

NEW YORK STATE
PUBLIC SERVICE COMMISSION

Case 15-E-0302 – Proceeding on Motion of the
Commission to Implement a Large-Scale Renewable
Program and 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 INDEPENDENT
POWER PRODUCERS OF NEW YORK, INC.

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Pursuant to the New York State Public Service Commission’s (“Commission”) January 27, 2025, Notice Soliciting Comments¹ (“Notice”) and Notice Extending Deadline,² Independent Power Producers of New York, Inc. (“IPPNY”) hereby submits its comments on the questions raised by the Commission in its Notice. In its Notice, the Commission seeks additional comments “to more fully comprehend issues regarding utility ownership of renewable generation.”³ These issues include: (1) potential ratepayer impacts; (2) impacts/advantages or disadvantages of utility renewable generation siting; (3) Standardized Interconnection Requirements queue placement/management; (4) solicitation competitiveness; (5) potential regulatory impacts of utility ownership of renewable generation; and (6) the alignment of wholesale energy and capacity markets with State policy clean energy procurement goals and the Commission’s role with respect to maintaining resource adequacy.⁴

¹ Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Notice Soliciting Comments (Jan. 27, 2026) (“Notice”).

² Case 15-E-0302, *supra*, Notice Extending Deadline (Feb. 5, 2026); Case 15-E-0302, *supra*, Notice Further Extending Deadline (Mar. 26, 2026).

³ Notice at 1.

⁴ *Id.*

I. BACKGROUND

On May 15, 2025, the Commission issued its Order Adopting Clean Energy Standard Biennial Review as Final and Making Other Findings in the above-captioned proceeding which, among other things, adopted several proposed modifications to the State’s Clean Energy Standard (“CES”) to reflect current market conditions and maintain progress on building renewable generation to achieve the Climate Leadership and Community Protection Act’s (“CLCPA”) target of having 70 percent of electricity generated by renewable energy systems by 2030 (“70 by 30 target”) and having the electricity sector be zero-emissions by 2040 (“100 by 40 target”).⁵ Acknowledging the “sound rationales behind the establishment of the policy disfavoring utility-owned generation [(“UOG”)] that has been in place since the 1990s,” the Commission nevertheless noted that “a lot has changed in the energy market since deregulation” and that there is value in exploring the option further as another avenue towards achieving the CLCPA goals.⁶

In response to the Commission’s July 30, 2025 Notice Soliciting Comments,⁷ IPPNY and several other stakeholders forming the Affordable Clean Power Alliance (“ACPA”) submitted responses to a series of questions regarding whether the Commission should change its policy disfavoring UOG.⁸ ACPA’s comments demonstrated in detail the adverse impacts UOG would force captive-utility ratepayers to bear, the unequal playing field it would create for private independent power producers (“IPPs”) that have constructed, own and continue to operate almost

⁵ Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program*, Order Adopting Clean Energy Standard Biennial Review as Final and Making Other Findings (May 15, 2025) (“Biennial Review Order”).

⁶ *Id.* at 63, 65.

⁷ Case 15-E-0302, *supra*, Notice Soliciting Comments (Jul. 30, 2025) (“July 30 Notice”).

⁸ Biennial Review Order at 65–66.

all of the generation in the State since the inception of the competitive markets in New York 25 years ago, and how UOG would be counter-productive to achieving the State's clean energy goals affordably.⁹ Those very same considerations remain determinative today.

The member companies of IPPNY, a not-for-profit trade association representing the independent power industry in New York State, have invested billions of dollars in New York's competitive electric generation system to meet the electric needs of New York consumers and ensure electric system reliability since the inception of the wholesale competitive market. IPPNY member companies continue to be actively involved in the development and ongoing maintenance of electric generating facilities, including renewable resources, the generation, sale, and marketing of electric power, the development of natural gas facilities, and the development of energy storage facilities in the State of New York. IPPNY member companies produce a majority of New York's electricity, utilizing almost every generation technology available today, such as wind, solar, natural gas, oil, run-of-river hydro, biomass, energy storage, and nuclear.¹⁰

IPPNY's members have substantially contributed to the significant reductions in New York's emissions levels achieved to date and are developing and operating renewable and energy storage resources as well as maintaining the conventional dispatchable facilities that continue to prove essential to safeguard system reliability. IPPNY's fundamental interest remains rooted in the continued development and enhancement of reliable, efficient, and non-discriminatory integrated regional wholesale competitive electricity markets. To date, the Commission has implemented its public policy initiatives in a manner that generally has been consistent with competitive markets while requiring IPPs, not utilities (and, by definition, New York consumers),

⁹ Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program*, ACPA Comments (Oct. 28, 2025) ("ACPA Comments").

¹⁰ IPPNY's comments do not necessarily reflect the views of individual members of IPPNY.

to bear the risk of developing and operating generation, consistent with the Commission's long-standing policy to rely on competitive markets to provide reliable electric service at lowest cost.¹¹ With respect to the Commission's questions regarding resource adequacy, IPPNY's interest continues to lie mainly in ensuring that any Commission policies developed in this proceeding do not increase market uncertainty and risk and are consistent with, and do not undermine in any respect, the functioning of non-discriminatory, competitive wholesale electricity markets in New York and its surrounding regions. Safeguarding the proper functioning of these markets is fundamental to ensuring market stability and encouraging continued investment.

As IPPNY continues to demonstrate in the responses to the questions below in furtherance of the ACPA Comments, the Commission must continue its long-standing policy prohibiting UOG supported by an order strongly reaffirming its policy in this proceeding. Allowing UOG will increase risks and costs to captive ratepayers, reduce competition and commensurately raise the costs of achieving State policy goals, and will not bring more renewable resources online any faster than through the competitive auctions for RECs held by the New York State Development and Research Authority ("NYSERDA") for IPPs.

No changes to the New York Independent System Operator, Inc.'s ("NYISO") market design or market power mitigation rules can adequately mitigate the fact that the utilities alone are uniquely poised to exercise vertical market power ("VMP") should the Commission allow UOG in any form going forward. The NYISO's installed capacity market has generally

¹¹ See Cases 15-E-0302 et al., *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Order Adopting A Clean Energy Standard (Aug. 1, 2016), at 102 (determining that the mandated procurement of renewable energy credits ("RECs") "is a continuation of the Commission's policy of relying on markets where feasible, as the best long-run approach to reducing costs and promoting innovation").

functioned well to maintain resource adequacy since the inception of the competitive wholesale markets. While the capacity market structure requires enhancements to address transmission security and other issues materializing as the system composition continues to evolve and the current price signals are not able to incent needed investment due to the NYISO's selection of a 2-hour battery storage facility as the proxy unit to set the capacity demand curves, the NYISO is proactively working with stakeholders on developing these needed market design enhancements. It is important to emphasize that the Commission should exercise restraint and refrain from intervening or attempting to change how resource adequacy is maintained in New York and, in any event, the Federal Power Act preempts the Commission from unilaterally changing the way resource adequacy needs are met under the NYISO's tariffs.

Moreover, in light of the confluence of factors the NYISO has identified as driving the system to an inflection point, it is critical to put issues like these that engender uncertainty and unnecessarily increase merchant risk fully and finally to rest. The Commission should instead provide its input in NYISO's stakeholder meetings to develop and implement market design changes that harmonize the State's public policy initiatives with competitive markets, *e.g.*, taking steps to demonstrate its support for the NYISO's comprehensive market design and associated tariff amendments that would internalize the value of greenhouse gas emission reductions in wholesale energy prices (the "carbon adder"). By supporting and approving such proposals, the Commission can help ensure that the market continues to evolve in a way that meets the State's ambitious climate and energy targets without sacrificing reliability or competition.

II. RESPONSES TO UOG QUESTIONS

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 [“NYSEG”] and Rochester Gas and Electric Corporation [“RG&E”] (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.

For over 25 years, IPPs have responded to price signals in the competitive market to build more efficient generation facilities and improve the operations and capacity factors of the existing fleet, thereby delivering significant benefits to consumers through lower electricity costs, emission reductions, and economic growth, while protecting ratepayers from the risks of developing and operating generation.¹² All options referenced in the question—build transfer, develop transfer, milestone-based transfer and self-build—would not fully insulate ratepayers from project risk like IPP developed projects have. By shifting investment risk from IPPs to consumers, the State risks eroding the significant benefits formerly realized by New Yorkers through the restructuring of the electric industry. The cost savings, risk mitigation, and market efficiencies that have been hallmarks of this approach would be reduced significantly, if not erased entirely.

Prior to restructuring the electric industry in New York and the establishment of the NYISO, utilities had little incentive to operate their generation assets effectively and at the lowest cost, which in turn lead to New Yorkers facing the second highest electricity costs in the nation.¹³ Under the cost-of-service rate recovery model, electric rates were based on the average cost of producing electricity and utilities were guaranteed recovery of all expenses incurred in

¹² See Case 15-E-0302, *supra*, Competitive Power Benefits for New Yorkers (Mar. 26, 2025) (“FTI Report”).

¹³ *Id.* at 11 (citing *Electric Sales and Revenue 1994*, Energy Information Administration (Nov. 1995), at 23, https://www.eia.gov/electricity/sales_revenue_price/archive/054094.pdf).

the construction and operation of assets, plus a reasonable rate of return. With complete cost recovery from ratepayers guaranteed, utilities had little incentive to efficiently operate their generation assets at the lowest cost as ratepayers would bear the risk of all cost overruns and operating inefficiencies. Ratepayers have suffered the consequences of UOG project cost overruns. For example, after obtaining approvals to construct two additional nuclear reactors at the Vogtle Plant in 2009,¹⁴ Georgia Power and Westinghouse Electric oversaw the construction of the costliest power plant ever.¹⁵ The plant owner's initial pledge that the units would begin commercial operation in 2016 at a cost of \$14 billion evaporated quickly and the units ultimately commenced operation in 2023 and 2024 at a cost of nearly \$35 billion.¹⁶ The project contributed to Westinghouse Electric's bankruptcy and residential rates for Georgia ratepayers were increased by 10% to pay for the cost overruns.¹⁷ Conversely, studies have shown that plant efficiency improved by 5% when competitive ownership is introduced, which reflects "the pressures that drive operational improvements in the open market."¹⁸

To address high electricity costs and eliminate concerns related to the exercise of VMP, the Commission ruled that the ownership of generation assets should be separated from transmission and distribution assets and that a wholesale competitive electricity market be

¹⁴ The Vogtle Plant is jointly owned by four distribution utilities: Georgia Power (45.7%), Oglethorpe Power (30%), Municipal Electric Authority of Georgia (22.7%) and Dalton Utilities (1.6%). See *Vogle Plant Brochure*, Southern Nuclear (last visited Mar. 25, 2026), https://www.southernnuclear.com/content/dam/southern-nuclear/pdfs/our-plants-/plant-vogtle/Vogtle_Plant_Brochure.pdf.

¹⁵ See Paul Hockenos, *Anatomy of a mess: the cautionary tale of the US's last mega nuclear reactor*, Energy Transition (Feb. 15 2024), <https://energytransition.org/2024/02/anatomy-of-a-mess-the-cautionary-tale-of-the-uss-last-mega-nuclear-reactor/>.

¹⁶ *Id.*

¹⁷ FTI Report at 27.

¹⁸ FTI Report at 29 (citing Lucas Davis & Catherine Wolfram, *Deregulation, Consolidation, and Efficiency: Evidence from U.S. Nuclear Power* National Bureau of Economic Research, National Bureau of Economic Research (Aug. 2011), https://www.nber.org/system/files/working_papers/w17341/w17341.pdf.)

developed.¹⁹ The Commission found that competition “should result in lower bills as competitors have a greater incentive to lower costs than do utilities under a regulatory regime.”²⁰

Under the resulting competitive market structure administered by the NYISO, IPPs compete in wholesale markets creating an environment where competition drives innovation and cost-efficiency, which leads to lower prices and reduced power supply costs for electricity consumers. IPPs in these markets shield ratepayers because they bear the risk of cost overruns and uneconomic investments. Market pricing for generation is no longer based on utilities’ average cost over long periods of time but rather the marginal cost—the system-level cost of generating an additional unit of energy in any given hour. This shift ensures that prices are closely aligned with real-time market conditions, which promotes greater efficiency throughout the system and encourages generators to operate responsively, responsibly and cost-effectively.

The benefits of the competitive market in New York were realized soon after its introduction. In 2009, the NYISO found that the fuel-adjusted wholesale electricity costs decreased by 11% between January 2000 and August 2008.²¹ Those benefits have continued to grow over time. Comparing the five years preceding restructuring to the years 2019-2023, the FTI Report, filed with the Commission in Case 15-E-0302 on March 26, 2025, found that the competitive market reduced power supply costs in New York by over 35%.²² Moreover, the FTI Report concluded that these cost savings abound in States that have embraced competitive markets, finding that between 1996 and 2002 the average retail rates in states with restructured

¹⁹ See 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) (“Deregulation Order”).

²⁰ *Id.* at 30.

²¹ *Power Trends 2009*, NYISO (Oct. 4, 2009), at 9, <https://www.nyiso.com/documents/20142/2223154/2009-Power-Trends.pdf/fa52a83b-a290-37f3-3ef2-04a29f35f6df>.

²² FTI Report at 12.

electricity markets declined by 13.3%, compared to a 2.9% increase for states with a vertically integrated market.²³

The data also shows that competitive markets champion environmental stewardship. Since 2000, the FTI Report found that emissions rates in states that generate a majority of their power from competitive markets have declined faster than states in which the majority comes from utility-owned plants.²⁴ Competitive markets are therefore not only best suited to address both environmental concerns and cost savings, but, moreover, they also continue to ensure resource adequacy. For the past 25 years, competitive markets have provided the foundation for grid reliability, resulting in approximately 14 GW of generation capacity being put in-service since 2001, 87% of which was developed and constructed by IPPs.²⁵ IPP investment interest continues despite significant cost increases, supply interruptions and strong political headwinds at the federal level as evidenced by the fact that, as of February 3, 2026, 92 projects totaling approximately 15,600 MW of renewable and storage projects have elected to advance to Phase II of the NYISO's Interconnection Transition Cluster Study process, which is set to conclude by the end of this year.²⁶ The NYISO anticipates that "for the foreseeable future there will continue to be an increased number of required interconnection and related agreements, and amendments to these agreements, as significant numbers of new generation seek to interconnect in New York."²⁷

²³ *Id.*

²⁴ *Id.* at 30.

²⁵ *Id.* at 32.

²⁶ See *Public Dashboard for Transition Cluster*, NYISO (Feb. 3, 2026), https://www.nyiso.com/documents/20142/56802634/08_01%2029%202026%20-%20Interconnection%20Cluster%20Study_%20Projects%20Dashboard%202026%20R2.pdf/e051da98-8a97-0696-a819-ca373eebdb38; *Interconnection Agreement Enhancements For Consideration*, NYISO (Feb. 26, 2026) ("NYISO IA Enhancements"), at 7, https://www.nyiso.com/documents/20142/57254820/05a_Presentation%20Re%20IA%20Reforms%2020260226%20TPAS%20-%20354865578-v1.pdf/bedb9ccc-d575-0bb5-b049-ad7bcea71e02.

²⁷ NYISO IA Enhancements at 8.

While enhancements to the capacity market structure are required to continue to advance competitive markets in New York, the core structure remains fundamentally sound.

The Commission itself has repeatedly confirmed the benefits of competitive markets in numerous proceedings. From the outset, the Commission determined in its order adopting its VMP Policy that competitors would have a greater incentive to lower costs than utilities under a cost-of-service regulatory regime, which would inure to the benefit of New York’s consumers.²⁸ The Commission also recognized that the most efficient means of selecting new resources is via the competitive market.²⁹ Further, the Commission found that one of the primary benefits of competitive markets is that investment risks shift from captive utility ratepayers to private investors.³⁰ The Commission’s decision 30 years ago to restructure New York’s energy markets from vertically integrated monopolies to a competitive wholesale and retail market structure was based on the fundamental tenet that competition brings forth efficiencies, technical advancements, savings, and other benefits, which are unlikely to occur as effectively, if at all, absent the motivation provided by such markets.³¹

Twenty years later, the Commission reaffirmed its commitment to competitive markets in its 2016 order implementing the CES Program as it did with respect to distributed energy resources (“DERs”) in its REV Track One Order, stating that it is continuing its policy of “relying markets where feasible, as the best long-run approach to reducing costs and promoting innovation.”³² The Commission rejected the utilities’ attempts then to support their ownership of

²⁸ Deregulation Order at 30.

²⁹ *Id.* at 31–32.

³⁰ *Id.* at 31.

³¹ *Id.* at 26.

³² Case 15-E-0302, *supra*, Order Adopting a Clean Energy Standard (Aug. 1, 2016) at 102 (“CES Order”) at 102.

renewable generation, agreeing with IPPNY’s comments and Staff’s recommendation that “utility owned generation . . . has the potential to inhibit entry by other market participants, which can result in less competition and higher costs in the long-run.”³³ More recently, the Commission, in 2023, reaffirmed its policy that competition controls the costs of supporting renewable energy generation in its rejection of two petitions by renewable generation developers to modify their REC contracts with NYSERDA. In rejecting petitions requesting that REC and offshore REC contracts be modified, the Commission ruled that the petitions “do not support departing from the Commission’s years-long commitment to competitive procurements as the appropriate mechanism for soliciting RECs and ORECs.”³⁴

The Commission has consistently emphasized that the cornerstone of restructuring involved utilities’ divestiture of generation assets, and the Commission continues to maintain a rebuttable presumption that UOG carries a grave risk of anticompetitive behavior, with consumers potentially bearing the excessive costs.³⁵ While the original determination was reached over 25 years ago, the economic principles and the underlying factors supporting these steps have remained just as compelling today. The Commission’s embrace and commitment to fostering competitive markets has greatly benefited ratepayers while leveling the playing field for generators, since its inception.

In stark contrast to the benefits of the current structure, New Yorkers would become subject to all project risks and associated cost overruns, including permitting, construction,

³³ *Id.* at 100.

³⁴ Case 15-E-0302, *supra*, Order Denying Petitions Seeking to Amend Contracts with Renewable Energy Projects (Oct. 12, 2023), at 40.

³⁵ See 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”).

operational and cancellation risks, under NYSEG’s and RG&E’s proposed self-build model. In this model, the utility would develop the project without any competitive pressure to minimize development and operating costs that ensures the lowest possible costs to ratepayers in NYSERDA’s competitive solicitations for RECs. Further compounding this problem, a self-build model would also disrupt existing competitive markets—not be complementary to them as NYSEG and RG&E claim.³⁶ The Commission correctly stated in its REV Track One Order, “[m]arkets thrive best where there is both the perception and the reality of a level playing field, and that is best accomplished by restricting the ability of utilities to participate.”³⁷ Allowing UOG creates not only the perception of an unlevel playing field but the reality of it, too.

The main difference between the build transfer, develop transfer, and milestone-based transfer options is the timing of project transfer and payment: procurement of fully constructed facilities, procurement of fully developed unbuilt facilities, or purchase of a project in stages.³⁸ They all impose more risk on ratepayers than projects entirely developed by IPPs. While these models may impose less risk on ratepayers relative to a self-build option, varying levels of project risk are still needlessly shifted to ratepayers. The proponents of these various models fail to rebut the fact that the harms resulting from this shift in risk from IPPs to captive ratepayers are outweighed by any potential benefits.

Under its proposed build transfer option, BMR Energy LLC (“BMR Energy”) states that developers would assume the risk of developing and constructing projects and any costs incurred by the developer through construction, plus an “appropriate profit, will be transferred to the

³⁶ Case 15-E-0302, *supra*, NYSEG-RGE UOG Comments (Oct. 31, 2025), at 2.

³⁷ Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Regulatory Policy Framework and Implementation Plan (Feb. 26, 2025), at 67.

³⁸ *See* Case 15-E-0302, *supra*, BMR Energy LLC Comments (Oct. 29, 2025), at 2.

utility.”³⁹ Like NYSEG’s and RG&E’s self-build option, however, captive ratepayers would ultimately be on the hook for all project cost overruns. The developer would not be subject to any competitive pressure to lower costs as much as possible. So long as the project is completed, the utility would be required to purchase the project at any price. Indeed, this model would perversely incent a developer to continue project construction even if it incurs cost overruns that would otherwise render a project developed on a merchant basis uneconomic. Moreover, it logically follows that developers would only offer higher cost projects to utilities while reserving their lower cost projects for their own benefit. Thus, the pool of projects offered to utilities for transfer would likely have higher costs and lower profits to the detriment of captive ratepayers. Notably, BMR Energy admits that the build transfer option “will result in the highest capital cost and as a result the highest energy cost of the options.”⁴⁰ Accordingly, ratepayers would be worse off thereunder than if the developer contracted with NYSERDA for RECs.

The Indicated Utilities’ proposed Build Transfer Agreement (“BTA”) option is different from BMR Energy’s build transfer option.⁴¹ According to the Indicated Utilities, the utilities would conduct statewide joint competitive solicitations to procure BTAs from developers under which participating utilities would purchase renewable generation projects upon successful completion at set prices.⁴² In addition to claiming that this option shields ratepayers from construction risk, the Indicated Utilities also claim that ratepayer risks would be reduced by contractual tools (*e.g.*, claw-backs, performance bonds, termination related liquidated damages,

³⁹ *Id.*

⁴⁰ *Id.*

⁴¹ See Case 15-E-0302, *supra*, Indicated Utilities’ Initial Comments on Commission Questions Regarding Utility Ownership of Renewable Generation and the Comprehensive Review of Renewable Solicitation Practices (Oct. 31, 2025) (“IU UOG Comments”).

⁴² *Id.* at 4.

etc.), and price transparency.⁴³ However, these measures merely reduce ratepayer risks as ratepayers remain exposed to operating risks once the projects are developed—risks which they would not bear at all under the existing IPP ownership model. Moreover, if private developers are barred from recovering construction cost overruns, the private developer’s bid in response to the competitive solicitation will include a higher risk premium to cover potential construction risks, the same risk premium the developer would have included in its bid in response to NYSERDA’s competitive solicitation for RECs. If the risk premium is not sufficient to cover the risk, the project may not go forward regardless of whether it has a REC contract with NYSERDA or a BTA with utilities.

The develop transfer option raises the same issues but additionally shifts construction risks to ratepayers. The milestone transfer option may provide some additional ratepayer risk protection compared to the other options, but ratepayers are at risk for milestone payments when subsequent milestones cannot be achieved and operating cost risks if the project is completed.

Ratepayers paying for these projects would also be adversely affected by reduced competition by IPPs. A utility solicitation for these transfer model contracts would be limited to developers that choose to transfer their projects and not operate them. Renewable development companies that are in the business of owning and operating projects would not participate. In contrast, the NYSERDA REC solicitation attracts a broader field of developers producing more effective competition and concomitantly resulting in lower prices.

⁴³ *Id.* at 17–19.

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.

Utilities do not have any advantages over IPPs in siting renewable generation as UOG face the same timeline in seeking permits, in negotiating with landowners and local governments, proceeding through the interconnection process, and in acquiring equipment and labor. With respect to procurement, the FTI Report found that UOG would provide no relief from procurement pressures faced by IPPs because the cost pressures “affect all types of developers and would also drive up utilities’ costs if they were permitted to build largescale renewables.”⁴⁴

With respect to permitting, utilities are not exempt from Public Service Law Article VIII or federal or State environmental regulations and must engage in real property negotiations with landowners and satisfy local municipal requirements. Indeed, because utilities have been out of the business of generation development and ownership for decades, they are at a significant disadvantage in siting compared to IPPs. Given the lack of in-house experience, utilities likely do not have the necessary personnel to site projects and will have to hire them at ratepayer expense. Such expenses will accrue regardless of whether the utility develops any projects to completion. Once hired, it will take years to reconstitute the required knowledge base within these companies, aided by outside consultants or not. Conversely, ratepayers pay nothing for IPP development costs if a project is not built and are not otherwise on the hook to ensure IPPs recover their costs.

⁴⁴ FTI Report at 5, 18.

Moreover, the utilities face a disadvantage compared to IPPs because the utilities must obtain Commission approval for their staffing levels through rate cases which would have to be expanded to develop generation through rate cases. Incremental FTEs requested by utilities are often a contentious issue in rate cases and have recently taken on an even greater importance as the State and utilities make efforts to improve utility affordability. For example, the Joint Proposal approved by the Commission in Con Edison's recent rate case included 981 incremental FTEs reflecting a 66% reduction of the 2,889 FTEs originally requested.⁴⁵ The Commission noted the ultimate number of incremental FTEs that was permitted was consistent with positions taken by other parties in their pre-filed testimony "which stressed affordability concerns and proposed that the minimum levels necessary to maintain safe and reliable service be permitted."⁴⁶ The authorization of UOG requiring incremental FTEs where such FTEs and associated costs are currently borne by IPPs is counterproductive to affordability improvement efforts.

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.

If utilities are allowed to own generation, they will have an advantage over IPPs because they would have an incentive to increase hosting capacity, at ratepayer expense, near property they already own near their interconnection infrastructure on which they can site renewable and storage projects. IPPs do not own transmission and distribution facilities and would be unlikely

⁴⁵ Cases 25-E-0072 et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Order Adopting Terms of a Joint Proposal and Establishing Electric and Gas Rate Plans (Jan. 22, 2026), at 76–77.

⁴⁶ *Id.* at 77.

to own property near interconnection assets. As the cost of interconnection generally decreases the closer a project is to interconnection assets, utilities with property near their interconnection facilities would have an unfair cost advantage over IPPs that will have to buy or lease property that may be further from the interconnection facilities than the utilities' property. Private developers that do not own property near interconnection assets will face higher interconnection costs which may make their projects uneconomic. IPPs may face longer interconnection timelines as utilities would be incentivized to prioritize development and construction of interconnection facilities serving their own projects at the expense of competing IPPs.

If UOG is permitted, earnings adjustment mechanisms ("EAMs") that provide higher earnings for interconnection of projects would further incentivize utilities to prioritize their own projects to the detriment of IPPs and ultimately the detriment of consumers. For example, NYSEG's shareholders were able to earn between \$6.0 to \$7.4 million additional revenues annually from ratepayers in its three year rate plan approved in 2023 if NYSEG achieves the maximum MW targets for solar and storage project interconnections under the Solar DER Utilization MW and Storage DER Utilization MW EAMs.⁴⁷ If the Commission permitted UOG and expanded the scope of this mechanism to incorporate them, the utility would have a perverse incentive to interconnect its own storage projects to achieve the EAM targets instead of improving the interconnection process for others.

⁴⁷ Case 22-E-0317, et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service.*, Order Adopting Joint Proposal, Att.1, App'x X at 2.

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?

It is impossible to monitor every interaction between a utility and its development arm and private developer. Utilities could favor their own projects by assigning more resources to perform studies, expedite their own studies while delaying those of their competitors, complete design engineering, and build interconnection facilities for their own projects versus what the utilities assign to private developers. Delay tactics can materially affect project development but are likely nearly impossible to detect or monitor effectively. It would be impossible for DPS Staff to know which projects may be in a better position to build more quickly as so many variables impact a developer's ability and time to build.

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?

Utilities could not ensure build transfer solicitations are as competitive as NYSERDA REC solicitations. A utility solicitation for a build-transfer model contract would be limited to developers that engage in this build-transfer business model. Renewable development companies that are in the business of developing, owning and operating projects would not participate in the utilities' solicitation. This narrowing of the participant pool means that utility solicitations are generally less competitive, as there are fewer bidders and less diversity among the types of projects and entities involved. In contrast, the NYSERDA REC solicitations are structured to attract a broader spectrum of developers. By appealing to a wide range of market participants, NYSERDA creates a more dynamic and competitive environment, which encourages greater innovation and ultimately helps to drive project costs lower. This broader

participation ensures that the marketplace remains competitive, resulting in better outcomes for all stakeholders, including consumers.

NYSERDA's solicitations have attracted meaningful developer interest even in a challenging market environment, demonstrating that the competitive framework remains intact. The Commission should focus on removing structural barriers that have prevented viable, shovel-ready projects from successfully completing their contracts.

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?

The primary barrier to project completion is unanticipated costs that make a proposed project uneconomic. There are no safeguards that can be put in place that would both ensure project completion and eliminate risk to ratepayers in a milestone payments model. As discussed in the CES Biennial Review Order, unanticipated costs can arise from inflation, supply chain pressures, interconnection complications, or permitting delays.⁴⁸ If the Commission decides that projects should be completed at any cost, the milestone payments model will not protect ratepayers from risk because they will be required to bear unanticipated costs to ensure project completion. Ratepayers would bear the same risk as with the utility self-build model. NYSERDA's REC solicitations incorporate several mechanisms targeted to reduce the attrition of contracted projects. For example, the solicitations contain a minimum maturity threshold to ensure projects are advanced enough to have a high likelihood of reaching commercial

⁴⁸ See Biennial Review Order at 8.

operation.⁴⁹ The solicitations also have formulaic strike price adjustments specific to inflation that may occur between the time of an award and the time the project enters commercial operation.

Moreover, the Commission has continued to identify cost as the primary factor to determine project selection. The Commission has rejected several proposals that would reduce project attrition due to affordability concerns. For example, the Commission declined to adopt a broader strike price adjustment for unknown events because “the approach lacks the certainty to adequately ensure costs remain reasonable.”⁵⁰ The Commission’s rationale applies equally to a milestone based model. NYSERDA's competitive solicitation framework has proven to be the right foundation, and IPPNY encourages the Commission to continue directing NYSERDA to refine and strengthen that framework to reduce project attrition so that the competitive process continues to deliver the affordable clean energy outcomes ratepayers depend on.

In addition, there is no way to eliminate the risk of lost milestone payments in this model. If a project fails to get built, ratepayers will have already incurred the milestone payments already made and yet will have no project to show for them. Conversely, if the developer must return milestone payments if its project is cancelled, the developer will include a risk premium into its bid to the utility, which will be passed on to ratepayers.

⁴⁹ Biennial Order at 37.

⁵⁰ Biennial Order at 43.

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.

No criteria can prevent the utility from exercising VMP and in turn optimizing utility revenues. Since the inception of the competitive markets in New York, the Commission has recognized this fundamental fact and applied its policy to prevent utilities from exercising VMP, which has prohibited the State’s utilities from owning generation in New York unless the utility demonstrated specific facts and circumstances rebutting the presumption that ownership of generation by an IOU would unacceptably exacerbate the potential for vertical market power.⁵¹

In its seminal opinion issued in 1996 which introduced competitive markets in New York State, the Commission determined that competitors would have a greater incentive to lower costs than utilities under a cost-of-service regulatory regime, which would inure to the benefit of New York’s consumers.⁵² The Commission also recognized in Opinion 96-12 that the most efficient means of selecting new resources is via the competitive market.⁵³ Further, the Commission found that one of the primary benefits of competitive markets is that investment risks shift from captive utility ratepayers to private investors. In 1998, the Commission’s VMP Policy Statement addressed the problem with potential vertical market power:

Vertical market power occurs when an entity that has market power in one stage of the production process leverages that power to gain advantage in a different stage of the production process. A utility with an affiliate owning generation may, in certain circumstances,

⁵¹ See VMP Order.

⁵² Deregulation Order at 30.

⁵³ *Id.* at 31–32.

be able to adversely influence prices in that generator's market to the advantage of the combined operation.⁵⁴

The Commission reiterated the concern in its VMP Policy Statement that, as monopolies, the utilities were uniquely situated to directly influence market conditions.⁵⁵ Likewise, the Commission highlighted the fact that the utilities alone would possess system information about, *e.g.*, potential upgrades in their service territories, that they could obfuscate thereby allowing them alone to forego action that would benefit consumers in order to benefit their own generation interests, and thus, their shareholders.⁵⁶ The Commission determined that the utilities' 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).⁵⁷ Moreover, the Commission found that divestiture was preferable to relying on regulatory controls and enforcement mechanisms because these mechanisms were incapable of timely identifying and remedying the potential for utility abuse. The Commission thus established a rebuttable presumption that separating these functions was necessary.⁵⁸ As stated in the first paragraph of the VMP Policy:

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.⁵⁹

⁵⁴ VMP Policy Statement at 1.

⁵⁵ *Id.*

⁵⁶ VMP Order at 5.

⁵⁷ *See* Deregulation Order.

⁵⁸ VMP Policy Statement at 1.

⁵⁹ *Id.*

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.

Competition can never be fair if utilities are allowed to rate base generation, with guaranteed cost recovery, while IPPs must recover their costs through the wholesale market and REC contracts. As discussed above, prior to divestiture, utilities had little incentive to operate their generation assets efficiently and at the lowest cost, which in turn lead to New Yorkers facing the second highest electricity costs in the U.S.⁶⁰ The Commission took decisive action addressing monopoly utility high electricity costs by requiring divestiture, finding that competition “should result in lower bills as competitors have a greater incentive to lower costs than do utilities under a regulatory regime.”⁶¹ The Commission was proven right. The NYISO found in 2009 that the fuel-adjusted wholesale electricity costs decreased by 11% between January 2000 and August 2008⁶² and the FTI Report found that power supply costs in 2019-2023 were 35% lower than the five years preceding restructuring.⁶³ Furthermore, even if UOG is limited to 1 GW of solicitations per year as proposed by the Indicated Utilities, private investment would nonetheless be discouraged. Utilities would have an unfair advantage by leveraging VMP, properties near interconnection facilities, their role in the interconnection process, and cost recovery from their captive ratepayers. UOG projects would not be as cost-effective as IPP projects because they would not face competitive pressures to reduce costs.

⁶⁰ FTI Report at 11 (citing *Electric Sales and Revenue 1994*, Energy Information Administration (Nov. 1995), at 23, https://www.eia.gov/electricity/sales_revenue_price/archive/054094.pdf).

⁶¹ *Id.* at 30.

⁶² *Power Trends 2009*, NYISO (Oct. 4, 2009), at 9, <https://www.nyiso.com/documents/20142/2223154/2009-Power-Trends.pdf/fa52a83b-a290-37f3-3ef2-04a29f35f6df>.

⁶³ FTI Report at 12.

Accordingly, IPP investment would be chilled and achievement of the State's climate goals and affordability concerns would be further frustrated instead of aided.

Importantly, the uncertainty this proceeding has engendered by considering allowing UOG comes at a critical time for the wholesale markets in New York as a whole and, particularly, in New York City. For the first time in over twenty years, the NYISO has identified the potential for deficiencies to arise in meeting the New York City Locational Capacity Requirement for upcoming Summer 2026 spot auctions.⁶⁴ If deficiencies occur, the NYISO will be required to procure supplemental capacity supply to satisfy the deficiency and meet the local reliability need. As the NYISO explained, this potential local reliability shortfall comes as part of the dwindling reliability margins statewide. To satisfy these reliability deficiencies timely and affordably, this is exactly the time IPPs need certainty that can best come from the Commission fully and finally reaffirming its prohibition on UOG.

III. RESPONSES TO ENERGY AND CAPACITY MARKET QUESTIONS

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?

The best way to align and improve existing clean energy procurement activities with the NYISO's competitive markets is to internalize the value of carbon emissions in wholesale energy prices. As IPPNY demonstrated in its comments submitted in the Commission's proceeding to consider resource adequacy matters in 2019, the carbon adder can help the State meet its clean energy goals faster, more efficiently and more cost effectively while reducing emissions and

⁶⁴ See *Summer 2026 ICAP Market Auctions*, NYISO (Apr. 8, 2026), <https://www.nyiso.com/documents/20142/57614757/summer%202026%20icap%20market%20auctions%20040826%20icap.pdf/a6f59999-3f78-5dd1-2560-ad707616655e>.

maintaining grid reliability.⁶⁵ Carbon pricing is the single most effective way to attract private investment through the wholesale market in the technologies the State desires and to ensure that the resource additions are added in the most efficient way to displace carbon emissions.

In 2019, the Analysis Group (“AG”) studied the effect of a carbon price mechanism on the NYISO markets and concluded that carbon pricing can “accelerate the electric-system transition at lower cost and less financial risk to consumers than otherwise.”⁶⁶ In its final report, AG found that a carbon price will send the necessary price signals to provide sufficient revenue certainty for investors to support significant capital expenditures.⁶⁷ AG conservatively estimated that a carbon price coupled with local pricing incentives would result in market efficiency savings on the order of \$280 to \$850 million between 2022 and 2040.⁶⁸

Indeed, the very body tasked with creating a framework for how the State will achieve the goals set in the CLCPA, the Climate Action Council, recommended in its Scoping Plan that a form of carbon pricing be implemented via a cap-and-invest program as the comprehensive, economywide policy necessary to achieve the CLCPA goals.⁶⁹ As the CLCPA requires that the Department of Environmental Conservation’s (“DEC”) emission reduction regulations “[r]eflect,

⁶⁵ Case 19-E-0530, *Proceeding on Motion of the Commission to Consider Resource Adequacy Matters*, Comments of Independent Power Producers of New York Inc. (Nov. 8, 2019) (“IPPNY RA Comments”), at 14–15.

⁶⁶ See Susan F. Tierney & Paul J. Hibbard, *Clean Energy in New York State: The Role and Economic Impacts of a Carbon Price in NYISO’s Wholesale Electricity Markets*, Analysis Group (Oct. 3, 2019) at 3, <https://www.nyiso.com/documents/20142/2244202/Analysis-Group-NYISO-Carbon-Pricing-Report.pdf/81ba0cb4-fb8e-ec86-9590-cd8894815231>.

⁶⁷ *Id.*

⁶⁸ *Id.*

⁶⁹ *Scoping Plan*, Climate Action Council (Dec. 2022), at 339–341, available at <https://climate.ny.gov/-/media/Project/Climate/Files/NYS-Climate-Action-Council-Final-Scoping-Plan-2022.pdf>.

in substantial part, the findings of the scoping plan,” Governor Hochul directed DEC and NYSERDA to design a cap-and-invest program.⁷⁰

On December 20, 2023, DEC and NYSERDA issued its New York Cap-and-Invest Pre-Proposal Outline (“NYCI Outline”).⁷¹ In its comments in support of several components of the NYCI Outline, the NYISO correctly noted:

Reflecting the cost of greenhouse gas emissions and public policy mandates in wholesale electricity markets would send price signals to accelerate the new resource development required to support the CLCPA mandates, signal where carbon abatement efforts would have the most effect, and efficiently maintain electric system reliability.⁷²

The NYISO further found that other possible approaches, such as resource-specific incentives or contracts “would be an inefficient approach acting in isolation to supporting the statewide turnover of the generation fleet necessary to satisfy the CLCPA” because such contracts “alter the allocation of risk that is fundamental to competitive markets, shifting increased risk to consumers” and “obscure additional consumer funded payments to renewable resources and impede the market’s ability to minimize costs to consumers by procuring the most efficient electric generation resources and greenhouse gas abatement.”⁷³

⁷⁰ ECL § 75-0101(2)(c); Governor Kathy Hochul, 2023 State of the State: Achieving the New York Dream 123 (2023), <https://www.governor.ny.gov/sites/default/files/2023-01/2023SOTSBook.pdf>.

⁷¹ New York Cap-and-Invest Pre-Proposal Outline, NYSERDA & DEC (Dec. 20, 2023), *available at* <https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Press-Releases/Second-Stage-of-Pre-Proposal-Outreach.pdf>

⁷² *Comments of the New York Independent System Operator in Response to the DEC and NYSERDA Request for Feedback on the New York Cap-and-Invest Pre-Proposal Outline*, NYISO (Mar. 1, 2024) at 3, <https://www.nyiso.com/documents/20142/1402310/20240301-NYISO-NYCI-Cmts-2nd-Round.pdf/508a706b-c570-4d87-97c7-9b9cc0a7e2f9>.

⁷³ *Id.* at 4.

Accordingly, the Commission should support the NYISO's carbon adder proposal as it would better align and improve existing clean energy procurement activities with the State's wholesale energy and capacity market mechanisms.

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 NYISO's Installed Capacity ("ICAP") product is an effective price signal if the signal is adequate to incent resources needed to meet reliability needs. The ICAP Demand Curve structure, if implemented correctly, establishes market price signals that provide a level of compensation adequate to attract new resources and retain needed existing resources to promote system reliability over the long term while neither under-compensating nor over-compensating generators. The ICAP Demand Curves are based on the net cost of new entry ("CONE") of a proxy peaking plant, *i.e.*, the costs of developing and operating a flexible and dispatchable resource capable of meeting peak load requirements and associated long-term reliability needs.⁷⁴ The ICAP Demand Curves are reviewed every four years pursuant to an independent analysis and stakeholder comment process and are reset for a four-year period, referred to as the ICAP Demand Curve reset process ("DCRP").⁷⁵

The NYISO's erroneous selection of a 2-hour battery energy storage system ("BESS") as the proxy peaking plant in the most recently completed DCRP in 2024, which set the reference price for capacity market years 2025-2029, results in capacity market signals that cannot support the development and ongoing operation of the resources required to meet identified reliability needs. The NYISO considered various gas turbine and BESS designs in this DCRP and

⁷⁴ NYISO Market Administration and Control Area Services Tariff ("MST"), § 5.14.1.2.1.

⁷⁵ See NYISO MST § 5.14.1.2.2.

ultimately chose a BESS technology for the first time as the proxy peaking plant, finding that 2-hour BESS represented the “lowest fixed, and highest variable costs” among the considered technology options.⁷⁶ As IPPNY demonstrated in its protest to the Federal Energy Regulatory Commission (“FERC”) opposing the NYISO’s DCRP filing, due to its short duration, the 2-hour BESS cannot meet the transmission security reliability needs identified by the NYISO.⁷⁷ Numerous studies have identified the fact that longer duration resources will be required to resolve identified reliability needs.⁷⁸ Prior to that time, various types of combustion turbines had been the only technology under extensive consideration which, by their very nature, were dispatchable, were only limited in duration by how much fuel they had available, and therefore, could address resource adequacy criteria regardless of the duration required.

Given the NYISO’s findings in its 2025-2034 Comprehensive Reliability Plan (“CRP”), longer duration storage resources and/or simple cycle gas turbines (“SCGT”) will likely be required to resolve reliability needs.⁷⁹ Attempting to meet these needs with a 2-hour BESS resource would require multiple 2-hour BESS installations and the net result would be a cost that is multiples of the \$/kW-month 2-hour BESS costs of the proxy unit selected by the NYISO. Consequently, the Capacity Accreditation Factor (“CAF”)—a new mechanism designed to reflect

⁷⁶ Docket No. ER-25-596, *N.Y. Indep. Sys. Operator, Inc.*, 2025-2029 ICAP Demand Curve Reset Proposal (Nov. 29, 2024), at 9.

⁷⁷ See Docket No. ER-25-596, *supra*, Protest of Independent Power Producers of New York, Inc. (Dec. 20, 2024).

⁷⁸ See Paul J. Hibbard, et al., *Climate Change Impact Phase II, An Assessment of Climate Change Impacts on Power System Reliability in New York State*, Final Report (Sept. 2, 2020), at 82–84, <https://www.nyiso.com/documents/20142/15125528/02%20Climate%20Change%20Impact%20and%20Resilience%20%20Study%20Phase%202.pdf/89647ae3-6005-70f5-03c0-d4ed33623ce4>; Energy and Environmental Economics, Inc., *Pathways to Deep Decarbonization in New York State* (June 24, 2020), at 37, <https://climate.ny.gov/-/media/Project/Climate/Files/2020-06-24-NYS-Decarbonization-Pathways-CAC-Presentation.pdf>.

⁷⁹ 2025-2034 Comprehensive Reliability Plan (“CRP”), NYISO (Nov. 21, 2025) (“2025 CRP”), <https://www.nyiso.com/documents/20142/2248481/2025-2034-Comprehensive-Reliability-Plan.pdf/61984e49-f7a2-ceeda-bdd3-176c5ae40ba9>.

the marginal reliability value of suppliers by resource type and capacity Locality—for 2-hour BESS is significantly below 100%.⁸⁰

Accordingly, while the ICAP Market is the most efficient mechanism to provide an effective price signal for the construction of new, and maintenance of needed existing, resources, it does not currently provide adequate investment signals to meet the reliability needs identified by the NYISO. At the conclusion of the 2024 DCRP, the NYISO began engaging with stakeholders as part of its Capacity Market Structure Review project in 2025. This comprehensive effort started with an understanding that while New York’s markets are already effective at ensuring resource adequacy is maintained, enhancements are necessary to align market design rules with State mandates such as the CLCPA.⁸¹ These enhancements include:

- **ICAP DCR Process and Methodology Improvements** – a project to consider modifying the shape and slope of ICAP Demand Curves to better reflect marginal reliability improvements, refine the definition of peak proxy units, review appropriateness of net CONE estimates, and alternative approaches to net Energy and Ancillary Services revenue offsets.
- **Winter Reliability Capacity Enhancements** – a project to address the shift toward near-term winter reliability risks that are projected to increase over the long-term as the grid transitions to a winter-peaking system.
- **Reliability Attribute-Based Capacity Pricing** – a project to align market incentives with the evolving reliability needs of the grid by explicitly compensating resources for attributes that address reliability needs such as transmission security.
- **Capacity Zone Redesign** – an effort seeking to improve the locational accuracy of capacity pricing.
- **Improving Capacity Accreditation and Resource Adequacy Modeling** – a project aiming to increase transparency and visibility into the resource adequacy models.⁸²

⁸⁰ See *Final Capacity Accreditation Factors for the 2026-2027 Capability Year*, NYISO (Feb. 27, 2026), <https://www.nyiso.com/documents/20142/41593818/Final-Capacity-Accreditation-Factors-for-the-2026-2027-capability-year.pdf/83685470-882d-66d2-e6d8-68ed4d449e44>.

⁸¹ See *Capacity Market Structure Review Issue Discovery Report*, NYISO (Dec. 16, 2025), <https://www.nyiso.com/documents/20142/55778551/CMSR%20Issue%20Discovery%20Report%20-%20Final.pdf/d778ecf7-f64a-c9a5-0784-c7501aa05cda>.

⁸² *Id.* at 7–8.

The ICAP Demand Curve Reset and Methodology Improvements Project is underway, and the NYISO's goal is to implement any stakeholder approved changes before the next DCRP, the work for which commences in 2028.

In addition, the NYISO recently filed proposed tariff changes with FERC as part of its Winter Reliability Capacity Enhancements work.⁸³ This filing encompasses tariff changes which integrate season specific reliability metrics into the capacity market, providing more accurate price signals during the winter season. The NYISO plans to address the other proposed enhancements later this year. The NYISO's market structure is necessarily organic. The NYISO instituted a first in its kind marginal capacity accreditation methodology in 2022, which provided much more granular market prices than other ISO/RTOs and was a major step forward. Work remains to safeguard against erroneous outcomes (like a 2-hour BESS being the proxy unit) and fine tune the current structure; the Commission should support these efforts.

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?

The Commission should not consider alternatives to the NYISO's capacity market to meet resource adequacy needs. The Commission considered changes in the way resource adequacy needs are met in New York in Case 19-E-0530 in 2019.⁸⁴ While the Commission initiated that case to avoid the previously-effective NYISO's buyer side market power mitigation

⁸³ Docket No. ER26-1431, *N.Y. Indep. Sys. Operator, Inc.*, Winter Reliability Capacity Enhancements (Feb. 18, 2026).

⁸⁴ See Case 19-E-0350, *supra*, Order Instituting Proceeding and Soliciting Comments (Aug. 8, 2019).

measures on State public policy resources, IPPNY's comments submitted in that case are pertinent here.⁸⁵

As demonstrated in detail in IPPNY's comments, the Commission is preempted by the Federal Power Act from establishing unilaterally its own resource adequacy program—whether couched in terms of environmental, local reliability benefits, or otherwise—that would remove load and supply from the NYISO's capacity market. FERC has recognized that states may have a role in resource adequacy and planning and has found ISO-proposed tariffs, such as the California ISO's tariff, that provide that resource adequacy is secured through state resource adequacy constructs rather than centralized ISO-administered ICAP markets, can be just and reasonable based upon the specific facts and circumstances presented. FERC has established that it has jurisdiction over resource adequacy and it is—and must, by law, be—FERC that will exercise that jurisdiction cognizant of the traditional role for state regulatory authorities. Unlike the FERC-approved California ISO tariff structure and the rules implemented by the California Public Utilities Commission based on that structure, the NYISO's Services Tariff mandates that ICAP procured by load serving entities (“LSEs”) in New York must be reflected in the NYISO's spot market auction and otherwise contains a comprehensive set of rules establishing the rates, terms, and conditions for all LSEs in the State to meet resource adequacy requirements. Thus, any changes to the method that resource adequacy is secured in New York cannot be implemented absent FERC approval of changes to the current ICAP market structure as set forth in the NYISO's tariffs.

Assuming, *arguendo*, FERC approved changes to the NYISO tariff allowing the Commission to take on a resource adequacy role, the Commission should not take this approach.

⁸⁵ See IPPNY RA Comments, at 17–24.

It would essentially require LSEs to enter into a series of long-term bilateral contracts with existing and new resources needed for resource adequacy, local reliability, and State policies to ensure they continue operations. However, as the Commission determined in its 1996 order directing the State's utilities to create the NYISO and retail and wholesale competitive markets,⁸⁶ and has reiterated numerous times since,⁸⁷ competitive markets are the preferred options because they are more efficient and shift investment and performance risks from captive customers to private investors, the entities best positioned to manage such risk. Taking on this role will impair the ability of the competitive ICAP market to incent the maintenance of existing, and development of new, resources on a merchant basis in an efficient and cost-effective manner over the long term. Adopting this approach would thus be entirely contrary to the Commission's long-established and oft-reiterated policy choosing competitive markets as the preferred mechanism to meet resource adequacy and State policy requirements.

Abandoning the NYISO's competitive ICAP market will ultimately harm consumers. Competitive markets require investors to determine whether market prices provide the necessary incentive to build and maintain resources. Because private investors put their own capital at risk, poor investment decisions result in losses for their shareholders, not New York consumers. Thus, as has been evidenced by the operations of the competitive electric market over the past 25 years, the rigor of the competitive market have consistently fostered and driven innovation, enhanced

⁸⁶ See Deregulation Order.

⁸⁷ See, e.g., Case 00-M-0504, *Proceeding on Motion of the Commission Regarding Provider of Last Resort Responsibilities, the Role of Utilities in Competitive Energy Markets, and Fostering the Development of Retail Competitive Opportunities*, Statement of Policy on Further Steps toward Competition in Retail Energy Markets (Aug. 25, 2004), at 18 ("Competitive markets, where feasible, are the preferred means of promoting efficient energy services, and are well suited to deliver just and reasonable prices, while also providing customers with the benefit of greater choice, value and innovation. Regulatory involvement will be tailored to reflect the competitiveness of the market."); REV Track One Order ("A basic tenet underlying [Reforming the Energy Vision] is to use competitive markets and risk based capital as opposed to ratepayer funding as the source of asset development.").

efficiency, and sustained investment in the development, maintenance, and operation of facilities at the lowest possible cost. This enduring record affirms the market's effectiveness in delivering value and protecting consumer interests. The Commission should continue to rely on the NYISO's competitive markets to facilitate renewable and storage development with accurate market signals while maintaining the appropriate allocation of financial risk between investors and consumers.

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?

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

The Commission should direct DPS Staff to work through the NYISO's stakeholder process to develop and implement market design changes, such as the NYISO's carbon adder proposal and capacity market enhancements, that will most efficiently and cost effectively harmonize the State's public policy initiatives with the NYISO's competitive electricity markets. By adopting this approach, the Commission can help deliver optimal outcomes for consumers across New York State, both in terms of cost effectiveness and policy alignment.

IV. CONCLUSION

For the foregoing reasons, the Commission should issue an order reaffirming its long-standing policy prohibiting UOG and work through the NYISO's stakeholder process to support the NYISO's carbon adder and other market enhancements to better align the wholesale competitive market with State clean energy policy. By advancing these measures, the Commission will not only strengthen the State's commitment to sustainability but also contribute to the development of a more resilient energy system—one that stands to deliver enduring benefits for all stakeholders.

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