April 24, 2026

VIA ELECTRONIC FILING

Hon. Michelle L. Phillips, Secretary
NYS Public Service Commission
Empire State Plaza, Agency Building 3
Albany, NY 12223-1350
secretary@dps.ny.gov

Re: Case 15-E-0302 - Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard.
Case 22-E-0633 - In the Matter of New York Independent System Operator, Inc. Proposed Public Policy Transmission Needs for Consideration for 2022.

Dear Secretary Phillips:

The Alliance for Clean Energy New York and Advanced Energy United respectfully submit these comments in response to the Public Service Commission's January 27, 2026 Notice Soliciting Comments.

Thank you for your consideration of these comments. If you have any questions or need additional information, please reach out to me.

Respectfully submitted,

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NEW YORK STATE

PUBLIC SERVICE COMMISSION

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

CASE 22-E-0633 - In the Matter of New York Independent System Operator, Inc. Proposed Public Policy Transmission Needs for Consideration for 2022.

COMMENTS OF THE ALLIANCE FOR CLEAN ENERGY NEW YORK & ADVANCED ENERGY UNITED

On July 30, 2025, the New York State Public Service Commission ("Commission") issued a Notice Soliciting Comments requesting feedback in three areas pertaining to the Clean Energy Standard. Through the Commission's January 27, 2026 Notice, the Commission seeks additional feedback regarding utility ownership of renewable generation including, but not limited to: (1) potential ratepayer impacts of utility ownership of renewable generation; (2) utility impacts/advantages or disadvantages of renewable generation siting; (3) Standardized Interconnection Requirements queue placement/management; (4) solicitation competitiveness; and (5) potential regulatory impacts of utility ownership of renewable generation.

Pursuant to Commission's January 27, 2026 Notice Soliciting Comments by February 27, 2026, a subsequent extension[1] of the filing deadline until March 27, 2026, and then an

[1] February 5, 2026 Notice Extending Deadline, Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard.

additional extension[2] until April 24, 2026, in the above-mentioned cases, the Alliance for Clean Energy New York (ACE NY) and Advanced Energy United (United), collectively referred to as "we", hereby submit these responses to the Commission's questions.

ACE NY is a member-based organization with a mission of promoting the use of clean, renewable electricity technologies, transportation electrification, and energy efficiency in New York State to increase energy diversity and security, boost economic development, improve public health, and reduce air pollution. ACE NY's diverse membership includes companies engaged in the full range of clean energy technologies as well as consultants, academic and financial institutions, and not-for-profit organizations interested in their mission.

United is a national association of businesses that works to accelerate the move to 100% clean energy and electrified transportation in the U.S. The term advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting our energy needs today and tomorrow. These include electric vehicles, energy efficiency, demand response, energy storage, solar, wind, hydro, nuclear, heat pumps (ground-sourced and air-sourced), and smart grid technologies. United represents more than 100 companies in the $374 billion U.S. advanced energy industry, which employs 4.1 million U.S. workers, including 231,600 individuals in the Empire State.

We respectfully submit that utility ownership of renewable energy generation would impose significant and unnecessary costs and risks on New York ratepayers, and would undermine the competitive market structure that the Commission has carefully maintained since Opinion 96-12[3]. The Commission's framework has delivered meaningful benefits to ratepayers over more than two decades — more competition, lower market power risk, and

[2] March 26, 2026 Notice Further Extending Deadline, Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard.
[3] Opinion 96-12, Opinion and Order Regarding Competitive Opportunities for Electric Service, Issued and Effective May 20, 1996 (Case 94-E-0952)

the entry of newer, cleaner, and more cost-efficient energy suppliers. We respectfully urge the Commission to preserve that framework and to resist proposals that would erode it. In a moment of significant federal uncertainty, we should be reinforcing New York's investability, not introducing new doubt about its regulatory commitments.

The Commission's consideration of utility ownership of generation appears premised, at least in part, on a concern that the existing competitive procurement framework has not delivered renewable energy resources at the pace and cost New York needs. ACE NY and United respectfully submit that this premise warrants careful examination. The challenges that have affected renewable energy development in New York over the past several years — project attrition, cost escalation, and delayed commercial operation — are not evidence that competitive procurement and independently owned generation are structurally flawed. The challenges are the direct consequence of well-documented, unprecedented market disruptions: post-COVID supply chain dislocations, sustained construction cost inflation, sharply rising interest rates, and federal policy uncertainty that have affected the entire energy sector globally – as well as local opposition to new project development. These conditions would have challenged any development model — utility-owned or otherwise — and do not reflect a failure of competitive markets or developer performance. Notably, utilities are currently able to develop generation in certain scenarios, including through unregulated, discrete entities, and have faced the same obstacles. The appropriate solution is to strengthen and de-risk the competitive procurement framework, not revert to a cost-of-service model that would transfer those same risks — and more — directly onto ratepayers.

Utilities are already allowed to form subsidiaries with the ability to develop and own generation facilities, and many of New York's utilities already have unregulated affiliates for this purpose. Therefore, the State provides a mechanism for utilities to participate in generation development through unregulated affiliates, which appropriately preserves the separation between regulated T&D functions and competitive generation. Under a model that enables regulated utility development and ownership, any risks associated with utilities'

investment in new generation facilities would be fully borne by ratepayers. This proposal is not in line with the state's ambitions to develop energy generation at minimal cost to ratepayers.

The cost-of-service regulatory model, by design, allows for recovery of prudently incurred costs — an appropriate framework for T&D infrastructure, but one that does not provide the same cost minimization incentives that competitive markets deliver for generation resources. When generation and transmission are controlled by the same regulated entity, the structural incentives that drive cost efficiency in competitive markets are absent, to the detriment of ratepayers. The Commission should weigh these structural distinctions carefully and maintain the current deregulated model.

We would like to convey our agreement with the following statements made by Environmental Defense Fund in their April 9, 2026 comments[4],

> *[N]either the Commission nor the utilities have yet demonstrated that allowing for utility ownership of new renewable energy projects is the solution, or even a solution, to today's constraints, and the Commission should not move forward on this topic before addressing baseline questions that remain unanswered. .... At this point, there is insufficient evidence in the record of this proceeding that supports either side of this argument; until this evidence is available, any Commission decision moving away from the status quo would be happening blindly and without any confidence that it will address the barriers that have constrained deployment of renewable generation in New York to date. The questions included in the January Notice (and the July Notice) largely presuppose that the question of whether to allow utility ownership of renewables is settled and that the question of how is what requires further stakeholder input. This is the wrong starting point.*

[4] April 9, 2026 comments submitted by Environmental Defense Fund hereby in Case 15-E-0302 on the Notice Soliciting Comments Regarding Utility Ownership of Renewable Generation.

Utility-Owned Generation:

DPS STAFF QUESTION: ***Identify the financial impacts and risks to ratepayers of the various options proposed by BMR Energy (build transfer, develop transfer, or milestone-based transfer), Indicated Utilities (build transfer agreement), and New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation (self-build model) as described in response to the July Notice. To the extent possible, include potential ways in which the risks and or impacts could be avoided, mitigated, or managed.***

Transfer mechanisms, while mitigating some anti-competitive concerns, still increase the risk for development, raise significant structural concerns for ratepayers, and create market distortion. These agreements require developers to bear all the upfront construction and regulatory risks while long-term asset value shifts to the utility and is added to the utility's rate base. In a transfer agreement, ratepayers may be buying the energy project/asset after value has been created but before it starts operations. Ill-timed transfer points may expose risks to ratepayers that would have been otherwise absorbed by private capital. Ratepayers are then still subject to utility cost-recovery to maintain the asset and may not pay a fixed price for energy competitively derived as they would under a PPA or similar contract with an independent power producer.

Private developers typically invest in and construct generation projects with the expectation of strategic, long-term ownership and operation. This model aligns incentives around cost control, efficient performance, and lifecycle optimization because developers bear both construction and operational risks. These competitive pressures deliver direct value to ratepayers. A develop-and-transfer structure disrupts this risk alignment by requiring developers to assume early-stage risks while stripping away long-term ownership incentives, ultimately shifting costs and risks back to ratepayers. In addition, this will increase the risk premium for development, increasing the costs to ratepayers. The Commission should

weigh carefully whether any claimed benefit of utility ownership justifies this fundamental reallocation of development and operational risk onto the ratepayers the Commission is charged to protect.

These factors may reduce accountability for cost discipline, particularly at the O&M stage, and leave ratepayers accountable for unforeseen costs and poor performance.

Avoiding, mitigating, managing risks/impacts: The separation of generation from transmission and distribution ("T&D") has resulted in more competition, less ratepayer risk, less market power risk, and the entry of newer, cleaner, and more efficient energy suppliers. Utility ownership of generation would backtrack on that progress and set an uncompetitive and harmful precedent. Extending ownership into generation would reintroduce the structural tensions that competitive market reform was designed to resolve, to the detriment of ratepayers and the competitive market participants they depend on.

The Commission can protect ratepayers and foster renewable energy generation growth by continuing to reform the Commission's procurement processes to ensure future Renewable Energy Certificate ("REC") solicitations alleviate the significant risk developers face, focus on flexible contracting to guarantee adaptability to the ever-changing landscape, and prioritize thoughtful planning for transmission upgrades that ultimately save ratepayers money. This maintains competition among independent developers.

See **Appendix A, Utility Owned Energy Storage and the Risk to Ratepayers** which illustrates the risk to ratepayers of a utility owned energy storage model – this provides a close look at two recent Con Edison storage projects, the Fox Hills BESS project and the Brownsville BESS project. Both of these projects experienced cost overruns and the ratepayer impact was 3-4 times that of a comparable project operating under the VDER framework. Additionally, one of the projects needed repairs after coming online and could

not provide grid services throughout the peak summer season; in a case like this, privately owned projects would not be compensated, limiting the downside risk to ratepayers.

DPS STAFF QUESTION: ***What advantages and disadvantages would utilities face overall in terms of siting renewable projects that may not have been considered previously? Identify any potential shortcomings of the advantages described and any remedial action the utilities could take to address any disadvantages described.***

The pace of renewable energy deployment has been influenced by various factors, some of which are within utility operational control, including interconnection processes and transmission system planning. The Commission should continue to focus on improving these foundational competitive market mechanisms, rather than altering ownership structures.

Utility development or ownership of generation will not result in projects being permitted, sited, or constructed more quickly, nor will it deliver generation to ratepayers at lower cost. A utility-owned project will face the same timeline in seeking permits, negotiating with landowners and local governments, and acquiring equipment and labor as any independent developer — with the critical difference that any cost overruns or delays would be borne by ratepayers rather than the developer. Therefore, we respectfully ask the Commission to reject the premise that utility ownership resolves the siting and development challenges New York faces. Those challenges are structural and systemic, and are better addressed through transmission planning, interconnection reform, and competitive procurement improvements that protect ratepayers while accelerating development.

Industry experience in New York's interconnection process further illustrates this point. Renewable energy developers routinely elect to self-build interconnection network upgrade facilities — upgrades that would otherwise be constructed by the incumbent utility — and upon completion, transfer those assets to the utility to own and operate. This practice

reflects private developers' demonstrated ability to deliver transmission infrastructure on schedule and at competitive cost. Developers consistently construct interconnection facilities at significantly lower cost than the utility estimates provided in the interconnection study process. It is a real-world, New York-specific demonstration that at-risk capital engenders discipline, because a developer bears full construction risk with no guaranteed cost recovery.

As for the cost of capital to which utilities have access, it is true that utilities have a low cost of capital, due to the ability to recover all costs from ratepayers. There is, however, no evidence that it is lower than that of many of the Independent Power Producers ("IPPs") operating in New York already, whose good credit is based on their ability to reliably deliver projects on time and on budget. Utilities' low cost of capital is based on their low risk profile, which is supported by the fact that any project cost overruns will be underwritten by the ratepayers of this state. Ultimately, comparing cost of capital is the wrong approach. The comparison should be the ultimate cost impact on ratepayers.

If the utilities were in the same situation as the development community where projects were subject to unforeseen inflationary pressures, the state wouldn't likely have the option of cancelling the projects as significant ratepayer funding would have already been expended. Clearly, this is not an advantage that benefits ratepayers. In addition, the utilities already have significant work ahead in terms of building out distribution architecture. In the case of Con Edison, they proposed the most aggressive capital spending plan in decades in the rate case (25-E-0072)[5]; their plan calls for the expansion of the distribution grid capability by 3 GW or 17% of the current capability at a cost of $12 billion[6] (ratepayer impact: $1.4+

[5] Case 25-E-0072, https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=25-E-0072; Exhibit_(EIOP-2 UPD), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B20172196-0000-CF8D-A6FE-1D567712803A%7D

[6] https://www.utilitydive.com/news/after-rate-case-con-edison-q3-electric-revenues-up-106-on-flat-sales/805107/

billion per year). That is just for new infrastructure. For the past few decades, total demand on the system has remained flat or declining. There is no evidence that they will be able to successfully execute on time and budget and expanding their ability to also build generation will significantly increase risks to ratepayers.

DPS STAFF QUESTION: ***Identify the potential of a utility to exercise vertical or horizontal market power related, but not limited to: (a) property ownership adjacent or in close proximity to beneficial interconnection assets; (b) decisions to build or upgrade facilities that increase hosting capacity or otherwise grow its rate base; (c) impacts on the function or structure of earning adjustment mechanisms; or (d) other traditional utility functions maintained by a utility after the unbundling of generation.***

Property ownership adjacent or in close proximity to beneficial interconnection assets: First, vertical market power ("VMP") could be exercised when an investor-owned utility ("IOU") owns generation in its own service territory. In 1996, when the Commission began to deregulate the state's electric industry, the Commission was concerned that the IOU could use its control of the T&D system to favor its own generation or thwart competition by lowering competitors' revenues, raising their costs, or delaying their projects.[7] Second, VMP could be exercised when an IOU owns generation that is located on the high side of a transmission constraint.[8] The Commission was rightly concerned that the IOU could use its control of the transmission system to increase constraints and raise the value of its generating assets.

[7] Cases 96-E-0900 et al., In the Matter of Orange & Rockland Utilities, Inc.'s Plans for Electric Rate Restructuring Pursuant to Opinion 96-12, Statement of Policy Regarding Vertical Market Power (July 17, 1998) ("VMP Order"); id. at Appendix I ("VMP Policy Statement").
[8] *Id*.

Decisions to build or upgrade facilities that increase hosting capacity or otherwise grow its rate base: The Commission addressed VMP considerations in its merger order[9] by requiring National Grid to divest the 2,450 MW Ravenswood generating facility portfolio as an express condition to approval of the merger given the specific facts and circumstances then presented. Under traditional cost-of-service regulation, a utility's financial incentives differ fundamentally from those of a merchant developer, who bears full construction and operating risk. This structural difference — not a criticism of any utility — is simply how cost-of-service regulation works. Competitive procurement is designed to harness that market discipline for the benefit of ratepayers. It remains the regulated utilities' responsibility to increase hosting capacity when and where needed, regardless of who owns the generation. As utilities plan the future grid, they will have significant conflicts of interest if they own assets that are advantaged by their own plans. This could lead to suboptimal overall planning that would increase ratepayer cost.

Impacts on the function or structure of earning adjustment mechanisms: Earnings Adjustment Mechanisms and Performance Incentive Mechanisms are tools designed to compensate for the absence of competitive market discipline in a cost-of-service paradigm. In a competitive procurement framework, market pressure itself provides the performance incentive that such mechanisms attempt to approximate — at no additional cost to ratepayers. Developers of renewable generation are driven by the opportunity for return on at-risk investment and have a strong incentive to minimize costs, deliver on schedule, and operate efficiently because their returns depend on it.

Introducing Earnings Adjustment Mechanisms for utility-owned generation would layer additional ratepayer obligations onto a cost-of-service structure that already lacks the competitive pressure to minimize costs; compounding, rather than correcting, the structural misalignment between the cost-of-service framework and ratepayer interests.

[9] Case 06-M-0878, National Grid PLC & KeySpan Corp., Order Authorizing Acquisition Subject to Conditions and Making Some Revenue Requirement Determinations for KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island (Sept. 17, 2007), at 111.

The Commission should weigh carefully whether any set of incentive mechanisms, however well-designed, can adequately substitute for the cost discipline that competitive markets already deliver to ratepayers without additional regulatory overhead.

Other traditional utility functions maintained by a utility after the unbundling of generation:

No comment offered in response to this aspect

DPS STAFF QUESTION: ***How would the utilities provide certainty and transparency to ensure that their renewable energy project(s) are not unduly favored over other non-utility projects that are further along in the Standardized Interconnection Requirements queue and/or in a better position to be built more quickly?***

Since IOUs divested most of their generation more than 25 years ago, the Commission has applied its VMP Policy Statement on a case-by-case basis. This careful evaluation has helped determine whether, and under what circumstances, a company and its unregulated affiliates may be permitted to own both generation and transmission in New York. The Commission should continue to apply its VMP Policy Statement consistent with the precedent it set for utility-owned generation ("UOG"). The Commission should reject any argument that the public interest requires it to weaken or abandon in any way its VMP Policy to accelerate the development of renewable resources. Competition's long-standing benefits to ratepayers would be jeopardized if the Commission were to stray from its current well-considered course. Utility development or ownership of generation will not result in more projects being constructed faster. UOG will have to face the same timeline in seeking permits, in negotiating with landowners and local governments, and in acquiring equipment and labor.

Because utilities control both the study process of the NYS Standardized Interconnection Requirements (SIR) and the construction schedule for any interconnection equipment, if

they were allowed to compete with the developers going through those processes there would be an inherent conflict of interest. We previously have expressed this concern, most recently in the comments filed by the coalition Affordable Clean Power Alliance ("ACPA") on October 31, 2025[10] in response to the questions encompassed in the Commission's July 30, 2025 Notice Soliciting Comments.

The Commission determined that the IOUs' total divestiture of generation was the clearest way to allay concerns about their ability to exercise VMP and avoid anti-competitive behavior—such as favored treatment of affiliates and cross-subsidies among affiliates in both competitive and monopoly environments.[11] That separation of ownership of generation from T&D for IOUs remains preferable to relying on regulatory controls and enforcement mechanisms. The Commission correctly established a rebuttable presumption that separating these functions was necessary because regulatory controls are lengthy and remedying abuse places undue risk on ratepayers.[12]

We support the Commission continuing its current VMP Policy on IOU ownership as summarized in its first paragraph:

> *In creating a competitive electric market, the Commission has viewed divestiture as a key means of achieving an environment where the incentives to abuse market power are minimized. Recognizing that vigilant regulatory oversight cannot timely identify and remedy all abuses, it is preferable to properly align incentives in the first place.*[13]

[10] October 31, 2025 comments submitted by Affordable Clean Power Alliance (ACPA) in Case 15-E-0302. ACPA includes the Alliance for Clean Energy New York, Advanced Energy United, the Independent Power Producers of New York, Inc. ("IPPNY"), and New Yorkers for Affordable Energy.
[11] Cases 94-E-0952 et al., In the Matter of Competitive Opportunities Regarding Electric Service, Opinion and Order Regarding Competitive Opportunities for Electric Service (May 20, 1996), at 64–65 ("Opinion 96-12").
[12] VMP Policy Statement at 1.
[13] Id. (emphasis added.)

DPS STAFF QUESTION: ***Under the build transfer agreement scenarios presented in comments (Indicated Utilities), the utilities would conduct statewide joint competitive solicitations and then purchase projects after they are successfully completed by developers. How would the utilities ensure that such solicitations would be competitive, and what criteria would be applied to determine if the winning bids were competitive regarding price and other factors?***

We believe that NYSERDA-run solicitations are the most effective way to create a competitive procurement process.

When NYSERDA has issued solicitations under the CES program, it has been met with abundant interest and proposed investment offers. Instead of allowing utilities to run solicitations, which would make the marketplace more complex and muddied, and bid groups smaller and less competitive, the Commission should continue to reform the procurement processes to ensure future REC solicitations alleviate the significant risk developers face, while focusing on flexible contracting to provide adaptability. The Commission should also prioritize planning for transmission upgrades, all of which would save ratepayers money.

A critical component of procurement strategy is the **preservation of value** for existing and contracted generation facilities. Adding new capacity without regard for generation facilities already contracted or operational can lead to excessive **basis risk and curtailment**, negatively impacting the financial health of both new and incumbent assets. To mitigate this, procurement processes should be centralized or strictly coordinated across agencies. This allows for a holistic evaluation of a project's impact on the surrounding generation in the vicinity, ensuring that state goals for new generation do not come at the expense of the operational viability of the existing fleet.

DPS STAFF QUESTION: ***In response to the questions posed in the July Notice, commenters suggested a Milestone-Based Transfer in which the purchase of the project would occur through a series of milestone-based payments where the developer would be responsible for obtaining the land, interconnection, permits, and developing the energy performance contract prior to the utility transfer, while the utility would be required to make payments at each development milestone. What safeguards could the utility put in place to ensure completion of the project or limit/eliminate risk to ratepayers while making the milestone payments under this model?***

While this process would reduce costs to the utility, it would place undue risk on generation developers. By requiring developers to assume early-stage risks while stripping away long-term ownership incentives, this will shift overall project costs and risks back to ratepayers because generation projects will have to increase their risk premiums. As stated earlier, this could lead to market suppression, the opposite of the claimed intent of deploying clean energy generation faster.

We posit that this model would remove the levers currently available to NYS to prevent ratepayers from bearing undue risk of cost overruns. Under the current model, private developers are paid when projects are fully executed and meet performance criteria. Moving to a milestone-based transfer model, ratepayers are exposed to cost overruns and the risk of partially paid projects being abandoned to the extent they become economically unfeasible. In these cases, there are no levers to pull in the case that project costs become unfeasible – the development may be abandoned in this case if higher costs are not absorbed regardless of the investments already made in the project.

DPS STAFF QUESTION: ***In its response to the questions posed in the July Notice, the Indicated Utilities (on page 20) stated that "the intermittency of large-scale renewables severely limits any market manipulation risk" and that if the utilities were to own co-sited energy storage in the future, "utilities would develop transparent operating rules in consultation with the Department of Public Service (DPS) that mitigate market power and that it would include rules that optimize providing value to the bulk power and transmission system rather than maximizing market revenues." Specifically, prior to any DPS consultation, what criteria would be utilized to ensure that the operating rules would result in strategically optimizing the bulk power and transmission system rather than utility revenues.***

The Commission should recognize that the very need to construct elaborate operating rules to prevent optimization of generation assets at the expense of the broader transmission system is itself compelling evidence that utility ownership of generation is structurally incompatible with the competitive market the Commission has maintained. The cost of administering and enforcing such rules would fall on ratepayers. The appropriate response is not more regulation, it is to preserve the structural boundary that has protected ratepayers and competition for more than two decades, rather than creating a new and costly regulatory apparatus to manage the conflicts that this ownership model would inevitably produce.

Moreover, operating rules will likely restrict the full flexible operation of the asset resulting in the asset likely being not used as efficiently as a merchant asset.

DPS STAFF QUESTION: ***If Utility Owned generation were to be allowed, what approaches should be considered in order to optimally ensure projects are completed cost-effectively and timely. Identify the role competition should play, and how proposed approaches should be structured to leverage competition to arrive at least cost resources.***

Before addressing the mechanics of a utility ownership model, we respectfully submit that the question itself reflects a concern the Commission should examine carefully: whether the challenges facing New York's renewable procurement are structural failures of competitive markets, or whether they are the product of specific, addressable barriers compounded by unprecedented external market conditions. We posit they are the latter. The reforms identified in these comments — to procurement structures, interconnection cost transparency, contract flexibility, basis and shape risk allocation, and transmission planning — address the root causes of development challenges without abandoning the competitive framework that has consistently served ratepayers well. The Commission is respectfully urged to pursue those reforms before concluding that utility ownership is a necessary or appropriate remedy.

The Commission's most effective path to achieving New York's clean energy goals at lowest cost to ratepayers is to continue prohibiting utility owned generation and strengthening the competitive procurement framework it has carefully built. Any purported benefits that would come from utility-owned generation being allowed would not outweigh the associated VMP concerns and impacts. The Commission has applied policy to try to prevent IOUs from exercising VMP.

UOG will have to face the same elongated timeline in seeking permits, in negotiating with landowners and local governments, ever-present public backlash, and in acquiring equipment and labor. These issues arise for all project development in New York and can be mitigated through the recommendations provided below. Allowing a direct UOG model does

not address the project barriers but rather provides a false solution on the backs of ratepayers.

In a ratepayer cost-of-service model under UOG, ratepayers would face increased risk with respect to costs because IOUs are not incentivized to minimize costs. In a cost-of-service model, the structural incentives that drive cost minimization in competitive markets are absent; ratepayers bear the risk of cost overruns with no competitive accountability. Competitive suppliers are incentivized to complete projects on time and at the lowest possible cost because they have to offer electricity into the market at competitive prices to recoup investments. IOUs have no such incentive and can pass the expense of delays and cost overruns to captive ratepayers.

- Competitive markets are harmed by cost-of-service, rate-regulated generation because it can artificially depress the market clearing price from competitive levels.
- Utility development or ownership of generation will not result in more projects being constructed faster. UOG will face the same timeline in seeking permits, in negotiating with landowners and local governments, and in acquiring equipment and labor.
- The separation of generation from T&D has resulted in more competition, less market power risk, less ratepayer risk, and the entry of newer, cleaner, and more efficient energy suppliers. Extending ownership into generation would reintroduce the structural tensions that competitive market reform was designed to resolve, to the detriment of ratepayers and the competitive market participants they depend on.

The competitive procurement framework is not broken — it has been tested by extraordinary and well-documented market conditions that would have challenged any development model. It remains the right foundation on which to build New York's clean energy future. The Commission's most powerful tool to accelerate renewable development and protect ratepayers is not utility ownership — it is a more durable, de-risked, and flexible competitive

procurement framework that removes unnecessary barriers, reflects market realities, and maintains the cost discipline that only competitive markets reliably deliver.

Energy and Capacity Market Design:

DPS STAFF QUESTION: ***In order to better align and improve existing clean energy procurement activities, including a potential utility owned generation approach, with the wholesale energy and capacity market mechanisms, what changes would be necessary with respect to: (1) Market Power Mitigation rules; (2) Bidding Requirements; (3) Capacity Auctions and Capacity Requirements; and (4) Other areas not included above?***

While we do not believe that a potential utility owned generation approach should be considered, as discussed above, we do believe that a number of reforms to the wholesale energy and capacity market mechanisms should be adopted to improve renewable energy procurement activities.

One important change would be to improve the Effective Load Carrying Capability ("ELCC") accreditation for offshore wind and renewables more broadly. The NYISO chose to use a marginal ELCC which systematically undervalues the capacity contribution from renewables and energy storage. The NYISO based this decision on the argument that this steered new entry. The value of steering function is minimal, however, as most of these assets are developed through state procurements: however, the systematic undervaluation of the assets in the NYISO markets is driving up the cost of these projects. We suggest moving to an ELCC methodology that accurately reflects these assets' reliability contribution. In the 2024/25 Capability Year, NYISO gave offshore wind a 31.56% capacity accreditation in the Long Island zone, and is considering further reducing this rate with its adoption of new marginal ELCC-based accreditation.

However, this value strongly understates offshore wind's reliability contribution; now that we have data from existing offshore wind projects, this is evident. While offshore wind is by definition intermittent, the recent data from the first year of South Fork Wind's operations demonstrates that the project was operating 99% of the time. That translates to an annual 46.3 percent capacity factor.[14] Other jurisdictions have taken note of offshore wind's performance and have provided much higher ELCC accreditations for offshore wind; in PJM, the 2024/25 class ratings gave offshore wind 47 percent ELCC.

NYISO has also determined that significant future reliability deficiencies occur in the winter. Offshore wind has higher winter output, for example, according to LIPA, in January 2026, South Fork's net capacity factor was 52 percent.[15] This performance aligns well with New York's reliability needs and compensates for resources that do not perform as well during these times.

On the topic of market power mitigation rules, we support the current language in the buyer-side mitigation rules to clearly distinguish state-directed, competitively procured clean energy resources from merchant generation. For example, offshore wind projects awarded through Commission-approved solicitations and supported by long-term contracts do not pose buyer-side market power concerns, as they are price-taking resources with largely fixed revenues and significant development and construction risk. Application of buyer-side mitigation measures, including administratively imposed offer floors in the capacity market, to such resources risks distorting market outcomes, increasing financing uncertainty, and raising costs to ratepayers. We therefore support the current language as written. Accordingly, mitigation frameworks should also provide a clear exemption or safe harbor for Commission-approved clean energy resources to ensure alignment between wholesale market rules and New York's clean energy and reliability objectives.

[14] See Long Island Power Authority (LIPA) CEO Report at https://www.lipower.org/wp-content/uploads/2025/12/3.-March-25-2026-CEO-Report.pdf.
[15] *Id*.

DPS STAFF QUESTION: ***Is an installed capacity product an effective price signal for resource adequacy given the required future generating resource mix? If not, what are potential approaches to ensuring resource adequacy and what would be the attending price signal?***

The existing installed capacity product ("ICAP") alone is not an effective signal for a system that needs to integrate a diverse portfolio of resources. ICAP does not capture differing contributions from intermittent and duration-specific resources in a seasonally driven reliability landscape.

As discussed above, a more effective approach would be a seasonal, ELCC-based resource adequacy framework that reflects each resource's reliability contribution. For instance, offshore wind generation can provide significant and valuable reliability benefits during winter peak periods while dispatchable generation (e.g., energy storage, thermal generation) can deliver targeted peak and ramping support. This seasonal value is already apparent: South Fork's capacity factor in the first half of 2025 was 53%. While capacity factors and ELCCs differ, offshore wind does ramp and peak during peak demand hours.

A seasonal ELCC-based resource adequacy approach can provide clearer price signals for diverse, high-value capacity while maintaining competitive procurement mechanisms.

DPS STAFF QUESTION: ***Should alternative approaches be considered to ensure the procurement of generation resources is aligned with State policy goals. If so, which ones? Are there existing or proposed models which might be instructive, such as the State overseeing LSEs' resource adequacy portfolios (e.g., an approach similar to the one used by California) or restructuring New York Independent System Operator, Inc. rules to accommodate State policies?***

Improving the structure of the NYISO capacity market will provide price signals that encourage long-term generation investments. NYISO's ICAP market has relatively short forward visibility, using monthly and spot auctions rather than multi-year commitments. This limits developers' ability to secure financing for effective, reliable projects with multi-year development cycles. In comparison, PJM's Base Residual Auction ("BRA") clears three years ahead of the delivery year, locking in capacity prices and commitments well before construction. This gives generation projects greater certainty and improves long-term financing capabilities. The 15-year firm capacity commitment currently being considered within PJM's Reliability Backstop Procurement process underscores that longer-term contracts are critical to providing the revenue certainty necessary for effective generation development.[16]

In addition, NYISO's planning assumptions should more accurately reflect the evolving resource mix, including the higher winter performance of offshore wind, the flexibility and rapid response characteristics of energy storage generation, and the potential reliability contribution of thermal resources that may be needed during periods of peak demand. Current planning frameworks continue to rely heavily on assumptions driven by historic resource mix, resulting in underestimation of new resource capabilities and the limitation of BESS flexibility; for example, the NYISO requires that distribution connected BESS projects are studied assuming charging at the peak hour.

[16] PJM Interconnection, *Reliability Backstop Procurement Workshop: Item 02 - Goals, Principles, and Elements*, at [Slide 18] (Feb. 6, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/workshops/rbpw/2026/20260206/20260206-item-02---goals-principles-and-elements.pdf.

Ensuring accurate modelling inputs for new generation, including site control costs, plant availability, duration, seasonal contributions, and transmission upgrade costs, is critical to align procurements with State policy goals.

DPS STAFF QUESTION: ***What is the State role with respect to resource adequacy matters that best serve New York's electricity customers with safe, adequate, and reliable service at just and reasonable rates in the context of State policies?***

The State's most effective role would be to define clear, reliability-aligned resource adequacy requirements that reflect updated system needs. Specifically, the State should focus on:

- Procuring effective generation for increasing winter peaks;
- Performance of specific resource types that align with policy goals and regional needs; and
- Continuing competitive, developer-led procurement (not utility driven).

Coordination between the State and NYISO on planning assumptions, ELCC values, and capacity product design will ensure reliability needs are met at the lowest cost for ratepayers.

Furthermore, the Commission cannot overlook the growing role of transmission in accommodating new generation that preserves and improves resource adequacy. Transmission is one of the most expensive pieces of generation development; coordinated and selective transmission investment is one of the most powerful tools at the Commission's disposal to encourage specific generation types.

As seen in California's Tehachapi Renewable Transmission Project and Texas's Competitive Renewable Energy Zones, proactive, coordinated transmission development is a powerful

tool to ensure the procurement of generation aligns with state policy goals. A report from Potomac Economics found that recent system deliverability upgrades ("SDUs") costs in New York for any developer: at $880 per kW of UCAP in CY23, the average SDU cost effectively cancelled out the net present value of 20 years of capacity payments for a generator in Zone K.[17] The Public Policy Transmission Planning Process ("PPTPP") could offer headroom on the system for developers that may not otherwise offer their projects into the capacity market. By coordinating transmission upgrades, the State will also streamline developments and centralize costs, which will bring down costs to individual projects and reduce the overall burden on ratepayers in the long-term. In addition, better transmission upgrades will mitigate curtailment, which in turn will help to drive down costs and increase reliability.

The PPTPP should be utilized more frequently for smaller scopes, especially in Zones J and K. Increasing frequency and decreasing scopes will reduce the costs for each Public Policy Transmission Need, thereby improving the likelihood that projects will be selected. The Commission should also collaborate with NYISO to create a mechanism by which the new headroom/Points of Interconnection can be reserved specifically for projects that meet the State's policy goals.

DPS STAFF QUESTION: ***What, if any, next steps should the Commission take with respect to potential wholesale or energy market reforms?***

Critically, State communications must support transmission and generation projects. New York must combat mis/disinformation by communicating the need for these projects and explaining to local residents why they are critical for achieving energy affordability and grid reliability. The State should facilitate adequate engagement with and buy-in from local municipalities when identifying transmission projects and have a comprehensive

[17] https://www.potomaceconomics.com/wp-content/uploads/2025/05/NYISO-2024-SOM-Full-Report_5-14-2025-final.pdf

understanding of the stakeholder landscape before determining locations. One mechanism to do this would be to create an office within NYSERDA focused on public communications and community engagement; another would be to provide grants to local organizations already doing this work in communities.

The Commission's decision more than a quarter century ago to restructure New York's energy markets from vertically integrated monopolies to a competitive wholesale and retail market structure was based on competition bringing forth efficiencies, technical advancements, savings, and other benefits, which are unlikely to occur as effectively, if at all, absent the motivation[18] provided by such competitive markets.

[18] Cases 96-E-0900 et al., In the Matter of Orange & Rockland Utilities, Inc.'s Plans for Electric Rate Restructuring Pursuant to Opinion 96-12, Statement of Policy Regarding Vertical Market Power (July 17, 1998) ("VMP Order"); at 26.

Recommendations for Procurement Reform

NOTE: We acknowledge the launch of the latest competitive solicitation (RESRFP26-1), administered by NYSERDA, on April 24, 2026. We welcome some of the changes made in the solicitation. The recommendations included below may not entirely factor in the RESRFP26-1's requirements, provisions, etc. as we are still reviewing the RFP and the associated documents.

The reforms recommended below are not evidence that competitive development is failing — they are evidence that competitive development is working, and that targeted, market-preserving improvements will make it work better for ratepayers. The Commission need not choose between a functional competitive market and reliable, affordable clean energy development. New York's renewable development landscape presents uniquely challenging conditions — long development timelines, complex interconnection processes, and a regulatory and permitting environment that exposes projects to cost and schedule risks accumulating over many years before a single megawatt reaches the grid. These structural challenges have been compounded by well-documented, unprecedented market disruptions: post-COVID supply chain dislocations, sustained construction cost inflation, sharply rising interest rates, and federal policy uncertainty that have affected the entire energy sector. These are not developer failures — they are conditions that any entity seeking to build generation in New York, utility or otherwise, would face, and they do not reflect any deficiency in the competitive procurement framework.

We acknowledge and value NYSERDA's demonstrated ability to adapt its solicitation structures to evolving market conditions, and we do not seek to constrain that flexibility. Rather, we ask the Commission to direct NYSERDA to remove unnecessary barriers, allocate risk more efficiently, and provide the revenue certainty that projects with multi-year development cycles require to compete at lowest cost — ensuring that the competitive market remains robust, accessible, and structured to deliver maximum affordability value

to ratepayers. The alternative — a procurement environment so burdened by structural barriers and unallocated risk that competitive development becomes unviable — serves no one, least of all the ratepayers who depend on a healthy competitive market to keep energy costs as low as possible.

ACE NY and United offer the following recommendations:

- Maximize New York's leverage of federal tax incentives to lower costs for New York ratepayers by granting NYSERDA flexibility to allow previously contracted projects that have experienced cost increases due to tariffs and federal policy delays to rebid in the next NYSERDA solicitation. If these projects are not allowed to reenter the competitive process, these tax credits will go to projects built in other states, and ratepayers will have to backfill the lost federal incentives with increased energy costs in the future.

- Improve the one-time adjustment mechanism to allow flexibility in the NYSERDA contracts, so projects have a way to explain and justify the unforeseen cost increases if they happen due to the very unpredictable federal environment. In the context of the previous point, this will allow mature land-based projects to re-enter the competitive market and start construction sooner and capture the greatest amount of federal tax credits for the benefit of NY ratepayers. Going forward, a functional adjustment mechanism would obviate the need for the majority of contract terminations, and more projects will move to construction faster.

- The Commission should note a tension in the current procurement framework and encourage NYSERDA to recalibrate contract security requirements, exit penalties, and solicitation eligibility restrictions to better distinguish between bad actors and developers facing systemic, market-wide cost pressures outside their control. Provisions designed to prevent contracts from functioning as financial options are

well-intentioned and necessary, but when applied without distinction to developers whose projects are viable but constrained by unprecedented market conditions, they increase risk premiums, reduce competitive participation, and ultimately raise costs for ratepayers. The goal should be a framework firm enough to ensure genuine commitment, and flexible enough to recognize that not all project attrition reflects developer failure.

- The Commission should ensure that future solicitations remain focused on the State's core energy procurement need. Non-energy obligations — including overlapping mitigation requirements, local content, and economic development commitments — while advancing important policy goals, carry real costs that are ultimately borne by ratepayers through higher bid prices. Every dollar of compliance cost associated with non-energy requirements is a dollar added to the price of contracted generation. The Commission should carefully calibrate these obligations, recognizing that an expanding list of non-energy requirements does not come without cost to the ratepayers, and that the most direct path to affordability is a solicitation structure that maximizes competitive participation on the merits of energy price and project viability.

- The Commission should direct NYSERDA to implement significant procurement reform in its upcoming Biennial Review process, prioritizing policies that increase contract flexibility, simplify procurement models, and implement longer contract tenors as previously approved by the Commission, all to derisk development in New York to drive down project costs and accelerate renewable energy development.

- Recommend that Maximum Contract Tenor be increased from 20 years to 25 years to allow the opportunity to reduce the Bid Price, create value for ratepayers and certainty for Sellers. This was approved in the recommendations from the 2024 biennial review. Also, multiple Canadian utilities (BC Hydro, Nova Scotia Power,

Sask Power and Hydro-Québec) have been requiring 25-year terms for the last few years in their renewable RFPs (Hydro-Québec and BC Hydro require 30-year contracts). Therefore, a transition to 25+ year NYSERDA contracts would match similar markets.

- The Commission should direct NYSERDA to remove basis and shape risk in future solicitations. These risks arise from market dynamics — nodal congestion, hub pricing behavior, and temporal price patterns — that are entirely outside a generator's operational control. NYSERDA is better positioned to manage these risks through portfolio diversification than any single project. Removing basis and shape risk from developers increases the financeability of projects, lowers the cost of capital, and ultimately reduces the overall cost of energy to New York customers. See **Appendix B** for a detailed discussion of our recommendations pertaining to basis and shape risk.

- Increase the number of solicitations in the coming years to ensure more projects can come online before 2030, when onshore federal tax credits are lost.

- Award projects on a rolling basis without delay as evaluations are completed, and concurrently issue the next RFP to maintain procurement momentum.

- Publish a multi-year solicitation schedule that is explicitly synchronized with NYISO interconnection capacity releases. This approach would inform developers' decisions around NYISO Phase 2 security deposit timing when developers need to decide to put significant money at risk to secure their queue position and Coordinated Grid Planning Process and Public Policy Transmission Need milestones.

- The Commission should require greater transparency in interconnection cost methodologies, including publication of upgrade scopes, costs, and timelines by

Transmission Owners. The Commission should also establish enforceable deadlines for cluster study completion and upgrade delivery, ensuring that developers are not forced to make consequential bidding decisions — including significant financial commitments — without complete interconnection cost information. For background, delays in Transmission Owner upgrades are creating significant uncertainty for renewable and storage projects, with revised transmission in-service dates extending beyond developers' expected commercial operation timelines. For example, some NYSEG delays exceed five years. This misalignment is already affecting projects in advanced stages of development and limiting developers' ability to commit to procurement schedules. These delays increase curtailment and basis risk across impacted regions and can affect both new and existing projects until upgrades are completed, creating prolonged system constraints and undermining project economics.

- The Commission should direct NYSERDA to rebalance bid evaluation criteria to increase the weight of project viability relative to price from 70/30 to 60/40, as the Commission approved for the Storage Procurements. Moving toward a more balanced weighting between price and non-price factors will reduce attrition and ensure that awarded projects can achieve commercial operation.

Other Recommendations:

Remove Renewable Energy Projects from Outdated Public Service Law Requirements: Currently, Public Service Law sections 68, 69, and 70 include requirements regarding energy facilities which for renewable energy projects are unnecessary, duplicative of other permitting processes, and slow down renewable development without providing any additional public policy benefit. These are archaic traditional regulated utility provisions that do not have a substantive or beneficial role in the deregulated renewable energy sector and slow down renewable development as duplicative paperwork is reviewed and approved by

the Public Service Commission. In slowing down project development, project expenses are increased. We recommend that renewable energy generation be removed from Public Service Law sections 68, 69 and 70. This will lead to lower project expenses and in turn result in lower electric rates.

Expand the New York Power Authority's Ability to Address Transmission Bottlenecks: The lack of sufficient transmission capacity in New York limits the capacity for the interconnection of renewable energy projects and results in curtailment of renewable power. Absent investment in local and/or bulk transmission solutions, new renewable projects could experience deliverability and curtailment problems. This is a massive barrier to bringing lower cost power to ratepayers and to decarbonizing the state's grid. To remedy this, ACE NY advocates for directing NYPA to, within nine months, propose priority transmission projects to solve transmission problems in the most congested zones identified in the NYISO's 20 Year System Outlook. These proposals would be reviewed and approved or rejected by the Public Service Commission.

Award multiple upstate PPTNs through the CGPP Process: Through competitive solicitations, award multiple no-regrets PPTN projects upstate to unbottle new generation and load. The areas of congestion have been known for years, and no matter what specific location new generation or load is built in, these known areas of bottleneck need to be upgraded to allow for economic expansion.

Getting interconnection costs under control: Developers in the NYISO Transitional Cluster Study are facing unusually high and inconsistent interconnection cost estimates, largely driven by protection requirements, legacy infrastructure, and delays in transmission upgrades by Transmission Owners that shift costs onto individual projects. These estimates often include high contingencies and escalation factors, with limited transparency into assumptions or least-cost alternatives. Greater oversight and standardization of utility cost methodologies—including benchmarking and clearer documentation of assumptions and

alternatives—are needed. Utilities and regulators should also assess whether some upgrades belong in broader transmission planning rather than being assigned to individual projects. Without action, these costs risk making viable projects infeasible and undermining clean energy goals. Reducing interconnection costs will lead to lower project expenses and in turn result in lower electric rates.

Building Necessary Energy Infrastructure: We appreciate the steps the State has taken to improve the project siting process. ACE NY has filed comments over the past several years with recommendations regarding ways the siting process could be improved, including comments filed in 2025 in the RAPID Act docket.[19]

Reducing Interconnection Risk: The unpredictability of non-local SUFs and SDUs ("Network Upgrades" or "NUs") represents a major risk factor for NYSERDA procurement regardless of when in the NYISO Cluster process the procurement takes places. This is largely because NUs, unlike local upgrades, depend on the actions of other participants in the cluster study, and because NYISO requires 100% of interconnection costs to be put at risk prior to final cost allocation. If the procurement occurs prior to final NU allocation, bidders risk NU costs in excess of what a competitive bid price could support, leading to contract cancellation. If the procurement occurs after final NU allocation, bidders would

[19] Case 24-M-0433, In the Matter of the Rules and Regulations for the Environmental Review, Permitting, and Siting in this State of Major Renewable Energy Facilities and Major Electric Transmission Facilities Under the Renewable Action Through Project Interconnection and Deployment Act. (https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=24-m-0433);
ACE NY and IPPNY Dec. 8, 2025 Comments (https://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=374900&MatterSeq=73949);
NYOWA Dec. 8, 2025 Comments (https://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=374893&MatterSeq=73949);
ACE NY and IPPNY Apr. 18, 2025 Comments (https://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=359669&MatterSeq=73949);
NYOWA Apr. 18, 2025 Comments (https://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=359672&MatterSeq=73949)

have to put 100% of interconnection costs at risk without commercial certainty, driving attrition and reducing solicitation competition. Better aligning the NYISO interconnection studies with the NYSERDA procurements is also key to reducing the risk and financial burden on developers.

To address this risk, NYSERDA could implement a Network Upgrade Index that developers could opt into and would adjust the bid price based on the difference between the final NU allocation and a reference NU cost. Depending on the timing, the reference NU cost could either be based upon (a) the preliminary NYISO NU estimate or, if the NYISO estimate is unavailable, (b) a median NU estimate for each local capacity region produced by an independent power flow modeler.

APPENDIX A

Utility Owned Energy Storage and the Risk to Ratepayers

The risk to ratepayers of a utility owned energy storage model is illustrated by two recent Con Edison storage projects, the Fox Hills BESS project and the Brownsville BESS project. These projects ran over budget by significant percentages, resulting in an annual ratepayer impact of 3-4 times that of an equivalent BESS project owned by a private developer operating under the VDER framework. In addition, these examples also highlight how the lack of proper performance standards underpinning the traditional utility guaranteed rate of return model poses a risk to ratepayers in a utility-owned generation scenario.

Fox Hills is a 7.5 MW (30 MWh) BESS interconnected to Con Edison's radial network, which was intended to "facilitate DER interconnection and provide system support"[1] completed in 2023. The total cost of the project was $36.9 Mln ($4,916/kW / $1,226/kWh), which was 69% over budget resulting in an annual revenue requirement of $966/kW-yr (based on an annual carrying charge loader of 19.66%[2]. The annual ratepayer cost of $966/kW-yr represents roughly 3 times the equivalent cost of a BESS project operating under the VDER framework in 2025.

Fox Hills Battery Energy Storage System

Fox Hills BESS cost ratepayers nearly 3X more than a similar privately owned VDER project each year assuming Con Edison's BESS fleet cycles daily during the peak season as well as the NYCA peak hour.. Importantly, this project was offline for the 2024 operating season due to a flaw in the original design. Under those conditions, a private developer would not be paid.

Fox Hills Battery Energy Storage System		
Project Size	7,500 kW/ 30,000 kWh	
Original Budget	$22 Mln	
Cost Overruns	$14 Mln	
Fox Hills Energy Storage Incident	$868k	
Total Capital Cost	$36.9 Mln	+68%
Cost	$4,916/kW/ $1,229/kWh	
Carrying charge loader*	19.66%	
Annual ratepayer expense	$966/kW-yr	
Comparable VDER Project Annual Compensation		
DRV rate (2025)	$199/kW-yr	
Capacity Value (2025)	$138/kW-yr	
Total non-utility-owned compensation	$337/kW-yr	

Fox Hills Project Costs: Fox Hills was budgeted to end in 2022 but was delayed into 2023 due to pandemic related supply chain issues impacting battery delivery, increases in civil costs to relocate w/in property, regulation on ethylene glycol containment for battery, additional FDNY roadway, and increased construction/engineering costs.

Fox Hills Energy Storage Incident:
In December 2023, there was an incident that resulted in damage to the cables at the site due to the wrong size being incorporated into the design, requiring $700k of additional cables. As a result, the project was mostly offline in 2024.

Moreover, the full performance payment for a privately owned BESS hinges upon perfect Demand Reduction Value (DRV) and Capacity (ICAP) performance. While the Fox Hills BESS was completed in December 2023, it spent most of 2024 offline as the wrong cables were incorporated into the design, causing an incident that required cable replacement at a cost of $700,000[3]. **While the project was offline and unable to provide any grid benefits, ratepayers continued to bear the cost of the project.**

Similar trends were seen at the Brownsville BESS, as costs ran over the initial budget by 31% and the total associated revenue requirement was roughly 4 times what a privately owned BESS project operating under the VDER tariff would have earned in 2025. These examples highlight the risks of cost overruns, as well as the risk to ratepayers implicit in a guaranteed rate of return that is not tied to performance. Notably, the JU is currently not required to report on the performance of their BESS assets.

Brownsville Battery Energy Storage System

Brownsville BESS cost ratepayers nearly 4X more than a similar privately owned VDER project each year assuming Con Edison's BESS fleet cycles daily during the peak season as well as the NYCA peak hour. Con Edison's BESS fleet performance is not reported.

Brownsville Battery Energy Storage System		
Project Size	5.8 MW/ 23.2 MWh	
Original Budget	$30.3 Mln	
Cost Overruns	$9.3 Mln	+31%
Total Capital Cost	$39.6 Mln	
Total Cost / kW	$6,828/kW $1,707/kWh	
Carrying charge loader*	19.66%	
Annual ratepayer expense	$1,342/kW-yr	
Comparable VDER Project Annual Compensation		
DRV rate (2025)	$199/kW-yr	
Capacity rate (2025)	$138/kW-yr	
Total non-utility-owned compensation	$337/kW-yr	

The primary use cases for this system are load relief, peak shaving, and reliability. The system will be designed for N-2 contingency configuration, and under normal operation the system will be connected to four 4kV feeders in parallel, and the system will be able to support all of those feeders.

Renewable energy generation, particularly from residential PV arrays are posing a challenge for local substations as the peak generation does not overlap with the peak consumption. Placing energy storage at those substations, allows the Company to charge the systems during peak/over generation and then discharge during peak consumption

[1] ConEd 2024 T&D Spending Report (Case 22-E-0064)

[2] Estimated using the carrying charge loader for substations from Marginal Cost of Service Study (Case 15-E-0751) with an adjustment to depreciation. According to the Embedded Cost of Service Study, "*The Substation function represents the fixed costs associated with Land and Land Rights, Structures and Improvements, Station Equipment, and Storage and Battery Distribution Equipment*". *(Case 25-E-0072, Exhibit___(DAC-2)*,

Page 7 of 130). Depreciation modified from 50 years for substation to 15 years based on recommendations in Depreciation Study, (Case 25-E-0072, Exhibit DP-1, page 68). However, Con Edison's BQDM and REV demo projects are depreciated on a 10-year schedule. (Joint proposal, Annual Depreciation Rate and Life Table, page 231). A 10-year depreciation schedule would result in a carrying charge loader of 25.4%.

[3] *Con Edison Report on 2024 Second Quarter Capital Expenditures (pages 28-31) (Case 22-E 0064), Con Edison Report on 2024 Capital Expenditures and 2025 - 2029 Electric Capital Forecast, (Case 22-E-0064)*

APPENDIX B

RECOMMENDATION: Headroom Protection

Provide headroom protection for renewable energy projects that are operating, at an advanced stage of development (i.e., meets the NYISO inclusion rules per the NYISO Reliability Planning Process), and/or under contract to deliver energy for end use in New York State.

I. Congestion-Driven Curtailment and Basis Risk

NYSERDA can reasonably expect risks that are outside the control of bidders, such as transmission congestion risk, will cause bidders to raise their strike price bids. By limiting these risks for bidders, NYSERDA will be able to contract at lower REC prices for the 20-year tenor of the PPA, saving tens of millions of dollars per contract.

Transmission Congestion risk causes: **(1) curtailment of offered energy and (2) LBMP basis risk** (the risk that energy revenues will be significantly lower than the Reference Energy Price (REP) that NYSERDA will withhold from the Indexed REC payment as a proxy for realized energy revenues).

When a local renewable resource is partially curtailed, it sets the LBMP for itself and for its nearby competitors that are constrained by the same transmission facility limit. This local LBMP is usually a negative value, while the REP at the zone level is a positive value. Therefore, during times of high local energy production, when congestion occurs, <u>many MWh are paid a negative LBMP</u>. A small percentage of the MWh that were available would not be produced, and this "curtailment" facet of congestion seems to be well understood. However, the LBMP depression is more impactful on a resource than the curtailment is.

> A realistic example to illustrate this could involve two renewable resources, each producing 100 MWh in a single hour, when the first is curtailed 1 MWh (1%) and the other is not curtailed at all. The combined output (199 MWh) would be paid LBMP equal to the negative offer price of the curtailed resource, for example -$35/MWh. If

the REP for the settlement month were higher than $20, this example would show a net loss of at least $55 for each of 199 MWh, with 1 MWh not produced.

II. Solution for Headroom Protection – Congestion Cap Provision

As NYSERDA/ DPS rightly and repeatedly recognized through changes to the Tier 1 RFP requirements and evaluation criteria, mitigating congestion and curtailment risk is critically important to ensure the viability of existing and contracted project pipeline. Nonetheless, we believe that if this risk is not further mitigated, it would (a) erode the economics of existing Tier 1 projects by reducing their saleable output and increasing their congestion basis costs, (b) erode the economics of contracted Tier 1 projects by reducing their expected saleable output and increasing their congestion basis risk, undermining their financial viability and continued investment in their development, and (c) substantially increase strike prices in future procurements, ultimately increasing the ratepayer costs.

As the principal contracting entity in New York, NYSERDA should coordinate its awarding of REC contracts to projects in each constrained area to minimize the risk of energy curtailment and the severe LBMP depression that accompanies it. If NYSERDA accepts that some curtailment risk may be unavoidable in this process, NYSERDA should offer some protection against severe LBMP depression via a new congestion capping mechanism that would make the resource owner whole for extremes of lost revenue caused by factors that are outside its control. In other words, the resource owner would not be obligated to absorb this risk above a given threshold.

Although NYSERDA would occasionally make a payment to exceptionally affected facilities, overall savings would accrue to NYSERDA from paying a lower Bid Price for every delivered REC given the de-risking of the REC cash flow. The implementation of this mechanism would compare the nodal price at the facility Point of Interconnection (POI) and the REP. Any losses sustained by the project above the cap on basis would then be supplemented to the REC price every month. As basis and curtailment are usually inter-related the same concept should be applied to the deemed MWh from the project. If subject to major curtailment, i.e. grid curtailed energy above [10%] of the resource's potential, then

the generator would be compensated at the REC settlement price, with the rules regarding contract energy default notwithstanding.

Such mitigation mechanism can help achieve the state goals at lower costs for ratepayers and the state of NY as bidders would no longer include risk premiums in their bids, and would advance their development projects without concerns about excessive congestion risk. **Such a capping mechanism would also provide clear signals for avoiding further procurement and development of clean energy projects in areas where such congestion caps are met or forecast to be met.** NYSERDA, as quasi single buyer status will have higher control on the outcome of procurement decisions and locations of new generation relative to the available grid capacity. Furthermore, NYSERDA, via its coordination with state agencies and entities responsible for transmission planning (e.g. NYISO, DPS for the CGPP) can provide meaningful and actionable input for design and approval of transmission expansion projects that provide more headroom for future resources with minimum congestion risk.

RECOMMENDATION: Shape Risk

Update the formula for Monthly REC Price for facilities selected under an Index REC Price proposal to consider a Reference Energy Price based on a generation-weighted energy profile, rather than the around-the-clock simple average energy price, to alleviate bid price increases resulting from shape risk.

Shape risk describes the fact that contracted renewable resources produce electrical energy when the wind or solar energy is present, at zero marginal cost, and not at a constant rate around the clock as implied by the Reference Energy Price ("REP") being a time-average of prices. Hence, their energy production earns revenues that depart from the REP. (Example: Solar PV projects are not exposed to night-time LBMPs.) When formulating their Index REC Strike Prices, developers are left to predict and price in the difference between the energy revenue actually calculated by the facility based on its variable output, and the around the clock REP, over the entire term of the Index REC contract.

Most developers anticipate that at some point during the term of their Tier 1 contract the REP will exceed the energy revenue realized by the facility. This is because as renewable penetration grows and more resources deliver MWh at a zero marginal cost, lower prices than the time-average will result during hours of high renewables penetration. The solar and wind production-weighted average price is thus expected to be lower than the REP and therefore developers increase their offered strike prices to compensate. Uncertainty in the relationship between the REP and production-weighted price will likely increase the strike price further in bids as shape risk can be driven by rising REPs or falling production-weighted prices and a view must be taken on each. Further, when faced with the task of predicting these changes decades into the future, developers may include additional risk premium to capture the uncertainty of this revenue.

1. **Recommendation for changes to incorporate technology-specific generation profiles**

ACE NY proposes the following solar profile be used to calculate the REP, replacing the around-the-clock simple average shape.

Solar: All solar facilities generate power in a generally, predictable output shape. This output shape, which can be represented as a bell curve over the daylight hours of a given day, is based on solar resource availability. Accordingly, a solar facility output profile is not weighted equally across off-peak and on-peak hours but rather weighted towards on-peak hours (as defined in the NYISO tariff today). The NYSERDA REP in the Index REC calculation, however, is based on a simple average of off-peak and on-peak energy prices. Thus, the REP poorly matches the actual energy price that the solar facility receives. In order to improve the REP, we recommend incorporating a generic 12 x 24 solar generation shape into the calculation. This will enable the REP to better match a facility's actual energy pricing and result in the facility bidding a more accurate and lower strike price, as it does not have to incorporate the pricing risk between the REP and the actual price it receives.

Wind: Our internal conversations among ACE NY members demonstrated that it is challenging to decide on a wind specific shape, and therefore we decide to leave wind out of any shape proposal and continue with the current status quo settlement calculation. Unlike solar, wind does not have a predictable shape to its output over the course of a day. While altering the shape away from an equal weighting across 24 hours of a day will reduce shape risk on some days, it will increase it in others, and is thus unlikely to result in a meaningful reduction in overall shape risk. At this time, ACE NY recommends maintaining the equal weighting across 24 hours of the day, while reserving the right to advance alternate methods of addressing shape risk for wind, were they to emerge in the future.

2. Benefits of this change for NYSERDA and NY ratepayers

ACE NY recognizes that in some instances, the changes proposed herein may increase the Monthly REC price paid by NYSERDA to developers under the Index REC contracts. As the value of the REP decreases to reflect the actual generation-weighted energy revenue, it thereby increases the difference between the strike price bid by generators and the sum of the REP and calculated capacity revenue. However, ACE NY anticipates that this change will, all else being equal, reduce the strike prices bid by developers, as most include a risk premium on their calculation of shape risk or further discount their expectation of energy revenues, to accommodate the uncertainty of forecasting this risk over a twenty-year contract period. By contrast, NYSERDA would only be responsible for making developers whole for the shape risk that actually occurs, without any additional risk premium considered.