Impacts of offshore wind on reliability and affordability in ISO-NE and NYISO

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Executive summary

The Northeast power systems are undergoing a structural shift and face challenges in maintaining reliability and affordability amid growing load and aging infrastructure and uncertainty regarding the ability to bring on planned offshore wind onto the system. Both ISO New England (ISO-NE) and the New York Independent System Operator (NYISO) have raised concerns about maintaining near-term reliability amid winter load growth,[1] tightening fuel supply constraints[2], and the retirement of dispatchable thermal resources due to age, economics, and state policy requirements.[3]

Both systems are also transitioning from predominantly summer-peaking and summer-constrained to winter-peaking and increasingly dominated by winter-driven reliability risk as electrification of building heat and transportation increases cold-weather demand.[4]

Further, both regions are experiencing growing transmission congestion as they seek to deliver energy generated in rural areas – where onshore generation can be more easily developed – to dense coastal load centers. This challenge is particularly acute in NYISO, where demand is heavily concentrated in and around New York City while most generation is located upstate.[5]

Failing to meet the moment would result in material negative impacts for the public in these regions. Failing to maintain affordability would exacerbate the region's cost of living challenges[6] and reduce its ability to attract business investments.[7] A decline in grid reliability threatens national security, public health, economic competitiveness, and – at its worst – human life.[8]

To address these emerging challenges, both markets are exploring investments in new generation resources, especially fuel-free technologies such as offshore wind (OSW), that can help mitigate reliability risks and transmission congestion while also advancing the states' decarbonization goals. As reliability and affordability challenges intensify, greater scrutiny is being placed on the ability of each resource type to support the grid across a wide range of

1 New York Independent System Operator (NYISO). *Q3 2025 Short-Term Assessment of Reliability (STAR)*. Rensselaer, NY: NYISO, 2025. Available at: https://www.nyiso.com/documents/20142/39103148/2025-Q3-STAR-Report-Final.pdf

2 Northeast Power Coordinating Council. 2025. *Northeast Gas/Electric System Study: Public Version*. January 21. Boston: Levitan & Associates, Inc. https://www.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B70601B99-0000-C027-B1CF-31983983DAA0%7D

3 New York Independent System Operator (NYISO). *Q3 2025 Short-Term Assessment of Reliability (STAR)*. Rensselaer, NY: NYISO, 2025. Available at: https://www.nyiso.com/documents/20142/39103148/2025-Q3-STAR-Report-Final.pdf

4 New York Independent System Operator. *2024 Reliability Needs Assessment (RNA): A Report from the New York Independent System Operator*. November 19, 2024. https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf

5 NYISO, *2023–2042 System & Resource Outlook* (Rensselaer, NY: NYISO Electric System Planning Working Group, July 2024), accessed August 15, 2025, https://www.nyiso.com/documents/20142/46037414/2023-2042-System-Resource-Outlook.pdf.

6 ElectricChoice. (2025, November 11). *Electricity rates by state*. https://www.electricchoice.com/electricity-prices-by-state/

7 Wolverton, A., Shadbegian, R., & Gray, W. B. (2022). *The U.S. manufacturing sector's response to higher electricity prices: Evidence from state-level renewable portfolio standards* (NBER Working Paper No. 30502). National Bureau of Economic Research. https://doi.org/10.3386/w30502

8 Cybersecurity and Infrastructure Security Agency (CISA). *Energy Sector.* Washington, DC: U.S. Department of Homeland Security. Accessed September 24, 2025. https://www.cisa.gov/topics/critical-infrastructure-security-and-resilience/critical-infrastructure-sectors/energy-sector

operating conditions. The national conversation has shifted from an “all-of-the-above” strategy to an “everything-that-works” approach, prompting policymakers to examine more closely the real-world performance of each potential resource.

OSW has faced particular scrutiny in the evolving national conversation. For example, several OSW projects in the region – including Revolution Wind[9] and Empire Wind[10] – have faced stop-work orders that created uncertainty when, or even if, they will come online. These disruptions could pose challenges for planners and regulators, who have included these projects in their planning forecasts and are counting on these projects to contribute accredited capacity, mitigate fuel-supply constraints, support winter reliability, and advance state policy goals. If major OSW projects are delayed or canceled, regulators may need to take emergency measures, including temporary generation procurements, demand-side reductions, or modifications to reliability criteria — each of which carries reliability and customer-cost risks.

In organized electricity markets such as NYISO and ISO-NE, resource adequacy and system expansion are driven primarily by market-based mechanisms – energy, capacity, and ancillary service prices – rather than centralized utility planning. While these markets aim to deliver least-cost outcomes under their design, developers respond to price signals based on individual profitability, which may not fully align with broader objectives like long-term reliability and resilience. Although market rules continue to evolve to better align incentives with system needs, capacity markets clear only months ahead in NYISO and about three years ahead in ISO-NE. This limited forward horizon makes long-term system planning challenging, with capacity investment decisions often lagging behind needs-based determinations. As a result, market disruptions cannot be absorbed readily through market-based solutions; replacing lost planned capacity requires years of additional planning and regulatory processes.

Given the urgency of emerging reliability risks,[11] uncertainty surrounding the future availability of planned OSW resources, and the lack of a centralized mechanism to respond if projects are suddenly canceled, the consequences of OSW delays or cancellations could be significant. This white paper seeks to evaluate these potential impacts. To do so, we compare the performance of a range of technology futures using a unified, forward-looking analytical framework. This approach mirrors the practices in Integrated Resource Planning (IRP) processes undertaken by many vertically integrated utilities and system planners across the country.[12]

9 Ørsted A/S. *“Revolution Wind Receives Offshore Stop-Work Order from U.S. Department of the Interior’s Bureau of Ocean Energy Management.”* Company announcement, August 22, 2025. https://orsted.com/en/company-announcement-list/2025/08/revolution-wind-receives-offshore-stop-work-order--145387701

10 “Equinor’s New York Wind Project Resumes after Trump U-Turn.” *The Times*, May 20, 2025. https://www.thetimes.com/business-money/energy/article/equinors-new-york-wind-project-resumes-after-trump-u-turn-wxs6lfpmz

11 North American Electric Reliability Corporation (NERC). *2024–2025 Winter Reliability Assessment.* November 15, 2024. https://www.iso-ne.com/static-assets/documents/100017/2024-11-15-egoc-a3.4-nerc-winter-2024-25-reliability-assessment.pdf

12 U.S. Department of Energy. *Best Practices for Utility Integrated Resource Planning (IRP).* Washington, DC: U.S. Department of Energy, November 2024. PDF. https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf

Discussions about electricity futures frequently depart from these IRP-style methods. Stakeholders sometimes focus on a single element of grid planning – typically cost or emissions – rather than evaluating broader system impacts; further, they may advocate for or against specific technologies in isolation, relying on simplified measures such as levelized cost of energy (LCOE). Others may extrapolate historical operating conditions into the future, assuming that the relative stability of recent electricity markets will persist.

While these simplified analyses can be useful in many contexts, they are insufficient for the problem at hand. They do not reflect the multiple, and sometimes competing, objectives of grid planning; they overlook complex operational interactions between technologies; and they also may fail to account for rapidly changing system conditions.

In this white paper, we take a different approach. We adopt an IRP-style analytical framework and stress test a wide range of forward-looking grid conditions. IRP-style analyses provide three advantages:

- IRPs rely on quantitative, objective metrics rather than single-factor comparisons.
- They evaluate entire portfolios to capture both synergistic and antagonistic interactions between technologies.
- They assess performance across reliability, affordability, and sustainability objectives to understand the risks and benefits associated with different investment strategies.

The drawback of such an approach is its complexity. IRP-style analyses are multi-faceted and labor-intensive, which may be a barrier for readers less familiar with these planning methods. However, based on our collective experience in electricity planning and procurement, we believe these approaches are best suited to objectively assess the risks and benefits of OSW investments in these regions.

Our analysis uses five complementary modeling techniques and evaluates alternative generation portfolios through a unified scorecard of quantitative metrics. The five modeling techniques leveraged in this analysis include:

- **Long-term capacity expansion (LTCE)**
- **Production cost modeling (PCM)**
- **Loss of load analysis (AdequacyX)**
- **Supplemental modeling of oil use in downstate NYISO**
- **Net capital cost modeling**

Together, these models: forecast the future resource mix, including new builds and retirements as well as potential OSW additions; simulate how this forecasted grid would operate under typical conditions; stress test system performance under a wide range of weather-driven reliability conditions; and evaluate their costs.

From this unified modeling approach, we compare four portfolio constructs for each market. We adopt this scenario-based framework to evaluate a range of possible outcomes that evaluates portfolios with OSW as compared to credible alternatives. Our analysis isolates the portion of energy and capacity provided by OSW and examines how each market could respond if it were required to pivot away from current OSW plans. The four scenarios are:

- **Base Case**: including OSW consistent with current policy/queue expectations and existing natural gas resources retained,
- **No Alternatives**: OSW delayed/canceled without timely substitutes,
- **Renewables Only**: OSW replaced by inland onshore wind/solar plus storage as needed to achieve an equivalent accredited capacity and local reserve margin requirements, and
- **Gas Only**: OSW replaced by accredited natural gas peaking capacity in the same load pockets. This gas resource is added on top of existing resources.

Note that the Renewables Only and Gas Only scenarios refer *only* to the substitutes for the energy and capacity contributions of OSW. In all scenarios, the underlying portfolio includes a baseline mix of onshore renewables and natural gas. This reflects our view of likely resource development in these markets: substantial additions of onshore renewables to support load growth and advance state decarbonization and affordability goals, coupled with retention of natural gas resources to maintain system reliability.

Key findings

- **Balanced performance in portfolios with OSW**

  In both markets, portfolios that include OSW (Base Case) achieve lower modeled energy prices and lower emissions while meeting or improving resource adequacy, given stated assumptions on imports and technology builds. However, OSW may require capital investments relative to gas, but findings based on modeling are mixed between markets. OSW's benefits are driven by (1) interconnection proximate to coastal load pockets, (2) alignment with key stress hours and proximity to key stress regions relative to onshore renewables, and (3) scale relative to a gas alternative.

- **OSW can reduce the use of distillate back-up fuels**

  Without OSW additions, NYISO will increase its reliance on fuel oil during winter months. This has material sustainability and affordability implications because fuel oil is more expensive and more emissions-intensive than natural gas. OSW can meaningfully reduce this dependence by lowering net winter load during the coldest days, when dual-fuel generators are most likely to burn distillate fuels.

- **Pivots toward inland renewables can match price and emissions performance but weaken reliability without additional measures**

  Replacing OSW with inland onshore wind and solar, supported by storage, can preserve much of the energy price and emissions performance of the Base Case. However, these portfolios materially weaken reliability due to deliverability constraints and the differing diurnal and seasonal generation profiles of inland renewables. They also raise net capital costs because more megawatts must be built to approximate the energy and accredited capacity contribution of OSW.

  Targeted storage and transmission upgrades can mitigate these gaps, but do not fully eliminate winter reliability challenges. Importantly, these same investments would also enhance the reliability contribution of OSW portfolios.

- **Pivots toward gas alone raises prices/emissions and may reduce capital costs**

  Replacing OSW with peaking gas capacity has similar but modestly worse reliability but increases wholesale market electricity costs and emissions. These higher energy costs may be partially offset by lower net capital costs, although results are mixed.

  Our results show deterioration in the Gas Only case relative to the Base Case, but this reflects cold weather derates, outage assumptions, and replacement on an accredited (rather than nameplate) basis. A larger combined cycle unit or different technology selection would likely yield stronger performance. However, siting new large gas resources in constrained urban load pockets faces material headwinds: minimal land, limited access to firm fuel generation, and permitting complexity. As such, new gas projects may take too long to develop as a near-term replacement, though these constraints will ease, particularly as wider natural gas infrastructure investments materialize.

- **Failing to bring new resources has the worst performance**

  If delayed or canceled OSW is not replaced by any timely substitute, scarcity events increase, energy prices rise, emissions worsen, and resource adequacy risks meaningfully escalate – particularly in downstate New York.

- **NYISO faces material reliability risks, particularly downstate**

  Our results reinforce the concerns raised by the ISO itself. Specifically, NYISO faces material near-term reliability risks unless high-ELCC resources are added to the system, particularly in downstate zones.[13]

[13] New York Independent System Operator (NYISO). *Q3 2025 Short-Term Assessment of Reliability (STAR)*. Rensselaer, NY: NYISO, 2025. Available at: https://www.nyiso.com/documents/20142/39103148/2025-Q3-STAR-Report-Final.pdf

NYISO's exposure is heightened by tightening conditions in neighboring markets such as Hydro-Quebec (HQ)[14] and PJM, both of which have historically provided critical imports during winter peaks. As these systems face their own winter reliability challenges, the value of in-region, stress-aligned resources increases further.

Conclusion

Taken together, our analyses shows that portfolios including OSW materially improve reliability and sustainability. OSW is competitive on a cost basis with onshore renewables and may face higher capital costs than gas depending on local conditions, but it delivers reliability and sustainability benefits. Regulators should capture local conditions – particularly land, transmission, and fuel costs – when performing detailed cost comparison between OSW and natural gas.

OSW's proximity to coastal load centers, alignment with emerging winter peak conditions with further contribution to summer peaks, and ability to add fuel-free capacity at scale enable these portfolios to maintain or enhance resource adequacy while moderating energy costs and reducing emissions.

While no single technology fully resolves the Northeast's emerging challenges, OSW is well-aligned with the region's emerging needs and can play a role in meeting emerging reliability, affordability, and sustainability targets.

Introduction and preliminaries

The electricity grid in the American Northeast is undergoing a structural transformation in both demand and supply. The region's two independent system operators, ISO New England (ISO-NE) and the New York Independent System Operator (NYISO), are facing simultaneous challenges: rapidly growing winter load driven by the electrification of building heating and transportation due to consumer preferences and state decarbonization policies, along with the retirement of dispatchable thermal resources due to age, economics, and state decarbonization mandates. These shifts are tightening reserve margins and shifting reliability risks toward the winter months, when cold weather coincides with peak demand and natural gas system constraints.

Further, both regions are experiencing rising transmission congestion as they seek to deliver energy generated in rural areas to dense coastal load centers. This challenge is particularly acute in NYISO. NYISO projects that electrification will raise winter peak demand by nearly 19 GW by mid-century, with the steepest growth in New York City, Long Island, and the Lower Hudson Valley areas. These areas are already constrained by limited transmission and

14 Though cross-border tariffs are outside the scope of this study, they could also affect the affordability and viability of imports from HQ.

concentrated fossil retirements.[15] The state's interconnection queue is dominated by solar and battery projects, while commercially viable dispatchable, zero-carbon resources remain years away.[16] New York is presently targeting 9 GW of OSW by 2035[17] and currently has two projects under construction – Empire Wind 1 (810 MW) and Sunrise Wind (924 MW).[18]

New England faces a parallel set of challenges. According to ISO-NE's 2025 Capacity, Energy, Load, and Transmission (CELT) forecast,[19] winter peak loads are expected to grow nearly three times faster than summer peaks over the next decade. Retirements of firm dispatchable generation, coupled with limited fuel security during extended cold spells, leave the region vulnerable to multi-day periods of high demand and low renewable output. While storage is expected to play a growing role in the region's resource mix, studies show that batteries alone cannot sustain reliability during prolonged winter stress events. OSW, by contrast, has demonstrated some of the highest accredited capacity values among clean resources in ISO-NE studies, and offers geographic advantages because it can deliver energy directly into coastal load pockets such as Boston.[20] It can also support storage investments by providing excess energy needed to recharge batteries during multi-day events.

Both regions are planning for substantive investments in OSW. While regional leaders have primarily viewed OSW as a mechanism to achieve state decarbonization goals, the technology is increasingly relevant when considering reliability, affordability, and fuel security needs. However, OSW development in ISO-NE and NYISO has not been without challenges. Rising project-financing costs, supply-chain bottlenecks, and regulatory uncertainty have created headwinds for the industry nationwide, including a federal stop-work order temporarily halting work on Revolution Wind[21] and Empire Wind.[22] Such uncertainty poses material planning challenges for grid operators. If these projects are delayed or canceled, the resulting shortfall in future supply could elevate reliability risks and increase costs.

In a previous white paper, the authors reviewed resource adequacy challenges across American electricity markets and examined the potential reliability role of OSW. We found that

15 https://www.nyiso.com/documents/20142/39103148/2025-Q3-STAR-Report-Final.pdf/

16 New York Independent System Operator, *2025 Load & Capacity Data Report (Gold Book)* (NYISO, 2025), PDF, https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf.

17 New York State Energy Research and Development Authority. 2022 Offshore Wind Solicitation (Closed). Albany, NY: NYSERDA, 2022. https://www.nyserda.ny.gov/All-Programs/Offshore-Wind/Focus-Areas/Offshore-Wind-Solicitations/2022-Solicitation

18 The New Bedford Light. "Our Offshore Wind Tracker: What's New with Wind Projects off Massachusetts and Beyond?" The New Bedford Light accessed October 26, 2025. https://newbedfordlight.org/offshore-wind-tracker-whats-happening-to-massachusetts-projects/

19 ISO New England, *2025 CELT Report—2025-2034 Capacity, Energy, Loads, and Transmission Forecast* (Excel file, May 24, 2025), https://www.iso-ne.com/static-assets/documents/100023/2025_celt.xlsx.

20 ISO New England Inc., *Overview of Detailed Design: Resource Capacity Accreditation in the Forward Capacity Market,* presentation to NEPOOL Markets & Reliability Committees, December 12–14, 2023, accessed August 13, 2025.

21 U.S. Department of the Interior, Bureau of Ocean Energy Management. "Director's Order to Revolution Wind, LLC (Aug. 22, 2025)." Washington, DC: BOEM, 2025. https://www.boem.gov/sites/default/files/documents/renewable-energy/Director%26%23039%3BsOrder-20250822.pdf?VersionId=Y674sNo8zi7jLu3VWRvq2hFb_8KtMldc

22 "Equinor's New York Wind Project Resumes after Trump U-Turn." *The Times*, May 20, 2025. https://www.thetimes.com/business-money/energy/article/equinors-new-york-wind-project-resumes-after-trump-u-turn-wxs6lfpmz

rapid load growth, evolving seasonal risk, and infrastructure bottlenecks are creating mounting reliability and affordability pressures nationwide, increasingly concentrated in winter months.[23] We also found that OSW has key properties that make it well positioned to contribute toward solving these emerging winter-supply gaps. These characteristics include OSW's strategic siting near high-growth, transmission-constrained coastal load pockets, high capacity factors, and its stress-aligned generation profile. These attributes have resulted in OSW consistently achieving the highest capacity accreditation among renewable generation resource types and rivaling thermal resources in certain markets, though these accreditations will fall once OSW reaches high penetration levels.[24]

While the capacity accreditation of OSW is relatively high – particularly for the initial tranche of investments – resource decisions depend on more than accreditation metrics alone. In this white paper, we extend our previous analysis to examine the potential role of OSW in maintaining these key planning objectives in ISO-NE and NYISO. We evaluate the performance of alternative generation resource portfolios, including those with OSW, across these dimensions using analytical frameworks consistent with those employed in Integrated Resource Planning (IRP). Our objective is to assess how OSW interacts with other resource options, evaluate its performance relative to credible alternative futures, and investigate its potential benefits and drawbacks for achieving a reliable, cost-effective, and low-emissions grid.

We adopt an IRP-style analytical framework because simplified metrics are inadequate for the complexity facing ISO-NE and NYISO. Using this framework, we forecast future grid and load conditions, identify credible alternative portfolios if OSW does not come online, project energy prices and operational behavior for each portfolio, evaluate net capital costs, and stress test their performance across a wide range of weather conditions. In this manner, we can quantitatively and holistically evaluate the performance of OSW relative to substitutes. This approach enables us to assess the system-wide implications of including or excluding OSW and to understand how OSW interacts with alternative resources in ways that simplified metrics cannot.

23 Stover, Oliver, Jesse Dakss, Dean Koujak, Ryan Chigogo, Abdul Mohammed, Ryan Israel, Charles Merrick, and Chloe Romero Guliak. *The Contribution of Offshore Wind to Grid Reliability and Resource Adequacy.* Boston: Charles River Associates, 2025. https://www.crai.com/insights-events/publications/the-contribution-of-offshore-wind-to-grid-reliability-resource-adequacy/

24 Ibid.

Methodology

2.1 High-level overview

To quantify OSW's potential contributions under evolving grid conditions, we conducted five complementary modeling exercises for the two independent system operators that serve most of the Northeast – NYISO and ISO-NE. The analytical approach follows frameworks widely used in IRP and regional transmission organization (RTO) studies, linking long-term resource development, operational economics, and reliability outcomes.

- **Long-Term Capacity Expansion (LTCE)** modeling forecasts how the generation portfolio evolves over time under reliability, policy, and economic constraints.
- **Loss of load** evaluates the ability of a generator mix to serve electricity demand under a wide range of weather and outage conditions, with an emphasis on atypical winter stress hours.
- **Production Cost (PCM)** assesses operational and economic performance under expected system conditions, capturing hourly energy prices, dispatch patterns, power flows, and natural gas reliance.
- **Supplemental modeling** examines the use of fuel oil in downstate NYISO during future winter-peaking conditions
- **Net capital cost modeling** estimates the revenues needed to recover capital expenditures and returns associated with new resources, net of energy revenues.

Together, these models provide a comprehensive view of both futures of the grid resource mix (LTCE), performance under typical operating conditions (PCM), capital expenditure costs, and reliability outcomes (loss of load modeling). The PCM and LTCE analyses were performed using Energy Exemplar's Aurora[25] while the loss of load and supplemental modeling was performed using CRA's internal AdequacyX[26] reliability model. Both models have been employed in IRP efforts in utilities across the country.

These assessments were performed on various **scenarios** which represent alternative technological and policy futures.[27] Each scenario is assessed using our suite of models and evaluated for its reliability, affordability, and resource adequacy using various metrics. From these simulations and performance metrics, we examine the benefits and risks of pursuing various generator portfolio mixes.

2.2 Long-Term Capacity Expansion (LTCE) modeling

25 Energy Exemplar. "Aurora Energy Forecasting and Analysis Software." Accessed November 5, 2025. https://www.energyexemplar.com/aurora

26 Charles River Associates (CRA), *Introducing CRA AdequacyX: CRA's Resource Adequacy Model* (white paper, October 2024), https://media.crai.com/wp-content/uploads/2024/10/17133654/Introducing-CRA-AdequacyX-whitepaper-October2024.pdf.

27 U.S. Department of Energy. *Best Practices for Integrated Resource Planning.* November 2024. https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf

LTCE produces the Base Case resource mix for each market. The model identifies the least-cost set of additions and retirements that satisfy forecasted energy and capacity needs while meeting policy and reliability requirements. The model uses a mixed-integer linear optimization framework that adds or retires capacity in discrete increments, subject to realistic build limits reflecting supply-chain availability and existing decisions, transmission constraints based on known transmission line limits, workforce capacity, and permitting timelines.[28]

Selecting appropriate build limits is inherently challenging. In practice, these limits are informed by requests for information (RFIs), regional development patterns, historical build rates, and experience with resource planning and generator procurement within the planning footprint. In this study, the build limits reflect the authors' judgment, grounded in observed industry resource planning and procurement experience.

Key features and constraints in our LTCE modeling

- **Hard-coded builds and retirements:** Announced and/or policy-mandated additions or retirements – including OSW projects – are intrinsically included in the portfolio forecast.
- **Decision variables:** After including these hard-coded generator decisions, the model can opt to add or retire generators for the remaining energy and capacity needs.
- **Objective function:** Minimize total system cost subject to resource adequacy (reserve margin), emissions, policy constraints, and feasibility constraints.
- **Temporal scope:** Monthly time steps from 2026 through 2044.
- **Constraints:**
  - Reserve margin requirements consistent with ISO-NE and NYISO planning criteria and resource adequacy best practices.
  - Policy mandates, including state renewable-energy, state and federal emissions reductions targets, and other state and federal regulations.
  - Realistic build limits reflecting supply-chain, siting, transmission, and permitting considerations. These limit the annual and total amount of resources that can be added and the size of a resource that can be added. In this case, these build limits are based on the Author's judgment.
  - Technology-specific operating parameters such as capacity factors, forced-outage rates, and build lead times.

The LTCE analysis determines the least-cost mix of solar, onshore wind, OSW, energy storage, and thermal capacity additions required to maintain reliability while meeting policy mandates, including decarbonization and environmental targets. The resulting generator portfolio

28 Ibid.

trajectories serve as the foundation for subsequent market analysis, production cost, and reliability analyses.

The LTCE model provides a single least-cost path, but investment decisions in competitive markets can deviate based on developer behavior, supply-chain delays, fuel prices, and policy changes. For this reason, LTCE outputs serve as the baseline, while additional scenarios explore credible alternative outcomes.

Given this context, we emphasize that the LTCE resource mix represents one plausible future. To address the uncertainty inherent in long-term planning, we employ scenario analysis to examine how system performance changes under alternative portfolios. Scenario analysis enables planners to test critical uncertainties, such as natural gas prices, capital-cost trajectories, and the availability or timing of new technologies.

This work focuses on one such uncertainty facing market operators: how system performance changes if planners opt to — or are compelled to — reduce or eliminate OSW development. To explore this, we analyze three alternative futures that could emerge in the absence of OSW. These counterfactual portfolios allow us to objectively assess how substituting or removing OSW affects reliability, affordability, and emissions outcomes and to compare OSW's contribution against viable alternatives. Details on these counterfactual scenarios are provided in Section 2.7.1.

2.3 Production Cost Modeling (PCM)

PCM is used to forecast the energy prices, emissions, and reliance on natural gas units for the various generator scenarios. The PCM simulation captures detailed hourly system operations under expected (non-emergency) conditions. It performs chronological unit commitment and dispatch of all generators to meet hourly load, reserve, and transmission constraints at least cost.[29]

Model Inputs

- **Generation fleet** from LTCE results (or scenario analysis), including retirement and build decisions;
- **Load forecast**, including electrification;
- **Price assumptions** including fuel prices, variable O&M costs, and generator performance characteristics; and
- **Modeling footprint,** ISO-NE, NYISO, PJM, Independent Electricity System Operator (IESO), and HQ. Note, we did not include the impacts of cross-border tariffs which would impact the energy price.
- **Transmission limits** between modeled zones.

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29 Ibid.

Outputs and metrics

- **Hourly and zonal energy prices**, reflecting marginal cost of supply and congestion;
- Dispatch patterns and capacity factors for all resource types;
- System-wide fuel consumption and CO_2 emissions;
- **Natural gas capacity factors** (the ratio of usage for the natural gas fleet, relative to the theoretical maximum)**;** and
- **Interregional power flows**, indicating import/export relationships among markets

The PCM analysis quantifies the operational implications of each portfolio: how often natural gas units are dispatched, the emissions produced by the entire portfolio, and the resultant bulk energy prices. The simulations cover the period from 2026 to 2044. Both ISO-NE and NYISO are net importers of energy, meaning they import more energy from their neighbors than they export. As such, the PCM includes key additional markets to which these markets are interconnected including: PJM, IESO, and HQ. All five of these markets are jointly optimized to capture the flows of power between the systems.

2.4 Net capital cost modeling

Energy costs are only one component of affordability. Independent power producers and vertically integrated utilities must also recover their capital investments, plus a reasonable return, in order for new generating resources to be financially viable. Generators can receive this compensation in several ways, including capacity market payments, renewable energy credit payments, power purchase agreements, or other out-of-market payment structures.

In this white paper, we do not examine each revenue stream in detail. Instead, we use a simplified framework to estimate the remaining revenue, in addition to energy revenues, that generators would need in order to remain financially viable. To do this, we developed a simplified net capital cost model.

First, we identified overnight capital cost and fixed O&M (FOM) assumptions using a range of sources, including Lazard, NREL, and recent Integrated Resource Plans (IRPs).[30, 31, 32] Table 2-1 summarizes the capital cost and FOM values applied in the analysis. Table 2-2 summarizes the investment tax credits applied to the capital costs.

30 “Lazard Releases 2025 Levelized Cost of Energy+ Report.” 2025. Https://Www.lazard.com. 2025. https://www.lazard.com/news-announcements/lazard-releases-2025-levelized-cost-of-energyplus-report-pr/.

31 “Public Advisory Meeting #2 2025 Integrated Resource Plan.” 2025. https://www.aesindiana.com/sites/aesvault.com/files/2025-07/AES-Indiana-Public-Advisory-Meeting-2-2025.pdf.

32 “Data | Electricity | 2024 | ATB | NREL.” 2024. Nrel.gov. 2024. https://atb.nrel.gov/electricity/2024/data.

Table 2-1: Overnight capital costs and FOM assumptions

Resource class	Capital costs ($/kW)	FOM($/kW-yr)
Solar	$2,100	$21
Land-based-wind	$2,300	$58
Offshore wind	$5,800	$145
Storage	$2,200	$22
Gas	$2,500	$38

Table 2-2: Investment tax credits applied

Year	Solar	Wind	Storage
2026	33%	33%	33%
2027	33%	33%	33%
2028	26%	25%	30%
2029	20%	17%	28%
2030	8%	7%	25%
2031	-	-	21%
2032	-	-	18%
2033	-	-	15%
2034	-	-	12%
2035	-	-	8%
2036	-	-	5%
2037	-	-	2%
2038	-	-	-

For each portfolio, net capital cost was calculated by first identifying the amount of the incremental capacity additions, by resource type, in each year. We then computed annualized capital costs, including applicable tax credits, and annual fixed O&M costs over the lifetime of each resource. We assumed that the original cost of the project would be recovered at an estimated 10% Weighted Average Cost of Capital over a period of 20 years (a typical PPA tenor). From this annual revenue stream, including capital returns, we compute the net present value needed to make the portfolio financially viable.

For renewable technologies, including onshore wind, OSW, and solar, projected annual energy revenues were netted against these annual costs. Renewables are a price taker and follow a production curve pattern that varies from season to season and year to year based on weather patterns but nevertheless produce an expected amount of must-take energy that is absorbed by the market except in the most extreme system conditions which prevent its delivery. However, as fuel free resources, they incur minimal costs for generating this energy. As such, we net out energy revenues because such revenues towards the financing case when developing such project.

We did not apply this approach to gas technologies, because their energy revenues mainly correspond to and directly cover variable operating costs and the cost of fuel. We recognize that this is an approximation, since there are periods when energy prices clear above the marginal cost of a modern gas turbine.

2.5 Resource adequacy and loss of load modeling

2.5.1 Resource adequacy

Loss of load modeling is used to assess the resource adequacy of the various portfolio mixes. Resource adequacy focuses on ensuring that the bulk electricity generation system, subject to transmission constraints, can deliver sufficient power to meet all end-use demand. It is a single element of overall grid reliability, which also includes transmission and distribution outages. **Resource adequacy** analysis considers the ability of the generator fleet to:

- Serve all end-use hourly demand with an acceptable level of reliability, typically defined by reliability standards (discussed further below).
- Accommodate uncertainty and variability in load, variable renewable output, and unplanned generator outages, including weather-correlated events.
- Provide sufficient operating reserves and flexibility, including ramping capability, start times, minimum run times, and multi-hour duration needs.
- Ensure deliverability to load, accounting for internal transmission constraints.
- Manage seasonal variability, recognizing differing summer/winter risk drivers and shifting net load[33] dynamics.
- Withstand fuel assurance and common-mode risks, such as gas supply disruptions and cold/heat-related deratings.
- Reflect energy-limited characteristics, including storage discharge duration limits.

If a system does not have sufficient generation to meet demand at a given time, operators will perform **load shedding**: an intentional disconnection of certain customers to preserve the stability of the overall system. In practical terms, maintaining resource adequacy means ensuring that such events are exceedingly rare, so that households, businesses, and critical infrastructure can depend on a continuous and reliable supply of electricity.

[33] Gross demand less renewable generation. This represents the amount of demand that needs to be met by dispatchable generation.

To meet the resource adequacy standards that the American public expects, system planners and regulators rely on quantitative risk metrics to define the likelihood, duration, and magnitude of load shedding events. The most widely used metric in North America is the **Loss of Load Expectation** (LOLE), which measures the expected number of days per year with at least one instance of load shedding. North American systems are historically planned to an LOLE target value of less than 0.1 days/year – meaning that system planners design their system so that load shedding occurs at most once every ten years (i.e., "**1-Day-in-10-Years**").

While LOLE calculates the frequency of load shedding events, it does not consider the magnitude of events. Grid planners and regulators are adopting auxiliary metrics to improve resource planning that quantify the magnitude of potential outages. Planners are increasingly utilizing **Expected Unserved Energy** (EUE) – the anticipated amount of energy that will not be served due to load shedding.[34] For this white paper, we use EUE because it captures the magnitude of energy shortfalls and is, in our view, more robust to modest variations in modeling assumptions.

2.5.2 Loss of load modeling

To assess the resource adequacy of each potential resource mix, we performed **loss of load modeling** using *AdequacyX*[35], a Monte Carlo-based simulation tool that quantifies the probability, magnitude, and duration of load-shedding events. AdequacyX simulates correlated system "shocks" in load, renewable generation, and thermal outages, explicitly capturing how electrification of heating and transportation reshapes hourly load shapes and increases risk during the coldest hours. The structure of AdequacyX is shown in Figure 2-1.

Unlike the production cost PCM, which focuses on economic dispatch under expected conditions, the loss of load modeling emphasizes system performance under all possible grid conditions, including extreme stress conditions. For this analysis, AdequacyX represents NYISO, ISO-NE, and surrounding systems including PJM, HQ, and the IESO as an interconnected network of regions that first serve internal demand. After internal demand is served, it is modeled to then share surplus capacity across limited transmission interfaces. Shortfalls are met by discharging battery resources within their energy-duration limits.

From these results, we computed the expected unserved energy (EUE), normalized EUE, and the resource adequacy risk premium. The resource adequacy risk premium is calculated as the unserved energy multiplied by the value of lost load, assumed to be $35,000 per megawatt hour.[36] Because we performed loss of load modeling only in 2032 and 2036, we interpolate load shedding risk values between study years.

[34] National Renewable Energy Laboratory, *Explained: Fundamentals of Power Grid Reliability and Clean Electricity*, Golden, CO: National Renewable Energy Laboratory, January 2024, NREL/FS-6A40-85880, https://www.nrel.gov/docs/fy24osti/85880.pdf.

[35] Charles River Associates (CRA), *Introducing CRA AdequacyX: CRA's Resource Adequacy Model* (white paper, October 2024), https://media.crai.com/wp-content/uploads/2024/10/17133654/Introducing-CRA-AdequacyX-whitepaper-October2024.pdf.

[36] The Brattle Group. (2024). *Value of Lost Load Study for the ERCOT Region*. Retrieved from https://www.brattle.com/wp-content/uploads/2024/09/Value-of-Lost-Load-Study-for-the-ERCOT-Region.pdf

Treatment of neighboring markets

In the reference outlook, both NYISO and ISO-NE were modeled as being able to import from PJM, HQ, and IESO up to import limits. Under this assumption, surrounding markets are treated as being able to provide electricity during stress events, except for CHPE, which is assumed to be available only in the summer months. This matches the resource adequacy modeling performed by NYISO.

This assumption of firm neighboring supply raises concerns. All three neighboring systems are themselves tightening, meaning they will have fewer excess generating resources available to support NYISO or ISO-NE during emergencies, especially when stress conditions overlap. PJM faces acute resource adequacy risks[37] due to rapid load growth, aging dispatchable generation, and slower interconnection timelines, which are expected to reduce surplus capacity available for export in future years. IESO is also projecting tightening supply demand conditions, but not to the same degree as PJM.[38] Both NYISO and ISO-NE have invested in transmission infrastructure and entered contractual arrangements to access energy from HQ.[39,40,41] and NYISO's reliability studies likewise assume that HQ support is primarily available during summer months only, reflecting tight conditions in HQ in the winter months.[42,43]

As the American Northeast's transition toward winter-dominant risk and the surrounding markets tighten, NYISO and ISO-NE may experience their highest periods of grid stress during the same hours when the surrounding regions are already constrained. To examine this exposure, we conducted additional sensitivities for study year 2032 in which all imports were restricted or unavailable. While *extreme*, this assumption illuminates the degree to which both systems rely on imports and underscores the reliability benefits of additional in-region resources as a hedge against tightening conditions.

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37 PJM Inside Lines. "PJM Details Resource Retirements, Replacements and Risks." February 24, 2023. https://insidelines.pjm.com/pjm-details-resource-retirements-replacements-and-risks/

38 Independent Electricity System Operator (IESO). *Reliability Outlook: An Adequacy Assessment of Ontario's Electricity System, October 2025 – March 2027.* Toronto: IESO, September 2025.

39 ISO New England. *Tie Benefits and HQICCs — An IRH Perspective*. Presented to the NEPOOL Markets Committee, April 9, 2025. Available at: https://www.iso-ne.com/static-assets/documents/100022/a04.2_mc_2025_04_08-09_irh_presentation_tie_benefits_hqiccs.pdf

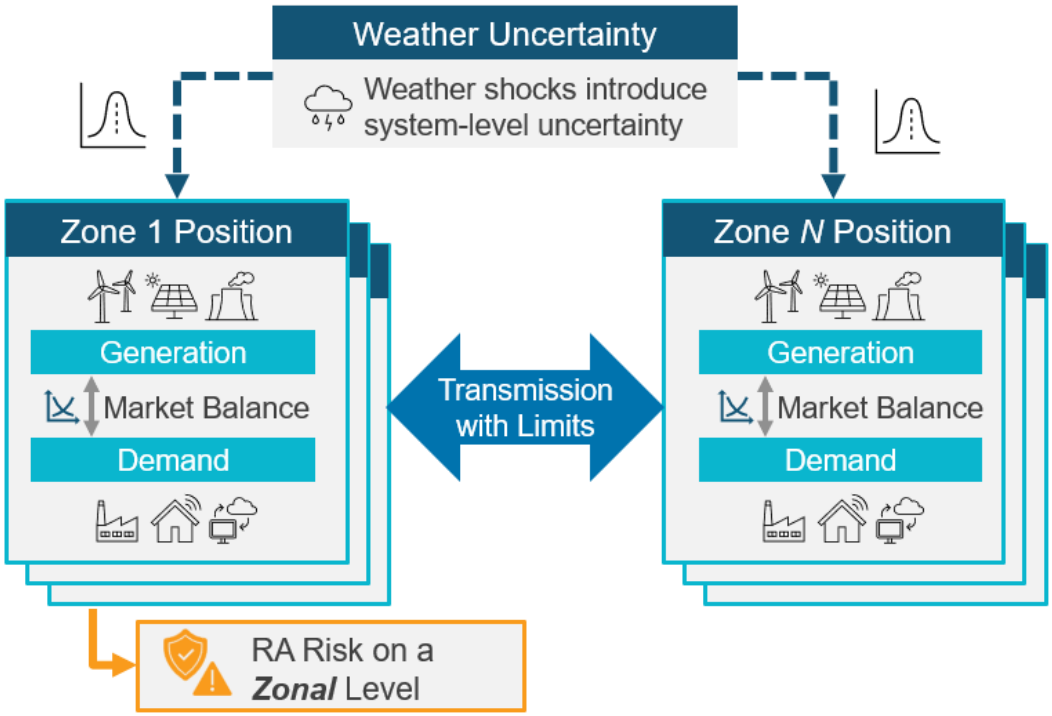
40 Federal Energy Regulatory Commission (FERC). *FERC Issues Orders in Docket No. ER25-1445 (ISO New England, Inc.) and Docket No. ER25-1462 (New York Independent System Operator, Inc.).* April 14, 2025. Available at: https://www.ferc.gov/news-events/news/ferc-issues-orders-docket-no-er25-1445-iso-new-england-inc-and-docket-no-er25-1462

41 ISO New England (ISO-NE). *Treatment of HQICCs in a Prompt Capacity Market.* Jericho Power Presentation, May 6, 2025. Available at: https://www.iso-ne.com/static-assets/documents/100023/a03.3_jericho_power_teatment_of_hqiccs.pdf

42 New York State Reliability Council (NYSRC). *Champlain Hudson Power Express (CHPE): 2026-2027 IRM Study Modeling Assumptions, Installed Capacity Subcommittee Meeting #304, June 4, 2025*. PDF. Accessed November 6, 2025. https://www.nysrc.org/wp-content/uploads/2025/05/CHPE-Modeling-Assumptions-06042025-ICS.pdf

43 Hydro-Québec. "Are We Running Out of Electricity in Québec?" Accessed July 2025. https://www.hydroquebec.com/residential/energy-wise/are-we-running-out-electricity.html

Figure 2-1: Structure of AdequacyX



2.5.3 Supplemental analysis for NYISO: OSW and oil-fired generation in downstate New York

As an extension of the AdequacyX reliability analysis, we conducted a supplemental study to examine OSW's effect on oil-fired generation in downstate New York under future winter-peaking conditions. This analysis uses the same weather years, synthetic load shapes, and electrification assumptions as the AdequacyX framework to ensure methodological consistency.

Background

Many gas-fired units in NYISO lack firm natural gas supply during extreme cold periods because pipeline infrastructure is constrained, and residential heating demand is prioritized. To meet capacity obligations during these conditions, a meaningful subset of generators relies on dual-fuel capability and can operate on distillate fuels stored on site when natural gas is not available.[44]

[44] Analysis Group. *2023 Fuel Security Study (Final)*. New York Independent System Operator, 2023. Accessed September 29, 2025. https://www.nyiso.com/documents/20142/41258685/Analysis-Group-2023-Fuel-Security-Study-Final.pdf

Operating on back-up fuels (typically fuel oil), however, presents several challenges:

- **High cost:** Distillate fuels are significantly more expensive than natural gas and raise wholesale energy prices when oil-fired units set the marginal price.
- **Limited storage:** On-site oil inventories typically cover only a few days of winter-peak operation, with resupply constrained by transportation and competing heating-oil demand. Deliveries during major winter events can create logistical risks if refueling disruptions occur.[45]
- **Maintenance and emissions**: Oil combustion increases maintenance needs and produces higher SOx, NOx, and particulate emissions. Permitting requirements also limit allowable annual oil-burn hours; for example, Ravenswood is restricted to 720 hours per year under its Title V permit.[46] Many of these units are located in dense urban areas, raising public-health concerns associated with higher-emission back-up fuel use.[47]
- **Retirement risks**: NYISO's fleet is aging.[48] Higher run-time on back-up fuels increases operational strain, accelerating the likelihood of retirement[49] and reducing available capacity in future winters.

As winter peaks increase, these stressed hours may occur more often, increasing reliance on oil-fired generation. OSW has the potential to reduce this exposure by providing fuel-free, stress-aligned energy during the coldest hours. In principle, this reduces the number of hours when dual-fuel generators must switch to back-up fuels, lowers emissions, eases pressure on limited oil inventories, and allows scarce natural gas and distillate supplies to be prioritized for the lowest-wind, highest-risk hours.

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45 New York Independent System Operator. (2024, November 19). *2024 Reliability Needs Assessment (RNA)*. Retrieved from https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf/0fe6fd1e-0f28-0332-3e80-28bea71a2344

46 New York State Department of Environmental Conservation, *Permit Review Report: Ravenswood Generating Station, Permit ID 2-6304-00024/00039, Renewal Number 2, Modification Number 2 (January 26, 2018)*, (Long Island City, NY: NYSDEC, 2018), accessed September 29, 2025, https://extapps.dec.ny.gov/data/dar/afs/permits/prr_263040002400039_r2_2.pdf

47 Law, Adam, Ali Snell, Allison Cardoso, et al. 2024. *Replacing Peaker Plants with Energy Storage in New York State*. Oakland: PSE Healthy Energy. October 9. https://www.psehealthyenergy.org/work/opportunities-for-replacing-peaker-plants-with-energy-storage-in-new-york-state/

48 New York Independent System Operator. (2025). *Power Trends 2025: A report on the grid in transition*. https://www.nyiso.com/documents/20142/2223020/2025-Power-Trends.pdf

49 New York Independent System Operator. (2024, November 19). *2024 Reliability Needs Assessment (RNA)*. https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf

Analytical approach

To estimate the amount of oil-fired generation downstate, we employ a relationship developed by NYISO that links daily winter peak load in Zones F–K (See Figure 2-2) to the corresponding level of oil-fired generation in those zones observed under historical stress conditions.[50, 51]

We apply synthetic hourly load shapes used in AdequacyX together with hourly OSW generation profiles. OSW output is subtracted from the load to create a net-demand profile for Zones F–K, which is then applied to the NYISO relationship to estimate oil-fired generation under future conditions.

Electrification plays a dual role in these outcomes. It increases electricity demand during the coldest days while reducing natural gas consumption for building heat. As gas use for heating falls, additional gas supply becomes available for power generation, reducing the likelihood that generators must switch to oil. This does not imply new gas-fired plants are added; it simply reflects increased access to primary fuel for existing units.

This effect allows a larger share of gas-fired generators, shown in Table 2-3. to remain on natural gas during cold-weather, high-load events. We quantify this by identifying the growth in peak electric-heating load and the corresponding reduction in gas needed for building heating, both of which influence oil-burn requirements under winter stress conditions.

50 New York State Reliability Council (NYSRC). (2025, March 5). *Fuel Availability Constraints: Modeling Phase 2* (Installed Capacity Subcommittee Meeting #301). NYISO. https://www.nysrc.org/wp-content/uploads/2025/03/Fuel-Availability-Constraints.pdf.

51 Note, this equation is given as y=- 0.0002 +7.6673*x-71512. However, this does not match the graphics provided in the presentation. we assume the correct equation is the inverse of that reported in the presentation: y=0.0002 -7.6673*x+71512. We also clip this value to enforce only non-negative values and only considers load values above 20,000 MW.

Figure 2-2: Oil generation in NYISO zones F-K as a function of winter daily peak load[52,53]

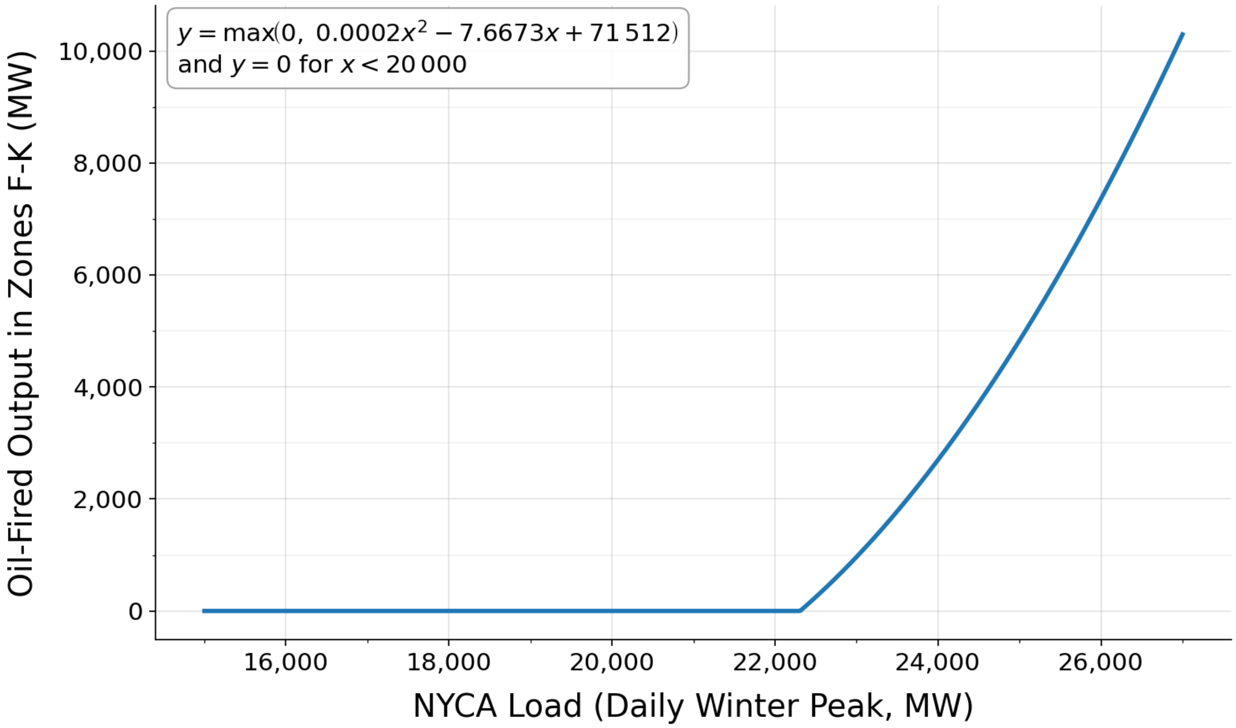

Table 2-3: New natural gas fuel availability during winter peaks in NYISO zones F-K due to electrification

Year	Increase in natural gas generating capability relative to 2025 on peak days (MW)
2032	2,084
2036	4,055

52 New York State Reliability Council (NYSRC). (2025, March 5). *Fuel Availability Constraints: Modeling Phase 2* (Installed Capacity Subcommittee Meeting #301). NYISO. https://www.nysrc.org/wp-content/uploads/2025/03/Fuel-Availability-Constraints.pdf

53 Note, this equation is given as y=- 0.0002 +7.6673*x-71512. However, this does not match the graphics provided in the presentation. we assume the correct equation is the inverse of that reported in the presentation: y=0.0002 -7.6673*x+71512. we also clip this value to enforce only non-negative values and only considers load values above 20,000 MW.

2.6 Integration across the models

The five modeling tools used in this study — LTCE, PCM, net capital costs simulation, loss of load modeling, and supplemental modeling — provide complementary insights into system performance. While each model serves a different purpose, their results are designed to be interpreted together to understand the reliability, affordability, and sustainability implications of alternative portfolios.

- LTCE modeling and market analysis forecasts the Base Case resource mix in each market and identifies credible alternative technology pathways;
- PCM evaluates the power price, emissions, and technology use in the market under typical conditions;
- Net capital cost forecast evaluates the fixed cost to build new generating resources;
- Loss of load modeling stress tests the same portfolios under extreme conditions to assess the resource adequacy and estimates economic impacts from load shedding; and
- The supplemental analysis examines the role that OSW can play in reducing the use of fuel oil – either as a primary or back-up fuel – in the downstate region of NYISO.

Together, these modeling layers provide a quantitative and holistic framework that enables robust, objective evaluation of the benefits, risks, and trade-offs associated with different generation portfolios, with a particular emphasis on evaluating the potential impact of OSW. The following section introduces the generator technology scenarios evaluated in this study and the performance metrics used to compare them.

2.7 Scenarios, sensitivities, and performance metrics

To evaluate how different resource portfolios perform under a wide range of future conditions, we develop a set of scenarios and sensitivities that capture key uncertainties in load growth, resource availability, policy requirements, technology performance, and imports. These scenarios are applied consistently across the LTCE, PCM, and loss of load modeling to ensure that results are comparable across modeling tools. Our goal is to examine how portfolios behave under realistic operating conditions as well as under more constrained or stressed environments.

2.7.1 Scenarios

The scenarios are designed to reflect plausible future outcomes for the Northeast electricity system and to isolate the effect of OSW availability. All scenarios begin with the same baseline assumptions on load growth, electrification, retirements, and announced projects. All scenarios also include a baseline of onshore renewables and natural gas resources. From this baseline, we vary the treatment of OSW and its substitutes to evaluate how different resource mixes perform across reliability, affordability, and emissions metrics.

Details for each are provided in Tables 3-1 and 3-2 and summarized visually in Figure 2-3. The four scenarios are as follows:

Figure 2-3: Modeling counterfactual scenarios

Base Case (Including OSW) – Expected portfolio mix
Use ISO load forecast, CRA generator portfolio forecast including OSW and no retirements
Goal: Evaluate the current trajectory of the systems

Counterfactual Scenarios

No Alternatives – Base Case with OSW removed
Goal: Evaluate the impact of canceling or delaying OSW, without alternatives
Rationale: Many OSW projects are advanced. There may be limited time to pivot to alternative generator resources, given supply chain and permitting challenges

Renewables Only – Replace with onshore renewables (scaled based on equivalent clean energy)
Goal: Evaluate the performance of OSW relative to inland, onshore renewables
Rationale: Replacing OSW with in-load zone resources may result in worse reliability performance, given transmission congestion and worse alignment with key stress periods

Gas Only – Replace with gas peaker in load zone (scaled on capacity contribution)
Goal: Evaluate the performance of OSW relative to in-zone dispatchable resources
Rationale: NYISO has identified a continued need for dispatchable (gas or DEFR) resources, particularly down-state

Base Case

The Base Case represents our base forecast for future system conditions across NYISO and ISO-NE and aligns with the most recent assumptions on load, resource mix, capacity accreditation, and reserve margins published by both system operators.[54,55,56,57] This technology view is based on results from our LTCE modeling, which optimizes system buildout to meet demand and policy goals at the least cost. The model allows new capacity additions only in solar, onshore wind, OSW, and energy storage, while existing gas units are retained for reliability support. This scenario represents the most realistic near-term outlook, capturing the full set of policy targets, market rules, and build constraints currently shaping the Northeast grid. It serves as the benchmark against which all other portfolios are evaluated.

NYISO

In New York, the Base Case assumes approximately 10 GW of OSW capacity by 2044, consistent with the New York State Climate Action Council's Scoping Plan (2022), which identifies OSW as central to achieving a zero-emission electricity system and targets 15 GW of

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54 New York Independent System Operator, 2025 Load & Capacity Data Report (Gold Book) (NYISO, 2025), https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf.

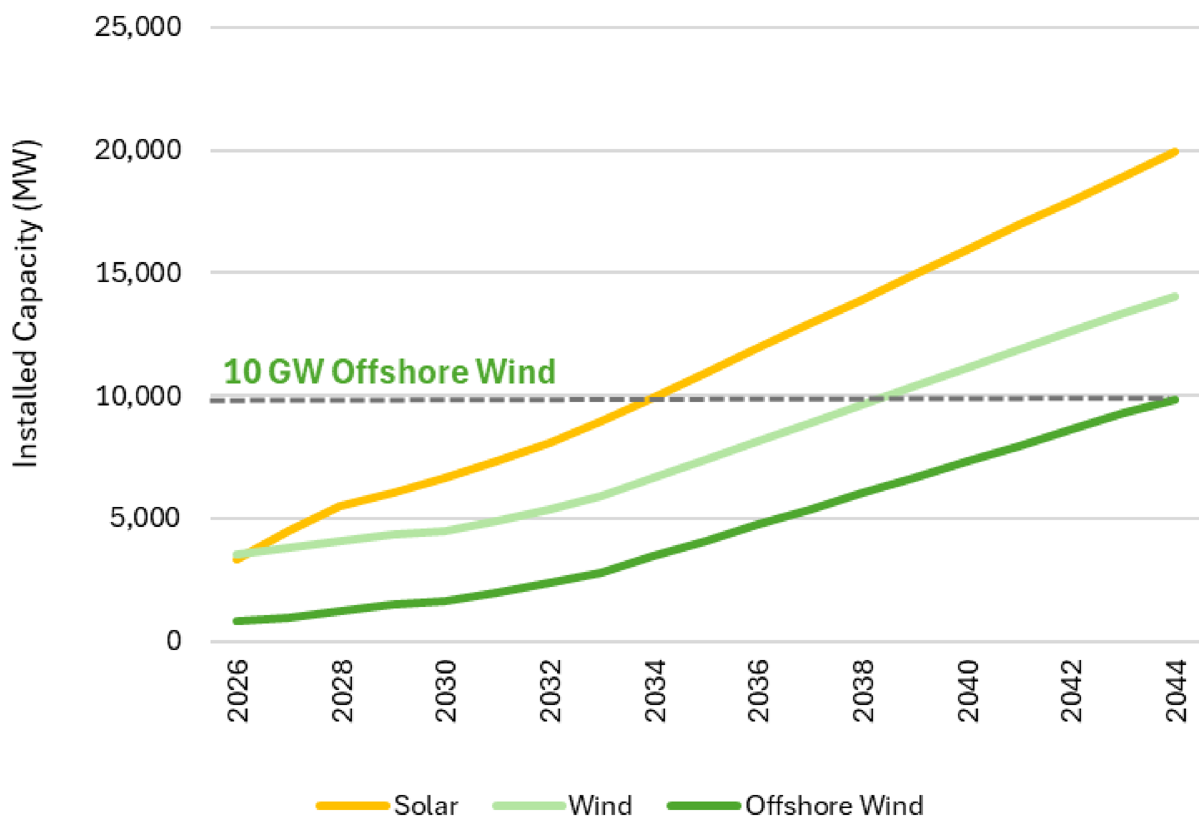
55 ISO New England, *2025 CELT Report—2025-2034 Capacity, Energy, Loads, and Transmission Forecast* (Excel file, May 24, 2025), https://www.iso-ne.com/static-assets/documents/100023/2025_celt.xlsx.

56 New York Independent System Operator, *Final Capability Adjustment Factors for the 2024–2025 Capability Year* (NYISO, [2023 or 2024], PDF file), https://www.nyiso.com/documents/20142/41593818/Final-CAFs-for-the-2024-2025-capability-year.pdf/3efc1e06-c1b0-72d6-f736-22721709c157?t=1708951801025.

57 ISO New England, *Impact Analysis Sensitivity Results – May 2024*, presentation to the NEPOOL Markets Committee, Milford, MA, May 7–8, 2024, https://www.iso-ne.com/static-assets/documents/100011/a02c_mc_2024_05_07_08_impact_analysis_sensitivity_results_may2024.pdf.

capacity by 2050[58]. The resulting renewables build-out is shown in Figure 2-4. We assume a resource trajectory that reflects a balanced pace of development that aligns with the Scoping Plan's long-term vision while maintaining system reliability.

Figure 2-4: NYISO Base Case renewable resources buildout



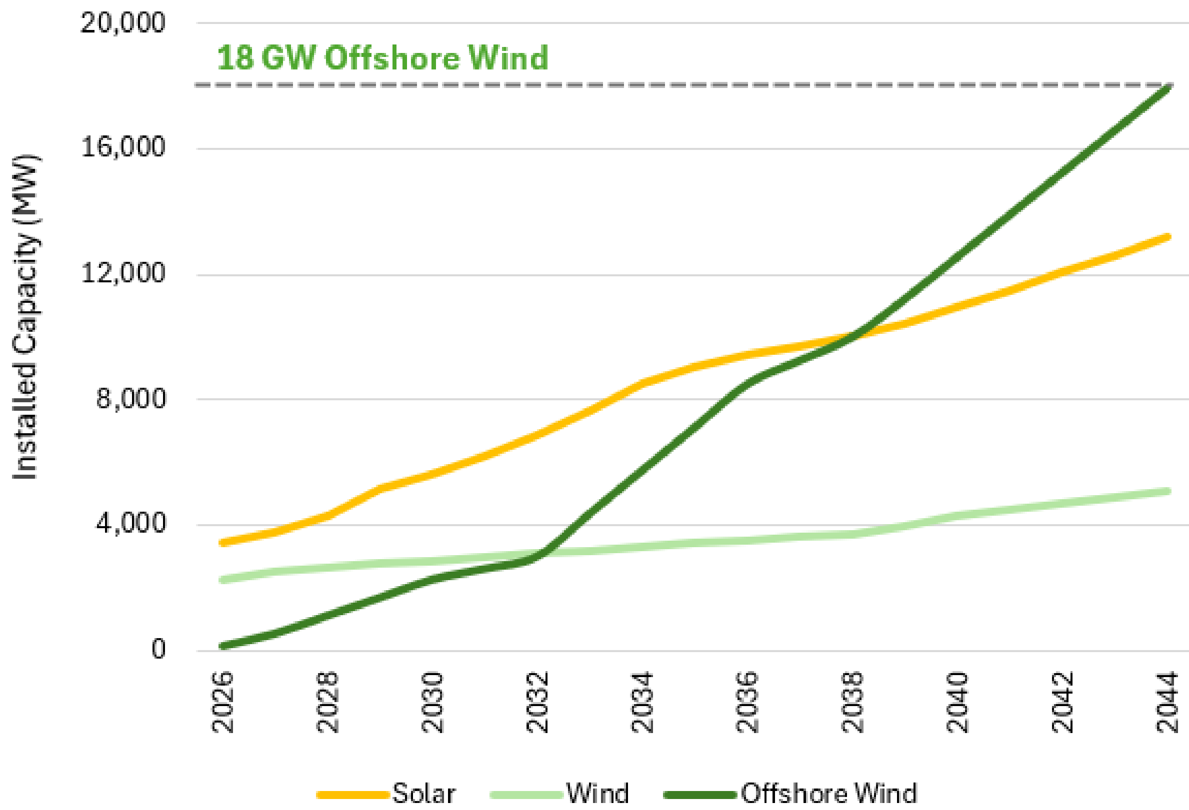
ISO-NE

In ISO-NE, the Base Case references the 2024 Energy Pathways to Clean Energy Transition (EPCET) report, which projects roughly 1,293 MW of OSW additions per year through mid-century.[59] Given ongoing interconnection queue backlogs, permitting challenges, and supply-chain constraints, we assume a more measured buildout, reaching 18 GW of OSW capacity by 2044, consistent with regional policy goals but reflective of practical development timelines.

58 New York State Climate Action Council. *New York State Climate Action Council Scoping Plan: A Framework for Meeting the Climate Leadership and Community Protection Act.* Albany, NY: New York State Energy Research and Development Authority, 2022. https://climate.ny.gov/resources/scoping-plan.

59 ISO New England, *Economic Planning for the Clean Energy Transition (EPCET)* (October 24, 2024), accessed [date], https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf.

Figure 2-5: ISO-NE Base Case Renewable Resources Buildout



Overall, the Base Case represents a reliability-constrained pathway where onshore and offshore renewable additions make meaningful progress toward policy goals while maintaining existing gas capacity to ensure system adequacy through the transition. The assumed renewables buildout is shown in Figure 2-5.

In order to maintain reliability, we do not include further retirement on natural gas generation. We recognize that policymakers in both regions have articulated long-term decarbonization goals that include the retirement of further natural gas generation.[60,61]

No Alternatives

The No Alternatives scenario evaluates the implications of a delayed or canceled OSW build-out, with no substitute resources developed to replace it. Given the advanced stage of several OSW projects in the region – such as Vineyard Wind and Revolution Wind – and the complexity

60 New York State Climate Action Council. *Scoping Plan: A Framework for Achieving the State's 2030 and 2050 Climate Targets.* Albany, NY: New York State Energy Research and Development Authority (NYSERDA), 2022. https://climate.ny.gov/Scoping-Plan/.

61 Commonwealth of Massachusetts. *An Act Driving Clean Energy and Offshore Wind.* Chapter 179 of the Acts of 2022. https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179.

of permitting, interconnection, and supply chain logistics, it may be difficult to bring alternative resources online quickly if OSW projects, particularly those in advanced stage of development, do not interconnect to the grid or are delayed due to policy and permitting reversals. Further, developing alternative resources may be delayed due to the lagging nature of market signals and the lack of central planning entity in these markets. This scenario illustrates the reliability and affordability risks associated with canceling OSW coupled with inaction or delays in developing alternative new resources. Note, in this scenario, the grid may violate global or local reserve margin requirements.

Renewables Only

In the Renewables Only scenario, OSW capacity is replaced by an equivalent level of onshore wind, solar, and battery storage, on an accredited capacity basis. These additions follow existing regional siting trends, with new onshore wind concentrated in upstate New York and northern New England, and new solar primarily located in southern and inland zones. Storage is added to make up for any capacity shortfalls and to meet local reserve requirements in the NYISO market. Because these resources are often distant from major coastal load centers and exhibit less generation during key stress winter stress hours, this scenario tests whether land-based renewables and storage can replicate OSW's contribution to winter reliability and local capacity needs in key coastal, urban centers. This scenario includes a broader baseline of natural gas and other onshore renewable resources.

Gas Only

The Gas Only scenario replaces OSW capacity with an equivalent amount of accredited natural gas capacity in the zones where OSW is currently connected.[62] This includes a broader baseline of natural gas and other onshore renewable resources. This scenario is useful for evaluating whether OSW can create equivalent reliability to dispatchable resources, like natural gas. While natural gas resources are retained across all scenarios, this is the only case in which net new gas resources are added to the system. We recognize that siting and permitting new gas plants in the Northeast is highly challenging – due to pipeline constraints, fuel-supply risks, and regulatory barriers. As such, we view the development of this level of net new natural gas capacity in New York City and southeastern New England as unlikely in the near-term. Further, we view the challenges of accessing firm gas contracts required for a combined cycle resource to be even more difficult. As such, we use a reference technology of a peaking gas plant.

[62] Accredited or UCAP-equivalent basis represents the amount of mega-watts that a resource is expected to supply during system stress periods. This differs from installed capacity (ICAP), which reflects the unit's full nameplate rating. To convert between ICAP and UCAP, ICAP is multiplied by the applicable Effective Load Carrying Capability (ELCC) or accreditation factor, which captures its performance during periods of grid stress. When sizing the replacement peaking unit, we determined the equivalent accredited capacity of a simple-cycle gas generator using the following relationship:
$ICAP_{Gas} = \frac{ELCC_{OSW}}{ELCC_{Gas}} ICAP_{Wind}$.

Nevertheless, this scenario provides a useful bookend for assessing how OSW's performance compares with a dispatchable, energy-dense alternative. It also allows examination of how potential future natural gas infrastructure investments – such as the Constitution Pipeline[63] – could influence resource adequacy as they enable net new resources to be added in the future.

2.7.2 Sensitivities

As discussed in Section 2.4.2, we perform sensitivity runs to examine the impact of tightening supply and demand conditions in surrounding markets. In the reference outlook, both NYISO and ISO-NE were modeled as being able to import from HQ, IESO, and PJM up to their transmission limits. We do not explicitly model these neighboring markets and instead assume that energy is available for import during stress hours. In the sensitivity run, no imports were allowed from these regions. We emphasize that this is a highly conservative assumption and is not intended to represent expected operating conditions. This sensitivity illustrates the exposure of NYISO and ISO-NE to tightening conditions in neighboring markets rather than providing a full assessment of regional resource adequacy.

2.7.3 Performance metrics

To evaluate how each portfolio performs under identical market and weather conditions, the analysis focuses on a common set of **performance metrics** derived from the modeling outputs. These metrics provide a quantitative basis for comparing portfolios across three dimensions – **reliability**, **affordability**, and **sustainability** – and serve as the foundation for the scorecard framework summarized below. They are also summarized in Table 2-4.

Most metrics are calculated for study years 2026 through 2044, while EUE and LOLE– derived from loss of load modeling – are computed specifically for 2032 and 2036, corresponding to the detailed adequacy simulation years. For the sensitivity run, only 2032 is reported.

The analysis employs a scorecard framework to summarize performance across three key dimensions:

- **Reliability** – measured through indicators such as EUE and resource adequacy costs and the capacity factor of the natural gas fleet (ancillary insights only).
- **Affordability** – evaluated using modeled energy costs under typical market conditions and net capital costs
- **Sustainability** – assessed through total system carbon-dioxide (CO_2) output and the operating intensity (capacity factor) of the natural gas fleet, reflecting how different portfolios affect overall system emissions and fossil fuel utilization.

63 The Williams Companies, Inc. (n.d.). *Constitution Pipeline*. https://www.williams.com/expansion-project/constitution-pipeline/

The natural gas capacity factor represents the ratio of actual electricity produced over a period to the maximum electricity the natural gas fleet could have produced if all units operated at full output continuously over that period. While EUE and LOLE remain the industry-standard reliability metrics, the capacity factor of the natural gas fleet offers important complementary insight into the operational burden placed on aging thermal resources. Higher utilization increases wear and tear, raises the probability of forced outages, reduces opportunities for planned maintenance, and increases stress on constrained natural gas delivery systems. Rising capacity factors therefore provide an early indication of elevated system-wide reliability risk, even when traditional metrics appear acceptable. We prioritize EUE as the primary resource adequacy metric because it more clearly reflects the magnitude of potential shortfalls.

Table 2-4: Performance metrics used to evaluate the performance of the scenarios

Metric	Category	Description	Granularity
Normalized EUE (ppm)	Resource Adequacy	The expected amount of energy unserved each year, normalized by the total energy sales and reported in parts per million	Reported only for study years 2032 and 2036
Energy price	Affordability	The net present value of the hourly energy price[64]	Reported over years 2026 to 2044
Net capital costs	Affordability	The net present value of the capital costs, net of energy revenue[65]	Reported over years 2026 to 2044
Natural gas capacity factor	Sustainability, Reliability (ancillary insights)	The average capacity factor for natural gas plants in the system	Reported over years 2026 to 2044
Emissions	Sustainability	The total amount of emission produced by the portfolio mix	Reported over years 2026 to 2044

64 Assumes a discount rate of 6.8% to match the after tax weighted average cost of capital for utilities in the Northeast.

65 Ibid.

Market outlooks

This section summarizes the market and system outlooks that form the foundation of our analysis. These outlooks define the Base Case from which the counterfactual scenarios are developed. Both NYISO and ISO-NE are undergoing structural transitions driven by the electrification of buildings and transportation, policy-driven fossil retirements, and increasing renewable penetration. These shifts are changing historical patterns of system stress, moving the region from summer-dominant to winter-dominant risk periods and creating new challenges for reliability planning and resource adequacy. The following subsections describe the key load, generation, and policy trends shaping each market.

3.1 ISO-NE

System overview and emerging trends

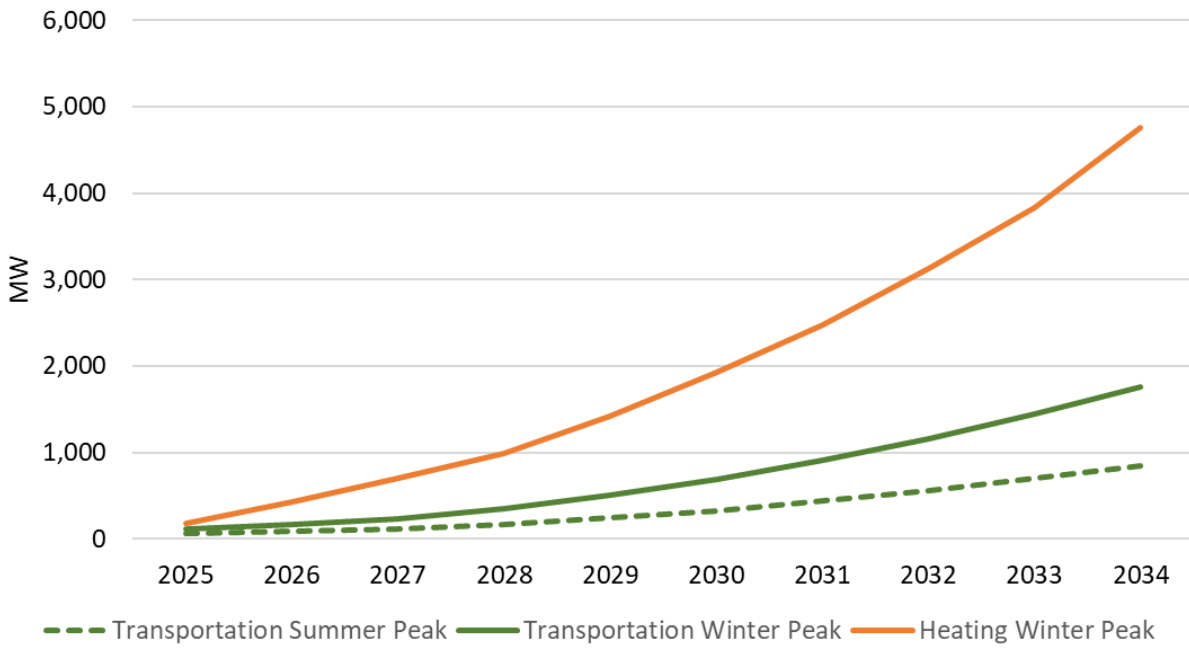
ISO-NE has historically been a summer-peaking system, but rapid electrification of heating, rising electric-vehicle adoption, and the retirement of aging fossil units are shifting reliability risk toward the winter months (see Figure 3-1).

According to ISO-NE's 2025 CELT report, summer peak demand is expected to grow modestly from 26.5 GW in 2025 to 28.7 GW by 2034 with a compound annual growth rate (CAGR) of 0.9%, while winter peak demand rises from 20.0 GW to 26.4 GW with a CAGR of 3.1%.[66] This rapid winter growth heightens concerns about fuel security, a long-standing challenge in New England.[67]

66 ISO New England, *2025 CELT Report—2025-2034 Capacity, Energy, Loads, and Transmission Forecast* (Excel file, May 24, 2025), https://www.iso-ne.com/static-assets/documents/100023/2025_celt.xlsx.

67 Stephen George, "Opening Presentation: Winters 2023/2024 and 2024/2025 in New England and the Role of Everett," presentation to the New England Winter Gas-Electric Forum, 2023 Winter Gas-Electric Forum, published on ISO-New England website, https://www.ferc.gov/media/iso-ne-opening-presentation.

Figure 3-1: ISO-NE electrification forecast, 2025[68]



Interregional dynamics

ISO-NE remains closely interconnected with NYISO, New Brunswick, and HQ.[69] ISO-NE is a net importer, with imports covering roughly 9% of its energy needs in 2024.[70] The region is exploring new transmission expansions, including the New England Clean Energy Connect, to strengthen its links to Canadian hydropower resources.[71] However, tightening conditions in surrounding markets, particularly HQ, may reduce ISO-NE's import flexibility during stress periods, increasing the importance of in-region resources.[72]

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68 ISO New England, *2025 CELT Report—2025-2034 Capacity, Energy, Loads, and Transmission Forecast* (Excel file, May 24, 2025), https://www.iso-ne.com/static-assets/documents/100023/2025_celt.xlsx.

69 Ibid.

70 ISO New England Inc. (2025, April 23). *ISO New England overview and regional update* [Presentation to the Business & Industry Association of New Hampshire]. https://www.iso-ne.com/static-assets/documents/100023/isone_2025_04_23_nh_bia.pdf

71 New England Clean Energy Connect. (n.d.). *Home*. Retrieved [access date], from https://www.necleanenergyconnect.org/

72 Hydro-Québec. "Are We Running Out of Electricity in Québec?" Accessed July 2025. https://www.hydroquebec.com/residential/energy-wise/are-we-running-out-electricity.html

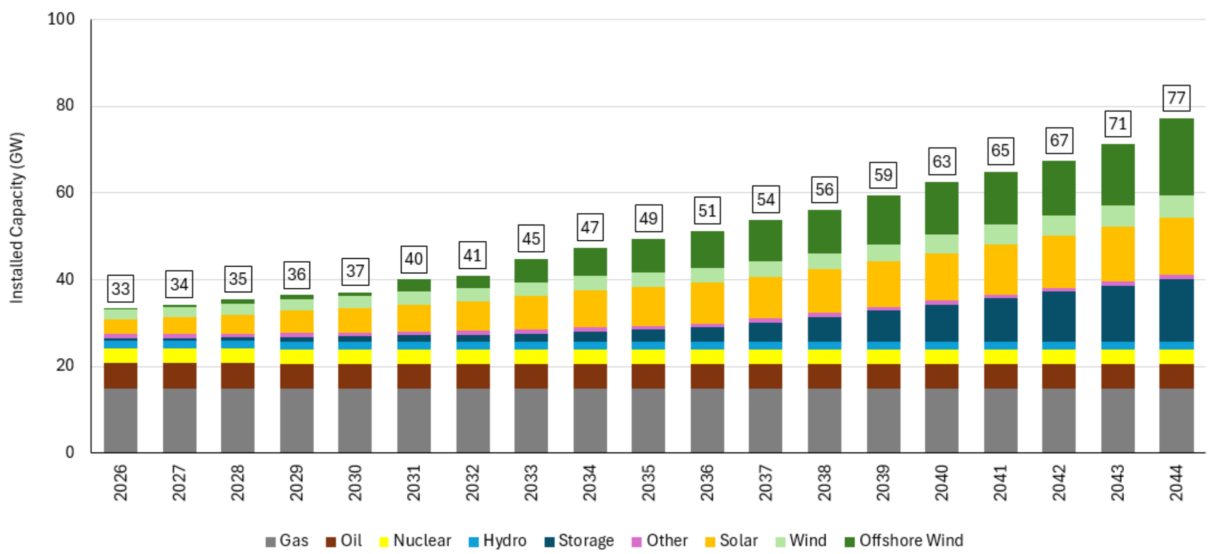
OSW development

Presently, ISO-NE is planning to build 18 GW of OSW, including Revolution Wind, (704 MW expected in 2026),[73] Vineyard Wind (800 MW partially online).[74]

Resource and load forecasting framework

Using the same LTCE modeling approach, we estimate ISO-NE's least-cost resource mix that meets reliability and policy goals. This output from the LTCE modeling forms the Base Case view and is shown in Figure 3-2.

Figure 3-2: CRA's generator resource forecast for ISO-NE



From this Base Case, a set of counterfactual scenarios is constructed to assess the reliability and economic implications of varying levels of OSW deployment. Capacity adjustments for two representative study years – 2032 and 2036 – are summarized in Table 3-1.

73 Revolution Wind. "*About Revolution Wind.*" Accessed November 21, 2025. https://revolution-wind.com/about-revolution-wind

74 Massachusetts Executive Office of Energy and Environmental Affairs, "*Vineyard Wind, America's First Large-Scale Offshore Wind Farm, Delivers Full Power from 5 Turbines to the New England Grid*," press release, February 22, 2024, https://www.mass.gov/news/vineyard-wind-americas-first-large-scale-offshore-wind-farm-delivers-full-power-from-5-turbines-to-the-new-england-grid.

Table 1-1: Portfolio adjustments for ISO-NE (2032 & 2036)

Scenario	Year	OSW	Solar	Onshore wind	Storage	Natural gas
Base Case	2032	**2,830 MW**	**6,855 MW**	**3,078 MW**	**1,442 MW**	**18,971 MW**
	2036	**8,497 MW**	**9,400 MW**	**3,514 MW**	**3,150 MW**	**14,971 MW**
No Alternatives	2032	-2,030 MW	*No change*	*No change*	*No change*	*No change*
	2036	-7,697 MW	*No change*	*No change*	*No change*	*No change*
Renewables Only	2032	-2,030 MW	+5,300 (ME, MA, RI, VT)	+925 (ME, MA, RI, NH)	*No change*	*No change*
	2036	-2,030 MW	+18,350 (ME, MA, RI, VT)	+3,300 (ME, MA, RI, NH)	*No change*	*No change*
Gas Only	2032	-7,697 MW	*No change*	*No change*	*No change*	+1,621 (Boston, SE MA)
	2036	-7,697 MW	*No change*	*No change*	*No change*	+5,558 (Boston, SE MA)

3.2 NYISO

System overview and emerging trends

Historically a summer-peaking system, New York is projected to become winter-peaking by the late 2030s, with winter peak demand approaching 50 GW.[75] NYISO's load forecast is shown in Figure 3-4. Much of this growth will occur in downstate regions (New York City and Long Island)

75 New York Independent System Operator, 2025 Load & Capacity Data Report (Gold Book) (NYISO, 2025), https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf.

where electrification of buildings and transportation is concentrated, and transmission import capacity is already limited. In addition, generation has retired.

Resource adequacy challenges are particularly acute downstate. Since 2019, 1,600 MW of peaking generating units have retired.[76] These retirements are creating tightening supply-demand conditions in the downstate regions of the grid, driving capacity prices roughly three times higher than those in upstate areas.[77] To maintain reliability in these constrained areas, NYISO establishes Locational Capacity Requirements (LCRs), which specify the minimum amount of installed capacity that must be physically located within a zone. LCRs are necessary because transmission limitations prevent importing sufficient power from other regions during peak conditions. NYISO determines these requirements annually using probabilistic reliability modeling based on the statewide LOLE criterion of 0.1 days per year. The process accounts for transmission constraints, generator availability, and emergency procedures, adjusting local capacity levels until both statewide and zonal reliability standards are met. This ensures that even under stressed conditions, each locality has enough in-zone resources to serve demand without violating reliability criteria. LCRs are significantly higher in New York City and Long Island than in upstate zones because these areas have limited transmission ties and dense load centers; for example, the 2025/26 LCR is approximately 78.5% of peak load for Zone J (NYC) and 76.8% for Zone K (Long Island)[78], compared to much lower percentages in unconstrained regions (24.4% statewide). Sustaining LCRs over time requires additional in-zone capacity to meet growing downstate reliability needs.

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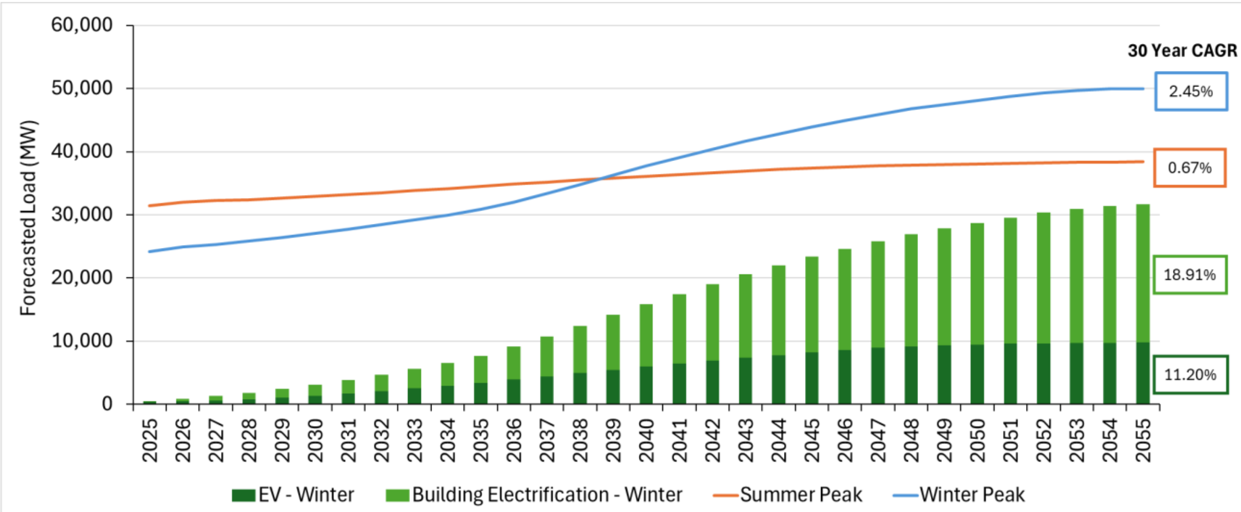
[76] New York Independent System Operator (NYISO). *Q3 2025 Short-Term Assessment of Reliability (STAR)*. Rensselaer, NY: NYISO, 2025. Available at: https://www.nyiso.com/documents/20142/39103148/2025-Q3-STAR-Report-Final.pdf

[77] New York Independent System Operator, *2025 Load & Capacity Data Report (Gold Book),* (2025), https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf.

[78] New York Independent System Operator, Locational Minimum Installed Capacity Requirements Study for the 2025-2026 Capability Year (NYISO, 2025) https://www.nyiso.com/documents/20142/49410485/2025-2026-LCR-Report-Clean.pdf/c8c65acd-0979-a67a-9fa8-f322536fc156

Figure 3-4: NYISO forecasted summer and winter peak demand with electrification impacts (2025–2055)[79]



Interregional dynamics

NYISO benefits from imports from neighbors – including PJM, IESO, and HQ. NYISO is a net importer, with imports serving over 13% of total energy needs.[80] In 2024, PJM alone served 12% of NYISO's energy needs.[81] Imports from HQ are projected to increase upon the completion of the Champlain Hudson Power Express (CHPE) linking Quebec to New York City.[82]

However, neighboring markets – including PJM, IESO, and HQ – are also tightening and shifting toward winter risk[83,84,85] Although NYISO is linked to parts of PJM with relatively lower reliability risk,[86] coincident stress events across these regions could limit import availability when it is most needed and may further spike downstate reliability needs/locational capacity requirements.

79 NYISO (New York Independent System Operator), 2025 Gold Book: Public (Albany, NY: NYISO, 2025), https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf.

80 Ibid.

81 Ibid.

82 New York Independent System Operator. *2024 Power Trends.* May 2024. Retrieved from https://www.nyiso.com/documents/20142/2223020/2024-Power-Trends.pdf

83 Hydro-Québec. "Are We Running Out of Electricity in Québec?" Accessed July 2025. https://www.hydroquebec.com/residential/energy-wise/are-we-running-out-electricity.html

84 Independent Electricity System Operator (IESO). *Reliability Outlook: An Adequacy Assessment of Ontario's Electricity System, October 2025 – March 2027.* Toronto: IESO, September 2025.

85 PJM Inside Lines. "PJM Details Resource Retirements, Replacements and Risks." February 24, 2023. https://insidelines.pjm.com/pjm-details-resource-retirements-replacements-and-risks/

86 U.S. Department of Energy. (2025, July 7). *Report on Evaluating U.S. Grid Reliability and Security* (DOE/Publication No.). https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf

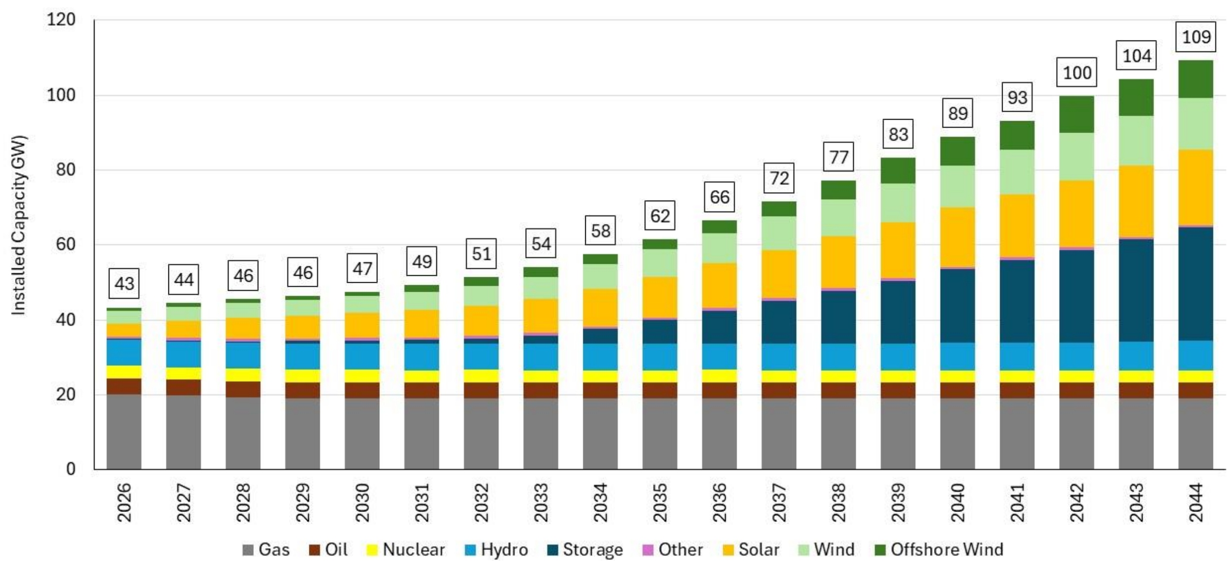
OSW development

NYISO plans to build approximately 9 GW of OSW as part of its goal of transitioning to a zero-emissions electricity system by 2040. OSW will interconnect directly to stressed downstate zones. For example, South Fork Wind, the first utility-scale offshore wind project in the United States, is helping to resolve gas- and transmission-constraints on Long Island.[87] South Fork was placed into service in March 2024 and provides 132 MW of installed capacity.[88] Construction is underway on further OSW projects: Sunrise Wind (924 MW, expected to come online in 2027[89]) and Empire Wind 1 (810 MW, expected to come online in 2027[90]).

Resource and load forecasting framework

To identify the Base Case, we use LTCE modeling to identify the least-cost, physically feasible generator mix satisfying both reliability and policy requirements. This is the Base outlook, from which we craft counterfactual scenarios. The resulting output of the LTCE model is the installed-capacity forecast, shown in Figure 3-5. It largely aligns with NYISO's 2023 System & Resource Outlook.[91]

Figure 3-5: Base Case generator resource forecast for NYISO



87 Stover, Oliver, Jesse Dakss, Dean Koujak, Ryan Chigogo, Abdul Mohammed, Ryan Israel, Charles Merrick, and Chloe Romero Guliak. *The Contribution of Offshore Wind to Grid Reliability and Resource Adequacy.* Boston: Charles River Associates, 2025. https://www.crai.com/insights-events/publications/the-contribution-of-offshore-wind-to-grid-reliability-resource-adequacy/

88 Welcome to South Fork Wind" n.d. Southforkwind.com. https://southforkwind.com/.

89 "US East Coast Sunrise Wind project faces schedule delays, rising costs." *Offshore Magazine*, January 21, 2025. https://www.offshore-mag.com/renewable-energy/news/55262445/rsted-east-coast-sunrise-wind-project-face-schedule-delays-rising-costs

90 Empire Wind. "Empire Wind 1." *Empire Wind*. Accessed October 5, 2025. https://www.empirewind.com/ew-1/

91 NYISO. (2023). *2023–2042 System Resource Outlook*. Retrieved from https://www.nyiso.com/documents/20142/46037414/2023-2042-System-Resource-Outlook.pdf

From this Base Case, we constructed a series of counterfactual scenarios to examine the role of OSW and evaluate alternative resource pathways. Capacity adjustments for two representative years are summarized in Table 3-2.

Table 3-2: Portfolio adjustments for NYISO (2032 & 2036)

Scenario	Year	OSW	Solar	Onshore wind	Storage	Natural gas
Base Case	2032	**2,234 MW**	**8,058 MW**	**5,388 MW**	**1,442 MW**	**18,971 MW**
	2036	**3,314 MW**	**11,932 MW**	**8,138 MW**	**8,842 MW**	**18,971 MW**
No Alternatives	2032	-2,096 MW	*No change*	*No change*	*No change*	*No change*
	2036	-3,176 MW	*No change*	*No change*	*No change*	*No change*
Renewables Only	2032	-2,096 MW	Upstate: +725 MW	Upstate: +3,075 MW	Downstate: +920 MW	*No change*
	2036	-3,176 MW	Upstate: +1,125 MW	Upstate: 3,950 MW	Downstate: +1,310 MW	*No change*
Gas Only	2032	-2,096 MW	*No change*	*No change*	*No change*	Downstate: +637 MW
	2036	-3,176 MW	*No change*	*No change*	*No change*	Downstate: +751 MW

Results

This section presents the modeling results across the four scenarios for both markets. The analysis compares the performance of each portfolio across the three key dimensions of the scorecard — reliability, affordability, and sustainability — to understand how different resource pathways affect system outcomes. We also report supplemental results on fuel oil generation in NYISO.

These results are not intended to prescribe a single pathway. Instead, they illustrate the trade-offs inherent in alternative futures and highlight the structural constraints facing each region. They are also not designed to replace assessments conducted by NYISO or ISO-NE, which differ in scope, geographic footprint, and study objectives.[92]

Across both markets, the Base Case, which includes OSW, delivers the most balanced performance, achieving meaningful emissions reductions and lower power prices while maintaining reliability. The magnitude of these benefits varies by region and depends on the ability to import power during stress events, reflecting differences in the availability of replacement resources, internal transmission constraints, fuel limitations, and the mix of renewable and thermal generation. Additionally, the performance on capital costs is mixed.

With the exception of the No Alternative Case, the Base Case has the lowest net capital costs in NYISO. The Base Case results in higher net capital costs relative to the Gas Only Case in ISO-NE. However, the results in both markets are sensitive to specific assumptions regarding resource buildout, land costs, transmission requirements, and fuel infrastructure needs. These cost differences likely merit project-specific analysis rather than system-wide generalization.

In addition to the quantitative modeling, planners and regulators should also consider broader elements of long-term grid planning. These include policy objectives, technology readiness and supply-chain risks, development risks, transmission and fuel infrastructure upgrades, capacity-market dynamics, customer affordability, and cross-market interactions. These considerations are especially important in dense regions of ISO-NE and NYISO, where siting new infrastructure is challenging.

The following subsections summarize key findings for ISO-NE and NYISO, followed by a cross-market comparison that highlights common trends and insights into the benefits and risks of different technology pathways.

4.1 ISO-NE

Overview

This section presents the detailed results for ISO-NE. The power price forecast is shown in Figure 4-1, the emissions forecast in Figure 4-2, and the natural gas capacity factor forecast in Figure 4-3. In these figures, the annual performance is reported for each year in the simulation horizon. The Base Case is shown in grey, the No Alternatives Case in purple, the Renewables Only Case in green, and the Gas Only Case in blue.

Table 4-1 provides the summary quantitative metrics, with each scenario shown as the first number and the percentage change from the Base Case in parentheses. Across all scenarios, reliability risks remain low, due in part to ISO-NE's ability to import energy from Canada and

[92] New York Independent System Operator. *2024 Reliability Needs Assessment (RNA): A Report from the New York Independent System Operator.* November 19, 2024. https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf

NYISO — even in the sensitivity that restricts imports. However, ISO-NE may still face resource adequacy risks if new resources are not brought onto the system. Further, risks not captured in the loss of load modeling, including fuel-supply disruptions, given ongoing stress on the natural gas system.[93]

Using the net present value of modeled power prices, the Renewables Only portfolio yields the lowest overall energy cost, followed closely by the Base Case. In contrast, the Gas Only and No Alternatives portfolios exhibit 1.08x and 1.10x power-price premiums relative to the Base Case.

Similarly, both the Base Case and Renewables Only portfolios achieve the lowest emissions and natural gas capacity factors, while the other scenarios depend more heavily on gas generation, resulting in higher costs and emissions. The Gas Only and No Alternatives portfolios produce approximately 1.35x and 1.75x increases in natural gas capacity factor and 1.30x and 1.24x increases in CO_2 emissions, respectively, compared with the Base Case.

Load shedding risk

Across all portfolios, resource adequacy remains strong, with only limited unserved energy observed in most cases. This outcome reflects assumed access to surplus imports from Canadian markets and substantial onshore renewable additions across the region.

A small amount of unserved energy appears in the No Alternatives and Renewables Only scenarios, but these values remain well below risk-tolerance thresholds. Risk increases modestly in the no-imports sensitivity (Table 4-2), reflecting the assumed inability to access neighboring systems during stress periods. Based on this analysis, any of these futures provides a viable resource mix from a reliability perspective and could consider adding few resources and/or retiring aging resources. This excess capacity could be due to incorrect capacity accreditation/reserve margin targets or excess resources needed to meet state decarbonization policies. ISO-NE's capacity accreditation methods are evolving[94], and as they mature, they will more accurately reflect underlying risk conditions. Alternatively, the system could maintain resource adequacy with fewer resources, potentially allowing for the retirement of aging gas or oil units.

Figure 4-4 presents the distribution of load-shedding risk for the no-imports sensitivity. Most of the risk is concentrated in Boston and Vermont, driven by limits on local resources and transmission constraints. Including OSW in the portfolio marginally shifts risk away from Boston because it directly connects to this coastal load zone.

[93] ISO New England. 2025. *2024 Assessment of the ISO New England Electricity Markets.* External Market Monitor Report. June. Available at: https://www.iso-ne.com/static-assets/documents/100025/iso-ne-2024-emm-report-final.pdf

[94] ISO New England, *2021 Economic Study: Future Grid Reliability Study, Phase 1 (Report*, PDF file), July 29, 2022, https://www.iso-ne.com/static-assets/documents/2022/07/2021_economic_study_future_grid_reliability_study_phase_1_report.pdf.

Cost implications

The net present value of the price forecast, including energy costs, net capital costs, and resource adequacy costs, is shown in Figure 4-5. The No Alternatives Case has the lowest net capital costs (62% lower than the Base Case), followed by the Gas Only Case (32% lower than the Base Case). These lower capital costs reflect the smaller amount of new resource build-out in the No Alternatives scenario. In this case, the No Alternatives portfolio appears viable due to relatively low market-wide risk, which is likely driven by overbuild that may stem from capacity accreditation assumptions or excess builds to meet state decarbonization targets. If less resources are brought into the system, the portfolios across the other scenarios would become more competitive with the No Alternatives scenario.

The cost premium of the Base Case relative to Gas Only is primarily driven by deep OSW deployment, 18 GW in total. Importantly, these cost comparisons do not include potential pipeline-upgrade costs required to add new natural gas generation, which could be substantial given constrained fuel supplies in the region.

These results highlight an important insight for grid planners: OSW may become less cost-competitive with natural gas at high penetration levels of OSW. This is because the per-megawatt accredited capacity contribution of OSW declines as more OSW is added to the system while the accreditation of natural gas remains relatively constant. At deep penetrations, OSW is a victim of its own success: it shifts risk to lower wind hours and its accreditation decline. Thus, under such high adoption conditions, a smaller quantity of natural gas capacity can maintain similar resource-adequacy performance, resulting in lower capital costs for the Gas Only scenario. To preserve OSW's cost competitiveness at deeper penetration, developers may need to pursue economies of scale to reduce the OSW capital costs and/or pair OSW with storage to mitigate declining capacity accreditation.

Table 4-1: ISO-NE metric scorecard

Metric	Base Case (with OSW)	No Alternatives	Renewables Only	Gas Only
EUE (ppm) 2032 w/ HQ imports	0.0	0.02 (0%)	0.02 (0%)	0.0 (0%)
EUE (ppm) 2032 without HQ imports	0.0	0.0 (0%)	0.01	0.0 (0%)
RA risk premium	$0 B	$0 B	$0 B	$0 B
Net capital cost	$62.0B	$23B (-62%)	$92B (48%)	$42.0B (-32%)
Energy price	$62.0B	$68.2 (+10%)	$55.9 (-9.8%)	$67.3 (+8.5%)
Natural gas capacity factor	20%	35% (+75%)	21% (+5%)	27% (+35%)
Emissions	211M Tons CO2	262M Tons CO2 (+72%)	219 M Tons CO2 (+4%)	274M Tons CO2 (+77%)

Note: change relative to Base Case shown in parenthesis

Table 4-2: ISO-NE: Reliability results – no imports sensitivity

Metric	Base Case (with OSW)	No Alternatives	Renewables Only	Gas Only
EUE (ppm) 2032	3.49	4.09 (+17%)	3.55 (+2%)	2.63 (-25%)

Note: change relative to Base Case shown in parenthesis

Figure 4-1: ISO-NE market-wide average energy price

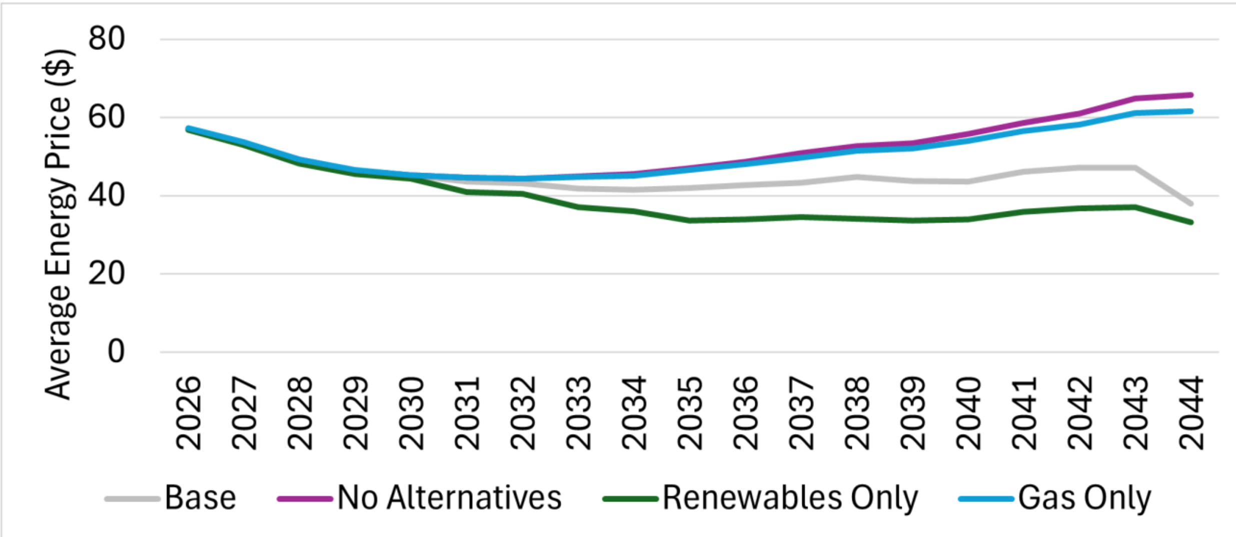


Figure 4-2: ISO-NE average gas capacity factor

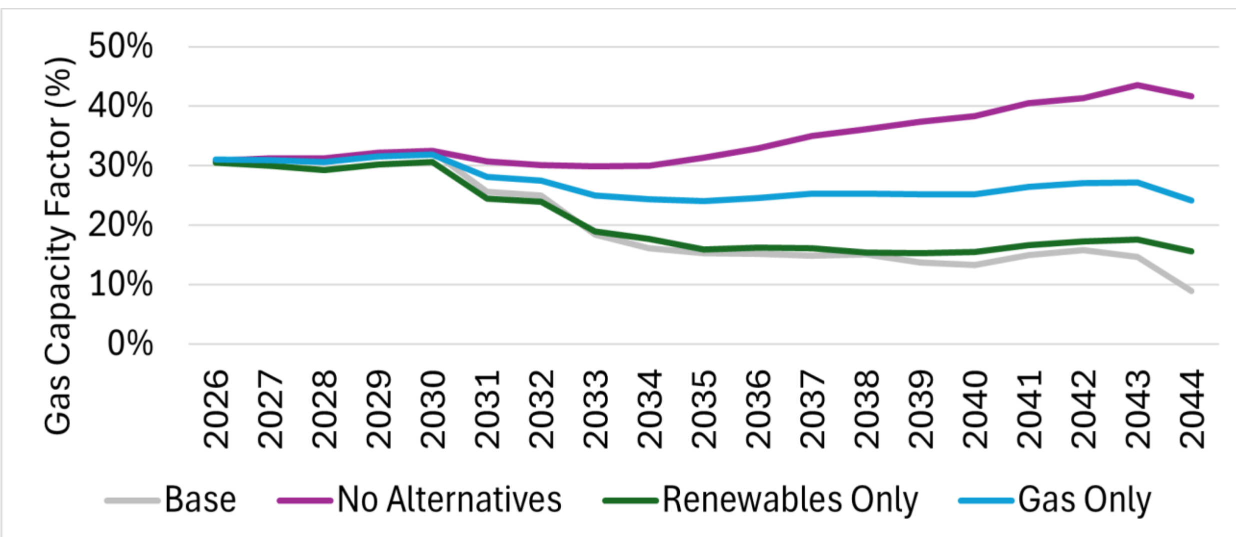


Figure 4-3: ISO-NE average annual system-wide emissions

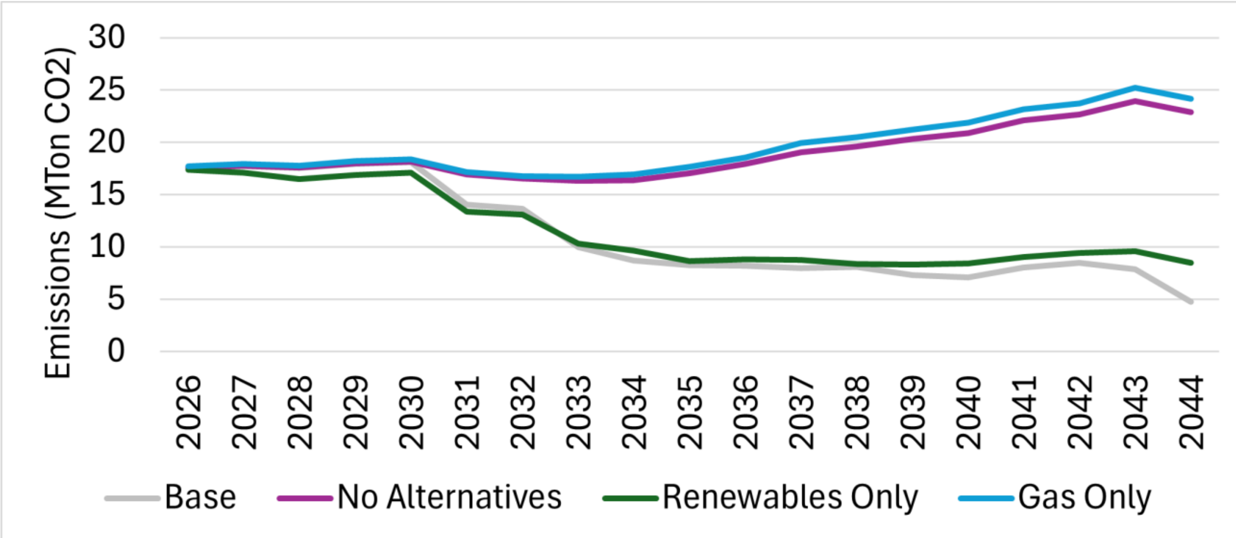


Figure 4-4: ISO-NE load shedding risk distribution (no imports sensitivity)

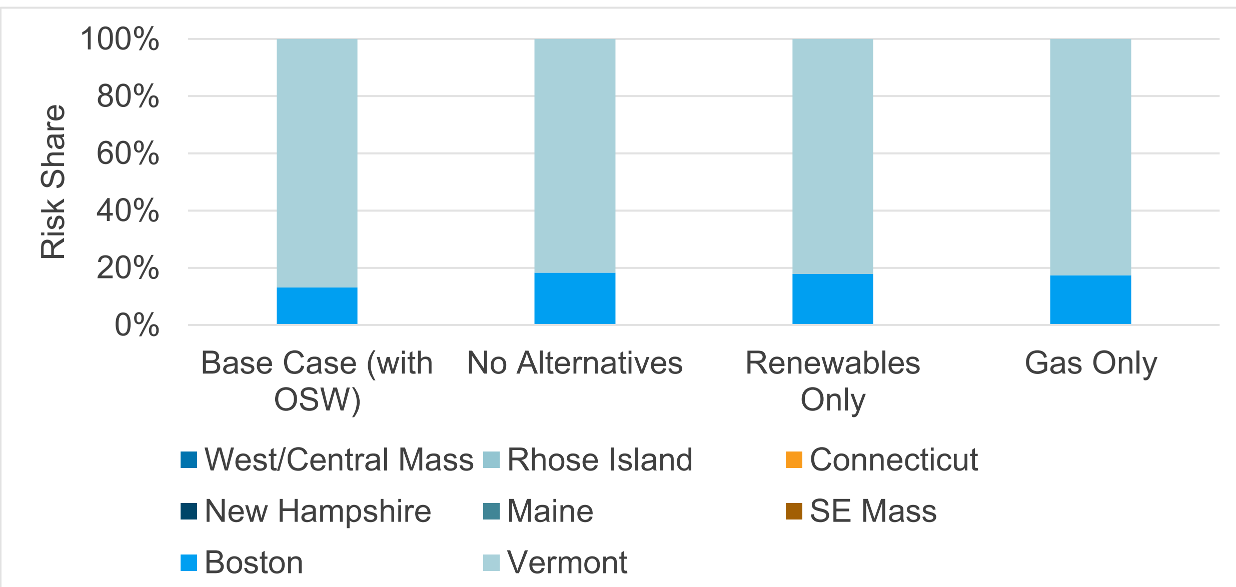
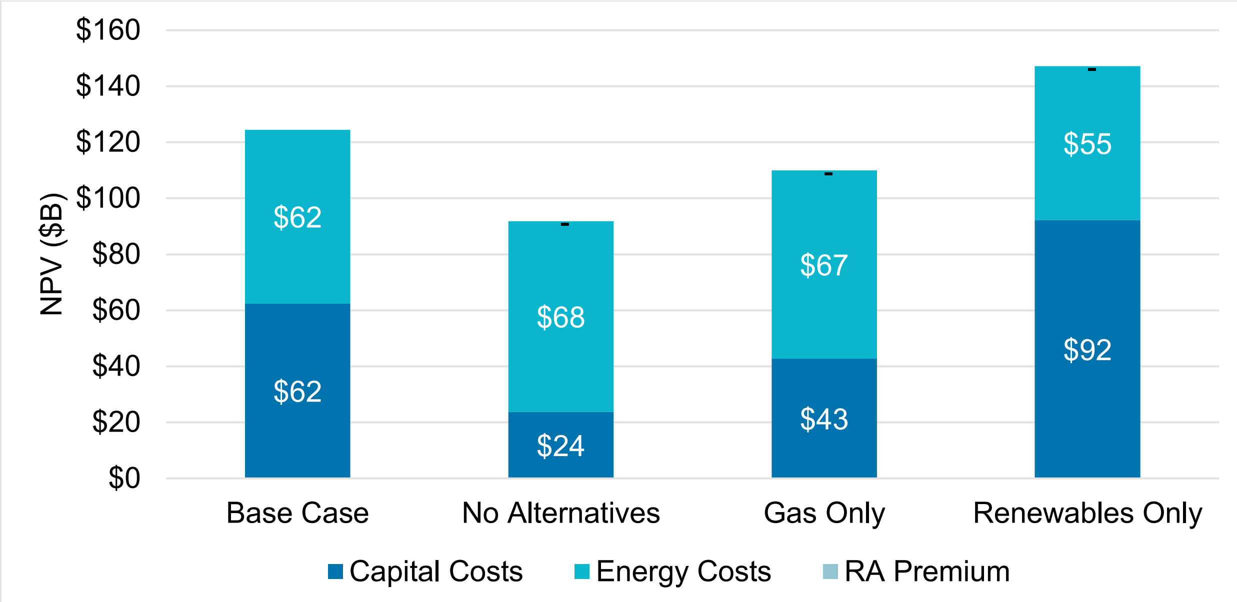


Figure 4-5: ISO-NE: Cost forecast



4.2 NYISO

Overview

This section presents the detailed results for NYISO. Overall, differences across scenarios are less pronounced than in ISO-NE, with the largest divergences occurring in reliability outcomes. The power price forecast is shown in Figure 4-6, the emissions forecast in Figure 4-7, and the natural gas capacity factor forecast in Figure 4-8. As in ISO-NE, annual performance is reported for each simulation year. The Base Case is shown in grey, the No Alternatives Case in purple, the Renewables Only Case in green, and the Gas Only Case in blue. In Figure 4-8, the No Alternatives and Gas Only outcomes appear closely aligned and overlap in the graphic.

Table 4-3 summarizes the modeled metrics. The Renewables Only scenario achieves the lowest overall power cost (based on the NPV of the modeled power price), followed closely by the Base Case. The Gas Only and No Alternatives portfolios show 1.06x and 1.07x power price premiums, respectively, relative to the Base Case.

Emissions and gas-fleet usage follow a similar pattern. The Base Case and Renewables Only portfolios deliver the lowest emissions and lowest gas capacity factors, while the Gas Only and No Alternatives portfolios rely more heavily on gas generation. These scenarios show 1.22x and 1.27x increases in gas-fleet capacity factor, and 1.27x and 1.26x increases in CO_2 emissions, respectively, relative to the Base Case. Although individual gas units operate less frequently in the Gas Only Case, the system overall depends more on gas-fired resources to meet demand.

Load shedding risks

Unlike ISO-NE, NYISO exhibits measurable load shedding risk. Load shedding events are observed in Zones A, B, D, J, and K (shown in Figure 4-9). The system-wide EUE in the Base Case is 69 ppm – approximately 3.5X the common target of 20 ppm. The Base Case has the lowest EUE risk, followed by the Gas Only Case. The No Alternatives and Renewables Only scenarios show material degradation in resource adequacy, largely because these portfolios do not add new resources in constrained downstate zones to meet rising winter load growth.

These findings are consistent with concerns raised by NYISO about elevated near-term reliability risk in New York City.[95] We observe higher and earlier reliability risk than NYISO's own analysis, likely due to differences in assumed generation builds and inter-ISO transmission limits.[96] Nevertheless, the conclusion is similar: **downstate New York faces rising reliability risk without new local resources or transmission.**

By 2036, load-shedding risks decline below target levels in the Base Case and Gas Only scenario because of new resource additions. Risk also declines in the No Alternatives and Renewables Only scenarios but remains above target, with particularly elevated risk in Zone J due to the lack of new in-zone capacity.

No-imports sensitivity

We also report results for a sensitivity in which no imports are assumed from HQ, IESO, or PJM in 2032. The results are reported in Table 4-4. The distribution of risk across zones is shown in Figure 4-10. This assumption is intentionally conservative and assumes neighboring systems are always in simultaneous stress and never able to export. While coincident stress is plausible during wide-area extreme weather, it is unlikely to occur in all stress events.

As such, this scenario is not intended as a risk forecast. The sensitivity provides insight into the role of native generation in hedging against tightening conditions across the broader Northeastern region.

As expected, NYISO would experience deep and frequent load shedding without imports. System EUE increases by 30 to 40 times, and risks spread beyond downstate to include Zones B, C, and D. Domestic investments in either OSW or natural gas mitigate some, but not all, of this risk.

95 New York Independent System Operator (NYISO). *Short-Term Assessment of Reliability (STAR), Q3 2025*. Albany, NY: NYISO. Available at: https://www.nyiso.com/documents/20142/39103148/2025-Q3-STAR-Report-Final.pdf

96 New York Independent System Operator. *2024 Reliability Needs Assessment Report*. July 25, 2024. Retrieved from https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf/0fe6fd1e-0f28-0332-3e80-28bea71a2344

Table 4-3: NYISO metric scorecard

Metric	Base Case (with OSW)	No Alternatives	Renewables Only	Gas Only
EUE (ppm) 2032	69	99 (+43%)	75 (+9%)	77 (+12%)
EUE (ppm) 2036	2.5	4.5 (+76%)	6 (+146%)	11 (+327%)
RA premium	$2.22B	$2.94B (+32%)	$2.23B (-0.29%)	$2.33B (-5%)
Net capital costs	$63.1B	$43.9B (-31%)	$77.5B (+22%)	$60.8 (-4%)
Energy price	$67B	$72B (6.6%)	$67B (-0.3%)	$72B (6.3%)
Natural gas capacity factor	22%	28% (+27%)	25% (+9%)	27% (+22%)
Emissions	335M Tons CO2	424M Tons CO2 (+27%)	371 M Tons CO2 (+10%)	428M Tons CO2 (+27%)

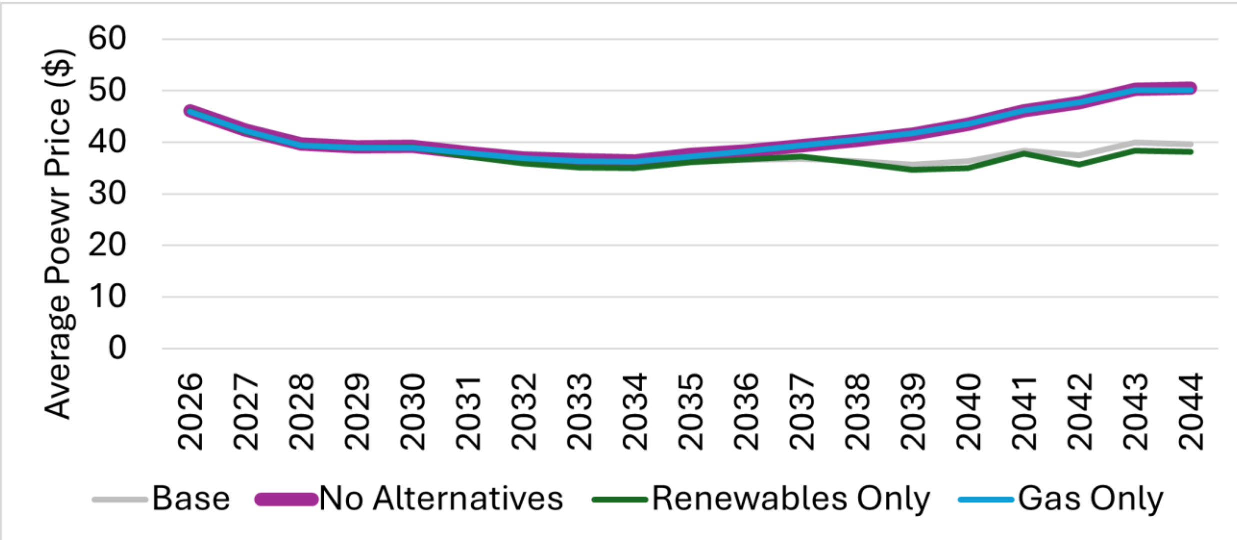
Note: Change relative to Base Case shown in paratheses

Table 4-4: NYISO: Reliability results – no imports sensitivity

Metric	Base Case (with OSW)	No Alternatives	Renewables Only	Gas Only
EUE (ppm) 2032	2,753	3,010 (+9%)	3,010 (+9%)	2,770 (+1%)

Note: Change relative to Base Case shown in paratheses

Figure 4-6: NYISO market-wide average energy price



Note, the No Alternatives Case partially covers the Gas Only Case. No Alternatives line has been made larger to improve visibility.

Figure 4-7: NYISO average gas capacity factor

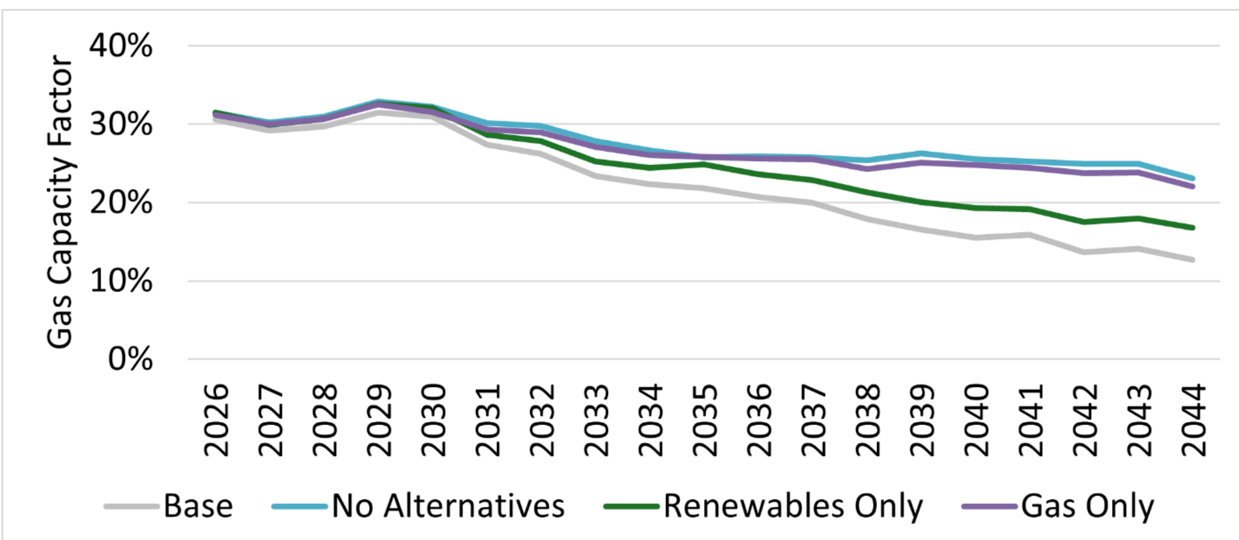
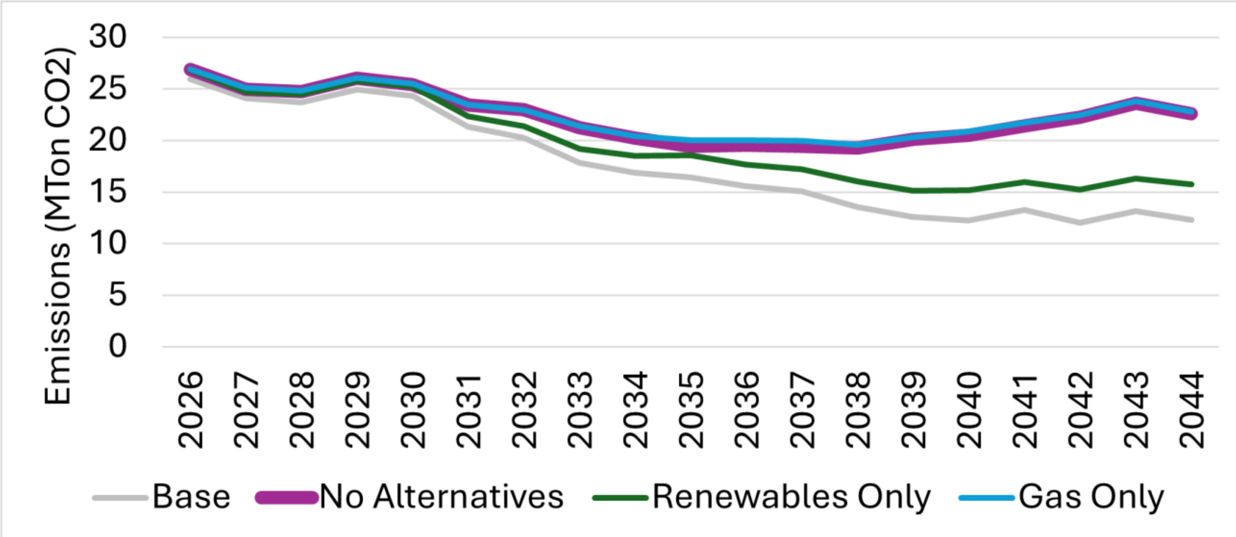


Figure 4-8: NYISO average annual system-wide emissions



Note, the No Alternatives Case partially covers the Gas Only Case. No Alternatives line has been made larger to improve visibility

Cost implications

The net present value of the price forecast, which includes energy costs, net capital costs, and resource adequacy premiums, is shown in Figure 4-11. As in ISO-NE, the No Alternatives scenario has the lowest net capital costs, approximately 10% below the Base Case, followed by the Base Case and then the Gas Only scenario, which is roughly 2% above the Base Case. The lower capital costs in the No Alternatives scenario reflect the reduced level of new resource development.

However, unlike in ISO-NE, none of the portfolios evaluated for NYISO are viable from a resource adequacy perspective. Some of these reliability challenges appear in the resource adequacy premium, but maintaining reliability is essential, particularly for critical infrastructure in New York City. In practice, regulators would be expected to increase investments to ensure sufficient resources. Such additional investment would raise capacity costs, although a detailed assessment of capacity-market impacts is outside the scope of this white paper.

Figure 4-9: NYISO load shedding risk distribution (with imports)

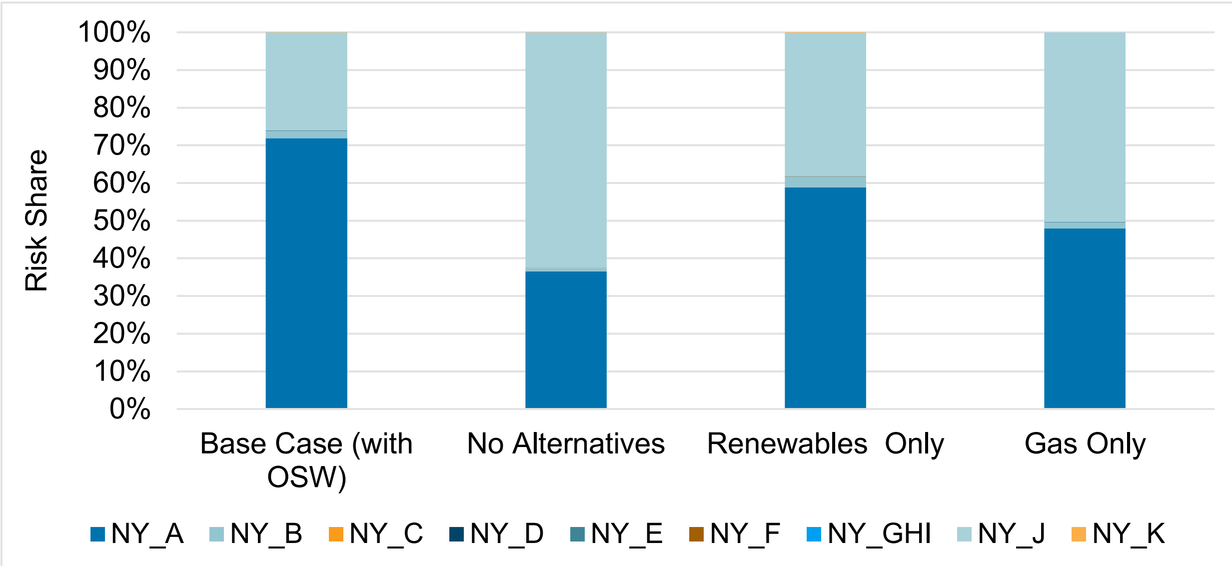


Figure 4-10: NYISO load shedding risk distribution (without imports sensitivity)

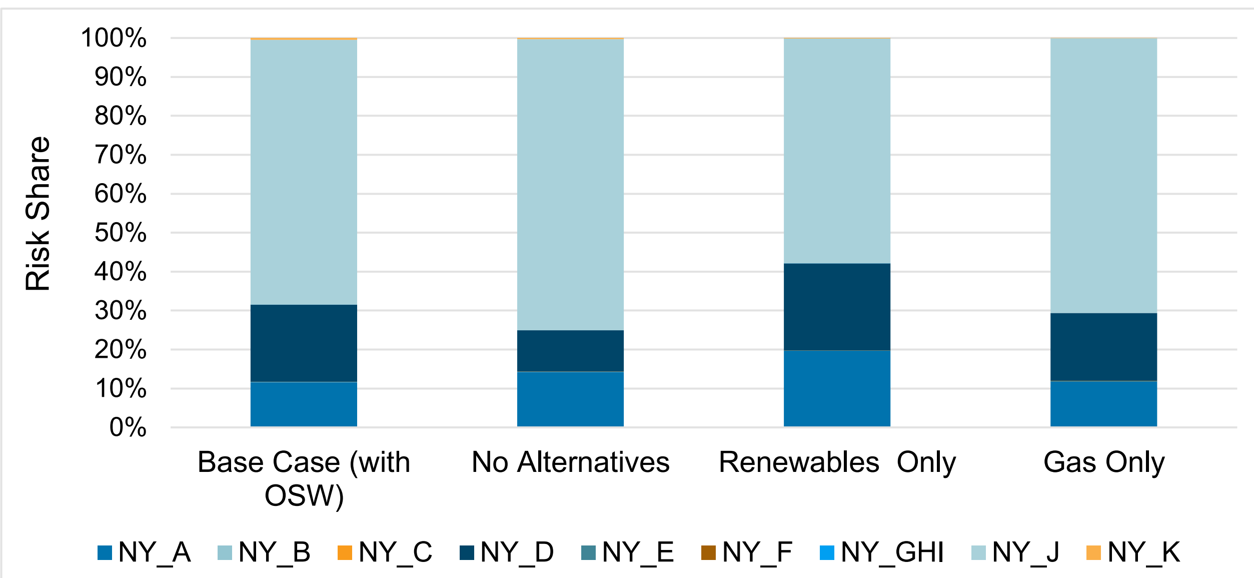
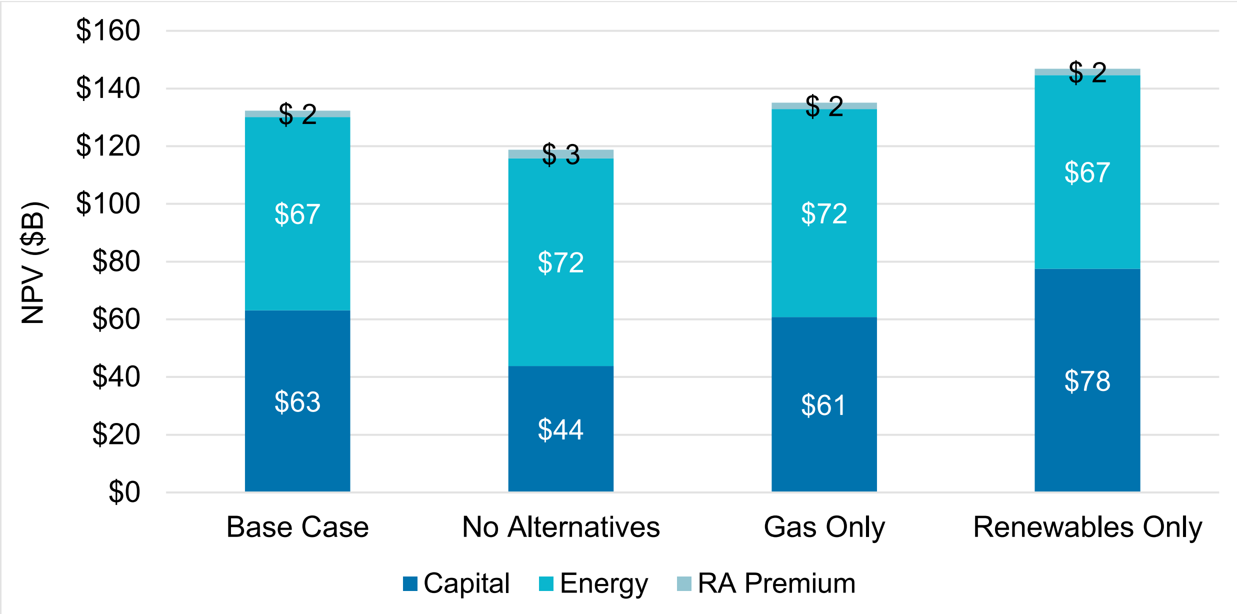


Figure 4-11: NYISO: cost forecast



4.2.1 Supplemental analysis on OSW and oil-fired generation in NYISO

This section presents the results of the supplemental analysis examining the relationship between OSW generation and oil-fired operations in NYISO. Results for 2032 and 2036 are shown in Figure 4-7 and Figure 4-8, and the reduction in oil-fired generation per installed unit of OSW is summarized in Table 4-5.

Without OSW, the oil-fired generation would rise. Between 2032 and 2036, the overall generation would increase over three-fold. Increasing OSW penetration meaningfully reduces reliance on oil-fired generation. The effect is more pronounced in 2036, when continued electrification further increases winter demand relative to 2032. However, the incremental impact of OSW declines beyond roughly 5 GW of installed capacity, after which most peak-coincident load hours are already mitigated.

Even beyond that threshold, additional OSW continues to drive down fuel oil usage by supporting battery-charging during off-peak hours and reducing the frequency of oil-fueled dispatch events during low-wind/high-load events. These findings highlight that initial OSW investments deliver the largest marginal benefits in reducing oil use and improving reliability, while subsequent additions may yield complementary value when paired with storage resources capable of bridging low-wind periods.

Figure 4-7: Annual electricity generated by oil in NYISO zones F-K (2032)

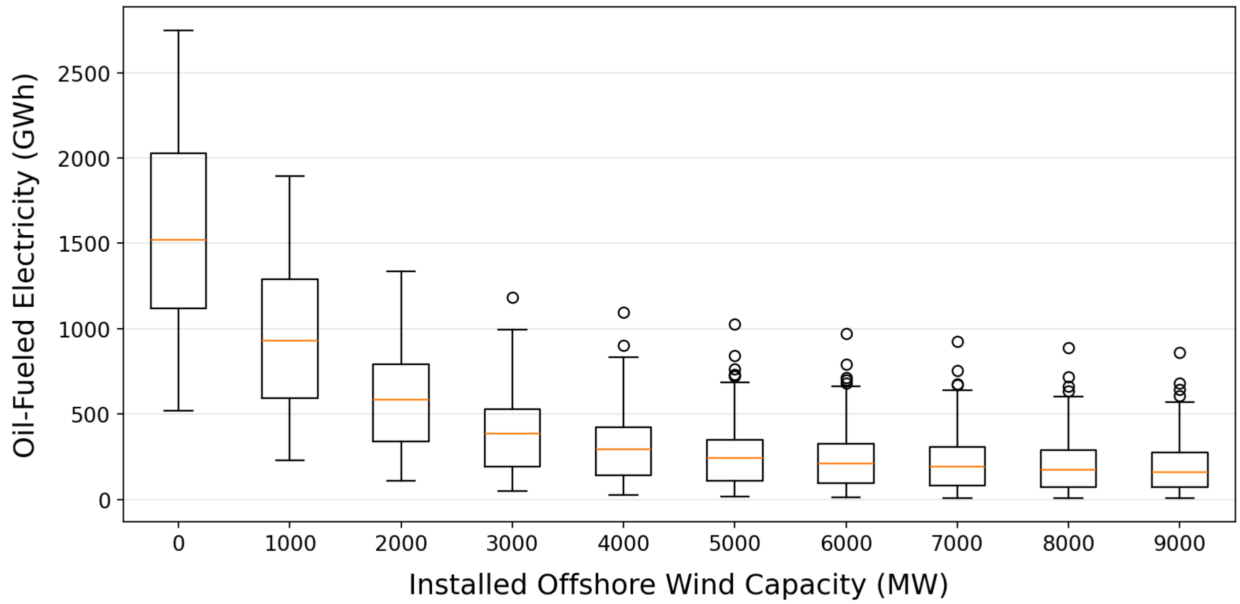


Figure 4-8: Annual electricity generated by oil in NYISO zones F-K (2036)

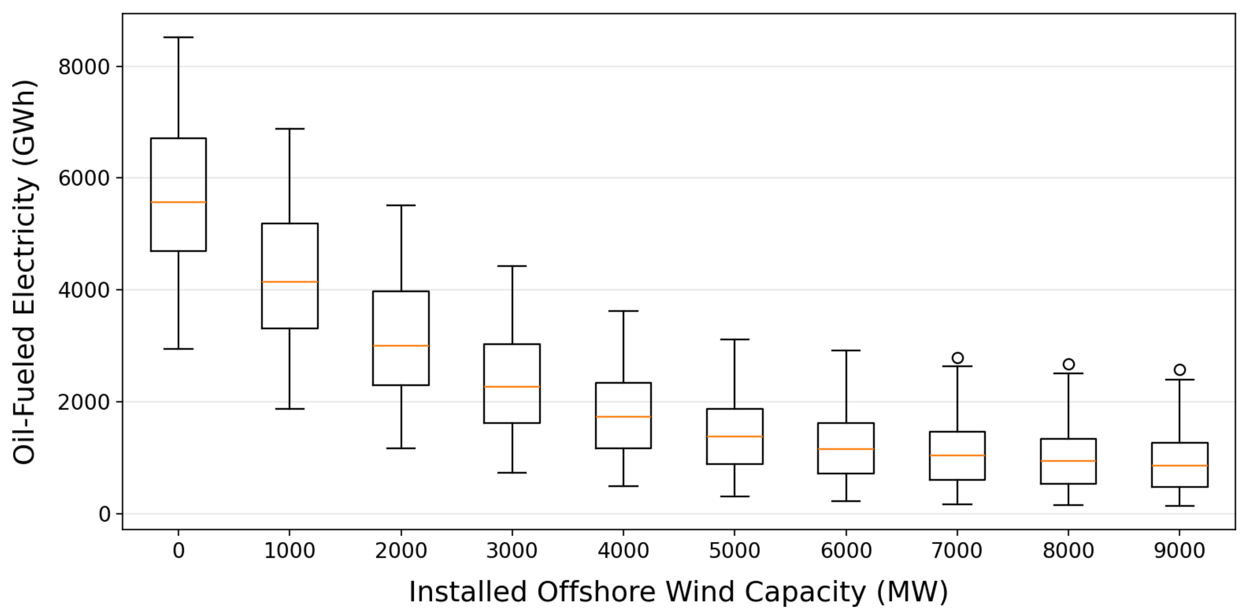


Table 4-5: Annual electricity generated by oil in NYISO zones F-K per OSW ICAP

Year	Annual oil generation displaced per MW of OSW at 1,000 MW of OSW	Annual oil generation displaced per MW of OSW at 3,300 MW of OSW
2032	590 MWh	180 MWh per MW
2036	1,468 MWh per MW	748 MWh per MW

4.3 Discussions of findings

This section summarizes our findings and documents insights that can be gleaned from the collective modeling results.

Base Case has the lowest power price, emissions, and natural gas capacity factor while maintaining reliability

The Base Case delivers the lowest power prices, emissions, and natural gas capacity factors while maintaining reliability. As OSW output displaces thermal generation, both NYISO and ISO-NE rely less frequently on natural gas, resulting in sustained declines in gas-fleet capacity factors. In NYISO, the average capacity factor falls from 31% in 2026 to 13% in 2044, and in ISO-NE, from 31% to 9% over the same period. These reductions allow operators to preserve gas-fired units for periods of very high demand, reduce operational strain on aging resources, and improve the ability to schedule maintenance or retire units at end of life.

Declining natural gas usage also leads to significant reductions in emissions and energy prices. NYISO energy prices decline by 13% and emissions fall by more than half between 2026 and 2044. ISO-NE energy prices decline by 33% and emissions fall by 73% over the same horizon. These changes reflect OSW's ability to provide fuel-free energy during winter and nighttime hours and reduce dependence on fuel-constrained thermal units.

Despite substantial load growth, the system maintains reliability in the Base Case. By providing fuel-free generation directly into transmission- and fuel-constrained coastal load pockets, OSW supports resource adequacy and enables the system to reliably accommodate increasing demand. Even though OSW generation is stronger in winter months, it is able to reduce remaining summer risk in downstate New York, particularly when compared to onshore renewables because unlike solar generation, it can produce across all hours of the day.

Renewable additions – either onshore or offshore – ease burdens on natural gas systems and drive down the need for back-up fuels

Adding fuel-free electricity resources displaces reliance on legacy gas generation during typical operating conditions, allowing these units to run primarily during periods of high demand or low renewable output. Fuel free generation also reduces reliance on back-up fuels during periods when access to natural gas fuel is constrained. Without renewable additions, the usage of fuel oil would increase over three-fold. Adding winter-aligned fuel free resources enables the system to prioritize limited fuel supplies for the most critical hours, reducing strain on both the fuel-delivery network and aging infrastructure while also lowering reliance on expensive, high-emission backup fuels.[97] It also drives down the emissions in these regions, making progress toward decarbonization targets set by policy makers in the region.

Non-OSW renewables are able to achieve similar price and emissions outcomes as the Base Case, but at the cost of reliability

The Renewables Only counterfactual scenario exhibits similar and sometimes better performance than the Base Case in terms of overall cost and emissions. By replacing offshore wind with an equivalent amount of onshore wind and solar generation, power prices and emissions both decline, similar to the Base Case. In NYISO, the natural gas capacity factor falls from 31% to 17% between 2026 and 2044, which contributes to a 17% decline in energy costs and a 40% decline in emissions. In ISO-NE, the natural gas capacity factor falls from 31% to 16% over the same period, and energy costs and emissions decline by 41% and 51%, respectively. These outcomes are sensitive to the relative sizing of onshore and offshore resources. It is likely that either portfolio could produce similar results with different assumed quantities or technologies.

However, these gains come at the expense of both reliability and capital costs. The Renewables Only portfolio requires significantly more installed capacity to reproduce the energy and capacity contributions of OSW, which increases capital costs. It also does not provide the same reliability benefits as OSW. Onshore renewables exhibit greater hour-to-hour variability, and they do not produce as consistently during winter and nighttime periods, which are the hours of emerging system stress. In addition, onshore wind and solar are generally sited far from transmission-constrained coastal load pockets, particularly New York City.

Some of the reliability limitations of onshore renewables could be reduced by pairing rural onshore generation with storage resources located closer to urban load centers, especially as longer-duration storage technologies mature. Such resources could help maintain local energy availability during multi-day cold-weather events. However, this same storage would also

97 New York State Reliability Council (NYSRC). (2025, March 5). *Fuel Availability Constraints: Modeling Phase 2* (Installed Capacity Subcommittee Meeting #301). NYISO. https://www.nysrc.org/wp-content/uploads/2025/03/Fuel-Availability-Constraints.pdf

materially enhance the performance of OSW. [98,99] The incremental reliability value of storage may be even greater when paired with OSW because it is located near major load centers, aligns more closely with winter peaks, and has a smoother generation profile. As a result, decisions to pursue large quantities of storage to enable onshore-only pathways should be evaluated carefully relative to the performance, siting advantages, and stress alignment of OSW.

Replacing OSW with new natural gas capacity increases emissions and energy prices. Depending on the technology type and scale of the replacement, gas alternatives may also perform less favorably from a resource adequacy perspective

In contrast to the No Alternatives and Renewables Only scenarios, the Gas Only scenario maintains reliability relative to the Base Case due to its energy-dense and dispatchable nature. In our results, the Gas Only case performs modestly worse on reliability relative to the Base Case in NYISO. This is primarily because the added resources are assumed to be simple-cycle peaking units, which are more susceptible to cold-weather derates and outages, and because capacity additions are sized to reflect accredited capacity rather than nameplate capacity. If larger plants or combined cycle resources[100] – shown to be historically modestly less sensitive to extreme-cold conditions – were used instead, the Gas-Only case would likely match or exceed the reliability of the OSW case. Further, the Gas Only case is able to achieve relatively similar resource adequacy results with less nameplate capacity, particularly as the penetration of OSW increases. This finding is consistent with the author's previous analysis. OSW provides comparable or superior resource adequacy value to gas at low penetration levels; while OSW's contribution remains material, its incremental per megawatt benefit declines as penetration grows.

Nevertheless, adding new gas-fired capacity, particularly base load combined cycle resources, in urban load pockets of ISO-NE or NYISO remains challenging in the near term. Both regions face constrained natural gas pipeline infrastructure, complex air and siting permitting, and persistent turbine supply-chain pressures.[101] These constraints are expected to ease over the medium to long term as national supply chains stabilize and new gas infrastructure projects – such as the Constitution Pipeline expansion[102] – come online, potentially improving fuel deliverability and siting feasibility.

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98 ISO New England, *2021 Economic Study: Future Grid Reliability Study, Phase 1 (Report*, PDF file), July 29, 2022, https://www.iso-ne.com/static-assets/documents/2022/07/2021_economic_study_future_grid_reliability_study_phase_1_report.pdf.

99 Charles River Associates. *Enabling 24/7 Carbon-Free Energy: Modeling Tools and Decision Frameworks.* June 20, 2024. https://www.crai.com/insights-events/publications/enabling-24-7-carbon-free-energy-modeling-tools-and-decision-frameworks/

100 Murphy, Sinnott, Luke Lavin, and Jay Apt. "Resource adequacy implications of temperature-dependent electric generator availability." *Applied Energy* 262 (2020): 114424.

101 Stover, Oliver, Jesse Dakss, Dean Koujak, Ryan Chigogo, Abdul Mohammed, Ryan Israel, Charles Merrick, and Chloe Romero Guliak. *The Contribution of Offshore Wind to Grid Reliability and Resource Adequacy.* Boston: Charles River Associates, 2025. https://www.crai.com/insights-events/publications/the-contribution-of-offshore-wind-to-grid-reliability-resource-adequacy/

102 The Williams Companies, Inc. (n.d.). *Constitution Pipeline*. https://www.williams.com/expansion-project/constitution-pipeline/

However, these resource adequacy benefits from energy-dense, dispatchable natural gas resources come at the cost of price and sustainability: replacing fuel-free resources with natural gas drives up power prices and emissions. In this scenario, wider investment in onshore renewables reduces overall system load served by natural gas, and the addition of newer, more efficient natural gas units lowers average run-time across the fleet. As a result, in NYISO the natural gas capacity factor declines from 31% to 22% between 2026 and 2044, contributing to a 9% reduction in power prices and a 15% reduction in emissions. In ISO-NE, natural gas capacity factors decline from 31% to 24%, but this is not sufficient to offset gas fuel costs and inflationary pressures. As a result, there is a 7% increase in power prices and a 37% increase in emissions between 2026 and 2044. This scenario still performs better on energy costs than the No Alternatives case because the introduction of newer, more efficient natural gas units lowers variable operating costs relative to legacy resources.

Failing to build new generation to support winter load growth leads to worse outcomes across all metrics

The No Alternatives scenario performs worst across all dimensions. Without new winter-performing resources, growing cold-season demand must be met almost entirely by the existing natural gas fleet, which increases emissions and heightens exposure to fuel-supply constraints. With fewer total resources online, operating reserve margins tighten, and scarcity pricing occurs more frequently, which drives up energy costs. The system operates closer to its reliability limits more often, resulting in elevated load-shedding risk and diminished resource adequacy.

In ISO-NE, the natural gas capacity factor rises from 31% in 2026 to 41% in 2044, indicating significantly greater annual run time for an aging fleet. This increased utilization raises maintenance needs and reduces the number of hours during which units can take planned outages, which amplifies both operational and reliability risks. These stresses translate directly into higher system costs over time. Energy prices increase by 15% between 2026 and 2044, and emissions rise by 30% as the region becomes increasingly dependent on natural gas-fired generation during winter peaks.

In NYISO, the natural gas capacity factor declines from 31% to 23%. Emissions decline by 15% due to wider investment in onshore renewables, but energy prices increase by 9%. Most importantly, the absence of new generation produces a material decline in resource adequacy, and the region must rely more heavily on older thermal units during the most severe winter conditions.

OSW benefits are linked to higher winter load growth

In both systems, winter load growth is approximately 3X that of summer load growth, and the system transition to becoming winter peaking by 2036. As the load and risk shifts toward winter, the benefits of including OSW relative to onshore renewable alternatives become more pronounced. This is further supported in the supplemental analysis in NYISO – where OSW has a greater impact on the amount of fuel oil used as the winter load grows.

OSW still has potential to play a role in summer reliability

Although load growth and reliability risk are increasing more quickly in the winter than in the summer, summer reliability challenges persist in the near term, particularly in downstate New York. While Atlantic-based OSW delivers lower output in the summer than in the winter, it still provides material generation across summer months and across all hours of the day. This includes meaningful production during the evening hours after solar output declines. As a result, OSW can support summer resource adequacy, reduce reliance on peaking units, and help mitigate risk during high-demand periods over the entire year.

Dependence on cross-border and interregional imports

NYISO's reliability outcomes are heavily influenced by its ability to import energy from neighboring markets, particularly HQ and PJM. In the Base Case, imports from HQ play a material role in mitigating reliability risks, with unserved energy events overwhelmingly concentrated in New York City (Zone J) and Western New York (Zone A). However, the sensitivity excluding HQ imports shows that NYISO's systemwide EUE risk increases more than thirty-fold, and load shedding events spread beyond downstate zones to include Zones B, C, and D.

Although conservative, these results highlight NYISO's dependence on cross-border and interregional energy flows to maintain reliability. HQ provides important support under normal conditions, but this supply is not assured during coincident winter stress periods when both regions experience elevated demand. Similarly, imports from PJM will likely face limitations due to tightening reserve margins and rapid load growth, which reduces the likelihood of emergency assistance during extreme events.

Under typical conditions, NYISO and ISO-NE benefit from economic interchange with PJM, HQ, and the IESO, which helps reduce power price and pool excess renewable generation. If regional coordination weakens or if Canadian surplus capacity declines, reliability risks in the region – especially in Zone J in NYISO – would rise materially. These findings underscore recent calls for stronger interregional coordination and joint, wide-area reliability modeling[103] to ensure that markets can respond collectively to tightening supply-demand conditions across the Northeast.

Mixed performance on capital costs

The No Alternatives scenario had the lowest net capital costs because it brings the fewest new resources onto the system. However, this outlook would not meet NYISO's resource adequacy requirements and would drive up capacity costs. In NYISO, the Base Case has the lowest net capital costs, followed closely by the Gas Only case among the portfolios with better resource performance. These patterns indicate that the capital competitiveness of OSW relative to natural gas is heavily influenced by the depth of OSW penetration. At higher penetration levels, the

[103] ISO-NE. (2024, October 23). *2024 Economic Study — Interregional Model Assumptions* [PDF]. Retrieved from https://www.iso-ne.com/static-assets/documents/100016/a11_2024_economic_study_interregional_model_assumptions.pdf

incremental accredited contribution of OSW declines, allowing a smaller amount of natural gas capacity to deliver a similar resource adequacy benefit. Grid planners can mitigate this effect by enabling economies of scale that reduce OSW capital costs and by pairing OSW with storage to preserve its per-megawatt reliability value. Finally, these results reflect national cost estimates; in practice, local land constraints, offshore transmission requirements, and fuel-delivery upgrades for new natural gas capacity could materially shift the relative economics of the scenarios.

Conclusions

Our modeling results indicate that including OSW in ISO-NE and NYISO can provide significant benefits to the region. OSW provides a strong combination of coastal deliverability, winter-coincident output with material summer contributions, and scalable fuel-free capacity. These attributes support portfolios that maintain reliability at lower cost and with lower emissions compared to alternatives that lack comparable transmission access or storage expansion. Depending on underlying assumptions, OSW may also be competitive from a capital cost perspective.

We also find that New York City (Zone J) is facing emerging resource adequacy challenges. This aligns with concerns identified by NYISO[104], driven by limited local generation and transmission constraints into the city. In ISO-NE, our results show that the region can maintain a resource adequate supply mix, but this outcome depends on adding a substantial volume of new generating resources. Bringing these resources online is not assured and will likely require transmission investments to access high-quality renewable resources in northern Maine.[105] If new additions are delayed or transmission projects stall, ISO-NE could also face shortages. In this case, OSW can act as a scalable addition, directly connected to high load regions.

In both markets, our analysis did not contemplate the net reduction in dispatchable resources. Our results indicate that ISO-NE could consider retirements of aging gas or oil units as broader grid investments materialize. In contrast, NYISO is likely dependent on dispatchable resources in the near term.[106] This finding aligns with concerns raised by NYISO which find that the region could face elevated risks if aging natural gas and fuel oil resources retire unexpectedly, particularly before additional investments come online.

Portfolios that include OSW result in lower energy prices and emissions while meeting or improving resource adequacy. These outcomes are driven by OSW's direct interconnection to transmission-constrained zones, strong generation during winter (with lower but still material

104 New York Independent System Operator (NYISO). *Q3 2025 Short-Term Assessment of Reliability (STAR).* Rensselaer, NY: NYISO, 2025. Available at: https://www.nyiso.com/documents/20142/39103148/2025-Q3-STAR-Report-Final.pdf

105 Ackerman, K. (2023, July 26). ISO-New England issues transmission RFP in Massachusetts and Maine for wind integration. *Utility Dive.* Retrieved from https://www.utilitydive.com/news/iso-new-england-transmission-rfp-maine-wind/744064/

106 New York Independent System Operator (NYISO). *Q3 2025 Short-Term Assessment of Reliability (STAR).* Rensselaer, NY: NYISO, 2025. Available at: https://www.nyiso.com/documents/20142/39103148/2025-Q3-STAR-Report-Final.pdf

summer generation) and nighttime stress periods, and the ability to add new fuel-free capacity at scale.

Replacing OSW with inland onshore wind or solar preserves or modestly improves price and emissions outcomes but materially weakens resource adequacy. This is because inland renewables are located far from transmission-constrained coastal zones. In addition, solar is not aligned with emerging periods of grid stress, including winter mornings and evenings. Investments in local storage and expanded transmission could mitigate these limitations.

Replacing OSW with an equivalent amount of accredited peaking natural gas capacity maintains resource adequacy but increases emissions and often raises energy cost. These findings are sensitive to technology selection, cold weather derates and outages, and the decision to replace based on accredited rather than nameplate capacity. The results show that natural gas has a higher per-megawatt impact on resource adequacy than OSW and may be more competitive on a net capital cost basis, particularly as OSW penetration reaches multiple gigawatts. However, near-term siting, permitting, and firm-fuel access in coastal load pockets remain material headwinds for adding new natural gas resources in both ISO-NE and NYISO.

If OSW projects are delayed and no alternative resources are added, outcomes worsen across all dimensions. Such portfolios result in higher power prices, higher emissions, greater reliance on natural gas, and meaningfully higher resource adequacy risks, particularly in downstate New York.

The net capital cost assessment does not identify a clear winner. The No Alternatives case has the lowest capital cost because it adds fewer resources. However, especially in NYISO, this is not a viable strategy because it results in elevated resource adequacy risks. Further, capacity shortfalls would drive up capacity costs. OSW can be competitive with Gas Only investments because its lower upfront fixed costs are offset by fuel-free operation. But, our results show that at deeper penetration of OSW, gas is likely more competitive, unless economies of scale materialize for OSW. OSW also outperforms onshore renewable alternatives because it can provide equivalent energy and capacity and greater resource adequacy benefits with fewer megawatts. However, these findings are highly dependent on local conditions, including land availability, transmission capability, and the fuel system upgrades required to add new resources of any time. Planners and regulators must accurately reflect these conditions when evaluating specific projects.

Regulators may also want to consider additional factors when selecting a resource mix. These include development and construction risks and implications for overall grid affordability – including capacity prices, power purchase agreement costs, customer bill impacts – permitting risk, and broader development risks. Given the scale of required investments in both generation and transmission, and the near-term reliability challenges in NYISO, these considerations are particularly important to ensure that new capacity additions keep pace with load growth and retirements.

In sum, OSW has the potential to help ISO-NE and NYISO meet their emerging reliability challenges while supporting affordability and decarbonization goals. OSW is particularly well suited to strengthen reliability in urban, coastal cities that have limited ability to add new natural gas generation because of fuel constraints, permitting complexity, or transmission limitations in these regions. It is also well positioned to support and harden the existing thermal fleet by reducing the need for back-up fuels and lowering natural gas capacity factors, thereby decreasing emissions and reducing long-term wear on aging resources and easing strain on fuel systems. As with all generation investments, regulators and permitting authorities must carefully weigh these benefits and fully account for local capital costs and related system investments when evaluating OSW alongside alternative resource options.

Finally, our findings show that accelerating load growth, particularly during winter months, is placing increasing pressure on existing infrastructure and exacerbating transmission congestion into major coastal urban centers, especially in New York City. Our results are directionally consistent with other studies that have identified emerging reliability risks in these areas, though numerical differences reflect varying modeling assumptions. Taken together, these findings and recent NYISO warnings[107] underscore the need for new local and stress-aligned resources, as well as expanded interregional planning and coordinated modeling, to sustain reliability and affordability in the region.

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[107] New York Independent System Operator (NYISO). *Q3 2025 Short-Term Assessment of Reliability (STAR)*. Rensselaer, NY: NYISO, 2025. Available at: https://www.nyiso.com/documents/20142/39103148/2025-Q3-STAR-Report-Final.pdf