Affordability and Reliability in Policy-Driven Energy Transition: A New York Case Study

Jacob Mays*

Civil and Environmental Engineering, Cornell University, Ithaca, NY 14853

October 21, 2026

Abstract

Electricity systems pursuing decarbonization need to finance entry of new clean resources, the cost of which may exceed the revenue needed to keep existing plants operating. In liberalized markets, allowing prices to rise to the level required for new investment can therefore lead to significant policy-induced windfalls for incumbent generators. To avoid such windfalls, policymakers may prefer to keep market prices below the cost of new entry and rely on alternative mechanisms to attract new resources. This paper examines that tension in the context of New York, where market revenues can be heavily influenced by the administrative choice of the reference technology used to construct the demand curve for electricity capacity. The paper develops an equilibrium model describing hypothetical 2040 investment mixes arising from alternative reference technologies and state procurement configurations, with entry of new carbon-emitting in-state generation prohibited across all designs. Across the 2040 comparisons, use of a more expensive clean reference technology rather than a conventional gas turbine increases annual ratepayer payments by $2.13–4.71 billion, compared with engineering cost increases of $101–110 million. Moreover, use of a clean reference fails to induce significant market-based entry of clean resources; instead, the most important responses to the higher prices are new external capacity and additional retention of incumbents. Uniform clean electricity payments to new entrants, meanwhile, can generate further inframarginal rents due to cost heterogeneity and geographic constraints in development. Overall, the results highlight the central design challenge of financing clean entry and retaining necessary incumbent resources while limiting the policy-created rents that can arise in both capacity markets and state-driven procurement.

1 Introduction

New York has set ambitious targets to decarbonize its electricity system, with a stated goal of achieving a 100% carbon-free mix by 2040. To achieve this goal, the state has introduced or expanded several programs to procure new clean resources while also denying environmental permits for new carbon-emitting resources. These policies operate alongside the state's competitive electricity market, operated by the New York Independent System Operator (NYISO), which drives entry and exit decisions for the balance of resources in the system.

This paper investigates the affordability and reliability consequences of different design choices within this "hybrid" structure of state-driven procurement and competitive markets. Three concerns in particular drive the analysis. First, prices in competitive electricity markets support investment by allowing generators to recover costs through revenues from energy, ancillary services, and capacity, but those prices also compensate existing plants. If environmental policy limits entry by relatively inexpensive fossil generators while allowing

*jacobmays@cornell.edu

incumbents to remain, a price sufficient to finance new clean capacity can substantially increase payments to the legacy fleet. Second, targeting out-of-market support to new projects offers an alternative means of attracting investment. However, state-driven procurement can itself leave substantial rents when inexpensive development opportunities are scarce. As such, the primary question is how to design policies and markets that support decarbonization goals without undue transfers from consumers to suppliers. Alongside these affordability concerns, legacy resources and imports remain critical to ensuring reliability. Since some efforts to claw back policy-induced windfall profits could be too aggressive, a third concern is how to avoid provoking the retirement of assets that are still beneficial to the system.

A more concrete version of the design question comes in the form of the administrative capacity market demand curve used in the NYISO capacity market. An important input to the parameterization of this demand curve is the choice of the reference technology considered to be the marginal entrant into the system. NYISO estimates the net cost of new entry (net CONE) for the reference technology by taking its annualized capital and fixed operating costs and subtracting the operating margins it can expect to earn from selling energy and ancillary services. Traditionally, capacity markets in the U.S. have chosen a gas peaker as a reference. In part because of restrictions on new unabated gas in the state, NYISO shifted in 2025 to a 2-hour lithium-ion battery (New York Independent System Operator, 2024). The entry of batteries into the system, however, is expected to be driven not by market revenues, but by state-directed procurement. New York is targeting 6 GW of storage deployment by 2030, supported through The New York State Energy Research and Development Authority (NYSERDA) procurement and incentive programs (New York State Energy Research and Development Authority and New York State Department of Public Service, 2022). Given that lower market revenues would in principle be balanced by higher state support, it can be questioned whether it is appropriate to consider batteries the marginal resource in the system: instead, the decisions more likely to be influenced by market design are the retention of legacy resources within the state and the attraction of new imports from the neighboring systems of PJM, ISO New England (ISO-NE), Hydro-Québec, and the Independent Electricity System Operator (IESO) in Ontario. Largely motivated by concerns about transfers to incumbents, NYSERDA has proposed a division of responsibility in which state procurement induces new entry and the capacity market focuses on retention (New York State Energy Research and Development Authority, 2026b). Both NYISO (New York Independent System Operator, 2026) and the Independent Power Producers of New York (IPPNY; Independent Power Producers of New York (2026)) instead favor preserving the current capacity framework, emphasizing private responsibility for investment and performance risk.

The economic distinction between supporting efficient investment and determining distributional impacts is familiar, but consequential for transition policy. Foundational electricity market analysis explains why revenues above operating costs are necessary for fixed cost recovery and why competitive entry need not eliminate profits associated with constraints on low-cost inputs (Stoft, 2002, especially p. 58). The capacity market literature similarly emphasizes the role of remuneration in supporting both investment and continued availability (Joskow and Tirole, 2007; Cramton et al., 2013). Environmental regulation adds a distributional dimension when it treats prospective investment differently from sunk assets. Restrictions on new sources can increase the value and longevity of grandfathered facilities (Heutel, 2011), while abatement policies can generate significant rents beyond what might be needed to compensate losers from policy changes (Bovenberg and Goulder, 2001).

The literature on hybrid electricity markets examines the complementary role of long-term procurement and short-run markets (Roques and Finon, 2017; Joskow, 2022). Long-term commitments address investment

risk, but do not by themselves determine who retains the surplus resulting from policy and market design changes. Fabra (2022) explicitly proposes separate procurement for existing and new firm capacity to limit payments to incumbents, and Fabra and Montero (2023) show that differentiated procurement can reduce supplier rents with moderate efficiency costs. At the same time, support for selected entrants also changes expected revenues for other developers, and Brown (2018) shows how it can weaken unsubsidized investment incentives. Reduced merchant investment is not itself an adequacy failure if other resources provide the required service.

This paper brings these concerns together in the New York context, comparing capacity demand curves referenced to gas turbines with curves referenced to the lowest-cost eligible clean alternative, under different procurement requirements. All of the configurations prohibit new unabated in-state gas in the model and retain inherited procurement commitments. The comparison asks whether a more expensive clean reference induces the resources sought by the state or primarily changes compensation and the availability of existing and external supply. The closest modeling antecedent is the NYISO market monitor's analysis of uniform and bifurcated capacity remuneration (Potomac Economics, 2025). Its bifurcated cases lower payments to existing resources while maintaining a higher reference for newer resources. In their experiments, the lower payments to incumbents provoked additional retirements requiring additional investment in new, higher-cost resources, with limited overall impact on ratepayers. The experiments reported here do not implement this vintage differentiation, instead focusing on the choice of reference under uniform capacity settlement and explicitly linking investment to endogenous energy and reserve margins.

The model represents five New York zones and four neighboring regions (Energy and Environmental Economics (E3) and Abt Associates, 2022), with continuous investment and retirement, storage and hydro operations, transmission constraints, and endogenous external investment. Economic dispatch determines energy and reserve margins, while a separate capacity accreditation assessment measures marginal reliability contributions over six historical weather years. A 2030 procurement case establishes a common inherited fleet for three hypothetical 2040 settings: no additional state-driven procurement, a 50 percent renewable requirement, and a broader 50 percent clean requirement that also admits new nuclear and hydrogen generation while omitting existing nuclear. Within each setting, the "clean reference" design is calibrated against a common reliability benchmark to select capacity accreditation factors and demand quantities. The "gas reference" comparison then holds those applied accreditation and quantity parameters fixed. Its resulting portfolio is assessed for reliability without a further procurement round to equalize reliability. This design isolates the reference price intervention from a simultaneous change in the quantity or accreditation rules.

Three main findings emerge. First, reference choice has distributional effects much larger than its effect on modeled resource costs. Across the three 2040 comparisons, the clean reference increases annual customer payments by \$2.13–4.71 billion, whereas engineering costs increase by approximately \$101–110 million. Much of the difference accrues to incumbents: in the broader-clean case, incumbent renewable and storage surplus rises by approximately \$1.09 billion and incumbent fossil surplus by \$0.88 billion.

Second, a stronger generic capacity signal does not necessarily deliver the intended composition of clean investment. Importantly, the choice of a clean reference in the construction of the demand curve does not imply that the clearing price in the market will equal the net CONE for that technology: instead, the market may clear at a lower price, with capacity beyond the targeted quantity supplied by cheaper incumbents and imports. Without additional 2040 state-driven procurement, the clean-reference design induces only 206 MW of New York merchant additions, all solar on Long Island, with no entry of the selected clean reference. By contrast, net external additions reach approximately 3.56 GW, including 2.76 GW of gas combined-cycle

generation. Under the procurement requirements, higher capacity remuneration also retains more incumbent generation, including downstate plants. These responses show how a market can improve modeled reliability through resources other than the clean technologies used to set its reference. External additions are not equivalent to imported energy, and the experiments do not estimate their causal emissions effect. They nevertheless demonstrate why neighboring supply cannot be treated as fixed when evaluating an in-state investment signal.

Third, targeting support to new clean resources does not ensure that customer payments track the cost of building them. In the New York context development opportunities are constrained, with significant land-use conflicts affecting the supply curve for new resources. In the model's uniform-price procurement, rising development costs and binding location-specific limits allow lower-cost resources to receive the support required by more expensive marginal projects, even without strategic bidding. Under the clean reference in the 50 percent renewable case, incremental contracted resources earn approximately $796 million annually above modeled costs. In the broader clean resource case, potentially due to the competition provided by nuclear plants, this total drops to $374 million. The policy implication is that shifting investment support from the capacity market to state-driven procurement does not, by itself, resolve the distributional problems that can come with clean energy policy.

Although the analysis focuses on New York, it motivates consideration of three reform pathways relevant to jurisdictions combining competitive electricity markets with state-directed decarbonization. One natural response to these challenges, as suggested by NYSERDA, is for the state to take a more expansive role in integrated resource planning for new generation, leaving the market to focus on retention rather than new investment. A central challenge to this approach is demonstrated by NYSERDA's own recent procurement experience, which has seen high levels of attrition on awarded contracts. Of the contracts awarded in the 2019, 2020, and 2021 Tier 1 solicitations for new-build solar and land-based wind projects, for example, all were subsequently canceled following substantial increases in supply costs between the award and project completion (New York State Department of Public Service and New York State Energy Research and Development Authority, 2024; New York State Energy Research and Development Authority, 2026a). High capacity prices in the NYISO market can provide a buffer against procurement shortfalls, supporting resource adequacy despite this significant attrition. A framework oriented more narrowly on the going-forward costs of existing resources would place greater responsibility on explicit planning and backstop arrangements to manage delays and non-delivery. A second possible response would be to move a greater percentage of existing resources onto long-term contracts, such that future policy-induced windfalls would flow back to customers. At the same time, incumbent owners would seek compensation for already-expected merchant returns, and customers would assume the corresponding downside risk. Public ownership and certain NYSERDA contracts already return some market upside to customers or public beneficiaries, although the extent and recipients depend on the ownership and settlement arrangements. A third response would be to allow the development of new gas-fired plants in the state, clarifying the choice of reference technology. Continued unabated operation of such a plant past 2040 would require relaxing the state's zero-emission target. Nevertheless, relative to continued reliance on older resources and imports, new gas could raise or lower emissions depending on its utilization and what it displaces, including under continued state procurement of clean resources. Additional assumptions and modeling would be required to assess the impact of these potential avenues on cost, reliability, and emissions outcomes in the New York system.

References

Bovenberg, A. L. and L. H. Goulder (2001). Neutralizing the adverse industry impacts of CO_2 abatement policies: What does it cost? In C. Carraro and G. E. Metcalf (Eds.), *Behavioral and Distributional Effects of Environmental Policy*, pp. 45–90. University of Chicago Press.

Brown, D. P. (2018). The effect of subsidized entry on capacity auctions and the long-run resource adequacy of electricity markets. *Energy Economics 70*, 205–232.

Cramton, P., A. Ockenfels, and S. Stoft (2013). Capacity market fundamentals. *Economics of Energy and Environmental Policy 2*(2), 27–46.

Energy and Environmental Economics (E3) and Abt Associates (2022, December). Integration analysis technical supplement: New york state climate action council scoping plan. Appendix G to the Final Scoping Plan; prepared for NYSERDA and the New York State Department of Environmental Conservation.

Fabra, N. (2022, November). Electricity markets in transition: A proposal for reforming European electricity markets. Discussion Paper 17689, Centre for Economic Policy Research.

Fabra, N. and J.-P. Montero (2023). Technology-neutral versus technology-specific procurement. *The Economic Journal 133*(650), 669–705.

Heutel, G. (2011). Plant vintages, grandfathering, and environmental policy. *Journal of Environmental Economics and Management 61*(1), 36–51.

Independent Power Producers of New York (2026). IPPNY comments: PSC questions on utility-owned generation. Comments in New York Public Service Commission Case 15-E-0302, reproduced on the association's website. Responses address wholesale energy and capacity market design as well as utility ownership of generation.

Joskow, P. L. (2022). From hierarchies to markets and partially back again in electricity: Responding to decarbonization and security of supply goals. *Journal of Institutional Economics 18*(2), 313–329.

Joskow, P. L. and J. Tirole (2007). Reliability and competitive electricity markets. *RAND Journal of Economics 38*(1), 60–84.

New York Independent System Operator (2024). NYISO staff 2025–2029 demand curve reset final report. Technical report, New York Independent System Operator. Source of the 2025–2026 seasonal NYCA, New York City, and Long Island ICAP and indicative UCAP demand-curve values used in the recalibration; accessed August 21, 2026.

New York Independent System Operator (2026). When electricity markets work as designed, investment follows.

New York State Department of Public Service and New York State Energy Research and Development Authority (2024, July). Draft Clean Energy Standard biennial review. Technical Report Case 15-E-0302, New York State Department of Public Service and New York State Energy Research and Development Authority. Dated July 1, 2024. See p. 47 for contract cancellations and rebidding requirements and Table 6, p. 48, for solicitation-level status as of June 1, 2024.

New York State Energy Research and Development Authority (2026a). Large-scale renewable projects reported by NYSERDA: Beginning 2004. New York State Open Data, dataset dprp-55ye. Data through

September 30, 2026; accessed October 20, 2026. Cancellation calculations use solicitation, project status, and Bid Capacity (MW). Cancelled denotes an award or contract cancellation, not necessarily physical project abandonment.

New York State Energy Research and Development Authority (2026b, April). NYSERDA comments on notice soliciting comments related to energy and capacity market design. Cases 15-E-0302 and 22-E-0633. Filed April 24, 2026.

New York State Energy Research and Development Authority and New York State Department of Public Service (2022, December). New york's 6 gw energy storage roadmap: Policy options for continued growth in energy storage. Technical report, New York State Energy Research and Development Authority and New York State Department of Public Service. Basis for the approximate 2 GW A–F and 4 GW G–K 2030 allocation; accessed August 21, 2026.

Potomac Economics (2025, May). Mmu analysis of capacity market structure. NYISO Market Monitoring Unit presentation.

Roques, F. and D. Finon (2017). Adapting electricity markets to decarbonisation and security of supply objectives: Toward a hybrid regime? *Energy Policy 105*, 584–596.

Stoft, S. (2002). *Power System Economics: Designing Markets for Electricity*. New York: IEEE Press and Wiley-Interscience.