Case 15-E-0302 - Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard.

DEPARTMENT OF PUBLIC SERVICE STAFF AND NYSERDA WHITE PAPER ON OPTIMIZING THE INDEX REC SETTLEMENT STRUCTURE

Dated: July 1, 2026

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1. Introduction

On May 15, 2025, the Public Service Commission (Commission) issued its Order Adopting the Clean Energy Standard Biennial Review as Final and Making Other Findings (2025 Biennial Review Order), that, among other things, directed the Department of Public Service (DPS) Staff and the New York State Energy Research and Development Authority (NYSERDA) to file a proposal to modify the Renewable Energy Certificate (REC) settlement structure to address issues relating to basis risk and shape risk either through the upcoming Clean Energy Standard (CES) biennial review process, or through a separate proposal filed prior to the upcoming CES biennial review process.[1] The Commission's directive recognized that, while the Draft Clean Energy Standard Biennial Review[2] did not propose specific changes to the REC settlement structure, stakeholders demonstrated significant interest in addressing basis risk and shape risk and that the matter warranted further analysis and consideration. In this proposal, DPS Staff and NYSERDA outline proposed changes to the Index REC settlement structure to align settlement more accurately with developers' expected generation profiles and grid impacts, address basis risk and shape risk, and provide benefits to ratepayers.

In the process of crafting the below proposals, DPS Staff and NYSERDA, with the support of Power Advisory LLC, consulted feedback received on the draft Clean Energy Standard Biennial Review and the White Paper on Clean Energy Standard Procurements to Implement New York

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1 Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Adopting Clean Energy Standard Biennial Review as Final and Making Other Findings (issued May 15, 2025) (CES Biennial Review Order).

2 Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Draft Clean Energy Standard Biennial Review, With Corrections (filed July 8, 2024).

State's Climate Leadership and Community Protection Act (2020 CES White Paper)[3] in addition to consulting with the New York Independent System Operator, Inc. (NYISO). Power Advisory LLC also conducted additional stakeholder outreach and analysis for input. The resulting recommendations are detailed in the sections that follow, along with supporting analysis. Recognizing that the CES Biennial Review Order also directed DPS Staff to evaluate the existing procurement processes utilized in the Clean Energy Standard and provide recommendations for improvements, this whitepaper may be considered by the Commission along with the recommendations that come from the procurement review, to best align the expected outcomes of any changes to the REC settlement process.

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[3] Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, White Paper on Clean Energy Standard Procurements to Implement New York's Climate Leadership and Community Protection Act (filed June 18, 2020) (2020 CES White Paper).

2. Background

On August 1, 2016, the Commission issued the Order Adopting a Clean Energy Standard (2016 CES Order), which established the Clean Energy Standard (CES) and set forth specific goals for New York's electricity to be generated by renewable energy resources.[4] To achieve this goal, the 2016 CES Order established, in part, a Renewable Energy Standard (RES) Tier 1 program under which NYSERDA was authorized to procure eligible new large-scale renewables projects. The Commission authorized NYSERDA to act as the central procurement administrator and to award long-term contracts to eligible generators through annual competitive solicitations for the purchase of Tier 1 RECs.

The 2016 CES Order further directed NYSERDA to undertake these procurements by employing Fixed-Price REC contracts, whereby awarded bidders would receive a fixed as-bid REC price throughout the contract lifetime for the environmental attributes associated with every megawatt hour (MWh) produced by the facility. This structure provided developers with Fixed-Price RECs for the contract term at a specific price unchanged by market conditions, while leaving energy and capacity to be sold by the developer as it sees fit, whether into wholesale markets administered by the NYISO or through bilateral arrangements.

The 2016 CES Order also recognized that New York had substantial potential for offshore wind production. The Commission requested that NYSERDA perform a study to identify mechanisms that could realize this potential. In July 2018, following completion of that study and presentation of NYSERDA's recommendations, the Commission issued its Order Establishing Offshore Wind Standard and Framework for Phase 1 Procurement, which established the

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4 Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Adopting a Clean Energy Standard (issued August 1, 2016) (2016 CES Order).

framework for the first phase of offshore wind generation solicitations.[5] The Offshore Wind Order directed NYSERDA to use a hybrid procurement model for offshore wind in which the developer was to provide both a fixed-price Offshore Wind REC (OREC) bid, similar to a Tier 1 Fixed-Price REC, and a variable-priced OREC bid based on the Index REC approach. Unlike a Fixed-Price REC, an Index REC is based on the developer's estimated revenue requirement for the project as represented by a strike price (i.e., an all-in price for RECs, energy, and capacity). Under this approach, the developer is paid a variable REC price that is calculated by subtracting, from the strike price, index prices for energy and capacity.

In July 2019, New York's legislature passed the Climate Leadership and Community Protection Act (CLCPA), which committed the State to the goal of reducing emissions by 85% by 2050.[6] The CLCPA also directed the Commission to establish programs to achieve the targets of a statewide electric generation system having a minimum of 70% of electricity generated by renewables by 2030 (70 by 30 Target) and a statewide electrical demand system with zero-emissions by 2040 (Zero by 40 Target), as well as a variety of technology-specific deployment goals.

On January 16, 2020, the Commission further incorporated the use of index-based contracts into the CES by directing NYSERDA to offer bidders an Index REC price option in RES Tier 1 solicitations from 2020 on.[7] In the Index REC Order, the Commission concluded that providing an Index-REC price option would (1) give developers more flexibility to adapt their bidding

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5 Case 18-E-0071, In the Matter of Offshore Wind Energy, Order Establishing Offshore Wind Standard and Framework for Phase 1 Procurement (issued July 12, 2018) (Offshore Wind Order).

6 Chapter 106 of the Laws of 2019.

7 Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Modifying Tier 1 Renewable Procurements (issued January 16, 2020) (Index REC Order).

behavior to their financing and operational needs, (2) reduce the risk premiums that developers account for in their bids to accommodate for uncertainty in power market revenues, and (3) lower ratepayer costs on a per-REC basis. The Commission also noted that the Index REC approach would prevent the double payment for renewable attributes in the event that carbon pricing is implemented in the NYISO's wholesale energy market. Building on this approach, on November 20, 2020, the Commission authorized NYSERDA to offer eligible Tier 1 projects the one-time option to convert the Fixed-Price REC price term in their existing contract to an Index REC price approach.[8] In response to this order, NYSERDA issued Request for Interest (RFI) RESVCO2021, "Voluntary Conversion of Eligible New York Renewable Portfolio Standard (RPS) or Renewable Energy Standard (RES) Agreements." Through this mechanism, eligible counterparties were able to participate in a conversion process to voluntarily modify their existing Tier 1 REC agreements from a fixed as-bid REC price to a variable-priced Index REC pricing structure.

On June 18, 2020, DPS Staff and NYSERDA jointly filed the 2020 CES White Paper. Among the procurement, evaluation, and settlement changes proposed, the 2020 CES White Paper also noted the intent to establish regulatory structures that give renewable generators the appropriate incentives to design projects in a manner that avoids curtailment and other negative impacts and solicited public comment on additional measures that would help do so, including "a procurement policy that, in agreements resulting from future procurements, NYSERDA would acquire without compensation any REC generated in hours and at locations where the applicable real-time [location-based marginal price (LBMP)] is negative."[9]

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8 Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Authorizing Voluntary Modification of Certain Tier 1 Agreements (issued November 20, 2020).

9 2020 CES White Paper, p. 34.

On October 15, 2020, the Commission issued its responsive Order Adopting Modifications to the Clean Energy Standard.[10] In the 2020 CES Order, the Commission adopted several modifications to align the CES with CLCPA goals. The Commission recognized that negative LBMPs at the zonal level could become more frequent as increased penetration of intermittent generation throughout a NYISO load zone causes high-level transmission congestion from zone to zone, and, while concluding that the policy proposal for NYSERDA to acquire without compensation any REC generated in hours and at locations where the applicable real-time LBMP is negative, stated that "that it would be beneficial for DPS and NYSERDA Staff to consult with the NYISO to discuss this issue further for possible future action."[11]

On May 10, 2023, the Federal Energy Regulatory Commission (FERC) approved the NYISO Capacity Accreditation Rules, which took effect in May 2024 and are designed to better reflect the capacity value of generation and storage resources, based on their marginal contribution to resource adequacy. In response, NYSERDA filed a petition on June 29, 2023, seeking to revise the way in which future REC and OREC agreements that utilize an Index REC and Index OREC pricing mechanism calculate the Reference Capacity Price. On November 20, 2023, the Commission issued its Order Addressing Capacity Accreditation Rules, removing the obligation that resources include a set production factor in their bids to ensure that future CES solicitations can accommodate the new NYISO Capacity Accreditation Rules.[12]

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[10] Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Adopting Modifications to the Clean Energy Standard (issued October 15, 2020) (2020 CES Order).

[11] 2020 CES Order, p. 36.

[12] Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Addressing Capacity Accreditation Rules (issued November 20, 2023).

On July 1, 2024, DPS Staff and NYSERDA jointly filed the Draft Clean Energy Standard Biennial Review in Case 15-E-0302, garnering significant public comment and feedback and on May 15, 2025, the Commission issued the 2025 Biennial Review Order. In addition to adopting procurement and evaluation changes, the 2025 Biennial Review Order further directed DPS Staff and NYSERDA to file additional proposals on further improvements to the procurement process.

As of May 31, 2026, NYSERDA's competitive solicitations conducted under the CES have resulted in nearly 100 currently active land-based wind, solar, hydro, and offshore wind awards – as well as investments in transmission through Tier 4 – as part of constructing New York's clean energy future. Since the Index REC implementation, more than 93% of NYSERDA Tier 1 and offshore wind awards have been with the Index REC or Index OREC pricing mechanism, signaling the success of the indexed approach and implementation. The 2025 Biennial Review Order highlighted the potential need for further improvement to the Index REC settlement to account for rising risks and authorized NYSERDA to conduct annual Tier 1 REC solicitations through 2029.[13]

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13 2025 Biennial Review Order.

3. Current Index REC Settlement Structure

As previously referenced, per the Commission's Index REC Order and subsequent Order Addressing Capacity Accreditation Rules, the current Index REC settles as:

Monthly REC Price = Index REC Strike Price – (Reference Energy Price + $/MWh Equivalent Reference Capacity Price)

Tier 1 Index REC Design	
Settlement Period	Monthly settlement period for both Reference Energy and Capacity Prices
Reference Energy Price	
Market Choice	Hourly day-ahead LBMP
Geographic Precision	Zonal – Based on project's location
LBMP Weighting	Simple averaging of hourly prices
$/MWh Equivalent Reference Capacity Price[14]	

The current Index OREC settles similarly, with a formula as follows:

Monthly OREC Price = Index OREC Strike Price – Reference Energy Price – (Reference Capacity Price x Mitigation Factor[15])

Figure 1 below depicts key transactions and components pertaining to the Index REC settlement between NYSERDA, developers/generators, the NYISO Wholesale Market, and Load-Serving Entities (LSEs).[16] From the developer's perspective, the revenue is comprised of (i) market revenue, determined by a project's actual generation and the realized nodal LBMP (settled according to the day-ahead or real-time market, depending on a project's market participation),

[14] The proposal regarding shape risk put forth in this white paper will solely pertain to the Reference Energy Price, not the Reference Capacity Price.

[15] Similar to the Reference Capacity Price, the proposals regarding shape risk put forth in this white paper will not pertain to the Mitigation Factor.

[16] As the proposals in the white paper do not pertain the Reference Capacity Price or Mitigation Factor, these components are not included in the referenced figure. Note that NYSERDA REC transactions with the voluntary market are also not depicted.

and (ii) the Index REC, which settles against the Reference Energy Price. The Reference Energy Price for each month is calculated by NYSERDA using data published by NYISO for its day-ahead energy market. To determine the Reference Energy Price, for each respective generator with a Tier 1 REC Purchase and Sale Agreement, NYSERDA:

(A) identifies the LBMP for each hour of the month in the applicable zone; and

(B) calculates the around-the-clock simple (not load-weighted) average of each such hourly LBMP during the entire month.

As the Reference Energy Price is currently calculated for "each month as a simple monthly average of NYISO's actual day-ahead energy prices,"[17] or as the simple, around-the-clock (ATC) average of the zonal energy price for a given month, this white paper will refer to the Reference Energy Price, as currently calculated, as the "ATC Average Zonal Price."

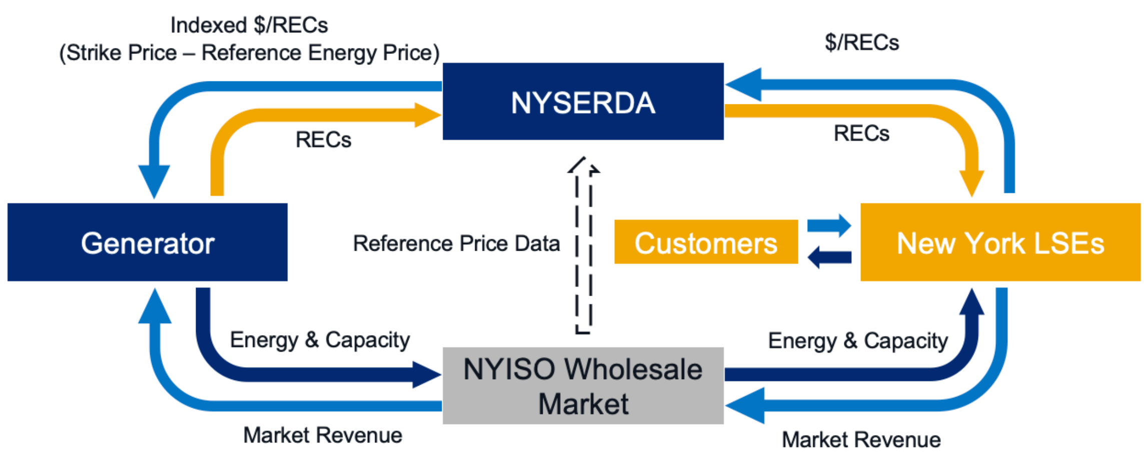


Figure 1: Key Transactions of the Index REC Settlement Structure
Source: ICF, "Unpacking New York's Indexed REC Renewable Procurement Framework"

[17] Index REC Order.

4. Discussion

The following sections will describe the ways in which shape risk and basis risk are each produced by renewable generation agreement designs, including within NYSERDA's variable-priced Index REC pricing structure, DPS Staff and NYSERDA's proposed changes to the settlement structure to address the respective associated premiums incorporated by developers within strike prices, and how each of the changes will help maximize ratepayer benefits.

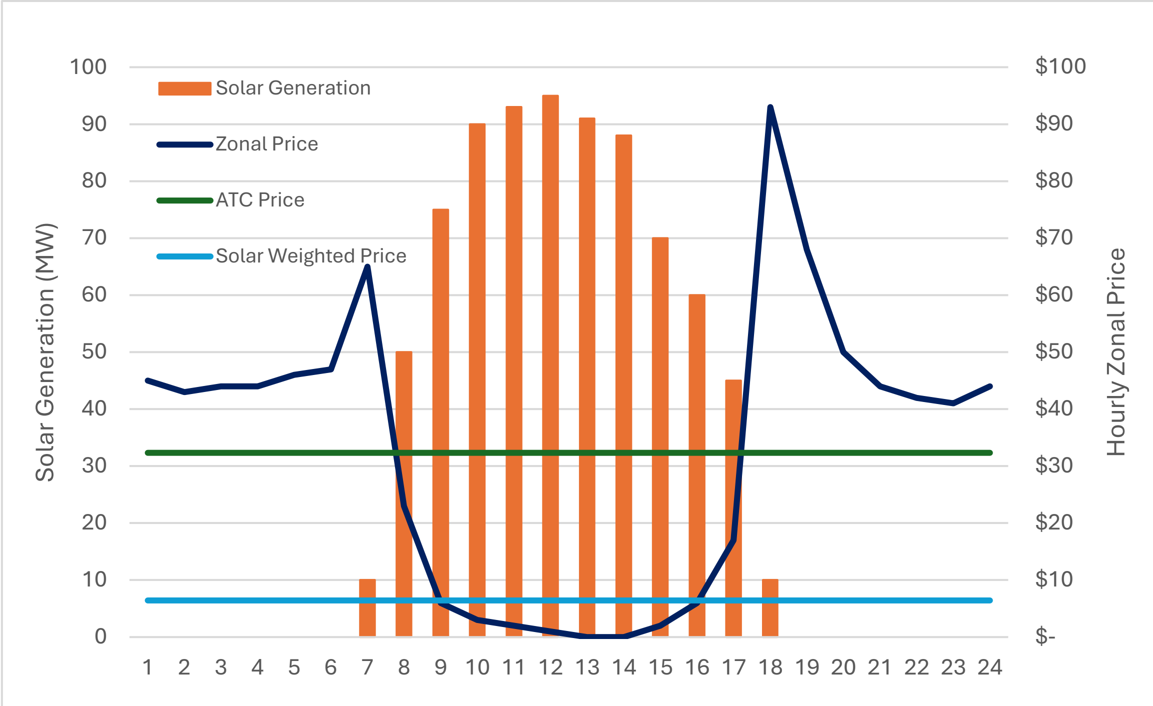
4.1 Shape Risk

*4.1.1. **Shape Risk in Renewable Generation** Agreements*

Shape risk in renewable energy contracts refers to the financial risk that arises from the mismatch between the actual generation profile of an intermittent energy resource (e.g., land-based or offshore wind, solar) and the technology-agnostic monthly ATC Average Zonal Price.

Figure 2 illustrates a theoretical example that is reflective of shape profiles seen in markets with high renewable resource penetration, particularly solar generation. In the below illustrative example, the ATC Average Zonal Price is \$32/MWh, and the solar-weighted average price – the average revenue received by solar generator based on the amount and time of generation – is \$6/MWh. The shape risk facing solar developers is the difference between these two values, or \$26/MWh (\$32-\$6/MWh) for the example month.

Figure 2: Illustrative Shape Risk Example – ATC Average Zonal Prices v. Solar-Weighted



Zonal Price

The mechanism that creates shape risk is also highlighted in Figure 2. As renewable energy market penetration increases, it increasingly alters market pricing dynamics in hours where it has high output levels. For this reason, shape risk is generally viewed as an increasing risk further into the future as markets add – or are expected to add – more solar and wind generation. While storage can mitigate shape risk to some degree, storage's economic value fundamentally relies on price differentials between hours, so the expected reduction in shape risk is limited. Shape risk increases revenue uncertainty for a renewable project and is expected to increase strike prices both due to the direct cost of the shape risk and due to the additional risk premium required by developers in setting their strike price bid for a long-term contract. The strike price must correct for the actual cost of the expected shape – the misalignment between how much and when a project generates as compared to the ATC Average Zonal Price – and also reflect the uncertainty in that expected shape cost being actually realized.

Although New York does not yet have the level of solar and wind penetration seen in some markets where shape risk is already apparent to the degree seen in Figure 1, there is already sufficient wind generation in the market currently to drive some shape risk. As shown in Figure 3 below, shape risk (defined as 'technology discount' by NYISO's Market Monitoring Unit (MMU) in its reporting) for wind generation from 2022 through 2024 was between $4 to $6/MWh.[18] From the MMU's findings, solar photovoltaic (PV) did not illustrate a technology discount against the ATC price during this period, nor did it show a premium over the ATC price. However, given the amount of utility-scale solar PV that is currently operational in New York, a greater shape premium would be expected. The lack of a pronounced technology premium in the current market for solar PV could be indicative of a technology discount for solar PV to emerge as additional utility-scale and behind-the-meter (BTM) solar resources are deployed.

Using the MMU's findings, a wind project could be expected to reflect $4 – $6/MWh of shape risk in its strike price, in addition to a risk premium to protect against the possibility that the project's shape discount is larger than expected. While the cost of realized shape risk will always be borne somewhere in the system, the risk premium associated with that risk does not necessarily need to be. Under the current settlement structure, ratepayers are bearing the cost of this risk premium via higher strike prices, which represents the *potential* for shape to materialize, in addition to the cost of the actual shape in present day and the actual shape that is likely to materialize.

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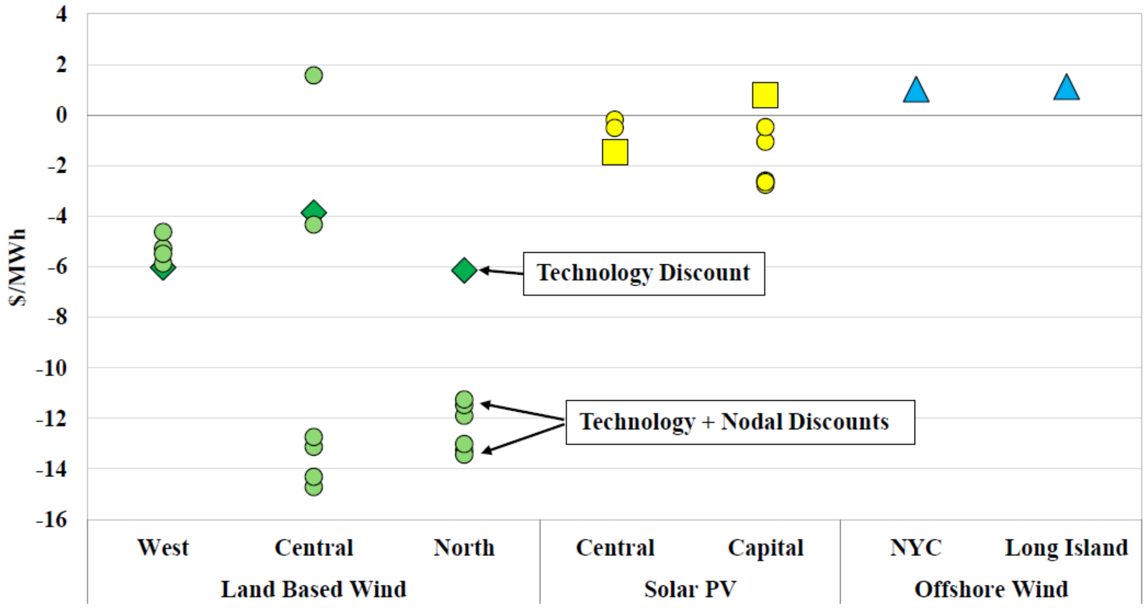
[18] Potomac Economics. 2025. "2024 State of the Market Report for the New York ISO Markets." Page 18. https://www.potomaceconomics.com/wp-content/uploads/2025/05/NYISO-2024-SOM-Full-Report_5-14-2025-final.pdf

Figure 3: Shape and Basis (Technology and Nodal) Risk in New York State, 2022-2024



Source: Potomac Economics, "2024 State of the Market Report for the New York ISO Markets."

Note: The diamonds, squares, and triangles show the shape risk, or "technology discount," for Land Based Wind, Solar PV, and Offshore Wind, while the circles show the combined effect of shape and basis risk, "Technology + Nodal Discounts."

With this dynamic, continued progress toward achieving New York's CLCPA targets – and the continued development and deployment of renewables in the State – has become a risk factor that is being incorporated by developers within submitted strike prices to NYSERDA-run CES solicitations. Shape risk, and associated premiums, is therefore driven by factors outside of a developer's control and is at the core dependent on the policy decisions, actions, and progress of New York State and other developers in regard to how quickly and effectively like-kind renewables are deployed.

__4.1.2. Proposed Changes__ to Address Shape Risk

To address the shape risk as described in the previous section and the associated premiums incorporated by developers within submitted strike prices, DPS Staff and NYSERDA propose to settle the Index REC and Index OREC based on a technology output weighted (TOW) zonal price rather than the ATC Average Zonal Price, with such a revision to be made for all future contracts and NYSERDA to offer existing contract holders a one-time opportunity to accept or reject an adjusted strike price along with the new TOW index methodology, as described below (for simplicity, references to "Index REC" in this section will refer to both Index REC and Index OREC contracts).[19] The TOW zonal price would be equal to the zonal price weighted by the applicable technology's overall *New York State-wide* generation profile for the month or a proxy generation curve (if actual generation data is unavailable or insufficient for the applicable technology). While adopting zone-specific technology curves could be feasible, using state-wide generation profiles ensures that shape risk is not fully mitigated and that developers still retain locational and performance incentives. Wind, solar, and hydropower generation is collected by NYISO, and the TOW zonal price is proposed to be settled according to such data, as published and made available by NYISO. For any resources without published state-wide generation curves, settlement would be done according to public, transparent proxy curves as further described below. The Index REC settlement formula is thus proposed to be altered in the following manner:[20]

Current settlement formula: **Monthly REC Price = Index REC Strike Price – ATC Average Zonal Price**

Proposed settlement formula: **Monthly REC Price = Index REC Strike Price – TOW Zonal Price**

Where TOW Zonal Price =

$$\sum_{1}^{Monthly\ Hours}(Total\ NYCA\ Hourly\ Output\ for\ given\ technology * Hourly\ Zonal\ Price)\ /\ (Total\ NYCA\ monthly\ output\ of\ given\ technology)$$

The expected benefit of using a TOW index in place of the ATC index is that the shape risk premium within strike prices will be materially reduced, thereby meaningfully reducing costs

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19 As noted earlier, this change would be to the Reference Energy Price, and no change is proposed to the Reference Capacity Price.

20 For any technology where actual data is not available, Total NYCA Hourly Output will be replaced by a public, transparent proxy curve as further described below.

borne by ratepayers. In addition, the uncertainty element of shape risk – the degree to which developers factor in potential tail-risk scenarios – will be similarly minimized and will no longer be a necessary factor for developers to incorporate within strike prices and development decisions. Due to reducing revenue uncertainty, it is expected that developers will also realize improved financing terms.

While there are power purchase agreements in other markets settled on an "as generated" basis that completely eliminates shape risk for the developer, the proposed settlement formula is expected to reduce shape risk by approximately 90% relative to the current ATC index, thereby retaining appropriate locational and efficiency incentives for projects.

While the ATC Average Zonal Price is greater than the TOW Zonal Price, the monthly Index REC price is expected to decrease in cost with TOW-based settlement because the risk premium that can be removed from the strike price is greater than the difference in switching from an ATC Average Zonal Price to a TOW Zonal Price.

Implementation Details

According to data availability, it is proposed that Index REC settlement be done according to either:

i) Public and verified technology-specific state-wide generation, broken down by hourly production, or

ii) Technology-specific proxy curves generated and published by NYSERDA and informed by capacity curves published by NYISO's independent MMU.

A transparent and reliable source of total hourly output by technology is beneficial, though other means of creating a proxy weighting for each technology are available. The NYISO Real-Time Dashboard currently publishes hourly monthly generation for (i) Hydro, (ii) Wind, and (iii)

Other Renewables (solar, energy storage, methane, refuse, wood).[21] For optimal utility for TOW settlement, the Real-Time Dashboard would have to segment land-based wind, offshore wind, and solar PV.

The TOW zonal price for projects with integrated storage components are proposed to be settled according to the project's primary energy generation resource (e.g., a co-located solar and battery energy storage system project would settle according to the solar TOW curve).

For all developers with an existing Index REC contract, NYSERDA and DPS Staff propose a similar conversion approach as was carried out pursuant to the Commission's Order Authorizing Voluntary Modification of Certain Tier 1 Agreements,[22] which authorized a process by which eligible developers with an existing Fixed-Price REC contract that had not yet commenced commercial operation could accept or reject an offered Index REC strike price and conversion to an Index REC contract. The Commission could direct NYSERDA to conduct a process by which Tier 1 developers with an existing Index REC contract – those whose projects have not yet commenced commercial operation as well as those whose projects are operational – would be given a one-time opportunity to replace the current index methodology in their existing contract with the new TOW index methodology alongside an adjusted, reduced strike price. The reduced strike price should be reflective of a project's technology type, zone, and level of forecasted shape risk. All implementation steps outlined above apply to both Index REC and Index OREC contracts.

NYSERDA and DPS Staff welcome feedback and input on how to most effectively implement a conversion process.

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[21] NYISO. 2025. "Real-Time Dashboard." Accessed August 18, 2025. https://www.nyiso.com/real-time-dashboard.

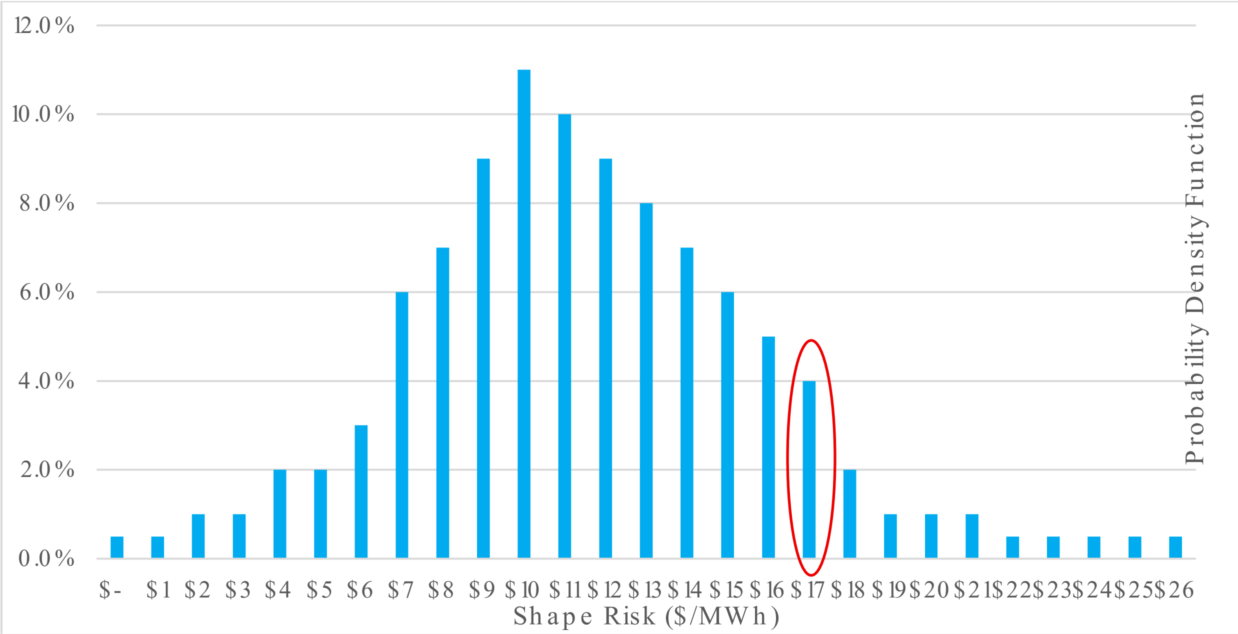
[22] Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Authorizing Voluntary Modification of Certain Tier 1 Agreements (issued November 20, 2020).

4.1.3. Supporting Analysis for Adopting Technology-Weighted Settlement

As noted above, shape risk is a growing factor that increases as more renewable generation is deployed or expected to be deployed. This is because energy prices in hours with large amounts of solar or wind generation will be reduced relative to energy prices in hours with lower amounts of solar or wind generation. Due to the higher correlation of generation for solar generators and the consistent hourly generation profile, shape risk is a particular factor of note for solar generation.

However, there are challenges in forecasting the magnitude of future shape risk as well as the timing of when said risk will be realized. For developers, assumptions around the timing and magnitude of shape risk is a key factor in setting strike prices for project proponents (i.e., developers must forecast when shape risk will materialize and the degree to which it will materialize, incorporating a risk premium buffer to protect against potential forecast inaccuracies). Developers and financiers tend to model these assumptions conservatively to ensure risk premiums protect against tail-risk scenarios. Figure 3 below details a theoretical probability distribution of possible shape risk embedded in a strike price for illustrative purposes. The graph reflects the likelihood that a project's shape risk will fall within a given range, with the y-axis showing the probability (i.e., a probability density function) that actual realized shape risk will land in that range. For the example, developers and financiers may ultimately embed a $17/MWh risk premium within a project's strike price despite it being above the mean or median estimate of likely shape risk.

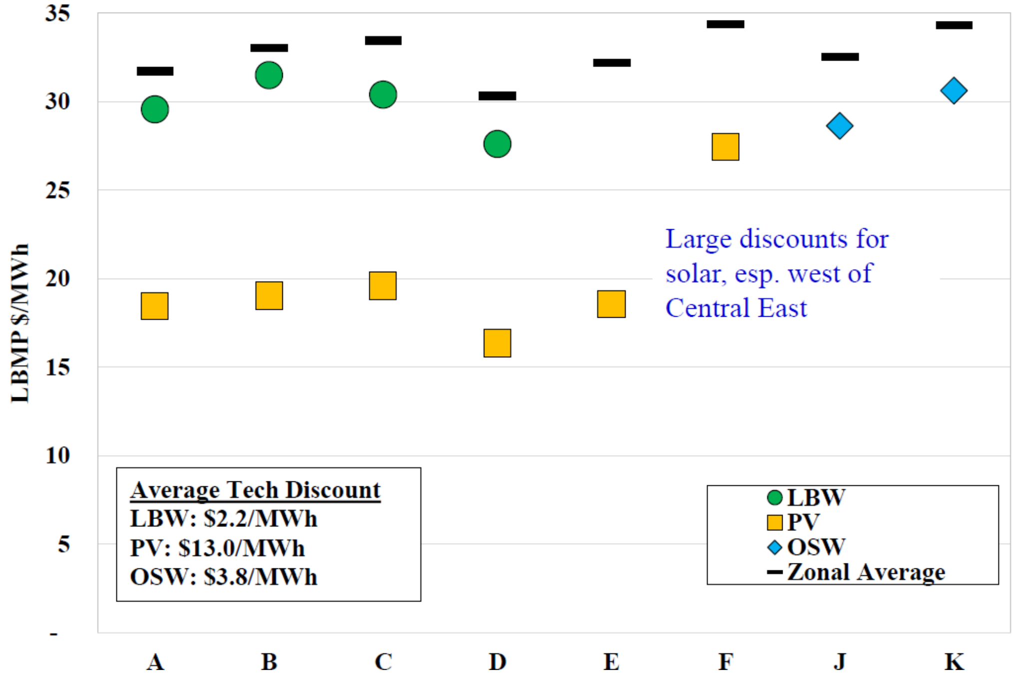
Figure 4: Illustrative Shape Risk Probability Distribution



In the MMU's review of NYISO's 2023-2042 System & Resource Outlook, the MMU estimated shape risk of about $14/MWh materializing in Zone A in 2035 for solar PV projects and about $3/MWh for land-based wind projects (see Figure 4 below).[23] To the extent that developers price in an additional premium for uncertainty pertaining to shape risk within their strike prices today, ratepayers bear higher costs. Reducing shape risk in the contract is intended to reduce this premium, which also rests on the assumption that firms will collectively remove these premiums from bids, and shield ratepayers from uncertainty around the timing and magnitude.

[23] Potomac Economics. 2024. "MMU Review of 2023-2042 System & Resource Outlook." https://potomaceconomics.com/wp-content/uploads/2024/06/MMU-2023-Outlook-Review.pdf

Figure 5: Forecasted Shape Risk by Technology (Technology Discounts), MMU's Low Policy Case 2035



Source: Potomac Economics, "MMU Review of 2023-2042 System & Resource Outlook."

In addition, the current Index REC settlement structure may be contributing to attrition risk by offering little recourse to developers that under-estimate shape risk. That is, developers that have an overly optimistic shape risk view may be incentivized to attrit, to the detriment of ratepayers, if greater-than-expected deployment of renewable generation and greater shape risk materializes prior to final investment decision and project completion.

There is also an argument to be made that current ratepayers are absorbing costs from future ratepayers under the current settlement structure, as the shape risk premiums being borne by ratepayers are due to the *expected* increase in shape risk that will materialize in the future as renewable penetration increases.

The proposed solution of using the TOW zonal price could resolve the noted issues. Strike prices would be expected to fall for the direct reason that shape risk is no longer a material risk for developers. Strike prices would nevertheless reflect a small cost or benefit of site-specific and project specific differentiators relative to the system average TOW index,[24] which are appropriate incentives for siting optimization. Current ratepayers would also no longer need to pay elevated prices today to compensate for potential future risk. Moreover, project attrition is likely reduced because project economics would no longer be impacted if technology discounts rise during the development cycle.

Ratepayer Benefits

As noted in the previous section, strike prices are expected to decline if shape risk is reduced for the direct reason that the strike price no longer needs to compensate for expected increasing shape risk. An expected benefit to ratepayers is lower strike prices – and a lower monthly Index REC – due to improved project financing and reduced cost of equity. The actual reduction in expected strike prices from improved financing terms is difficult to determine, but the U.S. Environmental Protection Agency (EPA) provides financial estimates in its 2023 Reference Case that can be used to inform preliminary forecasts (see Table 2 below).[25] The EPA provides detailed analysis on return requirements for Independent Power Producers (IPP), projects settled on an index basis or for those that operate in competitive markets, compared to Utility generation, those with contracts that are fully settled on a generation basis in vertically integrated markets. A potential range of ratepayer benefits – via lower strike prices – can be approximated from this data by extrapolating the risk premium developers may be including in their strike prices in response

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[24] For example, a site with a measurably different wind pattern due to its geography might expect to beat the price achieved by the overall average wind project. Solar projects could be configured with higher DC to AC ratios or different directional orientations for some panels as another example of expecting to beat the system average shape.

[25] U.S. Environmental Protection Agency. 2024. "2023 Reference Case: Financial Assumptions." https://www.epa.gov/system/files/documents/2024-04/chapter-10-financial-assumptions.pdf

to the Index REC settlement structure. As noted above, the magnitude of risk premium is difficult to calculate, and this analysis is not intended to suggest a deviation away from competitive markets at the wholesale level or return to vertically integrated markets. This analysis is intended to suggest one way to estimate the benefits to ratepayers by removing revenue uncertainty attributed to the current REC contract settlement structure. Commenters are encouraged to propose alternative ways to calculate reduced financing costs under the proposed TOW settlement proposal.

Table 1: Real Capital Charge Rate by Technology and Settlement Structure (% of Capital Cost)

	IPP		
Technology Type	**2023**	**2025**	**2028 and Beyond**
Wind Solar and Geothermal	9.14	9.12	9.12
Landfill Gas	9.15	9.15	9.28
Hydro	10.61	10.67	11.01
Energy Storage	11.77	11.74	11.77
	Utility		
Wind Solar and Geothermal	7.5	7.5	7.5
Landfill Gas	7.46	7.46	7.46
Hydro	7.01	7.01	7.01
Energy Storage	10.38	10.38	10.38

Source: U.S. Environmental Protection Agency. "2023 Reference Case: Financial Assumptions."

In Table 2, the capital charge rate is the proportion of initial invested capital that must be returned from market revenues to cover developers' fixed costs. It varies primarily based on capital structure, debt rates, debt life, and required return on equity.

As can be seen in Table 2, for wind and solar there is a 1.62% difference in the capital charge rate between IPP and Utility developers. To estimate the potential impact on strike prices from this difference in capital charge rate, as an example, were a solar project to cost $1,700 per kilowatt (kW) in upfront capital, this capital charge rate corresponds to required additional revenue of $1,700/kW * 1.62%, or $27.50/kW-year. If this is turned into a dollar-per-megawatt hour ($/MWh) cost saving, it can be calculated as ($28/kW-year * 1000) / (8760 hours * 20% capacity factor) = $15.72/MWh. As NYSERDA REC and OREC contracts are typically at least 20-years in contract tenor and the proposed TOW settlement is estimated to significantly de-risk investments, a material portion of the risk premium could be removed from strike prices, resulting in achievable savings to ratepayers from projects' lower financing costs. As noted earlier, the proposed change to TOW settlement reduces project shape risk by about 90%. This is a large benefit, particularly for solar, and the cost of solar RECs could fall by an estimated 25% to 50% of the noted premium, or approximately $4 to $8/MWh due to the reduction in risk premium. Using the same approach for a wind generation project with an initial capital cost of $2,000/kW and a capacity factor of 35%, there could be associated strike price decreases between $2.64 and $5.29/MWh. This acts as a conservative estimate of net benefit, taking into consideration that the cost of equity and reduction of premium in the cost of equity is very difficult to estimate and is expected to be an added benefit.

Two potential ancillary benefits of this proposal are that (1) it may also reduce basis risk because it will directly reduce the strike price (as detailed in the following sections, under the current Index REC contract structure higher strike prices increase the potential basis by allowing projects to bid into the market at greater negative discounts) and (2) by reducing financing risk, it could enable a higher debt-to-equity ratio, potentially allowing smaller, less-capitalized developers to compete in CES solicitations.

Without addressing the timing misalignment between the current Index REC settlement structure and when renewable generators are actually producing energy, developers will continue to price sizable risk premiums into their strike prices. In addition to direct costs placed on ratepayers via increased strike prices, this has an additional knock-on effect for basis risk (as higher strike prices increases basis risk, as will be outlined in the following sections).

Feedback Sought

DPS Staff and NYSERDA acknowledge the multifaceted nature of shape risk and invite stakeholder feedback on shape risk facing renewable developers in New York State as well as on the potential for the TOW settlement to address risk premiums in strike prices.

4.2 Basis Risk

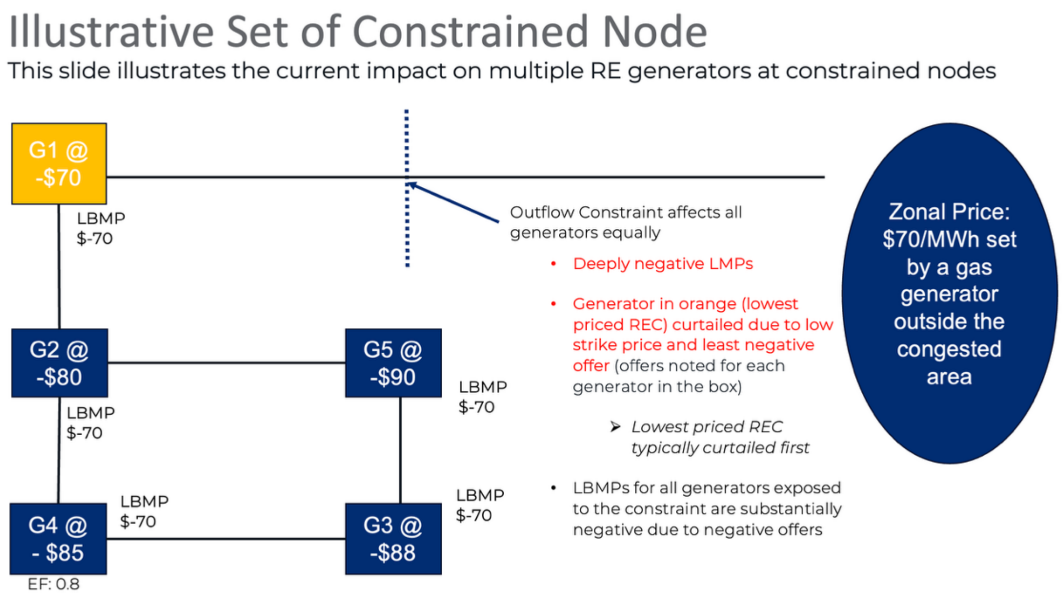
4.2.1. Basis Risk in Renewable Generation Agreements

Basis risk refers to the risk that the project-specific energy price, or the "nodal LBMP", is different than the ATC Average Zonal Price that the Index REC is settled against. Basis risk is largely the risk that a project's nodal LBMP is lower than the zonal price due to congestion, and, because the Index REC is calculated against the zonal LBMP, basis risk reflects the potential reduction in a project's actualized revenue relative to the expected revenue implied by the strike price.

Congestion is the key driver of basis risk, where congestion is defined as insufficient transmission capacity to allow the lowest cost set of generation resources to produce in a given interval. The specific bottleneck on the transmission system is known as a constraint. Congestion is managed by reducing output at a generator upstream of the constraint and increasing output at a generator downstream of the constraint. Nodal LBMPs at all points upstream of the constraint are reduced to reflect the lower value of energy in the constrained area. Figure 5 illustrates a simplified example of an outflow constraint from a renewable energy zone where the transmission system cannot accommodate all the available output.

In the simplified example, five generators share a single export line from the renewable area to the broader market. Each generator has a different offer price into the market ranging from -\$70/MWh to -\$90/MWh (as discussed further below, renewable energy generators with REC contracts are able to offer negative prices). All the generators behind the constraint are equally effective in reducing flows across the constrained line, illustrated as the outflow constraint. In this case, the generator with the highest priced offer (G1 offered at -$70/MWh is the least negative) is curtailed to manage the constraint. The nodal LBMPs at all the points in the constrained area are all set at -$50/MWh, which is the offer of the highest priced generator in the region. A key takeaway from the figure is that if generator offers are more negative, the differential between the LBMP and the zonal price is likely to grow.

Figure 6: Simple Congestion and Basis Example



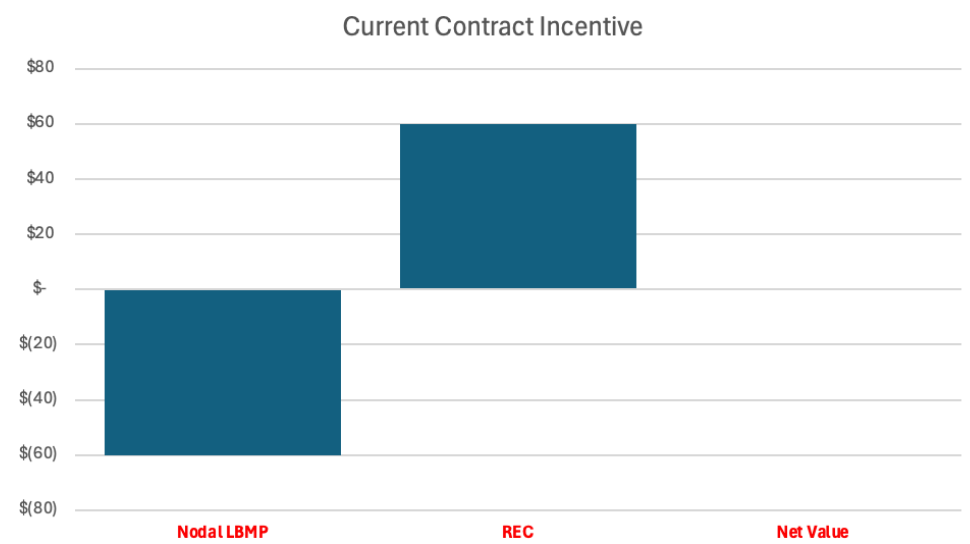
It is also important to note that this example highlights a critical dynamic created with the current Index REC mechanics, which is that in instances of congestion, the lowest priced REC – the developer that is least able to offer deeply negative prices while still realizing positive overall revenues – may be the most likely to be curtailed.

The current Index REC mechanism incentivizes generators with near-zero marginal cost of production (such as wind and solar) to offer energy at negative prices so long as the expected REC is a positive value in a given month.[26] Generally, the lowest expected offer price will reflect

26 If the ATC zonal price exceeds the contract strike price, this issue does not apply.

the negative value of the expected REC, as it is better for these zero marginal-cost generators to produce energy at any value that does not fully offset the REC value than to be curtailed. For example, if the expected REC for a project is $60/MWh for a given month, it would be expected that the project would be willing to offer energy to the market as low as -$60/MWh (see Figure 6). If the nodal LBMP in an hour were to fall to -$80/MWh, it would be better for the project financially to be curtailed than to generate at -$80/MWh to receive a $60/MWh REC. Alternatively, were the nodal LBMP price to rise to -$30/MWh, the project would still have value in producing at -$30/MWh and receiving the REC. A project with a higher strike price is therefore able to offer a more negative price, thereby reduce its curtailment risk. This dynamic causes the curtailment risk to be shifted to other projects with lower strike prices.

Figure 7: Illustrative Function of Current Index REC Settlement Structure



As the MMU stated in its 2023 State of the Market Report: “It is important to note that large-scale deployment of renewables will drive down wholesale prices in locations where the market is saturated with renewables, increasing market risk for renewable developers under the Index REC contract structure. Exposure to market risk encourages developers to pursue the most efficient projects, but they may also require higher strike prices to offset the risk of market saturation. In high-wind areas, significant reductions in market revenues to wind generators relative to zonal averages already exist (which are the basis for Index REC contract payments). This trend should continue as additional renewable projects are contracted with rising REC prices, increasing the financial risks to earlier projects and the likelihood that more contracts will be canceled."[27]

Basis risk at existing wind and solar assets is already material in many instances, as shown previously in Figure 3 (referenced in the figure as "nodal discounts"). Several wind projects in the Central region, for example, have experienced approximately \$10/MWh of basis risk, and projects in the North region have seen an estimated \$6/MWh to \$8/MWh.[28]

Basis risk results in increasing strike prices because developers must consider both existing basis risk as well as the potential for future basis costs when setting strike prices. In Figure 3, a wind project in the Central region would be expected to reflect at least \$10/MWh in basis risk in its strike price, depending on its location within the Central region, to account for current basis risk in addition to risk premium to reflect the uncertainty of further congestion occurring. It is also notable that this dynamic is not limited to zones and nodes that are experiencing high congestion, as projects with little or no current basis cost are nevertheless prompted by the current Index REC settlement structure to consider the potential that future renewable generation deployment could create basis risk. Similar to shape risk, a considerable degree of basis risk, and associated premiums incorporated within strike prices, is driven by factors outside of a developer's control – mainly, the future deployment of additional renewable generation by other developers on the same transmission path.

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[27] Potomac Economics. 2024. "2023 State of the Market Report for the New York ISO Markets." https://www.nyiso.com/documents/20142/2223763/2023-State-of-the-Market-Report.pdf/599b840b-6c80-fe3b-6725-7db24be4f386?t=1715779766752

[28] The basis risk is calculated from Figure 3 as the difference between the "Technology Discount" and the "Technology Plus Nodal Discounts" displayed data points. Nodal discounts in the figure are akin to TOW basis risk.

***4.2.2. Proposed Changes** to Address Basis Risk*

In the 2020 CES White Paper, NYSERDA and DPS Staff raised the option for NYSERDA to "acquire without compensation any REC generated in hours and at locations where the applicable real-time LBMP is negative."[29] As noted above, while the Commission did not adopt the proposal in the 2020 CES Order, it did recognize that reconsideration of the proposal in the future would be beneficial.[30] Accordingly, DPS Staff and NYSERDA propose for consideration by the Commission and stakeholders that, for future solicitations, the Index REC contract settlement mechanism adopt this proposal, with modifications. Specifically:

i. rather than NYSERDA acquiring RECs without compensation when the nodal LBMP is negative, NYSERDA should acquire the RECS at \$0.01/MWh, ensuring that a true financial transaction occurs to support developer financing, and

ii. the \$0.01/MWh settlement should apply if either the day-ahead or real-time nodal LBMP for the applicable hour is negative.

This mechanism is proposed solely to include in future contracts and would not be offered to eligible developers with an existing Index REC contract. The intent of the revised mechanism is to incentivize future contracted renewable generators to offer energy into the market in a manner consistent with other non-index REC contracted generators and to further incentivize competitive market behavior. Given that wind and solar generation have approximately \$0/MWh marginal cost, the proposed mechanism would be expected to incentivize generation offers of approximately \$0/MWh into the market, which is the competitive market expectation in the absence of contracts.

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[29] 2020 CES White Paper, p. 24.

[30] 2020 CES Order.

This mechanism would be expected to reduce basis risk because nodal LBMPs in congested regions will be more likely to settle at lowest cost generator's marginal cost, at or around $0/MWh, rather than the more deeply negative prices driven in part by available Index RECs. Under such a regime, while new projects deployed in a region may still increase curtailment if more transmission capacity is not added, the impact on nodal LBMPs would be expected to be relatively muted compared to the existing dynamic. Also, while this policy intervention aims to address basis risk in the current market, if additional transmission improvements successfully relieve congestion, this proposal would not burden developers or ratepayers.

The proposed approach is expected to result in developers pricing their projects and submitting strike prices in a manner more accurately aligned with a project's net deliverable energy when taking into account congestion and curtailment. Bid prices for projects in areas with anticipated congestion as well as bid prices for projects expected to contribute to increased congestion may increase. However, this would be a natural consequence of the proposal and would reflect the incentive for developers to seek out areas with less congestion and or areas where the project would be less likely to cause congestion. This would also allow the solicitation process to better incorporate the true value to ratepayers a project brings because projects' prices would represent the actual deliverable MWhs.

Existing renewable generators operating without a REC contract, such as hydropower generators, operating assets with a REC contract, and contracted projects under development would also benefit from the proposal as their basis and curtailment risk would be reduced, improving the deliverability of existing and soon to be deployed renewable generation. In addition, while the current Index REC settlement structure inadvertently creates a structure in which energy associated with a lower cost REC, or no REC at all, is curtailed to the benefit of energy associated with higher cost REC, the proposal would remove that inefficiency.

DPS Staff and NYSERDA welcome stakeholder feedback on how such a proposal would influence the energy markets and support renewable deployment in New York.

Implementation Details

The proposed change would include a modification to the form of future Index REC contracts to include the following condition:

If either the day-ahead or real-time project nodal LBMP settles below $0/MWh for a given hour in the month, the REC price in that hour will be $0.01/MWh. All hours where the nodal LBMP settles above $0/MWh will continue to settle per the Index REC mechanism.

There is a question of how to treat the real-time market for settlement, given that it settles on a five-minute interval basis rather than an hourly basis. For the reasons discussed below, NYSERDA and DPS Staff propose defining a negative real-time project nodal LBMP hour as any hour in which the average of the 12 individual real-time five-minute LBMPs settle below $0/MWh. The primary objectives of the proposed changes are to reduce the risk and impact of persistent congestion as well as to allow market signals to incent project development in areas with lower congestion risk. Transient congestion that impacts only a portion of an hour is less likely to result in large basis risk and curtailed energy.

While evaluating real-time prices at the five-minute level could strengthen the locational incentive created by the recommendation, it would add complexity and create a risk that projects receive the reduced REC price when transient congestion lowers the LBMP for a portion of an hour. Also under consideration is defining the criteria for the real-time market such that the REC would settle at $0.01/MWh *if the majority of five-minute intervals in an hour* settle below $0/MWh. Initial analysis indicates this approach would have a similar incentive outcome on developers as the above recommendation, albeit with additional administrative burden. DPS Staff and NYSERDA welcome feedback on how the real-time market should be treated as part of this settlement proposal.

It is also recognized that it could be worth considering whether projects opting for the production tax credit (PTC) should be considered differently under this settlement mechanism from projects with an investment tax credit (ITC). NYSERDA and DPS Staff welcome stakeholder comments on the need, or lack thereof of, for specific PTC treatment under the basis risk proposal.

This proposed change would only be included in future Index REC contracts. Due to the unique transmission and congestion considerations for offshore wind projects no changes to OREC contracts are proposed as this time. However, potential changes to future Index OREC contracts could be considered in a separate, future proceeding.

4.2.3. Other Potential Changes

NYSERDA's review considered nodal settlement of contracts as a potential basis-risk solution. After review, **NYSERDA and DPS Staff are not recommending pursuing a nodal-indexed settlement structure in New York**. The primary issue with tying payments to a project's nodal LBMP is that it could potentially interfere with proper energy market dynamics. Projects with a nodal-settled contract may be incented to operate regardless of the nodal price and therefore could be expected to offer deeply negative prices to ensure they are the last unit curtailed. This could incent such projects to locate based on project economics fully absent curtailment and basis risk, increasing basis and curtailment risk for other projects in the area. This dynamic would also exacerbate concerns that ratepayers under such a settlement structure would see energy associated with less expensive RECs curtailed prior to energy associated with more expensive RECs. To the extent stakeholders wish to propose alternative proposals to the ones set forth in this white paper, DPS Staff and NYSERDA request that any such proposals expressly address these concerns.

4.2.4. Consideration of a "Last In, First Out" Mechanism

Under a contract settlement mechanism in which the basis risk proposal described above is adopted, all resources procured under future solicitations would have equal exposure to congestion and curtailment. That is, all future contracted resources would face the same congestion risk and would be incentivized to offer at their marginal cost of generation (presumed to be approximately $0/MWh for wind and solar generators). Adoption of a "last in, first out" approach would cause curtailment risk to be borne by the "last in" project – i.e., the most recent project procured or deployed – while earlier projects would be the projects least likely to be curtailed. The intent of such an approach is that the last project to be deployed in an area should be the project that internalizes the curtailment it is expected to cause on existing projects, and the project's strike price therefore reflects the true cost of deliverable generation at that location in the procurement.

A "last in, first out" approach could be achieved by adjusting the $0/MWh day-ahead or real-time nodal LBMP floor depending on the status of the project. For example, whereas a just-operationalized project could be restricted to receiving $0.01/MWh for its REC when the nodal LBMP settles below $0/MWh in the day-ahead or real-time market, the contract could provide that once the project has been operating for five years, the project would receive the full standard Index REC amount as long as the day-ahead or real-time nodal LBMP is no less than, for example, -$5/MWh (rather than $0/MWh). Under such a structure, earlier operational projects would have an advantage by being able to bid more negative LBMPs – to a degree – while projects deployed later would be the ones to realize congestion risk.

Implementation Details

DPS Staff and NYSERDA put forward the "last in, first out" mechanism for consideration solely as an additional feature to be paired with the above-described basis risk proposal (it therefore would only be incorporated in future contracts). While existing contracts will not have this mechanism, including the basis risk proposal (even with the additional "last in, first out" mechanism described above) in all future contracts inherently provides current contract holders with a "last in, first out" dynamic, as they would not be constrained in the payment received for their RECs that occur in hours when the day-ahead or real-time nodal LBMP settles below $0/MWh and would therefore be able to economically bid a more negative price in the day-ahead and real-time markets as compared to future contract holders.

A "last in, first out" mechanism would function most ideally if new generation projects added to the system have exposure to the same constraints as existing projects, but this is unlikely to be the case. The transmission system is complex and continually evolving. Constraints change through time and unintended consequences could occur. As a result of this complexity, DPS Staff and NYSERDA posit that an approach allowing a project to receive the full Index REC at more negative prices based on the time elapsed from the start of commercial operations would be the most straightforward implementation. The following approach is illustrative of how this could be implemented in practice:

- Years 1 – 3 of a project's contract, the REC is settled at $0.01/MWh if the nodal LBMP is below $0/MWh;
- Years 4 – 6, the REC is settled at $0.01/MWh if the nodal LBMP is below -$5/MWh;
- Years 7 – 9. the REC is settled at $0.01/MWh if the nodal LBMP is below -$10/MWh;
- Years 10 – 12, the REC is settled at $0.01/MWh if the nodal LBMP is below -$15/MWh;
- Years 13+, the REC is settled at $0.01/MWh if the nodal LBMP is below -$20/MWh.

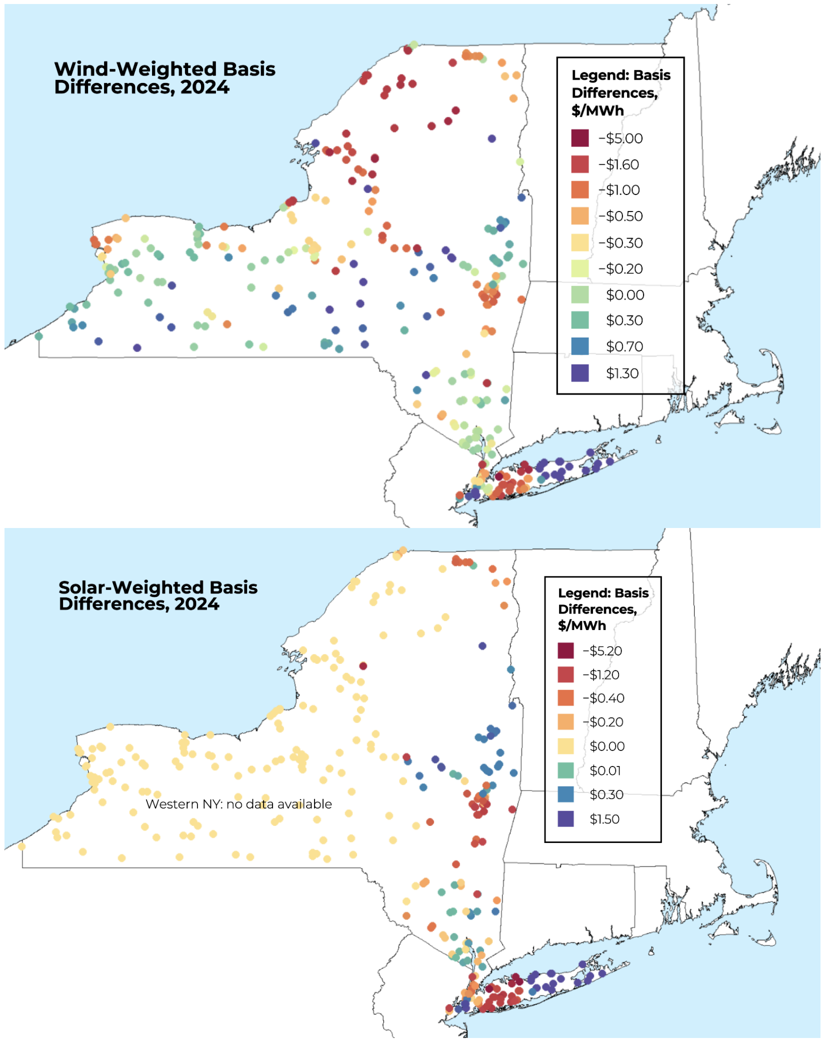
If no new generation is procured in a given load zone for an extended period, the reduction noted may not be necessary. Flexibility to defer the allowable price reductions could be built in the contract under these circumstances. This modification addresses stakeholder feedback on the 2020 CES White Paper proposal by modifying the contract such that a new project internalizes the curtailment it is expected to cause on existing projects and therefore offers a more accurate cost of generation at that location in the procurement.

DPS Staff and NYSERDA invite stakeholder feedback on ways in which a “last in, first out” approach could be best implemented, including the magnitude and timing of any contract features.

4.2.5. Supporting Analysis for Basis Risk Proposal

Basis risk is a localized issue, given that Index REC contracts are settled against zonal prices. Nonetheless, basis risk is material and, as illustrated in Figure 3, some existing wind projects are currently already experiencing in excess of $10/MWh in basis costs. Figure 7 below shows how wind-weighted and solar-weighted basis costs may already be materializing throughout New York based on local congestion. Note that each color in the figure represents 10% of all market nodes, and the value in the legend is the mid-point of that decile of basis. The figure represents a theoretical wind or solar facility at every single node in the market with basis calculated using historical prices. Adding additional generation at any given node can be expected to increase basis due to potential added congestion.

Figure 8: Technology-Weighted Basis Risk in New York, 2024

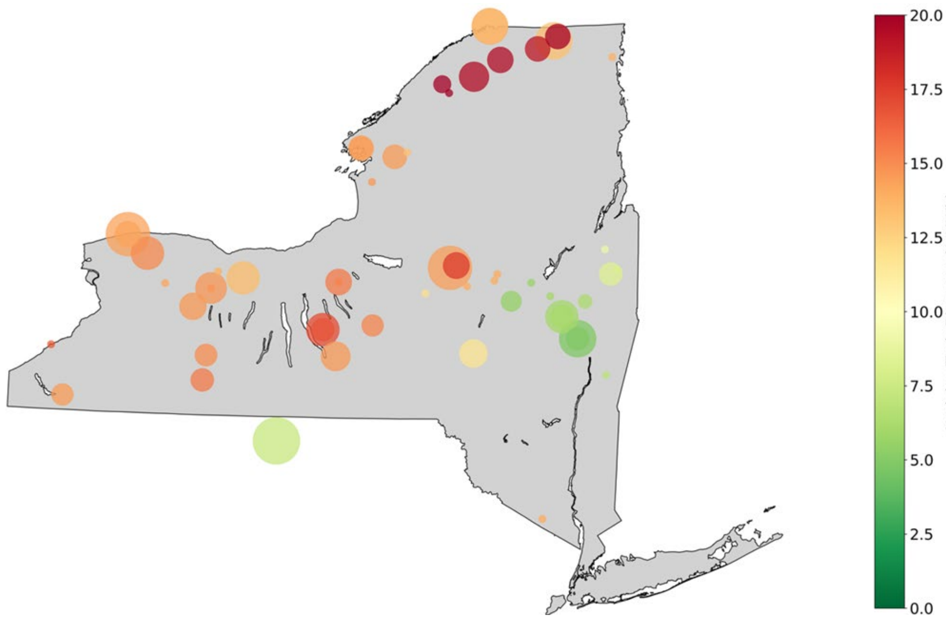


Source: NYISO, "Energy Market & Operational Data"

Projecting future basis risk is extremely challenging – contributing to many developers adopting a conservative approach to incorporating basis risk premiums within strike prices – because it is a function of transmission infrastructure development, generation development, generator offers, load growth at the local and state-wide level, and overall market prices. Higher market prices strongly correlate with higher basis risk for areas with excess renewable energy.

The MMU provided analysis of combined basis and shape risk for several cases, and the figures below highlight 2035 results from the Low Policy Case.[31] For solar, the basis component can be estimated in the $5 to $10/MWh range in the more congested regions in the map because technology discounts are in the $10 to $15/MWh range in all regions. For wind, as shown in Figure 9, projects in the west of the state are expected to see over $10/MWh of basis risk because the technology risk (shape) is about $2.50MWh in the MMU study and total risk is in the $15 to $17.50/MWh range.

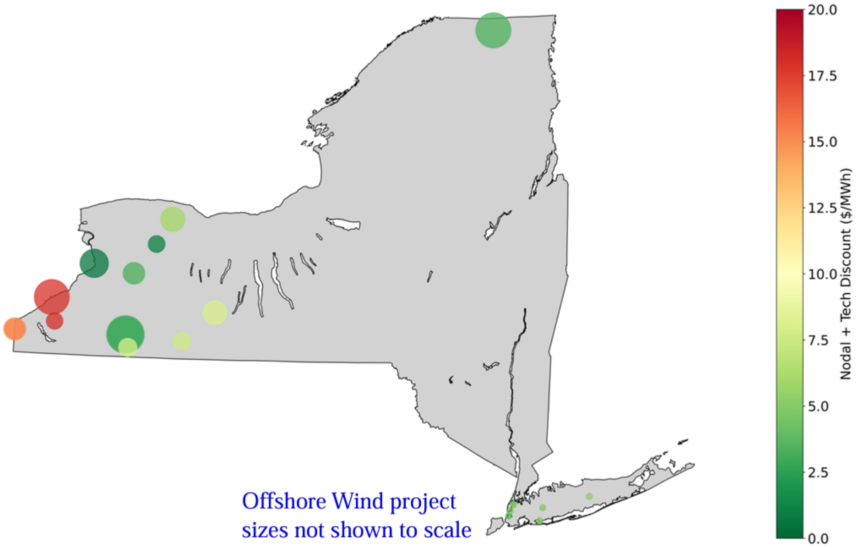
Figure 9: Solar-Weighted Shape and Basis Risk in New York State, MMU's Low Policy Case 2035



Source: Potomac Economics, "MMU Review of 2023-2042 System & Resource Outlook."

[31] Potomac Economics. 2024. "MMU Review of 2023-2042 System & Resource Outlook." https://potomaceconomics.com/wp-content/uploads/2024/06/MMU-2023-Outlook-Review.pdf

Figure 10: Wind-Weighted Shape and Basis Risk in New York State, MMU's Low Policy Case 2035



Source: Potomac Economics, "MMU Review of 2023-2042 System & Resource Outlook."

The outlined basis risk proposal – with or without the additional "last in, first out" mechanism – is intended to reduce basis risk through two key avenues. First, the incentive for contracted generators to offer energy at steeply negative prices will be materially reduced. Second, the incentive and market signal for generators to locate in areas with less congestion will be strengthened, as curtailment will be more likely to be borne by the most recent entrant to an area. This would contrast with the current settlement structure, which may be contributing to a dynamic in which curtailment is most likely to occur at an incumbent project that may either have a lower strike price or does not receive a REC.

Ratepayer *Benefits*

As noted above, basis risk is driven by a range of factors, including generator offers to the market. This proposal is intended to align generators' offers with competitive market behavior and to reduce the influence of the REC contract on market offers. Ratepayers may be expected to benefit from this change through reduced strike prices via two mechanisms:

(i) the magnitude of basis risk faced by projects is reduced, and

(ii) reduced project risk lowers developers' financing costs and cost of equity.

The additional "last in, first out" proposal for consideration would be expected to provide additional benefits to ratepayers, as it would further improve locational signals to developers and incentivize developers to more appropriately price projects according to the deliverable incremental energy from a given location.

As illustrated in Figure 8 and Figure 9 (reflecting the MMU's Low Policy Scenarios), the MMU estimates basis risk for wind and solar generation in New York State in 2035 to be \$5/MWh – \$15/MWh, depending on technology and project location. Basis risk could also be expected to elevate beyond these levels were overall market prices to increase, for example due to rising carbon prices, natural gas prices, or increased renewable penetration.

Analysis conducted on pricing models indicate that the core basis risk proposal presented – to offer payment of \$0.01/MWh for RECs in hours when the nodal LBMP is below \$0/MWh – could be estimated to reduce the magnitude of basis risk faced by developers by roughly 50% (i.e., taking the MMU's 2035 Low Policy Scenarios, developers would face basis risk of \$2.50/MWh – \$7.50/MWh, rather than the forecasted \$5/MWh – \$15/MWh). As projects would no longer need to price as much basis cost or premiums associated with potential future basis into their strike prices, ratepayers would benefit directly from the reduction in up-front REC costs.

As with shape risk, there is also the potential for improved financing terms that has a further, additive benefit to ratepayers. Conservatively, basis risk is estimated to account for 25% of the risk premium derived from Table 2, this proposed policy change would reduce the risk by up to 50%. This amounts to an *additional* ratepayer benefit of roughly \$1 – \$2/MWh in financing costs. This reduction would be incremental to the aforementioned \$2.50 – \$7.50/MWh reduction, indicating a ratepayer benefit as significant as \$9.50/MWh, depending on location, technology, and each developers' forecasted basis.

With the addition of the "last in, first out" additional policy intervention, the proposal should also support better siting decisions from future projects because the risk of curtailment would be most acutely borne by the newest project in a given area. In effect, developers will bid into procurements based on deliverable energy from their project. As a result, customers are likely to receive more incremental renewable energy from a given procurement, and prices will reflect the marginal cost of that incremental energy.

With the current settlement structure, some projects may have lower strike prices than they would with the "last in, first out" mechanism in place. However, this could be understood as a misleading price signal due in part to the fact that curtailment risk is currently borne by existing projects in a given area and therefore curtailment costs do not need to be fully internalized (reflected in the strike price) by new entrants. Accordingly, under the proposed "last in, first out" mechanism, projects participating in future solicitations would be incentivized to bid prices based on the project's deliverable incremental energy, reflecting the cost of curtailment. With a "last in, first out" mechanism, projects located in areas with high marginal curtailment rates would be much less likely to be competitively priced, leading to more efficient and value-add procurements that reflect actual incremental deliverable energy from a region, enhancing solicitations and supporting more targeted procurement of deliverable MWhs. These outcomes, combined, could result in significant benefit for ratepayers, as the marginal curtailment rate of new renewable energy in the coming years could be material (Figure 10 below indicates that up to 40% of new generation could be curtailed in some areas of the State in 2035 according to the MMU).[32]

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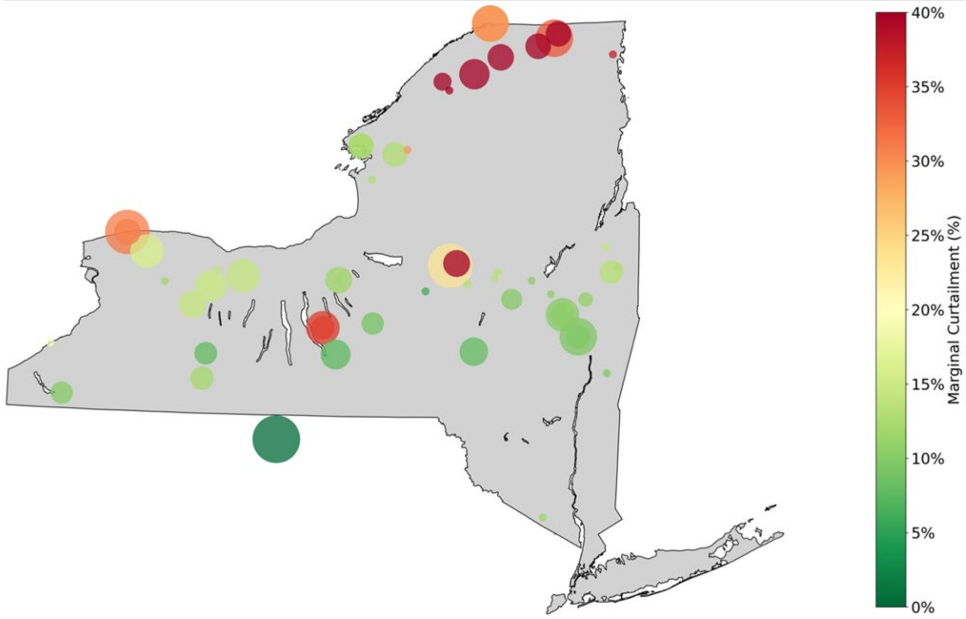
[32] Potomac Economics. 2024. MMU Review of 2023-2042 System & Resource Outlook. https://potomaceconomics.com/wp-content/uploads/2024/06/MMU-2023-Outlook-Review.pdf

Figure 11: Solar-Specific Marginal Curtailment Rate, MMU's Low Policy Case 2035



Source: Potomac Economics, "MMU Review of 2023-2042 System & Resource Outlook."

Finally, as noted and emphasized by the MMU, a notable unintended consequence of the current Index REC settlement structure is that the energy associated with the most expensive REC is the least likely to be curtailed when there is congestion. This is because the project with the most expensive REC can offer into the market most negatively to ensure it operates through congestion. In other words, in a given region where there is congestion, ratepayers may ultimately be paying for the most expensive RECs while the energy associated with lower cost RECs is curtailed.

As noted in the shape risk section, strike prices will likely increase as shape risk becomes more apparent and immediate in the market. This is particularly true for solar projects because shape risk is expected to be larger for solar. As noted, higher strike prices translate into an ability for generators to offer more deeply negative offers into the market, and the potential for basis increases as a result.

The phenomenon of increasing strike prices due to rising shape risk, inflation, and basis risk itself leads to elevated basis risk during periods of excess renewables. As a consequence, future projects will be able to offer ever more negative prices into the market and push curtailment risk onto projects that were developed earlier. This leads to lower cost RECs being curtailed prior to more expensive RECs, and it also forces developers to account for higher curtailment risk because future projects will be able to stay online at more negative prices than current projects. This is a negative feedback loop that serves to increase risk and force higher strike prices today to compensate.

Conclusion

DPS Staff and NYSERDA recognize the complexity of basis risk and shape risk – quantifying the magnitude of present and forecasted risk, ensuring risk-sharing is appropriately distributed, and, maximally, ensuring ratepayers are receiving the greatest value. The two core proposals recommended for advancement are estimated to save ratepayers between $4-$9 billion over the next two decades, in summary the proposals are:

i. To alter the Reference Energy Price contract settlement from the ATC index outlined above to instead settle against a TOW index, which would be weighted by state-wide hourly generation of that particular technology. We propose adopting this modification for all future contracts and also offering existing Index REC and Index OREC contract holders a one-time opportunity to accept or reject an offered modification to the contract which would implement the TOW index methodology with an adjusted strike price offered by NYSERDA.

ii. The Index REC price should settle at $0.01/MWh in all hours where the nodal LBMP is below zero, as described above, removing the incentive for projects with Index REC contracts to enter sub-zero LBMPs and thereby reducing basis risk (the spread between zonal and nodal settlement) for all projects at that location. We propose adopting this modification for future contracts.

    A. An additional element of this approach put forward for consideration would be to alter the settlement over time for projects with this version of the contract in a manner so that as new projects enter operation a "last in, first out" dynamic is created, further improving locational incentives and reducing future development risks for existing projects.