



Where the Wind Wins: The Competitiveness of Offshore Wind in New England

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Tricia K. Jedgele, Esq.
Offshore Wind Policy Manager

Cecile Coronato
Renewable Energy Project Manager,
Northeast Division
<https://www.nature.org/en-us/>

Dunsky Project Number: 25101

Prepared by:

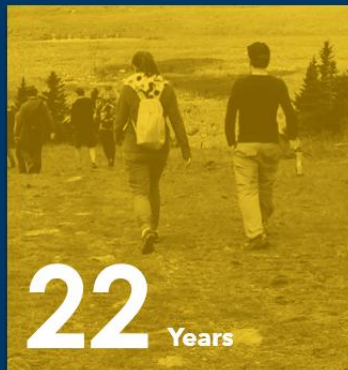


Dunsky Energy + Climate Advisors

50 Ste-Catherine St. West, Suite 420
Montreal, QC, H2X 3V4

www.dunsky.com | info@dunsky.com
+ 1 514 504 9030

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Executive Summary

Connecticut and New England today face several pressures: electricity prices are up 27% since 2020, peak demand is expected to grow and shift to the winter, and the generation mix is dependent on natural gas, which has seen increased volatility in recent years. Against this backdrop, Dunskey Energy + Climate Advisors, contracted by The Nature Conservancy, evaluated the economic competitiveness of offshore wind within a diversified resource portfolio for ISO-NE, using capacity expansion modeling and levelized cost of energy (LCOE) analysis.

We modeled three capacity expansion scenarios over a 2035 to 2050 planning horizon, assuming a natural gas price of \$6/MMBtu, and evaluated each of these scenarios against two demand forecasts:

- **Scenario 1 - All Fossil and Nuclear:** New renewables and storage are excluded; only dual-fuel combined cycle gas turbines (CCGTs) and small modular reactors (SMRs) are available for expansion.
- **Scenario 2 - Least-Cost Mix:** All technologies compete based on the direct ratepayer cost likely to be included in regional electric bills (offshore wind, land-based wind, solar, battery storage, SMRs, and CCGTs), with land-based wind capped at 3.6 GW due to siting constraints.
- **Scenario 3 - All Clean:** New CCGT construction is prohibited, and a declining carbon budget is imposed.

Importantly, carbon pricing or climate policies were not included. This was a deliberate choice to test offshore wind's competitiveness based on direct utility economics rather than a broader societal perspective. This is not meant to suggest that these policies should be ignored; instead, our analysis demonstrates that offshore wind remains a prominent and promising resource for New England regardless of the policy scenario.

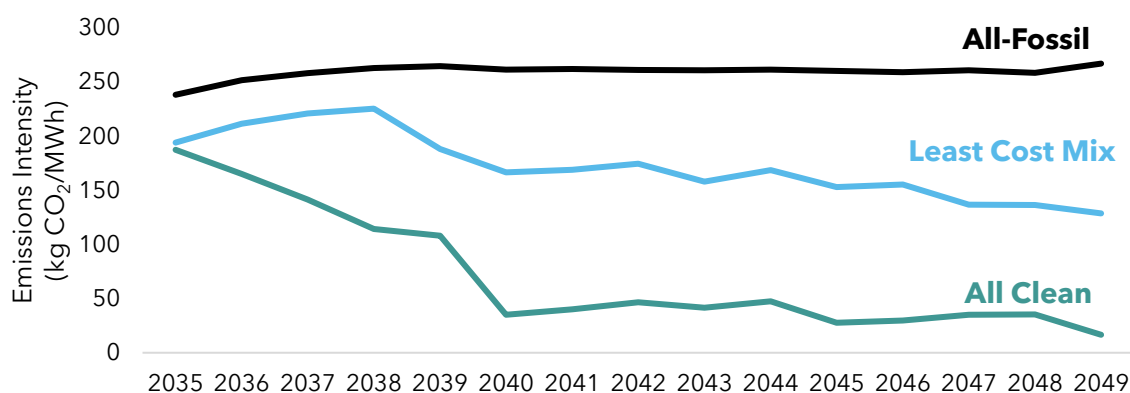
Capacity Expansion Results

The three scenarios produced distinctly different portfolios. The All Fossil and Nuclear pathway relies entirely on combined cycle gas turbine (CCGT) expansion, while the Least Cost Mix selects a diversified portfolio which includes offshore wind, land-based wind, battery storage, and some CCGT. The All Clean scenario achieves a fully clean mix of resources through a combination of offshore wind, land-based wind, storage, solar, and SMRs, with no new fossil infrastructure required.

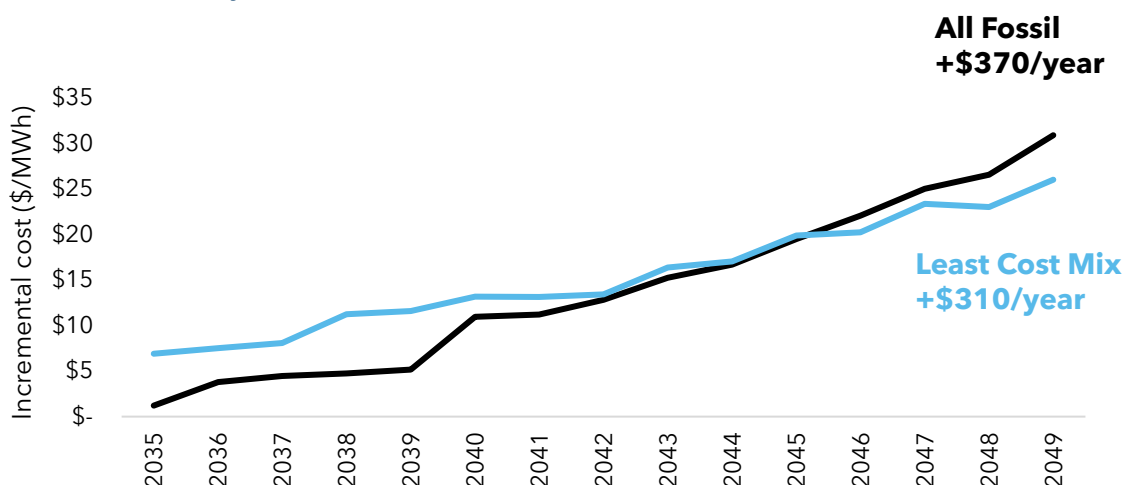
Given these varying generation portfolios, it follows that their emissions trajectories are substantially different (ES 1). The All-Fossil pathway sees emissions intensity rise, while the Least Cost Mix achieves a 31% reduction in emissions intensity over the modeling period. The All-Clean scenario achieves the steepest decline, reaching very low emissions intensity by 2050.

On ratepayer costs, the All-Fossil pathway is more expensive over the long run despite carrying no climate constraints (ES 2). By 2050, we estimate the All-Fossil pathway will add \$370/year in electricity costs to support additional generation resources versus \$310/year

under the Least-Cost Mix¹. Near term cost advantages for gas decline as capital and fuel costs accumulate, while offshore wind's low operating cost and fuel free cost structure helps provide greater long-run price stability.



ES 1: Emissions intensity across three modeled scenarios



ES 2: Incremental generation costs of All Fossil vs Least Cost Mix using the CELT forecast; costs shown in \$/year represent the incremental annual cost to a ratepayer that uses 1,000 kWh per month

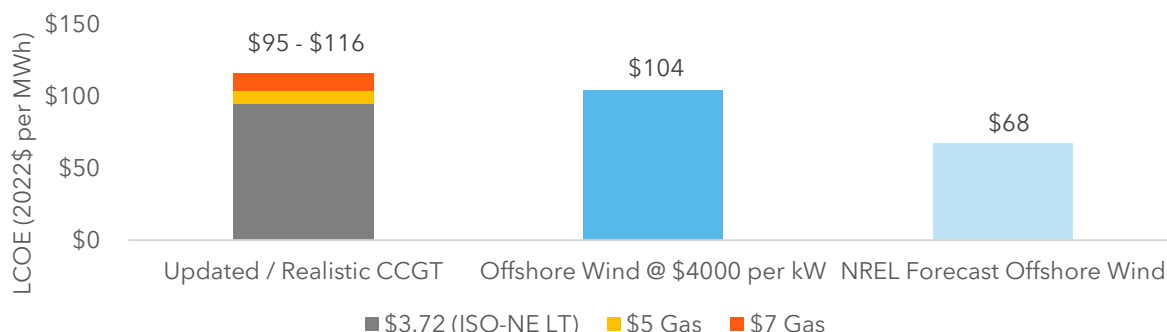
LCOE Results

When updated capital costs and capacity factors are applied to new CCGT plants, the cost gap with offshore wind narrows significantly (ES 3). Conventional planning benchmarks² have understated gas costs by assuming capital prices that no longer reflect current market conditions and idealized capacity factors that do not match actual ISO-NE dispatch patterns. Under more accurate assumptions, the LCOE of new gas generation approaches that of

¹ In this comparison, we isolate the additional cost for generation from the other drivers of system costs. This should not be taken as a forecast that in 2050, electric bills would increase by this amount per year, rather that this is one additional cost isolated to the choice of generation built. Additional costs for transmission, labor, etc. would be added on top of this projected cost.

² Derived from NREL's Annual Technology Baseline cost and performance data

offshore wind, particularly at moderate to high fuel prices. These results show that offshore wind should not be dismissed based on outdated assumptions.



ES 3: Updated LCOE Results of CCGT and Offshore Wind

Conclusions

Offshore wind plays a central role in the least-cost electricity portfolio

When all technologies are allowed to compete, the model selects significant offshore wind capacity, reaching approximately 14 GW by 2050. This indicates that offshore wind is economically competitive even without carbon pricing or emissions constraints. Its role becomes even more important in the New England context, where existing natural gas infrastructure constraints may limit the availability of new CCGT capacity, land-based wind faces siting limitations, and solar provides limited contribution during future winter peak demand periods.

Natural gas fuel price risk can be offset with offshore wind additions

Fluctuating natural gas prices increase the financial risk of building new CCGTs by creating uncertainty around long-term electricity prices and operating costs. Expanding offshore wind can help mitigate this risk by reducing reliance on natural gas and adding a generation source with no fuel costs. This diversification can improve price stability and reduce exposure to volatile fossil fuel markets.

Natural gas prices strongly influence long-term resource decisions

Offshore wind deployment increases as natural gas prices rise. Offshore wind begins entering the portfolio at approximately \$5/MMBtu and becomes a major component around \$6/MMBtu. These results highlight how assumptions about future fuel prices can significantly shape generation investment decisions and emphasize the importance of considering natural gas price uncertainty in long-term system planning. Planners may wish to consider that building more gas today *increases* their exposure to this uncertainty, while diversification through investment in other generation resources limits that exposure.

A diversified resource mix helps maintain reliability in a winter-peaking system

No single resource is likely to meet all system needs, and a diversified portfolio is required to help meet future winter peak demand. The least-cost portfolio therefore includes a combination of offshore wind, land-based wind, battery storage, and firm capacity resources such as CCGTs. This diversified mix allows the system to ensure adequate supply during periods of high demand and low renewable output.

Offshore wind can deliver zero-emission electricity at costs comparable to natural gas

Using updated cost assumptions that reflect current market conditions, including limited availability of gas turbines, rising equipment costs, and lower real-world utilization rates for gas plants, the analysis shows that the LCOE from offshore wind and natural gas can be comparable. Offshore wind costs are largely upfront capital investments with relatively low operating expenses. This cost structure can provide greater long-term price stability for ratepayers compared with fuel dependent generation such as natural gas.

Including climate impacts would further strengthen the case for offshore wind and other clean energy resources

This analysis adopts a deliberate approach to examine whether offshore wind can be cost-competitive without depending on policy factors like carbon pricing and related policies. By excluding factors such as the total costs of climate impacts, carbon pricing, and emerging technologies like long-duration storage, the study focuses solely on the core costs likely to be passed through on ratepayer electric bills, while setting aside the more comprehensive societal economics. Under these conditions, we still find offshore wind to be competitive and reliable. Analyses that incorporate broader climate considerations may identify pathways similar to the All Clean pathway in this study as the lowest-cost societal option and show a reduced role for natural gas. *Our Least-Cost Mix minimizes long-term electricity system costs and should not be viewed as the optimal societal approach for the future New England electric system.*

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List of Acronyms

Annual Technology Baseline (ATB)
Capacity, Energy, Loads, and Transmission Forecast (CELT)
Combined Cycle Gas Turbine (CCGT)
Independent System Operator New England (ISO-NE)
Land Based Wind (LBW)
Levelized Cost of Energy (LCOE)
Long Duration Energy Storage (LDES)
Megatonnes (Mt)
Million British Thermal Units (MMBtu)
National Renewable Energy Laboratory (NREL) *now the National Laboratory of the Rockies (NLR)
Offshore Wind (OSW)
Power Purchase Agreement (PPA)
Small Modular Reactor (SMR)
Stochastic Dual Dynamic Programming (SDDP)
The Nature Conservancy (TNC)

1. Introduction

Amid rising electricity prices and projected demand growth, Connecticut and the broader region face critical decisions about future resource investments to maintain an affordable, reliable, and clean grid. This section outlines the market trends, system conditions, and study context that frame our evaluation of offshore wind as a supply resource.

1.1 State of Play in Connecticut and New England

Electricity costs in Connecticut and New England have increased significantly over the past decade. For instance, Eversource residential customers in Connecticut have experienced a 27% increase since 2020.³ This increase has been driven by a myriad of factors, such as natural gas price volatility, transmission costs, and increasing costs of public policy programs and procurements. At the same time, following two decades of decreasing energy usage due to state policies that incentivized solar and energy efficiency, **ISO New England (ISO-NE) is also preparing for the possibility for significant load growth** over the coming years due to electrification, with peak demand expected to shift from summer to winter.⁴

Connecticut and ISO-NE Electricity Market Background

Within Connecticut, the two investor-owned electric distribution companies, Eversource and United Illuminating, serve most customers. They own and maintain the local distribution system and deliver electricity to customers, but they do not own generation. Customers can choose a competitive retail supplier or remain on the default Standard Service rate (under which utilities conduct procurements to select suppliers). Regardless of whether a customer takes Standard Service or chooses a competitive supplier, the electricity serving that load is procured and balanced through ISO-NE's wholesale markets.

Separately, Connecticut runs long-term procurements for certain resources to advance state policy goals, such as renewable energy contracts and the Millstone nuclear power purchase agreement (PPA). While these procurements are paid for by Connecticut ratepayers and the resulting emission benefits and net revenues are credited back to ratepayers (or recovered from), the electricity from those resources is still sold into and dispatched through ISO-NE's wholesale markets. The contracts function as financial arrangements to support specific resources or stabilize costs, rather than allowing the state to directly sell electricity to customers.

The generation mix within ISO-NE is dominated by natural gas, which accounts for roughly 55% of total generation (Figure 1). This heavy reliance on gas exposes the region to fuel price volatility and global supply shocks, as seen in 2022–2023 when the Russia-Ukraine war contributed to sharp increases in natural gas prices and wholesale electricity costs. Nuclear power supplies approximately 25% of generation, providing a significant source of carbon-free baseload energy. The remaining mix includes hydro, wind, and solar, along with smaller contributions from other renewable resources and oil.

³ Eversource. [Electric Rates Archive](#).

⁴ ISO-NE. [Load Growth & Demand Drivers in New England](#). Does not account for imports.

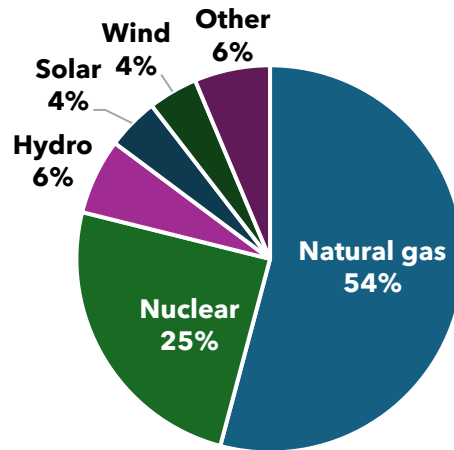


Figure 1: ISO-NE Generation Mix in 2025⁵

Under this backdrop of rising electricity prices, expected load growth, and fuel price volatility driven by natural gas within ISO-NE, Connecticut's Department of Energy & Environmental Protection is pursuing an Integrated Resource Plan to evaluate "all-of-the-above" supply options, with the goal of ensuring reliability, affordability, and progress towards the state's clean energy goals.⁶

1.2 Study Context and Objectives

Dunskey was contracted by The Nature Conservancy (TNC) to evaluate the role of offshore wind within a diversified energy resource portfolio. Our analysis focuses on ISO-NE as a whole because investments in one state affect costs and reliability outcomes across all six New England states.

Specifically, our analysis sought to answer the following key questions:

- **System needs:** What is the expected electricity demand growth in ISO-NE?
- **Resource economics:** How does the cost of offshore wind compare to other resources, such as natural gas?
- **Least-cost portfolio mix:** If meeting climate goals (e.g. through carbon pricing or emissions caps) were not requirements, what mix of resources can reliably meet projected future demand at lowest cost?
- **Role of offshore wind:** Within a least-cost portfolio, what role does offshore wind play, and under what conditions (e.g. natural gas price) does its deployment become economically attractive?

Importantly, excluding the effects of carbon pricing and related policies from this analysis is not meant to suggest they should be ignored. Rather, it allows us to test whether offshore wind can be a cost-competitive resource, independent of policy support, and to clearly isolate for the economics of different resource choices. In doing so, the results demonstrate that offshore wind remains competitive even under these assumptions. The sections that follow detail our methodology, key results, and conclusions.

⁵ ISO-NE. 2025 [Net Energy and Peak Load by Source](#).

⁶ Connecticut DEEP. 2025. [Notice of Proceeding and Opportunity for Public Comment](#).

2. Methodology

To assess the role offshore wind can play within New England’s resource portfolio and its competitiveness relative to other options, we conducted a capacity expansion analysis across multiple scenarios to evaluate impacts on ratepayers. We also analyzed the Levelized Cost of Energy (LCOE) to provide an apples-to-apples comparison of offshore wind and natural gas using updated cost assumptions that reflect market realities. This section details the methodology used for these two pieces of analyses.

2.1 Capacity Expansion Analysis

Capacity expansion analysis is a common tool used for long-term planning in the power sector (e.g. for integrated resource plans), and considers factors such as electricity demand projections, technology options, and system constraints to identify the least cost mix of resources required to meet electricity demand.⁷

To evaluate the impact of offshore wind deployment using the capacity expansion analysis, we modelled three capacity expansion scenarios (Figure 2). These scenarios are designed to represent a range of policy and resource development pathways in the region. The scenarios include: a system reliant on firm generation⁸ (both fossil and nuclear), a technology-neutral system focused on the least-cost mix of resources, and an all-clean energy system. These scenarios allow for the assessment of how and when offshore wind is best deployed and how it competes with other resources under various conditions.

Figure 2: Summary of capacity expansion scenarios modelled⁹



Scenario 1: All Fossil and Nuclear restricts the construction of new land-based wind, offshore wind, utility-scale solar, and battery storage capacity. Under this configuration, only dual-fuel combined cycle gas turbines (CCGTs) and small modular reactors (SMRs) are available as expansion options. Given existing pipeline capacity limitations, new CCGT

⁷ See “How the Capacity Expansion Model Works” on p.13 for more details on how this analysis works in practice

⁸ Firm generation resources refer to resources with a high degree of reliability and capability to deliver power on demand. Examples include natural gas, hydro, and nuclear.

⁹ Dual fuel CCGT refers to a combined cycle gas turbine that can operate with oil as a backup fuel if gas supply is constrained

deployment also includes the cost of interstate/interregional natural gas infrastructure expansion, estimated at approximately \$3.5 billion per 5 GW of additional capacity¹⁰.

Scenario 2: Least Cost Mix considers all technologies in the candidate resource set (land-based wind, offshore wind, solar, storage, SMRs, and CCGT) as eligible for expansion. The only binding constraint is a cap of 3.6 GW on land-based wind capacity additions, consistent with ISO-NE estimates of siting limitations for this resource. Resource costs are assessed over the full life of each generation asset, which extends beyond 2050 for many assets modeled to be built during the study period.

Scenario 3: All Clean aligns with the policy framework of the ISO-NE Economic Study. As in the previous case, land-based wind additions remain capped at 3.6 GW; however, the construction of new CCGT capacity is not permitted. The scenario also includes a declining annual carbon emissions limit, falling from 20 million metric tons in 2035 to 2 million metric tons in 2050. No carbon tax is applied; instead, the model must stay within this emissions limit when selecting the generation mix.

Across all three scenarios, the following assumptions apply:

- **No explicit carbon tax or carbon pricing mechanism was included** in the modeling assumptions. Although excluding climate externalities does not reflect the broader societal costs of fossil generation, this approach was adopted to isolate for the cost and performance of various portfolios.
- **The modelling horizon runs from 2035 to 2050.** ISO-NE has indicated that resources currently contracted in the interconnection queue are sufficient to meet projected demand through 2034. These resources are therefore assumed to come online and operate alongside all existing generation assets¹¹, except for those with retirements officially announced by ISO-NE.
- **Two demand growth scenarios assessed: ISO-NE's Economic Study and the Capacity, Energy, Loads, and Transmission (CELT) forecast.**¹² ISO-NE's 2024 CELT forecast runs from 2024 - 2034 and was projected out to the modelling horizon defined above (2035 - 2050).¹³
 - Both load scenarios indicate that the **system will transition from a summer-peaking to a winter-peaking system around 2035** due to heating electrification. In the economic study, winter peak increases rapidly in the early years, whereas the CELT projection exhibits a more gradual initial growth (see Figure 3: System peak load forecast for the economic study and CELT projection). Despite these

¹⁰ [Enbridge halts \\$3.2B Access Northeast natural gas pipeline for now | Utility Dive](#)

¹¹ Only signed resources from the 2024 Transmission Planning Technical Guide were added to the 2034 starting mix, representing around 4 GW of storage and 2.5 GW of utility-scale solar.

¹² The Economic Study projects future system conditions (including demand) under different policy and technology pathways. The CELT is a 10-year forecast of electricity demand used for reliability planning that is produced every year by ISO-NE.

¹³ The CELT forecast projection was developed by taking the average annual growth rate observed over the final three years of its horizon (2031-2034) and applying this rate to the total annual energy demand as well as winter and summer peak loads. The 2034 hourly CELT load profile was then scaled proportionally to match the projected annual energy demand and seasonal peak levels, producing an alternative hourly load forecast for the 2035-2050 period. Only the winter projection is shown as the summer projection stays flat.

differences, the two projections converge at similar levels in 2035, with peak demand increasing by approximately 24 GW relative to the 2034 baseline.

- Electricity demand in both growth scenarios includes power generated from behind-the-meter solar systems and is reported net of that generation.

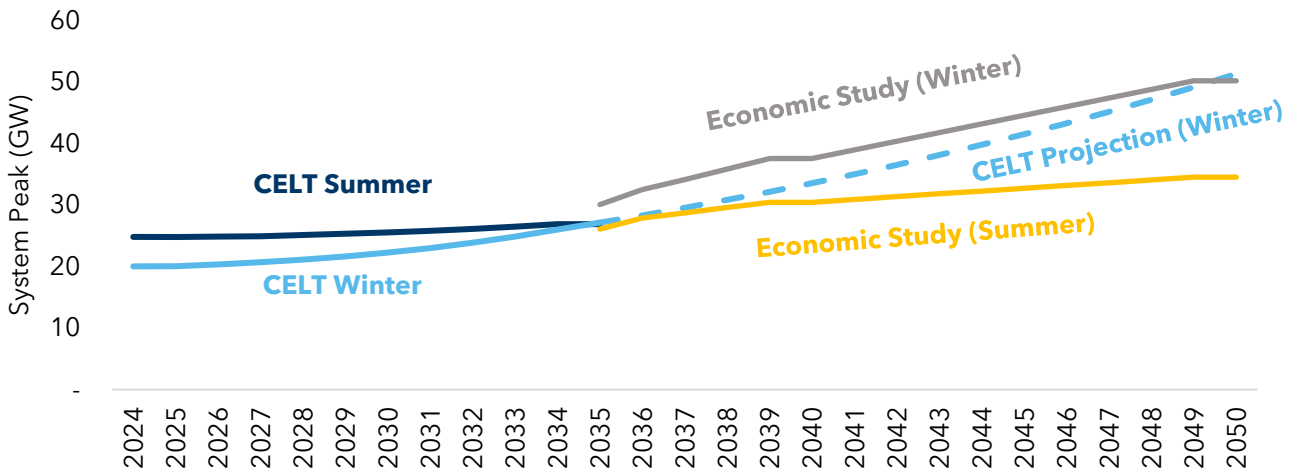


Figure 3: System peak load forecast for the economic study and CELT projection

- **Capital cost assumptions** are based on ISO-NE's Economic Study, with some updates to reflect current market conditions. A summary of capital cost assumptions is provided in Table 2 in Appendix A.
 - **Natural gas price:** In the ISO-NE 2024 Economic Study, new natural gas plants were not allowed to be built, and existing plants were modelled using an average fuel cost of \$3.72/MMBtu (the average fuel used in the Economic Study). In this study, a natural gas price sensitivity analysis ranging from \$3.72 to \$7/MMBtu was conducted to assess the impact of gas prices on portfolio mixes (see results in Section 3). For the three scenarios analyzed, we selected a price of \$6/MMBtu, which we view as a reasonable estimate as it is approximately aligned with the average price of natural gas delivered to Connecticut over the last five years.¹⁴

Table 1 summarizes the resource constraints and core assumptions for the scenarios modelled in our capacity expansion analysis.

Table 1: Summary of resource and general constraints

Scenario	Expansion Constraint by Resource	Additional Constraint
Scenario 1: All Fossil and Nuclear	- Wind, Solar, Storage = 0 - SMR ≤ 5,500 MW	Gas price = \$6/MMBtu
Scenario 2: Least Cost Mix	- SMR ≤ 5,500 MW - LBW ≤ 3,600 MW	Gas price = \$6/MMBtu
Scenario 3: All Clean	- CCGT = 0 - SMR ≤ 5,500 MW	Gas price = \$6/MMBtu Emission budget in line with the 2024 economic study

¹⁴ U.S. EIA. [Natural Gas Citygate Price in Connecticut](#).

Scenario	Expansion Constraint by Resource	Additional Constraint
	- LBW $\leq$ 3,600 MW - OSW $\leq$ 17,500 MW	

How the Capacity Expansion Model Works

Capacity expansion decisions are determined using a stochastic power system modeling framework from the PSR modelling suite. The power system is first represented using SDDP (Stochastic Dual Dynamic Programming) from the PSR suite, a mid- and long-term production cost model widely used by utilities for operational planning. SDDP determines the least-cost operating policy over the study horizon by minimizing system costs over the lifetime of the assets in question.

Uncertainty in demand and renewable generation is represented through a stochastic process embedded in a multi-stage optimization framework. Instead of optimizing independent deterministic trajectories, SDDP approximates the expected future cost, commonly referred to as the cost-to-go function. This formulation enables operational decisions, such as hydro reservoir releases and storage dispatch, to balance immediate operating costs with anticipated future system conditions.

ISO-NE is represented as an integrated system in which each of the thirteen load zones is modeled explicitly. Transmission constraints and interconnections between zones are represented consistently with the ISO 2024 Economic Study assumptions, including internal transfer limits and external import with neighboring markets. This spatial representation allows congestion patterns, regional adequacy constraints, and inter-area power flows to be captured within the stochastic dispatch framework.

Capacity Expansion Optimization

Within this operational structure, system adequacy is evaluated through the occurrence of unserved energy in the stochastic simulations. When deficits arise within the planning horizon, OptGen, the expansion planning module of the PSR suite, is employed to determine the optimal investment strategy. OptGen identifies the least-cost schedule for new generation and storage capacity, including both timing and sizing decisions, to restore supply-demand balance while satisfying reserve margin requirements. The expansion plan minimizes total system cost, defined as the sum of capital investment costs, fixed and variable operating costs, fuel expenditures, and penalties associated with unserved energy.

Estimated Impact on Ratepayers

To compare the three scenarios, we estimate the incremental cost to ratepayers associated with building and operating new generation sources, as defined in the equation below.

$$\text{Incremental Cost}_n = \frac{\text{Opex}_n - \text{Opex}_0 + \text{Levelised Capital Cost}_n}{\text{Total Load}_n}$$

The calculation includes two components. First, we measure the change in annual operating costs between year n and the starting year. Second, we add the levelized capital cost of new capacity built to meet projected demand. These two components together represent the total incremental system cost.

The total incremental system cost is then divided by the total system load in year n , which expresses the result as an average incremental cost per unit of electricity consumed. The metric therefore reflects the additional revenue required to cover both new generation investments and changes in system operating costs as the system expands. This can then be converted to an annual impact on a typical residential customer by multiplying by the expected annual electricity consumption of a household.

This approach accounts for system-wide operational changes. For example, while new natural gas plants may increase fuel spending because they operate more frequently, existing gas plants may run less often, reducing their fuel costs. By calculating operating costs for the entire generation fleet, the method captures these offsetting effects.

How do we model renewables?

The system is modelled hour by hour so it can capture changes in electricity demand and renewable intermittency. Wind and solar generation are modeled using the Time Series Lab tool, which takes weather data and turns it into hourly generation profiles for specific locations, which helps create realistic scenarios that keep relationships between renewable resources over time. Because the profiles are generated at the plant level, each one has its own hourly production pattern. As shown in Figure 4, offshore wind production is higher during winter months but remains variable, with periods where output can fall close to zero. In contrast, solar generation experiences a substantial reduction in the winter due to shorter daylight hours and lower solar irradiance. This seasonal limitation reduces the contribution of solar resources during periods of peak winter demand, making it less reliable in a winter-peaking system.

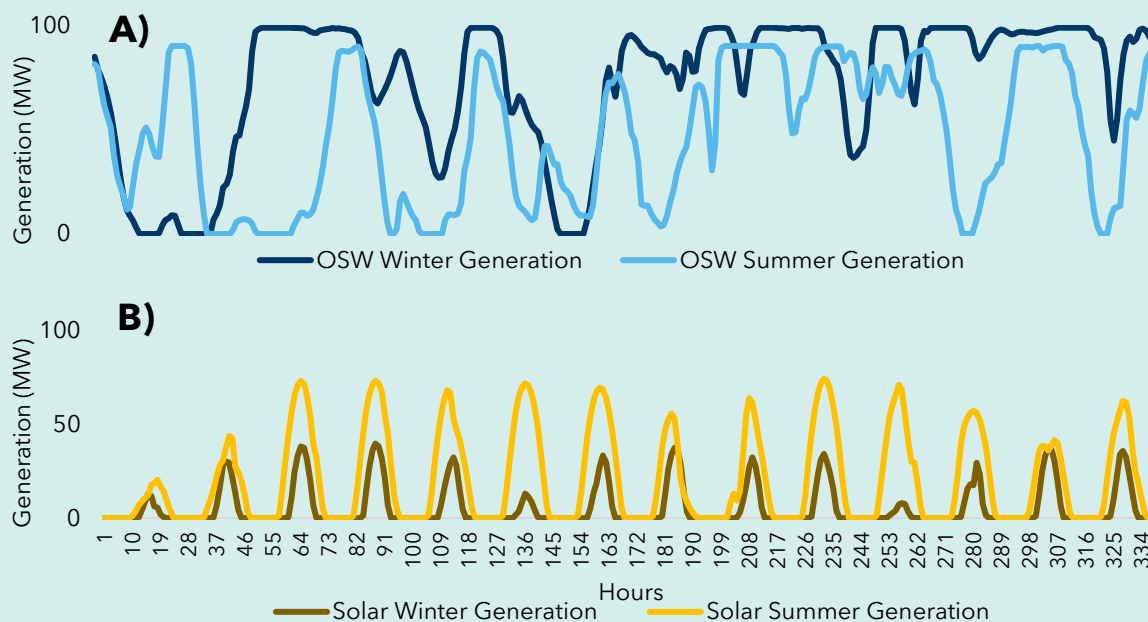


Figure 4: Two weeks of summer (July 1-14) vs. winter (January 1-14) generation for a 100 MW renewable plant: (A) offshore wind; (B) solar.

It should be noted however that real world offshore wind farms have exhibited generation patterns that can vary from typical modelling assumptions. A notable example is South Fork Wind, New York's first commercial offshore wind farm with 132 MW of installed capacity. Its operational profile shows that offshore wind can still provide significant output in the summer, particularly in the late afternoon and at night, when system demand remains high and solar generation declines.

This was evident during the June 2025 heat wave when record-breaking temperatures pushed New York's electricity demand to critical levels. In June, when NYISO declared a severe emergency, South Fork Wind achieved an evening capacity factor of 87%, bolstering the power supply when the grid needed it the most.¹⁵

2.2 Levelized Cost of Energy (LCOE)

The levelized cost of energy (LCOE) is the present value of all project costs throughout its lifetime (including capital and operating costs), divided by the discounted energy generated during that period. In mathematical terms:

$$LCOE = \sum_{t=0}^T \frac{\frac{I_t + M_t + F_t}{(1+r)^t}}{\frac{E_t}{(1+r)^t}}$$

Where I_t is the investment cost or capital at time t , M_t is the non-fuel operations and maintenance cost, E_t is the energy produced, F_t is fuel expenditures, and r is the discount rate.

While LCOE is helpful for an initial apples-to-apples comparison on a \$/MWh basis, it should be noted that it does not account for factors such as reliability, flexibility, location value, or grid interactions. **Therefore, it shouldn't be the sole basis for resource decisions, but it remains a key benchmark for understanding generation costs and guiding planning.** In our LCOE analysis, we compared CCGT with offshore wind using updated assumptions that better reflect current market realities, including rising gas turbine costs and limited equipment availability, as well as lower real-world utilization rates.

3. Results and Discussion

This section presents the results of the capacity expansion and LCOE analysis. We first compare capacity addition results across the three scenarios modelled and assess their implications for emissions and ratepayer costs. We then summarize the results of the LCOE analysis comparing offshore wind and CCGT under updated cost assumptions.

¹⁵ Ørsted, & Long Island Power Authority. (2025). [South Fork Wind: One year of South Fork Wind working for New York.](#)

3.1 Capacity Expansion Analysis Results

Scenario 1: All Fossil and Nuclear

In the All-Fossil expansion scenario, capacity expansion does not include offshore wind or other intermittent resources and is restricted to dual fuel CCGT and SMRs, representing a system in which only firm generation resources are allowed to be deployed.¹⁶

Under this constraint, CCGT becomes the primary expansion pathway. Additions increase progressively to meet rising winter peak demand, reaching approximately 25–26 GW by 2050 under both demand projections. While this outcome reflects the least-cost solution within the constraints imposed in this scenario, it should not be interpreted as a likely development pathway for the region. Natural gas transmission capacity in New England is already significantly constrained. The primary difference between the Economic Study and CELT demand scenarios lies in the timing of additions: under the CELT forecast, capacity expansion is pushed further into the planning horizon and becomes more concentrated between 2045 and 2050, although both scenarios converge to a similar total installed capacity by 2050.

To note, resources that are currently contracted in ISO-NE's interconnection queue are assumed to come online and are included in the capacity expansion result graphs, which represents around 4 GW of storage and 2.5 GW of utility-scale solar by 2034.

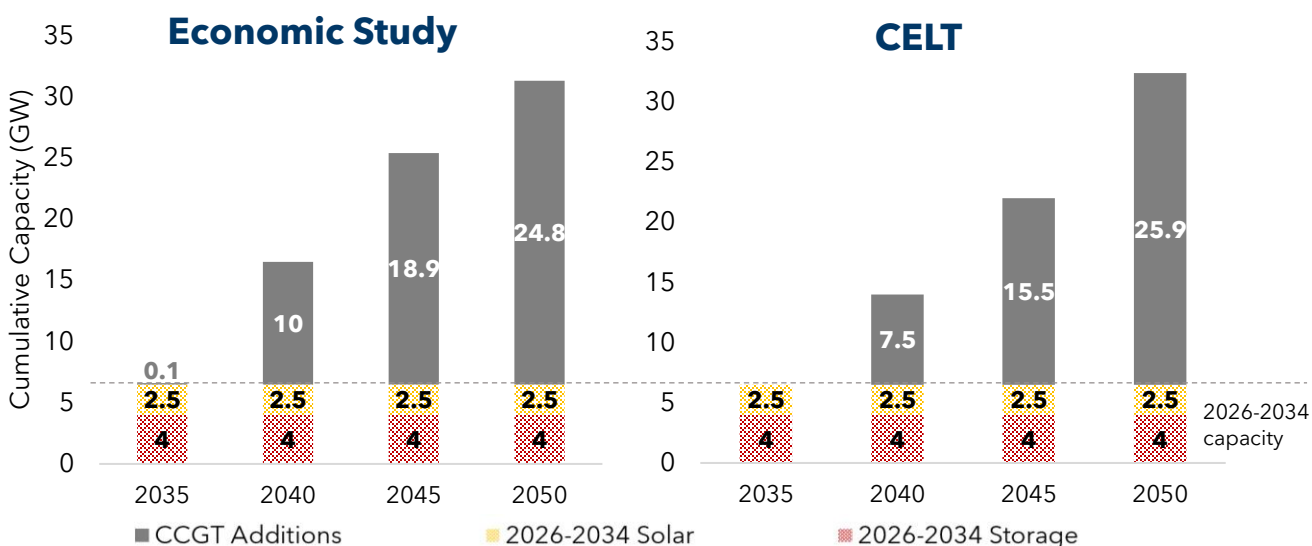


Figure 5: Fossil and Nuclear expansion plan with revised SMR cost; a) Economic Study; b) CELT

What about nuclear?

The results shown in Figure 6 assume an updated SMR capital cost of \$7,500/kW, reflecting recent techno-economic estimates that show costs in the \$7,000–\$8,000/kW

¹⁶ Solar and storage projects currently in the interconnection queue and expected to be deployed between 2026 and 2034 are included in the capacity expansion results.

range for SMR deployment in North America¹⁷, this assumption remains optimistic given that several recent SMR projects have experienced significant cost escalation.¹⁸

Even though we allow SMRs to be selected, under this updated capital cost assumption, the model does not select SMRs. However, when the more moderate NREL cost projections are applied (ranging from ~\$5,000/kW to ~\$7,300/kW depending on the year), the model deploys a limited amount of SMR capacity beginning around 2040, increasing to the maximum allowable capacity of 5.5 GW by 2045.

Hence, the outcome ultimately depends on whether one believes SMRs can achieve meaningful cost reductions over time; under lower cost assumptions, the model deploys SMRs (Figure 6) while under cost assumptions that align with in-progress project deployments, it does not (Figure 5). While proponents of SMRs expect costs to decline as designs are standardized and more units are deployed, these learning effects have yet to be demonstrated at scale, and recent project estimates remain relatively high. As projects advance in several jurisdictions, this uncertainty is expected to gradually diminish, and the choice will be clearer for decision makers in New England.

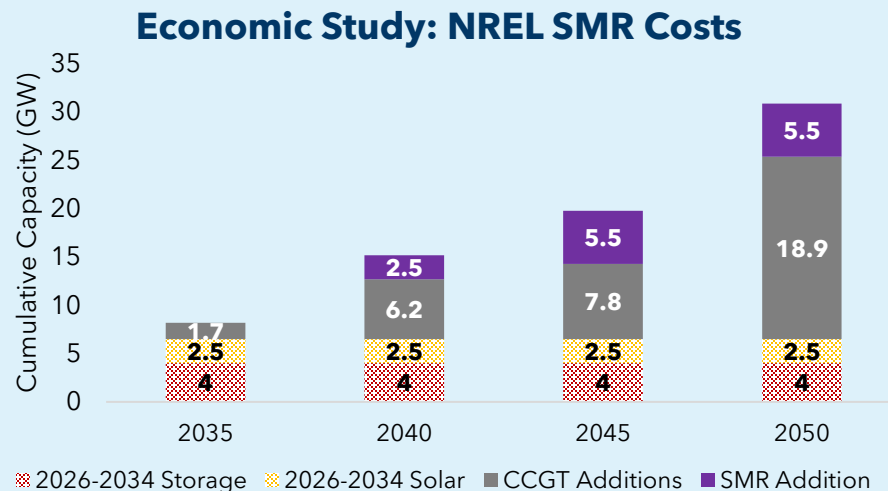


Figure 6: Fossil and Nuclear expansion plan moderate NREL SMR cost; a) Economic Study; b) CELT

Scenario 2: Least-Cost Mix

The Least-Cost Mix scenario allows all technologies to compete to determine the portfolio that achieves the lowest overall electricity system cost, including capital expenditures as well as fixed, variable, and fuel costs.

As seen in Figure 7, the model selects a diversified portfolio in this scenario. Offshore wind expands significantly, reaching approximately 14 GW by 2050 for both demand scenarios, while battery storage capacity increases to approximately 10-12 GW by 2050, reflecting its role in balancing renewable generation and supporting winter peak reliability.

¹⁷ [Woodmac: Nuclear needs to be cost competitive](#)

¹⁸ [Eye popping new cost estimates released NuScale small modular reactor](#)

CCGT additions are lower than the All Fossil and Nuclear case, stabilizing near 11 GW by 2050. In the absence of an emissions constraint, CCGTs are added to support system reliability and provide firm capacity during periods of low renewable output and high winter demand. While this result reflects the least cost solution within the constraints that we have set up as part of our modelling, several factors may limit the scale of additional gas fired generation in practice, such as transmission constraints, emissions limits, and other policy or regulatory considerations.

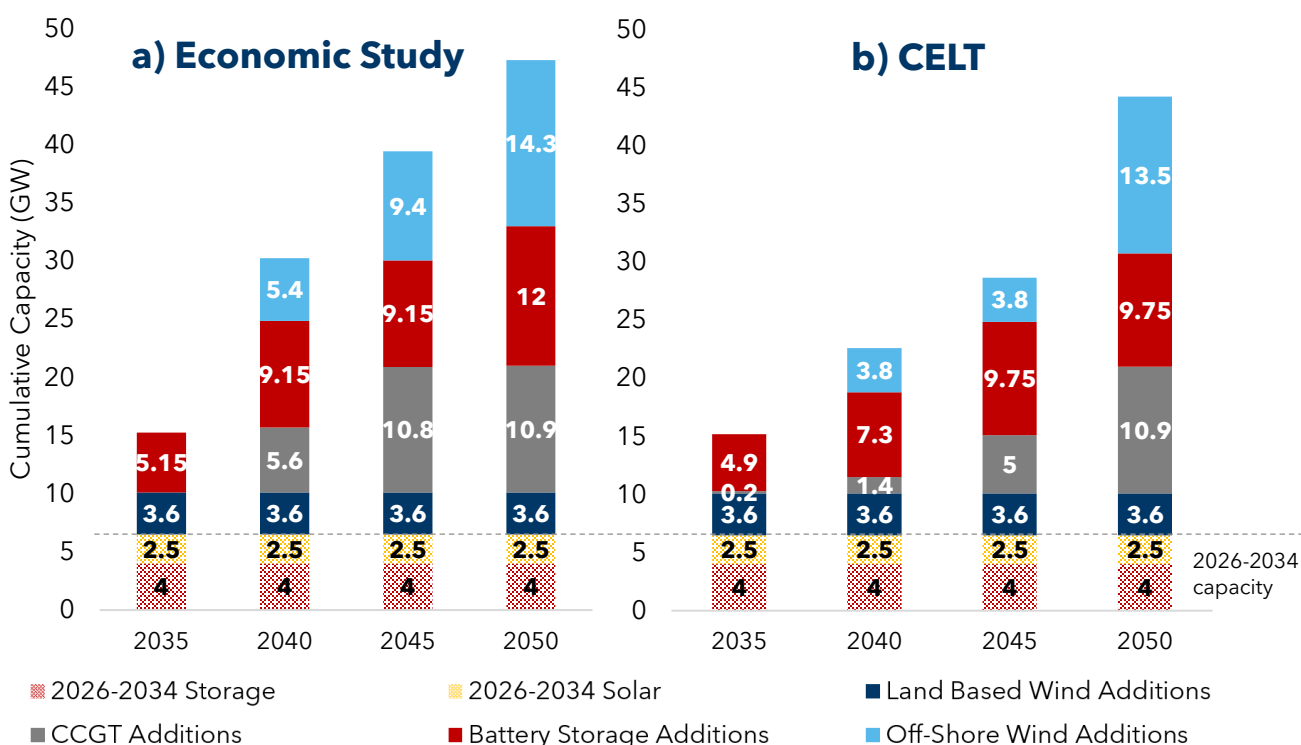


Figure 7: Least cost mix expansion plan; a) Economic Study; b) CELT

It should also be noted that no additional utility-scale solar capacity is built beyond 2035. Solar deployment in the model is primarily driven by carbon budget constraints and broader decarbonization objectives, as discussed in the Scenario 3 results below. This outcome may appear counterintuitive given that solar exhibits the lowest LCOE among the technologies considered. However, because by 2035 the system transitions to a winter-peaking profile, the model does not select solar for this scenario, as it provides minimal contribution during winter peak demand periods. While solar contributes to meeting summer peak demand, the model prioritizes land-based and offshore wind due to their stronger winter generation profiles, and surplus energy from these two resources in the summer months is balanced through storage. In addition, our load forecast assumes significant deployment of behind-the-meter solar, which contributes to summer supply and reduces the need for incremental utility-scale solar in this scenario.

In terms of energy storage, the model adds substantial 4-hour battery energy storage across the study period for both load scenarios. Long-Duration Energy Storage (LDES) was assessed using the cost of a 10-hour Lithium-Ion battery as a proxy. As an early commercial or emerging technology, the price used may overstate the cost for LDES at scale. While this

scenario, which excludes carbon pricing and related policy mechanisms, did not select LDES at this price, future technological improvements and corresponding cost reductions could change the result. Systems with more renewable generation, like our All-Clean Scenario described below, would be even more likely to benefit from a portfolio of storage options, including LDES technologies, that would help reduce reliance on new or existing natural gas generation for capacity and help meet regional climate commitments.

The overall pattern of deployment remains similar between the Economic Study and CELT load forecasts, although the timing of additions shifts slightly due to differences in peak demand growth trajectories. In all cases, land-based wind is built to its maximum allowable capacity early in the planning horizon.

Overall, the results indicate that, under moderate natural gas prices, offshore wind contributes meaningfully to the least-cost portfolio, particularly in a system transitioning to winter peaking. Its relatively strong winter generation profile complements other renewable resources and helps meet seasonal demand patterns, while also reducing reliance on fossil generation for energy supply over the long term.

Why are resources other than renewables in the least cost mix?

In the absence of carbon pricing or other comparable policy signals, scenarios with high offshore wind deployment (e.g. at higher natural gas prices – see text box below) still include build-out of dual-fuel CCGT capacity, reaching approximately 10 GW by 2050 and remaining relatively constant across the two scenarios.

Under these conditions, offshore wind supplies a large share of annual electricity demand; however, multi-day low-wind events can create periods of limited renewable generation during peak winter conditions. As illustrated in Figure 8, the light blue curve representing total renewable generation from more than 26 GW of installed capacity, including 14.3 GW of offshore wind, drops to approximately 4–5 GW for about 33 consecutive hours (hours 55–88), driven by a multi-day low-wind event. During such events, 4-hour lithium-ion batteries are unable to sustain system demand.

Although alternative technologies such as LDES and SMRs could technically address this reliability gap, under the modeled assumptions, which do not include carbon pricing or other related policy signals, dual-fuel CCGT is selected as the least-cost option. Incorporating factors such as carbon pricing and related policy mechanisms, as well as potential cost reductions as LDES technologies scale, would be expected to shift selection toward lower emissions alternatives.

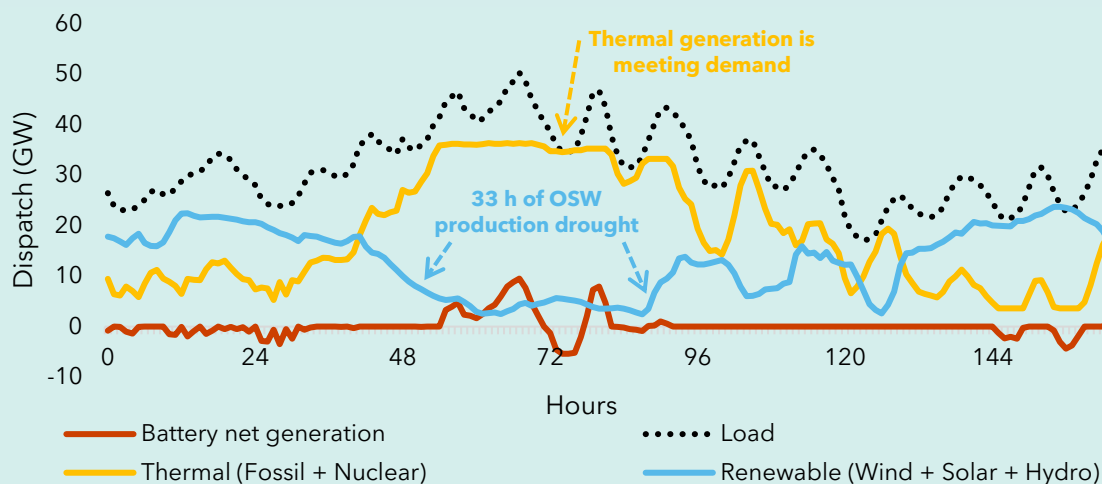


Figure 8: Hourly load and dispatch by resources for the worst week of 2049 (Jan 18 - Jan 25)

How do gas prices influence resource selection?

Natural gas prices have fluctuated significantly in the last decade, with several factors influencing prices such as supply constraints within the pipeline network and colder temperatures.

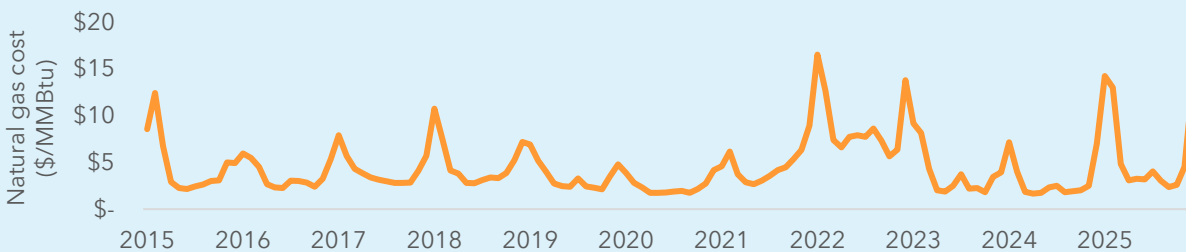


Figure 9: Average cost of natural gas delivered for electricity generation (U.S. EIA)

To assess the impact of fuel price on resource selection, a sensitivity analysis was conducted on the Least-Cost Mix using an average price of fuel purchased over the lifetime of a new natural gas generator, ranging from \$3.72 (the average fuel used in the Economic Study) to \$7/MMBtu, holding all other assumptions constant. Only the results of the Economic Study load forecast are presented below, as the dynamics of interest were found to be consistent across both load forecast scenarios.

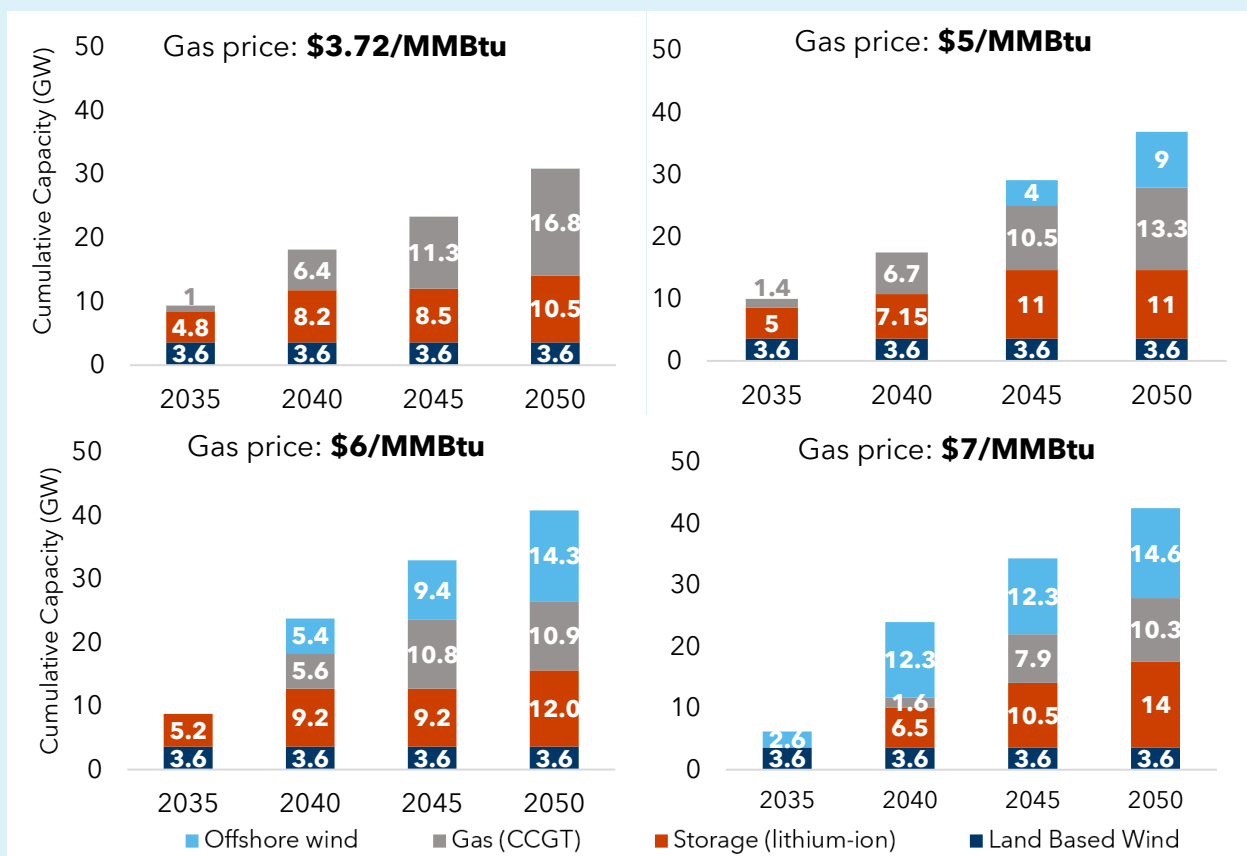


Figure 10: Capacity expansion gas price sensitivity under the economic study load forecast

At \$3.72/MMBtu, CCGT dominates the expansion, exceeding 15 GW of cumulative additions by 2050, while offshore wind is not selected. As gas prices increase to \$5/MMBtu, offshore wind begins to enter the portfolio in later years. At \$6/MMBtu, offshore wind deployment becomes material, reaching approximately 14 GW by 2050, which results in a 6 GW reduction in CCGT additions. At \$7/MMBtu, offshore wind deployment increases further and is added in 2035, the first year of our study horizon.

Across all gas price assumptions, land-based wind reaches its capacity cap of 3.6 GW and battery storage expands progressively to maintain adequacy in a winter-peaking system.

These results indicate that offshore wind competitiveness is strongly driven by fuel price assumptions and the \$5-6/MMBtu range is a clear inflection point.

Scenario 3: All-Clean

The All-Clean scenario prohibits new CCGT construction and imposes a declining carbon budget from 2035 to 2050, which aligns with the framework within ISO's Economic Study.

Under these constraints, the model selects a fully non-emitting expansion pathway. **Offshore wind deployment increases relative to the Least-Cost scenario, reaching 17.5 GW under the Economic Study demand forecast and 15 GW under the CELT forecast, reflecting its high winter capacity factor and strong contribution to peak adequacy.** Solar capacity also

expands substantially, particularly in the near term, to comply with the carbon budget and because offshore wind cannot be deployed instantaneously. Battery storage capacity increases to approximately 17-18 GW by 2050 to maintain reliability under higher levels of renewable penetration. This configuration is consistent with the assumptions of the Economic Study, and our ability to reproduce similar results provides confidence in the robustness of the model.

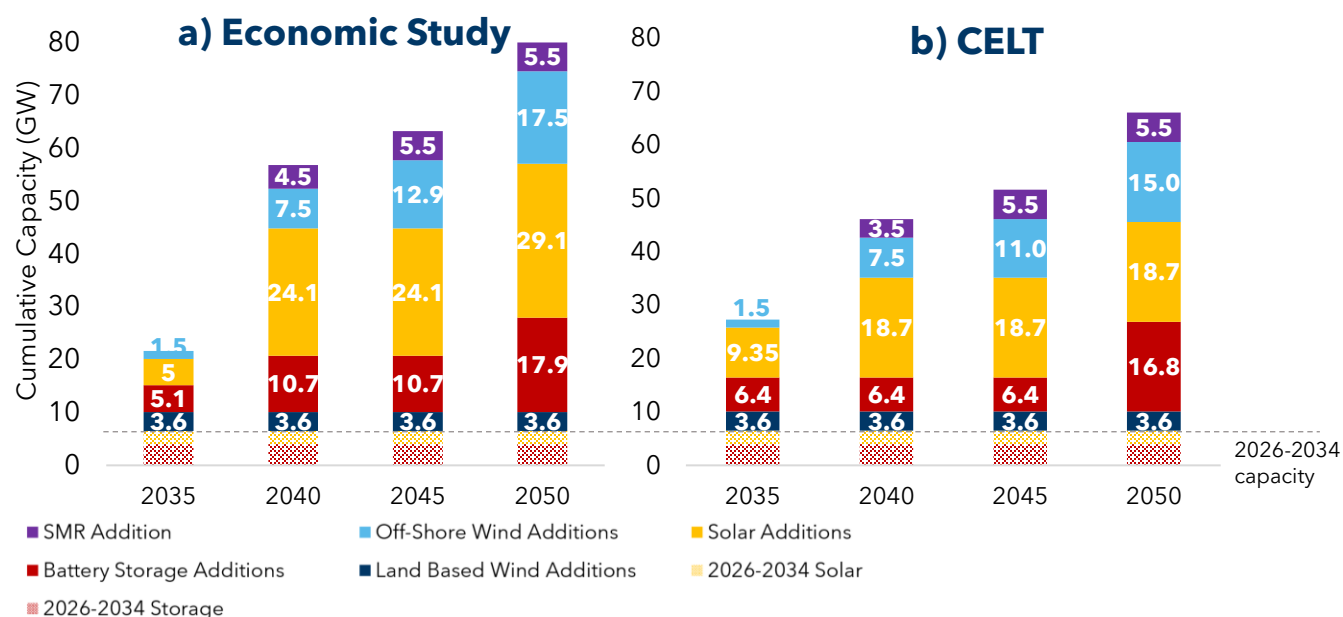


Figure 11: All clean expansion plan; a) Economic Study; b) CELT

Finally, SMR capacity is built up to its allowable limit even under the updated capital cost assumptions of \$7,500/kW, providing firm low-carbon capacity beginning around 2040. The model selects resources to minimise total system cost subject to the carbon budget and reliability constraints, so SMRs appear in the portfolio because they are part of the least-cost solution. Their value lies in the clean firm capacity they provide, which is more cost-effective than the alternative resource combinations needed to meet the same constraints. The resulting portfolio meets both reliability and emissions constraints without relying on new fossil fuel infrastructure.

The largest differences between the two demand scenarios appear in resources that primarily supply energy. Although both scenarios reach similar levels of peak capacity, the lower overall electricity demand in the CELT forecast leads to smaller additions of solar and offshore wind. In contrast, capacity-driven resources (resources added to meet peak demand), such as SMR and storage are deployed at comparable levels in both cases.

Cost and Emission Comparison

Total system emissions diverge substantially depending on the scenario, as shown in Figure 12, which compares total system emissions across the three modeled scenarios. In the All-Fossil scenario, emissions increase continuously, rising from approximately 32 megatonnes (Mt) of CO₂ in 2035 to over 50 Mt by 2050. This reflects sustained reliance on gas-fired generation to meet growing winter demand in the absence of renewable or storage

expansion. In contrast, the All Clean scenario achieves very low emissions by the end of the study period, reaching approximately 3 Mt.

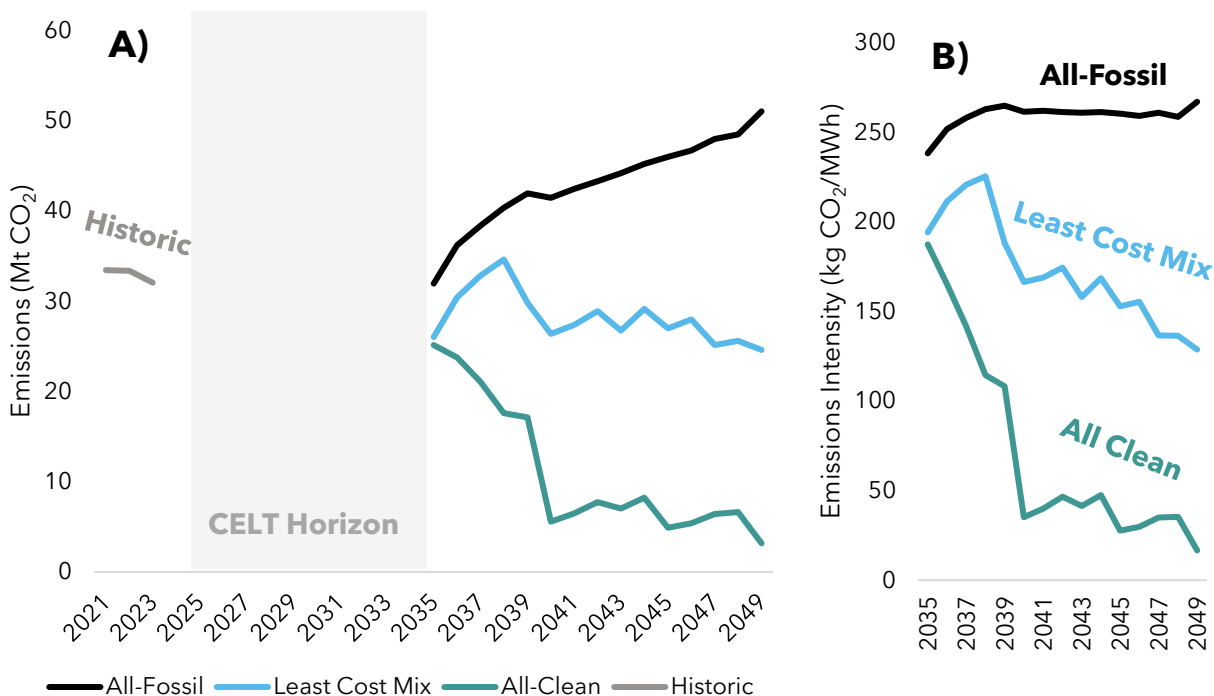


Figure 12: Total system emissions across the three modeled scenarios over the 2035-2050 horizon: (A) total emissions; (B) emissions intensity.

The Least-Cost Mix scenario yields intermediate emissions outcomes. Total emissions peak in the late 2030s and gradually decline thereafter, stabilizing near 24-25 Mt by 2050. Importantly, this reduction occurs despite substantial load growth over the modeling horizon. Even as the grid gets cleaner with a declining emissions intensity, higher overall electricity consumption partially offsets those gains. As shown in Figure B, by 2050 emissions intensity is approximately 31% lower than in 2035. Although absolute emissions in the Least-Cost Mix scenario remain materially above the All-Clean level, by 2050, the 24 Mt outcome still represents a significant reduction relative to the All-Fossil case, which exceeds 50 Mt.

From a cost-comparison perspective, even under a counterfactual framework in which all environmental externalities are excluded (i.e., no carbon pricing, no climate impacts, and no environmental compliance costs), **the All Fossil and Nuclear scenario ultimately proves more expensive than a diversified resource portfolio that includes offshore wind** (see Figure 13). Looking at the incremental costs in 2050 for the CELT demand forecast, the All-Fossil scenario has an impact of an additional ~\$370/year to ratepayers, while the Least Cost Mix has an impact of \$310/year – **saving ratepayers \$60/year compared to the All Fossil scenario**.¹⁹ The incremental cost analysis indicates that while the All Fossil and Nuclear pathway may offer short-term cost advantages, these benefits erode rapidly over time. Beyond the early years of the planning horizon, cumulative system costs increase more steeply relative to the Least-Cost Mix scenario.

¹⁹ Assuming 1,000 kWh are used in a month by an average residential customer

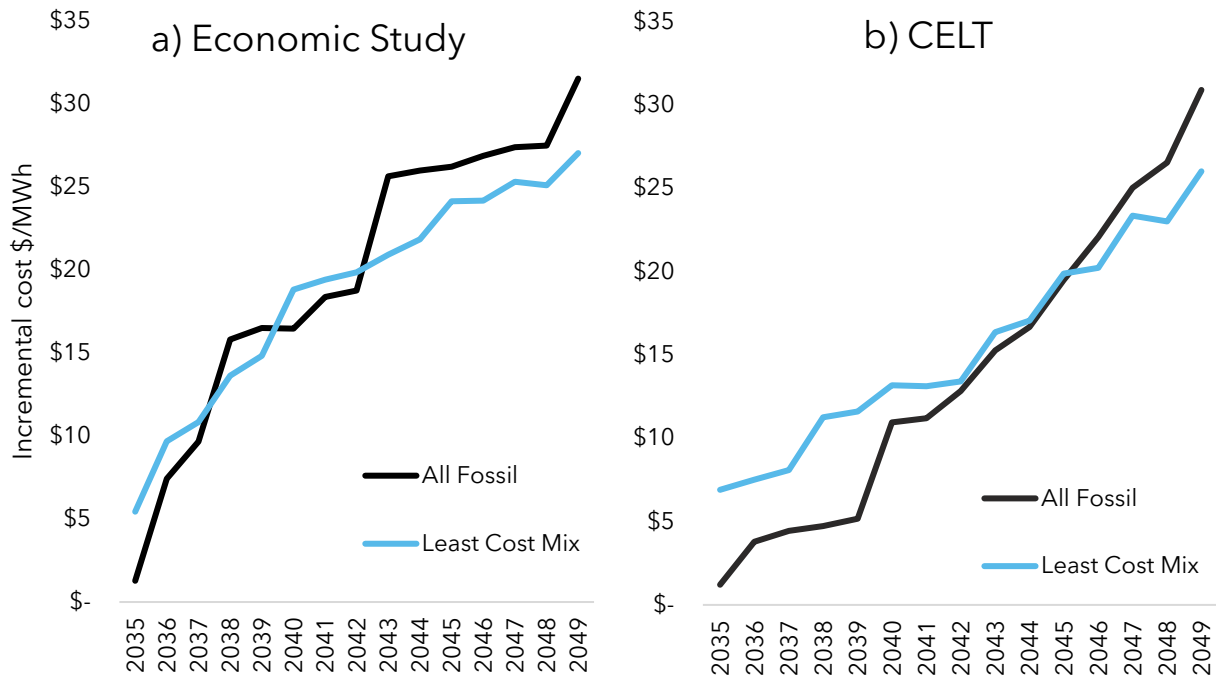


Figure 13: Incremental generation portfolio cost analysis All-Fossil vs Least Cost Mix; a) Economic Study; b) CELT

Importantly, this exercise is not intended to advocate for a framework that disregards climate impacts; rather, it serves as a thought experiment to isolate pure system cost dynamics. The results demonstrate that offshore wind maintains structural value within the generation portfolio even in the absence of carbon constraints. Its contribution to long-term price stability, reliability, and lower marginal system costs leads to reduced ratepayer burden over time. **The findings therefore suggest that offshore wind remains economically justified across several policy assumptions.**

When comparing the Least-Cost Mix with the All-Clean scenario, the results indicate that, **even in the absence of explicit climate constraints, the cost premium associated with a fully clean portfolio remains relatively modest** (see Figure 14). Over the planning horizon, the All-Clean pathway exhibits higher incremental costs; however, the differential remains contained and does not diverge dramatically from the Least-Cost Mix trajectory.

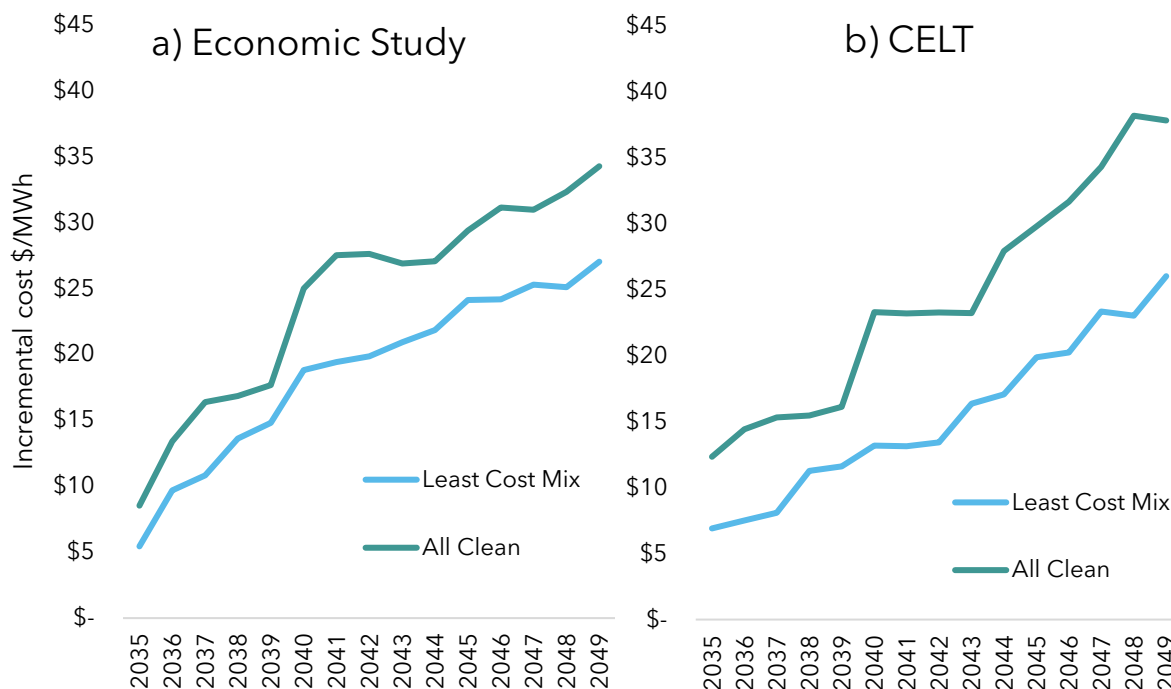


Figure 14: Incremental generation portfolio cost analysis All-Fossil vs Least Cost Mix; a) Economic Study; b) CELT

This limited premium suggests that the transition toward a fully clean generation portfolio does not impose a disproportionate economic burden on ratepayers, even under a framework that excludes carbon pricing or climate costs. When climate externalities, and long-term fuel price uncertainty are considered, the remaining cost gap would likely narrow further or potentially reverse.

3.2 LCOE Results

Using revised assumptions for new natural-gas combined-cycle plants, the cost difference between offshore wind and gas generation is much smaller than is often represented. When accounting for higher capital expenses and more accurate utilization rates of gas plants, the LCOE from new gas plants approaches that of offshore wind projects, which are developed at around \$4,000 per kW. This comparison indicates that offshore wind can be broadly cost-competitive with new gas-fired generation within ISO-NE, especially under moderate to high natural gas prices. Although these technologies have different operational roles in the power system, the updated LCOE analysis shows that **offshore wind is a viable option for regional planning and should not be dismissed based on outdated cost assumptions about new gas plants.**

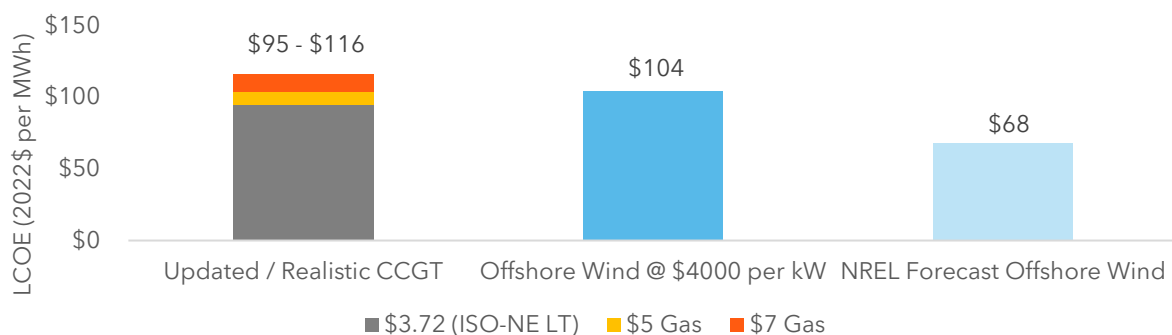


Figure 15: Updated LCOE Results of CCGT and Offshore Wind

Reassessing the Cost of New Gas-Fired Generation in ISO-NE

Recent market developments indicate that the levelized cost of energy (LCOE) for new natural gas-fired power in ISO-NE could be significantly higher than the frequently cited planning estimates. Revised assumptions that more accurately reflect current market conditions, such as increased capital costs and reduced utilization rates, substantially raise the projected costs.

The capital costs for new CCGTs have increased notably due to supply chain issues.²⁰ These factors have increased the initial investment required for new plants relative to the assumptions in many planning studies, which commonly cite the Annual Technology Baseline (ATB) from the National Laboratory of the Rockies.²¹ We researched recent natural gas turbine prices and updated the costs to reflect the dual-fuel capability required for resource adequacy in ISO-NE. These updated costs show a substantially higher LCOE for natural gas turbines.

Second, real operating patterns in ISO-NE show lower utilization rates than the minimum dispatch levels assumed in the ATB forecast. Historical data indicate that gas-fired units run fewer hours than the 50% minimum capacity factor used in the ATB forecast. This results in higher per-unit electricity costs because fixed costs are spread over fewer megawatt-hours. Therefore, we revised the LCOE for ISO-NE to better reflect actual historic dispatch patterns of natural gas resources in the region.

When these updated assumptions are incorporated, projected LCOE for new gas-fired generation increases substantially relative to the LCOE implied by the assumptions included in the ATB. **This suggests that reliance on outdated cost and utilization assumptions may underestimate the true cost of new gas capacity by a wide margin, with important implications for long-term resource planning in the region.**

The other important factor in the LCOE for natural gas-fired generation is the assumed average fuel cost over the life of the plant. In the graph below, we show the LCOE with updated capital costs and a range of fuel costs.

²⁰ Recent filings for Coyugo CC Project in Indiana and Homer City Generating Station in Pennsylvania reach prices closer to \$2300 per kW, diverging substantially from NREL. See also <https://www.latitudemedia.com/news/gas-turbine-prices-are-up-and-arent-going-down-anytime-soon/>.

²¹ Formerly the National Renewable Energy Laboratory (NREL)

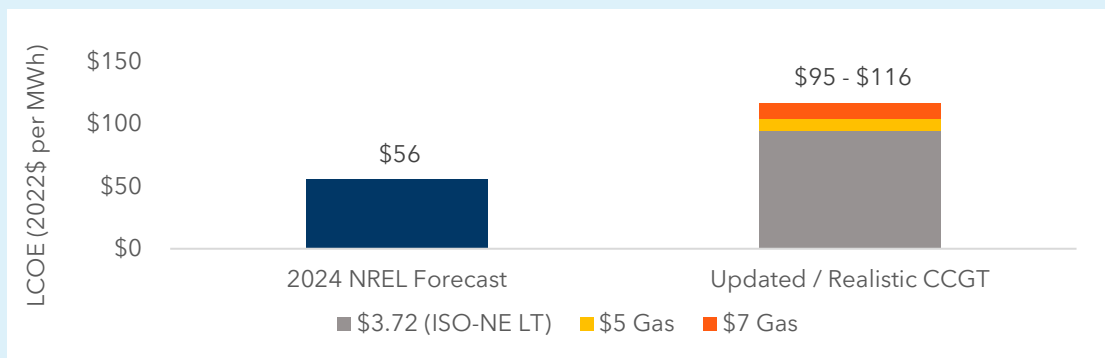


Figure 16: NREL CCGT LCOE vs. Updated CCGT LCOE

Benchmarking LCOE Costs

To benchmark the LCOE, we compared the costs of offshore wind and utility-scale solar to the ATB capital costs for a CCGT plant, using a natural gas price assumption of \$3.72/MMBtu. We assumed a 50% capacity factor, consistent with the minimum dispatch in the ATB. This benchmark reflects an outdated perspective on natural gas electricity costs and highlights why assumptions favoring natural gas as the primary option for new regional generation persist, especially when overlooking some environmental and public health costs associated with greenhouse gas emissions.

To provide a more realistic estimate, we increased the assumed \$1200-per-kW capital cost in the ATB to \$2300 per kW, consistent with recent turbine prices. Additionally, we updated the LCOE calculation to reflect a 40% capacity factor, more aligned with actual gas unit dispatch within ISO-NE. We also increased the fuel cost by scaling the \$3.72 per MMBtu to 150% of the ISO-NE figure, to better represent historic New England gas prices. **These changes highlight how natural gas electricity costs are highly sensitive to underlying fuel cost assumptions, whereas offshore wind costs are primarily driven by capital expenses.** The resulting changes were implemented as adjustments to the ATB forecast and are shown in Figure 17. These are consistent with the adjustments we used for the LCOE results above, except that the analysis explored a range of natural gas price forecasts.

When comparing the ATB forecast for solar PV generation to the offshore wind LCOE, it becomes evident that solar offers a significantly lower electricity price. **However, offshore wind delivers more energy during winter months, demonstrating that relying solely on LCOE is insufficient for choosing the most cost-effective resource to meet regional electricity demands.** The forecast cost reduction in offshore wind and solar costs is directly from the ATB and likely reflects the expected improvement in technology and efficiency for these technologies.

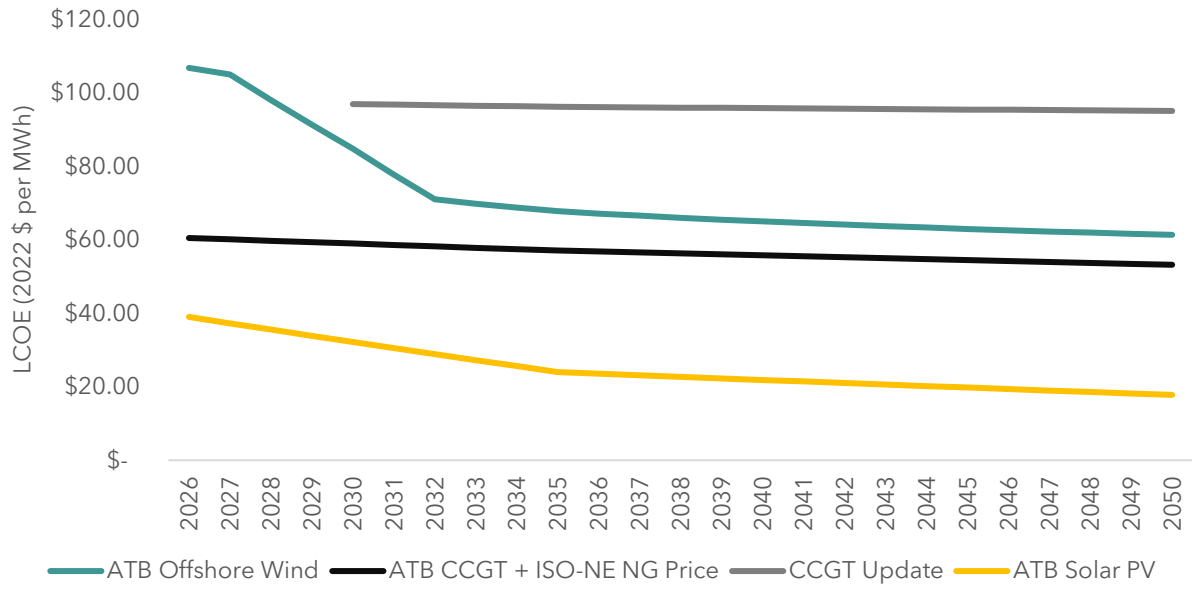


Figure 17: LCOE Benchmarking

4. Conclusions

Offshore wind plays a central role in the least-cost electricity portfolio

When all technologies are allowed to compete, the model selects significant offshore wind capacity, reaching approximately 14 GW by 2050. This indicates that offshore wind is economically competitive even without carbon pricing or emissions constraints. Its role becomes even more important in the New England context, where existing natural gas infrastructure constraints may limit the availability of new CCGT capacity, land-based wind faces siting limitations, and solar provides limited contribution during future winter peak demand periods.

Natural gas fuel price risk can be offset with offshore wind additions

Fluctuating natural gas prices increase the financial risk of building new CCGTs by creating uncertainty around long-term electricity prices and operating costs. Expanding offshore wind can help mitigate this risk by reducing reliance on natural gas and adding a generation source with no fuel costs. This diversification can improve price stability and reduce exposure to volatile fossil fuel markets.

Natural gas prices strongly influence long-term resource decisions

Offshore wind deployment increases as natural gas prices rise. Offshore wind begins entering the portfolio at approximately \$5/MMBtu and becomes a major component around \$6/MMBtu. These results highlight how assumptions about future fuel prices can significantly shape generation investment decisions and emphasize the importance of considering natural gas price uncertainty in long-term system planning. Planners may wish to consider that building more gas today *increases* their exposure to this uncertainty, while diversification through investment in other generation resources limits that exposure.

A diversified resource mix helps maintain reliability in a winter-peaking system

No single resource is likely to meet all system needs, and a diversified portfolio is required to help meet future winter peak demand. The least-cost portfolio therefore includes a combination of offshore wind, land-based wind, battery storage, and firm capacity resources such as CCGTs. This diversified mix allows the system to ensure adequate supply during periods of high demand and low renewable output.

Offshore wind can deliver zero-emission electricity at costs comparable to natural gas

Using updated cost assumptions that reflect current market conditions, including limited availability of gas turbines, rising equipment costs, and lower real-world utilization rates for gas plants, the analysis shows that the LCOE from offshore wind and natural gas can be comparable. Offshore wind costs are largely upfront capital investments with relatively low operating expenses. This cost structure can provide greater long-term price stability for ratepayers compared with fuel dependent generation such as natural gas.

Including climate impacts would further strengthen the case for offshore wind and other clean energy resources

This analysis adopts a deliberate approach to examine whether offshore wind can be cost-competitive without depending on policy factors like carbon pricing and climate policies. By

excluding factors such as the total costs of climate impacts, carbon pricing, and emerging technologies like long-duration storage, the study focuses solely on the core costs likely to be passed through on ratepayer electric bills, while setting aside the more comprehensive societal economics. Under these conditions, we still find offshore wind to be competitive and reliable. Analyses that incorporate broader climate considerations may identify pathways similar to the All Clean pathway in this study as the lowest-cost societal option and show a reduced role for natural gas. *Our Least-Cost Mix minimizes long-term electricity system costs and should not be viewed as the optimal societal approach for the future New England electric system.*

APPENDIX



Appendix A

Capital Cost Assumptions

- Capital cost assumptions for renewable generation and storage technologies are based on the data files of the ISO 2024 Economic Study²² to ensure consistency with the reference planning framework
- CCGT capital costs reflect recent project pricing, as turbine costs have increased substantially in recent years²³ due to supply chain constraints following the COVID-19 pandemic and heightened demand associated with AI data centers²⁴.
- SMR estimates are derived from recent project announcements and benchmarked against values reported by the National Renewable Energy Laboratory (NREL)

Table 2: Capital cost assumption

Year	Capital Cost (2026\$/kW)							
	LBW	BESS 4	BESS 10	OSW	PV	SMR NREL	SMR Revised	CCGT
2035	1335	1347	2736	3537	895	7290	7500	2350
2036	1320	1327	2688	3512	881	7095	7500	2350
2037	1305	1306	2640	3489	867	6900	7500	2350
2038	1291	1285	2591	3467	853	6705	7500	2350
2039	1276	1264	2543	3446	839	6509	7500	2350
2040	1261	1243	2494	3427	825	6314	7500	2350
2041	1247	1223	2446	3409	810	6184	7500	2350
2042	1232	1202	2398	3391	796	6054	7500	2350
2043	1217	1181	2350	3375	782	5923	7500	2350
2044	1203	1160	2302	3359	768	5793	7500	2350
2045	1188	1140	2253	3344	754	5663	7500	2350
2046	1174	1119	2205	3330	740	5533	7500	2350
2047	1159	1098	2157	3316	725	5400	7500	2350
2048	1144	1077	2109	3303	711	5272	7500	2350
2049	1130	1057	2061	3290	697	5142	7500	2350
2050	1115	1036	2013	3278	683	5012	7500	2350

²² [2024 economic study final policy results.pdf](#)

²³ [Gas Turbine Cost Report](#)

²⁴ [Spglobal: us gas fired turbine wait times as much as seven years costs up sharply](#)



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