Laboratory	
NYISO	New York Independent System Operator	

Abbreviations

Abbreviation	Stands for	Explanation
NYSERDA	New York State Energy Research and Development Authority	
O&M	Operations and Maintenance expense	
OPEX	Operational Expenditure	
ORNL	Oak Ridge National Laboratory	
OSW	Offshore wind	
PPA	Power purchase agreement	In this Study, power purchase agreements are referred to as providing fixed, fully hedged ("bundled") compensation to generators.
PSC	New York Public Service Commission	
PTC	Production Tax Credit	Federal tax credit incentive on a dollar per MWh produced basis, available to eligible generation owners for the first 10 years of commercial operation
PV	Photovoltaics	Solar to electricity energy conversion technology
RE	Renewable Energy	
REC	Renewable Energy Certificate	

Abbreviations

Abbreviation	Stands for	Explanation
REC	Renewable Energy Certificate	
RGGI	Regional Greenhouse Gas Initiative	
RPS	Renewable Portfolio Standard	
SCC	Social Cost of Carbon	
UCAP	Unforced Capacity	Term for an availability rating in NYISO ICAP market. UCAP is ICAP adjusted for performance.
UOG	Utility-owned generation	
WWTP	Waste Water Treatment Plant	
ZEC	Zero Emission Credit	

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