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EMM Report

REPORT

POTOMAC
ECONOMICS

Highlights of the 2025 Assessment of the ISO New England Markets

Presented to:

NEPOOL Participants Committee Summer Meeting

David B. Patton, Ph.D.
Potomac Economics

June 16, 2026

June 16-18, 2026
Summer Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

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Introduction

- Potomac Economics serves as the External Market Monitor (“EMM”) for the ISO-NE. In this role, we:
 - Evaluate the competitive performance and operation of the markets
 - Identify and recommend necessary changes to existing and proposed market rules, tariff, and market design elements
 - Evaluate the mitigation by the Internal Market Monitor (“IMM”)
- Our annual assessment of the ISO-NE markets complements the IMM’s report, focusing on key market areas summarized in this presentation:
 - Cross-market comparison of key market outcomes and metrics
 - Energy affordability challenges
 - Clean energy transition
 - Competitive assessment of the energy and reserves markets
 - Resource commitment and reserve pricing issues
 - Capacity availability and performance incentives

Summary of Findings

- The markets performed competitively but identify key improvements will be increasingly important in the coming years
- High priority recommendations to improve market performance and to facilitate the expected large-scale renewable resource entry include:
 - 2018-7: Modify the pay-for-performance rate to a reasonable level that would vary with the size of the operating reserve shortage
 - 2020-2: Accrediting capacity resources based on marginal reliability value
 - 2021-1: Replacing the FCM with a prompt seasonal capacity market
 - 2023-1: Evaluating a look-ahead dispatch model to manage fluctuations in net load and use of energy storage resources
- We recommend nine other improvements to lower costs and improve market performance, which are lower in priority to those above

Cross-Market Comparison and Competitive Assessment

Cross-Market Comparison of Key Outcomes & Metrics

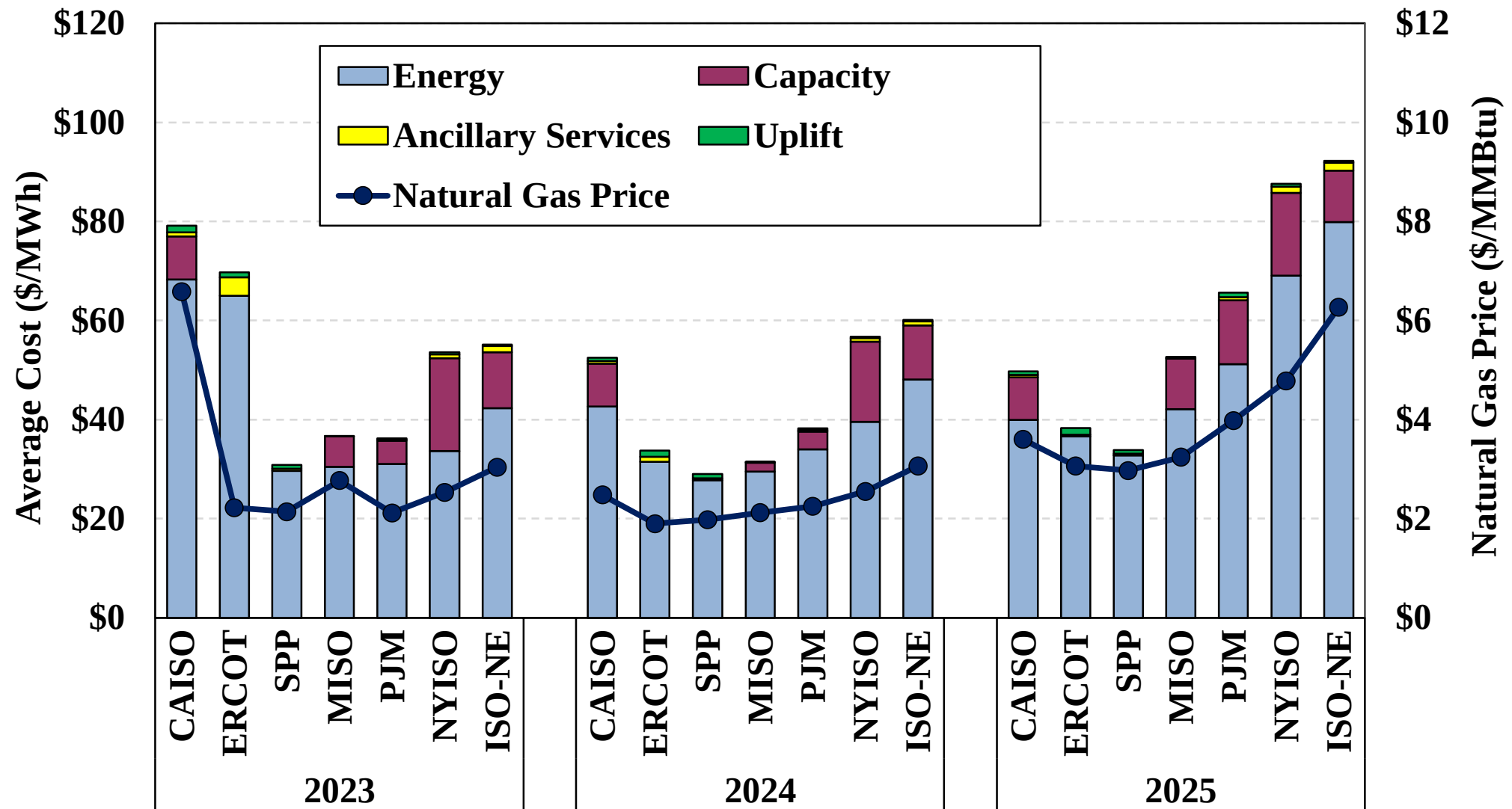
See Section I

Compared to most other RTO markets, ISO-NE has:

- The highest energy prices because it has the highest gas prices
- Far less congestion (9-20% of other RTOs per MWh of load) because of transmission investments over the past decade
 - Tx. rates are more than double the average rates in other RTO markets
 - Other RTOs have been expanding their transmission investment to support renewables integration, driving rising transmission costs more recently
- Stable capacity costs over the past three years at below \$3.0/kW-month
 - NYISO has the highest capacity cost following a significant amount of peaking-resource retirements and rising requirements
 - PJM and MISO saw significant increases in 2025 because of market reforms, demand growth, and recent retirements

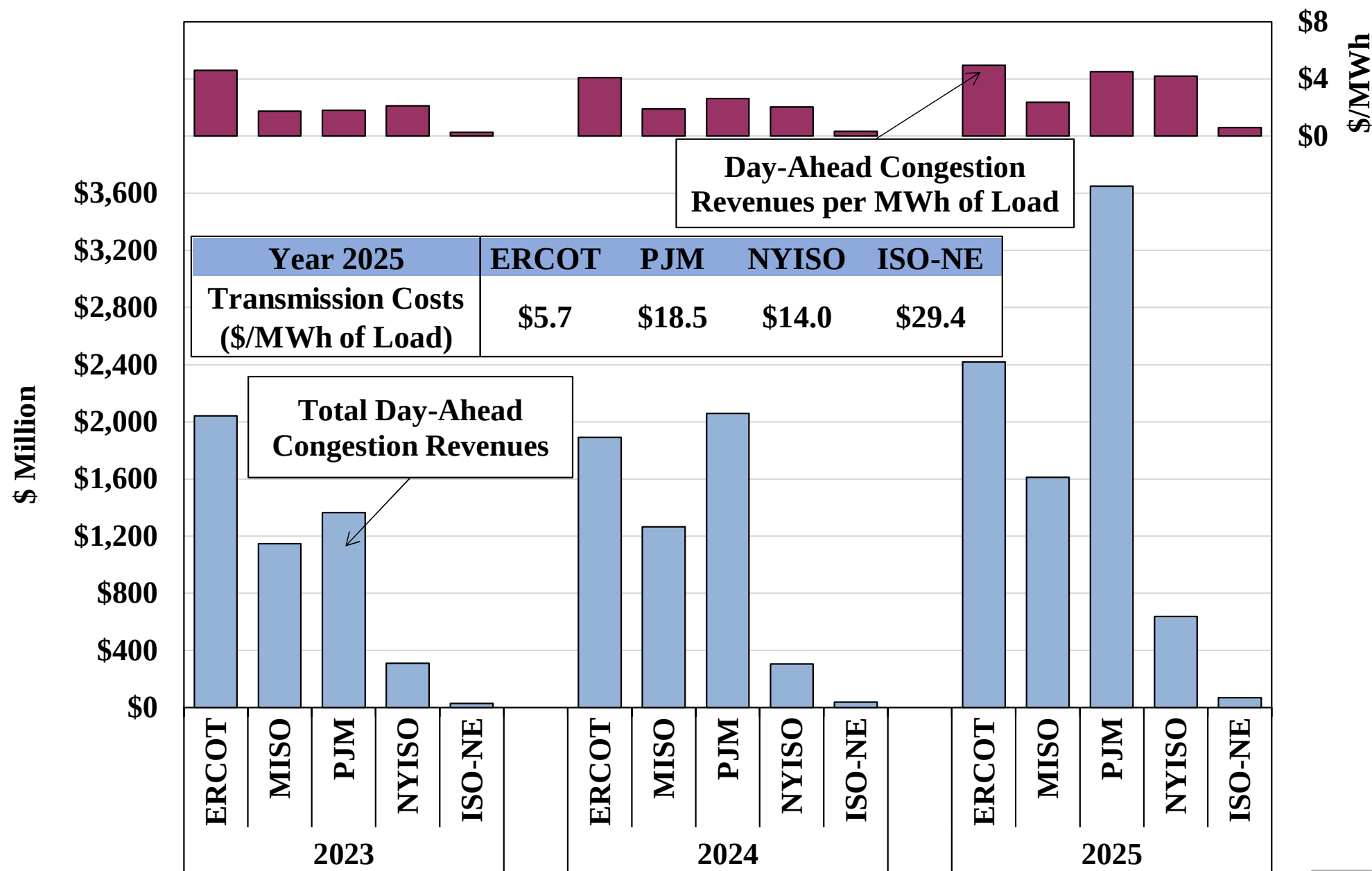
All-in Prices in RTO Markets

See Section I.A



Transmission Congestion Costs

See Section I.B



Cross-Market Comparison of Key Outcomes & Metrics

See Section I

In addition, ISO-NE has consistently exhibited:

- Less liquidity in the day-ahead market and poorer performance mainly because of the inefficient allocation of costs to virtual transactions
- Higher market-wide uplifts costs because of:
 - Higher fuel costs
 - More circumstances when uplift compensation is given
- However, day-ahead ancillary service markets introduced in March 2025 have helped lower market-wide uplift for capacity needs
- Lower local reliability uplift because of past transmission upgrades

Virtual Transactions

See Section I.C

Market	Year	Virtual Load		Virtual Supply		Uplift Charge Rate
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	
ISO-NE	2022	3.1%	-\$1.75	4.8%	\$3.23	\$1.02
	2023	4.2%	-\$2.09	6.3%	\$1.28	\$0.83
	2024	3.1%	-\$2.64	6.6%	\$2.21	\$0.75
	2025	4.5%	-\$3.19	8.0%	\$2.67	\$0.63
NYISO	2025	6.1%	\$3.39	7.7%	\$1.25	< \$0.1
MISO	2025	15.5%	-\$0.30	15.5%	\$1.49	\$0.16

Uplift Charges

See Section I.C

		ISO-NE			NYISO	MISO
		2023	2024	2025	2025	2025
Real-Time Uplift						
Total	Local Reliability (\$M)	\$1.0	\$1.3	\$1.3	\$9	\$2
	Market-Wide (\$M)	\$25	\$27	\$30	\$47	\$28
Per MWh of Load	Local Reliability (\$/MWh)	\$0.01	\$0.01	\$0.01	\$0.06	\$0.00
	Market-Wide (\$/MWh)	\$0.22	\$0.23	\$0.26	\$0.31	\$0.04
Day-Ahead Uplift						
Total	Local Reliability (\$M)	\$0.7	\$0.9	\$0.2	\$13	\$24
	Market-Wide (\$M)	\$4	\$6	\$10	\$13	\$25
Per MWh of Load	Local Reliability (\$/MWh)	\$0.01	\$0.01	\$0.00	\$0.09	\$0.03
	Market-Wide (\$/MWh)	\$0.03	\$0.05	\$0.09	\$0.08	\$0.04
Total Uplift						
Total	Local Reliability (\$M)	\$1.6	\$2.2	\$1.5	\$22	\$26
	Market-Wide (\$M)	\$29	\$33	\$40	\$60	\$53
Per MWh of Load	Local Reliability (\$/MWh)	\$0.01	\$0.02	\$0.01	\$0.14	\$0.04
	Market-Wide (\$/MWh)	\$0.26	\$0.28	\$0.35	\$0.39	\$0.08
	All Uplift (\$/MWh)	\$0.27	\$0.30	\$0.36	\$0.54	\$0.11

Competitive Assessment of Energy & Reserve Markets

See Section III

- Our competitive assessment shows little evidence of market power abuse and that mitigation has been effective in preventing such abuses
 - However, structural market power indicators have grown in recent years because of acquisitions and retirements, trends that are ongoing
 - It is important to ensure that the mitigation measures remain effective as these structural indicators change
 - Hence, we support IMM recommendation to review mitigation thresholds and eliminate exemptions for non-capacity resources (IMM Rec #2023-1)
- We also recommend improving the current mitigation process by implementing hourly conduct and impact tests in the automated procedure (Rec. # 2022-2a)

Day-Ahead Ancillary Services Market Performance

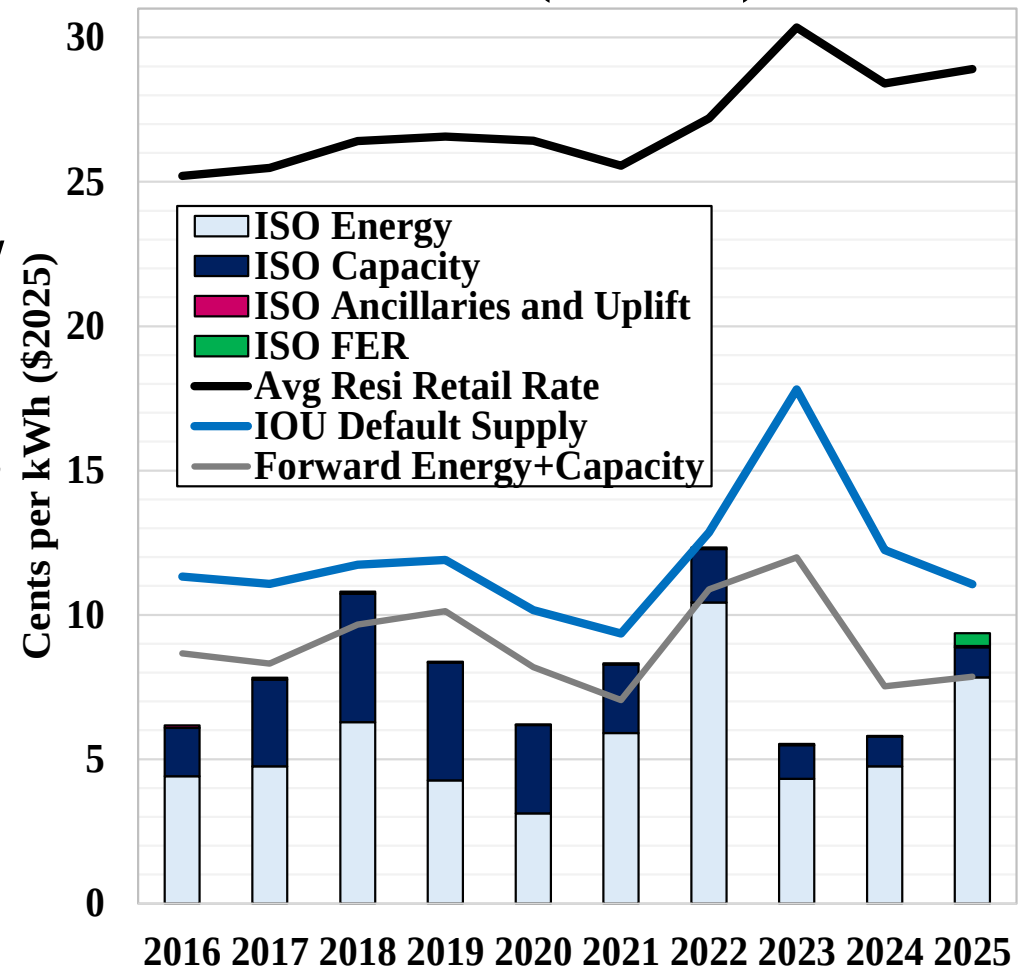
- The DA A/S markets have generated higher costs than expected in year 1 – the IMM estimated \$974 million or a 9% rise over the prior market
 - The IMM estimated that 75 percent of the incremental costs are due to fundamentals and 25 percent to participation and offers
 - Our prior concerns regarding the strike price contributed to the higher costs and we strongly support the ISO's reform to raise the strike price
 - These costs overstate the net effect on consumers because:
 - 1) DAA/S revenues are offsets in the capacity demand curve and lower capacity prices
 - 2) The IMM estimates do not consider that the DA A/S commitments will lower RT LMPs, which will lower DA LMPs and offset the estimated cost increase
- The DA A/S markets have improved the performance of the ISO markets overall, lowering uplift costs and improving generator availability
- DA A/S mitigation was frequently imposed but likely not for actual market power
 - Conduct threshold often allow ~ \$1/MWh for closeout costs that are volatile
 - Impact test threshold can be as low as \$1.50/MWh
 - We recommend revisiting the thresholds to allow legitimate range of risk preferences (**Rec. # 2024-2**) and support the ISO's proposals for \$3/MWh impact test floor

Energy Affordability Challenges

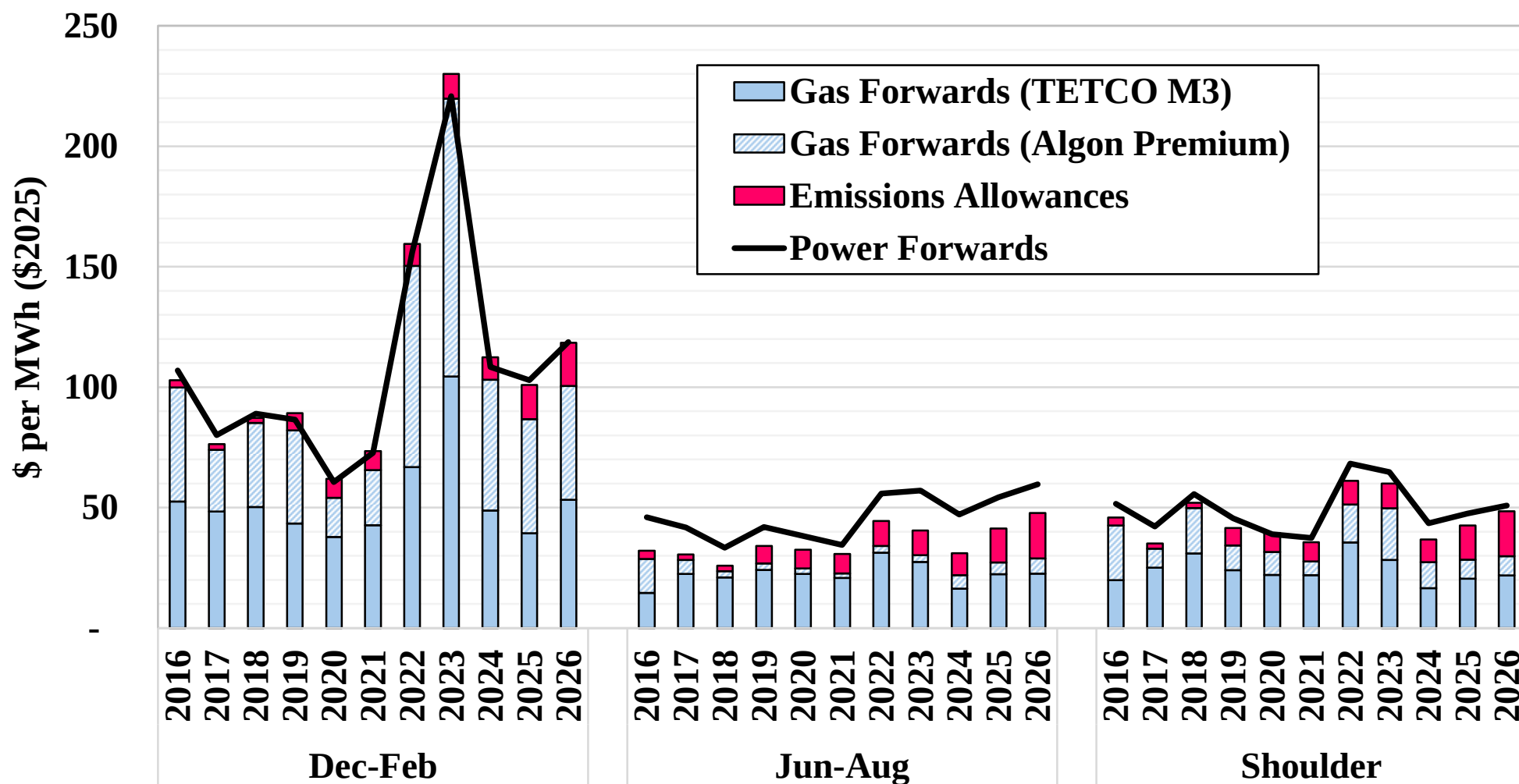
Retail and Wholesale Rate Trends in New England

- Average residential rates 67 percent higher than US average in 2025
- ISO-NE prices averaged 30 percent of retail rate, while IOU Default Service (excl. RECs) averaged 44 percent
- Inflation-adjusted residential rates in NE rose 12 percent over past decade, driven primarily by non-wholesale costs
- Wholesale prices/costs were flat w/ lower capacity costs offsetting higher energy prices
 - Rising energy prices driven primarily by gas and CO2 allowances (see next slide)
- IOU Default Service rates 16 percent higher than forward prices (adjusted for distribution losses and residential load shape/balancing)
 - Default service premiums: (a) have risen in recent years and (b) were elevated after the start of the Ukraine war in 2023
 - Reflects rising price and quantity risks

Residential Retail and Wholesale Costs (in \$2025)



Drivers of Hedged Wholesale Costs

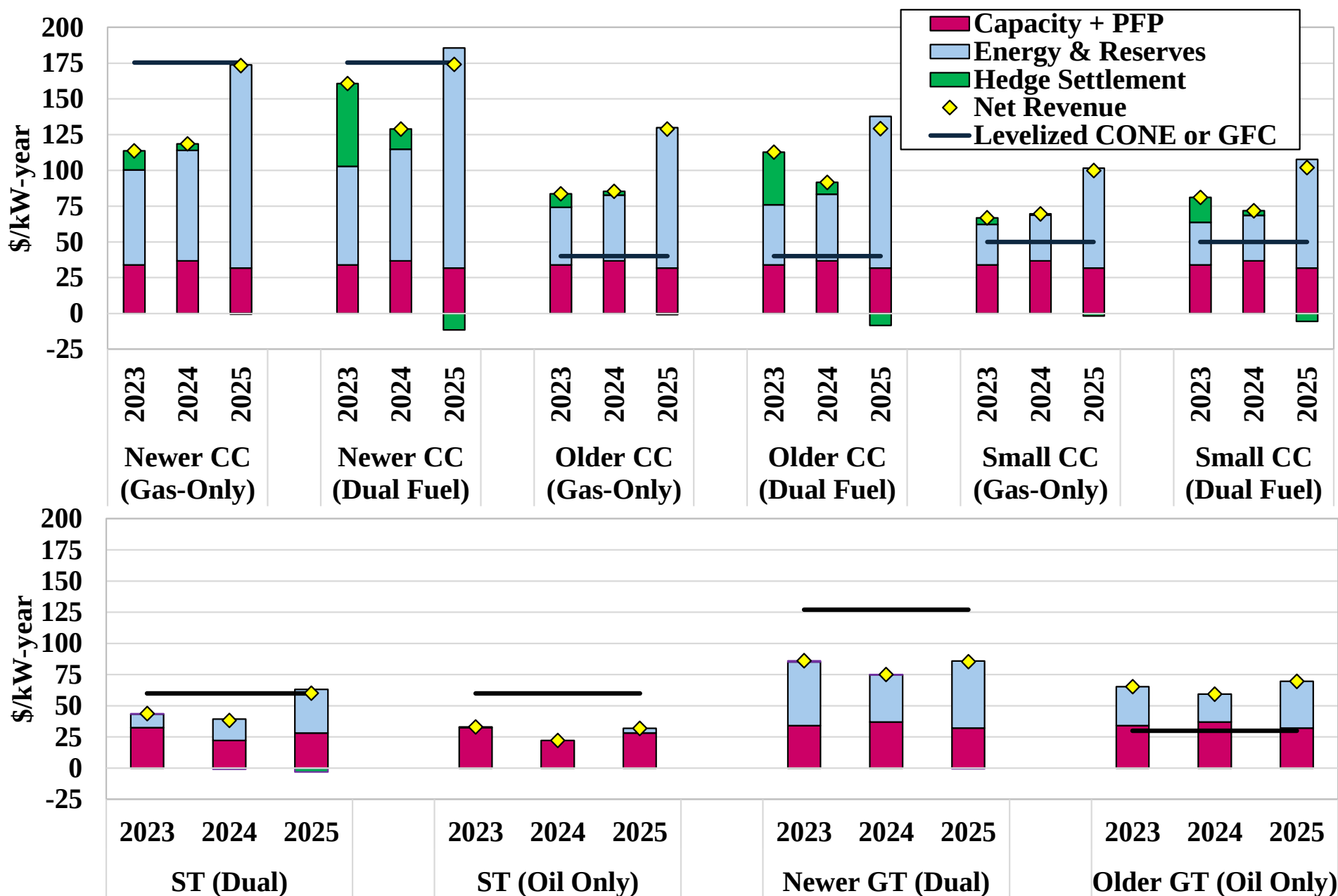


- Risk of pipeline constraints driving higher forward energy prices which have passed through to retail customers
- RGGI and MA CO₂ allowances made up ~24 to 30 percent of CC production costs in 2025

Impact of Generator Profits

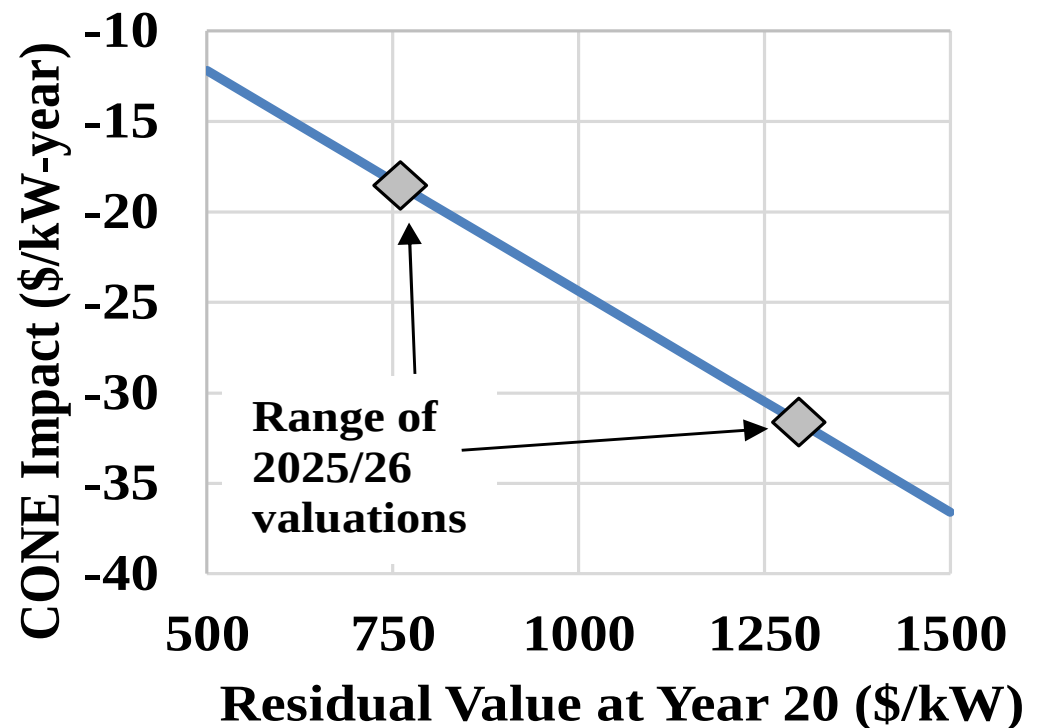
- We estimate net revenues from the ISO-NE markets vs. fixed costs for existing gas and oil unit categories in 2023-2025 (see next slide). Fixed costs include:
 - Going-forward costs (GFCs) for existing units; and
 - Capital recovery for newer units
- Profitability of existing units varies by unit type:
 - Newer units earn high net revenues but often less than full investment costs
 - Older CCs (90s/00s vintage) and some GTs earn revenues well above GFCs
 - ST units likely struggle to recover fixed costs
 - Dual fuel CCs earned ~\$12-19 per kW-year more than gas-only
- Estimated fossil generator profits divided by ISO-NE load were roughly 0.5 cents per kWh in 2023-2025 (~2 percent of the residential retail rate)
 - Generator profits have not contributed materially to affordability concerns and are necessary to reward capital investment and risk taking
 - Capacity market parameters should consider generators' ability to continue earning merchant revenue as they age

Estimated Generator Revenues and Fixed Costs



Actions to Reduce Retail Rate Pressure

- Permit new pipeline infrastructure to address cost impacts of fuel supply constraints – requires cooperation of federal government and New York
- Permit new dual fuel capability – likely the lowest-cost means to address winter reliability concerns with very little emissions impacts
- Explore more flexible forward contracting requirements for IOUs
- Consider long-term residual value in Net CONE used to set capacity demand curve
 - Addresses concern of potential excess profits to 20+ year old units
 - Recent US RTO M&A deals suggest CC/CT units retain value after 20 years



Resource Commitment and Pricing Issues

Resource Commitment and Reserve Pricing

See Section IV

- Efficient resource commitments and pricing are important for ensuring reliability in a cost-effective manner
- This section of the report evaluates:
 - Day-ahead commitments for local reserve needs
 - The incentives and eligibility criteria for receiving FER payments
 - The performance of the Real-Time Unit Commitment (“RTUC”) model and its convergence with UDS
 - The pricing of operating reserves in the fast-starting pricing logic

Resource Commitment and Reserve Pricing

See Sections IV.A. and IV.B

Day-Ahead Commitments for Local Reserve Requirements

- Day-ahead commitments are made to satisfy local second contingency requirements that market prices do not reflect
- Relying on out-of-market NCPC payments to satisfy these requirements does not efficiently compensate other resources that help meet them
- Accordingly, we recommend defining local operating reserve requirements in the day-ahead and real-time markets to satisfy these reliability needs (Recommendation #2019-3)

Eligibility to Receive FER Payments

- Day-ahead imports have received FER payments even when they are not available in real time and they are not obligated to be available
 - They are not comparable to other resources that receive FER payments
 - This reduces the effectiveness of the DA A/S market in supporting reliability

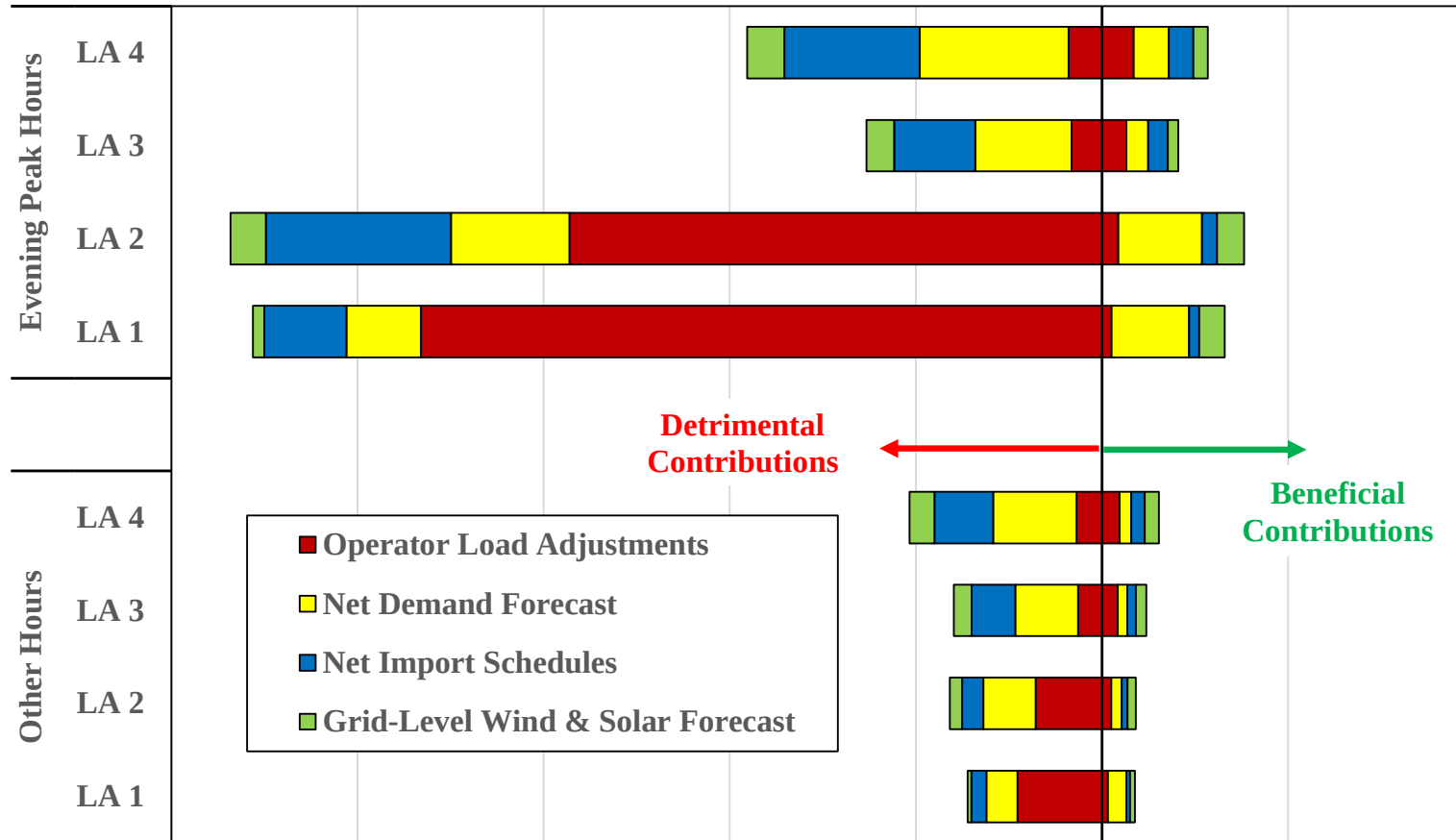
Resource Scheduling Efficiency by RTUC

RTUC Price Forecasting vs. UDS LMPs – See Section IV.C

- The real-time unit commitment (RTUC) model is a critical component of the commitment process
 - Runs every 15 minutes and identifies the units for RT commitment
 - It is important for RTUC prices to converge with UDS prices in order for the real-time commitments to be efficient
- RTUC frequently recommended committing fast-start resources inefficiently during evening peak hours (HE17-21)
 - Our analysis indicates that this was due to the RTUC frequently over-forecasting the need to commit fast-start resources in these hours
 - Avg. RTUC LMPs exceeded UDS LMPs by as much as \$50/MWh in 2025
 - Inefficient RT commitments undermine incentives to offer at marginal costs
- We identify factors that contribute to the divergence in prices between RTUC and UDS and recommend ISO-NE evaluate and address all causes of this price divergence **(Recommendation #2024-1)**

Resource Scheduling Efficiency by RTUC

Factors Contributing to RTUC Forecasting Errors – See Section IV.C

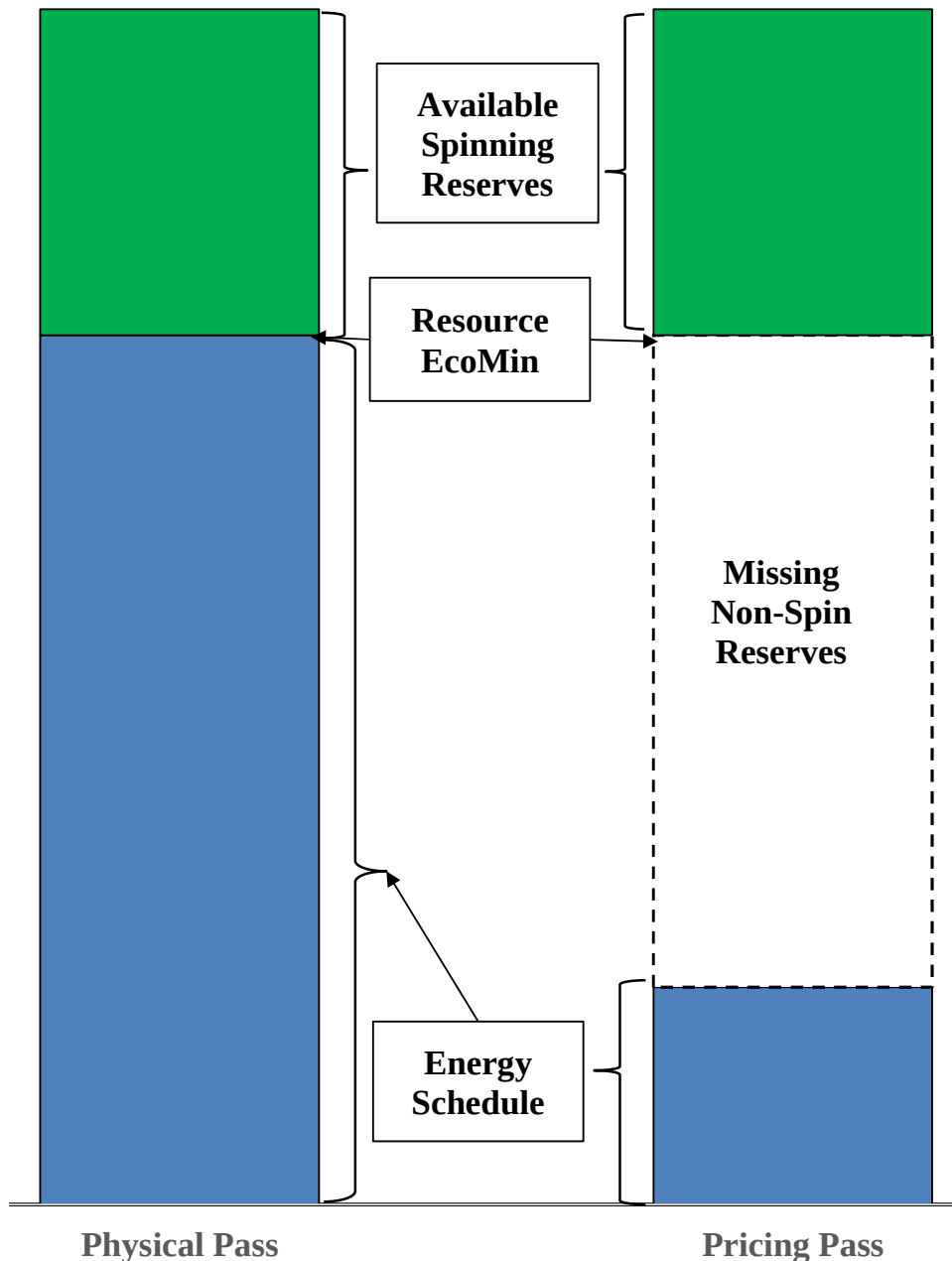


- We created a metric to show factors that contribute to divergence (<0) vs. convergence (>0 or beneficial)
- LA1 to 4 are 15-minute look-ahead intervals

- Operators frequently adjust the load upward manually in RTUC – these were the primary detrimental driver in LA1 & LA 2 during evening peak hours (HE17-21)
 - In **~10%** of intervals in LA1 & LA2, load adjustments were > 300 MW and median LMP differences up to $\sim \$180/\text{MWh}$

Reserve Pricing in the Fast-Start Pricing Logic

See Section IV.D



- Pricing Logic relaxes fast-start units' EcoMin to zero for pricing purposes
 - However, it does not allow reserves to be held below EcoMin
- The decrease in available NS reserves often raises energy and reserve prices inefficiently under tight conditions
- During intervals with binding reserve constraints in 2025, on average:
 - The 30-minute reserves in the dispatch was 320 MW > in the pricing model
 - 30-min OR prices: \$165/MWh in pricing model vs. \$80/MWh in physical dispatch
- We recommend ISO-NE modify the fast-start pricing to utilize the full capability of online units for reserves (**Rec. #2022-1**)

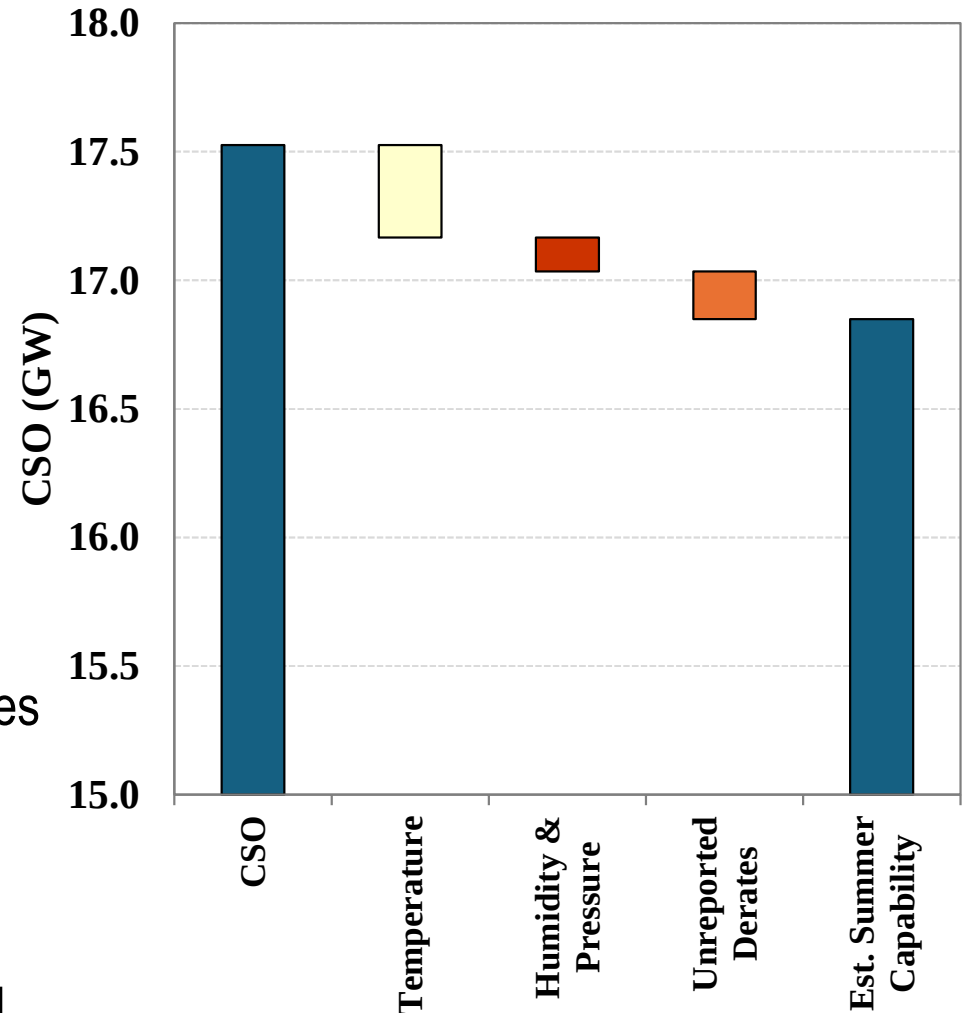
Capacity Availability and Performance Incentives

Overvalued QC and Reporting of Derates

See Section V.A

- Roughly 680 MW of QC identified as unavailable at peak summer conditions
 - Units are often tested under milder conditions (temp, humidity & pressure)
 - 360 MW unavailable because of hot conditions (temps between 90-99°F).
 - 130 MW identified due to humidity and pressure conditions
- Possible causes of the 190 MW underperformance on peak days:
 - Unreported mechanical & water temp derates
 - Understated aux. loads during SCC Audits
 - Not offering less reliable auxiliary operating modes (e.g. peak firing)
- **Recommendation #2024-3:** Enforce forced derate rqmts and reassess ambient conditions used to determine qualified capacity

Unavailable Capacity in 2025 Peak Conditions



Assessment of Capacity Shortage Events

See Section V.B

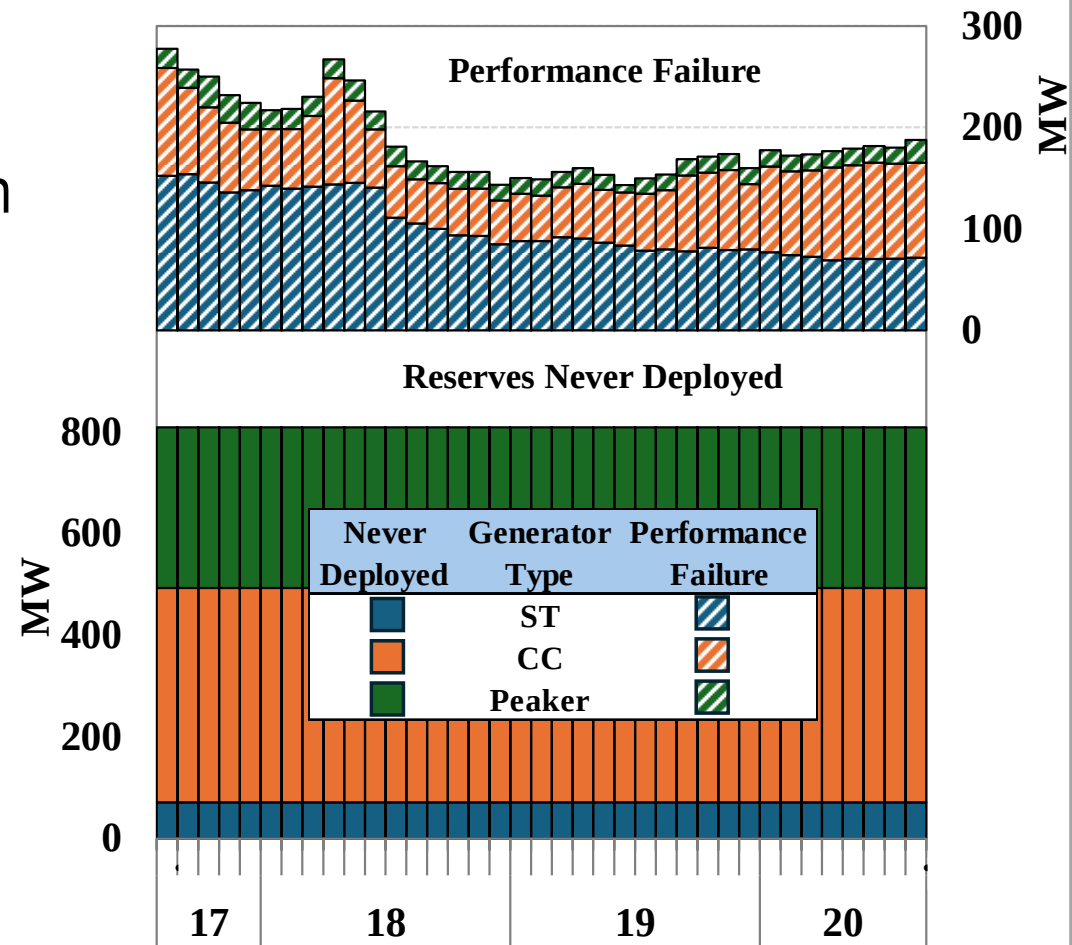
- Five PFP events occurred in 2023 - 2025
 - Shortage pricing + PFP settlements during these events up to \$12,000 per MWh, vastly exceeding the value of energy
- The extraordinary prices during these events led to very large PFP credits and charges (shown in the following figures)
 - \$57 million credits to non-CSO imports, while no charges to exports
 - \$142 million charges to steam turbines and combined cycles, most of which were available but not committed in the day-ahead markets
- Imposing these charges on high-cost resources that were not scheduled in the day-ahead market (and not foreseeably needed) leads to:
 - Lower net revenues that may lead to premature retirements
 - Inefficient incentives to self-commit such resources
- Inconsistent settlements with imports and exports is inefficient and raising gaming concerns

Evaluation of Reserve Shortage on June 24

See Section V.B

- Measuring performance of reserves during PFP events can be difficult
 - Resources have strong incentives to overstate reserve capability
- 150–270 MW failed to perform when dispatched for energy but provided reserves (credited as performing)
 - Amount dropped over event as derates were reported
 - Prompt reporting of forced derates needed to accurately measure performance
- Roughly 800 MW of reserves never dispatched during the PFP
 - Schedules for some far exceeded their Summer SCC

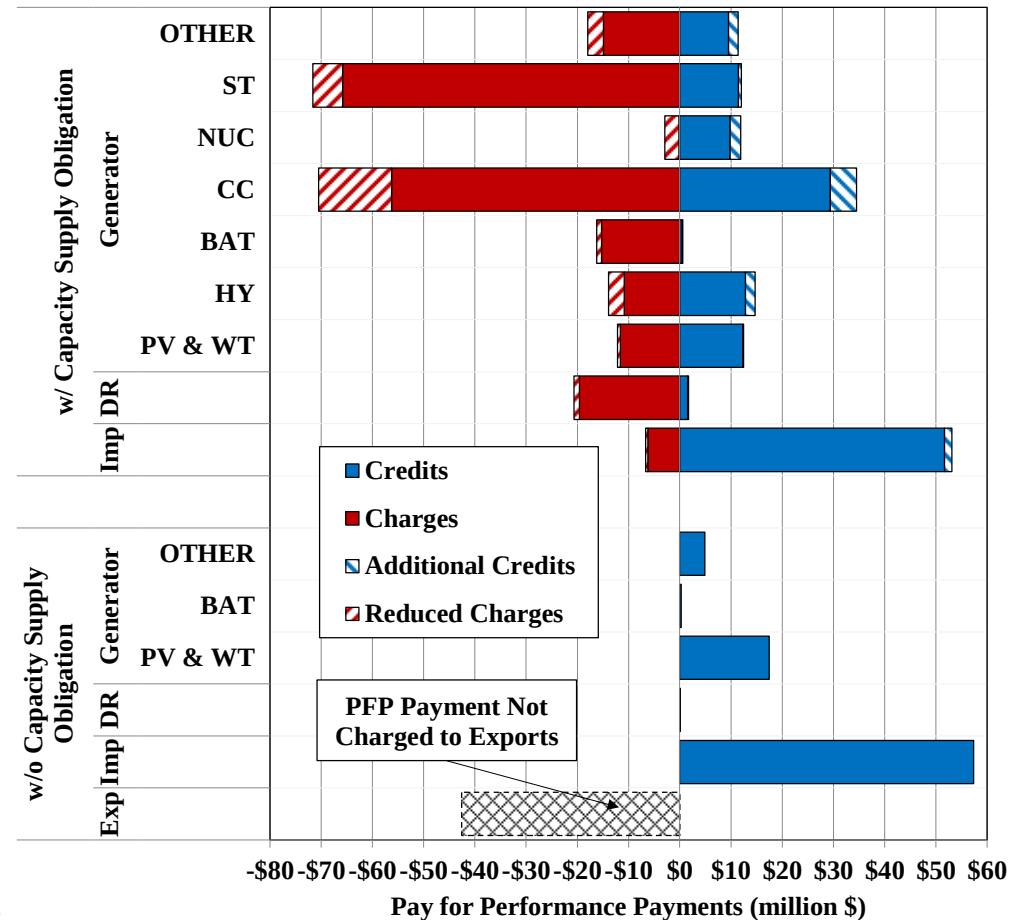
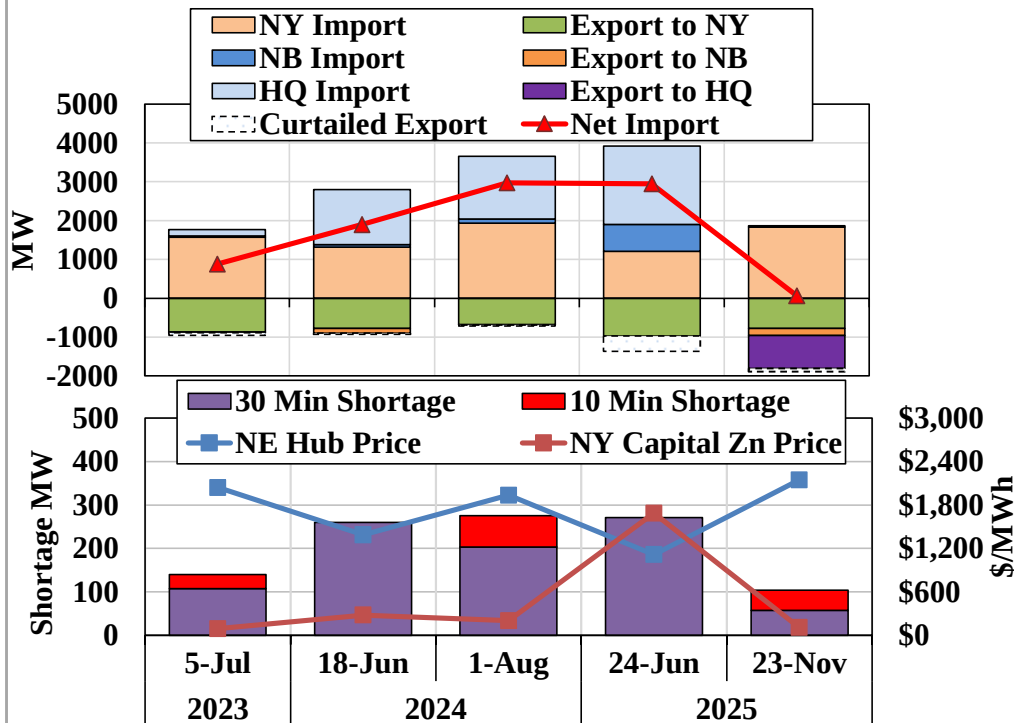
Assessment of Reserves – June 24, 2025 PFP



External Scheduling & PFP Credits and Charges

See Section V.B

- **700-1800 MW** of exports uncurtailed
- Shortages < **300 MW**

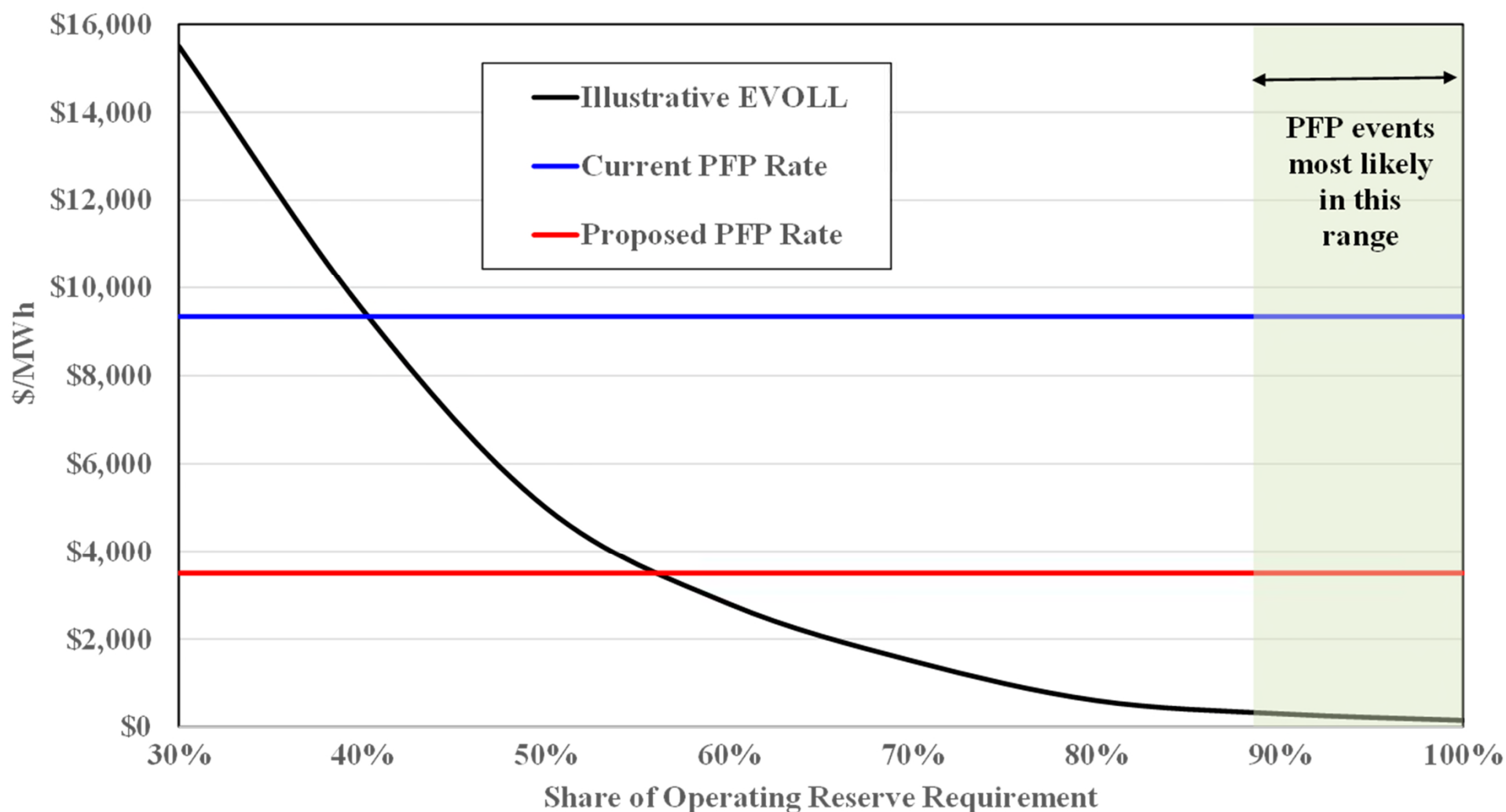


- **\$57M** credits to non-CSO imports, but no charges to exports
- **\$142M** charges to CCs and STs

PFP Rate and the Value of Lost Load

See Section V.B

- PFP rate not consistent with value of reserves – the rate is overstated and does not vary with the magnitude of shortage



Market Inefficiencies Raised by the PFP Events

See Section V.B

- **Inefficiency #1:** Inefficient incentives to export may increase frequency of reserve shortages
 - Imports were paid the PFP rate of \$9,337/MWh but exports were not charged the PFP rate – creates incentive to schedule in *both* directions - raises gaming concerns and disrupts import/export incentives
 - **Recommendation #2022-3:** Revise rules to charge exporters the PFP rate
 - o The ISO has proposed a revision that would charge System-Backed Exports
- **Inefficiency #2:** PFP rate not consistent with value of reserves
 - The rate is overstated and does not vary with the magnitude of shortage
 - Available units not committed day ahead received excessive penalties
 - **Recommendation #2018-7:** Recommend to modify the PFP rates to levels that align with VOLL and severity of the reserve shortage
 - o The ISO proposed reducing the PFP rate to \$3,500 per MWh, which partially addresses our recommendation
- In the longer term, the ISO should consider means to shift more of the performance incentives into the energy market

Full List of Recommendations

List of Recommendations

Recommendation Number and Description		High Benefit	Current/Planned Efforts	Report Reference
Reliability Commitments and NCPC Allocation				
2010-4	Modify allocation of “Economic” NCPC charges to make it consistent with a “cost causation” principle.			III of 2018 Report
Energy and Operating Reserve Markets				
2024-1	Evaluate and address causes of the price divergences between RTUC model and the real-time dispatch.			IV.C
2023-1	Evaluate benefits and costs of a look-ahead dispatch model to optimally manage fluctuations in net load and the use of storage resources.	✓		II of 2024 Report
2022-1	Allow fast-start pricing model to utilize the full capability of online units for energy or reserves.			IV.D
2019-3	Define a full set of local operating reserve requirements in the day-ahead and real-time markets.			IV.A
Energy & Ancillary Services Market Mitigation				
2024-2	Evaluate the appropriateness of the current conduct and impact threshold levels for reserves in the DAM.			III.E
2022-2a	Implement hourly conduct and impact tests in the automated energy mitigation procedure in RT.			III.D

List of Recommendations

Recommendation Number and Description		High Benefit	Current/ Planned Efforts	Report Reference
Capacity Market				
2024-3	Enforce compliance with forced derate reporting requirements and reassess the adjustments for ambient conditions to determine Qualified Capacity.			V.A
2022-3	Charge exporters the PFP rate during reserve shortages.		SBE Filing Plan 2026-Summer	V.B
2021-1	Replace the forward capacity market with a prompt seasonal capacity market.	✓	CAR-PD Filing Approved, CAR-SA Filing Plan 2026-Q4	V.B of 2023 Report
2020-2	Improve capacity accreditation by a) accrediting all resources consistent with their marginal reliability value, and b) modify the planning model to accurately estimate marginal reliability values.	✓	CAR-SA Filing Plan 2026-Q4	V.A of 2023 Report
2020-3	Account for energy efficiency as a reduction in load instead of as a supply resource in the FCM.			V of 2020 Report
2018-7	Modify the PPR to rise with the reserve shortage level, and do not implement the planned increase in the PPR.	✓	\$3,500 PPR Filing Plan 2026-Summer	V.B



2025 ASSESSMENT OF THE ISO NEW ENGLAND ELECTRICITY MARKETS

Prepared By:

**POTOMAC
ECONOMICS**

**External Market Monitor
for ISO-NE**

June 2026

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PREFACE

Potomac Economics serves as the External Market Monitor for ISO-NE. In this role, we are responsible for evaluating the competitive performance, design, and operation of the wholesale electricity markets operated by ISO-NE.¹ In this assessment, we provide our annual evaluation of the ISO’s markets for 2025 and our recommendations for future improvements. This report complements the Annual Markets Report, which provides the Internal Market Monitor’s evaluation of the market outcomes in 2025.

We appreciate the Internal Market Monitor and other ISO staff for providing the data and information necessary to produce this report.

The principal authors of this report are

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¹ The functions of the External Market Monitor are listed in Appendix III.A.2.2 of “Market Rule 1.”

EXECUTIVE SUMMARY

ISO-NE operates competitive wholesale markets for energy, operating reserves, regulation, financial transmission rights (“FTRs”), and capacity to satisfy New England’s electricity needs. These markets provide substantial regional benefits by coordinating resource commitment and dispatch so the lowest-cost supplies reliably satisfy short-term demand. They also establish transparent, efficient price signals that govern long-term investment and retirement decisions.

ISO-NE’s Internal Market Monitor (“IMM”) produces an annual report that provides an excellent summary of market outcomes and trends during the year, including:²

- Real-time energy prices increased about 70 percent from 2024 to 2025, primarily because natural gas prices rose 105 percent. Higher load levels, lower imports from Quebec, and higher CO₂ emissions allowance prices also contributed to the increase in energy prices.
- Average load rose about 1 percent, while peak load increased 7 percent to 26.6 GW. However, average summer load fell by 3 percent year-over-year, which reflects continued growth in behind-the-meter solar generation that reduces the apparent load during daylight hours. However, it contributed relatively little at the peak because the peak load hour has shifted later in the day to hour-ending 19 in 2025.
- The capacity clearing prices were \$2.61 and \$2.59 per kW-month in the 2024/25 and 2025/26 Capacity Commitment Periods (“CCP”), respectively. Capacity prices rise to \$3.58 per kW-month in the 2027/28 CCP, largely because of the effects of inflation on FCA demand curve parameters and market participants’ offers.

This report is intended to complement the IMM’s report by comparing key market outcomes with those in other RTO markets, assessing market competitiveness, and evaluating specific market design and operational issues. This year’s report also evaluates residential retail rates and highlights affordability challenges in New England. Where appropriate, we recommend measures to address these issues and ensure the markets continue to provide efficient price signals, support reliable system operations, and adapt effectively as system needs evolve.

Cross-Market Comparison of Key Market Outcomes

ISO-NE faces unique challenges that distinguish it from most other RTOs and affect the structure and performance of its markets. In particular, ISO-NE is at the end of several interstate pipelines whose aggregate capacity to deliver gas to the region’s gas utilities and gas-fired generators is limited. In addition, ISO-NE operates a network with far less congestion than other RTOs, which affects its competitive performance, operating needs, and reliability. In Section I of this report, we compare several key outcomes in the ISO-NE markets with those in other RTO markets.

² See ISO New England’s Internal Market Monitor 2025 Annual Markets Report, available at <https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor>.

Executive Summary

<i>Energy Prices</i>	In recent years, ISO-NE had the highest average energy prices among ISO markets in the Eastern Interconnect because of higher natural gas prices and CO ₂ emissions allowance costs.
<i>Capacity Prices</i>	ISO-NE capacity prices remained relatively stable over the past three years at below \$3.0 per kW-month. NYISO had the highest capacity costs because peaking-resource retirements from air permit limitations and reduced capacity imports tightened supply. Capacity prices also increased significantly in MISO and PJM in 2025 because of market reforms, demand growth, and recent generator retirements.
<i>Congestion</i>	ISO-NE experiences significantly less congestion than other ISOs, with average congestion costs of roughly \$0.40 per MWh of load over the past three years – just 9 to 20 percent of the levels in other RTO markets. This reflects large transmission investment, primarily to address conservative local reliability planning criteria. As a result, transmission rates exceeded \$29 per MWh in 2025, more than double the average rates in other RTO markets. Other markets have accelerated transmission investment in recent years, primarily to increase the deliverability of renewable generation to consumers.
<i>Uplift Costs</i>	ISO-NE generally incurs higher market-wide uplift costs, adjusting for its size, than MISO and NYISO because it is subject to higher fuel costs and its real-time unit commitment model often schedules fast-start resources poorly. However, the introduction of the day-ahead ancillary services markets lowers ISO-NE's market-wide uplift and this report recommends improvements in the real-time unit commitment model to achieve further reductions.
<i>Virtual Trading</i>	Virtual trading levels in ISO-NE have been significantly lower than those in NYISO and MISO, adjusting for size, primarily because ISO-NE over-allocates real-time Net Commitment Period Compensation (“NCPC”) charges to virtual transactions and other real-time deviations. Addressing this issue is valuable because virtual trading plays an important role in aligning day-ahead and real-time market outcomes, especially as the generation mix evolves.
<i>External Transactions</i>	The Coordinated Transaction Scheduling (“CTS”) process with NYISO has performed much better than other CTS processes between other eastern RTOs, largely because ISO-NE and NYISO do not impose fees on CTS transactions and forecast prices better. However, much larger savings could likely be achieved by transitioning to a 5-minute real-time adjustment process, which we are recommending in other areas.
<i>Shortage Pricing</i>	ISO-NE has employed the most aggressive shortage pricing among U.S. RTOs, primarily through the Pay-for-Performance (“PFP”) framework rather

than the energy market. In June 2025, ISO-NE increased its shortage PFP rate to \$9,337 per MWh. Together with its operating reserve demand curves, this rate produces the highest shortage pricing of any centrally-dispatched wholesale market. The PFP framework creates outsized risks from modest shortages that generally do not raise substantial reliability concerns. To address this issue, we recommend that ISO-NE vary the penalty rate with the size of the shortage and cap it at a reasonable Value of Lost Load (“VOLL”).

Energy Affordability Challenges

In recent years, rising electricity costs and their impact on consumers have received significant attention nationwide. Average retail rates for residential customers in New England were 28.9 cents per kWh in 2025, 67 percent higher than the US average (Section II.A). Residential retail rates rose by 12 percent in inflation-adjusted terms from the 2016-2019 period to 2025. Section II discusses trends in New England residential electricity rates over the past decade and the impact of the ISO-NE markets on retail rates.

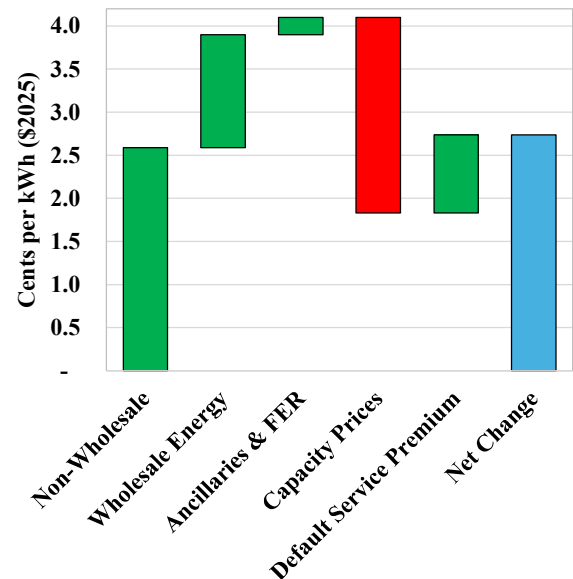
Figure ES-1 summarizes the factors driving the rise in residential retail rates. Non-wholesale costs drove most of the increase, including regulated transmission and distribution charges, renewable and energy efficiency programs, and other non-wholesale costs.

Total wholesale costs were relatively flat from 2016 to 2025, but the individual components diverged: wholesale energy prices and ancillary services costs rose, while capacity prices fell.

The primary causes of rising wholesale energy prices were natural gas prices and CO₂ allowance prices (Section II.B). Since 2022, forward gas prices in New England have increased significantly, and the premium over upstream areas has grown, reflecting a higher likelihood that pipeline constraints will cause extreme spot prices. Regional Greenhouse Gas Initiative (“RGGI”) and Massachusetts CO₂ allowance prices have also risen dramatically and now account for a large share of generators’ costs (e.g., about 24 to 30 percent of combined cycle generator production costs in 2025).

Wholesale market prices averaged 30 percent of the residential retail rate, while investor-owned utilities’ (IOUs’) supply rates for ‘default service’ averaged 44 percent of residential retail rates.³

Figure ES-1: Changes in Retail Rate Components, 2016-2019 to 2024-2025



³ Most residential load in New England is supplied under fixed-price default service rates. IOUs procure default service through RFPs conducted months in advance where power generators offer to supply 100 percent of the capacity, energy, and ancillary service needs of a group of utility customers in each hour.

Figure ES-1 shows that over the period, the premium on IOUs' default service over wholesale market components increased by about 0.9 cents per kWh. Even after adjusting for distribution losses and the additional cost of satisfying variable load at a fixed rate under the RFP requirements, we estimate that IOUs' default service prices carry an average premium of 16 percent above wholesale market prices. Suppliers participating in IOUs' default service RFPs likely require significant risk premiums to meet utilities' full-service requirements at fixed rates because they face both market price risk and quantity risk for the load served. Additionally, states tightly prescribe RFP requirements and timing in ways that may limit the pool of competitive bidders and result in higher premiums over wholesale prices.

In Section II.C, we estimate generator profits in the ISO-NE markets relative to residential retail rates. Overall, we estimate that net revenues of fossil fuel (gas and oil) generators built more than 20 years ago exceeded fixed operating costs and capital recovery for maintenance by roughly 0.5 cents per kWh of ISO-NE load (about 2 percent of the retail rate) in 2023-2025. Generators may earn revenues above their fixed operating costs through the ISO-NE markets, which incentivizes: (a) ongoing capital investment needed to keep generators in a reliable condition and (b) new generating facilities even when wholesale prices are below levels that would allow full recovery of the investment in the initial 20 years of operation.

In Section II.D, we review recent nationwide evidence that the economic life of combined cycle and combustion turbine units exceeds the 20 years often assumed in Net CONE studies. This finding is consistent with the estimated profitability of older units in New England. Considering generators' residual value after 20 years in future Net CONE studies would reconcile the market's long-term investment signals with the marginal value of new resources and reduce rate pressure if capacity prices rise.

Finally, we discuss policy actions to reduce retail rates while maintaining competitive, efficient markets, including:

- Permitting new pipeline infrastructure, which would require cooperation from New York State and the federal government;
- Permitting of new dual fuel generation capacity or retrofitting gas-only units to be dual fueled;
- More flexible forward-contracting requirements for IOUs to expand the pool of potential suppliers; and
- Consider long-term residual value in the Net CONE used to set the capacity demand curve.

Clean Energy Transition

State programs in New England have driven investment in wind and solar resources, with roughly 370 MW of solar, 120 MW of wind, and 420 MW of storage added to ISO-NE in 2025. However, intermittent renewables remain a much smaller share of total generation than in major

RTO markets with high wind and solar penetration. In our 2024 Assessment of the ISO-NE Markets, we described strategies MISO and ERCOT have developed to address operational issues caused by high levels of intermittent generation, including rising output uncertainty, greater ramp needs, and challenges maintaining voltage levels and transmission security.

New England’s shortage pricing and PFP rules provide strong incentives for flexible resources to manage net load fluctuations as intermittent output grows. Additional changes will help ISO-NE prepare for a grid with greater renewable penetration:

- *Marginal Capacity Accreditation*: The capacity market must accurately value the marginal reliability value of each resource type so that clean energy investment is directed to the most valuable projects and the market sends adequate signals to retain needed dispatchable generation. Therefore, we recommend that ISO-NE adopt marginal capacity accreditation (Rec. #2020-2) and move to a prompt seasonal auction structure (Rec. #2020-1). The ISO’s Capacity Auction Reform (“CAR”) projects address both recommendations.⁴
- Increasing reliance on intermittent resources and battery storage will create dispatch challenges that a short-term dispatch model cannot always solve efficiently, such as ramping conventional units in advance of net load ramps and optimizing energy storage dispatch. ISO-NE should develop a look-ahead dispatch model to optimize scheduling and price-setting across multiple time steps. Therefore, we recommend (#2023-1) that ISO-NE evaluate the potential benefits and costs of a look-ahead dispatch model that would optimize multiple hours into the future.

Lastly, we recommend treating Energy Efficiency as a load reduction in the capacity market rather than as a supply resource (Recommendation #2020-3). This would address gaming opportunities we have identified in ISO-NE and other RTO markets that allow EE to participate in the capacity market as supply. It would also be much less administratively burdensome and create more efficient incentives to invest in EE technologies.⁵ Both PJM and MISO recently filed changes with FERC to stop allowing EE to be sold as supply in its capacity market, noting that this shifts costs from EE beneficiaries to other consumers.⁶

Competitive Assessment

Based on our evaluation of ISO-NE’s wholesale electricity markets in Section III of this report, we find little evidence that suppliers exercised market power in New England, either at the system level or within individual sub-regions. However, recent and one pending acquisition,

⁴ These include the Capacity Auction Reform: Prompt/Deactivation (“CAR-PD”) and Capacity Auction Reform: Seasonal/Accreditation (“CAR-SA”) projects.

⁵ See our 2020 Assessment of the ISO-NE Markets, available [here](#).

⁶ See comments of PJM Interconnection and Monitoring Analytics in FERC Docket ER24-2995.

along with reduced imports from Canada and generator retirements, have increased indications of potential structural market power in the form of rising pivotal supplier frequencies since 2022. To ensure the market power mitigation measures remain effective, we support the Internal Market Monitor’s recommendation #2023-1 to *review mitigation thresholds and reference level methodologies, eliminate mitigation exemptions for non-capacity resources, and extend mitigation to export-constrained area.*

We also continue to recommend revisions to the current energy mitigation process to address an inefficiency identified in our 2022 annual report (Recommendation #2022-2a). Specifically, we recommend that the ISO implement hourly conduct and impact tests to ensure it does not impose mitigation when a resource’s conduct or prevailing competitive conditions no longer warrants it.

In addition, we find that market power mitigation in the day-ahead ancillary services (“DA A/S”) market has occurred more frequently and in higher volumes than expected, often during low-to-moderate-load conditions when market power concerns are not typically most acute. Given these results and the tight mitigation thresholds, we find that the current mitigation measures warrant reassessment. Therefore, we continue to recommend that ISO-NE evaluate the current conduct and impact threshold levels and revise them as needed to ensure they limit the exercise of market power without interfering with competitive behavior (Recommendation #2024-2).

The ISO’s proposed market reforms to address recommended improvements to DA A/S that are described in Section III help address Recommendation #2024-2 by reducing how often competitive DA A/S offers are mitigated. In particular, the proposal to apply a \$3 per MWh floor to the Impact Test Threshold (“ITT”) directly addresses these concerns by reducing mitigation caused by overly stringent thresholds, especially for smaller suppliers. After implementing these reforms, we will assess whether the rules still need further revision to avoid mitigation of competitive DA A/S offers.

Initial Observations on the Performance of the Day Ahead Ancillary Services Markets

The DA A/S markets have generated higher costs than expected in their first year of operation. The IMM estimated \$974 million or a 9% rise over the prior market. It estimated that 75 percent of the incremental costs are due to fundamentals and roughly 25 percent to participation and offers. We find this evaluation reasonable and will be providing more detailed comments on the performance of the day-ahead ancillary services markets after the IMM releases its full report on the first year of operation.

However, we believe these costs overstate the net effect on consumers overall for two reasons:

- DA A/S revenues will be included in the energy and ancillary service revenue offsets used to develop the net CONE for the capacity demand curve. Higher revenues from this market will ultimately lower capacity prices and offset the estimated cost increase.

- The IMM estimates do not consider that increased commitments in the day-ahead market will lower real-time LMPs. Lower expected real-time LMPs will lower day-ahead LMPs as participants arbitrage the two markets. This offsets the estimated cost increase.

Nonetheless, we do believe that the relatively low strike price in the DA A/S market contributes to higher costs. Hence, we strongly support the ISO’s reform to raise the strike price. More broadly, we find that the DA A/S markets have improved the performance of the ISO markets overall, lowering uplift costs and improving generator availability. While there are opportunities for improvements, the introduction of these markets have been highly beneficial.

Resource Commitments and Operating Reserve Pricing

Efficient resource commitment and pricing are important to ensure reliability cost-effectively. Accordingly, this report evaluates: (a) day-ahead commitments for local second contingency protection requirements; (b) incentives and eligibility criteria for receiving Forecast Energy Requirement (“FER”) payments; (c) the accuracy and efficiency of the Real-Time Unit Commitment (“RTUC”) model; and (d) operating reserve pricing in the real-time fast-start pricing logic.

Day-Ahead Commitments for Local Reserve Requirements. In Section IV.A, we find that day-ahead commitments satisfy local second contingency requirements that market prices do not reflect. Although such commitments have become less frequent, relying on out-of-market NCPC payments to satisfy these requirements does not efficiently compensate other resources that help meet them. Accordingly, we recommend defining local operating reserve requirements in the day-ahead and real-time markets to satisfy these reliability needs through the competitive market rather than out-of-market actions (Recommendation #2019-3).

Eligibility to Receive FER Payments – In Section IV.B, we discuss imports scheduled day-ahead that receive FER payments even when they are not available in real time. These day-ahead scheduled transactions are not obligated to be available in real time, so they do not provide a service comparable to other resources that receive FER payments. Over time, these incentives could reduce the effectiveness of the DA A/S market in supporting system reliability.

Real-Time Unit Commitment Model Performance. The RTUC model is a key operational tool that ISO-NE uses to schedule resources while maintaining system security and reliability during the operating day. Its primary outputs include startup and shutdown recommendations for fast-start resources and DARD pumps (i.e., pumped storage resources), which ISO-NE passes to the Unit Dispatch System (UDS) for execution.

Section IV.C indicates that RTUC frequently over-forecasts the need to commit fast-start resources. While we identify several contributors, RTUC over-forecasting was primarily caused by operator load adjustments and frequently led RTUC to “recommend” committing uneconomic

fast-start generation. As a result, real-time NCPC uplift exceeded \$10 million in 2025 and accounted for 65 percent of all real-time economic NCPC paid to internal resources. To improve fast-start commitment efficiency, we recommend that ISO-NE address the causes of price divergences between the RTUC and real-time dispatch models (Recommendation #2024-1).

Excessive Real-Time Reserve Prices. Section IV.D identifies an inefficiency in the fast-start pricing logic that tends to overstate reserves and energy pricing under certain system conditions. Specifically, the pricing model fails to recognize unscheduled capacity below generators' economic minimums. This reduction in supply can cause it to set inefficiently high prices. We recommend that the ISO modify the fast-start pricing logic to use the full capability of online resources for energy or reserves so reserve prices more accurately reflect the cost of maintaining operating reserves (Recommendation #2022-1).

Pay-for-Performance Incentives during Capacity Shortage Conditions

Capacity shortage events have been relatively infrequent since ISO-NE implemented Pay-for-Performance in 2018, occurring only five times over the past three years. These events generally lasted 30 minutes to three hours, with average 10-minute and 30-minute reserve shortages of less than 250 MW. Section V.B evaluates the PFP rules and outcomes.

Although none of these events posed a significant risk of firm load shedding in New England, settlement amounts over the past three years were substantial:

- Suppliers incurred more than \$230 million in performance charges, most of which came from available combined cycle or steam units that were offline because the day-ahead market had not committed them.
- The total price for imports or resources performing above their Capacity Supply Obligations ("CSOs") was as high as \$12,000 per MWh, including the \$9,337 per MWh penalty rate in 2025.

These prices and associated settlements vastly exceed the reliability value of energy during these events and create substantially inefficient incentives for ISO New England participants.

One key inefficiency is the inconsistent settlement treatment of imports and exports. Applying the PFP rate to importers but not exporters is a significant flaw that distorts incentives to schedule imports and exports. During these five events, ISO-NE curtailed few scheduled exports and allowed 700 to 1800 MW of scheduled exports to flow which led to additional PFP charges for other suppliers. To correct these inefficient incentives, we recommend that the ISO:

- Revise the PFP rules to charge exporters at the PFP rate during Capacity Scarcity Conditions (Recommendation #2022-3). The ISO recently proposed revising the PFP framework to charge System-Backed Exports, which addresses our recommendation and we fully support this rule change.

- Modify the PFP rates to levels consistent with a reasonable estimate of VOLL that escalate as reserve shortages deepen (Recommendation #2018-7). The ISO recently proposed reducing the PFP rate from the current formula-based value of \$9,337 per MWh to a fixed rate of \$3,500 per MWh, which partially addresses our recommendation. However, we continue to recommend that the ISO implement a graduated stepwise PFP structure that aligns incentives more closely with the severity of reserve shortages and the associated reliability risk.

Unavailable Qualified Capacity under Peak Summer Conditions

The Qualified Capacity (“QC”) values for generators with combustion turbines do not adequately reflect ambient conditions during periods with the greatest reliability risks because these values generally assume milder temperature, humidity, and barometric pressure conditions than the conditions that drive planning reliability needs (see Section IV.A). We also observed additional derates under peak summer conditions related to the effect of ambient conditions on cooling equipment. Together, these factors caused available capacity to be 680 MW less than qualified capacity during summer peak conditions in 2025. Therefore, we recommend that the ISO monitor generators’ compliance with forced-derating reporting rules and reassess how it accounts for ambient conditions in the calculation of Qualified Capacity after the CAR project is completed (#2024-3).

In addition, we identified generators that experienced partial derates during the June 2025 PFP event and did not promptly report them to the ISO. Consequently, the PFP settlement treated much of this capacity as operating reserves and produced a net benefit of \$6 million for these generators. Monitoring compliance with generators’ obligations to report unit status is particularly important when operating reserves are compensated at a marginal rate above \$10,000 per MWh (as we recommend in #2024-3).

Table of Recommendations

Although we find that the ISO-NE markets have generally performed competitively and efficiently, we identify several opportunities for improvement and make recommendations that we list in the following table.

This table references the location of our analyses and discussions supporting each recommendation and we indicate those we believe will deliver the greatest benefits. Several recommendations were first made in prior annual reports. Rather than repeat all prior analyses and discussions, we often cite the most recent annual report containing the relevant discussion.

Executive Summary

Recommendation Number and Description		High Benefit ⁷	Current/ Planned Efforts	Report Reference
Reliability Commitments and NCPC Allocation				
2010-4	Modify allocation of “Economic” NCPC charges to make it consistent with a “cost causation” principle.			III of 2018 Report
Energy and Operating Reserve Markets				
2024-1	Evaluate and address causes of the price divergences between RTUC model and the real-time dispatch.			IV.B
2023-1	Evaluate benefits and costs of a look-ahead dispatch model to optimally manage fluctuations in net load and the use of storage resources.	✓		II of 2024 Report
2022-1	Allow fast-start pricing model to utilize the full capability of online units for energy or reserves.			IV.D
2019-3	Define a full set of local operating reserve requirements in the day-ahead and real-time markets.			IV.A
Energy & Ancillary Services Market Mitigation				
2024-2	Evaluate the appropriateness of the current conduct and impact threshold levels for reserves in the DAM.			III.E
2022-2a	Implement hourly conduct and impact tests in the automated energy mitigation procedure in RT.			III.D
Capacity Market				
2024-3	Enforce compliance with forced derate reporting requirements and reassess the adjustments for ambient conditions to determine Qualified Capacity.			V.A
2022-3	Charge exporters the PFP rate during reserve shortages.		SBE Filing Plan 2026-Summer	V.B
2021-1	Replace the forward capacity market with a prompt seasonal capacity market.	✓	CAR-PD Filing Approved, CAR-SA Filing Plan 2026-Q4	V.B of 2023 Report
2020-2	Improve capacity accreditation by a) accrediting all resources consistent with their marginal reliability value, and b) modify the planning model to accurately estimate marginal reliability values.	✓	CAR-SA Filing Plan 2026-Q4	V.A of 2023 Report
2020-3	Account for energy efficiency as a reduction in load instead of as a supply resource in the FCM.			V of 2020 Report
2018-7	Modify the PPR to rise with the reserve shortage level, and do not implement the planned increase in the PPR.	✓	\$3,500 PPR Filing Plan 2026-Summer	V.B

⁷ Recommendation will likely produce considerable efficiency benefits.

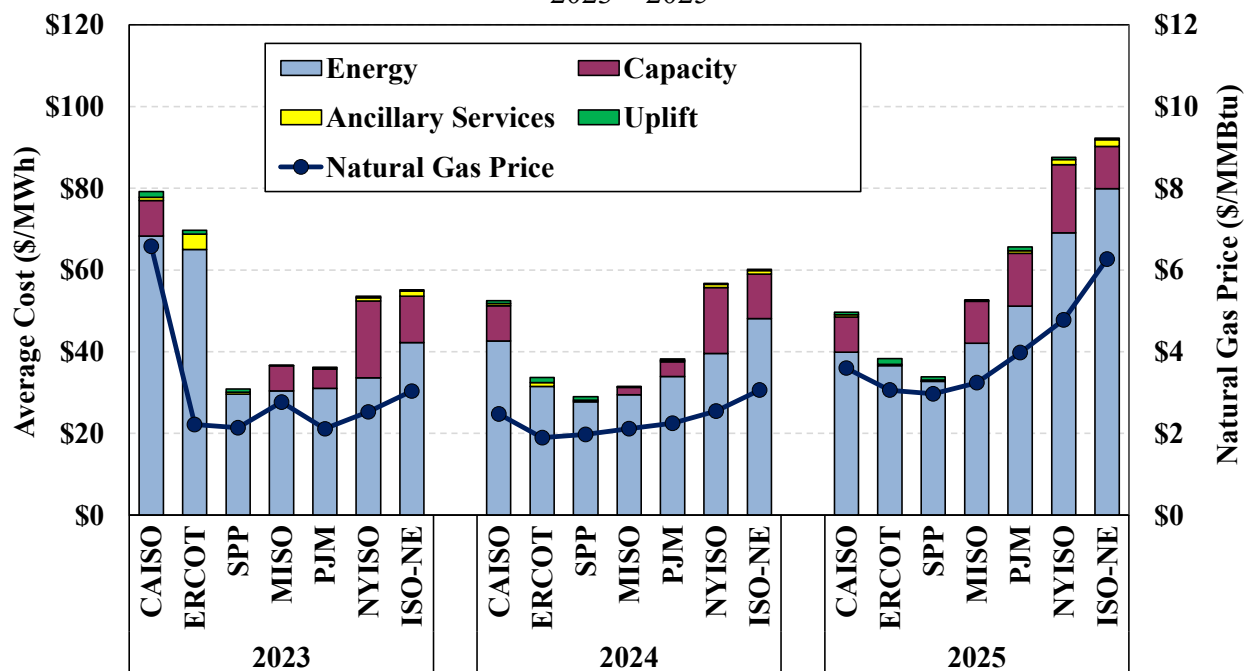
I. COMPARING KEY ISO-NE MARKET METRICS TO OTHER RTOS

The 2025 Annual Markets Report by the Internal Market Monitor (“IMM”) provides descriptive statistics and useful summaries of outcomes in the ISO-NE markets. It also discusses these outcomes and the factors that led to changes in 2025. In this section, we complement that discussion by comparing New England market outcomes and investment incentives with those in other RTO markets.

A. Market Prices and Costs

While US RTOs have converged to similar energy and ancillary service market designs, including Locational Marginal Pricing (“LMP”), some market rules still vary substantially across RTOs. In addition, the existence and design of capacity markets are far less consistent. Many factors affect market prices and costs across RTOs, including the types and vintages of generation assets, state policies supporting specific technologies, fuel market dynamics, and differences in transmission network capability. Figure 1 shows the “all-in price” of electricity to compare overall prices and costs across RTOs.⁸

Figure 1: All-In Prices in RTO Markets
2023 – 2025



⁸ These include only wholesale market costs and not, for example, transmission or distribution service charges. Section II of this report provides a more detailed analysis of how New England’s retail rates are affected by ISO-NE market costs, forward contracting, and other factors.

The all-in price metric comprehensively measures the wholesale market cost of serving load. It equals the load-weighted average real-time energy price plus capacity, ancillary services, and bid production cost guarantee costs (referred to industry-wide as “uplift costs”) per MWh of real-time load across each system. We also show the average natural gas price because it is the principal driver of generators’ marginal costs and energy prices in most markets.

Energy Costs: Figure 1 shows persistent differences in prices and costs across these markets that reflect differences in fuel prices, resource mixes, and market design.

Energy prices and natural gas prices were strongly correlated in ISO-NE, NYISO, PJM, and MISO, where natural gas-fired generation frequently set market prices across broad areas. From 2024 to 2025, energy prices in these markets increased by 43 to 75 percent, consistent with increases in natural gas prices. ISO-NE had the highest energy prices among these markets, primarily because natural gas prices at New England pipeline delivery locations were higher than in other regions. This pattern was most pronounced during winter months, when pipeline constraints tightened gas supplies and drove gas prices sharply higher.

In contrast, the relationship between energy prices and natural gas prices was weaker in ERCOT, SPP, and CAISO. In ERCOT, high energy prices often occurred during summer months despite relatively low natural gas prices. In prior years, this was partly because ERCOT did not jointly optimize the real-time scheduling on ancillary services and energy, which was remedied in late 2025. Average energy prices were especially elevated in 2023 because ERCOT implemented a new reserve product poorly in June 2023, resulting in frequent artificial shortage pricing. However, ERCOT prices have declined over the past two years as large-scale additions of solar and storage resources significantly reduced the frequency of shortage conditions.

The weaker correlation between energy and gas prices in SPP and CAISO reflects their significantly higher penetration of wind and solar resources. In these markets, intermittent renewable and hydroelectric resources more often set market clearing prices, which reduces the influence of natural gas prices on energy prices. By contrast, natural gas-fired generation sets clearing prices in more than 75 percent of pricing intervals in ISO-NE, NYISO, and MISO. In addition, CAISO remains the only major market that has not implemented fast-start pricing, so energy prices remain below efficient levels when fast-start resources are committed to maintain system reliability and balance supply and demand.

Other key factors affecting energy costs in New England include:

- *Rising Carbon Emission Costs.* ISO-NE energy prices are affected more than most other regions by the state greenhouse gas compliance costs.
 - In 2025, compliance added an average of \$14 to \$19 per MWh to the costs of gas-fired combined-cycle generators in Massachusetts and \$10 to \$13 per MWh in the other five New England states in the Regional Greenhouse Gas Initiative (“RGGI”).

- Generators in NYISO and several PJM states are also subject to RGGI compliance costs. ERCOT, MISO, and SPP have no such programs. CAISO’s greenhouse gas (GHG) allowance cap-and-trade system raised combined-cycle generators’ costs by an average of \$14 to \$19 per MWh.
- *Low Levels of Transmission Congestion.* Although we do not show the most congested locations in neighboring markets, some import-constrained locations in those markets have energy prices substantially higher than those in New England, contributing to higher system-wide average prices. Conversely, the unusually low levels of transmission congestion in New England tend to reduce system-wide average energy prices. We discuss congestion levels in more detail in the next subsection.

Capacity Costs: The figure shows that capacity costs in New England remained relatively stable over the past three years. Since 2023, New England has experienced substantial capacity surpluses, resulting in capacity prices below \$3.0 per kW-month, despite winter reliability issues that led to the out-of-market retention of the Mystic generating facility. The sustained low prices led 760 MW of retirement bids from units with on-site fuel supplies to clear in FCA18. After ISO-NE transitions to a prompt, seasonal market with marginal capacity accreditation, prices and market incentives are expected to improve. This change will facilitate better investment, retirement, and fuel supply decisions by market participants.

New York. NYISO had the highest capacity costs among the seven markets over the past three years. Capacity prices rose dramatically after 800 MW of peaking generation retired in 2023 because of air permit limitations and after capacity imports from neighboring control areas fell. NYISO also implemented marginal capacity accreditation beginning with the 2024/25 capability year. However, this change did not significantly affect prices immediately because NYISO’s resource adequacy model already included many of the factors driving accreditation values. NYISO is developing capacity market and resource adequacy model enhancements focused on winter reliability risk, which will affect prices and accreditation values in future years.

PJM. Capacity prices in PJM cleared at very low levels in 2023 and 2024, generally below \$2.0 per kW-month. These low prices reflected large capacity surpluses and were likely below the going-forward costs of many existing units, leading to retirements. In part, the surpluses resulted from low development costs that supported new capacity entry over the past decade. However, PJM’s capacity auction for the 2025-26 period cleared at much higher prices, ranging from \$8.2 to \$14.2 per kW-month. The sharp increase reflected rapid datacenter-driven load growth, recent retirements, and a new marginal capacity accreditation approach that significantly discounted the capacity contributions of many resource classes compared to prior auctions.

MISO. MISO has made major market design changes in recent years, including implementing a seasonal capacity market and capacity accreditation changes in 2023 and a sloped, reliability-based demand curve in 2025. Capacity prices increased sharply to roughly \$6.5 per kW-month (annualized) in the 2025-26 auction as the region continues to be affected by recent retirements.

CAISO. The California PUC also implements a resource adequacy program to ensure sufficient capacity for reliable grid operations, with an effective planning reserve margin requirement of 20 to 22.5 percent. Suppliers and load serving entities (“LSEs”) negotiate capacity contracts bilaterally, so there is no uniform clearing price. The capacity cost component in Figure 1 represents the soft offer cap of the capacity procurement mechanism in CAISO for backstop capacity procurement. The CPUC adopted a Local Capacity Requirement Reduction Compensation Mechanism (LCR RCM) to encourage development of preferred resources and energy storage resources in local capacity areas.⁹ Weighted-average Resource Adequacy (RA) contract prices have risen dramatically in recent years, from approximately \$7 per kW-month for 2022-2023 delivery to roughly \$25 per kW-month for 2025-2026 delivery. This increase likely reflects tightening capacity conditions in California, including generator retirements, growing resource adequacy requirements, and declining planning reserve margins.

ERCOT and SPP. These are “energy-only” markets (i.e., no capacity market), although SPP enforces a 12 percent planning reserve requirement.

Uplift Costs: The last cost component shown in Figure 1, although difficult to discern, is the average uplift cost per MWh of load in each region. Although this amount is small, it is important because market participants cannot easily hedge it and because it tends to occur when market requirements are not fully aligned with the system’s reliability needs or when prices are otherwise not fully efficient. We discuss uplift in more detail in Subsection C.

B. Transmission Congestion

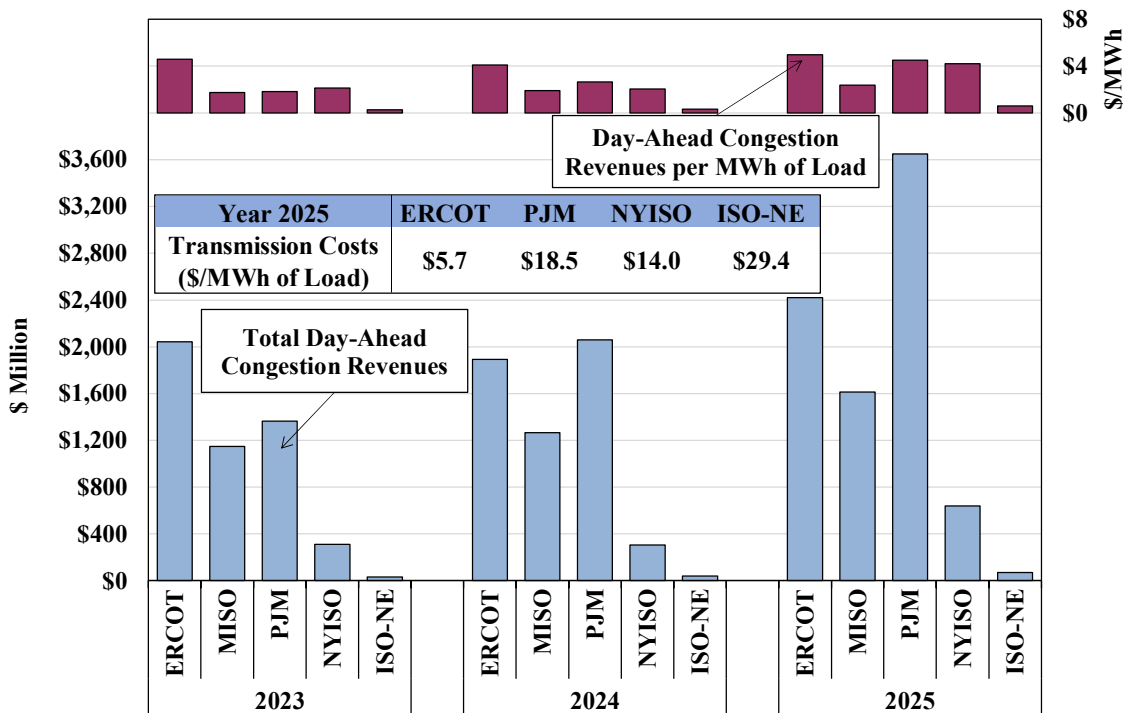
A principal objective of the day-ahead and real-time markets is to commit and dispatch resources efficiently to control power flows on the transmission system and manage transmission congestion. Figure 2 shows day-ahead congestion revenues across several U.S. RTOs. To compare markets of different sizes, the top panel normalizes total day-ahead congestion revenues by actual load.

Figure 2 shows that ISO-NE experienced far less congestion than other RTOs, averaging \$0.39 per MWh over the past three years. In contrast, congestion levels per MWh of load in the other RTOs were four to ten times higher. The low level of congestion in New England reflects substantial investments in transmission infrastructure over the past two decades to address reliability needs and support local transmission security. These investments produced transmission rates of over \$29 per MWh in 2025, more than double the average rates in the other RTO areas shown in the figure.¹⁰

⁹ See CPUC Decision (D.) 20-12-006.

¹⁰ The annual average transmission rate for MISO is not reported, as reliable data are not available.

Figure 2: Day-Ahead Congestion Revenues
2023-2025



Transmission rates in other RTO areas are significantly lower than in New England, despite substantial investments to support renewable integration:

- ERCOT has invested more than \$5 billion in transmission expansion to alleviate congestion between wind resources in western Texas and load centers in eastern Texas.
- MISO has invested more than \$15 billion in transmission to integrate renewables and approved more than \$35 billion through its Long Range Transmission Planning process.
- NYISO and New York state have invested \$7.5 billion and approved another \$8.5 billion in transmission projects since 2019 to deliver renewable energy to downstate load centers and support offshore wind development. This increase in transmission investment is largely responsible for the \$6 per MWh rise in average transmission charges since 2021.

Transmission expansion in these markets has primarily focused on improving the deliverability of renewable resources. By contrast, ISO-NE's transmission expansion over the past two decades has been driven largely by local reliability requirements. Under ISO-NE's reliability planning process, transmission needs are identified based on a conservative criterion requiring the system to withstand the simultaneous loss of the two largest contingencies under a 90th-percentile peak load scenario. This planning criterion is more stringent than those used by the other three RTOs. From 2002 through March 2026, New England invested more than \$13 billion in transmission to maintain reliability, with \$0.3 billion more planned through 2034.¹¹

¹¹ See *RSP Project List and Asset Condition List – March 2026 Update*, Planning Advisory Committee Meeting, March 24, 2026.

In general, transmission investment is economic when the marginal value of reduced congestion and capacity benefits exceeds its costs. Capacity benefits include the avoided costs of maintaining generating capacity to satisfy planning reliability needs and the value of improved reliability. Congestion reduction benefits are small because average congestion costs in New England have been approximately \$0.39 per MWh of load over the past three years.

Transmission costs totaled \$3.4 billion in 2025, compared to just \$1.2 from the entire capacity market, so much of the existing transmission is likely uneconomic, and additional transmission investment would likely be uneconomic in the near term. Nonetheless, prior investments have significantly reduced local reliability Net Commitment Period Compensation (“NCPC”) costs and better prepared the system to integrate renewable resources in the future.

C. Uplift Charges and Cost Allocation

Net Commitment Period Compensation (NCPC) costs, often called “uplift costs” across the industry, typically account for a small share of wholesale market costs. However, they are important because they usually arise when market requirements do not fully align with actual system reliability needs or when prices are otherwise inefficient.¹² This undermines the economic signals that govern behavior in the day-ahead and real-time markets in the short term, as well as investment and retirement decisions in the long term. Therefore, we monitor the market for potential inefficiencies by examining the causes of NCPC payments. Table 1 summarizes total day-ahead and real-time NCPC charges in ISO-NE over the past three years, along with comparable 2025 uplift charges in NYISO and MISO.

To allow meaningful comparisons despite differences in ISO size, the table also shows these costs per MWh of load. Because RTOs differ in the extent to which they make reliability commitments in the day-ahead horizon versus real time, the table also includes a total of day-ahead and real-time uplift at the bottom.

Local Reliability Uplift

Table 1 shows that local reliability NCPC uplift remained relatively low over the past three years, averaging less than \$2 million annually and accounting for less than \$0.02 per MWh of load. Minimal supplemental commitments in constrained load pockets reflect new resource additions and ongoing transmission upgrades in key areas. As a result, ISO-NE’s local reliability uplift was considerably lower than in other RTOs, particularly NYISO.

¹² For example, if the market clearing price is \$50 per MWh and the operator schedules a 100 MW resource outside of the market at a cost of \$55 per MWh so that it does not set the market clearing price, it could lead to NCPC charges of \$500 ($= 100 \text{ MW} \times \$5 \text{ per MWh}$). However, if load is 20,000 MW, the total amount of underpricing of transactions will total \$100,000 ($= 20,000 \text{ MW} \times \$5 \text{ per MWh}$). So, even small amounts of NCPC charges can be an indicator of a significant market inefficiency.

By contrast, NYISO continues to incur substantial local uplift. This is primarily because it must commit significant generation capacity for local second contingency protection within New York City load pockets. In addition, NYISO frequently dispatches oil-fired peaking resources on Long Island out-of-merit in real time to support local voltage requirements during the summer months. NYISO's energy and reserve market models do not fully reflect these local reliability requirements. Consequently, they produce inefficient prices, higher uplift costs, and weaker investment incentives for resources that could support local reliability more efficiently.

Table 1: Summary of Uplift by RTO

		ISO-NE			NYISO	MISO
		2023	2024	2025	2025	2025
Real-Time Uplift						
Total	Local Reliability (\$M)	\$1.0	\$1.3	\$1.3	\$9	\$2
	Market-Wide (\$M)	\$25	\$27	\$30	\$47	\$28
Per MWh of Load	Local Reliability (\$/MWh)	\$0.01	\$0.01	\$0.01	\$0.06	\$0.00
	Market-Wide (\$/MWh)	\$0.22	\$0.23	\$0.26	\$0.31	\$0.04
Day-Ahead Uplift						
Total	Local Reliability (\$M)	\$0.7	\$0.9	\$0.2	\$13	\$24
	Market-Wide (\$M)	\$4	\$6	\$10	\$13	\$25
Per MWh of Load	Local Reliability (\$/MWh)	\$0.01	\$0.01	\$0.00	\$0.09	\$0.03
	Market-Wide (\$/MWh)	\$0.03	\$0.05	\$0.09	\$0.08	\$0.04
Total Uplift						
Total	Local Reliability (\$M)	\$1.6	\$2.2	\$1.5	\$22	\$26
	Market-Wide (\$M)	\$29	\$33	\$40	\$60	\$53
Per MWh of Load	Local Reliability (\$/MWh)	\$0.01	\$0.02	\$0.01	\$0.14	\$0.04
	Market-Wide (\$/MWh)	\$0.26	\$0.28	\$0.35	\$0.39	\$0.08
	All Uplift (\$/MWh)	\$0.27	\$0.30	\$0.36	\$0.54	\$0.11

Market-Wide Uplift

Unlike local reliability uplift, ISO-NE has typically incurred higher market-wide uplift costs than the other two markets after adjusting for size. ISO-NE introduced day-ahead reserve markets in March 2025, which helped reduce market-wide NCPC costs. However, these costs rose from 2024 to 2025 because of high levels in January and February 2025. In previous years, ISO-NE's market-wide NCPC costs were generally more than double the average cost per MWh of load in NYISO and MISO, which we do not expect to be the case in the future. The day-ahead reserve markets provide additional market revenues, reducing the need for day-ahead NCPC. It also reduces the need for supplemental commitments, lowering real-time NCPC uplift payments.

Despite this reduction, several factors kept uplift costs in New England high:

- 1) Although all three RTOs have provisions for compensating resources when their scheduled output deviates from their most profitable output level, ISO-NE's rules offer compensation under a broader set of circumstances than those in MISO and NYISO. Examining these differences may help identify best practices across markets.

- 2) ISO-NE also experienced higher levels of real-time economic NCPC payments to fast-start units committed in economic merit order than NYISO and MISO. These payments accounted for approximately 65 percent of uplift in this category over the past two years. Section IV.C analyzes several of the factors contributing to these uplift payments.

Uplift Allocation and Virtual Trading

Beyond differences in uplift costs, their allocation also varies significantly across RTOs. ISO-NE allocates real-time “Economic” NCPC charges to real-time deviations, including virtual transactions, although such deviations do not directly cause most of these charges. Over the past three years, fast-start resources accounted for more than 60 percent of real-time Economic NCPC payments. Uneconomic real-time commitments in response to forecast errors often drive these payments. Real-time deviations such as virtual transactions typically play little or no role in causing this uplift. By contrast, virtual load can reduce NCPC costs by increasing day-ahead commitments and reducing the need for fast-start resources in real time.

Table 2 shows the average volume of virtual supply and demand cleared in the three eastern RTOs we monitor, expressed as a percentage of total load. It also reports the gross profitability of these transactions, measured as the difference between the day-ahead and real-time energy prices that settle the virtual positions. These profitability figures do not account for uplift costs allocated to virtual transactions, which the table shows separately in an additional column.

Table 2: Scheduled Virtual Transaction Volumes and Profitability

Market	Year	Virtual Load		Virtual Supply		Uplift Charge Rate
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	
ISO-NE	2022	3.1%	-\$1.75	4.8%	\$3.23	\$1.02
	2023	4.2%	-\$2.09	6.3%	\$1.28	\$0.83
	2024	3.1%	-\$2.64	6.6%	\$2.21	\$0.75
	2025	4.5%	-\$3.19	8.0%	\$2.67	\$0.63
NYISO	2025	6.1%	\$3.39	7.7%	\$1.25	< \$0.1
MISO	2025	15.5%	-\$0.30	15.5%	\$1.49	\$0.16

Table 2 shows that virtual trading is profitable overall, which suggests that it improves price convergence between the day-ahead and real-time markets. The table also shows that virtual trading activity increased in 2025 relative to prior years as uplift charge rates declined. However, virtual trading activity in ISO-NE remains lower than in the other RTOs, averaging about 11 percent of load, compared to 14 to 31 percent in the other two RTOs. This disparity arose in part from the over-allocation of NCPC charges to real-time deviations in New England. These allocations discourage virtual participation, reduce day-ahead market liquidity, and ultimately impair market performance.

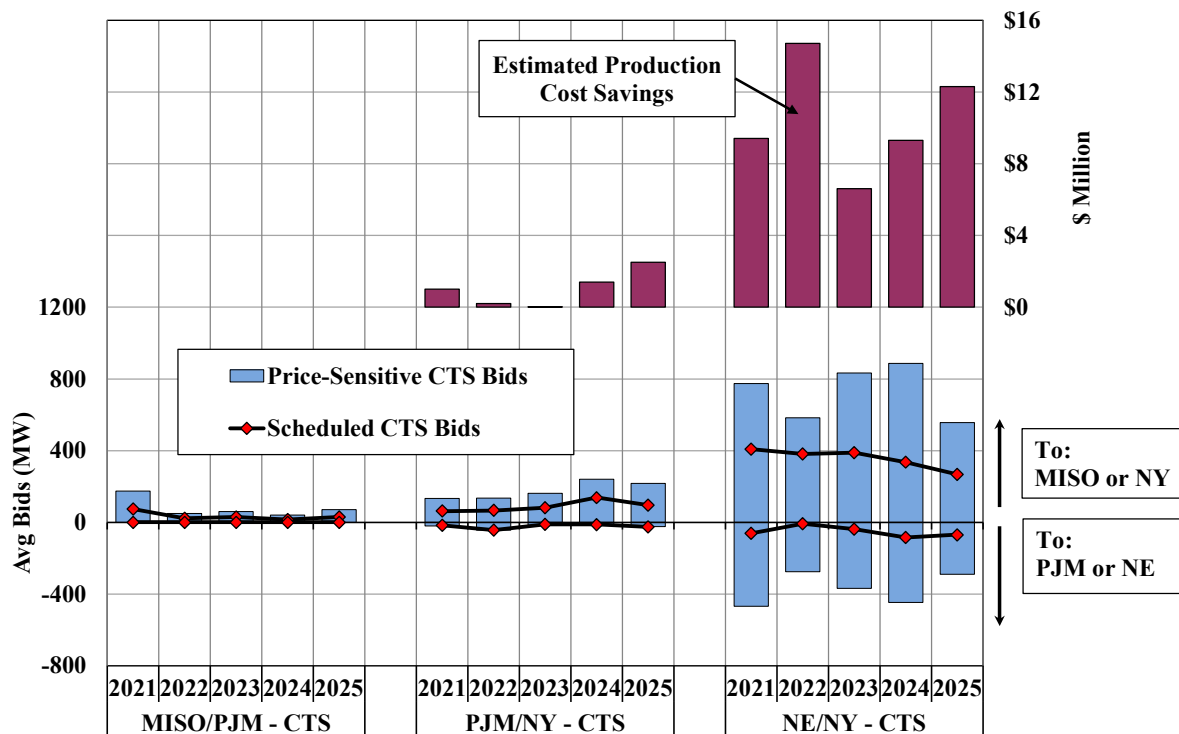
We continue to recommend that the ISO modify the allocation of Economic NCPC charges to align with “cost causation” principles. Specifically, the ISO should stop allocating NCPC costs to virtual load and other real-time deviations that do not cause real-time economic NCPC costs (Recommendation #2010-4).

D. Coordinated Transaction Scheduling

Coordinated Transaction Scheduling (“CTS”) is a vital process in which neighboring RTOs exchange real-time market information to schedule external transactions more efficiently. CTS optimizes use of the interface between markets, lowering costs and improving reliability in the region. As intermittent generation increases, CTS will play an even more critical role in helping RTOs balance supply and demand efficiently. Figure 3 compares CTS performance in the NE-NY process with the PJM-NY and MISO-PJM processes.

The lower panel in Figure 3 shows annual average quantities of price-sensitive CTS bids and schedules over the past five years.¹³ Positive numbers indicate transactions from neighboring markets to the NYISO or MISO markets, while negative numbers indicate transactions from neighboring markets to the PJM or New England markets. The upper panel shows CTS market efficiency gains measured by production cost savings, excluding estimates for the PJM-MISO process because of very limited participation.

Figure 3: CTS Scheduling and Efficiency
2021 – 2025



¹³ CTS bids in the price range of -\$10 to \$10 per MWh are considered price-sensitive for this evaluation.

Figure 3 shows significantly higher CTS participation at the NE/NY interface than at the PJM/NY and MISO/PJM interfaces. Substantial transaction fees at the PJM/NY and MISO/PJM interfaces discourage scheduling, while the NE/NY interface imposes no transaction fees. This pattern shows that transaction charges can impede efficient scheduling by discouraging CTS participation.

The estimated production cost savings from the NE/NY CTS process exceeded \$52 million over the past five years, compared to \$5 million at the PJM/NY interface.¹⁴ In addition to higher participation levels, more accurate price forecasting also contributed to higher savings at the NE/NY interface. ISO-NE's forecasting approach is more granular: it incorporates a supply curve with seven interchange levels, while PJM forecasts a single price at a fixed interchange level. Better forecast accuracy could further increase the cost savings from the CTS processes.

However, forecasting improvements may be limited because forecasts are produced roughly 40 minutes in advance. As an alternative, we evaluated a process for MISO and PJM that adjusts interchange every five minutes based on updated real-time prices. The estimated savings from such a real-time process are significantly larger than those achieved under current CTS processes, suggesting that a similar enhancement may warrant consideration for the New England and New York interface.

E. Net Revenues for New Entrants

A well-functioning wholesale market establishes transparent, efficient price signals that guide investment and retirement decisions. The New England states have set ambitious policy goals to decarbonize the electricity sector and implemented several programs to encourage development of clean energy resources. Efficient market incentives will help the states meet their goals at the lowest cost. This remains true even for projects primarily motivated by state and federal incentives because wholesale prices still play a significant role in most projects' profitability.

This subsection compares investment incentives in ISO-NE with those in other markets by estimating the net revenue new resources would have earned from wholesale markets and applicable state and federal incentives. Figure 4 shows the estimated net revenues for new combustion turbine ("CT") and combined-cycle ("CC") generators, while Figure 5 shows the net revenues for land-based wind, offshore wind, and solar PV units from wholesale market products and state and federal incentives.¹⁵ The figures also show the estimated annual net revenue these new investments would need to be profitable (i.e., the "Cost of New Entry" or CONE) in 2024 and 2025.

¹⁴ Production cost savings are calculated relative to our estimates of scheduling that would have occurred under the previous hourly scheduling process, which we proxy based on the advisory schedules in NYISO's RTC model that are determined 30 minutes before each hour.

¹⁵ See Appendix A for the assumptions used for this analysis. The CT chosen for each market is the most economic: a F Class Frame CT in MISO and ERCOT and a H Class Frame CT in NE and NY.

Figure 4: Estimated Net Revenues of CT and CC Units in ISO/RTO Markets
2024 – 2025

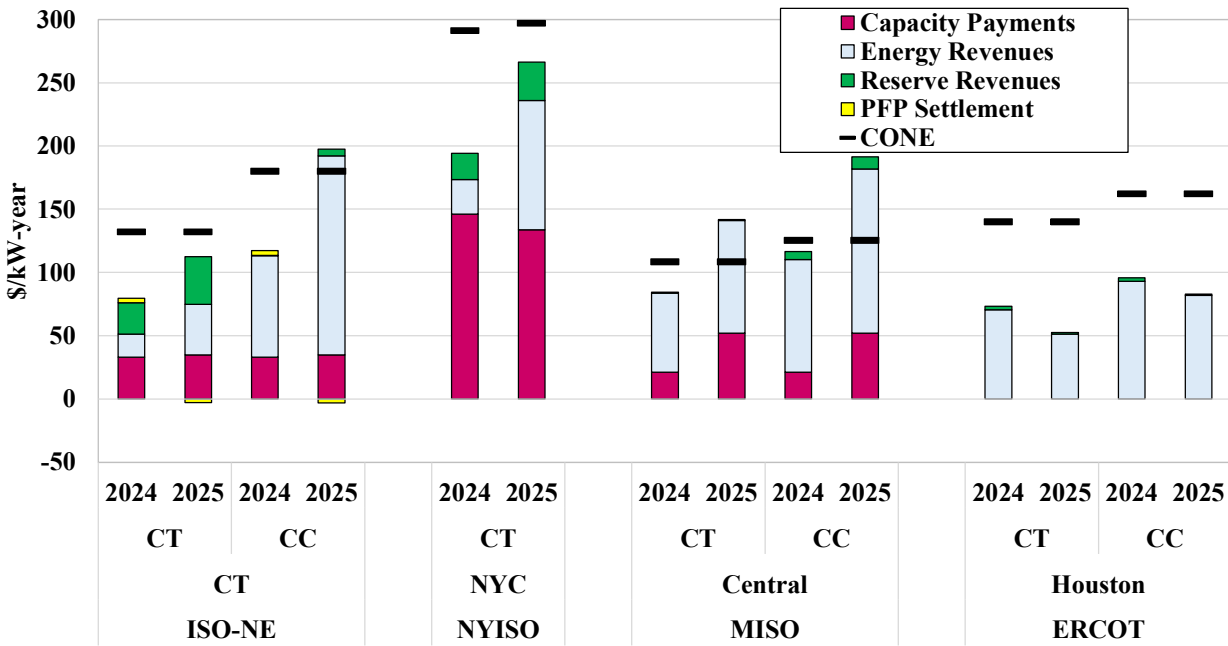
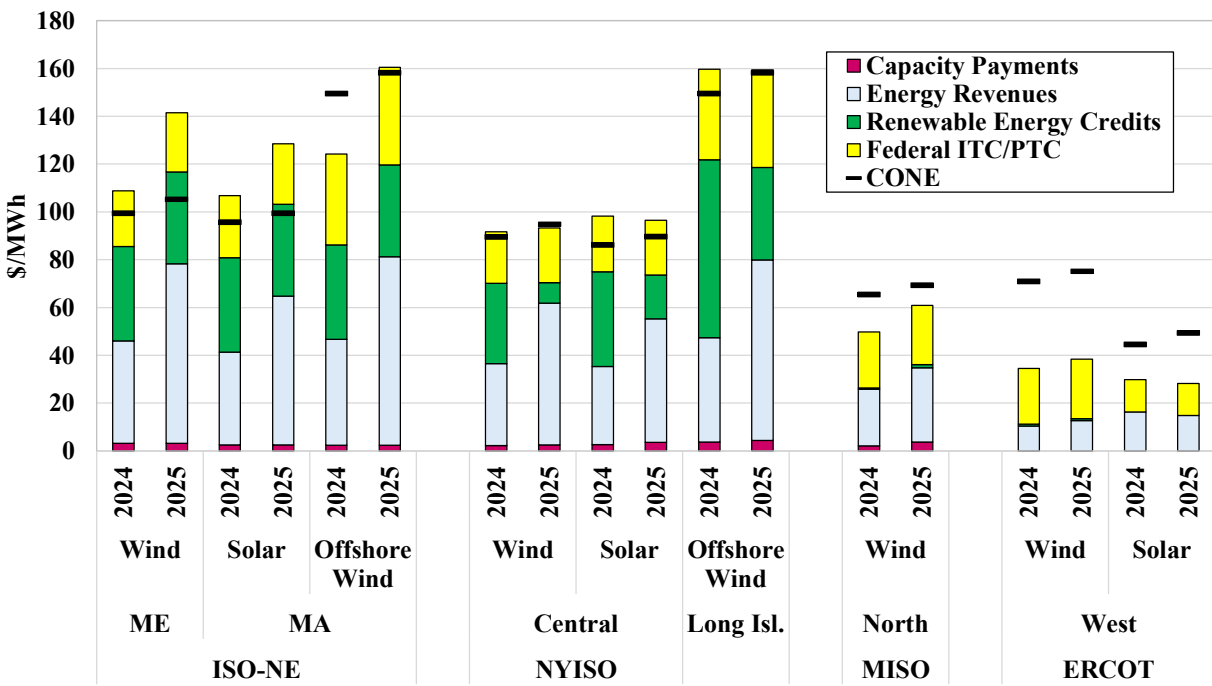


Figure 5: Estimated Net Revenues of Renewables in ISO/RTO Markets
2024 – 2025



Incentives for New Combustion Turbines and Combined Cycles

Net revenues of fossil generators increased markedly in most regions in 2025. In ISO-NE, 2025 net revenues exceeded the estimated Cost of New Entry for CCs. In MISO, they exceeded the estimated Cost of New Entry for both CTs and CCs. Figure 4 provides the following insights on incentives to invest in CTs and CCs in each market:

- *New England.* Net revenues of a new CT have remained below Net CONE because they rely heavily on capacity prices, which have been low in recent years. However, CT revenues rose in 2025 because of generally higher market spark spreads and the introduction of the day-ahead ancillary services (“DA A/S”) markets in March 2025, which raised reserve market revenues for new flexible CTs. Revenues of a new CC also increased substantially in 2025 because of rising energy prices, payment of the Forecast Energy Requirement (“FER”) shadow price to units that sell day-ahead energy as part of the DASI initiative, and higher winter gas prices in 2025, which created opportunities for a new unit built with dual fuel capability.
- *New York.* Net revenues of a new CT in New York City were below CONE despite comparatively high capacity prices because the region had nearly a 6 percent capacity surplus. New York City generally has higher prices than other areas because of its very high CONE. New York recently raised capacity requirements in New York City to better align them with transmission security requirements. Net revenues for a new CT would likely have been above CONE in 2024 and 2025 if those requirements had been used. We did not evaluate the economics of a new CC in New York because state policy has been to deny permits for new fossil generators.
- *ERCOT.* Net revenues of CT and CC units in ERCOT were much lower than in other markets in 2024 and 2025. ERCOT does not have a capacity market, so peaking units derive net revenues in tight market conditions from a higher frequency of scarcity pricing hours. Large-scale entry of solar and storage resources, along with very conservative market operations that lead to over-commitment of resources, significantly reduced the frequency of price spikes, resulting in lower net revenues.
- *MISO.* MISO held its first auction with a sloped demand curve in 2025, along with other changes to its capacity market structure and parameters. Those changes resulted in significantly higher clearing prices, which were sufficient to justify investment in new CT and CC capacity.

Although shortage pricing is an important component of expected revenues in both ISO-NE and ERCOT, ISO-NE settles a large share of it through its Pay For Performance (“PFP”) framework. Compared with very strong conventional shortage pricing, this approach alters the financial risks to consumers and suppliers under extreme conditions in at least five ways:

- i. The performance payments are a transfer from underperforming to overperforming resources. Hence, there is no direct increase in consumer payments.¹⁶

¹⁶ Although the PFP framework does not result in direct increase in consumer costs from higher prices during shortage events, it should increase capacity prices as capacity suppliers raise their offers in the FCM.

- ii. ISO-NE has stop-loss provisions that limit the losses a capacity resource could incur monthly and annually because of poor performance in PFP events.¹⁷ These provisions limit generators' financial risk while generally maintaining strong incentives to perform during shortages. Aside from PFP, the operating reserve demand curves can set energy and reserve clearing prices above \$2,500 per MWh.
- iii. The stop-loss provisions can also limit the compensation for generators that perform well during sustained shortages, which may weaken the incentives that PFP provides.
- iv. The expected frequency of shortages in New England is lower by design because the capacity market produces a higher reserve margin than an energy-only market like ERCOT.
- v. Under PFP, ISO-NE prices very small shortages of 30-minute reserves, which are difficult to forecast, much more aggressively than ERCOT or any other market. This increases participants' risk and is inefficient to the extent that these modest shortages raise only small reliability concerns.

Hence, the risk profile for suppliers and consumers, as well as the likelihood of shortage events, differs considerably in ISO-NE from that in a typical energy-only market.

Incentives for New Wind and Solar Projects

Investment in land-based renewables is driven by several factors, including resource potential (which affects the levelized cost of energy because projects in areas with greater annual output require a lower price per unit), wholesale market prices, transmission and interconnection bottlenecks, the availability of federal and state incentives or mandatory contracts, markets for voluntary PPAs, and the ease of land acquisition and permitting. Figure 5 shows the following:

- *New England and New York:* Net revenues of land-based wind and solar projects in New England and New York appear to justify investment because of relatively high market prices and generous state subsidies.
 - Federal and state incentives accounted for more than half of total revenues in these regions for all renewables examined.¹⁸ Offshore wind projects have much higher costs than land-based renewables, but higher-priced OREC contracts in New York and utility PPAs in New England incentivize them.
 - However, siting, permitting, and transmission challenges in these states have caused actual investment in utility-scale renewables to fall far short of state goals despite the apparent financial incentives. In 2025 and early 2026, about 400 MW of solar PV participating in the ISO-NE markets entered service, along with 180 MW of land-

¹⁷ The monthly stop-loss limit caps the loss to the capacity obligation times the FCA starting price. The annual stop-loss limit caps loss to three times the resource's maximum monthly potential net loss.

¹⁸ The figure reflects NYSEERDA Tier 1 Index REC prices for recently built projects in NY and MA Class I REC prices in New England. Prices of class I RECs for utility-scale renewables vary depending on the amount supplied relative to procurement requirements, while New York has adopted an 'Index REC' framework where higher energy prices reduce REC payments to renewables

based wind generation in Maine (where there are fewer challenges to siting new wind generation). Offshore wind projects originally contracted in the 2010s have recently begun to enter service in New England and New York, although many contracts have stalled or been canceled amid cost overruns and a volatile federal permitting environment.

- *MISO and ERCOT*: Land-based wind and solar investment has historically been stronger in MISO and ERCOT, where resource potential is better than in New England and New York, even though MISO and ERCOT lack highly priced REC programs. LMPs in MISO, and particularly in ERCOT, have fallen to very low or negative levels at times of day when renewable generation is highest because of high penetration in some areas.

Recent changes in federal law will eliminate key subsidies for wind and solar projects that are not in service by the end of 2027 or under construction as of July 4, 2026. These subsidies account for a large share of wind and solar revenues in all markets, and eliminating them will significantly challenge project economics absent a major increase in REC prices.

II. ENERGY AFFORDABILITY IN NEW ENGLAND

In recent years, rising electricity costs and their effects on consumers have received significant attention nationwide. This section examines long-term trends in residential electricity rates in New England and the role of the ISO-NE markets. Retail rates include cost-of-service elements (such as regulated transmission and distribution charges) and wholesale costs passed through to consumers. This section evaluates:

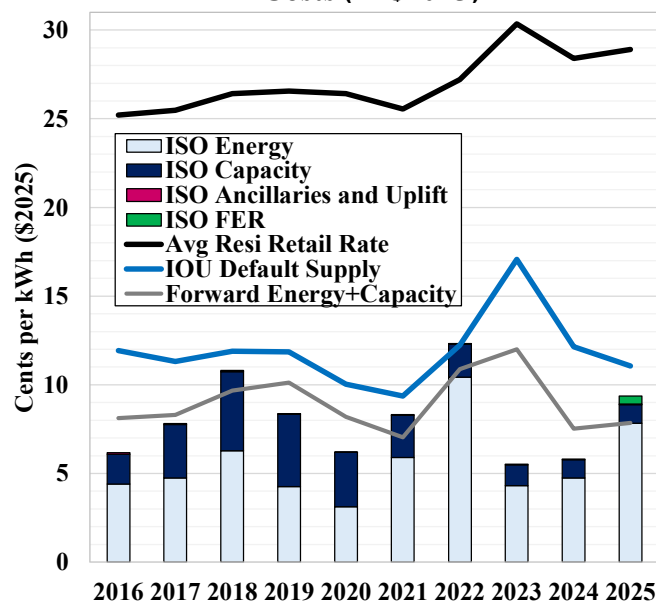
- How major components of retail and wholesale rates changed over the past decade. We find that non-wholesale costs rose while ISO-NE prices remained largely flat, with higher energy prices offset by lower capacity prices (in subsection A). Premiums associated with utility supply RFPs also contribute meaningfully to retail rates.
- Forward energy prices, which comprise most of consumers' supply costs, finding that gas pipeline constraints into New England and rising carbon allowance costs caused them to increase (in subsection B).
- Generator profit levels produced by the ISO-NE markets, which are significant for some older units but have little overall effect on retail rates (in subsection C).
- Indications that Net CONE should be adjusted to reflect that the economic life of most generators exceeds 20 years (in subsection D).
- Rate design and policy choices that would help reduce retail rates (in subsection E).

A. Long-Term Trends in Retail and Wholesale Rates

Figure 6 compares average New England residential retail rates with wholesale market prices from 2016 through 2025.¹⁹ All values are in inflation-adjusted 2025 dollars. The stacked bars show ISO-NE market prices weighted by typical residential class load shapes for energy, FER, and reserves, and by annual load factors for FCA capacity prices. In 2025, Figure 1 shows separately the effect of paying the FER price to DAM energy suppliers separate from the energy component of the day-ahead LMP.

The blue line in Figure 6 shows average residential default supply service rates, sometimes called standard service, for

Figure 6: Residential Retail and Wholesale Costs (in \$2025)



¹⁹ Retail rate and IOU supply cost data are derived from EIA Form 861 data and publicly filed or posted supply rates of IOUs in New England.

investor-owned utilities (IOUs) in New England. As of 2024, IOUs supplied approximately 60 percent of residential load, while municipal or competitive load-serving entities (LSEs) supplied the rest. The default supply rates shown in Figure 6 exclude costs for renewable energy credits that are sometimes bundled with supply on retail bills. The gray line shows average forward prices for ISO-NE Mass Hub traded 3 to 9 months before delivery, weighted by residential load shapes, plus FCA capacity prices.²⁰

Figure 6 shows that retail rates are rising in real terms, driven mainly by non-wholesale costs and IOU supply costs. The provide the following observations from this analysis:

Retail versus Wholesale Rate Observations:

- *New England retail rates are rising faster than inflation* – Residential retail rates in New England increased by approximately 12 percent in real 2025 dollars over the period shown, from 25.9 cents per kWh on average in 2016-2019 to 28.9 cents in 2025. New England residential retail rates were 56 percent higher than the US average in 2016-2019 and 67 percent higher in 2025.
- *Non-wholesale components account for most of the retail rate increases* – The non-wholesale component of retail rates has risen over the past decade. The difference between inflation-adjusted retail rates and IOU supply costs rose from 14.2 cents per kWh in 2016-2019 to 18 cents in 2025, an increase of almost 4 cents (or 27 percent).
- *T&D costs are the largest single driver of non-wholesale cost increases* – Non-wholesale market costs include transmission and distribution costs, renewable and energy efficiency programs, low-income ratepayer support, and other taxes and surcharges. Transmission and distribution cost recovery is the largest component of residential bills and was generally the largest source of rate increases. Regional Network Load charges that ISO-NE allocated to recover regulated high-voltage transmission costs rose from 3.1 cents per kWh in 2016 to 4.1 cents in 2025 (in real dollars weighted by residential load factor).

ISO-NE Supply Cost Observations:

- *ISO-NE all-in prices have risen modestly* – Annual all-in prices can be volatile, but they have been relatively flat over time, averaging 8.0 cents per kWh in 2016–2021 and 8.3 cents per kWh in 2022–2025.
- *ISO-NE costs have shifted from capacity to energy* – While overall prices were flat, capacity costs fell and energy prices rose. Average capacity prices fell by 1.8 cents per kWh, from 3.1 cents in 2016–2021 to 1.3 cents in 2022–2025. Average energy prices rose by 2.2 cents per kWh, from 4.8 cents per kWh in 2016–2021 to 7.0 cents per kWh in 2022–2025, primarily because of higher gas and CO₂ emission allowance prices.
- *Day Ahead Ancillary Services account for a small portion of retail rates* – Ancillary services prices (including the Forward Reserve Auction prior to March 2025 and Day Ahead Ancillary Services thereafter) generally accounted for a small share of rates. FER

²⁰ Forward prices in this section are obtained from NYMEX and Amerex using S&P Capital IQ.

payments to energy suppliers, introduced in March 2025, increased residential-weighted wholesale prices by 0.5 cent per kWh in 2025.

Observations on IOU Supply Costs:

- *IOU supply costs are significantly higher than ISO-NE wholesale prices* – On average, ISO-NE market prices equaled 30 percent of the residential retail rate during 2016–2025. IOU default service supply rates equaled 44 percent of retail rates.
- *IOU supply costs incorporate distribution losses and forward prices* – Utilities’ default service rates differ from ISO-NE prices because IOUs procure supply forward and incur distribution losses, typically about 10 percent. New England states require utilities to procure the full supply needs of their residential full-service customers at fixed rates through RFPs, which typically procure most supply several months to a year in advance.²¹ Hence, these rates are driven primarily by forward expectations for the cost of energy, capacity, and ancillary services.
- *The Ukraine war led to a temporary spike in IOU supply costs* – IOU default service rates were relatively flat, averaging 11.7 cents per kWh in 2016-2019 and 11.6 cents per kWh in 2024-2025. The outbreak of the Ukraine conflict in 2022 sharply and temporarily increased forward energy prices, resulting in IOU costs of 17.1 cents per kWh in 2023, compared to ISO market costs of 5.5 cents per kWh.
- *IOU supply costs show a consistent premium over wholesale energy forward prices*– IOU default service rates exceed average ISO-NE market prices and financial futures.
 - After adjusting for assumed 10 percent distribution losses, ancillary service and balancing energy costs, and residential class hourly load shape, default service rates were 16 percent higher on average than forward energy and capacity prices from 2016 to 2025. They were 26 percent higher from 2023 to 2025.²²
 - Suppliers participating in IOUs’ default service RFPs likely require significant risk premiums to meet utilities’ full-service requirements at fixed rates because they are exposed to both market price risk and quantity risk for the amount of load served. However, state governments tightly prescribe the requirements and timing of the RFPs in ways that may limit the pool of competitive bidders and result in higher premiums over wholesale prices.

Overall, recent increases in residential retail rates were driven primarily by non-wholesale costs. ISO-NE energy prices (including the FER) have risen in recent years, but lower capacity prices offset these increases as they fell from historically high levels in the late 2010s to historically low levels in recent years. Utility supply procurement practices in New England add a large

²¹ For an example IOU supply RFP, see National Grid’s “Request for Power Supply Proposals to Provide the Following Services: Default Service in Massachusetts for the period August 1, 2026 – July 31, 2027, issued March 27, 2026, available [here](#).

²² For purposes of this comparison, we adjusted forward energy prices for 10 percent assumed distribution losses, a 7.5 percent factor reflecting higher average day-ahead prices when weighted by a residential load shape compared to peak and off-peak averages, \$0.4 cents per kWh ancillary service costs, and 1 percent balancing energy costs.

premium above ISO-NE market prices in exchange for greater price certainty, and these premiums have risen in recent years as spot prices have become more volatile. The following subsection discusses the factors driving forward energy prices, the main component of IOU supply costs paid by consumers.

B. Drivers of Hedged Wholesale Costs

Load-serving entities (including IOUs and competitive suppliers) enter into forward hedges and supply contracts on behalf of their end-users. Their prices are driven by forward expectations of ISO-NE prices and risk at the time of contracting.

Figure 7 shows how changes in commodity price forwards (fuel and emissions) have contributed to forward power prices. All values are in real 2025 dollars per MWh. The black lines show average around-the-clock forward prices for ISO-NE day-ahead LMPs traded three to nine months ahead of each delivery month. The stacked bars show (1) forward natural gas prices with the same trade dates as the power forwards and (2) forward CO₂ emissions allowance prices, including RGGI and Massachusetts' emissions allowance program.

Gas and allowance prices converted to dollars per MWh using a 7.5 MMBtu per MWh heat rate comparable to older combined cycle units in ISO-NE. For gas forwards, the figure shows the portion of the Algonquin Citygates price that exceeds the TETCO M3 index, indicating the impact of pipeline constraints into the northeast U.S. ("Northeast"). The difference between the stacked bars and the black lines is correlated with combined cycle margins, but it excludes other cost items such as VOM expenses and gas delivery costs.

Figure 7: Forward Prices of Power, Gas and Emissions Allowances (\$2025)
2016 - 2026

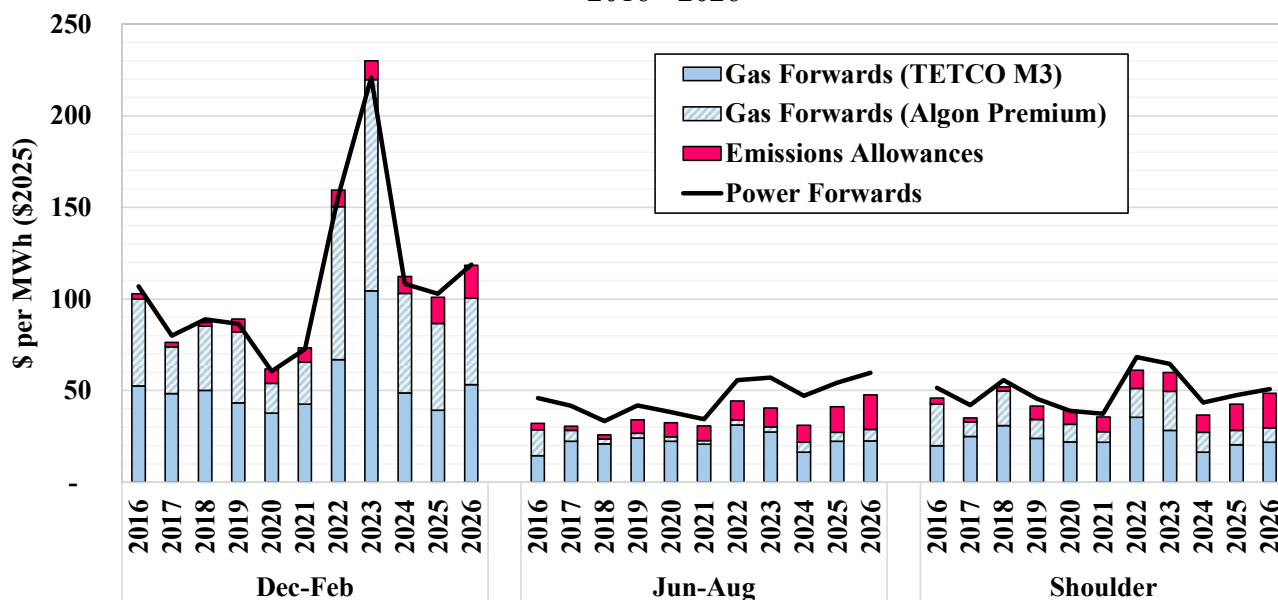


Figure 7 shows a number of key trends:

- Higher forward gas prices have been a primary driver of rising forward power prices since 2022. Average forward power prices for winter months rose by \$58 per MWh between 2016-2021 and 2022–2026. Average forward prices for summer and shoulder months rose by \$15 and \$10 per MWh, respectively. This excludes costs associated with the FER price in 2025 and 2026, which are not reflected in forward LMPs. Gas pipeline constraints into the Northeast, with the average winter premium over TETCO M3 forwards rising from \$31 per MWh in 2016-2021 to \$70 per MWh in 2022-2026.
- Because forward markets price the risk of gas price spikes, pipeline constraints drive higher consumer costs even in mild winters. For example, 2023 had notably low ISO-NE market prices (see Figure 6) but historically high supply costs due to the impact of the Ukraine war outbreak in the preceding year on forward gas prices.
- Emissions allowance prices also increased steadily during this period. RGGI costs rose from approximately \$3 per MWh in 2016 to \$11 per MWh in 2026, and Massachusetts allowance prices, implemented in 2018, added over \$7 per MWh in 2026 for Massachusetts units.
- Gas-fired generator margins have increased in the Northeast as nuclear generation and Canadian hydro imports have fallen. All-hours implied forward generator margins for a 7.5 heat rate unit rose by \$1.9 per MWh in Massachusetts and \$4.1 per MWh elsewhere between 2016-2021 and 2022-2026 (excluding the impact of the FER, which is not currently included in financial future settlement definitions but averaged \$4.8 per MWh in March through December of 2025).

Overall, the energy component of wholesale supply rates has risen in recent years primarily because of higher forward pricing of natural gas (which reflects the expected value of price spikes caused by pipeline congestion) and rising costs of RGGI and Massachusetts carbon allowances. The large and growing gas price premium in New England results from pipeline projects' inability to obtain permits in New England and New York (which most pipeline projects must cross to reach New England from supply regions). Permitting more on-site dual fuel capability for natural gas resources would also mitigate costs and improve winter reliability.

To a lesser extent, forward spark spreads have also risen, although suppliers participating in IOUs' default service RFPs may earn higher profits than forward spark spreads imply. The following subsection analyzes how profits that generators earn from the ISO-NE market and financial futures markets contribute to retail rates in New England.

C. Impact of Generator Profits on Affordability

This subsection examines whether rising generator profits in the ISO-NE and financial futures markets have significantly driven higher electricity costs in New England. By comparing estimated net revenues and fixed costs across major fossil generation technologies, we assess how much recent market outcomes have increased producer profitability and contributed to retail rates. This analysis considers returns from hedging energy and fuel prices at market rates but

excludes premiums above ISO-NE revenues for suppliers that participate in IOUs' default service RFPs.

Figure 8 and Figure 9 show estimated net revenues and fixed costs for fossil generators in ISO-NE from 2023 to 2025. We estimated revenues for several unit types comprising approximately 19 GW of summer capacity in ISO-NE: newer CCs (2010s vintage), older CCs (mainly late 1990s and early 2000s), small older CCs (plants with total capacity of about 300 MW or less), steam turbines, newer CTs (mostly late 2000s and 2010s vintage, many of which are dual fuel), and older CTs (many of which are oil fired).²³ We considered the following revenues and costs:

- *Capacity revenues.* Reflect FCA prices net of PFP settlements based on average performance by technology type. In years when clearing prices varied by location, we show a capacity-weighted average price.
- *Energy and reserve revenues.* Estimated using a model that simulates day-ahead and real-time market commitment with historic prices for LMPs, reserves, FER, natural gas, and emissions allowances (including RGGI and Massachusetts cap and trade, where applicable). Reserve revenues are based on the Forward Reserve Auction prior to March 2025 and on Day Ahead Ancillary Services thereafter. We model gas prices using the Algonquin Citygate index plus an adder of \$0.10 per MMBTU in summer and \$0.50 per MMBTU in winter.
- *Hedge settlement revenues.* Estimated assuming a generator hedges a portion of its expected output by selling forward power and buying forward gas and allowances. We calculate settlements based on the difference between average forward prices three to nine months ahead of the delivery month and spot prices. In winter months with high forward gas prices, we assume dual fuel units sell some forward power without an accompanying forward gas purchase. This locks in the expected value of periods when gas prices exceed oil prices.²⁴
- *Fixed costs.* Fixed costs for existing units reflect going-forward costs (including fixed O&M, administrative, site leasing and property tax, and periodic maintenance capex). For newer units (those built less than twenty years ago, mostly during the 2010s), fixed costs include amortization of the original capital investment. Although we do not know the actual fixed costs of individual generators, these estimates generalize by technology type based on our monitoring work in multiple US ISO/RTO markets.

²³ This includes approximately 2.5 GW of newer CCs, 6.8 GW of large older CCs, 3.5 GW of small older CCs, 1.2 GW of newer CTs, 1.6 GW of older CTs, and 3.1 GW of steam turbines.

²⁴ For hedge settlements, we assume that generators cover a portion of expected monthly peak and off-peak generation through forward sales of energy and purchases of gas and emissions allowances. We assume that generators hedge less than their full expected output to preserve market upside and manage outage risk, with the quantity varying based on the expected monthly capacity factor with a maximum of 75 percent of expected output. In winter months with high forward gas prices, we assume that dual fuel generators buy forward a proportionally smaller quantity of gas compared to their forward power sales in order to secure expected revenues from oil firing.

Figure 8: Net Revenues and Costs of Combined Cycle Generators
2016 - 2025

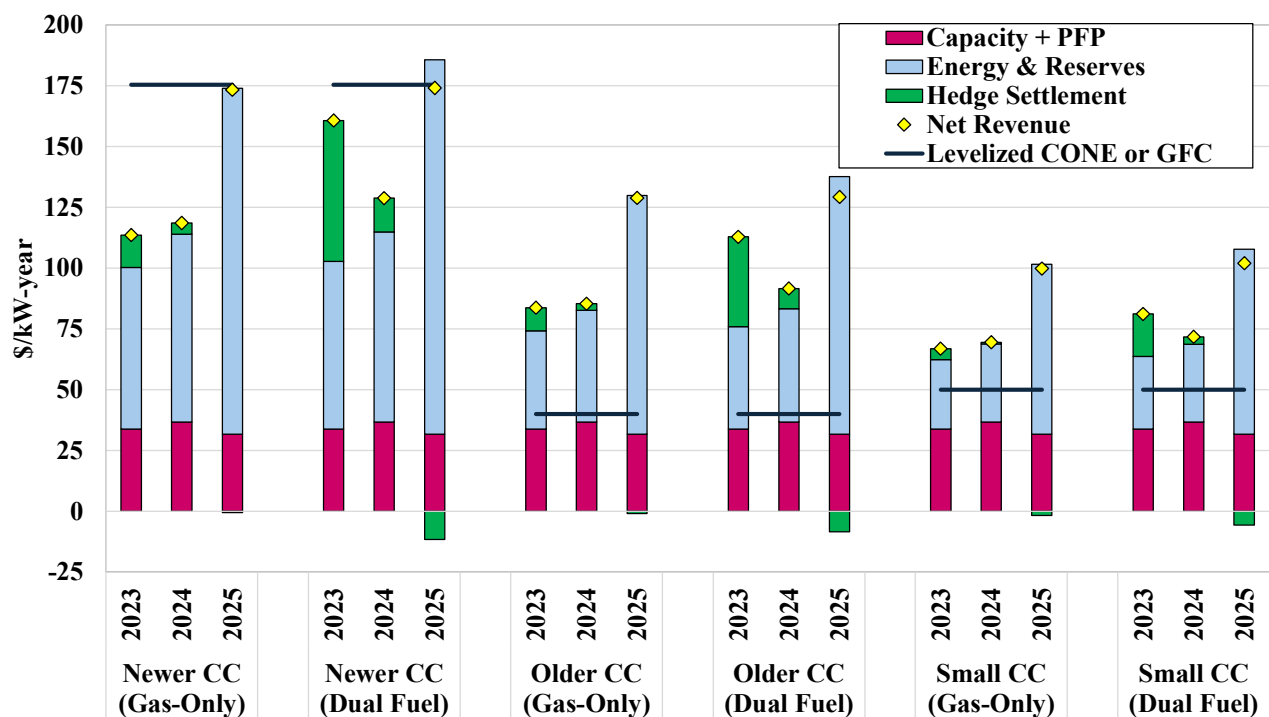
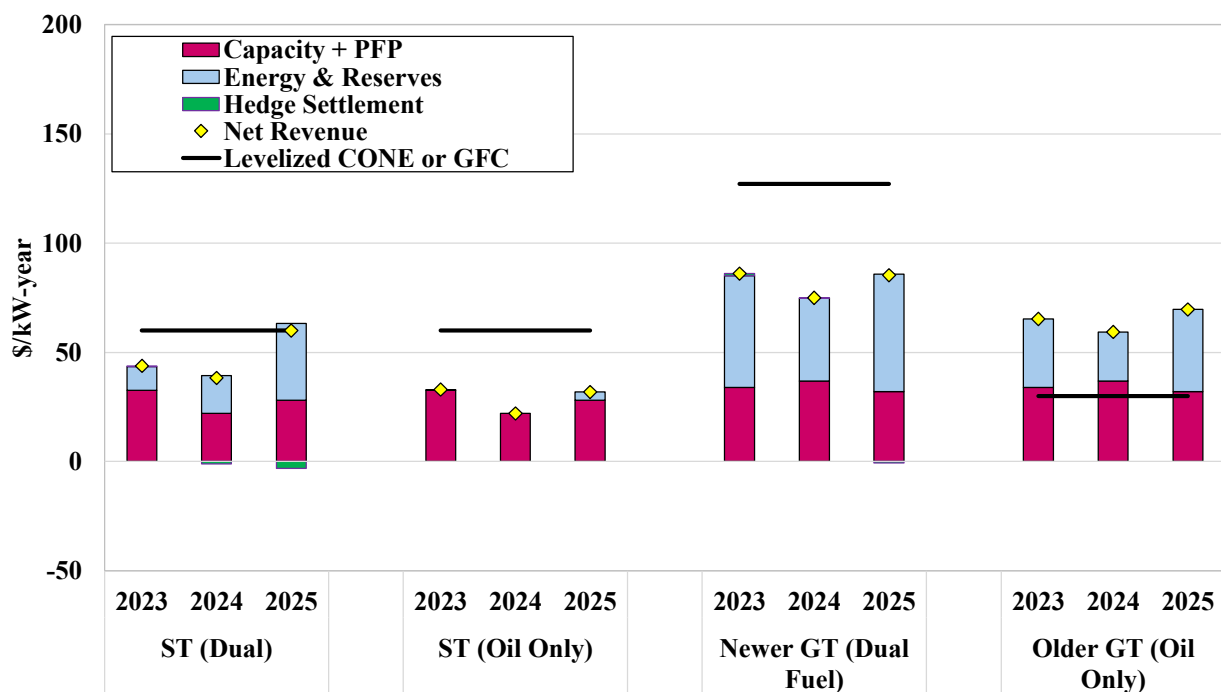


Figure 9: Net Revenues and Costs of Steam Turbine and Combustion Turbine Generators
2016 - 2025



Our analysis of net generator revenues shows the following:

- Net revenues exceed going-forward costs for many older combined-cycle and combustion turbine units. Revenues for newer units were often near or below their fixed costs, which include recovery of investment costs. Some newer units benefited from seven-year lock-in of relatively capacity rates secured in the late 2010s (not shown). By contrast, older steam turbine units appear to earn relatively little revenue, and some of these resources have cleared retirement offers in recent Forward Capacity Auctions.
- Dual-fueled combined-cycle units earned an estimated \$12 to \$19 per kW-year more than gas-only CCs over the three-year period. Dual-fuel generators earn additional revenues by burning oil during winter gas price spikes. Periods of extreme forward power and gas price uncertainty, such as in winter 2023 following the outbreak of the Ukraine war the preceding year, also allow dual-fuel units to lock in substantial forward margins.

Overall, although some existing generators likely earn revenues far exceeding their GFCs, fossil-fuel generator profits are a small component of retail rates. Based on the estimates in Figure 8 and Figure 9, total fossil generator profits divided by ISO-NE load were about 0.5 cents per kWh in 2023-2025 (about 2 percent of the residential retail rate). We did not assess the profits of nuclear and renewable facilities, many of which sell power under long-term contractual arrangements with states or utilities.

Generator profits reward capital investment and risk-taking by investors who are also exposed to losses when market conditions are unfavorable. Although fossil generator profits overall make up a small share of retail rates, their impact may rise if market conditions tighten in the future. Therefore, it is important to assess the adequacy of the market power mitigation measures on an ongoing basis as supply margins tighten.²⁵ In addition, it is worth considering whether elements of the wholesale market design that affect overall generator profits are appropriately calibrated. The following subsection discusses evidence that ISO-NE's capacity market demand curves do not adequately consider the long-term value of generator investments, which can lead to inflated estimates of the net cost of new entry.

D. Evidence on Economic Life of Fossil Generators

Estimates of the net cost of new entry ("net CONE") for a fossil fuel-fired generator are often based on the assumption that it will have a 20-year economic life. However, as shown in the previous subsection, when capacity margins are small, market revenues significantly exceed the GFCs of most existing generators that are more than 20 years old. This reflects that most generators still have significant residual value at the end of their first 20 years of operation. This subsection reviews information from recent transactions about the residual value of existing generation assets and how this is likely to affect the cost of new entry.

²⁵ See discussion of the market power mitigation measures in Section III.E.

Several major M&A transactions involving portfolios composed primarily of gas-fired generators in the US RTO markets were completed or announced in 2025 and early 2026. Tight market conditions driven by load growth and recent generator retirements likely drove these deals. Although many of the assets were outside New England, their valuations provide insight into the market value of older gas-fired generators under rising demand.

Table 3 summarizes recent transactions, including the share of each portfolio consisting of gas CC and CT units, the age of the generators purchased, and the purchase price per kW of capacity. All ten transactions consisted primarily of CC and CT assets, and in many cases, all or most of the portfolio consisted of generators over 20 years old. These generators retained significant value after more than 20 years, with older generator portfolio valuations ranging from 31 to 52 percent of the capital cost of the FCA18 Net CONE unit capital cost.

Table 3: Summary of Recent Gas-Fired Portfolio Transactions in US Wholesale Markets²⁶

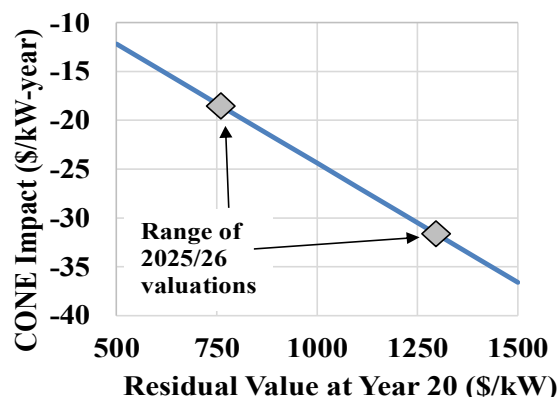
Transaction Close	Buyer	Seller	Primary Markets	Total Capacity (GW)	Percent Gas CT	Percent Gas CC	Price per kW	Average Age of CC and CT (Years)	Percent of CC/CT over 20 Years Old
Jun-25	Capital Power	LS Power	PJM	2.1	46%	54%	1,060	15	46%
Jun-25	Partners Group	Avenue Capital	CAISO	1.9	35%	63%	1,128	22	80%
Sep-25	CPS	ProEnergy	ERCOT	1.6	100%	0%	865	3	0%
Oct-25	Vistra	Lotus	PJM, ISO-NE, NYISO	2.5	8%	92%	760	24	87%
Nov-25	Talen Energy	Caithness / BlackRock	PJM	2.9	0%	100%	1,343	4	0%
Jan-26	Constellation	Calpine	ERCOT, CAISO, PJM, ISO-NE	27.4	5%	87%	969	23	81%
Jan-26	NRG	LS Power	PJM, ERCOT, NYISO	12.7	48%	35%	1,024	24	84%
2026 (expected)	LS Power	Constellation	PJM	4.4	0%	84%	1,139	20	61%
2026 (expected)	Talen Energy	ECP	PJM	2.7	19%	81%	1,296	23	100%
2026 (expected)	Vistra	Cogentrix	PJM, ERCOT, ISO-NE	5.1	20%	80%	789	19	57%

ISO-NE has historically assumed a 20-year economic life for the proxy unit used to set the capacity market demand curves. This creates an upward bias in the estimated Net CONE, which would be lower if the estimate considered the residual value the unit retains after 20 years.

²⁶ Purchase prices and lists of assets in each portfolio are from publicly reported details. Since capacity amounts are not reported in uniform units in the trade press (e.g. nameplate vs. net capacity), we show the average summer and winter net capacity for each portfolio based on EIA data and calculate the price per kW based on the publicly reported total purchase price. NRG's acquisition of assets from LS Power also included the CPOWER demand response platform in addition to the generation portfolio shown.

Figure 10 estimates the range of potential residual value impacts on Net CONE based on capacity sold in recent deals. Table 1 reports seven deals where the average age of capacity was between 19 and 24 years and the residual value ranged from \$760 to \$1,296 per kW. The figure shows how these residual valuations would affect the annualized CONE of a generator built 20 years earlier. A more thorough assessment of residual value might consider valuation adjustments applicable to the proxy unit technology (many of the recent portfolios include CCs), location, and future market expectations that are less favorable than those underlying recent transactions. We recommend that Future Net CONE studies consider residual value.

Figure 10: Residual Value Impact on 20-Year CONE Estimate



E. Conclusions

This section summarizes trends in residential retail rates in New England and analyzes how wholesale prices have contributed to them. Although residential rates have risen by almost 14 percent in real terms since 2021, the primary drivers have been non-wholesale market costs, including regulated transmission and distribution. Wholesale market costs have been relatively flat with energy cost increases caused by gas infrastructure constraints, fuel costs and emissions allowance costs have been offset by falling capacity costs.

Most residential customers in New England pay electric supply rates that IOUs lock in through RFPs conducted months in advance. These rates are driven mainly by forward energy price expectations, although they routinely exhibit a substantial premium over the prices of financial futures for ISO-NE products. Although some generators may earn net revenues through these RFPs and the ISO-NE markets that exceed their going-forward costs, the total impact on residential retail rates is very small. This suggests that competitive discipline in the ISO-NE markets has helped constrain retail rate increases over time.

Our analysis suggests that the following actions by ISO-NE and policymakers could slow or reverse rising electricity rates:

- **Permitting natural gas transport and/or storage infrastructure.** Although environmental policy considerations and the need for cooperation from New York State policymakers make this complex, gas infrastructure improvements would likely reduce electricity market prices more than any other single factor. They would do so by reducing New England's gas price premium, which generators pass through to wholesale prices.
- **Permitting dual-fuel generation capacity.** This is one of the lowest-cost means to address winter reliability concerns with little emissions impacts. New dual-fuel generation is likely economic without subsidies, particularly as capacity prices rise from

recent lows. Generation that is profitable without subsidies lowers consumer costs by adding additional supply in the capacity market and during fuel-constrained winter storm conditions. The capacity accreditation enhancements in the Capacity Auction Reform: Seasonal/Accreditation (“CAR-SA”) project may create long-term economic incentives to retrofit existing gas-fired generation with oil-fired capability if such projects can be permitted.²⁷ The back-up oil capability would produce negligible emissions since it would rarely be utilized, but would substantially improve winter reliability.

- **Changes to forward contracting practices.** Over the past decade, IOUs’ supply costs have exceeded the prices of financial futures that settle against ISO-NE prices by 16 percent. Our experience in the New York market, where utilities use a combination of physical and financial hedges to cover part but not all of their supply costs, suggests that alternative strategies may produce lower average rates than the mandatory full-service procurements that are common in New England.
- **Include Residual Value Estimate in Net CONE.** The Net CONE values used in the capacity market have historically assumed that investments must be fully recovered in twenty years. However, evidence after ~25 years of US RTO markets suggests that modern CT and CC units continue to have substantial value after twenty years. Reflecting this in capacity market Net CONE would result in more reasonable prices by recognizing units’ long-term revenue potential. It also highlights one benefit to consumers of non-discriminatory capacity pricing that treats existing and new generation on equal terms.

²⁷

The costs to upgrade an existing gas-fired unit to dual fuel capability (including combustion and fuel storage) are significant but lower than construction of a new plant. A 2016 Department of Energy study estimated the cost of field-installed dual fuel modifications for a gas turbine at \$54,000 per MW (approx. \$75,000 per MW in 2025 dollars). See “ISO New England Dual Fuel Capabilities to Limit Natural Gas and Electricity Interdependencies”, April 22, 2016, DOE/NETL-2015/1701, available [here](#).

III. COMPETITIVE ASSESSMENT OF THE ENERGY & RESERVE MARKETS

This section evaluates the competitive performance of the ISO-NE energy market in 2025. Although LMP markets generally increase economic efficiency, they can also reveal incentives to exercise market power in areas with limited generation resources or transmission capability. Market power in wholesale electricity markets is often dynamic and exists only in certain areas under particular conditions. The ISO employs market power mitigation measures to prevent suppliers from exercising market power under these conditions. Although these measures have generally been effective, it is still necessary to evaluate the competitive structure and conduct in the ISO-NE markets because participants may still have incentives to exercise market power below mitigation thresholds.

In this section, we identify the geographic areas and market conditions with the greatest potential for market power abuse based on our analysis. We use a methodology developed in prior assessments of ISO-NE's competitive performance to identify competitive concerns.²⁸ This section addresses five main areas:

- Mechanisms sellers use to exercise market power in LMP markets;
- Structural market power indicators to assess competitive market conditions;
- Potential economic and physical withholding;
- Market power mitigation in the real-time market; and
- Market power mitigation in the day-ahead ancillary services market.

These evaluations allow us to assess the competitive performance of the ISO-NE markets.

A. Market Power and Withholding

In electricity markets, supplier market power is the ability to profitably raise prices above competitive levels by withholding generating capacity, either economically or physically.

- **Economic withholding** occurs when a supplier offers a resource at prices above competitive levels, thereby reducing its output or otherwise raising market clearing prices.
- **Physical withholding** occurs when a supplier does not offer some or all of a resource's available and economic output into the market to raise clearing prices above competitive levels. For example, a supplier can implement this strategy by "derating" a generating unit (i.e., reducing its maximum operating limit).

Although many suppliers can influence prices through economic or physical withholding, not all can do so profitably. Withholding is profitable only when the gains from selling the remaining supply at elevated prices exceed the lost profits from the withheld output. In other words, the

²⁸ See, e.g., Section VIII, 2013 Assessment of Electricity Markets in New England, Potomac Economics.

price increase must outweigh the opportunity cost of foregone sales. Larger suppliers, which have a greater share of total market capacity, are generally more likely to have both the ability and the incentive to withhold resources profitably. In addition to supplier size, several factors affect the potential to exercise market power:

- **Sensitivity of clearing prices to withholding:** Prices can be highly sensitive to withholding during high-load conditions or in congested local areas;
- **Forward contracts:** These reduce a supplier's incentive to raise market prices;²⁹ and
- **Information availability:** Access to timely, accurate market information can help suppliers anticipate when the system is most vulnerable and time withholding strategies more effectively.

B. Structural Market Power Indicators

This subsection examines structural aspects of supply and demand that affect market power. Market power is most likely in areas with small capacity margins, particularly import-constrained areas. Accordingly, this subsection analyzes the three main import-constrained regions and all of New England using the following structural market power indicators:

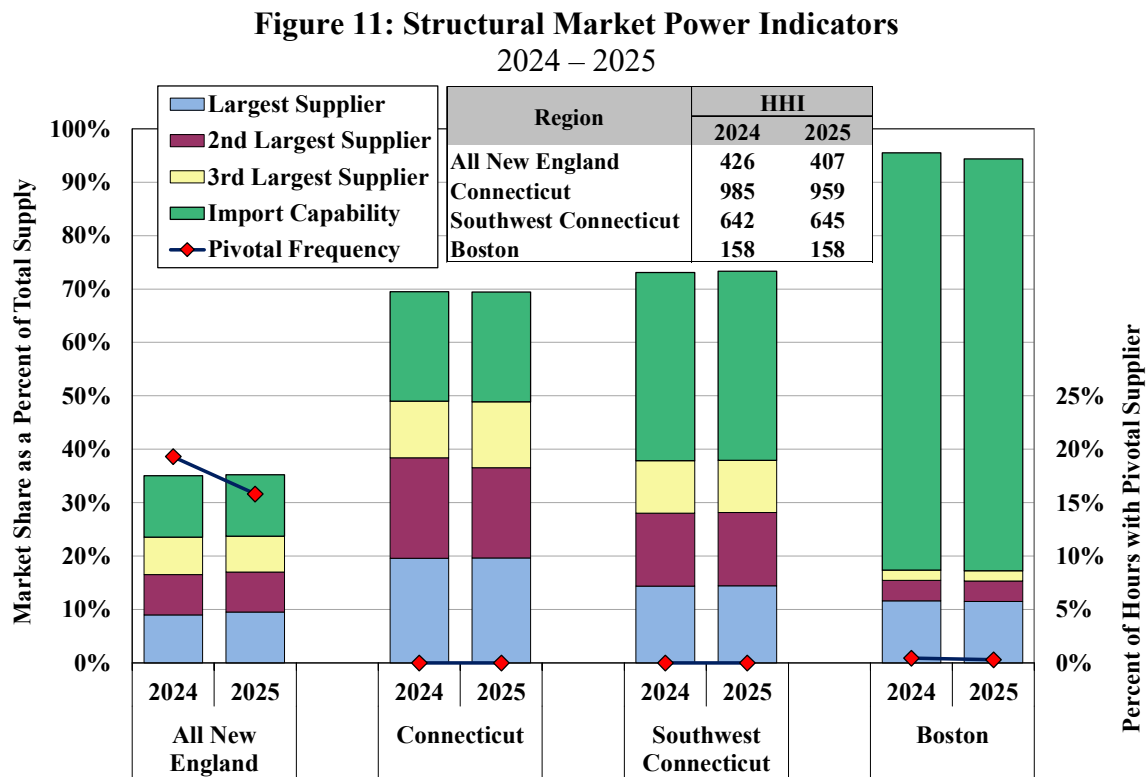
- **Supplier Market Share:** The market shares of the largest suppliers determine the possible extent of market power in each region.
- **Herfindahl-Hirschman Index (HHI):** This standard measure of market concentration is calculated by summing the squares of each participant's market share.
- **Pivotal Supplier Test:** A supplier is pivotal when some of its capacity is needed to meet demand and reserve requirements. A pivotal supplier can unilaterally raise spot market prices by raising its offer prices or by physically withholding generating capacity.

The first two structural indicators focus exclusively on the supply side. Although they are often used to analyze other industries, they are less useful in electricity markets because they ignore how inelastic electricity demand affects competition.

The Pivotal Supplier Test is a more reliable way to evaluate the competitiveness of electricity markets because it recognizes the importance of both supply and demand. Whether a supplier is pivotal depends on its size and the amount of excess supply (above demand) held by other suppliers. When one or more suppliers are pivotal, the market may be vulnerable to market power abuse, but not all pivotal suppliers have market power. Suppliers with market power must have both the *ability* and *incentive* to raise prices. A supplier must also foresee when it will be pivotal to exercise market power. This becomes easier when a supplier is pivotal more often. Finally, a supplier must also have a way to benefit from the higher prices (e.g., other resources or contracts that would receive the inflated price).

²⁹ When a supplier's forward power sales exceed the supplier's real-time production level, the supplier is a net buyer in the real-time spot market, and thus, benefits from low rather than high prices. However, some incentive to withhold may still exist because spot prices will eventually affect prices in the forward market.

Figure 11 shows three structural market power indicators for four regions over the past two years. The stacked bars show the market shares of the three largest suppliers and the import capability in each region. Smaller suppliers hold the remaining supply in each region.



The import capability and market shares are based on public ISO-NE data, and the inset table shows the HHI for each region.³⁰³¹ We assume imports are highly competitive and treat their market share as zero in the HHI calculation. The red diamonds indicate the portion of hours when one or more suppliers were pivotal in each region. We exclude potential withholding from nuclear units because they have limited flexibility and because withholding them would be costly given their low marginal costs.

Figure 11 shows that the market concentration of internal generation remained relatively stable across all regions from 2024 to 2025. Although asset ownership changed over the past two years, these shifts did not significantly affect the top suppliers' market shares in each region. Market concentration varied significantly across the four regions. In Boston, import capability accounted for 78 percent of total supply, including internal generation and imports. By contrast,

³⁰ The market shares of individual firms are based on information in the monthly reports of Seasonal Claimed Capacity (SCC), available at: <https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/season-claim-cap>. In this report, we use the generator summer capacity in the July SCC reports from each year.

³¹ The import capability shown is the transmission limit from the latest Regional System Plan, available at: <https://www.iso-ne.com/system-planning/system-plans-studies/rsp>. The *Capacity Import Capability* is used for external interfaces, and the N-1-1 Import Limits are used for reserve zones.

in all New England, the three largest suppliers each held relatively small, comparable market shares below 10 percent, while import capability accounted for 11 percent of total supply.

Market concentration, as measured by the HHI, remained low in 2025, with values below 1,000 in all regions. For context, the U.S. Antitrust Agencies and FERC typically consider HHI values above 1800 highly concentrated when evaluating the competitive effects of mergers. However, low HHI values do not necessarily eliminate market power concerns. Pivotal supplier analysis assesses these concerns more accurately, indicating that:

- There were almost no hours with a pivotal supplier in Southwest Connecticut and Connecticut.
- In Boston, pivotal supplier frequency remained very low at just 0.3 percent of hours in 2025, even after two large combined-cycle units retired in 2024. These infrequent instances generally coincided with minimal congestion into the Boston area.
- Across New England, at least one supplier was pivotal in 16 percent of hours.³²

The persistently low pivotal supplier frequency and minimal congestion in Boston over the past two years were mostly attributable to transmission upgrades that greatly increased import capability. This result underscores the importance of import capability into constrained areas for providing competitive discipline.

Across New England, the pivotal supplier frequency fell modestly from 2024 to 2025 because of several factors:

- *Load levels* – This reduction occurred mostly in the summer months, when average load fell by 3 percent year-over-year even as peak load increased by 7 percent. This pattern reflects continued growth in behind-the-meter solar, which significantly reduced net load in the summer but contributed relatively little at the peak because the peak load hour shifted later in the day (to hour-ending 19 in 2025).
- *New supply patterns* – Net imports from Quebec continued to decline in 2025, partly because of lower rainfall and reduced hydroelectric output.³³ Quebec became a net importer from New England in the last three months of 2025, a pattern not seen in previous years. This was partially offset by higher imports from New Brunswick, higher output from intermittent renewable generation because of new capacity additions, and higher nuclear generation because of fewer maintenance and forced outages.
- *Day-ahead ancillary services market* – ISO-NE implemented the DA A/S market in March 2025, which incentivized suppliers to be available, particularly during tight system

³² The pivotal supplier results are conservative for “All New England” compared to those of the IMM partly because of the differences in: (a) treatment of nuclear generation; (b) supply availability assumptions; and (c) frequency of pivotal evaluation. See the memo, “Differences in Pivotal Supplier Test Results in the IMM’s and EMM’s Annual Market Assessment Reports”, NEPOOL Participants Committee Meeting, Dec. 7, 2018.

³³ Our pivotal supplier analysis is based on actual import schedules, which is conservative because it may underestimate the amount of competitive supply available in a given hour. This is due to the presence of additional unused import capability that is offered into ISO-NE’s real-time market but not scheduled.

conditions. This market design change contributed to an increase in average surplus capacity in the real-time market by 175 MW year-over-year and the associated reduction in pivotal supplier frequency.³⁴

Together, these shifts in supply, demand, and market design contributed to the decline in pivotal supplier frequency. The next subsection examines supplier conduct across New England.

C. Economic and Physical Withholding

Suppliers with market power can exercise it through economic or physical withholding. We measure potential withholding using the following metrics:

- **Economic withholding:** we estimate an “output gap” for units that produce less output because they raised their economic offer parameters (start-up, no-load, and incremental energy) significantly above competitive levels. The output gap is the difference between a unit’s capacity that would be economic at the prevailing clearing price and its actual output.³⁵
- **Physical withholding:** we focus on short-term deratings and outages because they are more likely to represent strategic physical withholding. Withholding through a long-term outage would be more costly because it would cause larger lost profits in hours when the supplier does not have market power.

The following analysis shows the output gap and short-term physical deratings relative to load and supplier size because market power is most likely when load is high (and excess supply held by competitors is low) for larger suppliers. Correlating conduct with load and supplier size helps test whether the output gap and short-term physical deratings rise when the exercise market power is more likely to be successful.

Because the pivotal supplier analysis raises potential competitive concerns throughout New England, Figure 12 shows the output gap and short-term physical deratings by load level for the region. It calculates the output gap separately for:

- **Offline quick-start units** that would have been economic to commit in the real-time market, considering commitment costs; and
- **Online units** that can economically produce additional output.

Our short-term physical withholding analyses examine:

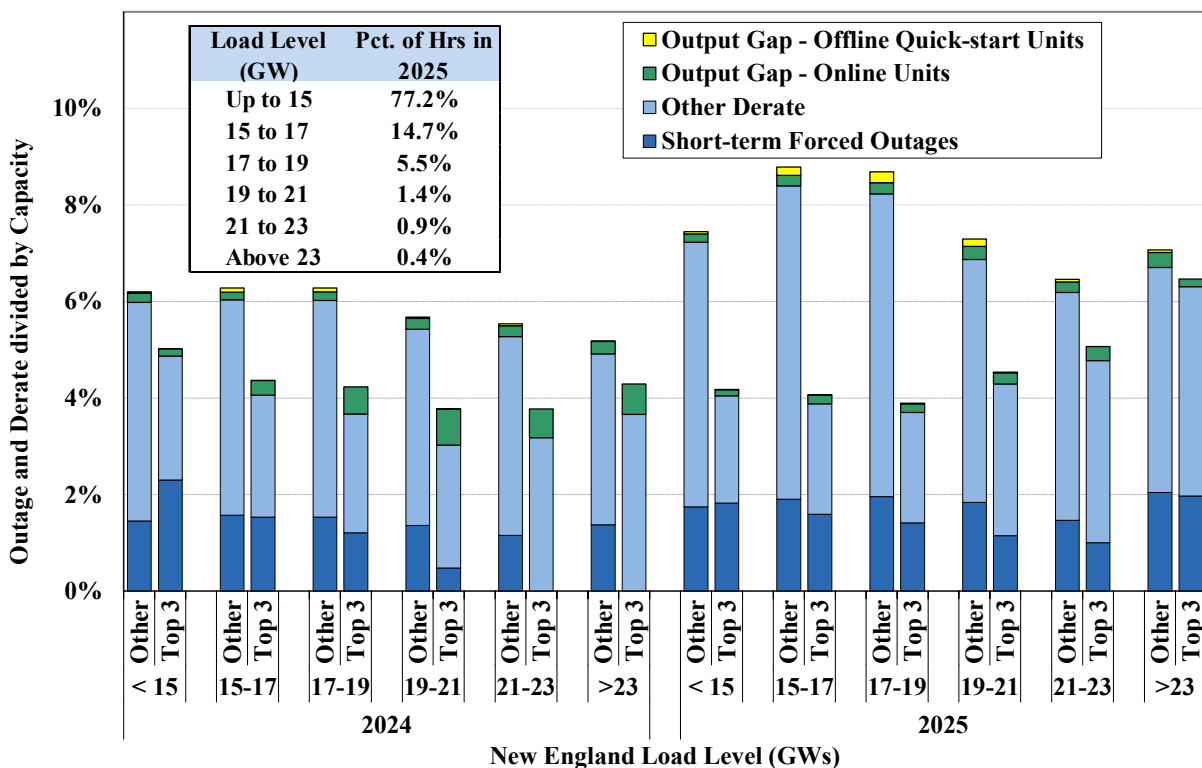
- **Short-term forced outages** that usually last less than one week; and
- **Other derates**, including reductions in a unit’s capability not logged as forced or planned outages. These can result from ambient temperature changes or other legitimate factors.

³⁴ Surplus capacity is defined as the headroom from online resources, along with available offline quick-start resources, after accounting for energy and ancillary services requirements.

³⁵ To identify clearly economic output, the supply’s competitive cost must be less than the clearing price by more than a threshold amount - \$25 per MWh for energy and 25 percent for start-up and no-load costs.

Figure 12 shows these metrics as a percentage of suppliers' portfolio size and distinguishes the largest suppliers from other suppliers over the past two years. The analysis compares the three largest suppliers, which collectively owned and/or controlled approximately 27 percent of internal generating capacity in both years, with all other suppliers.

Figure 12: Average Output Gap and Deratings by Load Level and Type of Supplier
All New England, 2024 – 2025



The figure shows that the “Other Derate” category was usually higher than the other categories. This category includes instances when suppliers offered and operated some combined-cycle capacity in configurations with reduced capability during off-peak hours. This operationally efficient practice generally does not raise competitive concerns. In addition, high ambient temperatures and humidity during summer peak load hours often reduce the capacity ratings of thermal resources and contribute to this category of derates. The overall output gap and deratings in 2025 were modest relative to total system capacity.

The output gap and short-term deratings generally declined as load levels increased. The output gap was particularly low during the highest load hours (above 23 GW), when prices were most sensitive to withholding. Although short-term forced outages, including “Other Derate”, rose modestly during these periods, the increase was largely associated with heat waves. High temperatures during these events reduced thermal unit capacity ratings and increased mechanical failure rates. In addition, the largest suppliers generally exhibited lower levels of output gap and short-term deratings than smaller suppliers, especially at higher load levels. Together, these

patterns support the conclusion that supplier behavior, particularly among large suppliers, was consistent with competitive conduct when market conditions were most critical.

Overall, these results indicate that the energy market was competitive in 2025, with no significant evidence of withholding intended to raise market clearing prices.

D. Market Power Mitigation in the Real-Time Market

Mitigation measures limit market power abuses while minimizing interference when the market is workably competitive. ISO-NE uses a conduct-and-impact test framework to determine whether to mitigate a participant's supply offers (including incremental energy offers, start-up offers, and no-load offers). It imposes mitigation only when suppliers' conduct exceeds well-defined thresholds above a unit's reference levels and the effect on market outcomes exceeds specified impact thresholds. This framework ensures that mitigation is used only when necessary to address market power, while allowing high prices during legitimate shortage periods.

In import-constrained areas, the market can be substantially more concentrated, requiring more restrictive conduct and impact thresholds than those used market-wide. The ISO uses two structural tests (i.e., Pivotal Supplier and Constrained Area Tests) to determine which of the following mitigation rules apply:³⁶

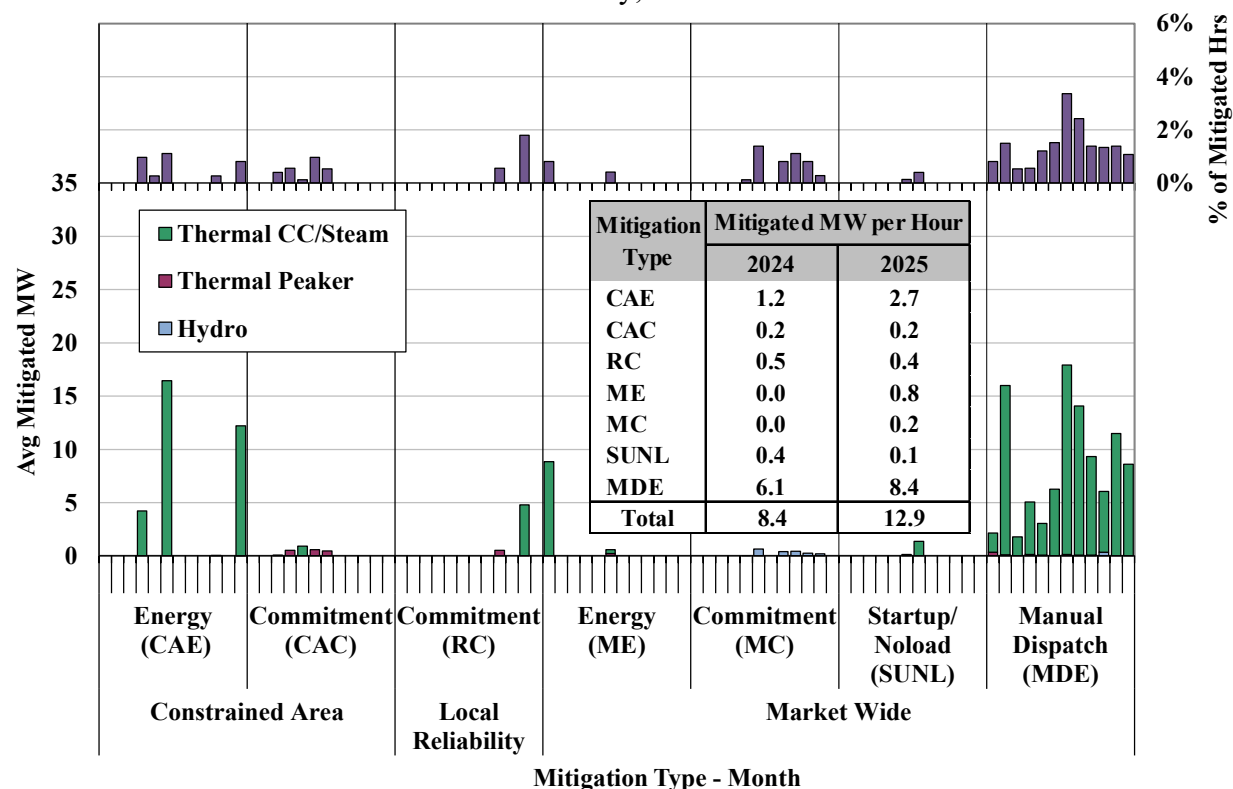
- **Market-Wide Energy Mitigation (ME):** ME mitigation evaluates the incremental energy offers of online resources. It is applied to any resource whose Market Participant is a pivotal supplier.
- **Market-Wide Commitment Mitigation (MC):** MC mitigation evaluates commitment offers (i.e., start-up and no-load costs). It is applied to any resource whose Market Participant is a pivotal supplier.
- **Constrained Area Energy Mitigation (CAE):** CAE mitigation is applied to resources in a constrained area.
- **Constrained Area Commitment Mitigation (CAC):** CAC mitigation is applied to a resource committed to manage congestion into a constrained area.
- **Local Reliability Commitment Mitigation (RC):** RC mitigation is applied to a resource committed or kept online for local reliability.
- **Start-up and No-load Mitigation (SUNL):** SUNL mitigation is applied to any resource committed in the market.
- **Manual Dispatch Mitigation (MDE):** MDE mitigation is applied to resources dispatched out of merit above their Economic Minimum Limit levels.

There are no separate impact tests for SUNL mitigation, MDE mitigation, or the three types of commitment mitigation (i.e., MC, CAC, and RC). Consequently, suppliers are mitigated if they fail the conduct test in any of these five categories. This approach is reasonable because this

³⁶ See Market Rule 1, Appendix A, Section III.A.5 for details on these tests and thresholds.

mitigation normally affects only uplift payments, which increase as offer prices rise. Therefore, it is unnecessary to determine whether an offer that failed the conduct test affected the payment to the generator. When a generator is mitigated, all offer cost parameters are set to their reference levels for the entire hour. Figure 13 examines the frequency and quantity of mitigation in the real-time market in each month of 2025. This analysis excludes mitigation changes made after the automated mitigation process, which constitute a very small share of overall mitigation.

Figure 13: Frequency of Real-Time Mitigation by Mitigation Type and Unit Type
Monthly, 2025



The upper portion of Figure 13 shows the share of hours affected by each type of mitigation. If multiple resources were mitigated in the same hour, the figure counts only one hour. The lower portion shows the average mitigated capacity per month (i.e., total mitigated MWh divided by total hours in each month) for each type of mitigation and for hydroelectric units, thermal peaking units, and thermal combined cycle and steam units. The inset table compares the average annual amount of mitigation for each type over the past two years.

Mitigation has been infrequent in recent years, occurring in approximately 2.6 percent of all hours in 2025, up modestly from 2024. In 2025, more than 70 percent of real-time market mitigation was for manual dispatch energy and local reliability commitment. This high proportion is expected because local reliability areas raise the greatest market power concerns and are mitigated under the tightest thresholds. Likewise, units manually dispatched for energy are selected outside the normal economic evaluation of offers, so competition does not

necessarily discipline their offers. These two mitigation categories typically affect only NCPC payments and have little effect on energy or ancillary service prices. Most MDE mitigation was on combined-cycle units that operators typically instructed to provide regulation service or dispatched manually to address transient network issues.

Effective mitigation depends on accurate generator cost estimates (i.e., “reference levels”). High reference levels allow suppliers to inflate prices and/or NCPC payments above competitive levels. Low reference levels may lead to mitigation below cost and inefficiently suppress prices. Estimating costs accurately is challenging for certain generators, including:

- **Energy-limited hydroelectric and battery storage resources:** Their costs consist almost entirely of opportunity costs (the trade-off between producing more now and producing or not charging later), which are difficult to reflect accurately.
- **Oil-fired resources during tight gas supply periods:** These units become economic when gas prices rise above oil prices. However, with limited on-site oil inventory, suppliers may raise offer prices to conserve oil for periods with potentially higher LMPs.
- **Gas-fired resources during tight gas supply periods:** Volatile winter natural gas prices create fuel cost uncertainties that can be difficult to reflect accurately in offers and reference levels. The requirement to determine day-ahead market offers and reference levels by 10 am the prior day exacerbates this uncertainty.

Recognizing opportunity costs appropriately in resources’ reference levels reduces inappropriate mitigation of competitive offers, conserves limited fuel supplies and improves scheduling efficiency for fuel-limited resources. ISO-NE uses a model to estimate opportunity costs for oil-fired and dual-fuel generators with short-term fuel supply limitations and include them in reference prices. The model estimates opportunity costs by forecasting each fuel-limited unit’s profit-maximizing generation schedule over a rolling seven-day period and the opportunity cost adder (“Energy Market Opportunity Cost” or “EMOC”) required to limit generation accordingly.

Market-wide energy mitigation has been rare in recent years. Before 2025, it last occurred on December 24, 2022, when nine resources in one Lead Market Participant’s portfolio were inappropriately mitigated over multiple hours. This significantly affected market outcomes on this day. Our 2022 report identified several aspects of the mitigation measures that resulted in inefficient outcomes.³⁷ Although the ISO has addressed two issues raised in that report, we continue to recommend that it implement the following revision to the real-time energy mitigation process (Recommendation #2022-2a):

- a) *Implement hourly conduct and impact tests: Mitigate resources only in hours when they fail both conduct and impact tests.*

Although we have consistently observed competitive outcomes in the real-time market, changes in the New England market could increase the potential for market power over time. Recently-

³⁷ See 2022 Assessment of The ISO New England Electricity Markets, Potomac Economics, June 2023.

announced acquisitions have increased or will increase the sizes of the largest portfolios. Generator retirements, increased load growth, and reduced imports from Canada have reduced capacity margins. In addition, the ISO is proposing changes under the CAR-SA project that will reduce the share of fossil-fuel generators with Capacity Supply Obligations (“CSOs”) during the winter. This change will reduce the share of installed capacity that is not subject to the physical withholding mitigation measures. Because of these changes, it would be appropriate to evaluate the adequacy of the market power mitigation thresholds. Therefore, we support the Internal Market Monitor’s recommendation:

#2023-1 to Review mitigation thresholds and reference level methodologies, eliminate mitigation exemptions for non-capacity resources, and extend mitigation to export-constrained areas.

E. Market Power Mitigation under Day-ahead Ancillary Services Markets

Launched on March 1, 2025, the DA A/S markets enhance the ISO’s ability to satisfy the reliability needs by procuring ancillary services in the day-ahead market. The ISO introduced four new day-ahead ancillary service products. Three of these, Ten-Minute Spinning Reserves (“TMSR”), Ten-Minute Non-Spinning Reserves (“TMNSR”), and Thirty-Minute Operating Reserves (“TMOR”), are Flexible Response Services (“FRS”) and align with the real-time reserve products used to manage system contingencies. The fourth product, Energy Imbalance Reserves (“EIR”), ensures that physical suppliers clear sufficient energy and EIR to satisfy forecasted load in the day-ahead market. The day-ahead market co-optimizes scheduling of all four products with energy and clears them using marginal-cost pricing.

DA A/S schedules are settled as call options on energy based on real-time clearing prices, giving generators not scheduled for energy in the day-ahead market stronger incentives to be available in the real-time market. For each hour of the day-ahead market, participants submit a single maximum quantity amount of ancillary services they are willing to provide across all four eligible products. They may also submit up to separate prices for each reserve product.

Like energy offers, DA A/S offers are subject to mitigation measures that prevent the exercise of market power. The mitigation framework includes the following components:

- **Conduct Test:** The conduct test identifies reserve offers that exceed a threshold, which equals the sum of: (a) the greater of either twice the expected close-out cost or \$2 per MWh, and (b) 1.5 times the avoidable input cost to cover the day-ahead reserve schedule.
- **Price Impact Test:** If at least one offer fails the conduct test, the impact test evaluates whether the conduct-failing offers materially affected day-ahead market prices. If the impact test identifies a sufficiently large effect on one or more day-ahead market prices, all conduct-failing offers are mitigated to their calculated Benchmark Levels.³⁸

³⁸ The price impact threshold is 150 percent of median of the hourly difference between conduct test thresholds and Benchmark Levels across all available resources with DA A/S offers.

- **Benchmark Levels:** The estimated close-out cost of reserves (estimated using the Gaussian Mixture Model which runs initially at 5:30 AM and again at 10:30 AM using updated inputs such as load forecasts) and estimated avoidable input costs.
- **Ex Ante Consultation with the IMM:** Participants may consult the IMM and submit analytically supported override requests so the IMM can consider their specific cost expectations.

This mitigation structure is designed to deter exercises of market power and support efficient pricing, while allowing offer flexibility for legitimate cost deviations and reasonable variations in risk tolerances associated with selling these option-based ancillary services. Mitigating offers that reflect these factors is unwarranted and undermines market performance. Therefore, ongoing evaluation of the mitigation framework is necessary to ensure its effectiveness.

Our analysis of mitigation outcomes during the initial implementation of DA A/S markets indicated that mitigation occurred far more frequently than in the energy market. In addition, each mitigation instance typically involved a substantial volume of reserve offers and disproportionately affected smaller suppliers that are unlikely to possess market power.³⁹ Mitigation also frequently occurred during low- to moderate-load conditions rather than during tight system conditions, when market power concerns were typically most acute.

We found that one primary reason for the relatively frequent market power mitigation is the small size of the mitigation thresholds. The threshold formulas described above are based in part on the expected close-out costs for the option-based reserve products. Because the expected close-out costs are frequently near or below \$1 per MWh and the avoided input costs are generally low or zero, participants can begin to violate the conduct threshold by offering more than \$2 per MWh. However, actual close-out costs have been volatile and frequently above \$20 per MWh. Hence, this conduct threshold is likely to interfere with competitive participants reflecting reasonable assessments of risk and legitimate risk preferences. Similarly, the impact threshold in this case can be as low as \$1.50 per MWh, which is likely too low to warrant market power mitigation. As a result, the mitigation framework appears overly sensitive, mitigating competitive conduct rather than the exercise of market power.

Based on these findings, we recommended that ISO-NE evaluate its current conduct and impact thresholds used in the DA A/S markets and, if necessary, revise them to avoid overly aggressive mitigation that may unduly burden smaller suppliers without addressing actual market power concerns (Recommendation #2024-2).

³⁹ See Figure 12 in our 2024 Assessment of the ISO New England Electricity Markets.

IMM Recommendations and ISO-NE Proposed Changes

In February 2026, the IMM issued recommendations to improve the efficiency of the DA A/S market design.⁴⁰ These recommendations addressed inefficiencies observed during the market's first year, including issues with price formation, procurement levels, and incentive alignment.

Key recommendations included:

- **Adjusting the Forecast Energy Requirement** to better reflect the expected contribution of front-of-the-meter renewable resources;
- **Increasing the Strike Price**, including consideration of a floor aligned with the short-run marginal cost of key suppliers; and
- **Reassessing the Non-Performance Factor (NPF)** used in reserve requirements to reflect improved generator performance.

The ISO has supported these recommendations and proposed corresponding changes to the DA A/S design, including:⁴¹

- A downward adjustment to the FER demand quantity to reduce over-procurement when intermittent renewable generators schedule less than their forecasted output in the day-ahead market;
- Implementation of a strike price floor based on the estimated marginal cost of an efficient combustion turbine; and
- A targeted revision to the mitigation framework to address issues the IMM's and EMM's analyses identified.

We support these changes because they address inefficiencies in the current design while maintaining appropriate incentives for performance and participation. In particular, introducing a floor on the Impact Test Threshold ("ITT") would help address the concern underlying Recommendation #2024-2. The ISO proposes a minimum ITT of \$3 per MWh to prevent the threshold from becoming excessively stringent in low-price conditions. Under the current design, the ITT can fall to very low levels when expected closeout costs are small, increasing the likelihood of mitigation when market power is unlikely to be a concern. This issue was a key driver of the frequent mitigation of smaller suppliers during the initial implementation of DA A/S markets.

Overall, the ISO's proposed changes address the IMM's and EMM's findings and should improve price formation efficiency, reduce unnecessary costs, and maintain appropriate performance incentives. These adjustments are incremental but meaningful improvements to the DA A/S market design and we support them.

⁴⁰ See memo *Recommended Changes to the Day-Ahead Ancillary Services Market* to ISO New England from David Naughton, Executive Director, Internal Market Monitor, dated February 4, 2026.

⁴¹ See memo *Adjustments to the Day-Ahead Ancillary Services Market* to NEPOOL Participants Committee from Rosendo Garza, NEPOOL Counsel, dated June 9, 2026.

F. Competitive Performance Conclusions

Overall, we find little evidence that suppliers exercised market power in New England, either at the system level or in sub-regions. Our evaluation of participant conduct also indicates that the markets performed competitively, with no evidence of market power abuse or manipulation in 2025. However, recent and one pending acquisition, along with reduced imports from Canada and generator retirements, have increased indications of potential structural market power in the form of rising pivotal supplier frequencies since 2022. To ensure the market power mitigation measures remain effective, we support the Internal Market Monitor's recommendation #2023-1 *to review mitigation thresholds and reference level methodologies, eliminate mitigation exemptions for non-capacity resources, and extend mitigation to export-constrained area.*

We also continue to recommend revisions to the current energy mitigation process to address an inefficiency identified in our 2022 annual report (Recommendation #2022-2a). Specifically, we recommend that the ISO implement hourly conduct and impact tests to ensure it does not impose mitigation when a resource's conduct or prevailing competitive conditions no longer warrants it.

In addition, we find that market power mitigation in the DA A/S market has occurred more frequently and in higher volumes than expected, often during low- to moderate-load conditions when market power concerns are not typically most acute. Given these results and the relatively tight mitigation thresholds, we find that the current mitigation measures warrant reassessment. Therefore, we continue to recommend that ISO-NE evaluate the appropriateness of its current conduct and impact threshold levels and revise them as needed to ensure they limit the exercise of market power without interfering with competitive behavior (Recommendation #2024-2).

Finally, the ISO's proposed market reforms to address recommended improvements to DA A/S that are described in the Section help address Recommendation #2024-2 by reducing how often competitive DA A/S offers are mitigated. In particular, the proposal to apply a \$3 per MWh floor to the ITT directly addresses these concerns by reducing mitigation caused by overly stringent thresholds, especially for smaller suppliers. After implementing these reforms, we will assess whether the rules still need further revision to avoid mitigation of competitive DA A/S offers.

IV. ASSESSMENT OF RESOURCE COMMITMENT AND PRICING ISSUES

To maintain system reliability, sufficient resources must be available to satisfy load and operating reserve requirements during the operating day, both systemwide and in local areas. The day-ahead market is designed to incentivize market participants to make resources available at the lowest cost. Satisfying reliability requirements in the day-ahead market is more efficient than waiting until after it clears because this allows less flexible resources with long start-up notification times to compete more effectively with fast-start resources to satisfy the system's energy and reserve needs at the lowest cost.

Before March 2025, the day-ahead market did not economically schedule all resources needed to satisfy the system's requirements because it lacked the operating reserve products required in real time. Instead, the day-ahead market process included commitment constraints that allowed the ISO to maintain reliability in key local areas in response to both the first- *and* second-largest contingencies; and satisfied system-level operating reserve requirements. However, the day-ahead market did not compensate resources for satisfying these requirements, so resources were not necessarily obligated to take the steps necessary to be available.

In March 2025, the ISO improved the day-ahead market's ability to satisfy New England's needs by introducing system-level operating reserve requirements. However, commitment constraints are still used to satisfy local reliability needs, resulting in commitments whose costs are not reflected in ISO-NE's market pricing. Hence, ISO-NE provides NCPC payments to cover the revenue shortfall when these resources do not recoup their full as-bid costs.

Although total NCPC costs are small relative to overall market costs, they are important because they usually occur when market requirements do not align with the system's reliability needs or when prices are otherwise inefficient. This alignment is key to efficient short-term performance incentives and long-term investment incentives. Efficient incentives for flexible, low-cost providers of operating reserves will become increasingly important as intermittent renewable generation penetrates further.

After the day-ahead market, ISO New England runs the Real-Time Unit Commitment ("RTUC") model to determine which resources may need commitment to satisfy the system's needs. The RTUC model needs accurate input data to identify the need for real-time commitments and to avoid inefficient commitments that tend to increase NCPC costs.

This section includes subsections that evaluate: (a) day-ahead commitments for local second contingency protection requirements; (b) scheduling patterns in the DA A/S markets; (c) the accuracy and efficiency of the RTUC model; and (d) pricing of operating reserves in the real-time fast-start pricing logic. The final subsection summarizes our conclusions and recommendations.

A. Day-Ahead Commitment for Local Second Contingency Protection

Most reliability commitments for Local Second Contingency Protection (LSCP) occur in the day-ahead market. Although these commitments may be justified for reliability, the day-ahead market pricing software still does not enforce the underlying local requirements, even after implementing new day-ahead reserve markets. As a result, these commitments lead to inefficient prices and concomitant NCPC uplift. Unlike most other RTOs, ISO-NE incurs most of its NCPC charges for local reliability commitments in the day-ahead rather than real-time market.

Table 4 summarizes day-ahead market commitments for local second contingency protection over the past three years, showing:

- The number of days in each year with such commitments;
- The number of hours in each year with such commitments;
- The average capacity (i.e., the Economic Max of the unit) committed over these hours;
- The amount of NCPC uplift charges incurred;
- The NCPC uplift charge rate (that is, NCPC uplift per MWh of committed capacity); and
- The implied marginal value of local reserves not reflected in market clearing prices, aggregated over the year.

The table below shows these values for each import-constrained area with LSCP commitments in the day-ahead market. The implied marginal reserve values are additive for areas nested within a broader import-constrained area.⁴²

**Table 4: Day-Ahead Commitment for Local Second Contingency and NCPC Charges
2023 – 2025**

Year	LSCP Region	# LSCP Days	#LSCP Hours	Average LSCP Capacity per Hour (MW)	DA NCPC (Million \$)	Average Uplift Rate (\$/MWh)	Implied Marginal Reserve Value (\$/kW-Year)
2023	NH-to-Maine	5	47	229	\$0.1	\$8.15	\$0.73
	Lw. SEMA & East RI	3	23	213	\$0.1	\$13.54	\$0.44
	NE West-to-East	25	202	322	\$0.5	\$7.17	\$1.84
2024	Rhode Island	1	12	154	\$0.1	\$32.77	\$0.38
	North East NE	7	89	408	\$0.4	\$12.26	\$1.13
	NE West-to-East	26	216	369	\$0.4	\$4.63	\$1.11
2025	NH-to-Maine	2	30	257	\$0.05	\$6.08	\$0.18
	Lw. SEMA & East RI	1	2	333	\$0.03	\$42.81	\$0.09
	NE West-to-East	10	63	404	\$0.09	\$3.39	\$0.28

Day-ahead commitments for local second contingency protection have declined notably in recent years, primarily because of reliability transmission upgrades in areas with these needs. In 2025,

⁴² For example, the NE West-to-East interface defines an import-constrained region that includes Central Mass, SE Mass, NEMA/Boston, Rhode Island, New Hampshire, and Maine. So, the implied marginal reserve value for a unit in Maine would be \$2.57/kW-year in 2023 (\$0.73 of NH-to-Maine plus \$1.84 of NE West-to-East).

the table shows that these commitments were limited to fewer than 100 hours over 13 days, mostly in the broader region east of the New England West-to-East interface. Most occurred during periods when planned transmission outages reduced transfer capability across the West-to-East interface, highlighting the continued sensitivity of local reliability commitments to transmission system conditions.

Although the frequency of these commitments and the associated total uplift costs have declined substantially, the uplift cost per MWh of committed capacity remained significant in 2025. It ranged from approximately \$3.4 per MWh in the broader region east of the New England West-to-East interface to \$42.8 per MWh in Lower SEMA and East Rhode Island. These outcomes continue to raise two efficiency concerns:

- Units receiving NCPC payments are typically higher-cost, less flexible resources that systematically receive more revenue than flexible, low-cost resources that generally do not require them.
- Operating reserve prices paid to other resources that help satisfy the same local reliability requirement do not reflect the costs of resources committed for local reliability.

These inefficiencies distort market incentives in favor of higher-cost, less flexible units and suppress prices for other resources. Therefore, although commitments for local second contingency protection have become relatively infrequent, relying on out-of-market NCPC payments to satisfy these requirements continues to produce inefficient price signals. Incorporating these local reliability requirements into a day-ahead operating reserve market would improve the efficiency and transparency of energy and reserve prices, align compensation more closely with reliability value, and further reduce the need for out-of-market commitments. Therefore, we continue to recommend (see #2019-3) that the ISO define local operating reserve requirements in the day-ahead and real-time markets to satisfy these reliability needs through the competitive market rather than through out-of-market actions.

B. Day-ahead Ancillary Services Scheduling Patterns

Before the ISO introduced DA A/S products, out-of-market commitments were needed when load was under-scheduled in the day-ahead market. To satisfy these reserve requirements through the market, the ISO introduced the FER as part of the original DA A/S market design. Now, the ISO procures additional EIR to cover any gap between the FER and the amount of scheduled physical energy resources. Accordingly, the market clearing price for EIR equals the FER price, which is paid to scheduled physical energy resources because they also contribute to satisfying the FER. Virtual supply does not contribute to satisfying the FER, so it does not receive the FER price.

In principle, physical energy resources are paid the FER price because they are expected to be available to satisfy forecasted needs the following day. Physical resources scheduled in the day-ahead market do not receive the FER price if they do not submit an offer in the real-time market.

This provision reduces the likelihood that resources could receive the FER price without being available. However, we have observed strategies that allow suppliers to schedule day-ahead energy and collect FER payments even though they were unavailable in the real-time market.

For example, one market participant simultaneously scheduled day-ahead imports and virtual load positions of equal quantities at the same location. In real time, the participant submits an import offer that is usually unavailable because the source control area has not scheduled the export component of the transaction. Under the current settlement design, when the source control area schedules the real-time import:

- The import receives the DA LMP plus the FER price,
- The virtual load pays the DA LMP minus the RT LMP, so
- The net payment to the participant = FER price + RT LMP

When the real-time import is *not* scheduled by the source control area:

- The import is paid the DA LMP plus the FER price minus the RT LMP,
- The virtual load pays the DA LMP minus the RT LMP, so
- The net payment to the participant = FER price

Ultimately, this strategy allows the participant to receive the FER price regardless of whether the import is available to New England in real time. Even when the import flows in real time, it results from the source control area's real-time export bid evaluation process rather than the participant meeting a clear obligation associated with its day-ahead import schedule in ISO -NE.

FER and EIR mechanisms were introduced to ensure that the ISO procures sufficient dependable supply in the day-ahead market to satisfy forecast energy requirements and improve real-time reliability. However, under the current rules, import schedules can receive FER-related compensation without a corresponding requirement to remain consistently available in real time. As a result, the ISO may compensate transactions that schedule financially in the day-ahead market but do not reliably provide operational capability when system conditions tighten.

The core problem is the lack of a clear performance obligation on the participant that schedules a day-ahead import. The ISO effectively treats day-ahead import schedules as satisfying the system's Forecast Energy Requirement even though the associated supply need not be available in real time.⁴³ Consequently, the day-ahead market solution may overstate the quantity of dependable supply available to the system during stressed operating conditions.

⁴³ This scheduling pattern also reveals an issue with the representation of the import transfer limit in the day-ahead market. Virtual load is treated as reducing import flows similar to export transactions. As a result, the day-ahead market solution may schedule more than the feasible amount of imports, thereby reducing the amount of EIR scheduled below what would be needed if the day-ahead net imports were limited by the interface transfer limit.

If day-ahead imports receive FER payments but need not be available, the ISO may under-procure EIR from resources that would be available in real time. Import transactions that receive FER compensation but are not subject to equivalent real-time performance obligations may displace resources capable of providing dependable capacity in the day-ahead clearing process. Over time, this could reduce the DA A/S market's effectiveness in maintaining reliability without resorting to out-of-market actions.

C. Resource Scheduling Efficiency by RTUC

RTUC is a key operational tool that ISO-NE uses to schedule resources while maintaining system security and reliability in the operating day. RTUC runs every 15 minutes (at :05, :20, :35, and :50 of each hour) and typically uses an 85-minute look-ahead period.⁴⁴ It evaluates near-term forecast conditions and commits fast-start resources to ensure reliability and reserve adequacy. RTUC produces startup and shutdown recommendations for fast-start resources and DARD pumps (i.e., pumped storage resources), which the Unit Dispatch System (UDS) then executes.⁴⁵

While the vast majority of unit commitment decisions are made in the day-ahead market or earlier, RTUC gives the ISO additional flexibility to commit non-dispatchable resources in the operating day. As New England attracts more investment in intermittent renewable generation, balancing supply and demand throughout the operating day will become increasingly challenging without RTUC's additional flexibility. Efficient commitment of peaking resources in the operating day can reduce ramping demands on dispatchable resources and help maintain system reliability.

Because RTUC commits fast-start resources in anticipation of supply shortfalls or system stress, evaluating the efficiency of these commitment decisions is important. This subsection examines the conditions under which forecasting inaccuracies lead to uneconomic commitment of fast-start resources and analyzes the key drivers of RTUC forecast errors.

Uneconomic Commitment of Fast-Start Resources by RTUC

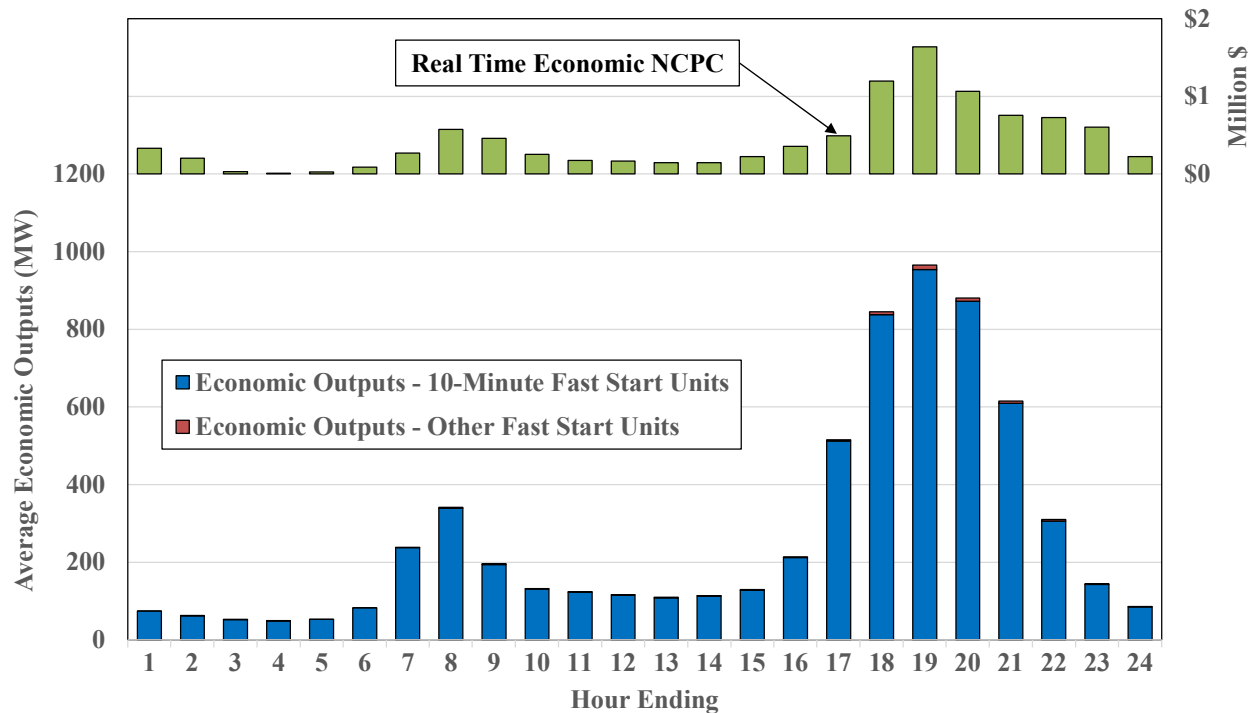
Figure 14 shows the average economically scheduled output from fast-start generators by hour in 2025. These values exclude output associated with self-scheduling, out-of-market commitments, and dispatch. The figure shows fast-start generators that can start and synchronize within 10 minutes separately from other fast-start resources.

⁴⁴ Each RTUC run typically includes six look-ahead intervals, with the first interval covering 10 minutes and the remaining intervals each spanning 15 minutes. However, operators have the flexibility to extend the look-ahead period by adding additional 15-minute intervals as necessary.

⁴⁵ UDS depends on RTUC for fast start resource commitment decisions. When RTUC is active, UDS cannot independently commit or de-commit fast start resources or DARD pumps. It can only dispatch fast start units that RTUC has committed.

The upper portion of the figure shows the corresponding real-time economic NCPC uplift payments to these resources and highlights periods when RTUC has the greatest effect on real-time market outcomes. Although these uplift payments are small relative to the overall wholesale market, they indicate periods when RTUC may be committing fast-start resources inefficiently.

Figure 14: Economic Outputs from Fast-Start Generators and Associated RT NCPC Uplift
By hour, 2025

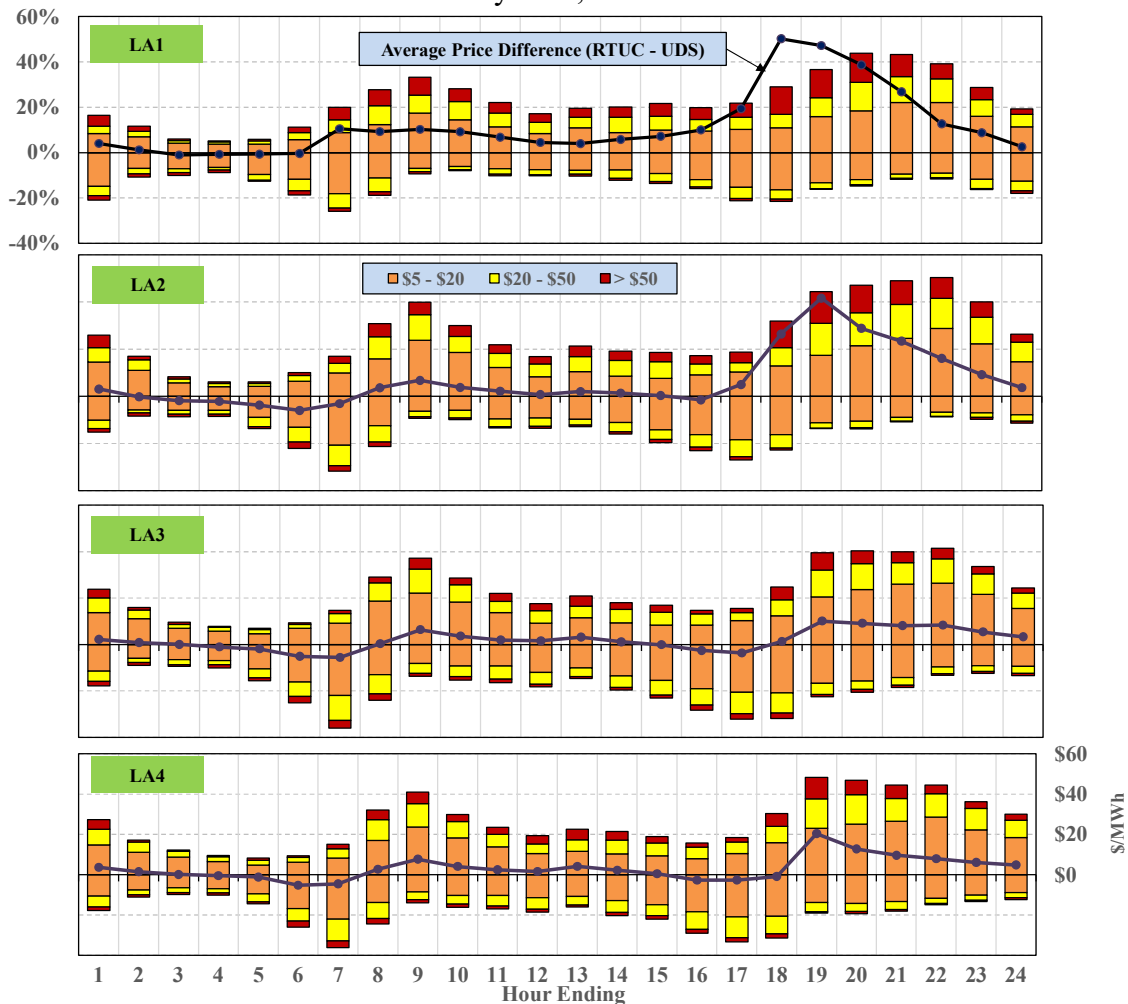


The figure shows several key insights:

- In 2025, fast-start generators incurred over \$10 million in real-time economic NCPC uplift, accounting for nearly 65 percent of such uplift to internal resources. This share is significantly higher than typically observed in other RTOs. For instance, NCPC payments to economically committed fast-start units in ISO-NE were 80 percent higher in \$ per MW-start than make-whole payments to comparable units in NYISO.
- Notably, 99 percent of the economic output from fast-start resources originated from units that can start and synchronize within 10 minutes, while these units account for only 90 percent of fast-start capacity. This indicates that 10-minute fast-start units are utilized more heavily than other fast-start units.
- Approximately 60 percent of economic starts occurred during the evening peak period (hours ending 17 to 21). This period also accounted for 51 percent of the associated real-time economic NCPC uplift payments. These results indicate that the ISO routinely relies on fast-start resources to satisfy the daily peak in net demand (load minus renewable energy) and manage changing system conditions during the evening ramp period.

These findings are consistent with the 2024 results. Elevated make-whole payments to economically committed fast-start units are generally associated with over-forecasting system needs in the operating day. To evaluate potential drivers of over-forecasting, the next analysis compares RTUC forecasts of real-time systemwide LMPs with UDS LMPs in Figure 15.

Figure 15: Price Forecasting by RTUC vs. UDS LMPs
By hour, 2025



The figure has four panels, each representing a different RTUC forecast horizon. Look-Ahead (LA) periods One through Four correspond to forecast windows ranging from less than 15 minutes (LA1) to one hour out (LA4), in 15-minute increments. The stacked bars summarize the frequency, direction, and magnitude of differences between RTUC and UDS prices; positive values indicate hours when RTUC prices exceeded UDS prices. The black line in each panel shows the average hourly difference between RTUC and UDS prices.

Figure 15 shows that the average hourly differences between RTUC and UDS prices were generally close to zero in most hours across all four forecast horizons. However, during morning and evening peak hours, RTUC prices were consistently higher than UDS prices across all four

forecast horizons. The differences were especially pronounced in Look-Ahead periods One and Two, when average RTUC prices exceeded average UDS prices by as much as \$50 per MWh in hour ending 18. Figure 15 highlights several issues with RTUC performance:

- RTUC frequently committed fast-start resources inefficiently during evening peak hours. When actual real-time prices were lower than forecasted prices, these units often operated at a loss and required substantial real-time economic NCP payments to cover their costs. This finding is consistent with the patterns observed in Figure 14.
- If market participants perceive a systematic bias in RTUC commitments, it may weaken their incentives to offer at marginal cost. For instance, if fast-start resources frequently receive NCP payments that depend on their offer prices, they may be incentivized to offer above marginal cost.
- Although less pronounced, an upward bias is also evident in LA3 and LA4 forecasts. These forecasts generally use the same inputs as the CTSPE model that forecasts prices for transactions scheduling with NYISO.

Drivers of Price Over-Forecasting in RTUC

This subsection evaluates the factors contributing to the inconsistencies between RTUC and UDS prices discussed above. It quantifies each factor's contribution using the metric described below and distinguishes between factors that tend to reduce or exacerbate the inconsistencies.

Inconsistencies between RTUC and UDS prices can cause inefficient scheduling decisions. This inefficiency stems from two related discrepancies: (a) differences in MW levels between RTUC and UDS (e.g., forecasted vs. actual load); and (b) differences in price levels between the RTUC forecast price and the actual UDS price. To capture these effects, we define an inconsistency metric for each generator, external transaction, or load i :

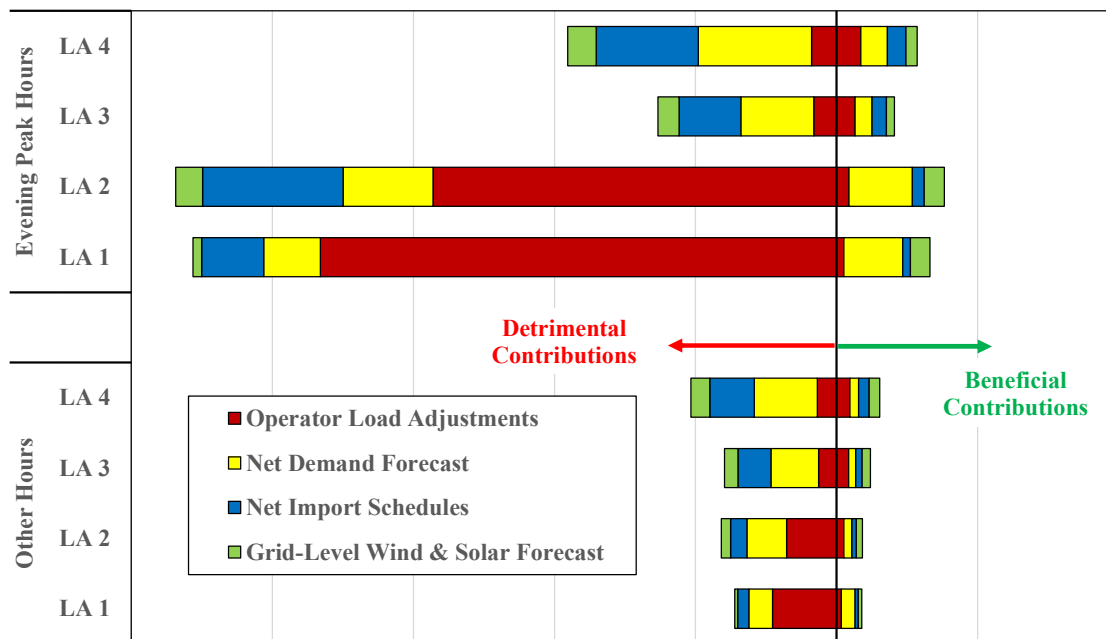
$$Metric_i = (NetInjection_i^{RTUC} - NetInjection_i^{UDS}) \times (Price_i^{RTUC} - Price_i^{UDS})$$

Using the example above, the following shows how the metric is calculated for each input/resource:

- Load Forecast: $Metric_{Load} = +100 \text{ MW} \times (\$50 - \$70) = -\$2,000$
This negative value indicates that the load under-forecast was a “detrimental” factor that increased the divergence between forecasted and actual prices.
- High-Cost Generator used in UDS:
 $Metric_{High-Cost \text{ Generator}} = -100 \text{ MW} \times (\$50 - \$70) = +\$2,000$
This positive value shows that the generator's contribution was “beneficial” because it helped meet the unexpected load and mitigate the price gap.
- Foregone Fast-Start Unit: $Metric_{Fast-Start \text{ Unit}} = 0 \text{ MW} \times (\$50 - \$70) = \$0$
The zero value reflects that the fast-start unit itself did not cause the divergence. Rather, the load under-forecast caused its absence from the RTUC commitment.

This metric differentiates between “detrimental” factors that increase price divergences between RTUC and UDS and “beneficial” factors that reduce them. Flexible resources, such as fast-ramping units, generally act as beneficial factors that alleviate differences between forecast and actual real-time schedules, while inaccurate forecasts of inputs determined outside the model (e.g., load forecast) tend to be detrimental. Figure 16 evaluates inconsistency metric values for four key factors that contributed to RTUC-UDS price differences in 2025: (i) net demand (demand minus behind-the-meter solar) forecast; (ii) operator load adjustments; (iii) scheduled net imports; and (iv) grid-scale wind & solar forecasts.

Figure 16: Factors Contributing to RTUC Price Forecast Errors
2025



The figure presents the cumulative detrimental and beneficial metric values for each factor over the year. To highlight impacts during peak periods, the analysis compares evening peak hours (HE 17 to 21) with all other hours. In addition, it disaggregates the results across the four RTUC forecast horizons to show how each factor’s contribution varies by look-ahead interval. For comparability, the figure displays hourly average metric values for each group rather than absolute totals. It does not show the actual metric values because this analysis focuses on each factor’s relative significance in driving price inconsistencies rather than on exact magnitudes.

Like the 2024 findings, Figure 16 shows several key insights into the drivers of RTUC and UDS price divergences in 2025:

- **Overall Impact Primarily Detrimental** – Although all four factors sometimes reduced price divergence, their net impact over the year was primarily detrimental.
- **Minor Impacts for Grid-Level Wind and Solar** – Forecast errors associated with grid-scale wind and solar had small effects relative to the other three factors. This is expected

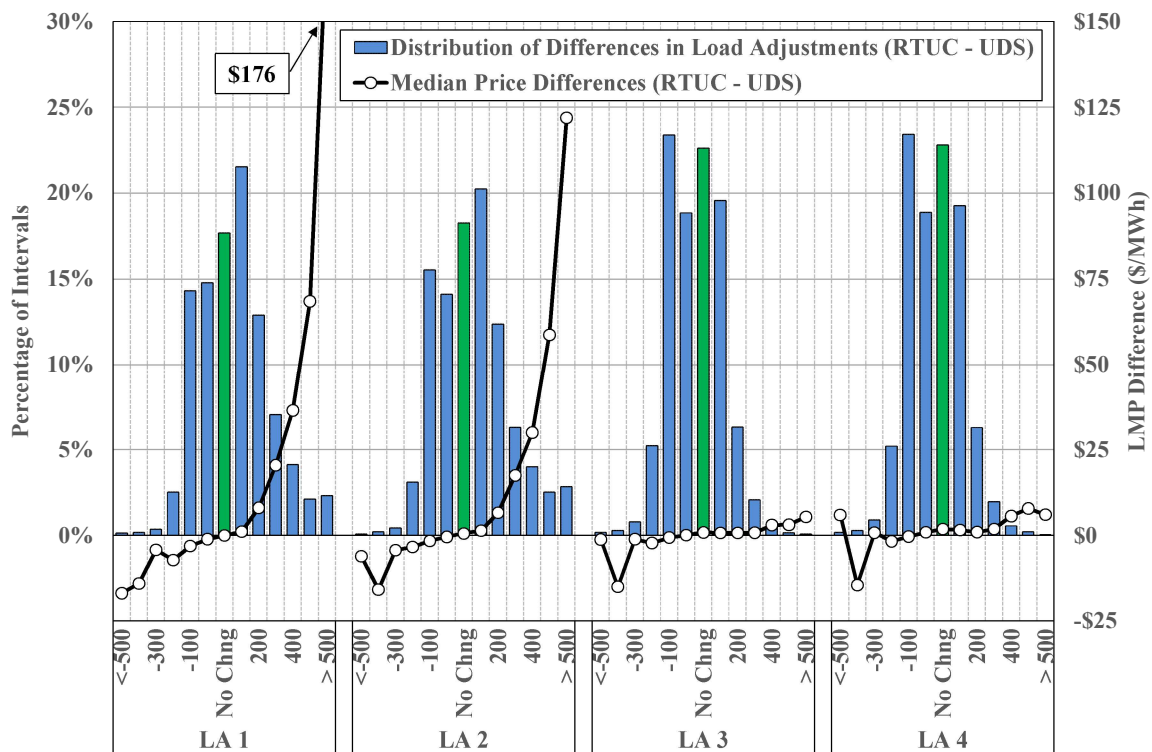
because ISO-NE currently has a modest amount of grid-level renewable generation capacity. By contrast, retail-level solar generation is embedded in the load forecast.

- **Modest Impact for Net Import Schedule Changes** – Net import variation had a modest overall effect on price inconsistencies. However, it contributed more to price divergence at the longer forecast horizons in LA3 and LA4.
- **Primary Driver of Divergence was Operator Load Adjustments** – Operator load adjustments were the largest detrimental factor in price inconsistencies during LA1 and LA2, particularly during evening peak hours (HE 17 to 21).

As the forecast horizon extended to LA3 and LA4, operator load adjustments had less influence. Instead, net demand forecast errors became the largest detrimental factor, reflecting greater uncertainty in longer-term demand forecasting and less frequent operator load adjustments.

Figure 17 examines the evening peak hours and the relationship between load adjustment differences and price differences between RTUC and UDS across the four look-ahead horizons. The bars show the distribution of load adjustment differences in 100 MW increments.⁴⁶ The green bars indicate the percentage of intervals where operators applied the same adjustment to both RTUC and UDS. The black lines mark the median price differences between RTUC and UDS, showing how variation in load adjustments correlates with price inconsistencies.

Figure 17: Differences in Load Adjustments and LMPs Between RTUC and UDS
Evening Peak Hours, 2025



⁴⁶ The MW values on the x-axis represent the upper bound of each tranche. For example, the 200 MW tranche includes the load adjustment differences between 100 and 200 MW.

Operators can make load adjustments in RTUC by applying the same adjustment across all look-ahead intervals, or by targeting specific intervals. Figure 17 shows that LA1 and LA2 had similar distributions of load adjustment differences that differed from those in LA3 and LA4, which also had similar distributions. In particular, the load-adjustment distributions in the near-term forecasts (LA1 and LA2) were skewed toward positive values, while those in the longer-term forecasts (LA3 and LA4) were skewed toward negative values. In addition, load adjustment differences exceeding 300 MW occurred in nearly 10 percent of intervals in LA1 and LA2, but in only 2 percent of intervals in LA3 and LA4. These patterns suggest that operators are more likely to apply larger or targeted upward load adjustments in the shorter-term horizons, while making fewer specific adjustments in the longer-term forecast windows.

Only 18 to 23 percent of intervals had no difference in load adjustments between RTUC and UDS across the four forecast windows, as the green bars in Figure 17 show. These intervals had near-zero median price differences, suggesting that more consistent load adjustments between RTUC and UDS improve price forecasting accuracy. In contrast, the largest load adjustments generally corresponded to the largest RTUC/UDS price inconsistencies. Across all four look-ahead horizons, load adjustment differences exceeding ± 300 MW corresponded to substantially higher median price differences.

Because most fast-start resources in ISO-NE can start and synchronize within 10 minutes, RTUC can commit these units beginning in its first or second look-ahead interval. However, the frequent, large load adjustments observed in LA1 and LA2 inflated expected demand levels, leading to higher projected LMPs and premature or excessive commitment of fast-start resources. A more measured, consistent approach to load adjustments in RTUC could reduce inefficient commitments and improve alignment with actual real-time system conditions.

Inconsistent Ramp Assumptions. We found that inconsistent ramp assumptions contributed to the large price differences between RTUC and UDS in the LA1 evaluation. UDS assumes a 15-minute ramp window regardless of the actual time available until the evaluation's "target time" (i.e., the forecasted point in time for which generation is scheduled). By contrast, RTUC always executes LA1 ten minutes ahead of the relevant target time and assumes a 10-minute ramp window. This inconsistency generally makes more supply available in UDS than in RTUC, contributing to lower prices in UDS. The inconsistent ramp assumptions in RTUC LA1 and UDS contributed to the observed price differences, particularly during periods of high system stress, when ramping flexibility is critical. UDS's inflated ramp assumption allows more aggressive dispatch solutions and leads to lower realized prices.

We recommend (see #2024-1) that ISO New England address the underlying causes of the price divergence between RTUC and UDS identified in this subsection. A comprehensive evaluation of these divergences and other drivers of fast-start commitment inefficiencies would improve the economic efficiency and reliability of real-time market operations.

D. Pricing of Operating Reserves in the Fast-Start Pricing Logic

Fast-start units create challenges for price formation because they often have limited dispatch ranges and relatively high costs, causing them to frequently run at their minimum output level where they cannot set the price as the marginal unit. In March 2017, the ISO implemented fast-start pricing logic in the real-time energy market, allowing fast-start resources to set prices when their output displaces output from more expensive resources.

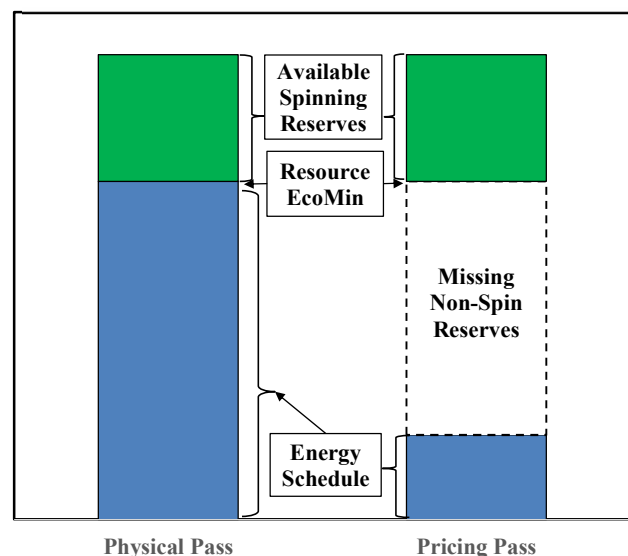
An optimal real-time dispatch model determines each resource's dispatch quantity to minimize as-offered production costs while enforcing transmission and operational constraints. After this physical dispatch (i.e., the “physical pass”), the fast-start pricing model produces the “pricing pass”, re-running the dispatch model re-runs with the EcoMin constraints of fast-start units relaxed to zero and allowing them to “set the price” for energy. In addition, the pricing pass adjusts the energy offers of fast-start resources to reflect their full costs by adding fixed start-up and no-load costs amortized over EcoMax for the minimum run-time duration. As a result, energy prices more accurately reflect the full costs of using fast-start resources to the real-time system needs. However, the fast-start pricing logic contains a flaw that can produce inefficient reserve pricing under certain conditions:

- In the pricing pass, fast-start units cannot provide reserves below their EcoMin level;
- When the pricing pass relaxes the EcoMin to zero and economically ramps down fast-starting resources, other units that would otherwise provide reserves ramp up to supply additional energy.
- This substitution reduces the available operating reserves in the pricing pass, which can inefficiently raise both reserve and energy prices.

Figure 18 illustrates the loss of available reserves. In the physical pass, a fast-start unit is dispatched at its EcoMin level and the headroom above EcoMin provides spinning reserves. In the pricing pass, the unit's EcoMin is relaxed to zero, allowing the unit to be dispatched down so it can be marginal and set prices. While the pricing pass continues to recognize the headroom above the unit's EcoMin as available spinning reserves, it does not account for the un-dispatched portion below the physical EcoMin level as available reserves. This omitted capability is depicted by the white dashed box labeled “missing non-spin reserves.”

As a result, less capacity from online fast-start resources is available in the pricing pass than in

Figure 18: Illustration of Available Reserves in Physical and Pricing Passes



the physical pass. This inconsistency primarily affects prices materially under tight conditions, causing reserve prices to be overstated. To highlight these price effects, Figure 19 and Figure 20 compare 10 and 30-minute reserve availability and shadow prices in the physical and pricing passes during UDS intervals when reserve constraints were binding in the pricing pass.

Figure 19: Available 10-Minute Reserves in UDS
Physical Pass vs. Pricing Pass, 2025

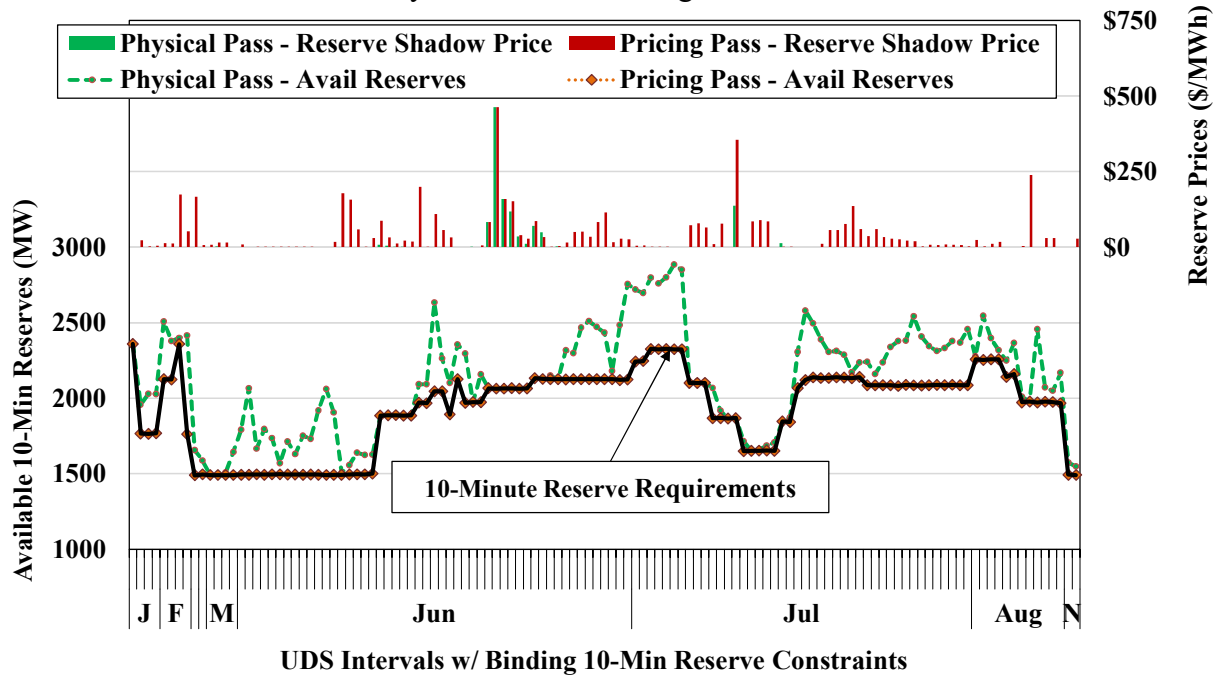
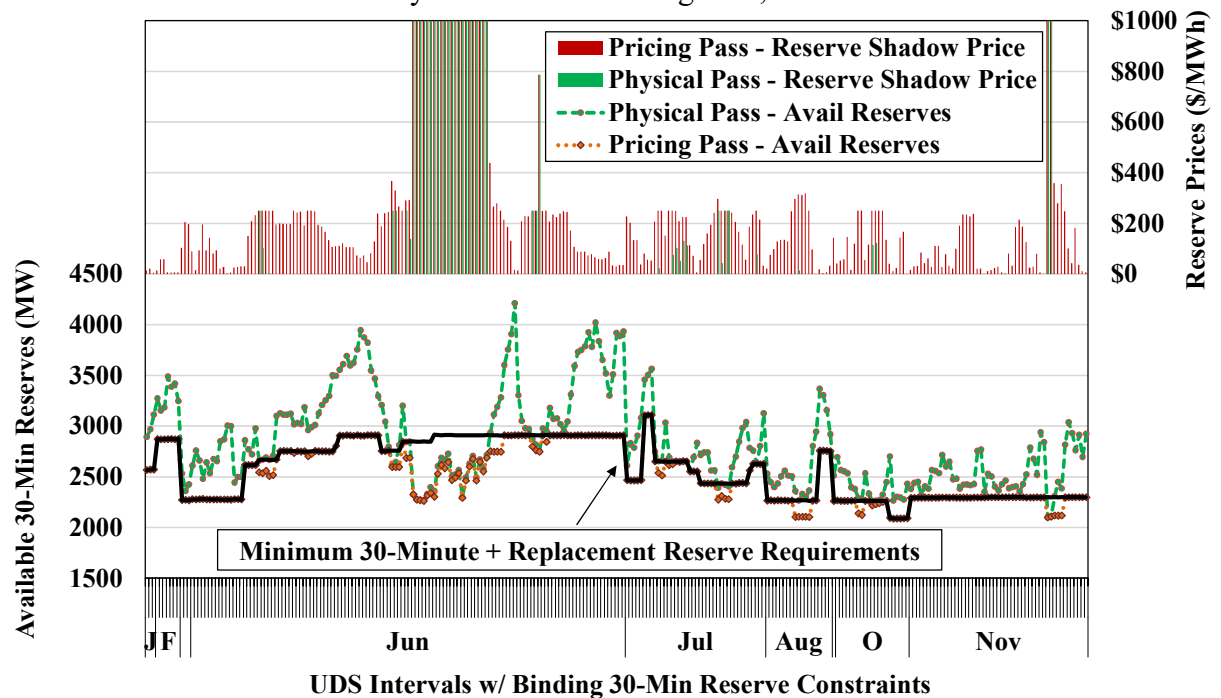


Figure 20: Available 30-Minute Reserves in UDS
Physical Pass vs. Pricing Pass, 2025



The upper portion of each figure compares the shadow prices of reserve constraints in the two passes. The shadow price indicates the marginal cost of satisfying the reserve requirement and contributes to the reserves and energy pricing. The lower portion shows modeled reserve availability in each pass as dashed lines and the requirements as a solid black line. A surplus is evident when the dashed line is above the solid line and a shortage when the dashed line is lower.

In 2025, 354 UDS intervals had at least one binding 10-minute or 30-minute reserve constraint in the pricing pass. During these intervals:

- The physical pass consistently showed greater reserve availability than the pricing pass – averaging 205 MW more 10-minute reserves and 320 MW more 30-minute reserves.
- Reserve prices were often much higher in the pricing pass, averaging \$165-\$179 per MWh for 30 and 10-minute reserves versus to \$80-\$83 per MWh in the physical pass.

These results highlight the flaw described above, which arises when any of the 10 or 30-minute fast-start resources are dispatched below their EcoMin in the pricing pass. To address this pricing inefficiency, we recommend that the ISO refine the fast-start pricing logic to treat undischarged capacity below EcoMin from 10 and 30-minute fast-start resources as available operating reserves for those respective products.

E. Conclusions and Recommendations

Day-ahead commitments for local reserve needs – These commitments satisfy unpriced local second-contingency requirements. Relying on out-of-market NCPC payments to satisfy these requirements does not compensate other resources efficiently for contributing to them.

- Recommendation #2019-3: Define local operating reserve requirements in the day-ahead and real-time markets to satisfy these reliability needs through the competitive market.

Eligibility to Receive FER Payments – Day-ahead imports receive FER payments even when they are not available in real time. Such transactions are not obligated to be available in real time so they do not provide comparable value to resources that receive FER payments. This could reduce the reliability benefits of the DA A/S market so it should be evaluated by the ISO.

Real Time Unit Commitment model performance – This Section shows that RTUC frequently over-forecasts the need to commit fast-start resources, which caused over \$10 million of NCPC costs in 2025 – 65 percent of all real-time economic NCPC paid to internal resources.

- Recommendation #2024-1: Address the causes price divergences between the RTUC and real-time models to make its fast-start commitments more efficient.

Excessive real-time reserve prices – An issue with the fast-start pricing logic caused inefficiently high real-time reserve prices in some intervals.

- Recommendation #2022-1: Address inefficient reserve prices in the fast-start pricing logic by modifying it to use the full capability of online resources in the pricing pass.

V. CAPACITY AVAILABILITY AND PERFORMANCE INCENTIVES

Capacity markets provide incentives to ensure adequate resources will be available to satisfy the system’s planning reliability needs. To provide efficient incentives for resource investment and retirement decisions, capacity markets should quantify available capacity accurately and provide efficient performance incentives.

ISO New England is replacing its forward capacity market with a prompt seasonal capacity market that bases resource accreditation on the marginal reliability value of capacity. We strongly support these design changes to address the region’s future reliability needs. In this section, we evaluate two aspects of capacity market performance: (i) the consistency between the amount of qualified capacity and the amount actually available during the tightest summer conditions and (ii) the incentives the Pay-for-Performance rules provide.

A. Qualified Capacity and Actual Availability during Peak Summer Conditions

Resource adequacy and transmission security criteria generally require enough resources to avoid load shedding under conditions more severe than the average annual peak demand level (e.g., a 90th percentile annual peak load forecast). Therefore, when setting capacity requirements, load forecasts quantify the additional demand expected under these relatively severe conditions. Ideally, the accreditation of each generator sells reflects its expected capability under the same severe conditions. For most thermal generators, maximum capability falls as summer weather conditions become more extreme. If the accreditation rules do not consider these factors, the total Qualified Capacity (“QC”) will exceed the amount available under the tightest conditions.

This section examines the factors that inflate summer QC values for the thermal generation fleet. It is divided into the following parts:

- *Ambient Conditions Background* – Overviews the ambient conditions that most affect conventional generator performance: air temperature, humidity, barometric pressure, and water temperature;
- *Quantification of Ambient Impacts in Summer 2025* – Analyzes how the ambient assumptions used to determine Summer 2025 QC values differ from actual peak-hour ambient conditions and the overestimate of QC values for certain capacity types; and
- *Actual Performance in Summer 2025* – Analyzes the gap between summer QC values and actual generator availability to quantify the underlying drivers in summer 2025.

Ambient Conditions and Generator Output – Background

Each resource that participates in the capacity market is qualified to sell up to its summer or winter QC. For thermal generators, QC is generally based on the Seasonal Claimed Capability (SCC) Audits, which are usually conducted under conditions more favorable than expected peak conditions. For some thermal generators, the ISO partially addresses the difference between

Audit conditions and peak conditions by adjusting test results to a uniform systemwide peak temperature of 90°F.⁴⁷ The ISO uses capability curves submitted by owners of gas turbine and combined cycle facilities that show capability as a function of dry bulb temperature in one-degree increments.^{48,49}

The gas turbine capability of combined cycle and simple cycle generators is also affected by humidity and barometric pressure. Higher relative humidity reduces the effectiveness of inlet cooling equipment that adds moisture to cool compressor inlet air to offset the effects of higher air temperatures on gas turbine output.^{50,51} Barometric pressure directly affects gas turbine capability because gas turbines can produce more output when air is denser. Generators can choose to adjust SCC Audit results based on barometric pressure and relative humidity, but doing so would generally not benefit the generator so none have opted to do so.⁵² In practice, audits are usually conducted under relatively favorable humidity and pressure conditions, which tends to inflate QC values. In this subsection, we estimate the effects of these ambient conditions on gas turbine capability.

The steam turbine capability of combined cycle units, older fossil-fueled steam turbines, and nuclear power plants with a steam cycle may decline at higher ambient air or water temperatures. The steam cycle of combined cycle generators with air-cooled condensers may be limited at higher air temperatures.⁵³ Older steam turbines with once-through cooling systems may be

⁴⁷ The normalization procedure is outlined in Market Rule 1 III.1.5.

⁴⁸ For example, if a combined cycle conducts an SCC Audit operating to 300 MW at an average temperature of 80°F and the relationship between capability (MW) and temperature between 80-and-90°F is -1 MW/°F, the weather-normalized Summer SCC of this resource would be 290 MW at the 90°F seasonal adjustment value. See Section 4 of https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isonet/op14/op14a_rto_final.pdf.

⁴⁹ The Qualified Capacity of an existing resource is equal to the median SCC from the resource's seasonal SCC Audits over the past five years. See Market Rule 1 III.13.1.2.2.

⁵⁰ Inlet cooling systems work to collapse the ambient dry bulb air temperatures towards the corresponding wet bulb temperature at the given ambient conditions. As relative humidity levels rise, the gap between dry bulb and wet bulb temperatures diminish which restricts the ability of the inlet cooling systems to decrease inlet air temperatures. In New England, the most common inlet cooling systems are evaporative coolers and inlet fogging systems, which are also the most prone to efficiency degradation with higher relative humidity conditions.

⁵¹ There is a smaller impact on CTs without these systems, amounting to roughly 0.4 percent between 0-and-100 percent humidity. See: https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-3567h-ge-gas-turbine-performance-characteristics.pdf

⁵² See Market Rule 1 III.1.5.1.4 (c). The relative humidity normalization value is 64 percent, while the barometric pressure is normalized to the value of the previous Establish Claimed Capability Audit.

⁵³ If a combined cycle power plant is equipped with duct burners and an air-cooled condenser (ACC) that is designed to handle 90°F conditions, the ACC equipment will be inadequate at higher temperatures, limiting output further because duct firing must be backed off to reduce steam flow to the condenser.

limited by the temperature of their cooling-water source during the summer. In this report, we do not estimate the effects of air and water temperatures on steam turbine capability. However, our review of generator performance during summer peak conditions identifies some deratings that were likely attributable to these factors.

Impact of Ambient Conditions on SCC Ratings – Air Temperature & Humidity

Current market rules acknowledge the importance of air temperature by requiring generators to adjust SCC Audit results from test conditions to a planning temperature of 90°F. However, the uniform 90°F temperature adjustment is inadequate for two reasons:

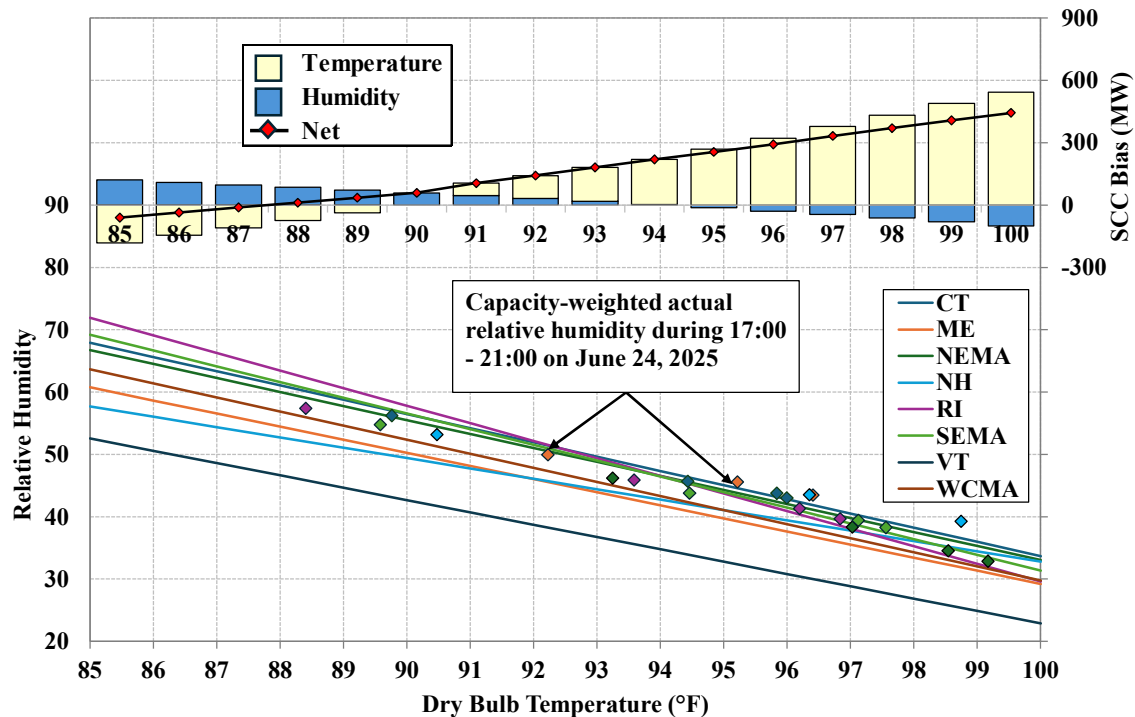
- Temperatures are not uniform across the system. Generators in certain load zones predictably experience warmer or cooler temperatures than those in other zones.⁵⁴
- Planning reliability requirements are driven by peak summer conditions when temperatures across New England exceed 90°F.

Hence, the uniform adjustment to 90°F is insufficient and favors generators in warmer areas. In many cases, the marginal effects of air temperature increase more rapidly above 90°F, especially for combined cycle generators. Under peak summer conditions that drive New England's planning reliability requirements, air temperature and humidity are inversely related. From late afternoon to early evening, air temperatures fall while relative humidity rises. To estimate the overall effects of ambient conditions on generator capability, we examined the 25 highest-load hours from the last seven years and calculated the capacity-weighted average temperature and relative humidity for each load zone. We then derived a linear trendline relating humidity to temperature. This is shown in Figure 21 for temperatures between 85 and 100 degrees Fahrenheit.

We estimate the relationship between humidity and capability for humidity-dependent generators based on SCC Audit results applicable to Summer 2025, observed generator performance at various temperature levels, and each generator's submitted capability curve relating capability to air temperature. Figure 21 summarizes how temperature and humidity combinations under peak summer conditions affect SCC and drive New England's installed capacity requirements. For example, if the temperature were 92°F throughout New England, relative humidity would range from 39 percent in Vermont to 52 percent in Rhode Island. Applying these temperature and locational humidity thresholds would *lower SCC by 142 MW overall*: 111 MW because of higher temperature and 31 MW because of lower humidity during SCC Audits. In reality, temperature is not uniform throughout New England, because southern regions are generally warmer than northern regions. However, the figure illustrates the correlation between temperature and humidity at a given location and the effects on generator capability.

⁵⁴ For example, generators in the NH and NEMA load zones often experience temperatures that are several degrees warmer than those resources in other zones while Maine generators often experience the coolest temperatures (excluding the small amount of capacity in Vermont).

Figure 21: Temperature & Humidity Impact on SCC Ratings
Summer 2025



Because of the increased penetration of distributed solar generation in recent years, summer peak load hours have shifted later in the day. For example, on June 24, 2025, the four peak load hours were hours-ending 18 to 21. At that time of day, temperature starts to fall while relative humidity increases. The figure shows that air temperature and humidity are both significant factors and that air temperatures were generally well above 90 degrees across much of New England during peak conditions. QC values should be adjusted to account for the combination of temperature and humidity conditions likely to prevail under the peak summer weather conditions the system is planned for (i.e., peak conditions more severe than expected in an average year).

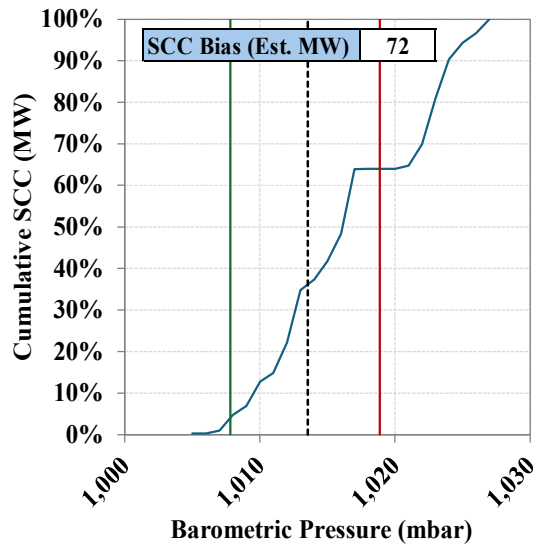
Impact of Ambient Conditions on SCC Ratings – Barometric Pressure

Barometric pressure affects the power output and efficiency of certain generation technologies, particularly CTs in simple-cycle and combined-cycle configurations. When the air is less dense, less air mass flows through the CT, reducing its output.⁵⁵ Therefore, barometric pressure and CT capability are positively correlated.

Barometric pressure tends to fall as air temperature and humidity rise. Warm air is less dense than cool air, and humid air is less dense than dry air because water vapor is less dense than nitrogen and oxygen. Since summer reliability risks are highest in hot, humid conditions, barometric pressure is lowest under high summer load conditions.

⁵⁵

See: https://www.governova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-3567h-ge-gas-turbine-performance-characteristics.pdf

Figure 22: Barometric Pressure during SCC Tests, Summer 2025

Since summer SCC audits are usually conducted outside peak load conditions, they generally occur at higher barometric pressures than expected during peak load conditions. Figure 22 shows the percentage of cumulative capacity from power plants with one or more CT that conducted an SCC Audit applicable to Summer 2025 at or below a given barometric pressure level, in mbar. Three additional lines provide context on typical barometric pressure conditions during peak load hours. The green line shows the 10th percentile of barometric pressure conditions across load zones during peak load days, whereas the red line shows the 90th percentile. The black dashed line shows the mean barometric pressure on peak load days.⁵⁶

For Summer 2025, 62 percent of all applicable Summer SCC Audits occurred at barometric pressures above the average barometric pressure (roughly 1013.6 mbar), which increased audit performance relative to expected summer peak conditions. In addition, 36 percent of SCC Audits occurred at barometric pressures above the 90th percentile band. We estimate that the difference between pressure conditions during SCC Audits and the mean pressure condition during historic peak load hours inflated Qualified Capacity by 72 MW.

Qualified Capacity Unavailable under Peak Conditions – Summer 2025

This subsection estimates how much Qualified Capacity was unavailable because of ambient conditions and unreported deratings during the June 2025 heat wave. While we estimated that ambient condition effects on gas turbine output likely accounted for much of the unavailable capacity, we did not estimate the effects of ambient conditions on steam turbine production, so to the extent these occurred, it would show up as an “unreported derate”.

Figure 23 shows the combined CSOs of all steam turbines, gas turbines, and combined cycles compared to the actual capability available under peak conditions. Ambient air temperature effects on gas turbine output (including the gas turbine component of combined cycles) are shown separately from humidity and pressure effects. On the peak load day (i.e., June 24, 2025), temperatures exceeded 90°F by a wide margin in all load zones except Vermont, significantly reducing generating capacity (~360 MW).

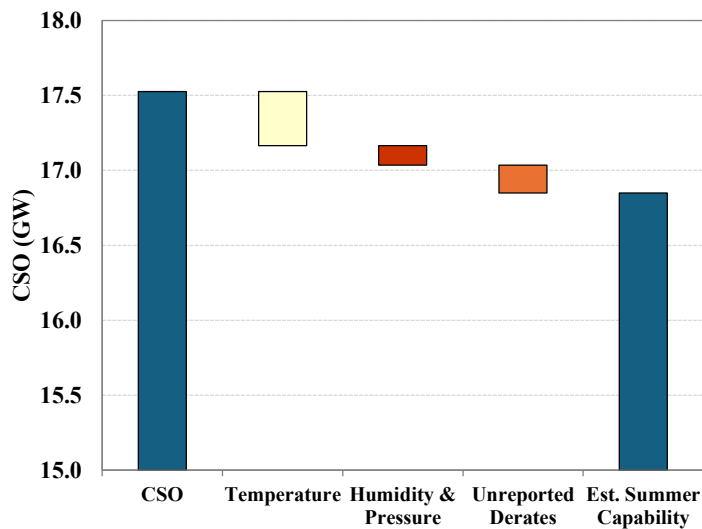
For steam turbines (including the steam cycle of combined cycles), ambient conditions likely explained a large quantity of the unreported deratings. Since ISO New England will begin using

⁵⁶ See Appendix for methodology.

NERC Generating and Availability Data System (GADS) data as an input to its capacity market in 2027, monitoring generator compliance with reporting requirements during deratings will be important.

Besides the estimated air temperature effect, ~320 MW of QC was unavailable under peak conditions. We estimate that relative humidity accounted for 60 MW and low barometric pressure accounted for 70 MW. We estimate that the remaining 190 MW resulted from unreported forced derates, much of which was credited as good performance during the PFP events.⁵⁷ Hence, we continue to recommend robust enforcement of GADS reporting obligations and reassessment of the ambient condition adjustments to Qualified Capacity (2024-3).

Figure 23: Unavailable Capacity under Peak Conditions in Summer 2025



B. Assessment of Capacity Shortage Events

ISO-NE implemented the PFP rules in June 2018 to strengthen incentives for generators to support grid reliability and stability during Capacity Scarcity Conditions (“CSCs”). Under the PFP framework, generators receive payments or penalties based on their performance relative to their CSOs during CSC events.⁵⁸ Since implementation, PFP events have been infrequent, occurring only seven times in eight years, including five events over the past three years that lasted between 30 minutes and three hours.

Although none of these events posed a significant risk of firm load shedding in New England, they produced extremely strong financial incentives. During the November 23, 2025 event, total payments to imports and resources performing above their CSOs exceeded \$12,000 per MWh, including the applicable PFP rate of \$9,337 per MWh. Over the past three years, shortage events resulted in more than \$230 million in performance charges to suppliers. Available steam and combined-cycle resources that were offline because they had not been committed in the day-ahead market incurred most of these charges.

⁵⁷ See subsequent subsection of this report for further analysis on this.

⁵⁸ A CSC occurs when the ISO is short of one or more of the three reserve requirements and the Reserve Constraint Penalty Factor (“RCPF”) is setting the real-time reserve prices: (a) systemwide 10-minute reserve requirement; (b) systemwide 30-minute reserve requirement; and (c) local 30-minute reserve requirements that exist to meet the second-contingency requirement in import-constrained areas.

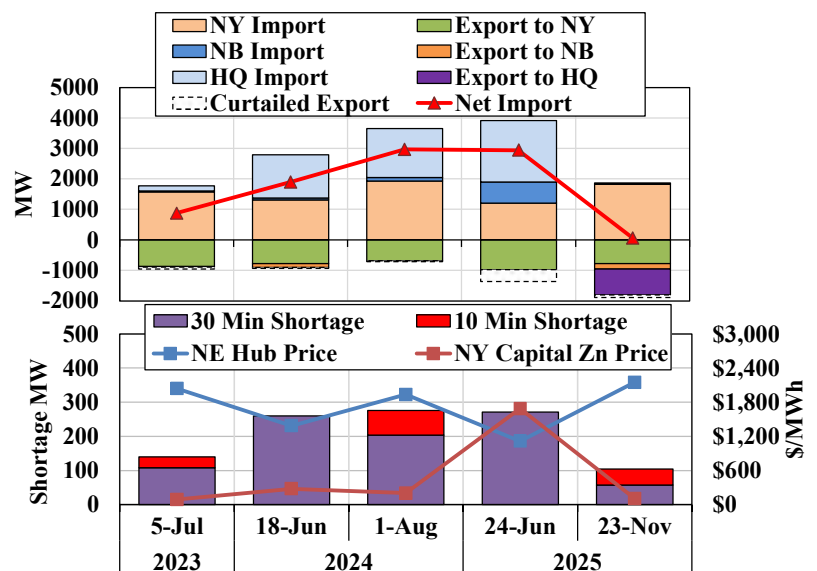
These settlements vastly exceed the underlying reliability value associated with the relatively small reserve shortages observed during these events and create inefficient incentives for market participants. This subsection examines several aspects of the PFP rules that fail to provide efficient incentives, including those related to the scheduling of export transactions, the reporting of generator deratings in real-time operations, and the shortage pricing levels used during 2025 PFP events.

Imports and Exports Scheduled During Shortage Events

Wholesale markets facilitate efficient use of transmission interfaces between control areas, allowing low-cost resources in one area to serve consumers in another and improving reliability in both. ISO-NE imports and exports substantial amounts of power from New York, Quebec, and New Brunswick, so it is critical to schedule the interfaces efficiently. During reserve shortages, efficient scheduling enables ISOs to optimize resource utilization across neighboring regions and minimize the overall cost of maintaining grid reliability.

Figure 24 summarizes external transaction scheduling with neighboring areas during capacity scarcity conditions over the past three years. The upper panel shows the average quantity of scheduled imports and exports at each interface during each PFP event. It aggregates transactions across the Highgate and Phase I/II interfaces with Quebec and groups together transactions across the three interfaces with New York. Hollow bars depict scheduled transactions that were subsequently cut or curtailed. The red line shows total net imports across all interfaces during these shortage periods.

Figure 24: Scheduling of External Transactions during Reserve Shortages from 2023 to 2025



The lower panel of the figure shows the average 10-minute and 30-minute reserve shortages during these events. It measures 30-minute reserve shortages relative to the minimum 30-minute reserve requirement, defined as the capacity needed to cover the largest contingency plus half of the second-largest contingency. This reserve product has a Reserve Constraint Penalty Factor (RCPF) of \$1000.⁵⁹ The panel also compares average energy prices at the New England Hub and the NYISO Capital Zone during

⁵⁹ This excludes the additional replacement reserve requirement of 160 MW during the summer events and 180 MW during the winter events, which is associated with a substantially lower RCPF of \$250.

the shortage periods, providing additional context for evaluating external transaction scheduling and regional market conditions.

During the five PFP events over the past three years, ISO-NE had systemwide 10-minute reserve shortages in only three events, which averaged approximately 50 MW. 30-minute reserve shortages occurred in all five events and averaged roughly 180 MW. Although these shortages were relatively small, they resulted in very high average energy prices at the New England hub, ranging from approximately \$1,100 per MWh to over \$2,100 per MWh.

Conditions in neighboring areas were generally much less severe during these events. In four of the five events, NYISO did not experience significant 10-minute or 30-minute reserve shortages, and average energy prices in Capital Zone remained below \$170 per MWh. The only exception was June 24, 2025. On that day, NYISO also experienced multiple reserve shortages, and average energy prices approached \$1,700 per MWh, exceeding Hub LMPs in New England. These pricing outcomes suggest that NYISO generally had substantially more favorable supply conditions than ISO-NE during four of the five shortage events.

Despite these conditions, ISO-NE curtailed only small quantities of scheduled exports during the five events, leaving approximately 700 MW to 1800 MW of scheduled exports to neighboring areas uncurtailed in each event. During the June 24, 2025 event, additional export curtailments would have worsened shortage conditions in the neighboring area because it was experiencing a more significant reserve shortage. However, during the other four events, additional export curtailments would have reduced or potentially eliminated reserve shortages in ISO-NE without causing reserve shortages in the neighboring area.

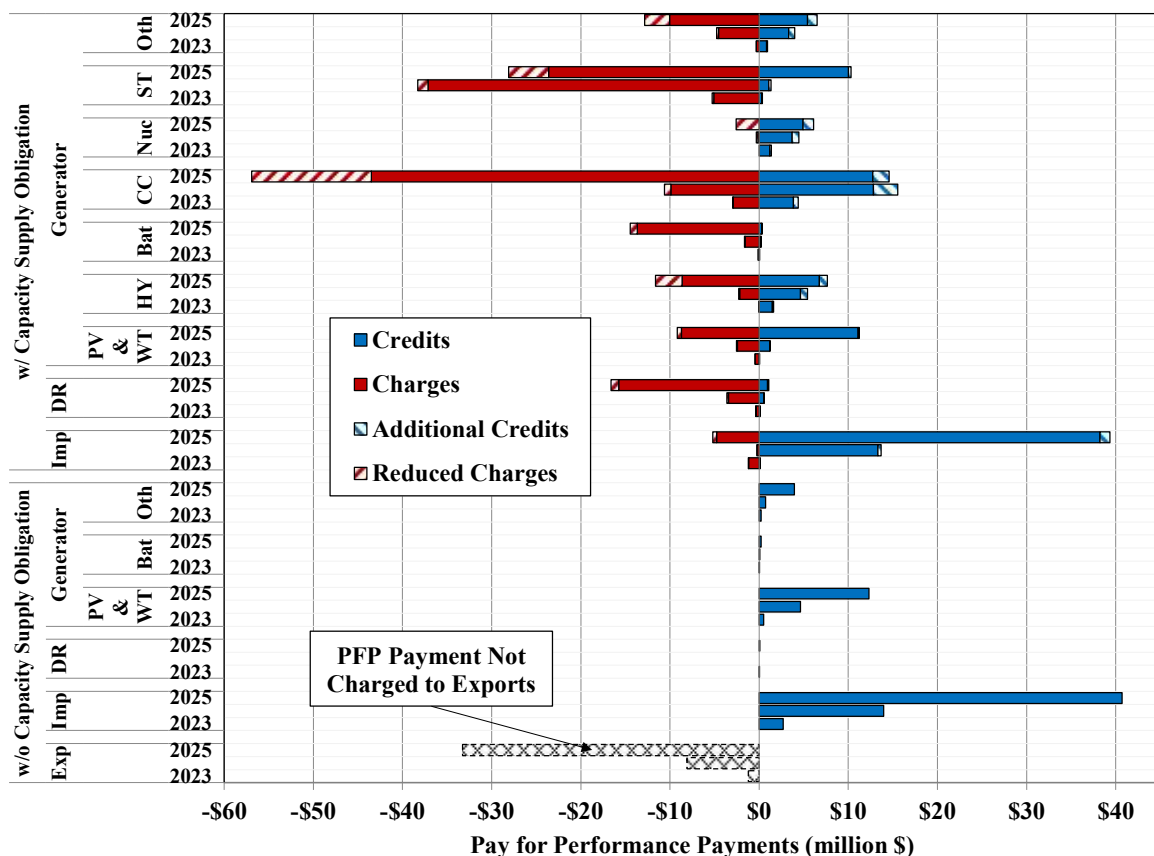
Although shortage conditions were generally brief during each of the five events, they triggered PFP rates of \$3,500 per MWh in 2023, \$5,455 per MWh in 2024, and \$9,337 per MWh in 2025. Under the current rules, imports receive credits at the PFP rate, while exports are exempt from corresponding charges. As a result, some market participants schedule imports while others schedule exports simultaneously because both transactions are profitable during shortage conditions. This outcome is inefficient because the market should reward participants for scheduling power from the area with more surplus supply to the area with less surplus supply.

Pay-for-Performance Settlements During Reserve Shortages

Overall, the PFP rules contribute to grid reliability in several ways. First, they help reduce the likelihood, duration, and severity of system-wide emergencies by incentivizing resources to improve their availability and operational performance during shortage conditions. Second, they strengthen financial incentives to invest in new resources with high availability. However, if PFP rules provide excessive incentives for flexibility, they may inefficiently discourage the retention of existing generation with less flexible characteristics.

Under the PFP rules, resources that fail to deliver energy or operating reserves during shortage events incur financial penalties, referred to as PFP charges, regardless of the reason. Conversely, resources that perform well and help maintain system reliability receive PFP credits. Figure 25 summarizes the distribution of PFP credits and charges during shortage events over the past three years. It categorizes resources by type and by whether they held CSOs. It shows units with longer lead times, including fossil fuel-fired steam turbines, combined cycle units, and nuclear units, separately from intermittent resources (solar and wind), battery storage resources, and hydro resources. It groups peaking units and all remaining resources in the “Other” category. It also shows imports, exports, and demand response resources separately from generation resources.

Figure 25: PFP Settlements and Impact of Export Treatment
2023-2025



The figure also shows: (a) the amount *not* charged to exports; and (b) the “*Additional Credits*” that performing resources would have received, along with the “*Reduced Charges*” that under-performing resources would have incurred, if exports had been treated as under-performers in the calculation of the PFP event Balancing Ratio.⁶⁰ We calculated these values using applicable PFP penalty rates of \$3,500 per MWh in 2023, \$5,455 in 2024, and \$9,337 in 2025. Approximately

⁶⁰ In the figure, the sum of the “Charges” category and the “Reduced Charges” category equals the total charges under the current PFP rules.

\$26 million in stop-loss adjustments were associated with the June 24, 2025 event. Any performance charges not covered by resources that reached their stop-loss limits were allocated to all other CSO holders. These stop-loss adjustments are not reflected in the figure.

Figure 25 indicates that resources with CSOs that underperformed during the five shortage events over the past three years incurred more than \$230 million in PFP charges. Approximately 63 percent of these charges fell on conventional slow-start generators, such as steam turbines and combined-cycle units. While some of these units experienced forced outages or deratings, many were simply offline because they were not committed in the day-ahead market. These outcomes highlight the significant PFP risk that resources with long lead times face during unforeseen real-time shortage events. While it is appropriate for such resources to bear some reliability risk, the resulting penalties should remain aligned with the system's underlying reliability value, which was relatively modest during these events.

Inefficient Incentives for External Transactions

Import transactions without CSOs received more than \$57 million in PFP credits during the five shortage events because imports were eligible for the full PFP incentives, which rose from \$3,500 per MWh in 2023 to \$9,337 per MWh in 2025. In contrast, exports did not incur any PFP charges, creating inefficient incentives for external transaction scheduling during shortage conditions. These rules may also create a gaming opportunity if a participant uses separate bidding entities to schedule equal quantities of imports and exports simultaneously. No net power would flow across the interface, yet the participant could still receive PFP credits for imports while avoiding corresponding charges on exports, up to \$9,337 for each MW scheduled. The figure indicates that, had exports incurred PFP charges, exporters would have incurred approximately \$43 million during the five events. In addition, other resource categories would have received \$13 million in additional credits and \$32 million less in charges.

Apart from the gaming opportunity described above, the treatment of exports also creates scheduling incentives that can lead to inefficiently high exports. The total incentive for scheduling imports and exports during shortages already includes ORDC shortage values, which start at \$1,000 per MWh for 30-minute reserve shortages and can rise to \$2,750 per MWh during simultaneous shortages of 10- and 30-minute reserves. However, because the PFP rate applies only to imports, import incentives can exceed \$12,000 per MWh when combined with the 2025 PFP rate of \$9,337 per MWh, while export incentives are capped at \$2,750 per MWh. This large disparity does not support efficient import and export scheduling during shortage conditions and may distort transaction behavior in ways inconsistent with reliability needs. Accordingly, we recommend that the ISO revise the PFP settlement rules to charge exporters the PFP rate during Capacity Scarcity Conditions. (Recommendation #2022-3)

ISO-NE has proposed revisions to the PFP treatment of external transactions that would create a new PFP charge quantity called System-Backed Exports (SBE). SBE represents excess energy

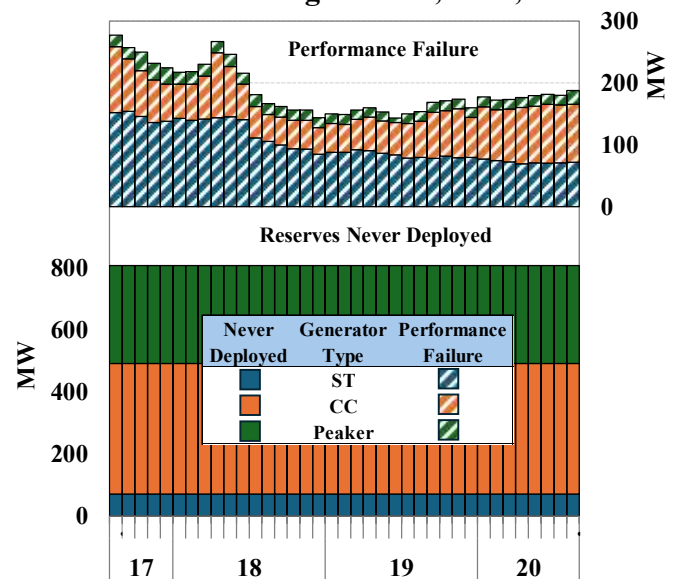
exported from ISO-NE when a generator-backed export exceeds the energy and reserves provided by its backing generator or when a market participant schedules exports in excess of imports. These quantities would be charged the applicable PFP rate and excluded from the Capacity Balancing Ratio calculation.⁶¹ The proposed revisions are consistent with our recommendation, and we fully support this rule change.

Impact of Unreported Derates on PFP Settlements

The PFP mechanism compensates resources based on their actual performance during reserve shortages. It is straightforward to assess the performance of capacity that is generating energy. However, for capacity providing operating reserves during a PFP event, it can be difficult to determine whether the capacity is actually available for the full amount of its reserve schedule. Output ranges offered at high price levels are generally scheduled for reserves rather than energy. If a resource is partially or fully unavailable, the owner has a strong financial incentive to offer the resource so it will be scheduled for reserves. This allows the owner to avoid demonstrating that the resource is unavailable while being compensated for reserves. To provide efficient incentives for capacity performance, the market must accurately determine whether resources were truly available during each event. The following analysis evaluates resources that were credited with providing reserves during the June 24, 2025 PFP event to determine whether those reserves were actually available to provide energy.

Figure 26 summarizes our analysis of units scheduled for operating reserves during the June 24, 2025 PFP event. The top portion of the chart shows the amount of capacity credited as reserves in the PFP settlements that either: (a) was scheduled for reserves because it could not ramp up in a previous interval, or (b) was subsequently dispatched up but failed to follow the instruction. In both cases, the capacity was credited with providing reserves but may not have been able to produce energy during the PFP event. The amount of capacity shown in the top portion fell during the event because the operator entered derates for some units after they demonstrated an inability to follow dispatch instructions. After the operator entered the derate, the resource was no longer credited with providing reserves. The figure breaks down this capacity into three generator types: conventional steam turbines, combined cycle generators, and peaking facilities.

Figure 26: Evaluation of Operating Reserves during June 24, 2025, PFP



⁶¹ See *Pay-for-Performance Revisions: Treatment of External Transactions*. NEPOOL Market Committee, April 14-16, 2026.

The bottom portion of the figure shows the quantity of reserves held on resources that were never dispatched for energy in those ranges during the event. There is no indication that most of this capacity is unavailable. However, for a relatively small portion, the generators were scheduled at quantities substantially higher than their Summer SCC value. Further investigation is needed to determine whether this capacity was available.

Misalignment with the Value of Lost Load

This may be the most significant concern with the current PFP design. During the 2025 shortage events, importers and other suppliers received average compensation exceeding \$11,000 per MWh from reserve shortage pricing and PFP settlements combined. This compensation substantially exceeds the true marginal reliability value of energy in New England during small reserve shortages, as measured by the Expected Value of Lost Load (“EVOLL”).

EVOLL equals the value of lost load (i.e., the value of keeping the lights on) times the probability of losing load, which increases as the reserve shortage deepens. Accordingly, EVOLL should rise as system conditions deteriorate. By contrast, the PFP rules use a constant rate regardless of the severity of the reserve shortage. Figure 27 shows how EVOLL increases as reserve margins decline and compares it with the fixed PFP rate used since June 2025.

Figure 27: PFP Rates and the Value of Lost Load

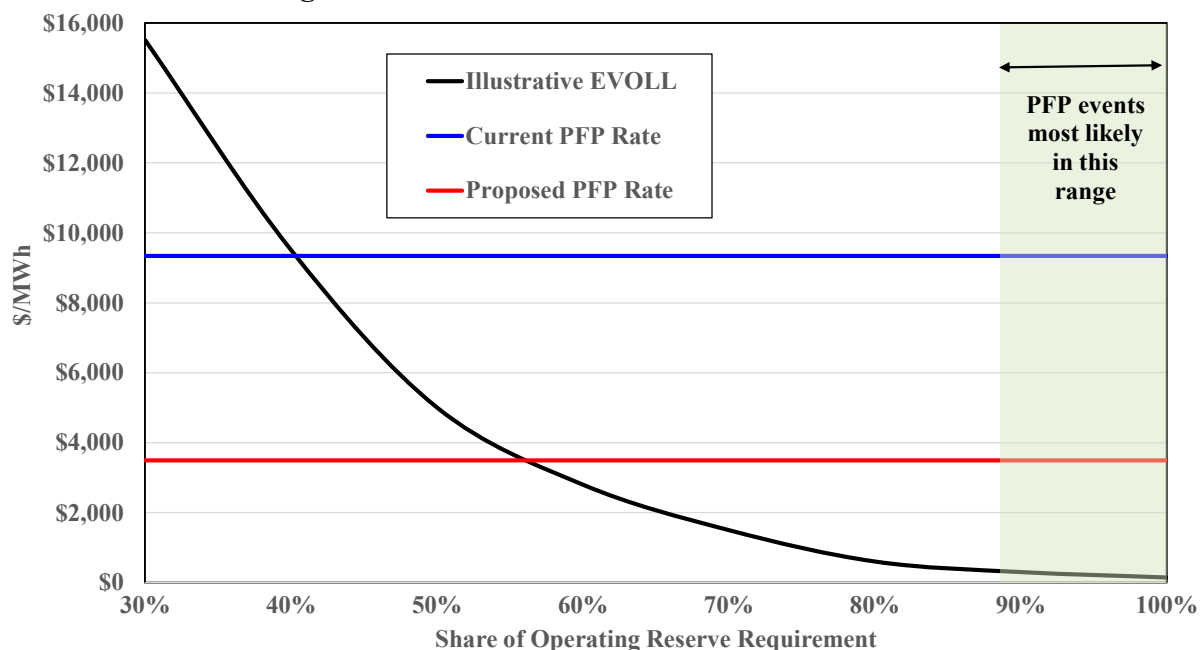


Figure 27 shows that applying a constant PFP rate across all levels of reserve shortages tends to overvalue energy and reserves during shallow shortages, when the probability of losing load is very low, and may undervalue them during deeper shortages. Moreover, the figure understates the potential overvaluation because it does not include shortage pricing in the energy market, which can contribute up to an additional \$2,750 per MWh.

While strong performance incentives are important, excessively high incentives can create inefficient risk for less flexible resources and may lead to inefficient retirement decisions. Therefore, we recommend that the ISO modify its PFP rate to align with a reasonable estimate of Value of Lost Load (“VOLL”) and the probability of load shedding based on the severity of the operating reserve shortage (see #2018-7). This approach would ensure that:

- Deep reserve shortages, when the risk of load loss is high, appropriately incentivize resources to respond; and
- Shallow shortages do not result in unnecessary costs when reliability risk is minimal.

Furthermore, when two neighboring systems simultaneously experience reserve shortages, a PFP structure that rises with shortage severity and underlying reliability risk would contribute to a more efficient allocation of reserves between regions by providing incentives for firms to schedule transactions from the area with a shallower shortage to the area with a deeper shortage.

ISO-NE recently proposed reducing the PFP rate from the current formula-based value of \$9,337 per MWh to a fixed rate of \$3,500 per MWh.⁶² In support of this proposal, the ISO recognized that the current PFP rate may unnecessarily increase supplier risk, raise capacity costs for consumers, and encourage the retirement of resources that still provide reliability value. We support this revision because the lower proposed rate better balances strong incentives for reliability and performance against excessive market risk, inefficient costs, and unnecessary resource retirements during most reserve shortages. In addition, the proposed \$3,500 per MWh rate is more consistent with EVOLL during significant reserve shortages as shown in Figure 27.

The proposal partially addresses Recommendation #2018-7, but we continue to recommend that the ISO consider implementing a graduated stepwise PFP structure that better aligns incentives with the severity of reserve shortages and the associated reliability risk. In the longer term, the ISO should consider means to shift more of the performance incentives into the energy market.

C. Conclusions and Recommendations

This section evaluates two issues that affect the performance of the capacity market.

Comparison of Qualified Capacity to Actual Availability under Peak Summer Conditions

We found that qualified capacity values for generators with combustion turbines do not adequately reflect ambient conditions during periods with the greatest reliability risks because these values generally assume milder temperature, humidity, and barometric pressure conditions than the conditions that drive planning reliability needs. We also observed additional derates under peak summer conditions related to the effect of ambient conditions on cooling equipment. Together, these factors caused available capacity to be 680 MW less than qualified capacity

⁶² See *Pay-for-Performance Revisions: Proposed Change to the Performance Payment Rate (PPR)*. NEPOOL Market Committee, April 14-16, 2026.

during the summer peak conditions of 2025. Hence, we recommend that the ISO monitor compliance with forced derating reporting rules by generators and reassess how it considers ambient conditions in the calculation of Qualified Capacity after the CAR-SA project (#2024-3) is implemented.

Pay for Performance Events

Pay-for-performance events have occurred only five times over the past three years, generally lasting between 30 minutes and three hours and exhibiting average 10-minute and 30-minute reserve shortages of less than 250 MW. Although none of these events posed a significant probability of firm load shedding, settlement amounts were substantial in these events:

- Suppliers incurred more than \$230 million in performance charges, most for available combined cycle or steam units that were not committed in the day-ahead market.
- The total price paid to imports or resources performing above their CSOs was as high as \$12,000 per MWh, including the \$9,337 per MWh penalty rate in 2025.

These prices and associated settlements vastly exceed the reliability value of energy during these events and create substantial inefficient incentives for ISO New England participants.

One key inefficiency is the inconsistent settlement of imports and exports. Applying the PFP rate to importers but not exporters is a significant flaw that distorts scheduling incentives. During these five events, ISO-NE curtailed minimal amounts of scheduled exports, allowing 700 to 1800 MW of scheduled exports to flow, which led to additional PFP charges for other suppliers.

We also identified generators that experienced partial derates during the June 2025 PFP event and did not promptly report them to the ISO. Consequently, the PFP settlement treated much of this capacity as operating reserves, resulting in a net benefit of \$6 million to these generators. Monitoring compliance with generators' obligations to report the status of their units is particularly important when operating reserves are compensated at a marginal rate of more than \$10,000 per MWh (as we recommend in #2024-3).

To address these inefficient incentives, we recommend that the ISO:

- Revise the PFP rules to charge exporters at the PFP rate during Capacity Scarcity Conditions (Recommendation #2022-3). The ISO has recently proposed a revision that would charge System-Backed Exports under the PFP framework, which addresses our recommendation, and we fully support this rule change.
- Modify the PFP rates to levels in line with a reasonable estimate of VOLL and that escalate as reserve shortages deepen (Recommendation #2018-7). The ISO has recently proposed reducing the PFP rate from the current formula-based value of \$9,337 per MWh to a fixed rate of \$3,500 per MWh, which partially addresses our recommendation. However, we continue to recommend that the ISO consider implementing a graduated stepwise PFP structure that aligns incentives more closely with the severity of reserve shortages and the associated reliability risk.

I. Appendix

A. Assumptions Used in Net Revenue Analysis

In this section, we list various assumptions underlying the net revenue estimates for various technologies discussed in Section I.E and II.C.

Net Revenues of Fossil Units

Our net revenue estimates of CC, CT and ST units are based on the following assumptions:

- Natural gas costs are based on the Algonquin City Gates gas price index.
- In the day-ahead market, generators are scheduled based on day-ahead prices, considering commitment costs, minimum run times, minimum generation levels, and other physical limitations.
- In the real-time market, units are committed in real-time based on hourly real-time prices and settle with the ISO on the deviation from their day-ahead schedule.
- Prior to March 2025, CTs are assumed to sell forward reserves in a capability period when it will be more profitable than selling real-time reserves. Following the introduction of DA A/S markets, CTs sell reserves up to their UOL when doing so would be more profitable than generating, and CC and ST units may sell available headroom as reserves subject to ramp limitations when scheduled for energy.
- Fuel costs assume transportation and other charges of \$0.50 per MMBtu in winter and \$0.10 in other months and \$2 per MMBtu for oil on top of the day-ahead index price. Intraday gas purchases are assumed to be at a 20% premium due to gas market illiquidity and balancing charges, while intraday gas sales are assumed to be at a 20% discount for these reasons. RGGI compliance costs are included, if applicable.
- The assumed operating parameters are shown in Table 5:

Table 5: Unit Parameters for Net Revenue Estimates

Characteristic	CT- 7HA	CC (Newer)	CC (Older)	CC (Small)	CT (Newer)	CT (Older)	ST
Average Heat Rate (MMBTU/MWh)	9.2	6.6	7.5	8.5	10	12	9.7
Min Run Time (Hours)	1	4	6	6	1	1	16
Variable O&M (\$/MWh)	1.75	3	3.5	3.5	7	7	6
Startup Cost (\$/MW)	30.6	0	30	30	30	30	22
Startup Cost (MMBTU/MW)	10	10	10	10	1.25	1.25	10

- The heat rate and capacity for a unit on a given day are assumed to vary linearly between the summer values on August 1 and the winter values on February 1.

Net Revenues of Renewable Resources in New England

We estimated the net revenues of renewable units in ISO-NE using the following assumptions:

- Net E&AS revenues are calculated using real time energy prices.
- For cross-market comparison of land-based wind revenues, we utilized a generation profile that is based on inputs to NREL's ReEDS model.
- The capacity revenues in each year are estimated using clearing prices from the corresponding FCAs. For our cross-market comparison of revenues, we assumed a capacity value of 18.9 percent for solar and 39.3 percent wind in ISO-NE based on FCA18 ORTP assumptions.
- We estimated the REC revenues for land-based wind using MA Class I REC prices obtained from S&P Global Market Intelligence.
- The net revenues of all renewable projects included Investment Tax Credit (ITC) or Production Tax Credit (PTC). The ITC reduces the federal income tax of the investors in the first year of the project's commercial operation. The PTC is a per-kWh tax credit for the electricity produced by a wind facility over a period of 10 years.
- The CONE for renewable units was calculated using the financing parameters and tax rates specified in the ISO-NE Net CONE study and publicly available market data.⁶³
- We estimate capital and operating costs using publicly available sources including NREL's Annual Technology baseline (ATB) and Lazard's Levelized Cost of Energy.

Net Revenues of Wind and Solar Resources in Other Markets

In this subsection we discuss assumptions underlying our net revenue estimates for land-based wind resources in three other markets. Net revenues and CONE estimates for the wind plant in NYISO are based on the information presented in the NYISO State of the Market report.⁶⁴ Net revenues of wind units in MISO and ERCOT are based on the following assumptions:

- Net E&AS revenues are calculated using real time energy prices in the West zone in ERCOT and in Minnesota / North for MISO.
- The energy produced by these units is calculated using location-specific hourly capacity factors. We considered capacity factor for recent wind installations in MISO and ERCOT, and the capacity factor information presented in 2024 NREL ATB for our assumption regarding the capacity factor for land-based wind in these regions. We assumed a 40 percent annual average capacity factor for wind in ERCOT west and a 45

⁶³ See Norton Rose Fulbright Cost of Capital: 2026 Outlook, available [here](#). We estimated cost of capital in each year assuming a pre-tax cost of debt equal to the Secured Overnight Financing Rate (SOFR) plus indicated lender spreads, a debt to equity ratio targeting a debt service coverage ratio (DSCR) that reflects a combination of merchant and contractual revenues, and a cost of equity based on the NYISO and ISO-NE Net CONE studies. For 2025, we calculate an ATWACC of 8.0 percent for wind and 7.8 percent for solar.

⁶⁴ See Section IV and Appendix VII of our 2025 report on the New York ISO markets, available [here](#).

percent annual capacity factor for wind in MISO. We assumed a 30 percent capacity factor for solar in ERCOT.

- We estimated the value of RECs produced by the wind unit in ERCOT the Texas REC Index reported by S&P Global Market Intelligence. For MISO, we utilized publicly available information on the REC prices in Minnesota.
- Consistent with the assumption for other markets, we assumed full PTC revenues for the land-based wind plants in ERCOT and MISO regions.

B. Assumptions Used in Evaluation of Ambient Conditions Effects on SCC

Common Types of Ancillary Cooling Systems on Combustion Turbines

Combustion turbines are frequently equipped with one or more of the following inlet cooling systems:

- Evaporative Coolers
 - Uses a water-saturated media to cool CT inlet air.
- Inlet Fogging
 - Sprays a mist of water into the inlet air flow which then evaporates and cools the inlet air comparably to evap coolers.
- Chillers
 - Relies on a refrigeration cycle to absorb heat.
- Wet Compression
 - Sprays atomized water directly into the compressor inlet to cool inlet air via evaporation.

Of the systems listed above, the cooling efficiencies of evap coolers and inlet fogging systems are dependent on relative humidity conditions at the site since. Both systems work to add moisture to the ambient air entering the CT inlet. Therefore, the more humid the ambient air is, the less cooling capacity these systems can provide. Consequently, it is only those ambient conditions dependent generators that have either or both of evaporative cooling or inlet fogging systems installed that ought to be normalized to peak humidity conditions.

Figure 21 Methodology

When the system is off, the GT inlet air temperature will be consistent with the ambient air temperature. However, with the evaporative coolers or inlet foggers in use, the GT inlet air temperature converges on the corresponding wet bulb temperature, itself dependent on the dry bulb temperature and the relative humidity of the ambient air. The ability of the ancillary system to reduce the GT inlet air temperature from dry bulb to wet bulb is called the system efficiency.

For this analysis, we used an efficiency assumption of 90 percent.⁶⁵ To calculate the wet bulb temperature at each relative humidity level, we used the following equation:⁶⁶

$$Tw = T * \arctan(0.151977 * \sqrt{RH + 8.31659}) + 0.00391838 * \sqrt{RH^3} \\ * \arctan(0.023101 * RH) - \arctan(RH - 1.676331) + \arctan(T + RH) \\ - 4.686035$$

The equation to estimate GT inlet air temperature with ancillary system in service based on the efficiency metric “e” was:

$$T_{inlet} = T - [e * (T - Tw)]$$

We assumed that the ancillary cooling systems would only be used at ambient temperatures of 60°F or greater.

Figure 22 Methodology

We matched hourly barometric pressure values to each ZIP code where a generator with a combustion turbine in New England is located when systemwide load was above 14 GW. All barometric pressure measurements were grouped into categories of 200 MWs from 14 GW to 24.2 GW (i.e., 14 GW, 14.2 GW, 14.4 GW, etc.). We calculated the 90th and 10th percentile values from each group and created linear regressions between the percentile values against load. The solid green line shows the results of the regression for the 90th percentile barometric pressure value while the solid black line denotes the 10th percentile per bucket as a function of systemwide load. Together, these lines give a sense of the likely range of barometric pressures at a given load level.

Next, we ran a similar regression based on the mean barometric pressure for each load bucket. This curve gave the expected value barometric pressure at the peak load condition observed in the weather data. From that curve, we estimated the mean barometric pressure at the forecasted 2025 peak load level and plotted as the dashed red line.⁶⁷ The blue markers denote the actual barometric pressures for each Summer SCC Audit of relevant generators from 2022-2024. Finally, the secondary y-axis shows the estimated impact on SCC Audit results based on the delta between audit pressure conditions and expected peak pressure conditions for 2025.⁶⁸

⁶⁵ The actual efficiency of the cooling systems of each resource are unknown, but 90 percent is a commonly assumed average efficiency number. For example, see https://www.iso-ne.com/static-assets/documents/2017/01/npc_20170106_composite4.pdf.

⁶⁶ See <https://www.omnicalculator.com/physics/wet-bulb>.

⁶⁷ Forecasted peak (net) load for 2025, per the ISONE [CELT Report](#), is 24,579 MW (net).

⁶⁸ Impact of barometric pressure on generator output was assumed to be +1% per +0.1 psia which was derived from Figure 10 of [GE Gas Turbine Performance Characteristics](#), Frank J. Brooks.

Adjustments for Barometric Pressure and Relative Humidity

Temperature normalization relies on capability curves in the current ISO processes. These are curves given by market participants to the ISO that depict generator capability as a function of air temperature in one-degree Fahrenheit increments. Temperature dependencies are given based on the slopes between points on the curve. Adjustments for barometric pressure and relative humidity could be incorporated using the following approach.

Ambient Adjusted SCC = T * P * H * Audit MW

Where T = Temperature Normalization factor

P = Pressure normalization factor

H = Humidity Normalization Factor (which equals 1 for non-humidity dependent units)

15

Administrative Matters

Admin
Matters

June 16-18, 2026
Summer Meeting

16

Host State Welcome Remarks

Admin
Matters



June 16-18, 2026
Summer Meeting

17

IMM Report



JUNE 17, 2026 | NEPOOL PARTICIPANTS COMMITTEE, NEWPORT, RI

Annual Market Performance Report and 1-Year Review of Day-Ahead Ancillary Services



Key takeaways

Dave Naughton

EXECUTIVE DIRECTOR, INTERNAL MARKET MONITOR



June 16-18, 2026
Summer Meeting

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

Annual Market Performance Report and 1-Year Review of Day-Ahead Ancillary Services



Key takeaways

Dave Naughton

EXECUTIVE DIRECTOR, INTERNAL MARKET MONITOR



About the Internal Market Monitor

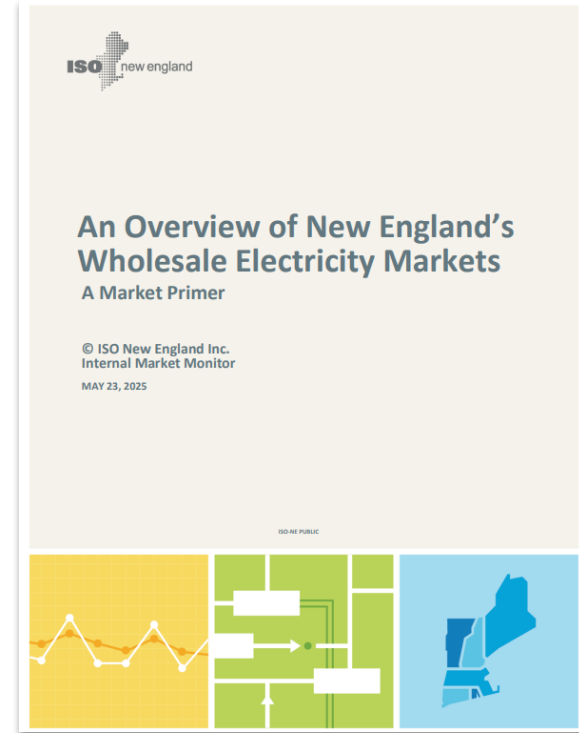
- The IMM is an independent group within ISO-NE with a mission to protect both Consumers and Market Participants in carrying out its 5 core functions:
 1. Monitor Market Performance & Participant Behavior
 2. Report on Market Performance and Competitiveness
 3. Assess and Refer (to FERC) Potential Market Violations
 4. Administer the Market Power Mitigation rules
 5. Evaluate New and Existing Market Rules
- The IMM is composed of economists, market analysts, data scientists, business managers and legal counsel



Accompanying Market Primer Document

- Provides an overview of products procured through the wholesale markets: product definitions, procurement mechanisms, settlements
- Second edition adds Day-Ahead Ancillary Services content

See [IMM section](#) of ISO-NE website or click on document image



ANNUAL MARKETS REPORT

[Link to report](#)



Market Outcomes Overview

- Capacity, energy, and ancillary service markets generally **performed well** and exhibited **competitive outcomes** in 2025; energy price changes were consistent with fuel prices, electricity demand and the supply mix
- Notable factors impacting the cost of supply were higher **natural gas prices**, **emissions costs** under the Regional Greenhouse Gas Initiative (RGGI) and Massachusetts Electricity Generator Emissions Limits (EGEL) program, **lower net interchange** with Quebec, and new market design features (**DA A/S**)

	2021	2022	2023	2024	2025	NEPOOL PARTICIPANTS COMMITTEE			
Demand (MW)	JUN 16-18, 2026 SUMMER MEETING, AGENDA ITEM #17								
Load (avg. hourly)	13,561	13,576	13,096	13,299	13,441	↑	1.1%		
Weather-normalized load (avg. hourly) ^[a]	13,419	13,514	13,132	13,236	13,394	↑	1.2%		
Peak load (MW)	25,801	24,780	24,043	24,871	26,586	↑	6.9%		
Generation Fuel Costs (\$/MWh) ^[b]									
Natural Gas	36.07	72.41	23.68	23.83	48.91	↑	105.2%		
No.6 Oil	138.30	221.15	164.91	154.92	154.29	→	-0.4%		
Diesel	184.69	332.15	253.44	217.28	207.33	↓	-4.6%		
Hub Electricity Prices: LMPs (\$/MWh)									
Day-ahead (simple avg.) ^[c]	45.92	85.56	36.82	41.47	71.81	↑	73.2%		
Real-time (simple avg.)	44.84	84.92	35.70	39.50	65.89	↑	66.8%		
Day-ahead (load-weighted avg.)	48.30	91.36	39.19	44.52	78.44	↑	76.2%		
Real-time (load-weighted avg.)	47.34	91.13	38.25	42.46	72.21	↑	70.1%		
Estimated Wholesale Costs (\$ billions)									
Energy	6.1	11.7	4.8	5.6	9.9	↑	76.7%		
Capacity ^[d]	2.3	2.0	1.8	1.4	1.2	↓	-16.4%		
Uplift (NCPC)	0.04	0.05	0.03	0.03	0.04	↑	20.2%		
Ancillary Services ^[e]	0.1	0.1	0.2	0.2	0.2	↑	37.6%		
Regional Network Load Costs	2.7	2.8	2.7	3.0	3.6	↑	23.0%		
Total Wholesale Costs	11.2	16.7	9.5	10.2	15.0	↑	47.6%		
Supply Mix ^[f]									
Natural Gas	45%	45%	48%	50%	50%	→	0.1%		
Nuclear	22%	23%	20%	22%	23%	→	0.7%		
Imports	16%	14%	13%	9%	7%	↓	-1.9%		
Hydro	6%	6%	8%	7%	6%	↓	-1.0%		
Other ^[g]	5%	4%	4%	4%	4%	→	0.1%		
Wind	3%	3%	3%	3%	4%	→	0.9%		
Solar	2%	3%	3%	4%	5%	→	0.6%		
Coal	0%	0%	0%	0.2%	0.2%	→	0.0%		
Oil	0%	2%	0%	0.3%	1.0%	→	0.7%		
Battery Storage	0%	0%	0%	0.3%	0.1%	→	-0.2%		

Executive Summary (1)

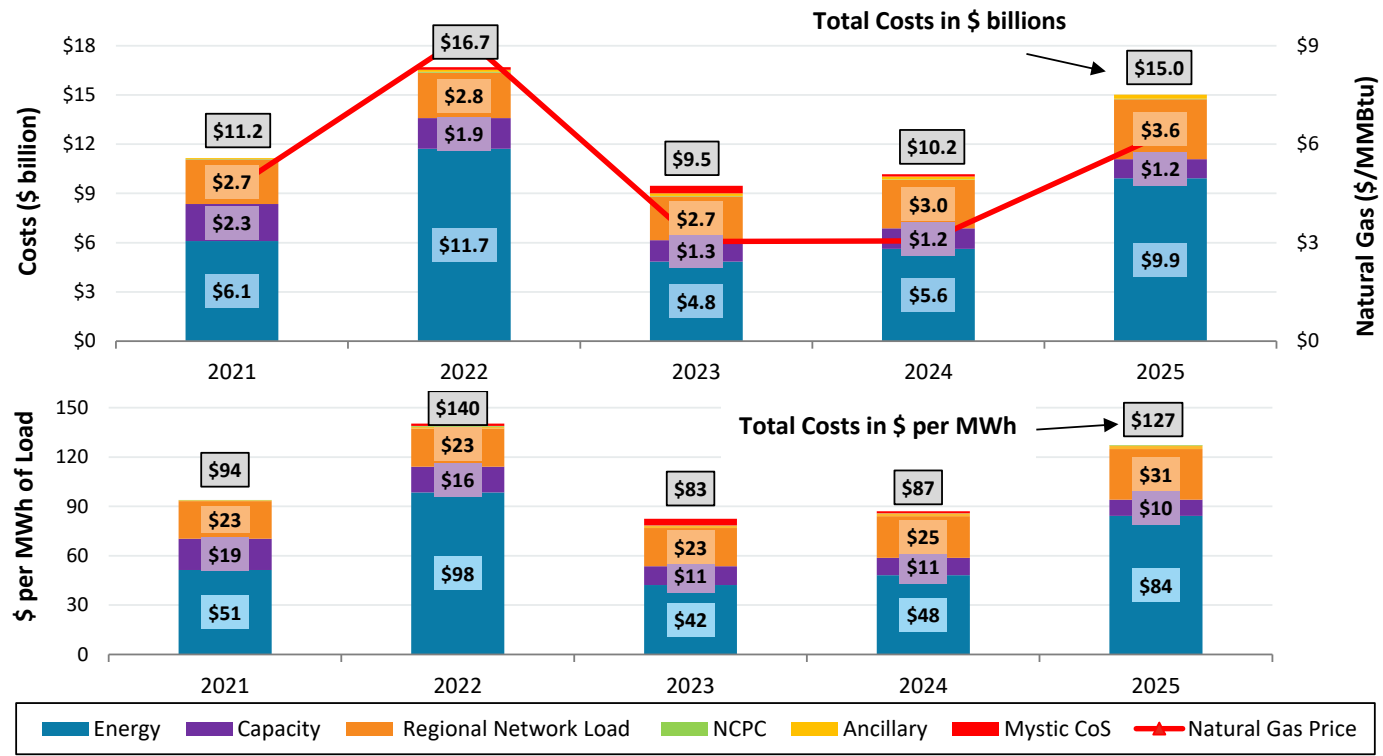
- **Wholesale costs** rose sharply in 2025 to \$15 bn—nearly 50% higher than 2024 and the second highest since 2008 (in nominal terms); driven by higher energy costs (up \$4.3 bn) and transmission costs (up \$0.6 bn) [[slide 8](#)]
- **Energy costs** of \$9.9 bn (~66% of total costs) and energy prices (\$71.81/MWh, up 73%) were driven by higher natural gas and CO₂ prices, tighter supply conditions including declining imports, as well as market design changes (day-ahead ancillary services or DA A/S)
 - Avg. **natural gas** price doubled in 2025 (from ~\$3 to \$6/MMBtu) and was the dominant driver of energy prices; higher national prices particularly at Marcellus and elevated national and New England prices during winter months [[slide 9-10](#)]
 - Higher **CO₂** prices from the Regional Greenhouse Gas Initiative (up 6.5%) and Massachusetts Emissions Generation Limits cap-and-trade programs (up 290%) due to tightening emissions limits and increased demand for allowances. [[slides 10-11](#)]
 - Net **imports** continued to decline to the lowest level since 2011 (932 MW per hour), meeting 7% of demand; dry hydro conditions in Quebec and a prolonged nuclear outage in New Brunswick continued a multi-year decline in imports from Canada; higher reliance on internal (natural gas) supply to meet demand [[slide 12](#)]
 - The incremental costs of the new **DA A/S** market changes were \$477 m in 2025, slightly offset by the sunsetting of the Forward Reserve Market (\$54 m) and lower uplift costs

Executive Summary (2)

- Relatively few but increasing number of **shortage conditions** (3.6 hrs., up from 2.3 hrs. in 2024), very few reliability commitments, and low levels of transmission congestion
 - **Uplift** of \$42 m (\$0.35/MWh or 0.4% of energy costs) primarily covered resources committed and dispatched in economic merit order
 - **Congestion** costs of \$75 m (0.8% of energy costs) were modest, with export constrained flows at the main interface with New York and in northern New England continuing to be the significant drivers
- **Profitability** and net revenue metrics increased as a result of higher natural gas prices and revenues from DA A/S, with total revenues for hypothetical new combined cycle and combustion turbines exceeding Gross Cost of New Entry estimates [[slides 13-14](#)]
 - DA A/S revenues to fast-start combustion turbines materially increased E&AS revenues and should reduce reliance on capacity payments
- The pace of the **energy transition** and impact on operational and market metrics is gradual; most significant impact is on load and pricing profiles due to solar generation; NECEC and offshore wind additions potentially significant [[slides 15-16](#)]
- Market power indices consistent with **competitive** outcomes; despite pivotal suppliers in 33% of real-time hours, there are few pivotal suppliers in the day-ahead market and the estimated cost impact of above-cost offers was modest [[slide 17](#)]
- New **recommendations** since the last annual report relate to DA A/S and were [published in February 2026](#)
 - Recommendations trending up in importance relate to reviewing aspects of the energy market mitigation rules (including conduct and price impact thresholds) in the context of potential larger supply portfolios

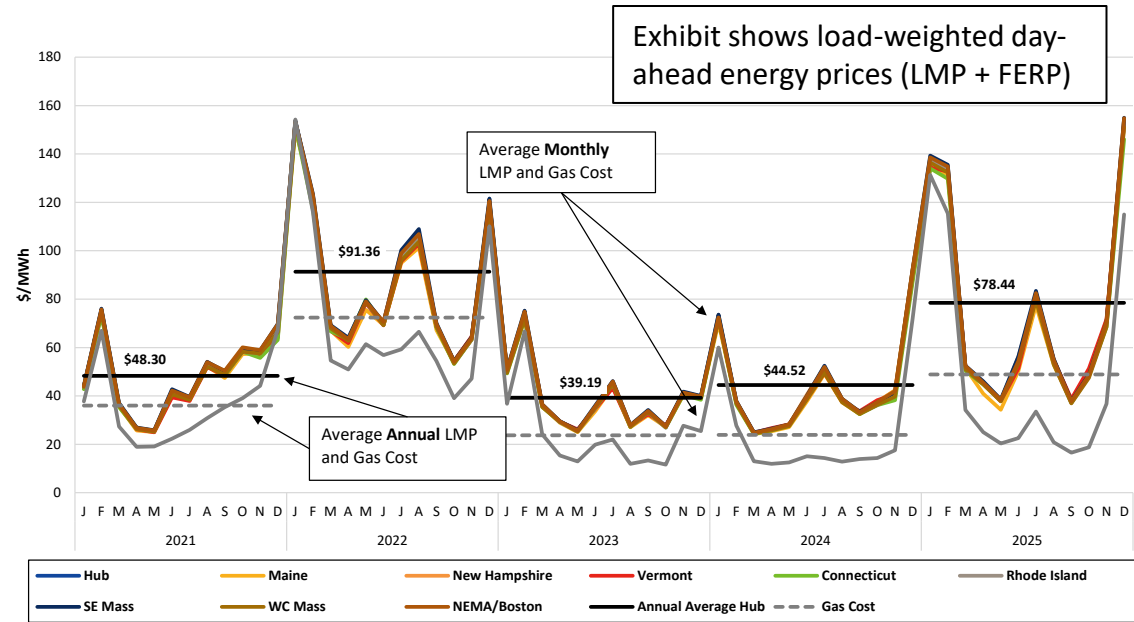


Higher energy costs drove a \$4.8 billion increase in wholesale costs; transmission costs also rose



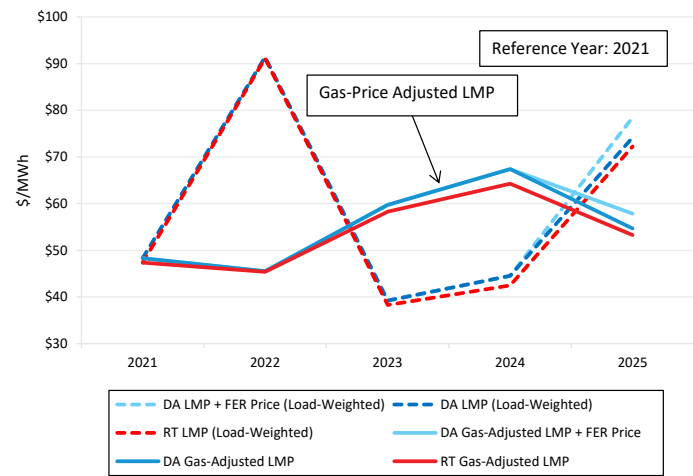
Natural gas continues to be the significant driver of energy prices, but annual changes driven by other supply and demand factors, and market changes

Day-Ahead Load-Weighted Prices



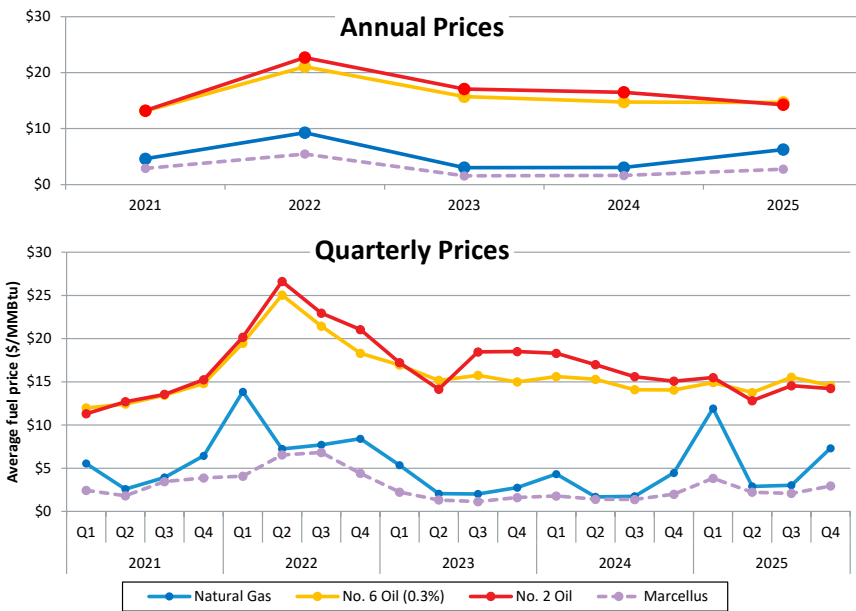
Natural gas cost presented in \$/MWh terms based on a heat rate of 7,800 Btu/kWh, the average heat rate for a typical New England natural gas generator

Annual Average Natural Gas Price-Adjusted LMPs



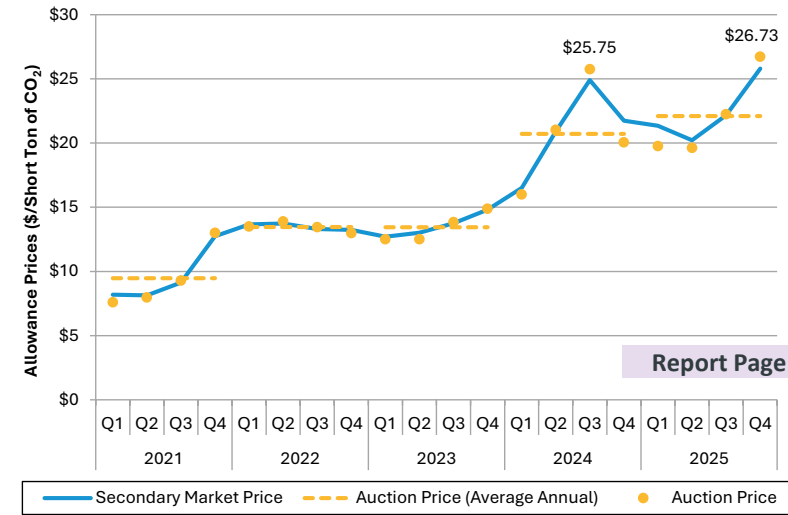
National and regional natural gas price increases and rising CO₂ prices drove higher generation production costs

Average Fuel Prices by Quarter and Year



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Regional Greenhouse Gas Initiative (RGGI) Prices



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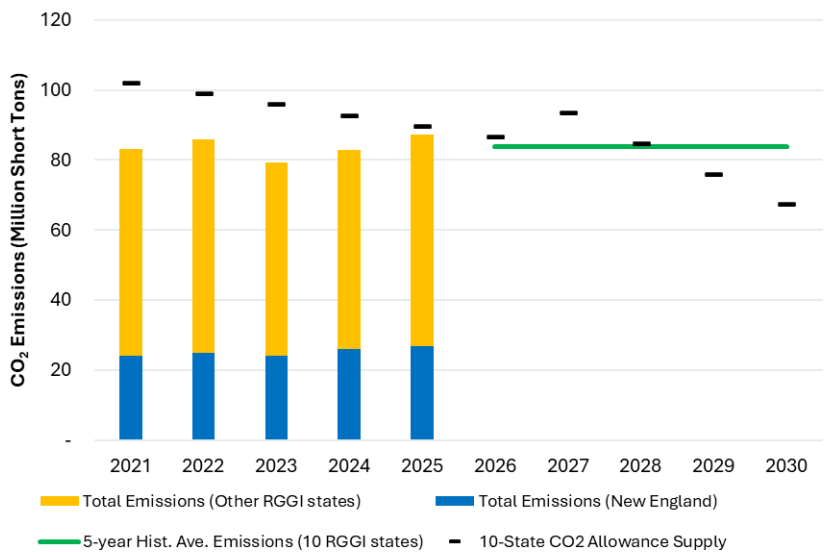
CO₂ Production Cost Component by Fuel

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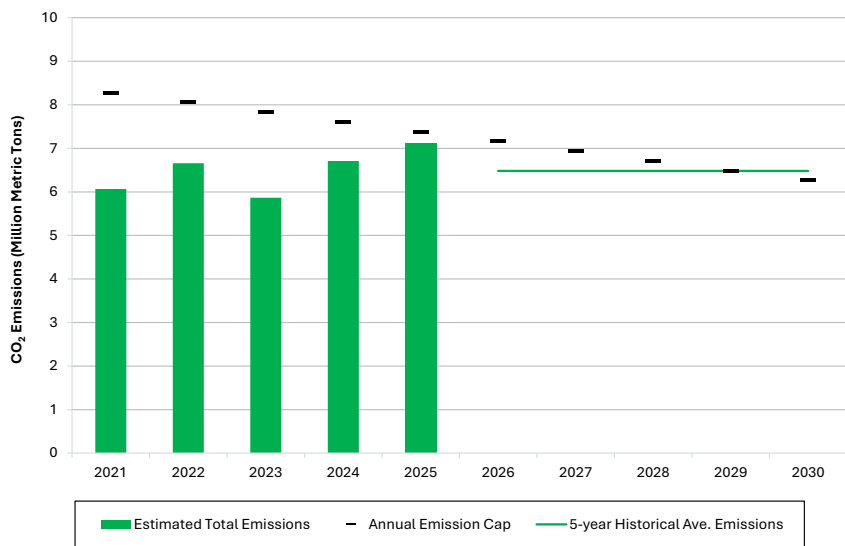
2025 Emissions Costs (in \$/MWh)	Natural Gas	No. 6 Oil	No. 2 Oil
RGGI Costs (\$/MWh)	\$10.21	\$20.44	\$21.08
RGGI % of Generation Costs	17%	11%	11%
MA EGEL Costs (\$/MWh)	\$3.56	\$8.70	\$8.97
Total CO ₂ % of Generation Costs	21%	15%	15%

Carbon prices increase due to higher demand and declining allowance supply; actual emissions approaching caps in both RGGI and MA EGEL programs

RGGI Emissions Levels and Allowance Supply



MA EGEL Emissions Levels and Cap



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Impact of Carbon Allowance Prices on Day-Ahead Energy Market Prices

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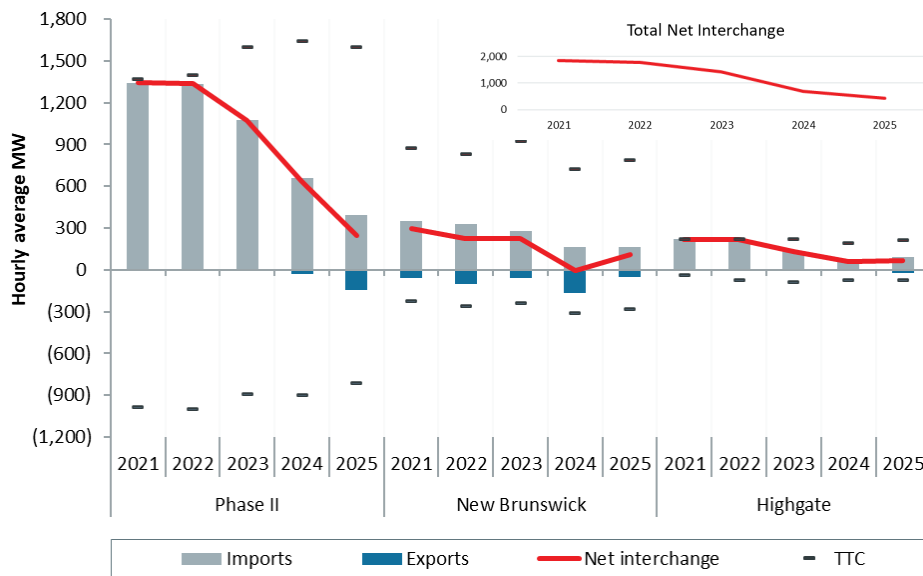
	2023	2024	2025
Energy Price Impact	\$6/MWh	\$8/MWh	\$9/MWh
Energy Cost Impact	\$690 million	\$910 million	\$1.1 billion

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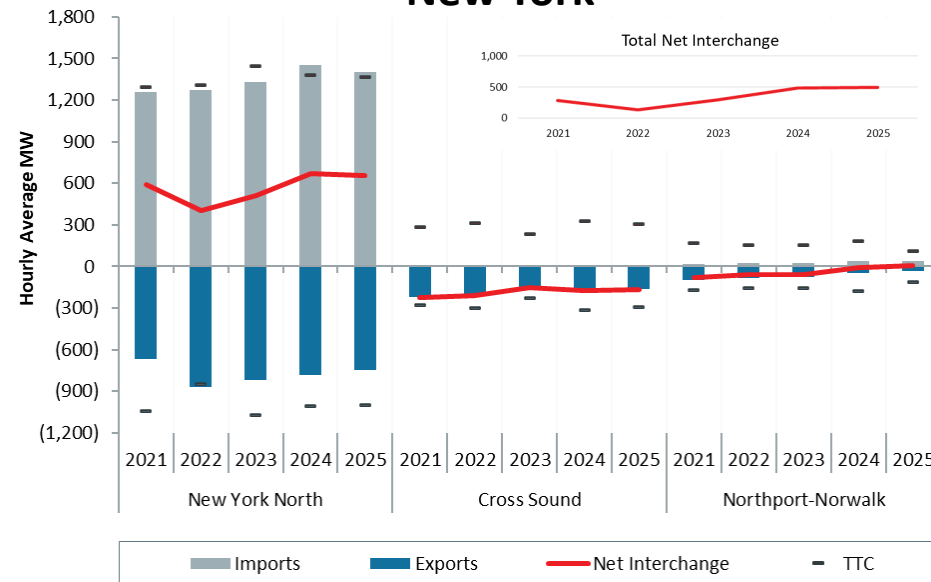
Net interchange between New England and Canada fell substantially for the third consecutive year, flows with New York remained stable

Canada



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New York

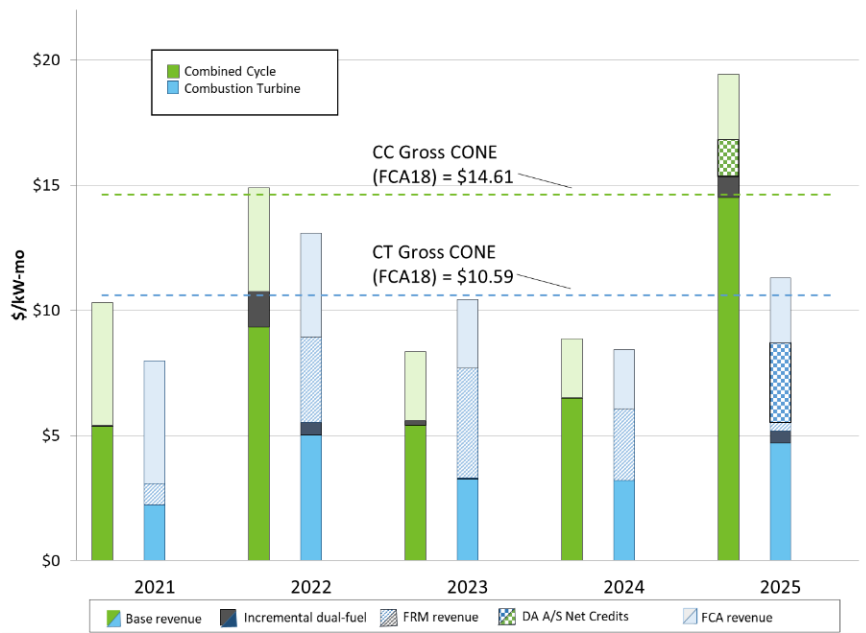


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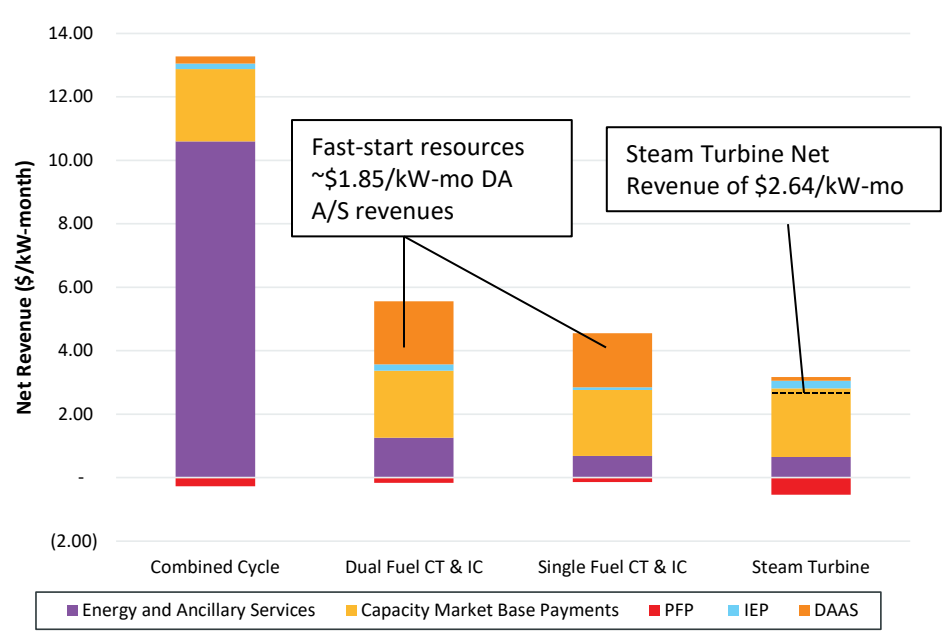
Despite the overall decline, net interchange remained a critical supply source during high-load periods; During hours where day-ahead energy prices were above \$100/MWh, net interchange averaged nearly 2,700 MW per hour, in line with prior years

Market revenues improved in 2025, with significant variation across resource types; DA A/S revenues materially increased the share of energy and ancillary services revenues for fast-start resources

Hypothetical New Entrant Combined Cycle and Combustion Turbines

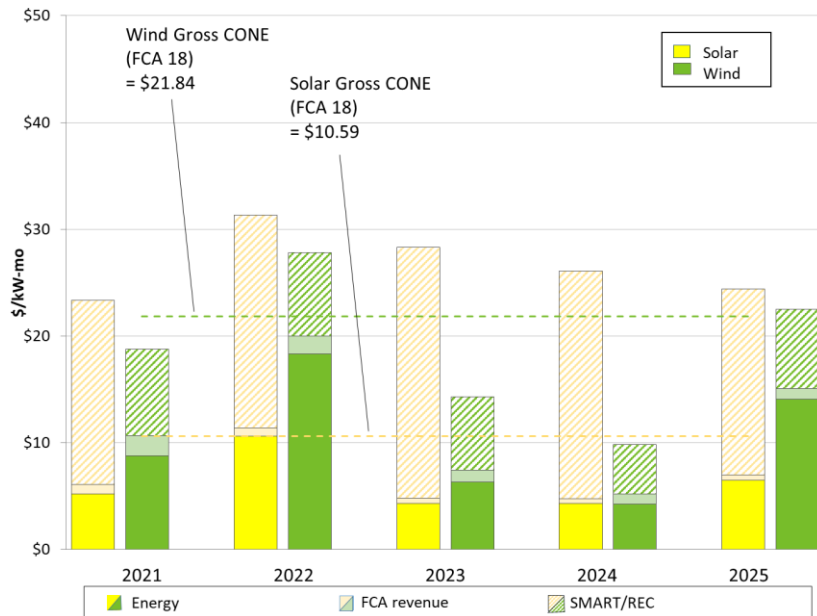


Existing Resources Net Market Revenues



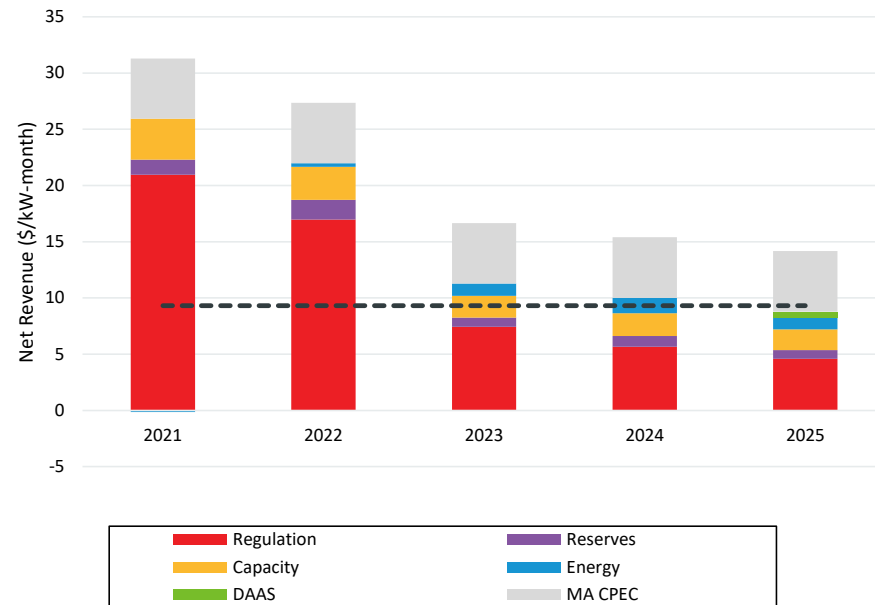
Profitability of new entry wind and solar shows more dependence on state programs

Estimated Net Revenue for Solar- and Wind-Powered Units



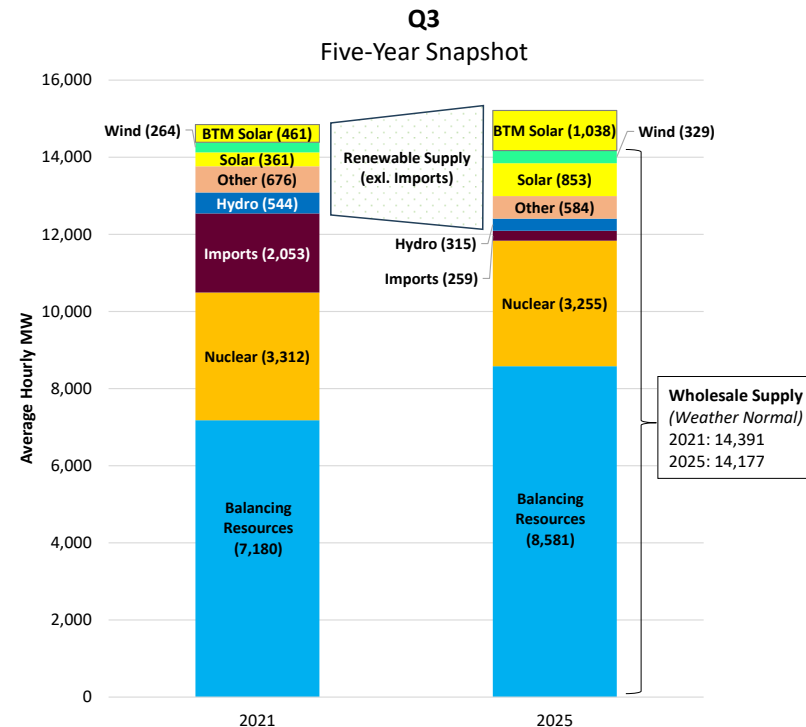
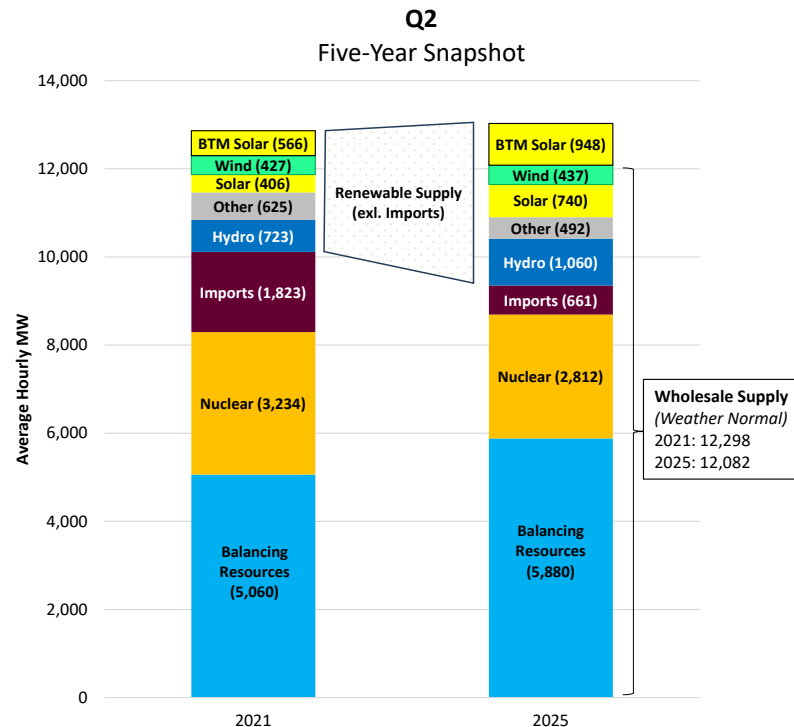
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Net Revenues for Battery Resources



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5-year snapshot of supply and demand shows gradual change; NECEC and offshore wind additions potentially significant



Energy transition and changes to operational/market metrics are gradual to date, impact on intraday ramping and flexible generation utilization more pronounced

Metric	Description of Expected Trend	Trend
Energy Usage	Sustained load growth, with winter energy use and peak demand increasing faster than summer demand.	—
Seasonal/Annual Load Variability	Increasing variability in annual energy needs, driven primarily by winter heating demand and heightened sensitivity to cold weather.	—
Morning and Evening Load Ramps	Steeper morning (down) and evening (up) load ramps as solar generation penetration increases.	▲
Downward Flexibility of Supply	More frequent periods where net load falls below the minimum stable operating levels of conventional generation.	—
Fast-Start Generator Utilization	Greater reliance on fast-start, dispatchable resources to manage steeper and more volatile load ramps.	▲
Load Forecast Error	Increased difficulty forecasting load accurately, with a focus on day-ahead and intra-day timeframes.	—
Negative Energy Prices	Increasing frequency of negative LMPs as renewable generation grows and negative offer prices become more prevalent.	▲
Energy Price Level	Downward pressure on energy prices associated with higher renewable generation levels.	▲
Energy Price Volatility	Price volatility driven by intermittent renewable output and changing net-load conditions remains consistent with prior years.	—

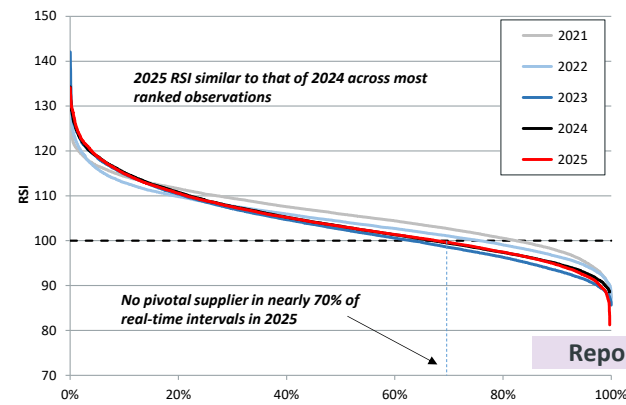
The trend indicator reflecting our assessment of whether the underlying issue has increased (▲), remained stable (—), or decreased (▼) in magnitude over time

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Market outcomes were competitive overall, and exercise of market power was generally not a concern

- No significant change to structural indices such as market share, real-time **Residual Supply Index** and **Pivotal Supplier Test** (~33%); day-ahead shows much less structural concentration
- Price-cost markup** metrics in both the day-ahead and real-time markets were within 1% of the prior year; they remained well below the tightest mitigation threshold of 10%
- Withheld capacity** due to above-cost bidding remained in line with prior years (below 2%)
- Mitigation** activity remained minimal, totaling just 399 asset hours—approximately 0.02% of all asset hours subject to mitigation
- With **concentration levels** potentially increasing, growing importance of proactively assessing mitigation thresholds and other rules to ensure appropriate calibration

System-wide Residual Supply Index Duration Curves



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Price Cost Mark-up Metrics

Year	Day-Ahead Price-Cost Markup	Real-Time Price-Cost Markup
2021	-0.6%	0.2%
2022	-1.8%	-1.7%
2023	-2.2%	-3.6%
2024	2.4%	6.8%
2025	2.7%	5.9%

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DAY-AHEAD ANCILLARY SERVICES (DA A/S)

*An Assessment of Market Performance and Competitiveness
after 1-Year of Operation (March 1, 2025, through Feb 28, 2026)*

[Link to report](#)



Background, Scope and Approach

- IMM must publish and file with the Commission a report on the Competitiveness of major market design changes within 1 year of operation and on Performance within 3 years, or as soon as adequate data becomes available (Appendix A, Market Rule 1, I.A.17.2.5.)
- IMM quarterly markets reports, recent [memorandum with recommendations](#), and this report “An Assessment of the Day-Ahead Ancillary Services Market” cover DA A/S extensively
- This assessment is organized around 3 broad analytical questions:
 - **What was the incremental cost of this initiative?**
 - **What factors drove these costs?**
 - **What benefits has this initiative produced?**
- Our assessment relies on quantitative analysis and simulation-based studies, and was supplemented by survey-based information from Market Participants

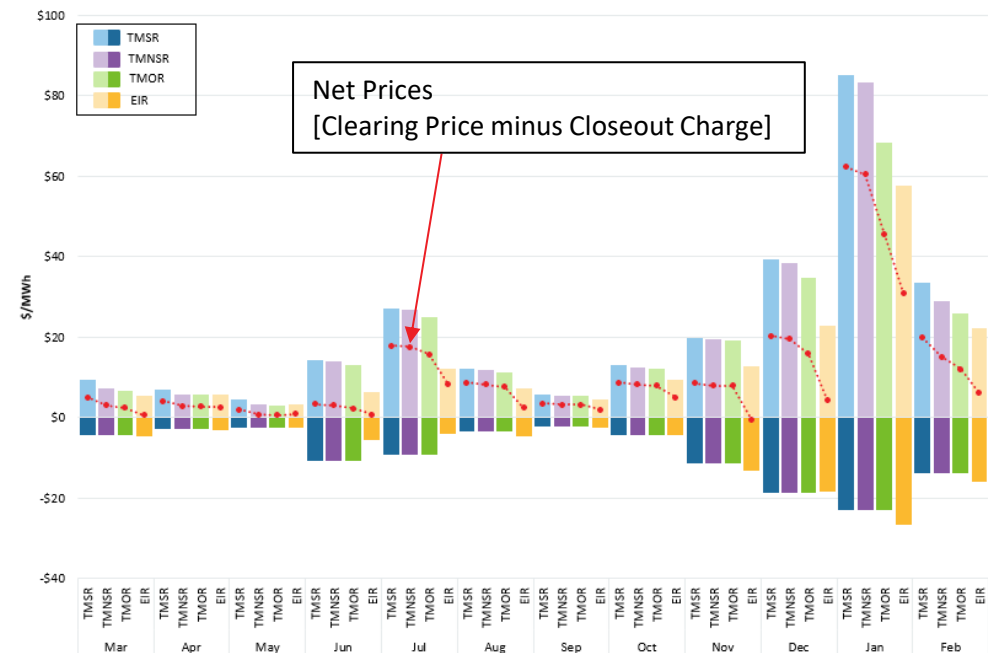


Recap: The design addresses limitations of the prior energy-only construct

- Establish a market construct to procure and price ancillary services and energy, enabling a reliable next-day operating plan that meets expected reserve and load requirements
- Provide advance signals to resources needed to meet operating reserve and load obligations
- Align compensation with performance by creating financial incentives for resources to be ready and able to deliver in real time
- Reduce reliance on unpriced, out-of-market actions, improving price formation to better reflect the true cost of reliability services

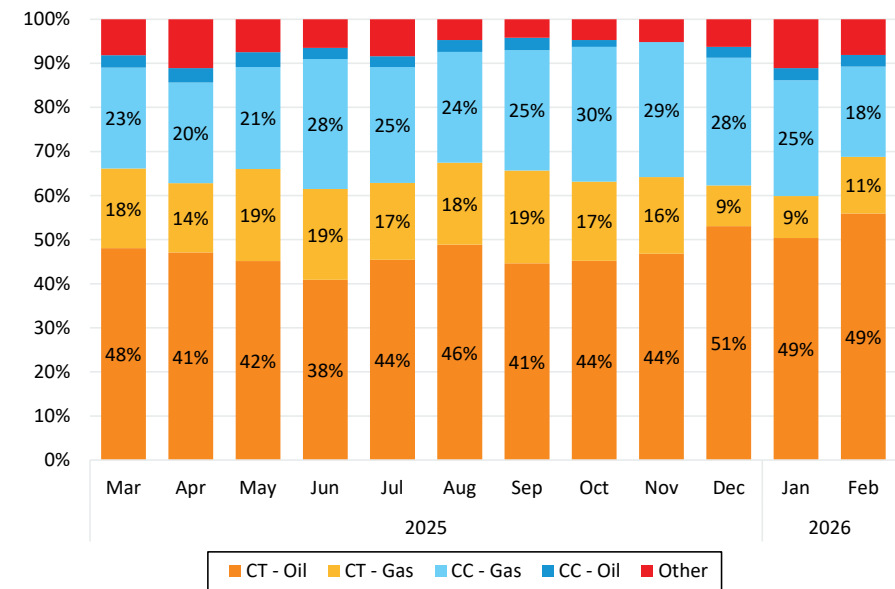
Clearing Prices and Resource Mix Overview

Average Hourly DA A/S Clearing Prices by Product and Month



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DA A/S Clearing by Technology and Offered Fuel



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Settlement Costs versus Incremental Costs

DA A/S Settlements (\$ millions)

DA A/S	Spring 2025	Summer 2025	Fall 2025	Winter 2026	Total
DA TMSR (net)	\$3.7	\$16.6	\$8.5	\$45.6	\$74.4
DA TMNSR (net)	\$6.3	\$26.1	\$16.1	\$65.1	\$113.6
DA TMOR (net)	\$2.9	\$13.3	\$7.8	\$36.3	\$60.3
EIR (net)	\$0.2	\$1.4	\$1.7	\$10.1	\$13.4
Total (net)	\$13.1	\$57.4	\$34.1	\$157.1	\$261.7
Total E&AS Costs	\$1,284	\$2,346	\$1,610	\$6,261	\$11,500
% Total E&AS Cost	1%	2%	2%	3%	2%

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FER Settlements (\$ millions)

	Spring 2025	Summer 2025	Fall 2025	Winter 2026	Total
FER Credit	\$74.4	\$122.2	\$166.9	\$641.6	\$1,005.1
Total E&AS Costs	\$1,284	\$2,346	\$1,610	\$6,261	\$11,500
% Total E&AS Cost	6%	5%	10%	10%	9%

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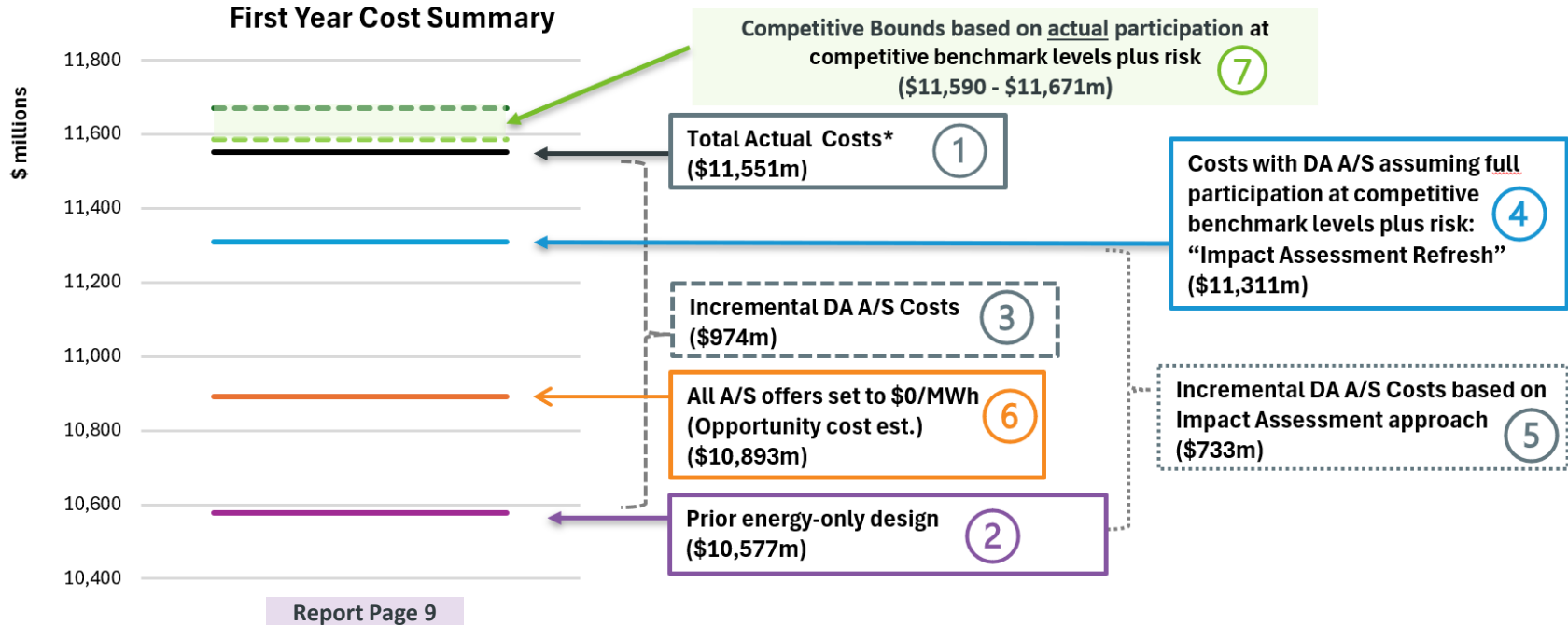
- **Settlement costs** totaled over **\$1.25 billion**, or \$10.70/MWh of load served (\$2.21 for A/S, \$8.49 FER)
- **Incremental costs** of the design are lower, reflecting the interplay between the FERP and (lower) DA LMP
- Our economic analysis focuses on Incremental costs relative to the prior energy-only construct

Day-Ahead Ancillary Services Assessment: Key Findings

1. Estimated Incremental Costs of DA A/S Totaled \$974 Million in the First Year, with 12 Days Accounting for 50% [[slides 25-26](#)]
2. Higher-than-Expected DA A/S Costs Primarily Reflect Changes in Market and System Conditions [[slides 27-28](#)]
3. Higher-than-Expected Costs also Reflect Differences Relative to Assumed Market Behavior and Highlight the Role of Opportunity Costs in Price Formation [[slide 29](#)]
4. Satisfying Flexible Response Service requirements is the main driver, although most costs flow through the FER price [[slide 29-30](#)]
5. DA A/S Costs were Consistent with Competitive Market Participant Behavior [[slides 31-36](#)]
6. The Strike Price and Expected Closeout Cost Calculator (the “GMM”) Showed Systematic Bias [[slide 37](#)]
7. Evidence of Reliability Benefits is Promising but Preliminary [[slides 38-39](#)]
8. Potential Cost Implications for the Capacity Market and Uplift [[slide 40](#)]
9. Continued Monitoring and Openness to Refinements Will Be Important

Summary: Key Numbers from Simulation Studies

Indicator of values on this slide referenced in subsequent slides



* Based on simulated DA A/S market rules used as the benchmark for counterfactual comparisons. Total costs modeled in the simulation include LMP, FER, DA Flexible Response Services and EIR net costs, and the cost of real-time incremental energy.

Total Incremental Costs of DA A/S

Estimated Change in Market Costs

Category	No DA A/S (\$M)	DA A/S (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$10,437	\$11,153	\$716	6.9%
LMP	\$10,437	\$10,127	-\$309	-3.0%
FER Price	\$0	\$1,026	\$1,026	
DA A/S	\$0	\$261	\$261	
Credits	\$0	\$453	\$453	
Closeouts	\$0	-\$192	-\$192	
Total Charges/Credits	\$10,437	\$11,415	\$978	9.4%
Cost of Incremental RT Energy	\$140	\$136	-\$4	-2.9%
Total Cost/Revenue Change	\$10,577	\$11,551	\$974	9.2%

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- Energy and Ancillary Services costs totaled **\$11.55 billion**

(\$98/MWh of load served), the highest since 2022 and the second highest total since 2008

- DA A/S Vs. Prior Day-Ahead Design:** DA A/S cost an estimated \$974m (\$8.23/MWh*), a 9% increase on the prior design of \$10.6 bn

1

2

3

*Based on 12-month Load of 118,400 GWh or average hourly load of 13,516 MW

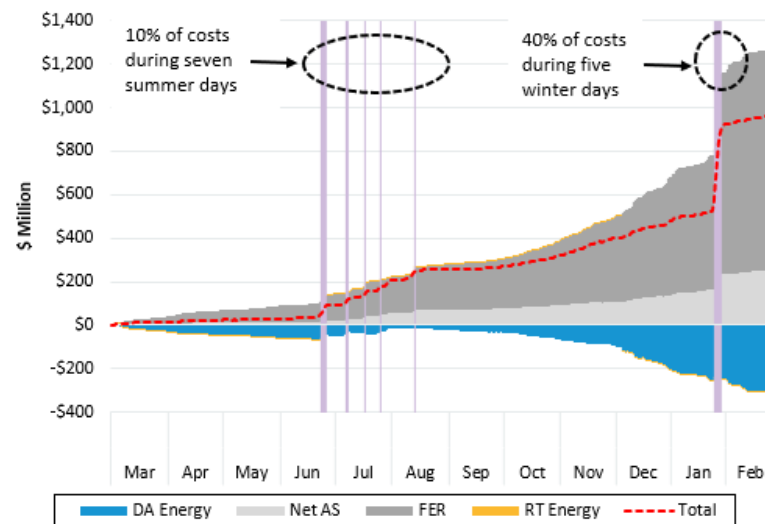
Twelve days of high demand/stressed system conditions accounted for 50% (\$490m) of total incremental costs

Comparison of Incremental DA A/S Costs: High-Cost Days to All Other Days

Category	Incremental Cost (\$M) <i>12 Highest-Cost Days</i>	Incremental Cost (\$M) <i>All Other Days</i>	Incremental Cost (\$M) <i>Complete Year</i>
DA Energy	\$386	\$331	\$716
LMP	\$44	-\$353	-\$309
FER Price	\$342	\$684	\$1,026
DA A/S	\$93	\$169	\$261
Credits	\$134	\$319	\$453
Closeouts	-\$41	-\$151	-\$192
Total Charges/Credits	\$478	\$500	\$978
Cost of Incremental RT Energy	\$11	-\$15	-\$4
Total Cost/Revenue Change	\$489	\$485	\$974

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Cumulative Incremental Change in Market Costs



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Changes in market fundamentals placed significant upward pressure on total incremental DA A/S costs (1)

Differences in System Conditions and Competitive Offer Components

Index	(1/1/2019 – 12/31/2021) Average	(3/1/2025 – 2/28/2026) Average	Delta (%)
DA Gas Price ⁴⁹ (\$/MMBtu)	\$3.24	\$6.82	110.5%
DA Hub LMP (\$/MWh)	\$33.48	71.44	113.4%
DA Load Forecast (MW)	13,151	13,019	-1.0%
Summer Peak Load ⁵⁰ (MW)	25,095	26,586	5.9%
Winter Peak Load ⁵¹ (MW)	19,512	20,221	3.6%
Competitive Offer ⁵² (\$/MWh)	\$10.00	\$12.78	27.8%
Expected Closeout (\$/MWh)	\$3.20	\$7.74	141.9%
AIC (\$/MWh)	\$0.48	\$3.35	597.9%
Risk Premium (\$/MWh)	\$6.33	\$1.70	-73.1%

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- “Impact Assessment (IA) Refresh” scenario is based on the same approach as the original IA, assuming full participation and offer prices at competitive benchmark levels plus estimated reasonable risk premiums
- **Original IA** provided incremental costs estimates of \$140 million based on 2019-2021 market data

Changes in market fundamentals placed significant upward pressure on total incremental DA A/S costs (2)

Estimated Change in Market Costs from DA A/S (IMM “IA Refresh”)

Category	No DA A/S (\$M)	IMM Refresh (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$10,437	\$11,029	\$592	5.7%
LMP	\$10,437	\$10,214	-\$222	-2.1%
FER Price	\$0	\$815	\$815	
DA A/S	\$0	\$146	\$146	
Credits	\$0	\$340	\$340	
Closeouts	\$0	-\$194	-\$194	
Total Charges/Credits	\$10,437	\$11,175	\$738	7.1%
Cost of Incremental RT Energy	\$140	\$136	-\$5	-3.3%
Total Cost/Revenue Change	\$10,577	\$11,311	\$733	6.9%

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- Accounting for market fundamentals, total costs would have been \$11.3 bn, reflecting estimated incremental DA A/S costs of \$733 m compared to the prior design (~75% of total observed incremental costs of \$974 m)*
- Of the \$240 m of total incremental costs not explained by market fundamentals, lower participation levels as well as higher offer prices are the significant drivers

4
5

* Reflects the current FER framework that excludes anticipated renewable generation contributions; the metric is expected to decline following adoption of the IMM’s recommendation

Impact of Opportunity Costs and FRS Constraints

- **Opportunity Costs** play a significant role in price formation, ensuring that resources are no worse off compared to their next best alternative in the joint clearing of energy and ancillary services (e.g., ensures that a combined cycle that is otherwise in-merit for energy but cleared for 10-min spinning reserve is held indifferent between the two) 6
 - If all bid-in ancillary services capability was offered for free (\$0/MWh), the system would still incur **~\$316 m** in incremental costs
- While most incremental DA A/S costs flow through the FER price, the **Flexible Response Services** (10- and 30-min reserves) drive 65% (\$613 m) of the total incremental cost
 - FRS-Only simulation: a scenario in which the FER constraint is ‘turned off’ but the FRS constraints remain ‘turned on.’ This scenario is intended to reflect a modified version of the current DAM that doesn’t have the FER constraint. [see page 40]



Drivers of the Forecast Energy Requirement Price

Winter Highest-Cost DA A/S Days

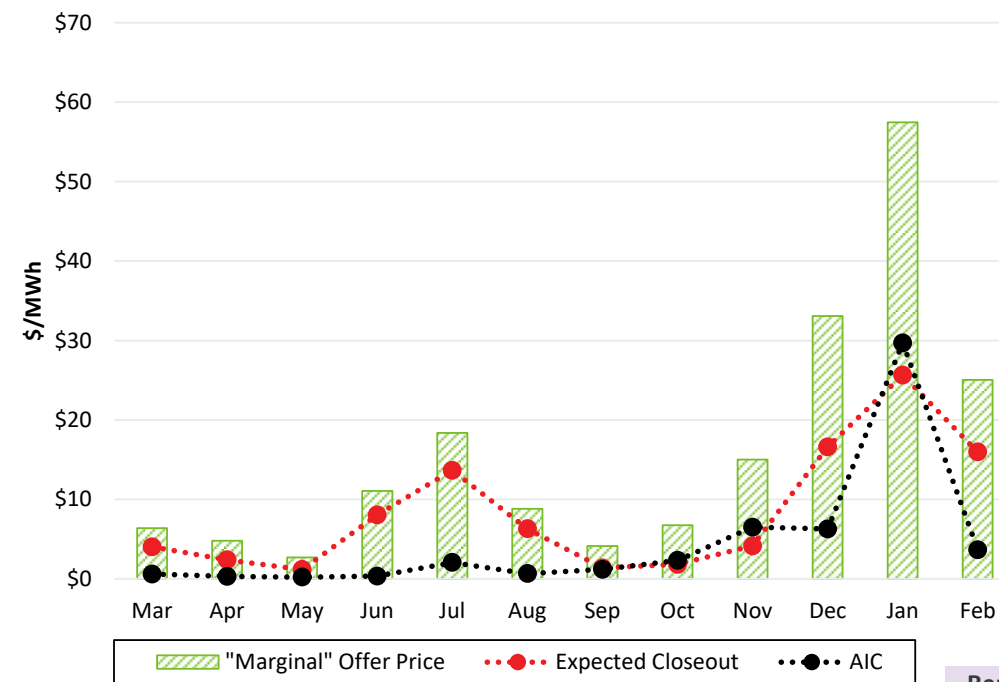
	25-Jan	26-Jan	27-Jan	28-Jan	29-Jan
Forecasted Load	19,500	19,650	19,700	19,600	19,550
Temp (min)	4	14	5	2	3
Temp (max)	19	22	19	21	21
Natural Gas Price	\$45.22	\$45.22	\$89.84	\$99.32	\$60.99
DA LMP	\$433.96	\$436.01	\$639.14	\$423.31	\$346.81
TMSR Price	\$219.08	\$365.43	\$750.60	\$327.92	\$141.32
TMNSR Price	\$219.08	\$365.43	\$750.60	\$327.92	\$131.27
TMOR Price	\$214.49	\$328.24	\$423.16	\$313.78	\$105.73
FER Price	\$60.82	\$231.18	\$349.80	\$32.88	\$15.74
Net Interchange	106	1,076	1,900	2,936	2,400
Outages	3,934	4,553	4,295	4,416	4,286
DA A/S Offered MWs	9,788	8,662	8,599	9,227	9,315
Cleared load as % of RT Load Obligation	93%	98%	97%	99%	99%
Cleared load as % of DA Load Forecast	96%	94%	94%	97%	97%

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- Both supply- and demand-side factors can contribute to high FER prices making it challenging to identify cost drivers precisely
- During highest-cost days, **summer** FER prices were lower with LSE clearing a high percentage of demand day-ahead (97%-105% of real-time load), while **winter** FER prices were much higher at the same time LSEs under-cleared (94%-97%)

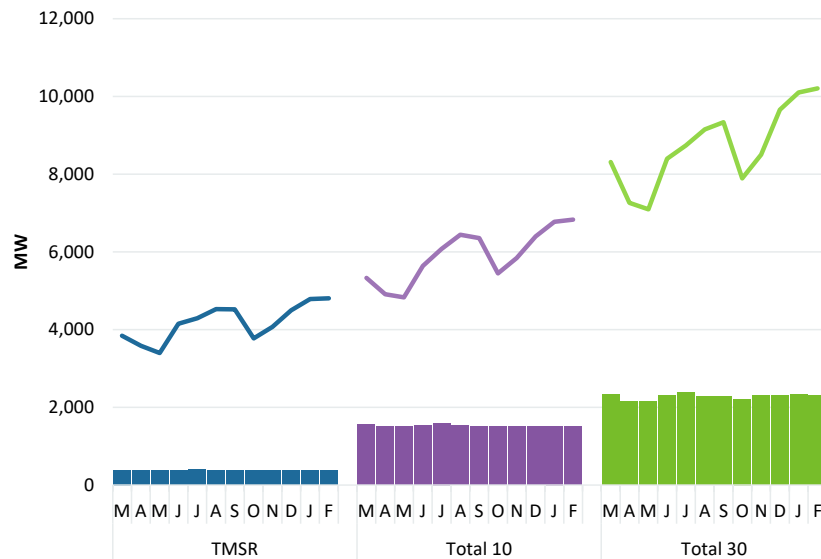
Clearing prices also track expected closeout costs and avoidable input costs as expected

“Marginal” Offer Price for Total 30 Requirement with Offer Components



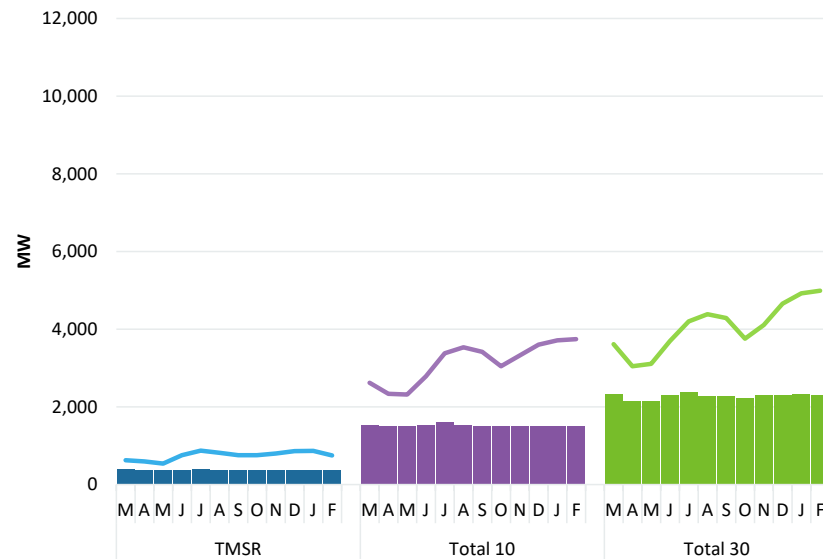
Offered reserve capability exceeds requirements across all products

Offered FRS Capability relative to Requirements, Ex-ante



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Offered FRS Capability relative to Requirements, Ex-post

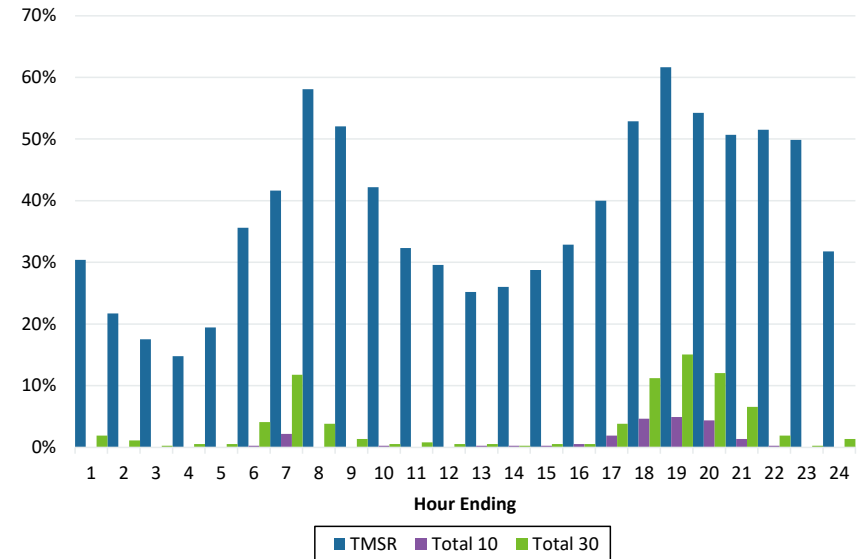


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Market structure shows moderate concentration

- Largest suppliers account for a majority of capability
 - ex-ante TMSR: top 4 participant share or CR4=61%; increases on an ex-post basis (ex-post TMSR: CR4=75%)
 - At least one pivotal supplier in 38% of hours for TMSR

Percentage of Hours with at least One Pivotal Supplier (Ex-post) in the DA A/S Market



DA A/S costs were consistent with competitive market participant behavior

- Participation levels have generally not raised **physical withholding** concerns that would impact overall competitive cost estimates
 - However, participation levels are impactful on clearing prices during periods of high system demand; this is most evident when opportunity costs play a significant role in price formation
 - Participation levels are increasing with market experience, but survey respondents indicated a desire for additional technical training, which could help accelerate adoption
- ➔ **We recommend that the ISO provide additional and ongoing technical training related to DA A/S to facilitate and accelerate market participation.**
- No indication of impactful **economic withholding** on overall costs
 - Simulated market clearing using a range of IMM competitive cost estimates based on two risk premium approaches (Sharpe and Conditional VaR metrics); in practice, risk and market expectation are highly idiosyncratic
 - Market costs of \$11.55 bn are consistent with (slightly below) IMM's competitive bounds of \$11.59 bn and \$11.67 bn

Overall, actual costs are consistent with simulated outcomes based on competitive offer benchmark costs

Comparison to Outcomes with Competitive Offers plus Sharpe Ratio Risk Premia

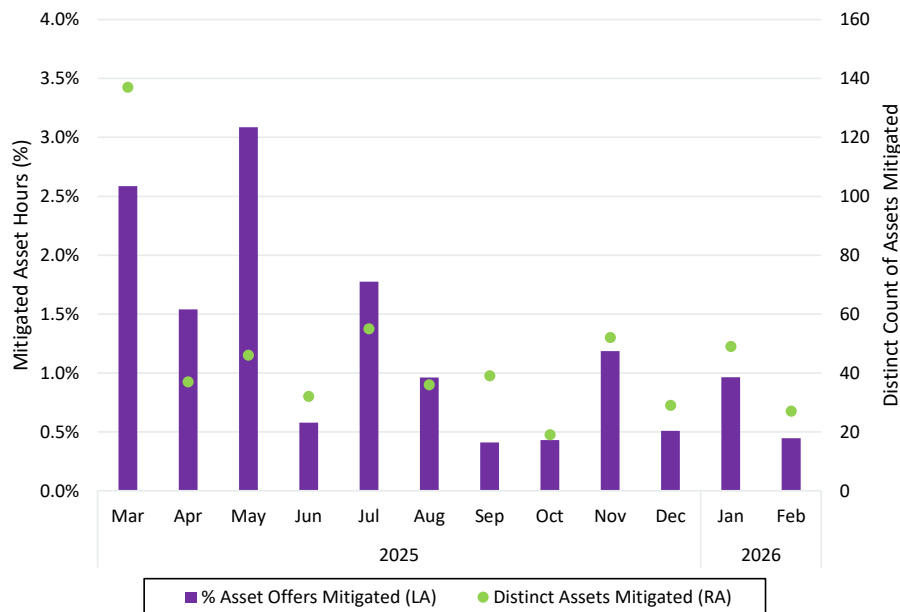
Category	DA A/S (\$M)	Sharpe (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$11,153	\$11,194	\$40	0.4%
<i>LMP</i>	\$10,127	\$10,081	-\$47	-0.5%
<i>FER Price</i>	\$1,026	\$1,113	\$87	8.5%
DA A/S	\$261	\$259	-\$2	-0.9%
<i>Credits</i>	\$453	\$450	-\$4	-0.8%
<i>Closeouts</i>	-\$192	-\$191	\$1	-0.7%
Total Charges/Credits	\$11,415	\$11,453	\$38	0.3%
Cost of Incremental RT Energy	\$136	\$138	\$1	0.9%
Total Cost/Revenue Change	\$11,551	\$11,590	\$39	0.3%

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- Two competitive offer scenarios differ by risk premium methodology; Sharpe and Conditional Value at Risk metrics
- Actual costs are *lower* than the IMM estimates during the Top-12 Days and *higher* during the remaining days

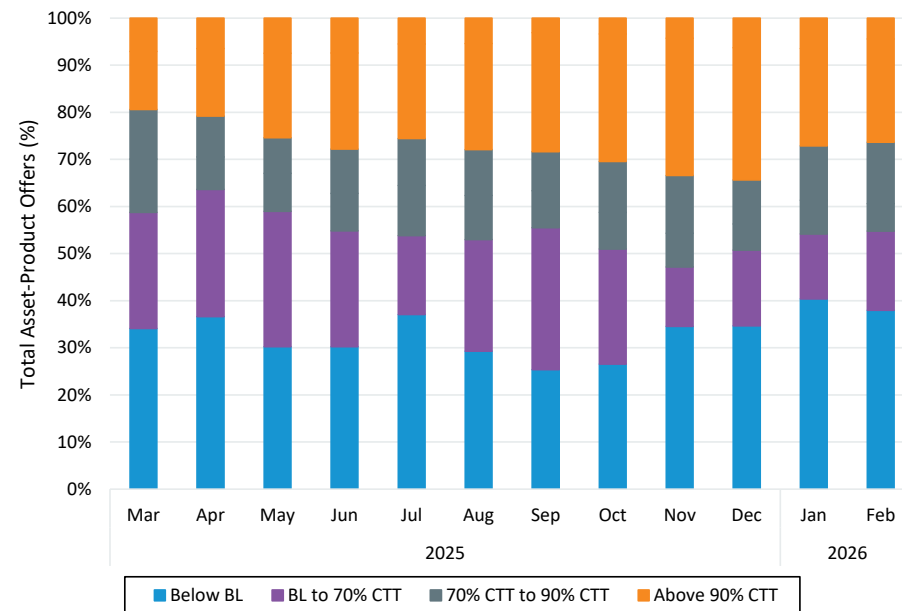
Mitigation was infrequent but instances of over-mitigation persisted at low price-impact thresholds

DA A/S Mitigations



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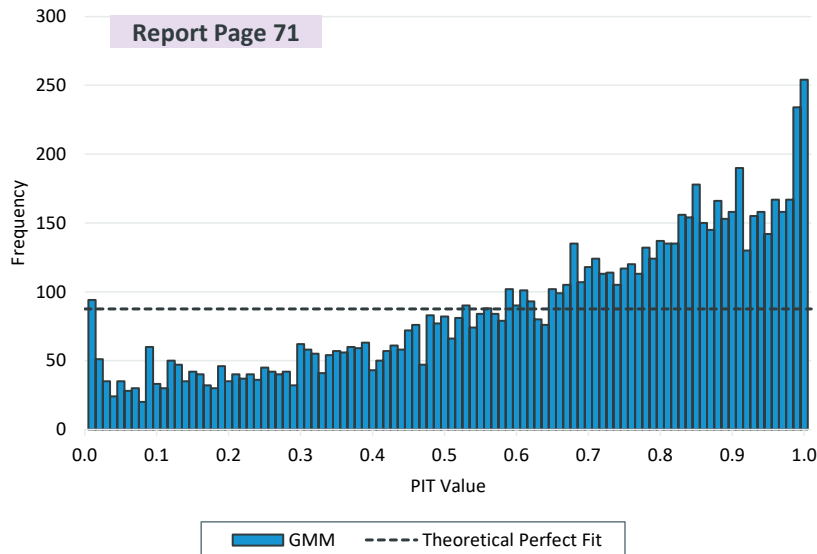
Supply Offers Relative to Mitigation Values



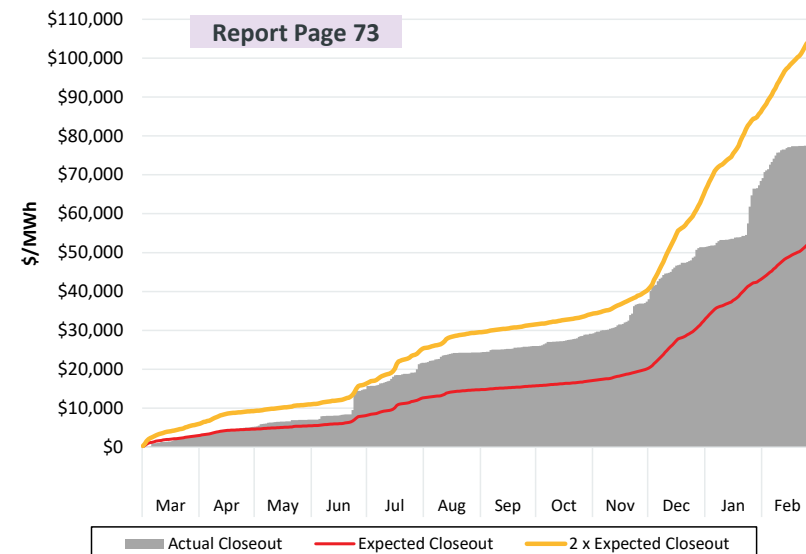
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The Strike Price and Expected Closeout Cost Calculator (the “GMM”) Showed Systematic Bias

Probability Integral Transform (PIT) Histogram, All Hours



Actual and Expected Closeouts, Cumulative



➔ Even with the IMM’s recommended strike price adjustments, we encourage the ISO to continue to invest in its modeling tools and processes to ensure that expected real-time energy prices and closeout costs better track prevailing market conditions.

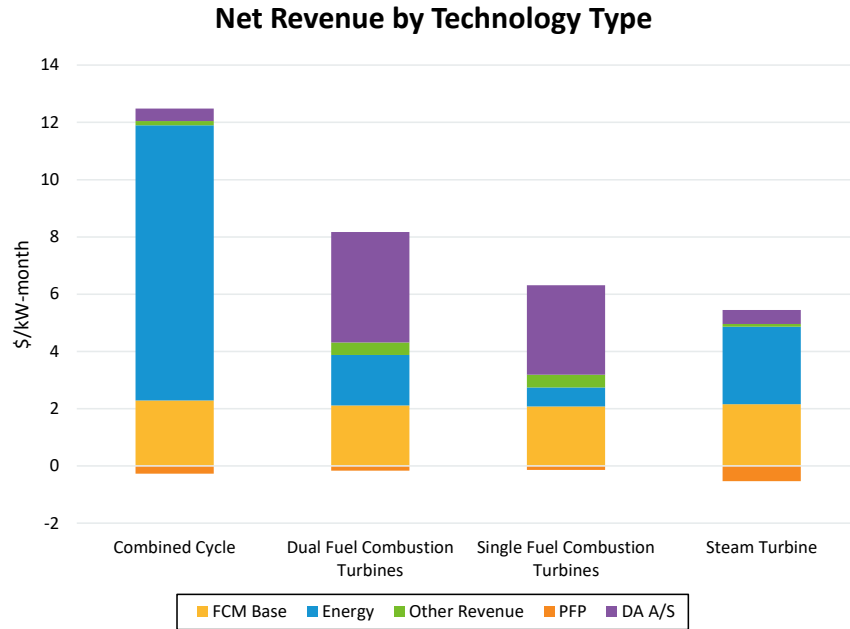
Reliability Outcomes (1)

- DA A/S has strong reliability-enhancing elements (transparent pricing and market-based two-settlement performance incentives)
 - However, overall performance incentives stem from energy, capacity, and A/S positions
 - Therefore, care is needed in linking performance and reliability value to DA A/S (or any single design feature)
- We use an evaluation framework to assess and quantify performance changes over time for resources taking on DA A/S positions, and will continue to refine these metrics and welcome stakeholder feedback
 - Metrics compared in DA A/S period to pre-DA A/S periods (March 1, 2023-February 28, 2025)

Reliability Outcomes (2)

- **Natural gas procurement:** We have not observed gas-fired generators scheduling additional gas the day before the operating day to meet DA A/S positions, despite DA A/S stronger incentives to be prepared to perform [Page 87]
- **Outage Rates:** Combustion Turbine availability has improved since DA A/S; lower outage rates at 11% compared to pre-DA A/S of 18% [Page 89]
- **Operational changes:** In response to survey questions, participants indicated that DA A/S awards influence operational decisions; 71% of respondents reported taking actions in response to awards, most commonly procuring fuel [Page 93]
- **Day-Ahead commitments:** More commitments of long-lead time resources occur under DA A/S, with no commitments made through the out-of-market next-day Reserve Adequacy Analysis process; such commitments face financial obligations and stronger performance incentives, and create additional responsive capability in real-time (increased bench strength) [Pages 77 & 84]

Cost allocation implications



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- DA A/S revenues reduce “missing money” recovered through the **capacity market**—particularly for combustion turbines—creating potential downward pressure on future capacity prices
- **Uplift** savings are modest, with an upper-bound estimate of ~\$35 m tied to commitments shifted into the day-ahead market (vs. post-day-ahead processes such as RAA)
- **Real-time price** impacts are not quantified, but are directionally expected to be lower than they would be absent DA A/S

Questions





2025 Annual Markets Report

© ISO New England Inc.
Internal Market Monitor

MAY 29, 2026



Date	Version	Remarks

Preface/Disclaimer

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2025 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2025. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of *Market Rule 1*, Appendix A, Section III.A.17.2.4, *Market Monitoring, Reporting, and Market Power Mitigation*:

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, Net Commitment-Period Compensation costs and the performance of the Forward Capacity Market and Financial Transmission Rights Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.¹

This report is being submitted simultaneously to the ISO and the Federal Energy Regulatory Commission (FERC) per FERC order:

The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of a Regional Transmission Organization's market monitor at the same time they are submitted to the RTO.²

This report presents key findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2025. The executive summary gives an overview of the region's wholesale electricity market outcomes, the important market issues and our recommendations for addressing these issues. It also addresses the overall competitiveness of the markets, and market mitigation and market reform activities. Sections 1 through 10 include more detailed discussions of each of the markets, market results, analysis and recommendations. A list of acronyms and abbreviations is included at the back of the report.

¹ ISO New England Inc., "Transmission, Markets, and Services Tariff (ISO tariff), Section III.A.17.2.4, Market Rule 1, Appendix A, Market Monitoring, Reporting, and Market Power Mitigation", http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

² FERC, PJM Interconnection, L.L.C. et al., "Order Provisionally Granting RTO Status", Docket No. RT01-2-000, 96 FERC ¶ 61, 061, July 12, 2001.

A number of external and internal audits are also conducted each year to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders. Further details of these audits can be found on the ISO website.³

All information and data presented are the most recent as of the time of writing. The data presented in this report are not intended to be of settlement quality and some of the underlying data used are subject to resettlement.

In case of a discrepancy between this report and the ISO New England Tariff or Procedures, the meaning of the Tariff and Procedures shall govern.

Underlying natural gas data are furnished by the Intercontinental Exchange (ICE):



Underlying oil and coal pricing data are furnished by Argus Media.

³ ISO New England Inc., “*Financial and Performance Reports*”, <https://www.iso-ne.com/about/corporate-governance/financial-performance> .

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Executive Summary

The 2025 Annual Markets Report by the Internal Market Monitor (IMM) at ISO New England (ISO) reviews the development, operation, and performance of the region's wholesale electricity markets. The report provides an assessment of each market based on observed outcomes, market data, and established performance criteria.

Market participants transact energy in both the day-ahead and real-time markets, while also buying and selling a range of related products, including operating reserves, regulation service, financial transmission rights, and capacity, in the real-time and forward markets. Together, these markets and products are designed to promote the efficient and competitive supply of electricity while ensuring that sufficient resources are available to maintain reliable system operations across New England.

For additional background, the supporting document [An Overview of New England's Wholesale Electricity Markets: A Market Primer](#) provides a summary of key concepts and market mechanics.

This executive summary highlights key market trends, performance outcomes, and emerging issues, and concludes with a consolidated set of the IMM's recommendations to improve market design and rules based on findings from this and prior IMM reports.

Total wholesale electricity costs rose sharply in 2025 to \$15 billion, nearly 50% higher than in 2024. These elevated costs were driven by higher natural gas costs, tighter supply conditions, and ongoing structural changes to the resource mix and market design. While overall market performance remained competitive, these factors increased costs, shifted reliance toward internal New England resources, and continued to highlight the growing importance of resource flexibility and energy security in maintaining reliability.

Higher natural gas prices were the principal driver of increased wholesale costs, rising 105% year-over-year to \$6.27/MMBtu and elevating energy prices throughout the year. Carbon emissions costs also increased as allowance prices rose and emissions limits tightened, particularly under the Massachusetts Electricity Generator Emissions Limits (EGEL) program. Although fuel prices dominated cost increases in 2025, carbon costs are expected to play a larger role in generator economics as allowance availability tightens and compliance costs rise.

Higher energy prices also reflected a shift up the supply stack driven by greater reliance on internal generation. Continuing a multi-year trend, net imports declined further in 2025, reaching their lowest level in more than a decade due to reduced Canadian hydro availability and outages. While the interchange of electricity with neighboring power systems provided critical supply to New England during high-demand periods, lower import levels throughout the year meant that higher-cost resources located inside New England more frequently set the marginal price. At the same time, growth in solar generation continued to reshape load profiles, increasing the magnitude and variability of evening ramps and reinforcing the need for flexible, dispatchable resources.

Despite structural indicators pointing to tighter conditions—including a higher frequency of pivotal suppliers—market outcomes remained broadly competitive. The analysis indicates limited economic withholding, and market power mitigation levels remained minimal.

High-level market statistics for the five-year period covered in this report are presented below.

At a Glance: High-level Market Statistics

	2021	2022	2023	2024	2025	% Change '24 to '25	Sparkline
Demand (MW)							
Load (avg. hourly)	13,561	13,576	13,096	13,299	13,441	↑ 1.1%	
Weather-normalized load (avg. hourly) ^[a]	13,419	13,514	13,132	13,236	13,394	↑ 1.2%	
Peak load (MW)	25,801	24,780	24,043	24,871	26,586	↑ 6.9%	
Generation Fuel Costs (\$/MWh)^[b]							
Natural Gas	36.07	72.41	23.68	23.83	48.91	↑ 105.2%	
No.6 Oil	138.30	221.15	164.91	154.92	154.29	→ -0.4%	
Diesel	184.69	332.15	253.44	217.28	207.33	↓ -4.6%	
Hub Electricity Prices: LMPs (\$/MWh)							
Day-ahead (simple avg.) ^[c]	45.92	85.56	36.82	41.47	71.81	↑ 73.2%	
Real-time (simple avg.)	44.84	84.92	35.70	39.50	65.89	↑ 66.8%	
Day-ahead (load-weighted avg.)	48.30	91.36	39.19	44.52	78.44	↑ 76.2%	
Real-time (load-weighted avg.)	47.34	91.13	38.25	42.46	72.21	↑ 70.1%	
Estimated Wholesale Costs (\$ billions)							
Energy	6.1	11.7	4.8	5.6	9.9	↑ 76.7%	
Capacity ^[d]	2.3	2.0	1.8	1.4	1.2	↓ -16.4%	
Uplift (NCPC)	0.04	0.05	0.03	0.03	0.04	↑ 20.2%	
Ancillary Services ^[e]	0.1	0.1	0.2	0.2	0.2	↑ 37.6%	
Regional Network Load Costs	2.7	2.8	2.7	3.0	3.6	↑ 23.0%	
Total Wholesale Costs	11.2	16.7	9.5	10.2	15.0	↑ 47.6%	
Supply Mix^[f]							
Natural Gas	45%	45%	48%	50%	50%	→ 0.1%	
Nuclear	22%	23%	20%	22%	23%	→ 0.7%	
Imports	16%	14%	13%	9%	7%	↓ -1.9%	
Hydro	6%	6%	8%	7%	6%	↓ -1.0%	
Other ^[g]	5%	4%	4%	4%	4%	→ 0.1%	
Wind	3%	3%	3%	3%	4%	→ 0.9%	
Solar	2%	3%	3%	4%	5%	→ 0.6%	
Coal	0%	0%	0%	0.2%	0.2%	→ 0.0%	
Oil	0%	2%	0%	0.3%	1.0%	→ 0.7%	
Battery Storage	0%	0%	0%	0.3%	0.1%	→ -0.2%	

[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average

[b] Generation costs are calculated by multiplying the daily fuel price (\$/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh)

[c] The Day Ahead LMP shown for 2025 is the total of the Day Ahead LMP and the Forecast Energy Requirement Price (FERP)

[d] Capacity costs in 2022-2024 include Mystic cost-of-service costs

[e] Ancillary Services also include inventoried energy program costs and DA A/S costs for the FRS products in 2025

[f] Provides a breakdown of total supply, which includes net imports; Note that section 1.2 provides a breakdown of native supply only

[g] The "Other" fuel category includes landfill gas, methane, wood, refuse and steam

→ denotes change is within a band of +/- 1%

Sparkline: Green = High Point, Red - Low Points

Looking ahead, several recent and near-term resource additions have the potential to significantly expand the region’s supply capability, including the New England Clean Energy Connect (NECEC) transmission project (1,200 MW) and the Vineyard Wind offshore wind facility (805 MW), with Revolution Wind (704 MW) expected to enter service later in 2026. Together, these resources will make a meaningful contribution toward meeting the anticipated 8% growth in energy use over the next decade—equivalent to roughly 1,100 MW of additional average hourly demand.⁴

As New England transitions towards greater renewable generation and electrification-driven load growth, the performance of flexible resources and energy-secure supply are increasingly necessary to maintain reliability. Market design changes are addressing these evolving system conditions. The implementation of the Day-Ahead Ancillary Services (DA A/S) market in 2025 represents an important shift toward more transparent pricing and compensation for reliability services. Additionally, proposed capacity market reforms aim to ensure that system procurement better reflects resource capabilities, load conditions, and seasonal reliability risks. Together, these design changes will better align markets with the system’s emerging reliability needs.

Joint Procurement of Energy and Ancillary Services Represents a Major Day-Ahead Market Enhancement

The Day-Ahead Ancillary Services (DA A/S) market, launched in March 2025, introduced a significant change to the energy market by replacing the Forward Reserve Market and effectively integrating the operators’ next-day Resource Adequacy Analysis into market clearing. The new framework is intended to ensure the system is reliably positioned to meet the ISO’s next-day operating needs, while compensating and incentivizing resources to be prepared to perform in real time.

In the day-ahead timeframe, the market jointly procures and prices operating reserves—ten- and thirty-minute Flexible Response Services (FRS) and the sixty-minute Energy Imbalance Reserve (EIR)—as well as physical energy to meet expected real-time load through the Forecast Energy Requirement (FER). Over the first ten months of implementation, net settlements for the four reserve products totaled approximately \$137 million, representing about 2% of total energy and ancillary services (E&AS) costs.

The procurement of physical energy to satisfy the FER results in the Forecast Energy Requirement Price (FERP), which is credited to physical supply resources that satisfy the FER constraint, with corresponding charges to load-serving entities. FER costs totaled \$529 million from March through December, accounting for more than 5% of total E&AS costs. Combined, DA A/S settlements totaled \$666 million over the first ten months of implementation.

Importantly, these reforms increased transparency around the cost of meeting reliability needs by shifting compensation that was previously embedded in uplift or forward mechanisms into explicit day-ahead market prices, accompanied by stronger performance incentives. However, DA A/S costs have exceeded expectations to date, and based on our assessment of market performance to date, the IMM recommended targeted refinements to improve the cost-effectiveness of the

⁴ ISO New England Inc., “2026 Capacity, Energy, Loads, and Transmission (CELT) Report: 2026–2035 Forecast”, May 1, 2026, <https://www.iso-ne.com/system-planning/system-plans-studies/celt>. Due to timing, several references to the CELT report elsewhere in this Annual Markets Report reflect the 2025 CELT forecast. The 2026 CELT update further revised projected peak demand and total energy use downward.

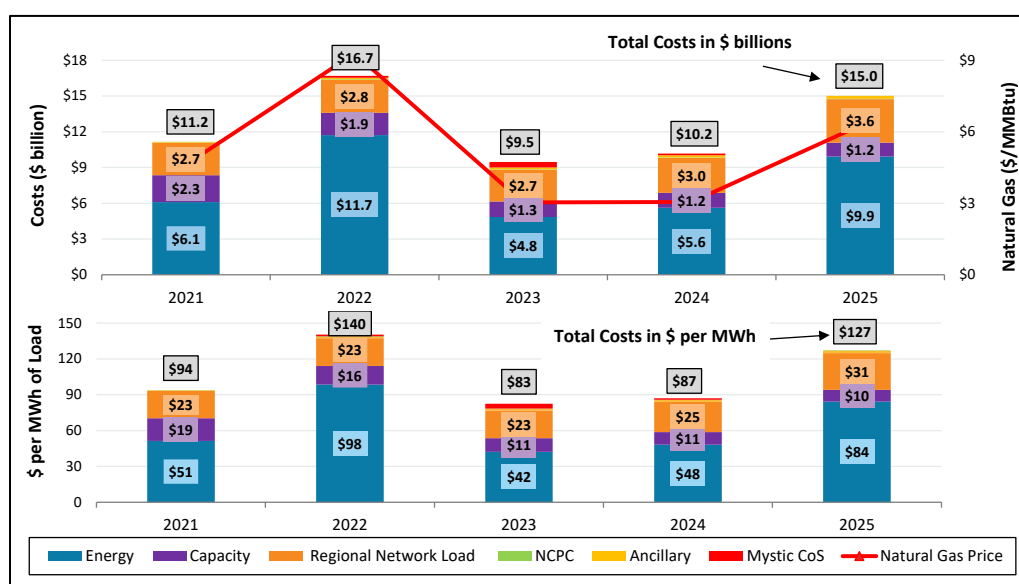
DA A/S design, including changes to strike prices, the FER construct, and reserve requirements.⁵ ISO-NE is working with stakeholders on these recommendations and expects to file proposed revisions in the coming months.

The IMM is also issuing a report with a detailed assessment of DA A/S performance concurrent with this annual report.

Increasing Wholesale Costs in 2025 Reflect Higher Fuel Prices, New Market Design Elements, and Rising Transmission Costs

Wholesale electricity costs in New England rose sharply in 2025 to \$15 billion, a 48% (\$4.8 billion) increase from 2024.⁶ Although costs remained below 2022 levels—when global commodity prices peaked following Russia's invasion of Ukraine—2025 marked the second-highest year for wholesale costs since 2008. The increase was driven primarily by energy costs, which rose 77% to \$9.9 billion and accounted for nearly two-thirds of total wholesale costs.

Wholesale Costs (\$ billions and \$/MWh) and Average Natural Gas Prices



The rise in energy costs was largely attributable to higher natural gas prices, which more than doubled year-over-year; up 105%, from \$3.06/MMBtu to \$6.27/MMBtu. As discussed in the preceding section, beginning in March 2025 with the implementation of the DA A/S market, energy costs also reflected the introduction of the FERP, which compensates resources for providing the physical capability needed to meet the day-ahead load forecast. FER payments totaled \$529 million from March through December, accounting for approximately 5.3% of total energy costs.

⁵ ISO New England Inc., Internal Market Monitor, "Recommended Changes to the Day-Ahead Ancillary Services Market" memorandum to ISO New England (cc: NEPOOL Markets Committee), February 4, 2026, https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf.

⁶ For context, the average retail electricity price in New England across all customer classes was 23.03 cents/kWh in 2024. By comparison, the all-in wholesale electricity cost in 2024 was approximately 8.7 cents/kWh, representing about 38% of the average retail price paid by end-use customers. Retail price data are from U.S. Energy Information Administration (EIA), Table 2.10: Average Price of Electricity to Ultimate Customers by End-Use Sector.

Regional Network Load (Transmission costs) increased to \$3.6 billion, representing 24% of total wholesale costs, driven by higher regional network service rates and continued investment in transmission infrastructure, including reliability upgrades and asset-condition projects.

Capacity costs totaled \$1.2 billion, reflecting payments associated with the fifteenth and sixteenth Forward Capacity Auctions held in 2021 and 2022. Capacity costs accounted for 8% of total wholesale costs and reflected surplus procurement relative to the Net Installed Capacity Requirement, with clearing prices of approximately \$2.60/kW-month—well below the cost of new entry for a combustion turbine. Capacity costs have remained relatively stable over the past three years, and are expected to remain between \$1.0 and \$1.1 billion over the next two calendar years based on forward auction outcomes through May 2028.

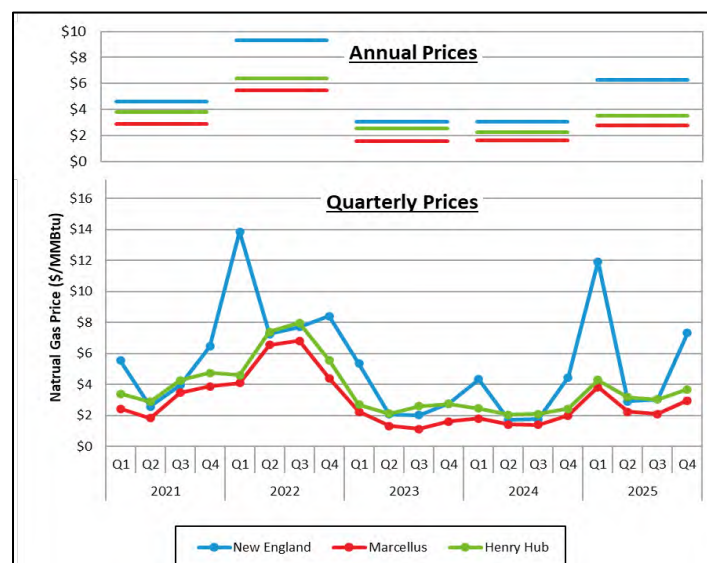
Ancillary services costs, which include payments for day-ahead and real-time reserves, regulation, and the temporary Inventoried Energy Program (IEP), totaled \$242 million in 2025—an increase of \$66 million (7%) from 2024. The increase was primarily due to the new day-ahead reserve products procured under the Day-Ahead Ancillary Services (DA A/S) market, which accounted for \$137 million in costs, partially offset by lower IEP expenditures.

Net Commitment Period Compensation (NCPC), or uplift, totaled \$42 million in 2025—an increase of \$7 million from 2024—but remained a very small component of overall costs, representing just 0.4% of total energy costs, the lowest share in at least a decade. Consistent with prior years, first-contingency payments accounted for the majority of NCPC, driven primarily by real-time commitments made in economic merit order to meet load and reserve requirements

Natural Gas Price Increases and Rising Carbon Emissions Costs Drove Higher Generation Costs

Natural gas prices rose significantly in 2025, with annual average prices exceeding \$6/MMBtu, a 105% increase from 2024. Prices peaked in the first quarter—particularly in January and February—when cold weather and a polar vortex drove regional hub prices to approximately \$11/MMBtu, well above typical winter levels and the unusually low prices observed in early 2024.

Wider Spread between New England and Marcellus/Henry Hub Benchmark Natural Gas Prices

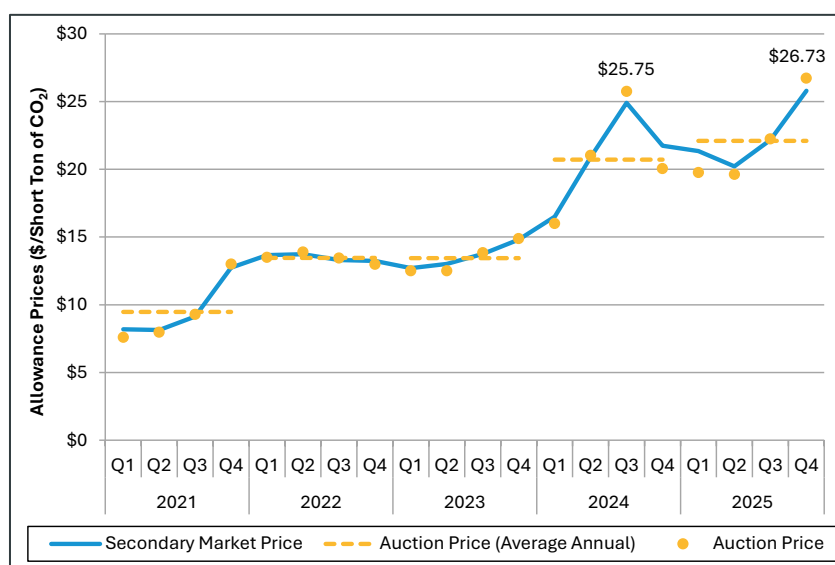


Although prices declined as winter conditions eased, they remained elevated throughout the year relative to 2024. The increase reflected both higher national benchmark prices—including at Marcellus and Henry Hub—and stronger demand for heating and gas-fired generation during colder

conditions. Prices in New England rose by more than national benchmarks, highlighting the region’s heightened exposure to winter demand and pipeline constraints.

Carbon emissions costs also increased in 2025, reflecting rising allowance prices and tightening emissions limits across both regional and state programs that are established by state policymakers. Prices under the Regional Greenhouse Gas Initiative (RGGI) continued their upward trend, while Massachusetts Electricity Generator Emissions Limits (MA EGEL) prices rose sharply, driven by higher emissions, declining allowance surpluses, and expectations of future scarcity.

Rising Regional Greenhouse Gas Initiative (RGGI) Prices



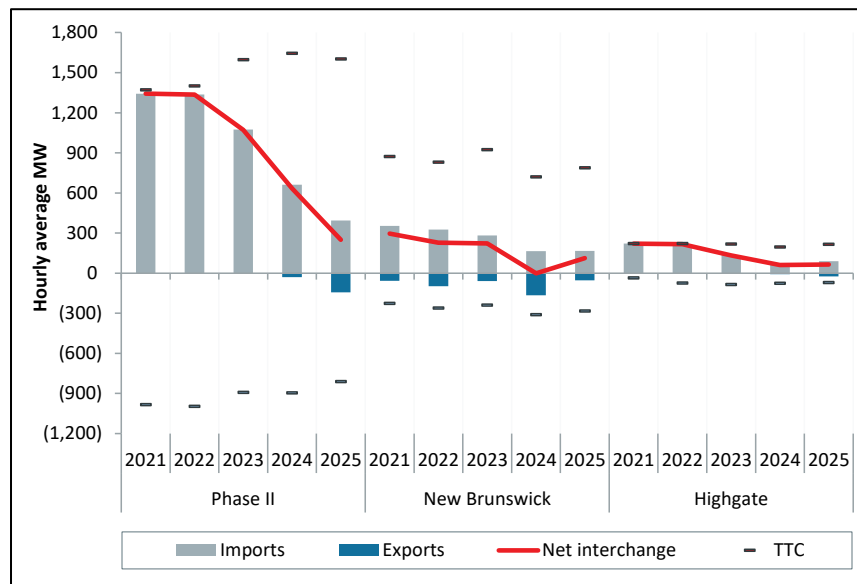
These dynamics increased the cost of operating fossil-fuel-fired generation, although emissions costs represented a smaller share of total generation costs than in 2024 due to the much larger increase in natural gas prices. RGGI allowance prices rose 6.5% year-over-year (to \$22.38/short ton), while the average MA EGEL auction clearing price increased 290% (to \$11.63/metric ton). These prices translate to estimated production cost adders of \$10.21/MWh (RGGI) and \$3.56/MWh (MA EGEL) for a typical natural-gas combined cycle unit. For context, fuel-related production costs alone averaged approximately \$49/MWh for a combined cycle in 2025.

Overall, we estimate that carbon pricing programs increased average (load-weighted) energy prices by approximately \$9/MWh in 2025 (up from \$8/MWh in 2024), contributing about \$1.1 billion to total energy costs. As emissions approach program caps, allowance availability is expected to tighten further, placing additional upward pressure on prices and reinforcing incentives for generators to reduce emissions through efficiency improvements, fuel switching, or lowering carbon-intensive output.

Declining Interchange Increased Reliance on Internal Supply; NECEC Expected to Partially Reverse the Trend

Net interchange into New England declined further in 2025, with real-time net imports averaging 932 MW per hour—about 7% of load—the lowest level since at least 2011. The decline was driven primarily by reduced Canadian imports due to dry hydro conditions in Quebec and a prolonged nuclear outage in New Brunswick, with Canada’s share of total net imports falling to 47%. The volume of net interchange with New York remained relatively stable, with net imports across all three New York interfaces averaging nearly 500 MW per hour in 2025.

Continued Trend of Decreasing Net Interchange over the Phase II Interface



Despite the overall decline, interchange continued to play a critical role during periods of high demand and elevated prices. In hours when day-ahead prices exceeded \$100/MWh, net imports averaged nearly 2,700 MW per hour, underscoring their importance during stressed system conditions. Day-ahead net interchange remained higher than real-time net interchange, driven largely by additional real-time scheduled exports at the New York North interface. When net real-time interchange is lower, New England must commit additional real-time native generation which can lead to higher real-time prices.

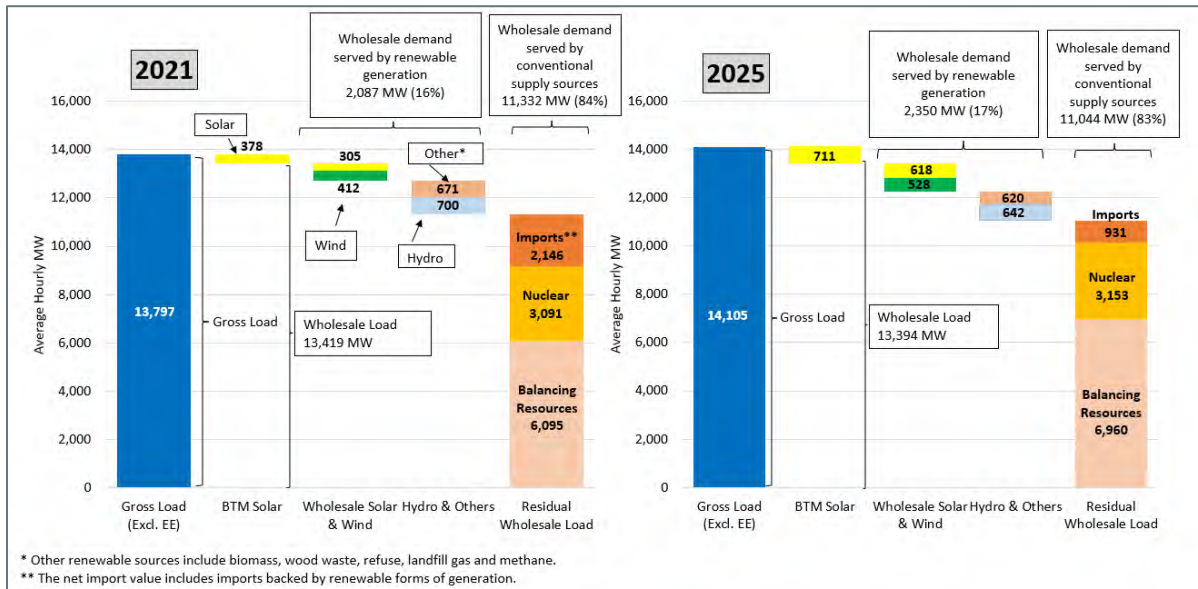
Looking ahead, the NECEC transmission line, which entered service in early 2026, has the capability to increase imports from Canada and partially offset the decline in interchange. This will ease pressure on internal resources and moderate reliance on higher-cost supply during tight system conditions.

Evolving Demand and Supply Conditions are Increasing Reliance on Flexible Resources

New England's demand and supply landscape continues to evolve as the region advances its clean energy transition, with growing levels of renewable resources and a critical reliance on dispatchable generation (balancing resources). In 2025, renewable supply met approximately 22% of gross demand, up from 18% in 2021, driven largely by growth in solar generation—including behind-the-meter installations.

At the wholesale level, the renewable share also increased more modestly, from 16% to 17%, as higher solar output offset reduced hydroelectric generation due to drought conditions and declines in other renewable sources. Over the same period, a 57% decline in net imports shifted a greater share of system needs onto internal balancing resources.

A Five-Year Snapshot of Demand and Supply, 2021 vs. 2025



Overall, the contribution of renewables to gross demand increased meaningfully over the five-year period. In the near term, major infrastructure projects—including Vineyard Wind I (806 MW), Revolution Wind (704 MW), and the New England Clean Energy Connect (1,200 MW) transmission line—are expected to significantly expand the region’s renewable energy portfolio in the coming years.

We track the system and market impacts of the clean energy transition through a suite of metrics that reflect anticipated changes in demand patterns, supply flexibility, and price dynamics. Many of these anticipated trends have been examined in prior studies including ISO-NE’s *Economic Planning for the Clean Energy Transition* and the Analysis Group’s *Pathways Study*. However, observed impacts to date remain relatively muted, reflecting stable load growth and incremental renewable additions compared to the scale required for deep decarbonization. Nonetheless, the framework below provides a useful baseline for monitoring emerging conditions.

Trends in System and Market Metrics

Metric	Description of Expected Trend	Trend
Energy Usage	Sustained load growth, with winter energy use and peak demand increasing faster than summer demand.	—
Seasonal/Annual Load Variability	Increasing variability in annual energy needs, driven primarily by winter heating demand and heightened sensitivity to cold weather.	—
Morning and Evening Load Ramps	Steeper morning (down) and evening (up) load ramps as solar generation penetration increases.	▲
Downward Flexibility of Supply	More frequent periods where net load falls below the minimum stable operating levels of conventional generation.	—
Fast-Start Generator Utilization	Greater reliance on fast-start, dispatchable resources to manage steeper and more volatile load ramps.	▲
Load Forecast Error	Increased difficulty forecasting load accurately, with a focus on day-ahead and intra-day timeframes.	—
Negative Energy Prices	Increasing frequency of negative LMPs as renewable generation grows and negative offer prices become more prevalent.	▲
Energy Price Level	Downward pressure on energy prices associated with higher renewable generation levels.	▲
Energy Price Volatility	Price volatility driven by intermittent renewable output and changing net-load conditions remains consistent with prior years.	—

The trend indicator reflecting our assessment of whether the underlying issue has increased (▲), remained stable (—), or decreased (▼) in magnitude over time

Importantly, the most pronounced impacts are reflected at the hourly operational level rather than in annual averages. Behind-the-meter solar has significantly altered load profiles—reducing morning ramps while steepening evening ramps. Between 2021 and 2025, the evening ramp in residual load increased from 467 MW/hour to 826 MW/hour. Midday minimum load conditions have also become more frequent, with the system’s lowest load shifting from nighttime to daytime hours in 51% of days in 2025, up from 7% in 2021, contributing to the emergence of a persistent “duck curve.”

Despite these changes, the system has maintained adequate operational flexibility, with no material over-supply conditions or ramp constraints observed. However, growing net-load variability is increasing reliance on flexible, fast-start resources, particularly during the evening ramp. Looking ahead, projected load growth—8% higher energy usage by 2035, with winter peaks rising 30%—is expected to further increase the need for flexible and fuel-secure resources, especially under cold-weather conditions.

Competitive Market Outcomes Persisted Amid Tightening Supply

Energy market outcomes in 2025 remained broadly competitive, with supplier concentration at levels consistent with competitive market conditions. The four largest suppliers accounted for approximately 42% of generation, with shares relatively evenly distributed. At the same time, structural market power indicators reflected greater reliance on large suppliers under tighter supply conditions. In real time, at least one supplier was pivotal in roughly one-third of hours, consistent with recent years. These outcomes primarily reflect reduced import availability and tighter supply margins, but they did not translate into material realized market power concerns.

Indicators of supplier behavior continued to support this assessment. Economic withholding remained low, with economically withheld capacity below 2%, and the day-ahead price-cost markup at 2.7%, indicating limited impact of any divergence between observed offers and the IMM's competitive cost benchmarks. Mitigation activity remained minimal, totaling just 399 asset hours—approximately 0.02% of all asset hours subject to mitigation—consistent with prior years.

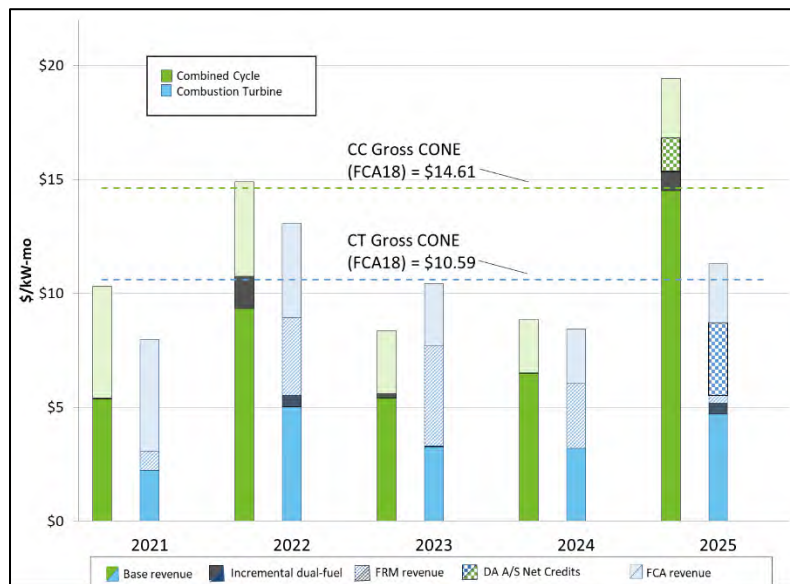
Other markets also remained competitive overall. The regulation market exhibited substantial excess supply, with residual supply index (RSI) values consistently above 900%, indicating the absence of pivotal suppliers. The Financial Transmission Rights (FTR) market remained active but concentrated, with the top four participants holding approximately 67% of MWs. FTR profitability totaled \$34 million in 2025, driven primarily by increased congestion—particularly associated with scheduled transmission outages—rather than structural market power *concerns*.

We have made several market design recommendations in the energy market mitigation space over the past few years, including proposals to review conduct and price impact thresholds and to enhance the pivotal supplier screen (see Recommendations 2023-1 and 2015-3). The importance of these recommendations has increased in the context of heightened merger and acquisition activity, which is contributing to greater portfolio concentration. Accordingly, we encourage proactive action to ensure that mitigation rules remain appropriately calibrated to support competitive market outcomes going forward.

Market Revenues Improved in 2025, with Significant Variation across Resource Types

New resources: Wholesale market revenues increased significantly in 2025 due to higher natural gas prices, improving profitability metrics and signals for new entry. Energy and ancillary services revenues rose sharply for proxy new combined-cycle (CC) and combustion turbine (CT) units, with net revenues (excluding capacity) reaching approximately \$16.8/kW-month for a CC and \$8.4/kW-month for a CT. When combined with capacity revenues of \$2.60/kW-month, total revenues for both technologies exceeded their estimated Gross Cost of New Entry, marking the second time in five years that aggregate market revenues were sufficient to support new entry.

Revenue and Cost of New Entry Estimates for a Combined Cycle and Combustion Turbine

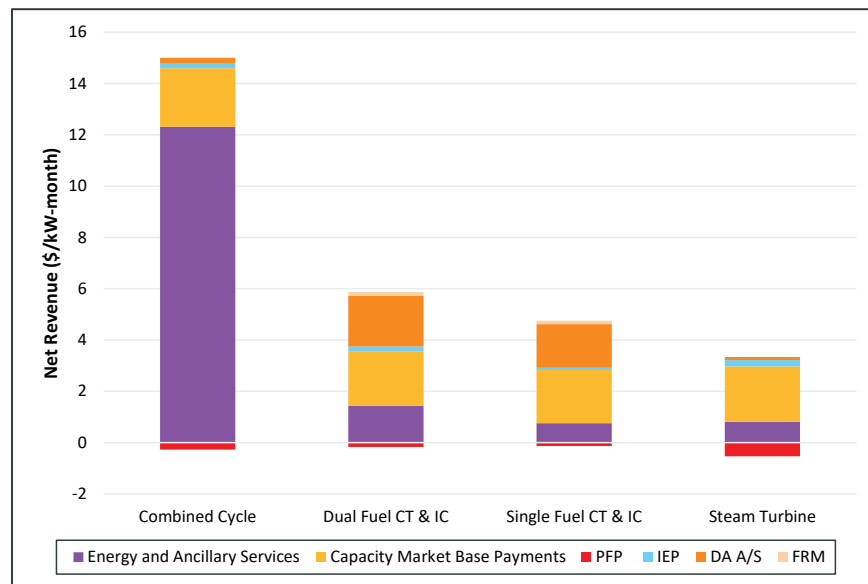


Renewable and storage resources: Profitability for renewable resources continued to depend heavily on out-of-market revenues. In 2025, Renewable Energy Certificate (REC) revenues accounted for approximately 33% of total wind revenues, down from prior years as higher energy prices increased market-based revenues. Solar resources remained predominantly supported by state incentives, with about 71% of revenues derived from the Solar Massachusetts Renewable Target (SMART) program. Battery storage revenues declined to just under \$10/kW-month, reflecting lower revenues from the regulation market as clearing prices fell significantly amid increased participation by battery resources.

Existing resources: Among existing resources, combined-cycle (CC) units derived roughly 85% of revenues from the energy and ancillary services markets, while steam turbines relied on capacity payments for approximately 77% of revenues. Steam turbine resources, in aggregate, incurred performance charges under the Pay-for-Performance framework due to lower delivered capacity during scarcity events. These outcomes suggest that some older, less efficient resources will face increasing economic pressure—and potential retirement—if current market conditions persist.

For combustion turbines (CTs), revenues from the DA A/S market comprised ~35% of overall revenues, reducing reliance on capacity market payments. This pre-distribution of revenues will have important implications in terms of downward pressure on capacity market offers and potentially capacity costs in the future.

Existing Resource Net Revenues from Energy, Capacity and Ancillary Markets, 2025



Capacity Auction Reforms Address Resource Performance, Seasonal Reliability Risks, and Supply-Demand Uncertainty

ISO-NE’s Capacity Auction Reform (CAR) initiative represents a significant evolution of the capacity market, aimed at better aligning capacity procurement with system reliability needs and reducing uncertainty for both supply and demand. The reforms are being implemented in two phases.

The first phase—**Capacity Auction Reform: Prompt and Deactivation (CAR-PD)**— replaces the three-year-forward capacity auction with a prompt auction conducted one month ahead of the commitment period, along with associated changes to resource deactivation rules. FERC approved CAR-PD tariff changes in early 2026, and the IMM supported these reforms as a meaningful improvement over the existing framework. The prompt auction design reduces uncertainty by shortening the load-forecast horizon and requiring resources to be fully constructed before participating, thereby improving price formation and eliminating reliance on unbuilt “phantom” capacity. The revised deactivation process replaces priced retirement bids with unpriced, irrevocable notices submitted one year in advance, better reflecting how market participants make exit decisions while preserving the ISO’s ability to assess reliability impacts and mitigate potential market power concerns.

The second phase—**Capacity Auction Reform: Seasonal and Accreditation (CAR-SA)**— continues development toward a more reliability-focused capacity market. CAR-SA introduces separate summer and winter auctions and adopts marginal resource accreditation to better reflect how different resource types contribute to reliability under season-specific stress conditions. A key feature of CAR-SA is the introduction of a winter natural-gas resource constraint, which recognizes pipeline limitations and reduced fuel deliverability during cold-weather periods. By discounting the accredited capacity of gas-only generators that rely on constrained pipeline capacity, while exempting dual-fuel and firm-fuel resources, the reform improves investment signals and more accurately aligns compensation with expected reliability performance.

Together, the CAR-PD and CAR-SA reforms represent a shift toward a more timely, reliability-driven capacity market design that improves market efficiency, strengthens price formation, and better

reflects evolving system risks—particularly winter reliability challenges driven by fuel constraints and changing resource characteristics.

Summary of IMM Market Enhancement Recommendations

One of the IMM’s key functions is to recommend rule changes to enhance the performance of the markets. In practice, we communicate our recommendations through our reports, including our quarterly markets performance reports, memorandums, and comments filed with FERC on proposed rules changes.

The tables below summarize the IMM’s recommended market enhancements, first showing issues with an “open” status, followed by recently closed issues. A hyperlink is provided to the document in which the recommendation was first put forward, along with the IMM's priority ranking of each recommendation. Recommendations included in this report for the first time are included in the first table. The second table summarizes recommendations included in prior year reports.

The priority ranking (High, Medium or Low) considers the potential market efficiency gains, as well as the potential complexity and cost of implementing each recommendation. High priority recommendations may deliver significant market efficiency gains, with the benefit outweighing the cost of implementing them. At the other end of the scale, low priority recommendations are not intended to indicate low importance, but rather issues that may not have as significant long-term efficiency gains (compared to high priority recommendations) and/or may be very costly to implement.

Summary of New IMM Recommendations since prior Annual Report

ID	Recommendation	When made	Status	Priority Ranking
2026-1	Increase the Day-Ahead Ancillary Services (DA A/S) Strike Price to better align with the short-run marginal costs (SRMCs) of resources that provide the majority of operating reserve capability. The current Strike Price frequently falls below resource SRMCs, which increases expected closeout risk, increases DA A/S offers, and discourages participation without delivering commensurate reliability benefits. Adjusting the Strike Price to better reflect cost fundamentals would reduce embedded risk premiums, improve participation, place downward pressure on DA A/S clearing prices, and better align price signals with periods of elevated system reliability risk while preserving strong real-time performance incentives.	2026 Memo to ISO New England/ NEPOOL Markets Committee	ISO New England is proposing changes to address this recommendation.	High
2026-2	Reduce the Forecast Energy Requirement (FER) to account for expected real-time production from front-of-the-meter wind and solar resources that routinely exceed their day-ahead cleared awards. The current FER overstates required physical supply by not accounting for renewable output that the ISO already relies upon operationally, resulting in unnecessary procurement of higher-cost physical generation or Energy Imbalance Reserves and higher DA A/S costs. Netting expected renewable production against the FER would improve consistency between day-ahead and real-time operations, reduce reliance on expensive physical supply, and place downward pressure on the combined LMP plus FER, which represents the marginal cost of day-ahead physical energy under the joint energy and ancillary services design.	2026 Memo to ISO New England/ NEPOOL Markets Committee	ISO New England is proposing changes to address this recommendation.	High

ID	Recommendation	When made	Status	Priority Ranking
2026-3	Reevaluate and consider a downward adjustment to the Non-Performance Factor (NPF) applied to ten- and thirty-minute operating reserve requirements in light of strengthened performance incentives and improved observed resource performance. The current 20% NPF reflects historical conditions that predate Pay-for-Performance, higher reserve penalty prices, and the implementation of the DA A/S market, all of which have materially increased incentives for real-time performance. A data-driven reassessment could demonstrate that a lower NPF is appropriate, better aligning reserve requirements with demonstrated system needs, reducing DA A/S procurement costs, and avoiding systematic over-procurement while maintaining reliability.	2026 Memo to ISO New England/NEPOOL Markets Committee	ISO New England implemented a reduced NPF (15%) on May 1, 2026	High

The following table summarizes IMM recommendations from prior year reports. The table includes a trend indicator reflecting our assessment of whether the underlying issue has been increasing (▲), remained stable (—), or decreased (▼) in magnitude over time

Summary of Prior IMM Recommendations

ID	Recommendation	When made	Status	Priority Ranking	Trend
2025-6	Adopt a Capacity and Impact (C&I) Approach for Single-Year Capacity Offers Subject to IMM Review Implement a Capacity and Impact (C&I) framework for evaluating single-year capacity offers that are subject to IMM cost reviews. Eliminate the existing Pivotal Supplier Test (PST), under which only resources belonging to pivotal suppliers are subject to market power mitigation. The C&I framework provides a more accurate assessment of market power and reduces the risks of both over-mitigation and under-mitigation associated with the current PST and Conduct approach.	2024 AMR (May 2025)	Not in the scope of the ISO's current work plan.	High	—
2025-5	Review and clarify the time-out trigger for capacity resources to prevent inefficient transmission reservation The current market rules state that a resource will be considered retired, and its interconnection rights terminated, if it does not "operate commercially" for three calendar years. The term "operate commercially" is not clearly defined, potentially allowing resources to retain interconnection rights by producing minimal energy output, even without plans to return to full operation. To prevent inefficient reservation of transmission capacity, the IMM recommends clarifying the Tariff to require that a resource demonstrates meaningful and sustained energy production to be considered commercially operational.	2024 AMR (May 2025)	Not in the scope of the ISO's current work plan.	Medium	—

ID	Recommendation	When made	Status	Priority Ranking	Trend
2025-3	Treatment of Export Transactions in Pay-for-Performance Settlements The current Pay-for-Performance (PfP) rules create unequal incentives for imports and exports during scarcity events, crediting imports at the PfP rate but not applying a corresponding charge to all exports. While there is netting of imports and exports at the market participant level, this does not fully address the issue. This misalignment can lead to inefficiencies as it fails to address potential gaming opportunities, where related entities can profit from simultaneously scheduling imports and exports, receive credits for the import, and provide no reliability benefit.	2024 AMR (May 2025)	Currently in the ISO's work plan. The ISO's proposal will be voted on at the June 16-18, 2026 NEPOOL Participants Committee Meeting.	Medium	▲
2025-2	Provide Clarity on Need to Shed a CSO During Outage Periods The Tariff requires non-intermittent resources to offer their full CSO unless they are physically unavailable, but it lacks clear definitions and enforcement mechanisms for prolonged unavailability. The IMM considers a resource physically available if it is not on a forced or planned outage, consistent with other Tariff provisions and FERC rulings. However, resources can remain on outage and continue receiving capacity payments without being required to shed their CSO, which has led to enforcement actions in the past. Given the range of unavailability scenarios—such as early retirements, long-term outages, lack of fuel, or insufficient demand backing—the IMM recommends amending the Tariff to better define physical unavailability and to require resources to shed their CSO or face penalties if they cannot deliver capacity for extended periods.	2024 AMR (May 2025)	Not in the scope of the ISO's current work plan.	Medium	—
2024-1	Publish generation retirements that have occurred either prior to the effective retirement date in the FCM or outside of the FCM process. Retirement timings do not always align with capacity commitment periods and early retirements remain outside of the publication of information associated with capacity market qualification and results. We believe there is value in the release of such information in the interest of transparency and the free flow of important information to market participants.	2023 AMR (May 2024)	Implemented for FCA 19 under CAR-PD.	Medium	▼
2023-2	Review reserve pricing mechanics under fast-start pricing. Under current fast-start pricing rules, we have observed frequent non-zero reserve pricing in scenarios when resources' dispatch instructions were not impacted by the reserve constraint and the system had a surplus of reserves. Due to tradeoffs presented by the separation of the dispatch and pricing software, the ISO chose a pricing optimization methodology that minimizes false negatives (no reserve pricing when there is a physical reserve constraint binding) but allows false positives (reserve pricing when there is not a physical reserve constraint binding). This was an intentional decision	2022 AMR (May 2023)	Not in the scope of the ISO's current work plan.	Medium	—

ID	Recommendation	When made	Status	Priority Ranking	Trend
	when fast-start pricing was implemented, however, the frequency in which we have observed reserve pricing when there is not a physical reserve constraint binding has exceeded the frequency in which we expected these scenarios to occur, and the cost of reserve payments in these intervals warrants additional consideration of other solutions.				
2023-1	Review mitigation thresholds and reference level methodologies, eliminate mitigation exemptions for non-capacity resources, and extend mitigation to export-constrained area. Market power mitigation rules need to strike a reasonable balance between producer and consumer interests, and in turn prescribe adequate threshold tests to determine when market monitors override generator supply offers. The IMM has identified a number of potential rule improvements to better serve the mitigation function. 1. Review of the current mitigation thresholds that apply to instances of system-wide and local market power. The current thresholds allow for considerable latitude in supply offers levels over competitive benchmarks (300% and 50%) and have been in place for many years with little empirical support. 2. Eliminate the energy offer mitigation exemption for non-capacity resources in the day-ahead energy market. 3. Extend the scope of offer mitigation to cover the potential exercise of market power in export-constrained areas. 4. Review the methodologies for determining reference levels, which are used to evaluate if an offer is competitive (the “conduct test”). Currently, reference levels can be based on marginal cost, or historical fuel-adjusted accepted supply offers or LMPs. We have observed instances in which the latter two methodologies produce unreasonably high reference levels.	2022 AMR (May 2023)	Not in the scope of the ISO’s current work plan.	Medium	▲
2022-1	Incentive rebuttal component of proposed Buyer-side Mitigation Rules The ISO’s proposed buyer-side mitigation rules will allow a Project Sponsor to demonstrate a lack of incentive through a Net Benefits Test to avoid mitigation of a below-cost supply offer from certain resources. The IMM has recommended that removing the incentive rebuttal provision from the proposal would make the buyer-side mitigation review more predictable and capable of being administered more reliably and with less subjectivity.	Filed Comments with FERC on MOPR Elimination and Buyer-side Mitigation Rules (Apr 2022)	Not in the scope of the ISO’s current work plan.	Low	—

ID	Recommendation	When made	Status	Priority Ranking	Trend
2020-1	Reference level flexibility for multi-stage generation Given that 2023-1 is not part of the ISO's workplan, and is unlikely to be developed for some time, we recommend related changes that could be made to the market power mitigation function in the meantime. We believe these changes will be less resource-intensive and complex to adopt, compared to incorporating multi-stage generation modeling into the day-ahead and real-time market and systems software. However, it is not a replacement of the above recommendation on reviewing mitigation thresholds and methodologies. The recommendation is to provide generators with the ability to dynamically select their active or planned configuration and to adjust reference levels to be consistent with their operating costs and their supply offers. This will address the current risk of false positive and negative errors in mitigation, given the potentially high costs differences between configurations. It may also eliminate a potential deterrent to generators from offering configurations to avoid the risk of mitigation, which may ultimately be more cost effective to consumers.	Winter 2020 QMR (May 2020)	Not in the scope of the ISO's current work plan.	Medium	▼
2018-1	Unoffered Winter Capacity in the FCM The IMM is concerned that generators may be contracting at, or close to, their maximum capacity (i.e. their winter qualified capacity), as determined by the ISO, even though that capacity is not deliverable in certain months given expected ambient temperatures. The IMM recommends that the ISO review its existing qualification rules to address the disconnect between the determination of qualified capacity for two broad time horizons (summer and winter), the ability of the generators to transact on a monthly basis, and the fluctuations in output capability based on ambient conditions. A possible solution would be for the ISO to develop more granular (e.g. monthly) ambient temperature-adjusted qualified capacity values, based on forecasted temperatures and the existing output/temperature curves that the ISO currently has for each generator.	Fall 2018 QMR (Mar 2019)	The IMM will evaluate this recommendation in the context of the ISO's planned revisions to its capacity accreditation methodology as part of the CAR project, which will separately account for summer and winter physical capabilities.	Medium	—
2017-1	Treatment of multi-stage generation Due to the ISO's current modeling limitations, multi-stage generator commitments can result in additional NCPC payments and suppressed energy prices. This issue was first raised by the external market monitor, Potomac Economics.[1] The IMM recommends that the ISO consider improvements to its current approach to multi-stage generator modeling. Two possible options are: a. Expanding the current pseudo-combined cycle (PCC) rules- Consider whether to make PCC rules a mandatory requirement for multi-stage generators through proposed rule changes , or b. Adopt multi-configuration resource modeling capability- More	Fall 2017 QMR (Feb 2018)	Not in the scope of the ISO's current work plan.	Medium	▼

ID	Recommendation	When made	Status	Priority Ranking	Trend
	dynamic approach to modeling operational constraints and costs of multiple configurations.				
2016-2	Analyzing the effectiveness of Coordinated Transaction Scheduling: ISO-NE should implement a process to routinely access the NYISO internal supply curve data that is used in the CTS scheduling process. This data is an important input into the assessment of the cost of under-utilization and counterintuitive flows across the CTS interface.	2016 AMR (May 2017)	Related to 2016-1. Not in the scope of the ISO's current work plan.	Medium	—
2016-1	Improving price forecasting for Coordinated Transaction Scheduling: There is a consistent bias in the ISO's internal price forecast at the New York North interface, which may reduce the effectiveness of CTS. To date, biases in ISO-NE and NYISO forecasts have been in opposite directions, which increase the price spread between the markets relative to actual spreads, and may produce inefficient tie schedules. ISO-NE should assess the causes of biases in the price forecast and assess how the accuracy of the forecast can be improved. ISO-NE should periodically report on the accuracy of its price forecast at the NYISO interface, as well as the differences between the ISO-NE and NYISO price forecasts.	2016 AMR (May 2017)	Not in the scope of the ISO's current work plan.	Medium	—
2015-3	Pivotal supplier test calculations: The ISO, working in conjunction with the IMM, enhance the real-time energy market mitigation pivotal supplier test to include (1) ramp-based accounting of supply recognizing the differences between energy and reserve products and (2) participant affiliations.	2015 AMR (May 2016)	IMM and ISO to assess the implementation requirements for this project. Not currently in ISO's workplan.	Medium	▲
2015-1	Corporate relationships among market participants: The ISO develop and maintain a database of corporate relationships and asset control that allows for accurate portfolio construction for the purpose of identifying uncompetitive participation, including the potential exercise of market power and market manipulation.	Q2 2015 QMR (Oct 2015)	The project is not in the scope of the ISO's current workplan. The IMM will continue to rely on a combination of internal data and its own market research to satisfy its monitoring needs.	Medium	▲
2010-1	NCPC charges to virtual transactions: The ISO develop and implement processes and mechanisms to reduce NCPC charges to virtual transactions (to better reflect the NCPC cost causation principle) in response to the historical decline in virtual trading activity. A reduction in NCPC charges to virtual	2010 AMR (Jun 2011)	Not in the scope of the ISO's current work plan.	Medium	▲

ID	Recommendation	When made	Status	Priority Ranking	Trend
	transactions will likely improve day-ahead scheduling by adjusting expectations of real-time conditions.				
2025-4	Option for real-time-specific offer schedules to automatically be used in real-time energy dispatch, in support of renewable resources Wind and solar capacity resources must offer into the day-ahead market but face uncertainty in real-time output. To manage this risk, these resources often submit higher day-ahead prices to account for volumetric uncertainty, while offering lower prices in real-time to reflect their low marginal costs. However, ISO-NE's bidding system automatically carries day-ahead offers into real-time if a resource receives a day-ahead award, requiring manual action by the participant to overwrite the supply offers. The IMM has observed several cases in which the participant failed to take the manual overwrite action, leading to unnecessary downward dispatch of low-cost renewables in real-time. The IMM recommends ISO-NE enhance its systems to allow separate day-ahead and real-time offers to prevent such issues, especially as renewable capacity grows.	2024 AMR (May 2025)	Not in the scope of the ISO's current work plan.	Low	—
2025-1	Clearing mechanics used at External Interfaces Participants have increasingly used virtual demand bids at the Highgate interface to secure real-time clearing priority for their imports. By pairing virtual demand bids with early-submitted import offers, participants can create counter-flow in the day-ahead market, enabling full clearing of their imports and gaining a timestamp advantage in real-time scheduling. While the direct costs of such strategies (e.g., uplift or transaction costs) appear to be mostly borne by the participants employing them, these transactions are not consistent with their intended purposes of hedging or promoting price convergence. Moreover, there may be efficiency gains if participants competed for import opportunities based on price rather than submission time. To address this, we recommend that ISO-NE reevaluate clearing rules at non-CTS external interfaces, particularly the use of timestamps as a tiebreaker, to reduce incentives for strategic virtual bidding and allow participants to submit more accurate, cost-reflective offers closer to the operating day.	2024 AMR (May 2025)	Not in the scope of the ISO's current work plan.	Low	—

ID	Recommendation	When made	Status	Priority Ranking	Trend
2024-2	Establish an automated process to ensure transmission-constrained resources are not designated for reserves. Resources in New England are not eligible to provide operating reserves if constrained by transmission limitations. In practice, this is achieved through a manual process performed by system operators. When a transmission constraint binds, operators are tasked with applying a ‘reserve down’ flag to resources limited by that constraint. ISO dispatch software will not designate reserves on units that have the reserve down flag applied. This reflects the fact that, due to the transmission constraint, the reserves that would normally be counted on such resources are not deliverable to the system as energy. While market impacts related to this issue are not large in magnitude, they consistently persist from year to year. Market outcomes could be improved in this regard if the ISO implemented an automated process for applying the reserve down flag to resources limited by binding transmission constraints.	2023 AMR (May 2024)	Not in the scope of the ISO’s current work plan.	Low	—
2021-1	Develop Offer Review Trigger Price (ORTP) for co-located solar/battery facilities. Under the current rules, the ORTP for a co-located battery and solar project is based on the weighted average of the individual technologies. This results in a value that is below the true “missing money” for the combined resource, allowing such resources to offer in at prices below competitive levels without review and mitigation, and undermining the protections put in place by the minimum offer price rule (MOPR). In our opinion, a bottom-up calculation is preferable because it accurately represents the constraints that co-located solar/battery facilities face and results in a more precise cost estimate.	Filed Comments with FERC on ORTP Recalculation (Apr 2021)	Closed: This issue is moot with the elimination of MOPR.	Low	▼
2013-1	Limited energy generator rules: The ISO modify the market rules as necessary to ensure that the use of the limited-energy generator (LEG) provisions in both the day-ahead and real-time markets are restricted to instances when the availability of fuel is physically limited.	2013 AMR (May 2014)	Not in the scope of the ISO’s current work plan.	Low	—

Section 1

Overall Market Conditions

This section provides an overview of key trends in the wholesale markets. It covers the underlying supply and demand conditions behind those trends and provides important context for the more detailed discussions on market outcomes and performance in later sections of this report.

The implementation of Day-Ahead Ancillary Services (DA A/S) in 2025 represents a significant change to the structure of the energy markets. Prior to this change, day-ahead Locational Marginal Prices (LMPs) reflected the marginal cost of energy. With DA A/S, the market co-optimizes energy and ancillary services, so clearing outcomes reflect both the cost of serving load as well as the cost of satisfying system operating reserve constraints. Accordingly, care is required when comparing prices to prior years.

It is important to note that in this report, we define the marginal cost of physical energy as the sum of the Day-Ahead Locational Marginal Price (LMP) and the Forecast Energy Requirement Price (FERP). Under the DA A/S framework, FERP reflects the value of meeting the system's physical energy requirement and must be included to capture the full marginal cost of serving load. In other words, the LMP alone does not reflect this component and will understate energy costs when this constraint is binding.

1.1 Wholesale Cost of Electricity

Key Takeaways

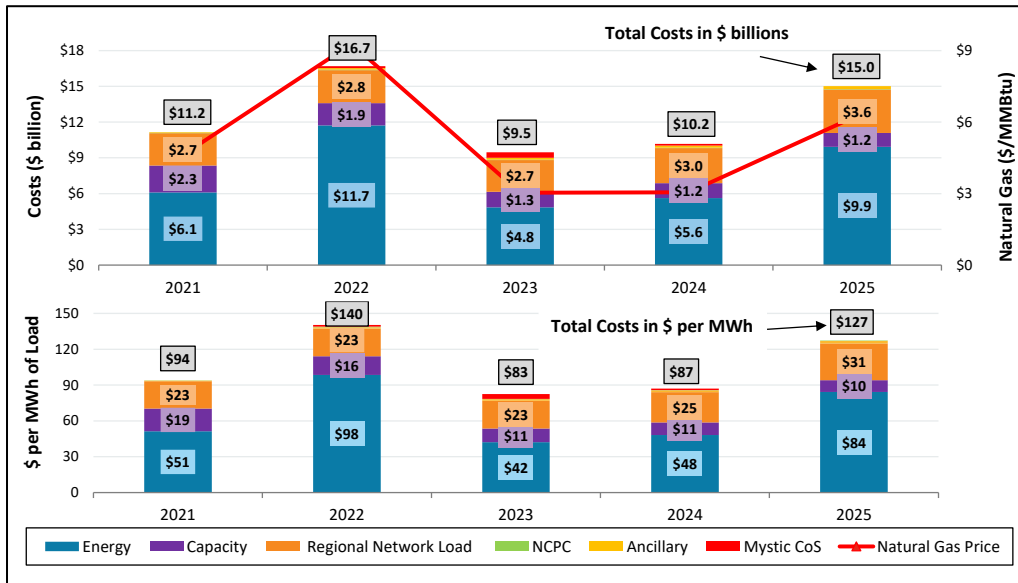
Wholesale market costs totaled \$15 billion in 2025, a 48% (\$4.8 billion) increase from 2024. The increase was driven primarily by higher energy costs, which rose to \$9.9 billion, up 77% (\$4.3 billion) year-over-year.

Higher energy costs were largely attributable to natural gas prices, which increased by 105% in 2025 (from \$3.06/MMBtu to \$6.27/MMBtu). In addition, the introduction of the Day-Ahead Ancillary Services (DA A/S) market on March 1, 2025—including Forecast Energy Requirement (FER) costs—added approximately \$666 million in settlement costs over the first ten months of implementation.

Figure 1-1 below gives an overview of wholesale electricity costs and average natural gas prices over the past five years, including significant changes in each cost category.⁷

⁷ The figure includes the Mystic Cost-of-Service Agreement. This agreement ended in 2024 and is covered in prior IMM reports.

Figure 1-1: Wholesale Costs (\$ billions and \$/MWh) and Average Natural Gas Prices



Energy costs accounted for 66% of wholesale electricity costs in 2025. Total energy costs of \$9.9 billion increased 77% from 2024. While energy costs were high this year, they remained below costs in 2022, which was the highest total in the last 17 years.⁸ Energy costs increased largely because of higher natural gas prices, which were up by 105% compared to 2024 prices (\$6.27/MMBtu vs. \$3.06/MMBtu).⁹

Energy costs reflect volumes settled at the day-ahead LMP and Forecast Energy Requirement price (FERP). Introduced on March 1, 2025, as part of the Day-Ahead Ancillary Services Initiative (DASI), the Forecast Energy Requirement (FER) ensures that the day-ahead market clears sufficient physical capability to meet the ISO’s day-ahead load forecast. The FER credit compensates physical supply resources—including generators, demand response resources, and imports—with day-ahead energy awards for their contribution to meeting the FER constraint. FER credits totaled \$524 million from March through December 2025.

Regional network load (RNL) costs, or transmission costs, include the costs associated with pool transmission infrastructure operation, maintenance, and investment borne by the transmission

⁸ Energy costs in 2022 were the highest since 2008, due to significant increases in natural gas prices. Natural gas prices were driven by a combination of market conditions and events at an international and national level, in addition to regional New England winter issues. These factors included the Russian-Ukrainian conflict and the significant uptick in international demand for Liquefied Natural Gas (LNG), higher US demand and periods of sustained cold weather in New England. ISO New England Inc., Internal Market Monitor, “2022 Annual Markets Report”, June 5, 2023, <https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf>

⁹ Unless otherwise stated, the natural gas prices shown in this report are based on the weighted average of the Intercontinental Exchange next-day index values for the following trading hubs: Algonquin Citygates, Algonquin Non-G, Portland, Tennessee gas pipeline Z6-200L, Tennessee North gas, Tennessee South gas, and Maritimes and Northeast. Next-day implies trading today (D) for delivery during tomorrow’s gas day (D+1). The gas day runs from hour ending 11 on D+1 through hour ending 10 on D+2.

owners as well as certain reliability and administrative costs.¹⁰ RNL costs in 2025 were \$3.6 billion, representing nearly 24% of total wholesale costs and a \$681 million increase over 2024 costs.¹¹ Transmission costs are recovered based on monthly peak demand through the regional network service (RNS) rate, which rose from \$154.35/kW-year in 2024 to \$185.28/kW-year in 2025.¹² The RNS rate primarily increased because of 1) an under-collection of transmission costs in 2023 and 2) project additions across the region requiring cost recovery.

Transmission costs in New England have increased in recent years as transmission owners have made investments to respond to reliability needs identified by the ISO as well as to replace aging transmission equipment within their local systems (known as “Asset Condition” projects). Notable projects undertaken by transmission owners to improve greater system reliability that were placed in-service in 2025 included work done to increase the load serving capability of greater Boston as well as to resolve thermal overloads in Maine.¹³ Numerous asset condition projects across New England also went in-service in 2025.

Capacity costs comprise payments to supply resources in the Forward Capacity Market, and fell slightly in 2025, accounting for 8% of wholesale costs. Capacity clearing prices increased in 2025 relative to 2024, with prices of \$2.61/kW-month in capacity commitment period (CCP) 15, which includes January-May 2025, and \$2.59/kW-month in CCP 16, which includes June-December 2025. While clearing prices increased, cleared capacity fell in CCP 16, and there was less upward price separation in the import-constrained Southeast New England capacity zone.

Ancillary service costs include payments to supply resources for providing day-ahead reserves, real-time reserves, regulation services, and the costs of the Inventoried Energy Program (IEP). Ancillary service costs totaled \$242 million in 2025, up \$66 million (7%) on 2024 costs due to the day-ahead reserve products included in the DA A/S market. The four day-ahead ancillary products cost \$137 million in 2025. The sunseting for Forward Reserve Market and lower IEP costs offset some of the increase in ancillary service costs.¹⁴

Net Commitment Period Compensation (NCPC) costs, or uplift, covers supply resource production costs not recovered through energy prices. NCPC totaled \$42 million in 2025, up \$7

¹⁰ The reliability costs include costs associated with resources retained for reliability (RFR) in the Forward Capacity Market (FCM), voltage support, high-voltage control, and system restoration. The administrative costs include local and system level dispatch and control costs as well as the budget for the New England States Committee on Electricity. ISO New England Inc., “Monthly Regional Network Load Cost Report December 2025”, February 19, 2026) https://www.iso-ne.com/static-assets/documents/100032/2025_12_nlcr_final.pdf.

¹¹ The annual figure is the sum of the monthly Total RNL Costs. ISO New England Inc., “Monthly Regional Network Load Cost Reports”, <https://www.iso-ne.com/markets-operations/market-performance/load-costs/>.

¹² RNS rates are established using a prescribed methodology and then shared with FERC via an informational filing. More information about the determination of the 2025 RNS rate can be found in the following presentation: ISO New England Inc., “RNS Rate Effective January 1, 2025”, August 13, 2024, https://www.iso-ne.com/static-assets/documents/100014/a05.1_2024_08_1314_tc_rns_rates_presentation.pdf.

¹³ For more information about the transmission projects that went into service in 2025, see the following June and October presentations: ISO New England Inc., “RSP Project List and Asset Condition List” June, 16, 2025 & October 23, 2025, https://www.iso-ne.com/static-assets/documents/100025/final_project_list_presentation_jun_2025.pdf and https://www.iso-ne.com/static-assets/documents/100029/final_project_list_presentation_oct_2025.pdf. These presentations are updated three times per year.

¹⁴ IEP costs decreased because 2025 was the final two months of the winter program (January and February) while 2024 included three total months (January, February and December).

million from 2024, and comprised a small component of total energy costs at 0.4%. First contingency or “economic” payments made up 94% of total NCPC payments, a comparable share to 2024. Real-time uplift payments to resources committed in economic merit order to meet load and reserve requirements continued to drive the majority of NCPC payments.

1.2 Fuel and Emissions Costs

Fuel and emissions costs are major drivers of electricity prices. While oil prices were down year-over-year, both natural gas and CO₂ allowance prices were higher in 2025 than in 2024.

Key Takeaways

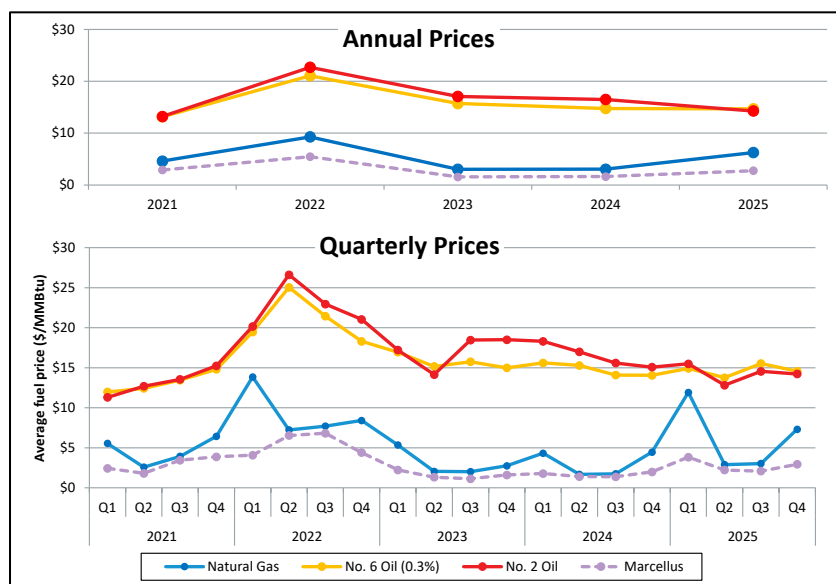
Annual average fuel prices changed significantly from 2024 to 2025. Natural gas prices increased sharply, rising by approximately 105% due to higher demand and colder than normal winter conditions across the Northeast and the broader U.S, while oil prices declined by about 13% due to oversupply conditions.

Carbon allowance prices rose under both the Regional Greenhouse Gas Initiative (RGGI) and Massachusetts Electricity Generator Emissions Limits (EGEL) programs, due to tightening emissions limits and increased demand for allowances. CO₂ emissions costs continue to be a notable driver of energy prices; we estimate that carbon programs contributed approximately \$9/MWh to the average annual load-weighted energy price and added about \$1.1 billion to total energy costs.

1.3 Fuel Costs

Annual and quarterly trends in fuel prices are shown in Figure 1-2 below.

Figure 1-2: Average Fuel Prices by Quarter and Year



Natural Gas

Annual average gas prices exceeded \$6/MMBtu in 2025, a 105% increase from 2024. Price increases were most pronounced during Q1, especially in January and February, due to cold temperatures and a polar vortex. During this period, regional hub natural gas prices, such as Henry Hub and Marcellus, averaged approximately \$11/MMBtu, which was higher than typical winter levels and well above the unusually low prices observed in early 2024, when benchmark prices averaged around \$4/MMBtu. Although prices decreased as winter conditions eased, monthly average regional hub prices remained above 2024 levels.¹⁵

In 2025, higher national natural gas basin prices, including at major upstream benchmarks such as Marcellus and Henry Hub, increased baseline fuel costs for New England as colder seasonal conditions raised demand for both space heating and gas-fired generation, contributing to year-over-year price increases across most U.S. trading hubs. In addition, prices in New England increased by a greater margin due to region-specific factors, as the U.S. Energy Information Administration reported that prices at constrained Northeast delivery hubs, such as Algonquin Citygate and Transco Zone 6 New York, increased substantially more than Henry Hub prices, reflecting winter demand sensitivity and limited pipeline capacity relative to national benchmarks.

¹⁶

Oil

Crude oil prices declined in 2025 as global supply exceeded demand.¹⁷ No. 2 oil prices averaged \$14/MMBtu in 2025, down 13% from 2024, and No. 6 oil prices averaged \$15/MMBtu in 2025 similar to 2024. Oil-fired generation accounted for only a small share of total output in 2025, as lower-cost natural gas generators more frequently set market prices, with oil-fired generators largely dispatched only during cold winter conditions.

1.4 Emissions Costs

New England Carbon Emissions Programs

New England's carbon programs, the Regional Greenhouse Gas Initiative (RGGI) and the Massachusetts Electricity Generator Emission Limits (MA EGEL), are designed to reduce greenhouse gas emissions by directly pricing CO₂ emissions. RGGI creates a unified carbon market across the Northeast, incorporating all New England states as well as Delaware, Maryland, New Jersey, and New York, while MA EGEL imposes additional emissions constraints on Massachusetts

¹⁵ ISO New England Inc., Internal Market Monitor, "Fall 2025 Quarterly Markets Report", https://www.iso-ne.com/static-assets/documents/100032/a04_mc_2026_02_10-11_imm_fall_2025_qmr_presentation.pdf.

¹⁶ U.S. Energy Information Administration (EIA), "In 2025, U.S. natural gas spot prices increased from 2024's record low", January 9, 2026, <https://www.eia.gov/todayinenergy/detail.php?id=66984>.

¹⁷ U.S. Energy Information Administration (EIA), "Crude oil prices fell in 2025 amid oversupply," January 5, 2026, <https://www.eia.gov/todayinenergy/detail.php?id=66944>.

generators.^{18,19} These frameworks influence generator operating costs and wholesale electricity prices by making the cost of carbon an integral factor in generation production costs.

At the heart of these programs is the cap-and-trade mechanism in which a limit (or cap) is set on total emissions. The cap is ratcheted down each year in line with carbon reduction goals. Generators must hold permits for each ton of CO₂ they emit. These permits are distributed through competitive auctions, allowing the market to establish a transparent, real-time value for pollution. As fossil fuel-based generators face higher costs under these systems, they are incentivized to invest in cleaner technologies and more efficient operations. In addition, auction revenues are strategically reinvested into initiatives that support environmental initiatives such as energy efficiency, clean and renewable generation, and greenhouse gas abatement and climate change adaptation. Some states also use RGGI funds for direct consumer bill assistance.

Estimation of CO₂ Emission Programs Impact on LMP and Other Market Outcomes

In 2025, carbon allowance prices rose under both the RGGI and MA EGEL programs. RGGI allowance spot prices increased by 6.5% compared to 2024, while the average annual MA EGEL auction clearing price rose 290% year-over-year. Both carbon markets recorded their highest quarterly auction clearing price to date during 2025. In Section 4 below, we describe pricing trends for both carbon programs in more detail and provide estimates of the annual average cost of emissions compliance by generator fuel type.

In this section, we present the results of day-ahead energy market simulations assessing the impact of carbon allowance prices on wholesale energy prices. The simulations, shown over the past 3 years in Table 1-1, indicate that CO₂ compliance programs increased average energy prices by about \$9/MWh, consisting of roughly a \$7/MWh increase in the LMP and a \$2/MWh increase in the FERP. In aggregate, CO₂ programs added just over \$1.1 billion to total energy market costs, accounting for about 12% of the approximately \$9.9 billion in total energy market costs.²⁰

Table 1-1: Impact of Carbon Allowance Prices on Day-Ahead Energy Market Prices

	2023	2024	2025
Energy Price Impact^(a)	\$6/MWh	\$8/MWh	\$9/MWh
Energy Cost Impact	\$690 million	\$910 million	\$1.1 billion

(a) The 2025 Energy Price Impact includes the Day-Ahead LMP for all months plus the FERP for March to December 2025.

In Figure 1-3 below, we summarize at a high-level the flow of carbon program funds from the auctions to energy initiatives and the impacts on wholesale market costs.²¹ In 2025, the total cost

¹⁸ Massachusetts Department of Environmental Protection, “*Electricity Generator Emissions Limits (310 CMR 7.74)*”, <https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774>.

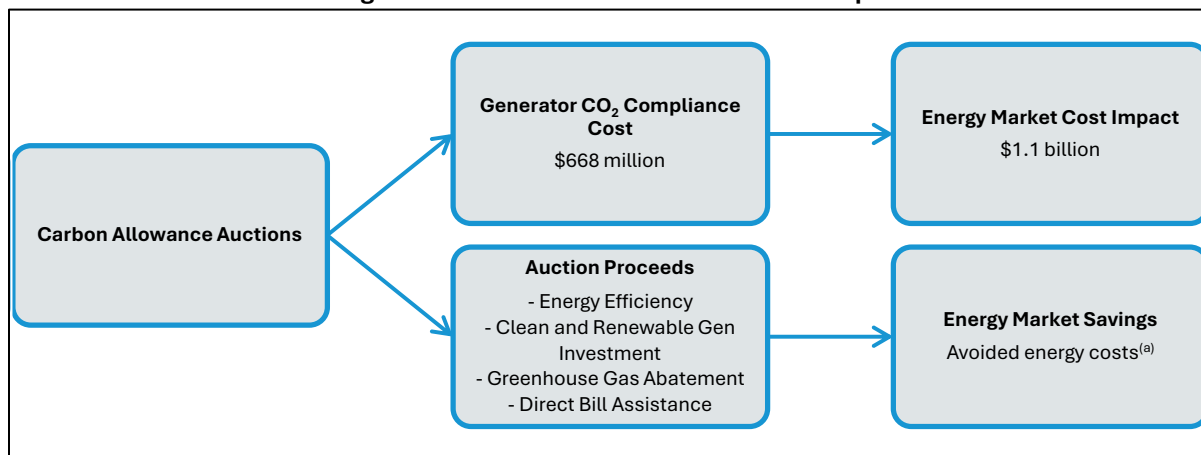
¹⁹ State participation in RGGI has changed over time. In 2025, Pennsylvania withdrew from RGGI, though its participation in the cap-and-trade program had been held up in courts for over three years. Virginia will re-join RGGI in July 2026 after having withdrawn in 2023.

²⁰ The simulation study compared two cases; the first based on actual supply offers and the second with the daily price of CO₂ emissions for both RGGI and MA EGEL programs subtracted from supply offers.

²¹ This high-level conceptual flow chart is provided as a visual aid and is not intended to depict the precise uses of auction proceeds or the full funding mechanisms for energy efficiency (EE) programs, which are typically funded in part through retail electricity charges.

for carbon compliance, based on spot prices for allowances, was about \$668 million.²² The total cost of carbon allowances is lower than the total cost to the energy market because when fossil fuel-fired generators are on the margin, the inclusion of carbon costs raises the market clearing price. This affects all cleared supply, even from those resources that do not require carbon allowances, e.g., renewable generators, nuclear generation and imports.

Figure 1-3: Flow Chart of Carbon Market Impacts



(a) In the 2024 Annual Markets Report we calculated estimated avoided energy costs of \$757 million based on ISO-NE's estimate of energy savings from energy efficiency programs. The ISO has changed its methodology for integrating energy efficiency savings into the load forecast. For that reason, we do not present an estimate of avoided energy costs in this report. The reader may refer to the RGGI *Investments of Proceeds* reports for more information on how states allocate their auction proceeds and for estimated impacts of RGGI investments.

While the gross energy market impact is significantly higher than the total cost of compliance for generators, the energy market net cost of these carbon programs is significantly lower because the proceeds from auctioning the allowance credits are invested in initiatives that focus on reducing emissions, such as energy efficiency programs and clean and renewable energy. For example, two-thirds of auction proceeds from RGGI are invested by the New England States in energy efficiency programs.²³ Similarly, most proceeds from MA EGEL auctions are invested in supporting programs or projects to reduce greenhouse gas emissions.²⁴

In addition to price impacts, CO₂ costs can also influence dispatch patterns. Our simulation results showed modest changes to the day-ahead generation mix. Without carbon pricing, there is a slight reduction in imports into New England in response to lower energy prices and the simulation showed a slight increase in natural gas generation and oil generation particularly during cold winter periods when natural gas and oil price converge.²⁵ However, these effects are muted,

²² The value of emissions is estimated using reported daily emissions data for New England generators for 2025 sourced from the EPA together with daily prices for RGGI and/or MA EGEL from an external vendor. United States Environmental Protection Agency, "Clean Air Markets Program Data", <https://campd.epa.gov/data>.

²³ The Regional Greenhouse Gas Initiative, "Investments of Proceeds" reports, <https://www.rggi.org/investments/proceeds-investments#:~:text=The%20RGGI%20states%20issue%20CO, strategic%20energy%20and%20consumer%20programs>.

²⁴ Commonwealth of Massachusetts (Mass.gov), "310 CMR 7.74 Public Hearing Draft to Final Redline, Allowance Auction Procedures (6.h.1.i.)", <https://www.mass.gov/doc/310-cmr-774-amendments-to-electricity-generator-emissions-limits-0/download>

²⁵ The simulation did not remove CO₂ costs from New York, which also participates in RGGI.

as combined-cycle natural gas-fired generators remain the dominant balancing resource, and production cost differences among these units are relatively small. As a result, carbon pricing tends to result in a parallel shift in the supply curve. This raises prices across the market rather than causing substantial changes to the dispatch order.

1.5 Supply Conditions

Below, we present an overview of New England’s generation and capacity mix by fuel type, location, and age. The composition of the system supply portfolio provides context to the relationship between fuel and wholesale prices, as well as emerging operational challenges.

Key Takeaways

Overall: Combined-cycle generators, including dual-fuel units, remained the largest resource type in 2025, accounting for nearly 50% of contracted capacity in the Forward Capacity Market (FCM). Natural gas and nuclear resources together supplied almost 75% of total energy, similar to 2024. Notably, solar and wind generation increased to 8.4% of total energy production, supplying a larger share of energy than net imports.

Capacity: Overall capacity composition remained relatively stable in 2025. Combined-cycle resources represented approximately 45% of total contracted capacity (about 12,800 MW), with roughly a 40/60 split between dual-fuel and single-fuel generators. Single-fuel combined-cycle capacity declined by about 700 MW, reflecting the retirement of the Mystic generators in May 2024. Other fossil fuel-fired resources—combustion turbines, internal combustion engines, and steam turbines—retained a 23% share of the capacity mix. Nuclear and hydro resources each accounted for about 12%, while solar, wind, and battery storage together totaled 740 MW, or roughly 3% of total capacity.

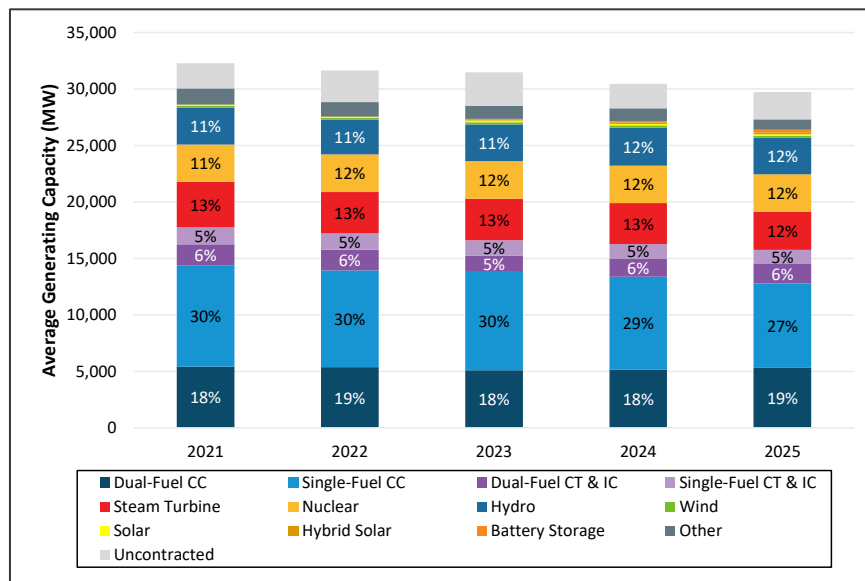
About 2,400 MW of generation capacity did not have a capacity supply obligation in the FCM. About 20% of this uncontracted capacity was associated with solar and wind resources, with an additional ~1,500 MW of uncontracted fossil fuel capacity.

Energy: The share of energy produced by natural gas generation and nuclear generation was similar to 2024. In 2024, increased reliance on natural gas generation (at 50%) stemmed from a reduction in net interchange from the Canadian provinces. This decrease persisted in 2025, and was primarily driven by extended dry weather conditions in Canada, which limited hydroelectric generation. The dry weather conditions also led to a decrease in New England hydroelectric generation, which went from 13% in 2023 to 7% in 2025. In 2025, net interchange with Canadian and New York balancing areas combined was at its lowest level in thirteen years (since 2011).

Generation Capacity

Capacity by generator fuel type in Figure 1-4 below shows the breakdown of total capacity contracted in the FCM, as well as capacity without a capacity supply obligation.²⁶

Figure 1-4: Average Capacity by Fuel Type²⁷



Average contracted generating capacity declined slightly in 2025, as generator retirements exceeded new additions. This continued a five-year downward trend consistent with the decline in the Net Installed Capacity Requirement (Net ICR). Overall, the capacity mix was largely unchanged from 2024, although contracted single-fuel combined-cycle capacity fell by 2% following the retirement of the Mystic Generation Station in FCA 15 (2024/25).

The amount of installed generation capacity without a capacity market position is significant at about 2.4 GW. About 20% of uncontracted capacity is from wind and solar resources that may not assume capacity supply obligations, potentially to avoid pay-for-performance risk, given the variable nature of their fuel. About half of claimed capability is backed by a capacity supply obligation. Fossil fuel-fired units, including combined cycles, CTs and ICs, and steam turbines are 92% backed by capacity supply obligations.

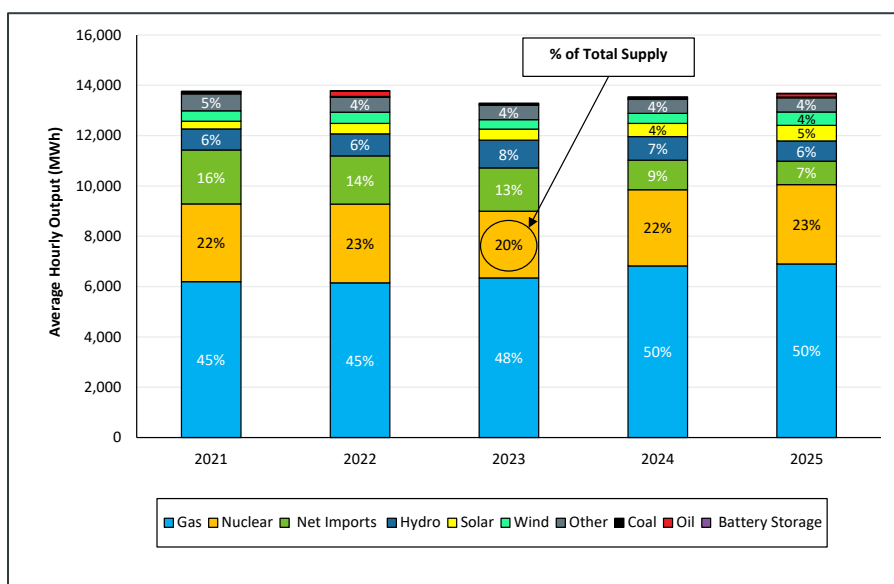
Energy Supply Mix

Energy production by fuel type is shown in Figure 1-5 below. The figure presents average hourly generation by fuel type within the New England control area, along with average net interchange with neighboring control areas.

²⁶ This figure shows generating capacity, which excludes imports and demand response units. We calculate “uncontracted capacity” as the total claimed capability of the generation fleet minus the total contracted capacity of the generation fleet.

²⁷ The “Other” category includes active capacity demand response, landfill gas, methane, refuse, steam, coal, and wood. Generator Types: CC: Combined Cycle, CT: Combustion Turbine, IC: Internal Combustion

Figure 1-5: Average Output and Share of Electricity Supply by Fuel Type



Natural gas generation accounted for half of all energy supply in 2025, more than twice the next largest fuel type, nuclear. Net imports—historically a key source of baseload energy—continued to decline, supplying just 7% of total energy, the lowest level since 2011 due to reduced imports from Canada.

Solar and wind production exceeded net imports in 2025, reflecting continued growth in renewable generation. State and federal policies have driven additional wholesale (front-of-the-meter) solar and wind energy production, with both accounting for 8.4% of total supply in 2025, an increase from 5.2% in the five-year period (since 2021).²⁸

Generation and Consumption by State

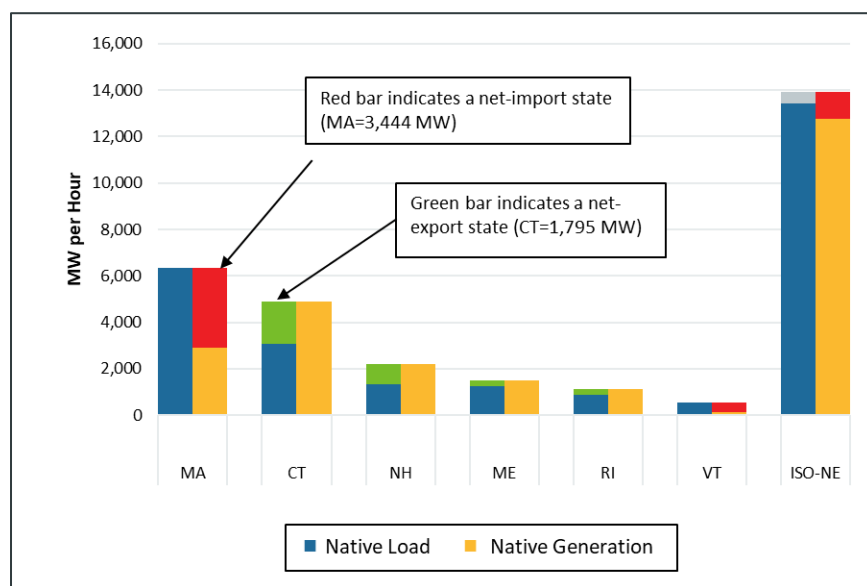
A breakdown of energy production and consumption within each state and aggregated across the ISO-NE market is shown in Figure 1-6 below.²⁹ Blue bars show state load, while yellow bars show state generation. The red and green bars simply show the difference between production and consumption; the red bars illustrate net imports into each state, and the blue bars net exports out of the state.³⁰ Systemwide net imports are also shown in red, and system losses are shown in light grey.

²⁸ Section 4.3 discusses the impact of solar generation on load from both behind- and front-of-the-meter solar.

²⁹ The state breakdown shows native energy production and consumption within each state; it does not include imports into the state from neighboring jurisdictions.

³⁰ Net imports in this context are not necessarily from neighboring jurisdictions outside of New England (New York or Canada) but refer to any imports from outside the state.

Figure 1-6: Average Electricity Generation and Load by State³¹



Because of their larger populations, Massachusetts and Connecticut are the largest consumers and producers of electricity in New England, together accounting for about 70% of regional load. Connecticut continues to be a significant net exporter of energy, consistent with recent years. Higher local supply combined with transmission constraints contributed to lower energy prices in Connecticut, where annual average prices were approximately \$1/MWh below the Hub price in 2025 (see Section 4.1). Massachusetts, by contrast, remains a significant net importer of energy.

Average native load in New England was relatively static in recent years, indicating that expectations of significant future load growth due to increased electrification of the heating and transportation sectors have not yet materialized as of 2025.³² New England continues to be a net importer of power, although its reliance on imports fell significantly in 2025, by more than 1,000 MW (a decrease of about two-thirds) in the past two years. This occurred primarily due to lower imports over the Phase II interface (see Section 5 for further discussion).

Capacity Additions and Retirements

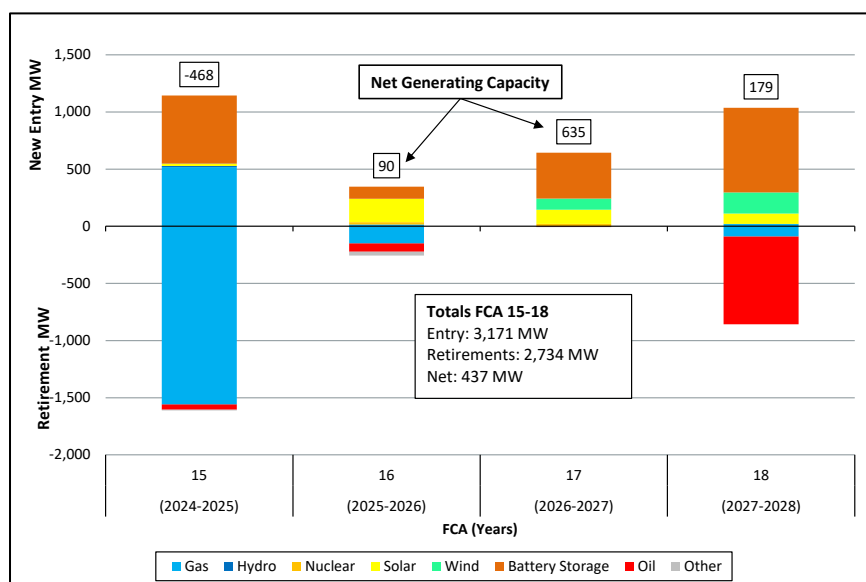
The supply mix in New England continues to evolve in response to aging infrastructure, market economics, and state policy objectives. Many existing generators are reaching advanced ages, requiring higher ongoing maintenance and capital investment to remain operational. Fossil fuel-fired generation also faces rising compliance costs as a result of public policies designed to reduce greenhouse gas emissions. In contrast, new resource entry has been driven predominantly by state policy incentives, with solar, wind, and battery storage resources accounting for the vast majority of recent additions to the generation fleet.

³¹ Note: MW values are rounded to the nearest 10 MW.

³² For more detailed analysis of future grid electrification, see ISO New England Inc., “2025 CELT report”, May 1, 2025, https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F100023%2F2025_celt.xlsx&wdOrigin=BROWSELINK.

Generator additions and retirements for the Forward Capacity Auctions for Capacity Commitment Periods 2024-25 (FCA 15) through 2027-28 (FCA 18) are shown in Figure 1-7 below, along with net surplus capacity (new capacity minus retired capacity).³³

Figure 1-7: Generator Additions and Retirements



On a net basis, generating capacity entered the market from FCA 15-18. Solar, wind, and battery storage comprised the majority (81%) of new generating capacity over this period. While new gas capacity entered the market in FCA 15 following a repowering project, all subsequent additions were overwhelmingly renewable generation and battery resources. Accredited capacity values for battery storage generators are likely to change under the CAR-SA initiative, as marginal accreditation methodology may penalize resources that are limited in duration relative to potential shortages.³⁴ Therefore, battery storage cleared capacity as a share of nameplate capacity will decrease in future CCPs under CAR-SA.

Relatively old oil- and gas-fired generators comprised the majority of asset retirements. The largest retirements occurred during FCA 15 with the delayed retirement of over 1,400 MW of gas-fired generation at the Mystic station.

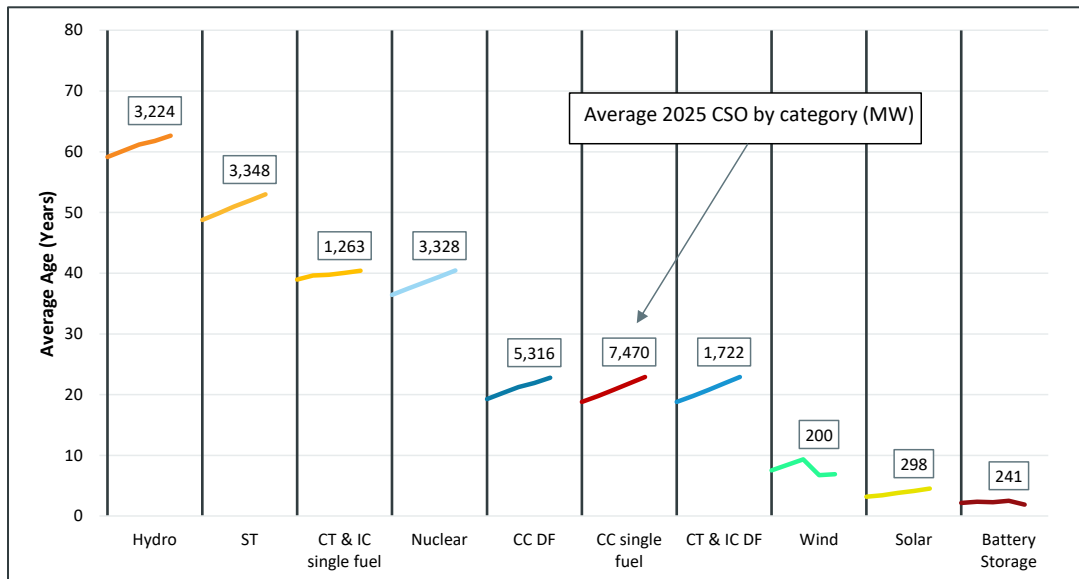
³³ The ISO did not administer a forward auction for CCP 19 in 2025. Capacity auction changes, including the transition to a prompt rather than forward capacity auction, are included in the Capacity Auction Reforms (CAR) key project. ISO New England Inc., “Capacity Auction Reforms Key Project” webpage, <https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project>.

³⁴ ISO New England Inc., “Capacity Auction Reforms: Seasonal/Accreditation, Resource Accreditation Modeling Impact Analysis Follow-up”, April 15, 2026, https://www.iso-ne.com/static-assets/documents/100034/a07.d_mc_rc_2026_04_14-16_carsa_ia_ram.pdf.

Average Age of Generators by Fuel Type

The average age of New England’s generation fleet is presented in Figure 1-8, providing insight into how the region’s supply mix is changing and how it may evolve over time.

Figure 1-8: Average Age of New England Generator Capacity by Fuel Type (2021 - 2025)³⁵



Hydro (average age of 63 years), steam turbines (53 years), and single fuel combustion turbines and internal combustion generators (40 years) comprise about one-third of FCM capacity, and are among the oldest generator types in New England, with virtually no new resource entry in these categories. Steam turbines, in particular, face growing economic pressure to retire due to competition from lower-cost resources, increasing emissions costs, and higher maintenance expenses associated with aging infrastructure and infrequent dispatch. Despite these economic challenges, oil and dual-fuel steam turbines continue to provide important reliability value—especially during winter periods when natural gas generation may be limited by pipeline constraints and renewable output is reduced.³⁶

The region’s newer supply of generators includes relatively efficient single and dual-fuel combined cycles generators (23 years) and an increasing share of renewable resources.

Renewable, Battery Storage, and Hybrid Capacity

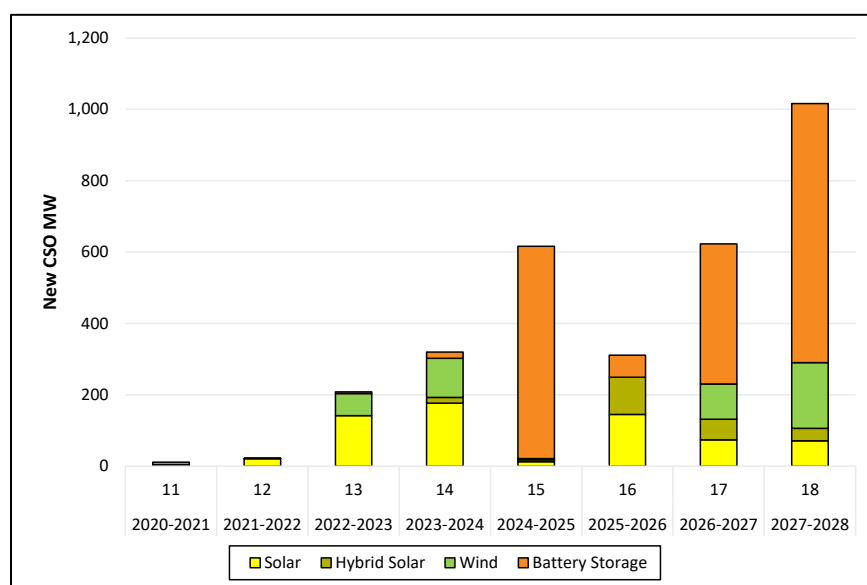
Renewable and battery storage generators are among the most recent additions to the generation fleet, with new capacity anticipated to grow in the coming years. Figure 1-9 below shows new

³⁵ Age is determined based on the generator’s first day of commercial operation. The average values are weighted by the max net output for each generator within the fuel type. If there were no retirements or new generation, we would expect each colored line to increase by one year as generators age. Either an influx of new generators or a retirement of old generators can cause a decline in average age. Data labels above the bars show average total FCM capacity in 2025 by fuel type.

³⁶ The IMM discusses winter oil utilization in its winter quarterly reports, including the Winter 2025 report. ISO New England Inc., Internal Market Monitor, “Winter 2025 Quarterly Markets Report”, June 4, 2025, <https://www.iso-ne.com/static-assets/documents/100024/2025-winter-quarterly-markets-report.pdf>.

capacity additions for these technologies by Forward Capacity Auction (FCA) commitment period. Solar facilities are separated into traditional and hybrid storage types.

Figure 1-9: New Renewable Capacity by Commitment Period



Solar, wind, and battery storage capacity accounted for the majority of capacity additions since FCA 15. Most recent wind capacity additions were offshore, with more than 100 MW of new cleared capacity in FCA 17 and FCA 18. Battery storage has also played a significant role, exceeding 500 MW of new capacity in FCA 15 and representing the largest share of new additions in FCA 17 and FCA 18. Hybrid solar resources—which account for over one-quarter of new solar capacity since FCA 15—pair solar generation with storage to shift output into higher-value hours following the solar peak.

As of February 2026, more than 600 MW of battery resources entered service between CCP 15 and CCP 16, and batteries have increasingly contributed to both the system supply mix and the set of marginal (price-setting) resources.³⁷ Many of these projects are supported by state renewable incentive programs, such as the Massachusetts Clean Peak Energy Portfolio Standard³⁸, which link compensation to charging and discharging during specified or peak load hours. These incentives were reflected in battery dispatch behavior during 2025.

The interconnection queue continues to be overwhelmingly comprised of wind, solar, and battery storage resources (>99%), including roughly 6,000 MW of offshore wind.³⁹ As of early 2026, these

³⁷ See above in this section for information on the supply mix and see Section 4.2.3 for information on real-time marginal resources.

³⁸ Commonwealth of Massachusetts (Mass.gov), Department of Energy Resources, “Clean Peak Energy Portfolio Standard 225 CMR 21.00”, <https://www.mass.gov/doc/225-cmr-21-clean-peak-energy-portfolio-standard-cps/download>.

³⁹ ISO New England Inc., “Resource Mix” webpage, updated January 28, 2026, <https://www.iso-ne.com/about/key-stats/resource-mix>.

renewable fuel types comprised the largest shares of capacity likely to complete construction within the next year.⁴⁰

1.6 Demand Conditions

This section covers trends and underlying drivers of historic and anticipated energy demand, including the impact of weather and behind-the-meter solar generation.

Key Takeaways

Average load levels in New England have been stable over the past five years, with a variation of +/- 2% from the five-year average. In 2025, load levels rose slightly (1%), averaging 13,441 MW per hour. Behind-the-meter (BTM) solar continues to contribute to load reductions, with an estimated 711 MW per hour in 2025. Peak load reached 26,586 MW in 2025, exceeding the Capacity Commitment Period 16 (2025/26) peak load forecast of 24,552 MW by approximately 8%.

Historically, actual load growth has tended to fall below forecast, reflecting uncertainty around the pace and timing of electrification. Forthcoming changes under the prompt capacity auction framework are expected to reduce forecast uncertainty by shortening the forecast horizon used to determine the Net Installed Capacity Requirement that anchors the capacity market demand curve.

Wholesale Demand

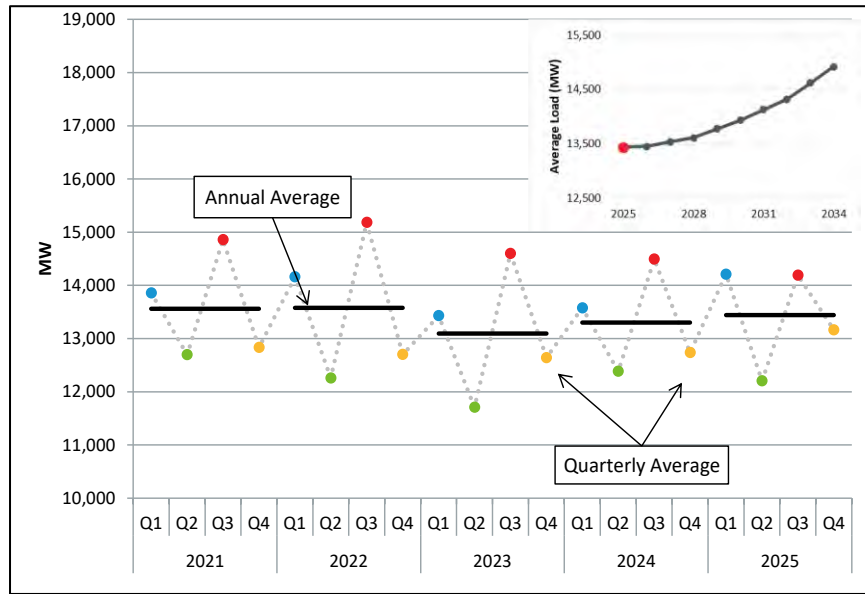
There has been slight year-over-year variation in wholesale demand over the past five years.⁴¹ Average annual load increased from 13,299 MW per hour in 2024 to 13,441 MW in 2025, a 1% increase. Annual and quarterly average loads from 2021 to 2025 are shown in Figure 1-10, along with projected load growth through 2034.⁴²

⁴⁰ ISO New England Inc., “System and Market Operations Report - February 2026”, <https://www.iso-ne.com/static-assets/documents/100032/system-and-market-ops-report-feb-2026.pdf>.

⁴¹ Wholesale electricity demand or Net Energy for Load (NEL) excludes both electricity demand that is met by behind-the-meter generation and asset-related demand for pumped-storage or battery-storage facilities.

⁴² To view load forecasts through 2034, see ISO New England Inc., “2025-2034 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) report”, May 6, 2025, https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F100023%2F2025_celt.xlsx&wdOrigin=BROWSELINK. Forecasted annual load in GWh is converted into average hourly MW values. Note that the forecasts shown are net of BTM solar.

Figure 1-10: Average Hourly Load by Quarter and Year



Wholesale load increased modestly in 2025, while Q3 demand declined slightly, consistent with similar average summer weather conditions and the growth in behind-the-meter (BTM) solar. For the first time in this five-year period, Q3 average demand was less than Q1 demand. The decline in Q3 demand relative to Q1 levels is primarily attributable to weather. Summer 2025 experienced relatively mild temperatures, limiting cooling demand and reducing overall load during what are typically peak months.

BTM solar continues to shape net load outcomes, with strong midday production increasingly reducing wholesale demand by 711 MW on an average hourly basis—representing a 14% increase from 2024. As a result, summer loads—historically the highest of the year—have continued a gradual downward trend as expanding BTM resources offset underlying load growth.

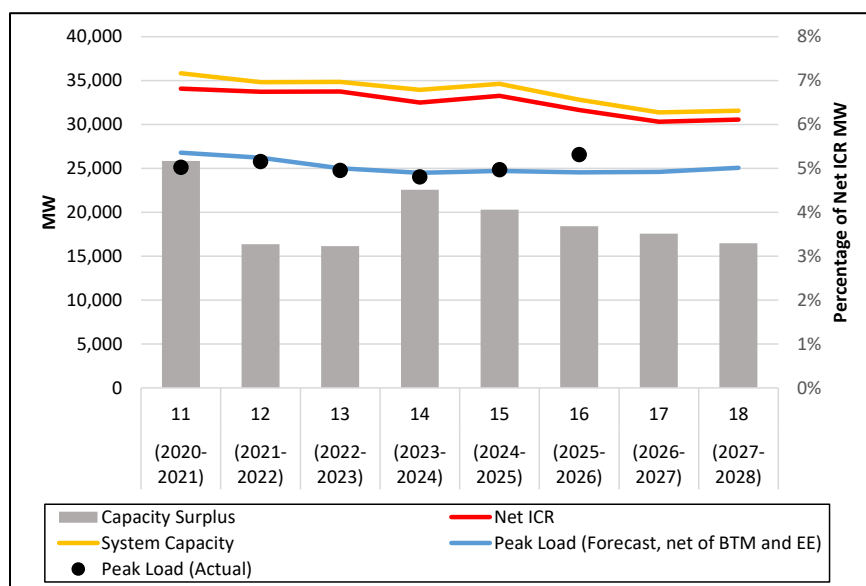
Capacity Market Requirements

The Net Installed Capacity Requirement (Net ICR) is the amount of capacity needed to meet the region’s 1-in-10-year reliability standard.⁴³ The Net ICR value is used to anchor the administrative system demand curve for the FCA and is a significant determinant of auction clearing prices.

Trends in system capacity requirements (Net ICR, peak load forecast) and system capacity procurement (system capacity, capacity surplus) are shown in Figure 1-11 below. The Net ICR, peak load forecast, and system capacity are represented as line series aligned with the left axis. Capacity surplus as a percentage of Net ICR is represented as a bar series aligned with the right axis.

⁴³ The ICR requirements are designed such that non-interruptible customers can expect to have their load curtailed not more than one day every ten years. When developing the target capacity to be procured in the Forward Capacity Auction (FCA), the ISO utilizes a combination of variables such as anticipated demand of local consumers and anticipated supply from neighboring control areas.

Figure 1-11: NICR, Peak Load Forecast, and Capacity MW for FCA 11-18



Net ICR and peak load forecast have steadily declined since FCA 11 (2020/21). For CCP 16, peak loads exceeded the load forecasts on June 24, 2025, when loads peaked at 26,586 MW relative to a forecast of 24,552 MW.⁴⁴ Under the FCM structure, significant load forecasting uncertainty exists within the Net ICR calculation due to the time between the capacity auction and the commitment period. Forthcoming changes under CAR-PD will introduce prompt capacity auctions, which should reduce load forecasting uncertainty in the capacity market.⁴⁵

⁴⁴ Note that the 24,552 MW load forecast is net of load met through BTM solar or Energy Efficiency. This allows for a direct comparison between NEL (which excludes BTM and EE) and the load forecast. Note that the Net ICR was set to reflect loads inclusive of Energy Efficiency.

⁴⁵ For more information on CAR-PD, see Section 7.1.1.

1.7 Generator Profitability

Wholesale electricity markets coordinate the efficient entry and exit of supply resources through price signals that reflect system reliability needs and compensate resources for the costs of providing system services. The profitability metrics presented here evaluate the financial incentives conveyed by New England markets to two types of decision-makers: prospective investors considering new entry, and current owners assessing whether to remain in the market.

Key Takeaways

New Entry: Market-based revenues in 2025 were sufficient to support new entry for a hypothetical new combined cycle (CC) and a combustion turbine (CT) for the second time in five years. Wind and solar units continued to rely heavily on out-of-market revenues, though elevated energy prices in 2025 reduced wind's dependence on Renewable Energy Certificate (REC) revenues relative to prior years; solar remained predominantly supported by incentives from the Solar Massachusetts Renewable Target (SMART) program.

Existing Resources: CC plants have generally earned energy market and ancillary services revenues that exceed their revenues from the capacity market, while simple-cycle peaking units—combustion turbines (CTs) and internal combustion (IC) engines—have relied on the capacity market to a greater extent. Steam turbine (ST) resources have earned very little in the energy market, relying nearly entirely on the capacity market. These observations indicate that some older, less efficient units could face exit decisions if current market conditions persist, especially when faced with large capital and fixed operating expenses.

1.7.1 New Resource Profitability Metrics

In this subsection, we examine whether the revenue available from the ISO-NE wholesale markets and other relevant markets and programs (e.g., Renewable Energy Certificates (REC) markets and the Solar Massachusetts Renewable Target (SMART) program) is sufficient to support the entry of certain types of new generation (gas-fired, solar, wind, and battery resources).

Gas-fired Generators

Here, we present estimates of the net revenues that hypothetical new gas-fired generators (combined cycle (CC) and combustion turbine (CT)) could have earned in the energy and ancillary services markets in each of the previous five years. In addition to providing a basis for the revenue required from the capacity market to build a new generator, the analysis highlights the incremental revenue that could be earned from dual-fuel capability and includes participation in the now-obsolete Forward Reserve Market for CT generators.⁴⁶

The analysis is based on simulations of generator scheduling under an objective that maximizes net revenue while enforcing operational constraints, i.e., ramp rates, minimum run and down

⁴⁶ Until the Forward Reserve Market was phased out in March 2025, a participating resource could receive revenue from the Forward Reserve Auction, but it would forego real-time reserve payments and, in most hours where the energy price was within a normal range, also forego energy revenue since it was held in reserve. When the energy price was very high, as in the case of a scarcity event, the forward reserve resource may have been dispatched for energy and would then receive net revenue (above variable cost) for those high-priced periods.

times, and economic limits.⁴⁷ The simulation model also includes a Regional Greenhouse Gas Initiative (RGGI) cost for every short ton of CO₂ emitted.⁴⁸

A key update is that the simulations now incorporate the new Day-Ahead Ancillary Services (DA A/S) market; for each resource, the model jointly chooses day-ahead energy schedules and day-ahead ancillary service awards (subject to the market's eligibility and capability rules) and then determines real-time outcomes and settlements consistent with a two-settlement design.⁴⁹

Figure 1-12 shows the result of the simulations. Each stacked bar represents revenue components for a generator type and year. The simulation produces baseline revenue (energy and real-time reserves), DA A/S net credit (DA A/S revenues less realized closeout charges), and incremental dual-fuel revenue numbers for 2021-2025.⁵⁰ Note that day-ahead (DA) energy is credited the DA LMP and the FER Price. The FCA revenue numbers shown are calculated using the actual payment rates applied to calendar years. For reference, the most recent Gross Cost of New Entry (Gross CONE) values for CC and CT generators in the Forward Capacity Auction for the 2027-2028 Capacity Commitment Period (FCA 18) are also shown.⁵¹

⁴⁷ The simulation uses historical market prices, which implies that the generator's dispatch decisions do not have an impact on day-ahead or real-time energy prices. Results should be considered in the high range for potential revenue estimates because this analysis does not account for forced outages (which should be infrequent for a new generator).

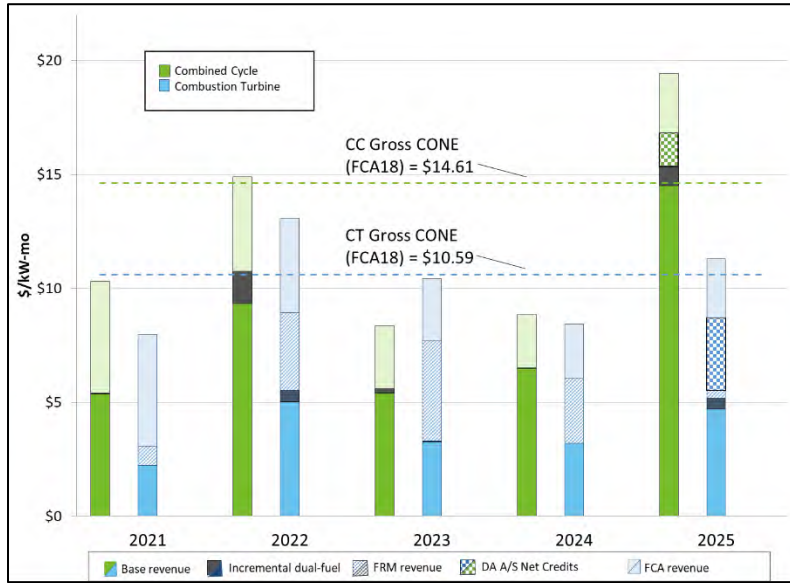
⁴⁸ In the model, the RGGI cost for each year is the average auction clearing price for RGGI allowances in that year. The Regional Green House Gas Initiative, "Allowance Prices and Volumes" data, <https://www.rggi.org/auctions/auction-results/prices-volumes>.

⁴⁹ Day-ahead decisions internalize expected real-time outcomes using provided expectation series (e.g., expected RTLMP and expected closeout), while real-time dispatch and real-time reserve provisions are based on realized prices; the model is implemented as a rolling-horizon optimization with limited look-ahead rather than perfect foresight. Expected closeout and estimates of the expected "dispatch option value" are computed from ISO-NE's hour-specific Gaussian mixture model (GMM) for RTLMP; these values are precomputed and passed into the optimization as inputs.

⁵⁰ Incremental dual-fuel energy revenue is earned by the generator when running on its second fuel type.

⁵¹ The Gross CONE values for the CC and CT gas-fired generators reflect Net CONE values of \$10.50/kW-month and \$6.33/kW-month with the difference between gross and net figures attributed to net revenue from energy and ancillary service sales. ISO New England Inc., "2027-2028 CCP Forward Capacity Auction 18 ISO Offer Review Trigger Price" update, <https://www.iso-ne.com/static-assets/documents/2023/03/2027-2028-ccp-forward-capacity-auction-18-iso-offer-review-trigger-price.xlsm>.

Figure 1-12: Estimated Net Revenue for New Gas-fired Generators



The remainder of this section discusses estimated base revenues, incremental dual-fuel revenues, and the revenue attributable to the forward sale of ancillary services, before comparing the total estimated revenues to Gross CONE benchmarks.

In 2025, estimated net energy and ancillary services revenues increased substantially for both the CC and CT proxy units, marking the largest year-over-year revenue gains observed in the five-year simulation horizon. Relative to 2024, base revenues (inclusive of the FER credit embedded in day-ahead LMPs) rose by approximately 124% for the CC unit (from \$6.49/kW-month to \$14.50/kW-month) and by roughly 47% for the CT unit (from \$3.19/kW-month to \$4.70/kW-month). These increases reflect a marked broad-based rise in day-ahead and real-time energy prices during 2025,⁵² with CC units benefitting more from the increase due to their higher utilization and relatively stable day-ahead scheduling pattern.

Consistent with their operational design, CC units remain predominantly day-ahead committed, enabling them to realize the benefits of sustained increases in day-ahead energy prices, including the FER component introduced beginning in 2025. In contrast, CTs continue to rely on real-time dispatch and benefit disproportionately from episodic high-price real-time intervals. Although real-time volatility played a somewhat larger role in 2025, the magnitude and frequency of day-ahead price increases resulted in proportionally larger revenue gains for CC units. As a result, the CC unit's base revenue growth outpaced that of the CT, consistent with the technology-specific revenue patterns observed in prior years.

Incremental revenues from dual-fuel capability remained modest again in 2025. For the CC unit, the dual-fuel adder increased annualized revenues by approximately \$0.86/kW-month, while for the CT, dual-fuel capability added \$0.48/kW-month. Although both represent slightly larger contributions than in 2024, these values remain small relative to base energy revenues. Lower natural gas prices for much of the year (compared with oil prices) and the scarcity of extended

⁵² See Section 4 for more detail on energy prices.

high-price oil-burning opportunities limited the economic value of dual-fuel capability for both technologies.

Seasonal patterns were pronounced in 2025: CC revenues peaked in winter (totaling \$17–19/kW-month depending on dual-fuel capability), while CT revenues were highest in summer (reaching roughly \$9.40/kW-month), reflecting the differing seasonal scarcity conditions each technology is positioned to capture. Dual-fuel capability contributed most in winter (particularly for CCs) suggesting that under a seasonal capacity market design, its economic value may concentrate in the winter season.

A major structural change in 2025 was the retirement of the Forward Reserve Market (FRM) in March and the initiation of the new Day-Ahead Ancillary Services (DA A/S) market. As a result, FRM revenues for CTs, which contributed \$2.88/kW-month in 2024, were no longer available for most of 2025. Instead, DA A/S net credits contributed \$1.47/kW-month to the CC unit and \$3.18/kW-month to the CT unit. For CTs, the DA A/S market provided meaningful offsetting value, replacing a significant portion of the former FRM contribution.

Overall, total energy-plus-ancillary services net revenues reached \$16.83/kW-month for the CC unit and \$8.36/kW-month for the CT unit in 2025. Comparing these simulated market revenues to Gross CONE provides some insight into the “missing money” that such units may seek to recover through the capacity market. While 2025 represented a significantly more profitable year for both technologies in the energy and ancillary services markets, total expected revenues from energy and ancillary services alone (i.e., absent capacity payments) would still fall short of levels required to support new entry for a proxy new gas-fired CT in the region.⁵³ However, capacity market revenues bring total market revenues above the Gross CONE benchmarks for the second time in the five-year horizon.

Wind and Solar Units

This section evaluates the profitability of wind and solar investments in the ISO New England markets. Renewable energy projects in the region receive significant portions of their overall revenue from state-level programs that exist outside the standard wholesale electricity markets. These “out-of-market” streams, such as Renewable Energy Certificates (RECs) or the Solar Massachusetts Target (SMART) program, offer price supports or production-based incentives that can be critical for a project’s financial viability. Out-of-market revenues may also impact an eligible facility’s bidding behavior, potentially distorting the energy market price signal. This analysis examines how the interaction between state policies and market conditions affects the profitability of these renewable resources.

In the analysis, we consider two representative units: (1) an onshore wind unit whose generation profile reflects typical wind generators in New England, and (2) a solar unit whose profile matches

⁵³ Note that CONE benchmarks are produced from financial and engineering studies that estimate the cost of adding green-field generators. In practice, the cost of new entry for a generator may be lower than the current CONE benchmarks for a number of reasons. In particular, when new generating units are built on existing generation sites or when there are material additions to the capacity of an existing operational plant, the presence of existing infrastructure tends to lower fixed costs.

that of solar installations across the region. Both resource types are assumed to offer 53% of their generation into the day-ahead energy market at their short-run marginal costs.⁵⁴

Although solar and wind resources have approximately zero marginal costs, which would imply economic offers at \$0/MWh, such resources typically have out-of-market arrangements that provide revenues when they generate energy and thus have an incentive to offer their energy into wholesale markets at negative prices. In our analysis, the wind unit offers into the day-ahead and real-time energy markets at a price equal to the negative of the annual average MA Class I REC price, while the solar unit offers at the negative of the SMART program compensation rate. In both cases, the units clear the energy market whenever the LMP at the Hub exceeds their offers.⁵⁵ In our analysis, the units do not provide ancillary services. However, the units earn FCA revenues in proportion to the qualified capacities assumed in recent offer review trigger price (ORTP) analyses.⁵⁶ Figure 1-13 summarizes the findings.

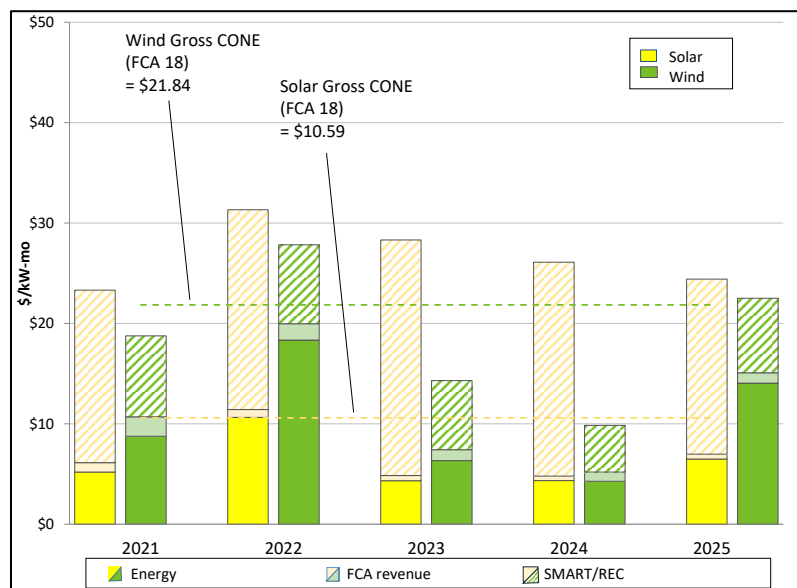
⁵⁴ ISO New England Inc., “ISO-NE Net CONE and ORTP Analysis – An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction FCA-16 and Forward”, December 2020, p. 88, https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf

⁵⁵ This analysis does not account for revenue streams from Power Purchase Agreements (PPAs), focusing instead on RECs and the SMART program. The SMART program is a Massachusetts tariff-based incentive structure that provides eligible facilities a fixed base compensation rate per MWh of electricity generated. The base compensation rates decline over time through a capacity block structure – as each capacity block (representing a set amount of capacity added to the system) is filled, the base rate for the next block decreases. Under the SMART program, a standalone facility receives a total compensation rate comprised of the base rate plus any applicable adders. When the wholesale price is below this all-in rate, the program makes up the difference so that the facility’s effective revenue per MWh is topped up to the all-in rate. If the LMP rises above the all-in rate, the solar facility does not receive a top-up payment and instead earns its revenue entirely from the wholesale market.

To determine the SMART compensation rate for the hypothetical solar unit, we set its characteristics to match the most popular combination of electric distribution company (and corresponding capacity block), unit capacity, and land type among standalone, commercial units that went commercial during the analysis year. For example, in 2025, this corresponds to a building-mounted facility with between 25 kW AC and 250 kW AC in capacity block 8 of Eversource’s MA East service territory. Based on these assumptions, the solar unit is eligible for a base compensation rate of \$0.19162/kWh, consistent with the eighth capacity block established for Eversource MA East, and a \$0.01920/kWh location adder, resulting in a total SMART compensation rate of \$0.19164/kWh. Specifically, this total compensation rate is used to “top up” the unit’s hourly real-time energy revenues to \$191.64/MWh whenever the hourly real-time LMP is less than \$191.64/MWh. For each unit of energy generated in real-time in a given year, the wind unit earns the average Massachusetts Class I REC Index price in that year.

⁵⁶ Solar and wind units earn 18.9% and 39.3% respectively of the \$/kW-month FCA revenue for each kW capacity. ISO New England Inc., “2027-2028 CCP Forward Capacity Auction 18 ISO Offer Review Trigger Price” update, ‘Assumptions’ sheet, <https://www.iso-ne.com/static-assets/documents/2023/03/2027-2028-ccp-forward-capacity-auction-18-iso-offer-review-trigger-price.xlsm>.

Figure 1-13: Estimated Net Revenue for Solar- and Wind-Powered Units



The profitability of wind and solar units in the region continues to depend heavily on state policy support and out-of-market revenue streams, with both resource types generally relying on additional revenue streams to those in the wholesale markets to be economically viable. Historically (2021-2024), the solar unit would have received the majority of their earnings (typically 75% to 90%) from the SMART program. Wind units showed a similar pattern, with roughly half of their revenues in most years attributable to RECs.

It is important to note that the Gross CONE benchmarks referenced for solar and wind reflect federal incentive assumptions in place at the time those values were developed.⁵⁷ Subsequent changes to federal policy have materially reduced the availability and certainty of such incentives for new renewable projects. As a result, these Gross CONE estimates may understate current entry costs for solar and wind resources, which should be considered when assessing profitability and cost recovery under present policy conditions.

In 2025, however, the wind unit experienced a notable shift. Energy revenues increased sharply, more than doubling from 2024. As a result, wind's reliance on out-of-market revenues dropped meaningfully; REC revenues accounted for 33% of total wind profits in 2025, down from 47% in 2024 and well below earlier years.

Even with this shift, out-of-market revenues continue to play a significant role in wind's financial performance, and they remain essential for ensuring full cost recovery. Solar, by contrast, continues to show high dependence on out-of-market revenues in 2025, with SMART revenues making up 71% of solar revenues. While these policies help to meet the region's clean energy targets, their economic impact on wholesale market prices due to their operational and bidding strategies require careful consideration to maintain market efficiency and reliability.⁵⁸

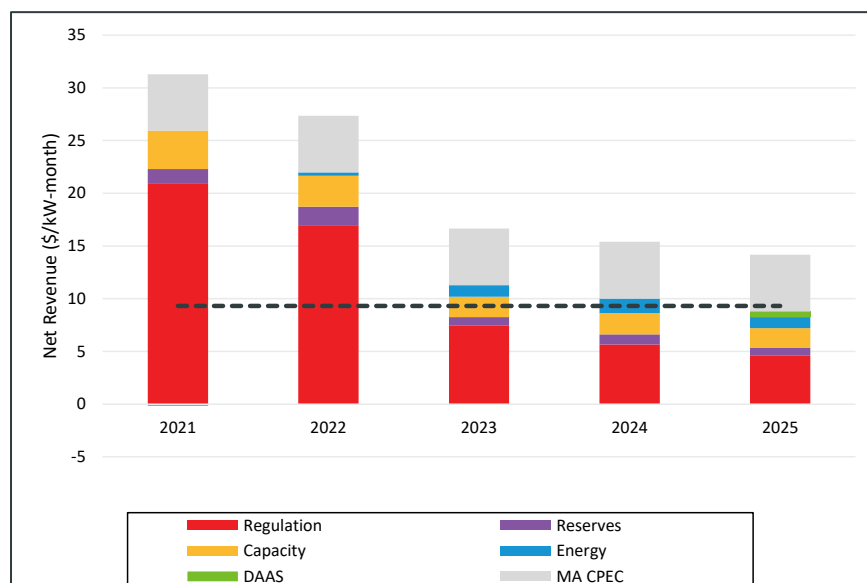
⁵⁷ ISO New England Inc., "2027-2028 CCP Forward Capacity Auction 18 ISO Offer Review Trigger Price" update, <https://www.iso-ne.com/static-assets/documents/2023/03/2027-2028-ccp-forward-capacity-auction-18-iso-offer-review-trigger-price.xlsm>.

⁵⁸ For example, energy market prices may be distorted, with negative clearing prices prevailing whenever solar or wind units benefiting from these policies are marginal.

Battery Storage

To assess the profitability of a proxy battery unit, we rely on data from ISO settlement records, including day-ahead and real-time energy sales and purchases, ancillary services, NCPC credits and charges, and Pay-for-Performance. Capacity prices are calculated using the FCA clearing price multiplied by the percentage of accredited capacity associated with a CSO. Figure 1-14 shows the different revenue sources available to batteries in the region.⁵⁹ The maximum revenue a generator can earn through Massachusetts clean peak energy certificates (CPEC) are also shown, with a grey bar.⁶⁰

Figure 1-14: Net Revenues for Battery Resources



Total net revenues across battery resources peaked in 2021 at nearly \$26/kW-month and gradually declined to just under \$10/kW-month in 2025. This high-water mark in 2021 was largely driven by substantial revenue from regulation service, which diminished over subsequent years. Although capacity payments declined steadily—from \$3.62/kW-month to \$1.84/kW-month by 2025, the decline in regulation credits was the primary driver of the falling prices. Energy margins, meanwhile, were initially small or negative in 2021 and 2022, reflecting the cost of charging the battery from the grid; by 2023, these margins became, and have stayed, modestly positive. DA A/S revenues were also a small contributor to battery revenues in 2025. Batteries in Massachusetts benefit from Massachusetts Clean Peak Energy Certificates (CPECs). A battery maximizing credits would have made about \$5.38/kW-month in 2025. CPEC credits have strongly shaped battery operating strategies to date, incentivizing dispatch during CPEC hours in ways that can reduce operational flexibility and result in missed price-arbitrage opportunities in non-CPEC hours. We plan to follow up with further analysis on this issue in a future report.

⁵⁹ To preserve confidentiality of participant information, only 2021 through 2025 are shown due to low sample size in 2020.

⁶⁰ Massachusetts Department of Energy Resources, Renewable and Alternative Energy Division, “Clean Peak Energy Standards” webpage, <https://www.mass.gov/clean-peak-energy-standard>.

When compared with a gross CONE estimate of \$9.31/kW-month, the total net revenues for these batteries (varying from about \$8 to \$11/kW-month between 2023 and 2025) indicate that market participation remains critical for them to meet or exceed the benchmark. Overall, these findings underscore how essential it is for battery resources to capture multiple revenue streams—especially regulation credits and capacity payments—to secure a viable return in New England’s markets.

1.7.2 Existing Resource Profitability Metrics

Over the past five years, combined-cycle (CC) plants have generally earned energy market and ancillary services revenues that exceed their revenues from the capacity market, while simple-cycle peaking units—combustion turbines (CTs) and internal combustion (IC) engines—have been much more reliant on the capacity market. Steam turbine (ST) resources have earned very little in the energy market, relying nearly entirely on the capacity market over the same period.⁶¹ These observations indicate that some older, less efficient units could face exit decisions if current market conditions persist, especially when faced with large capital and fixed operating expenses.

Using ISO settlement data and submitted offer data, we estimated revenues and costs for each resource in the ISO-NE footprint. Specifically, we used day-ahead and real-time energy, reserves, regulation, NCPC credits and charges, DA A/S payments and closeouts, forward reserves, capacity base payment, pay-for-performance (PFP), and inventoried energy program (IEP) revenue data. We estimated generator costs using participant-submitted offers.⁶²

Figure 1-15 below shows the net revenues of CTs and ICs per kW-month (of seasonal claimed capability) between 2021 and 2025. Note, to allow for easier visual comparison, the scale for each technology type is fixed from -\$2 to +\$16/kW-month. Revenues are broken into five categories:

- The first five include energy and ancillary services (including energy, FER payments, regulation, real-time reserves, and NCPC), forward reserves, PFP credits/charges, DA A/S net credits from the sale of reserve and EIR products, and IEP estimates between 2021 and 2025 and are based on actual revenues.
- The sixth category of capacity market base payments is calculated using the capacity auction clearing price, adjusted for the percentage of seasonal claimed capability that has a capacity supply obligation.⁶³

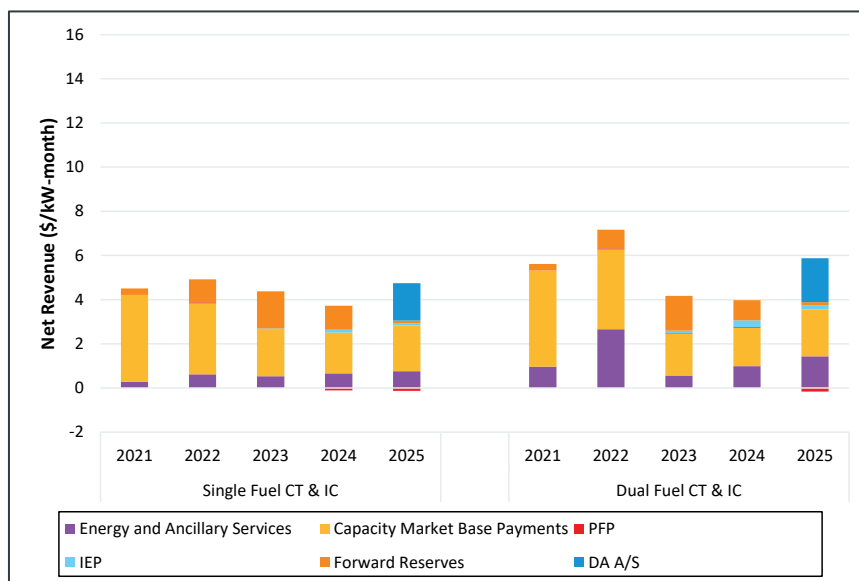
⁶¹ Combined cycle units are typically newer, more efficient, and slower-starting units (the average commercial year of combined cycle units is 1998). Gas turbines and internal combustion generators are combined in the charts below. Gas turbines tend to be newer (average commercial date in 1989), faster (nearly all fast-start capable), and are mostly oil-fired or dual-fuel units. Internal combustion engines are typically oil-fired, older (average commercial date in 1975), and are a mix of fast-start-capable and slower-starting units. Steam turbines are the oldest units, on average (average commercial date in 1967), non-fast-start units that are oil-fired.

⁶² About 2% of total asset-year observations were omitted from the analysis due to unique circumstances in which generators’ known incentives do not align with a typical generator in each category.

⁶³ This provides a realistic picture of the capacity revenues a generator in these categories can expect to receive. For example, in 2025 80% of the CT and IC single-fuel asset seasonal claimed capability (SCC) was linked to a capacity supply obligation. The average 2025 FCA clearing price was \$2.60/kW-month of CSO, giving a per-kW-month of SCC capacity base payment of \$2.07 (\$2.60 times 80%).

Note that the IMM does not have going forward cost (GFC) data that is either reliable or that can be published with this analysis. Comparing the net revenues shown below to GFC data would provide an indication of whether the technology type receives sufficient revenues from the wholesale markets to cover its fixed operating and amortized capital costs.

Figure 1-15: Combustion Turbine and Internal Combustion Generator Net Revenues



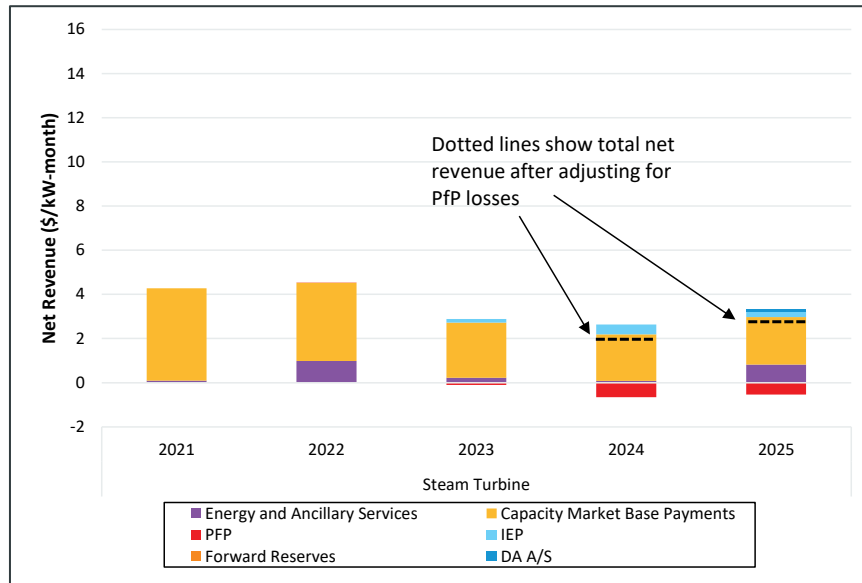
CTs and ICs are fast-start generators with relatively high operating costs and low utilization rates, typically dispatched during peak demand periods. In 2025, net revenues from the energy and ancillary services markets (excluding DA A/S) represented a relatively small share of total net revenues—about 16% for single-fuel and 25% for dual-fuel units.

Nearly 40% of total revenues came from the Forward Reserve Market (FRM) and the Day-Ahead Ancillary Services (DA A/S) market, a share comparable to 2023. CTs and ICs are well positioned to earn DA A/S revenues because they are less frequently dispatched for energy than combined-cycle units and can often provide operating reserves from an offline state.

Capacity market base payments accounted for less than half of total revenues in 2025. The now-expired Inventoried Energy Program (IEP) provided only a modest incremental contribution, accounting for under 5% of revenues.

Figure 1-16 shows the net revenues of steam turbines (STs) per kW-month of seasonal claimed capability between 2021 and 2025, broken into the same categories as the above graph.

Figure 1-16: Steam Turbine Generator Net Revenues

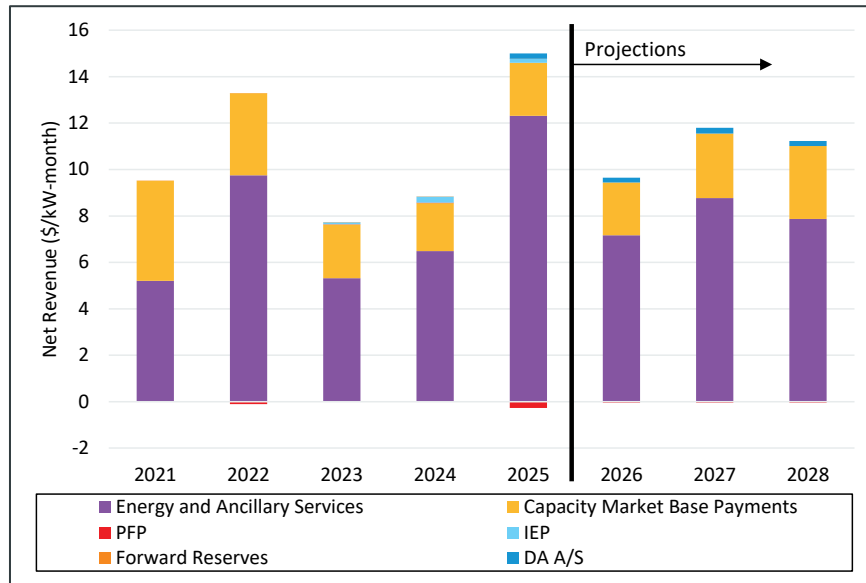


Steam turbines are highly reliant on capacity market base payments (77% in 2025). Pay-for-performance represented a net cost to these resources, reducing capacity payments by 25% in 2025, due to resource economics and long-lead times that prevented them from reacting to unanticipated and transient capacity scarcity conditions. The energy and ancillary services markets provided 29% of the net revenue, while IEP provided 9% of incremental revenues in 2025, as capacity factors rose from 1% to 3% and high gas prices resulted in higher spark spreads.

Figure 1-17 below shows the net revenues of combined cycle units (CCs) per kW-month of seasonal claimed capability between 2021 and 2025. In addition, projected revenues for 2026-2028 are shown based on forward commodity pricing data.⁶⁴ Gas and dual-fuel units are not separated in this chart, because dual-fuel capability did not produce incremental revenues in the observed outcomes.

⁶⁴ Energy and ancillary revenues are projected by scaling the average historical net revenue by the forward clean spark spread. The clean spark spread is estimated using historic and future on-peak energy prices, AGT gas prices, and RGGI prices sourced from S&P, Bloomberg, and ICE. Forward RGGI prices were only available until 2027, therefore 2027 prices are applied to 2028. The forward projections are not adjusted for the impact of DA A/S on energy and ancillary service numbers given the infancy of that market. FCM base revenues are projected forward using actual FCA cleared prices. PFP revenues are projected by taking the average PFP settlements between 2020 and 2024. The PFP revenues are projected forward using the average PFP revenues from those years, scaled by the increases in the PFP rate (\$2,000/MWh from June 2018 until May 2021, \$3,500/MWh from June 2021 until May 2024, \$5,455/MWh in June 2024 and \$9,337/MWh in June 2025).

Figure 1-17: Combined Cycle Generator Net Revenues



Combined cycles generators are relatively efficient with significantly higher utilization rates than the other technologies covered up to this point. About 85% of combined cycle net revenues were from the energy and ancillary services market in 2025, with almost all the remaining revenue (16% on average) earned through capacity market base payments.

Forward prices indicate that clean spark spreads will decrease in 2026 and increase in following years. Specifically, an increase in gas prices together with a smaller increase in energy prices is projected to reduce energy profits. LMP future prices in 2026 and 2027 are higher than in 2025 (7% increase in day-ahead on-peak hub LMPs from 2025 to 2026) but are more than offset by an increase in gas prices (20% increase in gas prices between 2025 and 2026).

Section 2

Markets and the Energy Transition: The Evolving Demand and Supply Landscape

The New England states continue to invest heavily in the power sector as a key strategy for achieving their decarbonization goals, including investments in energy efficiency (EE) measures, storage, and renewable supply at both the wholesale market and retail levels (behind-the-meter generation). Notable growth has occurred in solar generation, and offshore wind and energy storage capacity are also expected to increase significantly in the coming years.

We track the system and market impacts of the clean energy transition through a suite of metrics that reflect anticipated changes in demand patterns, supply flexibility, and price dynamics.

Table 2-1 provides an overview of these metrics presented in this section, the associated expected trends, and the trends observed empirically to date. Many of these anticipated trends have been examined in prior studies including ISO-NE's *Economic Planning for the Clean Energy Transition* and the Analysis Group's *Pathways Study*.^{65,66} However, observed impacts to date remain relatively muted, reflecting stable load growth and incremental renewable additions compared to the scale required for deep decarbonization. Nonetheless, the framework below provides a useful baseline for monitoring emerging conditions.

Table 2-1: Trends in System and Market Metrics

Metric	Description of Expected Trend	Trend
Energy Usage	Sustained load growth, with winter energy use and peak demand increasing faster than summer demand.	—
Seasonal/Annual Load Variability	Increasing variability in annual energy needs, driven primarily by winter heating demand and heightened sensitivity to cold weather.	—
Morning and Evening Load Ramps	Steeper morning (down) and evening (up) load ramps as solar generation penetration increases.	▲
Downward Flexibility of Supply	More frequent periods where net load falls below the minimum stable operating levels of conventional generation, with impacts on renewable generation curtailment.	—
Fast-Start Generator Utilization	Greater reliance on fast-start, dispatchable resources to manage steeper and more volatile load ramps.	▲
Load Forecast Error	Increased difficulty forecasting load accurately, with a focus on day-ahead and intra-day timeframes.	—
Negative Energy Prices	Increasing frequency of negative LMPs as renewable generation grows and negative offer prices become more prevalent.	▲
Energy Price Level	Downward pressure on energy prices associated with higher renewable generation levels.	▲

⁶⁵ Analysis Group, “Pathways Study: Evaluation of Pathways to a Future Grid”, April 2022, <https://www.analysisgroup.com/Insights/publishing/pathways-study-evaluation-of-pathways-to-a-future-grid/>.

⁶⁶ ISO New England Inc., “Economic Planning for the Clean Energy Transition: Illuminating the Challenges of Tomorrow’s Grid”, October 24, 2024, <https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf>.

Metric	Description of Expected Trend	Trend
Energy Price Volatility	Price volatility driven by intermittent renewable output and changing net-load conditions remains consistent with prior years.	—

The trend indicator reflecting our assessment of whether the underlying issue has increased (▲), remained stable (—), or decreased (▼) in magnitude over time

Key Takeaways

High-Level Changes: The growth in the renewable energy sector has been led by solar at both the retail (behind-the-meter) and wholesale levels. From 2021 to 2025, the contribution of renewables to meeting gross demand increased from 18% to 22%, though the wholesale share was relatively flat with a slight increase from 16% to 18%. Over the same period, residual wholesale load (load net of renewable generation) remained relatively stable; however, a sharp 57% decline in net imports has increased the system’s reliance on internal balancing resources.

Load Profiles and Ramps: While the overall impact of additional renewable resources has been relatively small at an annual and seasonal average level, the time-of-day impacts are demonstrably more pronounced. BTM solar generation has significantly altered hourly load profiles, reducing morning wholesale load ramps while steepening evening ramps. Between 2021 and 2025, the evening ramp in residual wholesale load increased from 467 MW per hour to 826 MW per hour. Consistent with these changes, real-time energy prices now tend to rise earlier in the morning, decline during mid-morning hours with increased solar production, and increase sharply during the evening ramp as higher-cost generation is dispatched to meet rising load.

Low Midday Loads: The wholesale demand “duck curve” has become a regular feature of system operations over the past five years. With solar capacity projected to continue expanding over the next decade, associated challenges for market operations and system reliability are expected to intensify. Historically, minimum demand occurred overnight; however, the frequency of minimum residual wholesale load occurring between 8 a.m. and 3 p.m. increased markedly—from 7% of days in 2021 to 51% in 2025.

Load Forecasting: Load uncertainty and forecasting challenges are expected to increase, and ISO-NE has already invested in enhancing short- and long-term forecasting techniques, with continued improvements planned. Despite the growth in BTM solar generation, there has been no discernible deterioration in day-ahead load forecast accuracy. Long-term, ISO-NE projects an 11% increase in average hourly load between 2025 and 2034, largely driven by the electrification of transportation and heating. Summer and winter peak loads are expected to rise by 8% and 24%, respectively, between 2025 and 2034, with additional uncertainty stemming from extreme weather conditions particularly during cold winter periods. Attracting and maintaining sufficient balancing resources to meet expected but infrequent surges in winter demand will be critical.

Downward Supply Flexibility To date, low wholesale load levels are not resulting in over

supply conditions or limited downward flexibility of supply during high solar output hours that could result in operators curtailing supply and negative energy prices. Further, with lower wholesale prices tracking lower midday load, we have observed changes in flexible demand (energy storage) shifting consumption from overnight to midday hours, though the aggregate annual impact of these changes remains modest.

Renewable Generation Curtailment: Curtailment levels remained very small in magnitude—accounting for less than 0.1% of total energy supply. Most curtailed energy was driven by localized transmission constraints, with a smaller share occurring during periods of low or negative system prices or due to economic offer behavior in export-constrained areas.

Reliance on fast-start generation: Reliance has increased during the evening ramp as steeper post-solar load ramps require rapid, flexible supply to meet rising demand. Peak evening fast-start output rose from 1,825 MW in 2021 to 1,991 MW in 2025, reflecting more frequent high-magnitude dispatch events. Despite this increase, evening fast-start dispatch remains well below total offered fast-start capacity, indicating that sufficient operational headroom remains available.

By contrast, reliance on fast-start generation during the morning ramp has declined and become more stable over time, as behind-the-meter solar offsets early-day load increases and reduces the need for fast-responding supply during these hours.

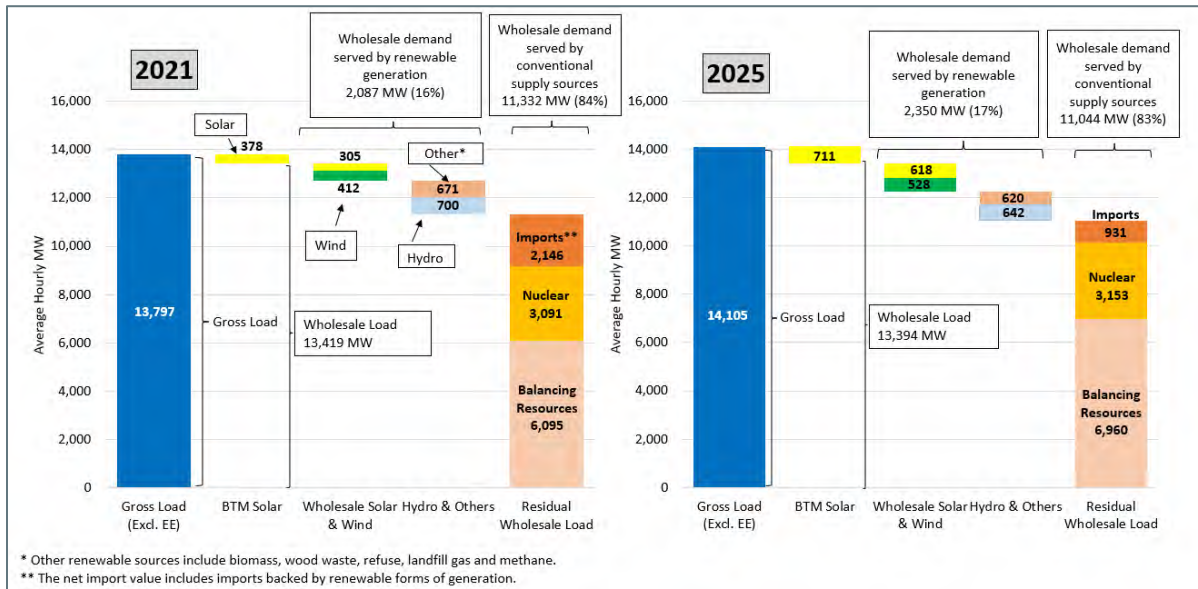
2.1 Trends in Demand and Supply Composition

Figure 2-1 below provides a five-year snapshot of changes in the region’s electricity demand and the forms of generation that serve both gross demand (a proxy for retail demand) and wholesale demand.^{67, 68}

⁶⁷ Demand is weather-normalized to allow for a clearer comparison. Weather-normalized load adjusts observed load for the effects of weather, leap year and non-holiday weekdays.

⁶⁸ Behind-the-meter solar production estimates are provided by ISO New England’s system planning department. Note that estimated energy efficiency savings are not shown in this year’s exhibit since this data is no longer available.

Figure 2-1: A Five-Year Snapshot of Demand and Supply, 2021 vs. 2025



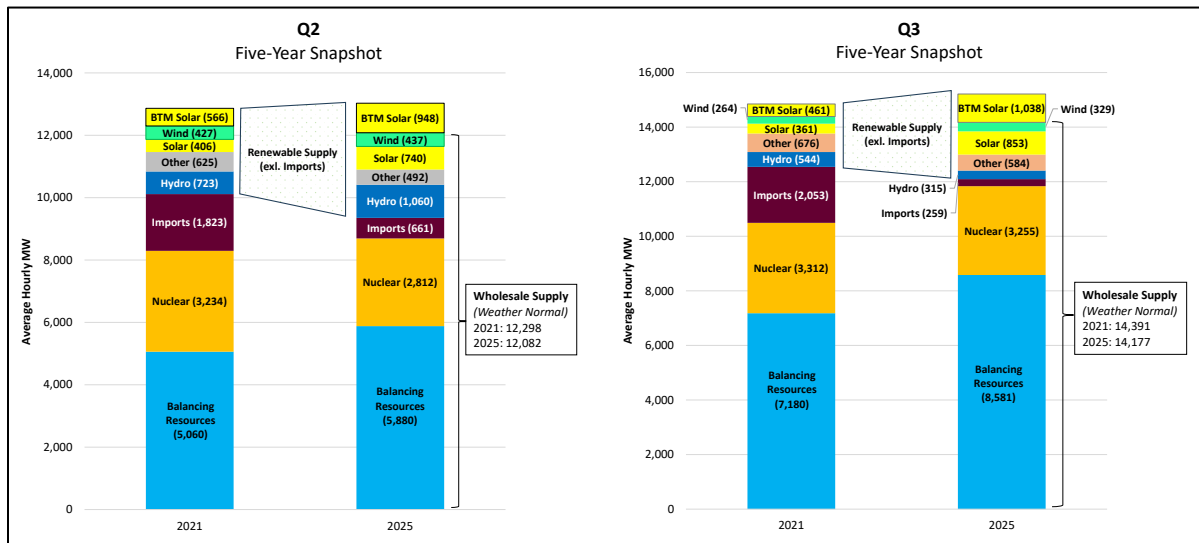
The most significant growth in the renewable energy sector has occurred in solar, at both the retail and wholesale levels. Overall, the contribution of renewables to meeting gross demand increased from 18% to 22%. At the wholesale load level, the share increased from 16% to 18%, as higher solar output offset reduced hydroelectric generation due to drought conditions and a decline in other renewable sources. Looking ahead, the commissioning of major infrastructure projects—including Vineyard Wind I (806 MW), Revolution Wind (704 MW), and the New England Clean Energy Connect (1,200 MW) transmission line—will significantly expand the region’s renewable energy portfolio over the coming years.⁶⁹

Finally, demand met by remaining supply technologies—referred to as Residual Wholesale Load—has decreased by 2.5% (or 300 MW) in 2025 with respect to 2021. The composition of supply meeting this residual demand shifted significantly in 2025. Notably, the contribution of net imports declined by approximately 57% in the five-year period, leading to an increase of roughly 870 MW per hour in non-renewable dispatchable generation, referred to as Balancing Resources in the above figure.

In the prior section on demand conditions, we noted that wholesale energy demand in Q3 2025 fell below Q1 levels, in part reflecting the growing influence of BTM solar generation. Figure 2-2 presents the composition of supply using a similar framework to the preceding chart but focuses on a five-year snapshot of Q2 and Q3 outcomes to illustrate the seasonality of supply source contributions.

⁶⁹ Values shown are nameplate capacities and are sourced from each project’s respective website.

Figure 2-2: Q2 and Q3 Five-Year Snapshot of Demand and Supply, 2021 vs. 2025



Three key trends emerge. First, wholesale energy demand during Q2 and Q3 has declined over time in the five-year period, reflecting the growing impact of behind-the-meter solar. Second, renewable resources, particularly solar generation, have played a growing role in meeting regional energy needs during summer months. Third, the reduction in net imports into the region has increased reliance on dispatchable balancing resources to meet residual demand, highlighting an ongoing shift in how the system is supplied as the resource mix evolves.

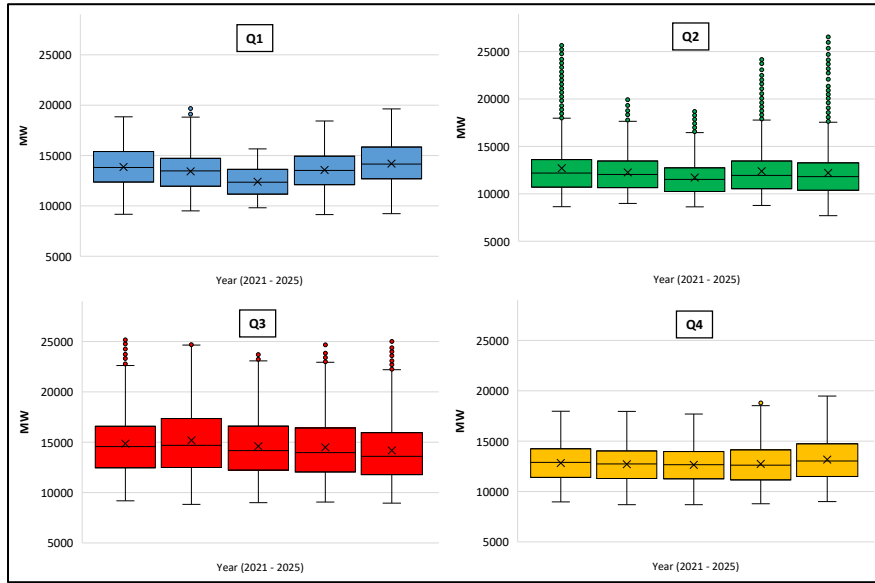
Quarterly Wholesale Loads

Variability in annual average and peak loads is expected to increase significantly in future years particularly driven by heating demand for electricity during the winter and the sensitivity of demand to winter temperatures. Further, with the growth of BTM solar generation, challenging minimum load conditions may occur which could lead to curtailed supply. While current load profiles already show significant day-to-day and intraday variability due to BTM solar output, a clear trend of increased variation at the annual or quarterly level is yet to emerge.

Figure 2-3 below presents a summary of wholesale load distributions by quarter over the past five years. The box plots show several statistical measures of load levels and variability, including minimum, maximum, median, mean, as well as the interquartile range (IQR).⁷⁰

⁷⁰ The IQR represents the middle 50% of the data, with 25th percentile and 75th percentile marking the boundaries. The higher the IQR, the larger is the variability of data. Upper whiskers extend from the 75th quantile to the highest data point that falls within 1.5 times the IQR. Lower whiskers extend from the 25th quantile to the lowest data point that falls within 1.5 times the IQR. The whiskers determine the upper limit of what is considered a “typical” value. This is intended to separate unusually high values from the rest of the data. Data points above that limit are plotted individually (as dots).

Figure 2-3: Quarterly Wholesale Load Distributions



Quarterly load distributions show greater variation in Q3, when summer demand is more sensitive to fluctuations in temperature and humidity. For example, the average interquartile range (IQR) in Q3 was approximately 4,400 MW, compared to about 2,800 MW in Q2 over the same five-year period. Average and peak demand during the colder Q1 months continues to be significantly lower than Q3 levels, a statistic that is expected to reverse in a decade.

2.2 Level and Drivers of Expected Load Growth

The ISO develops peak load and the energy forecast for the ISO-NE Control area every year. Figure 2-4 below shows the historical and 10-year forecast of average annual load, along with the major drivers.⁷¹

⁷¹ Since this report was written, the ISO has updated its long-run energy and peaks forecast. The 2026 draft forecast has revised down the forecast of energy and summer & winter peaks. For example, in 2034, the average hourly load is 3.9% lower than the most recent published forecast. Summer and winter peak projections for 2034 are down by 1.3% and 2.5% in the summer and winter respectively.

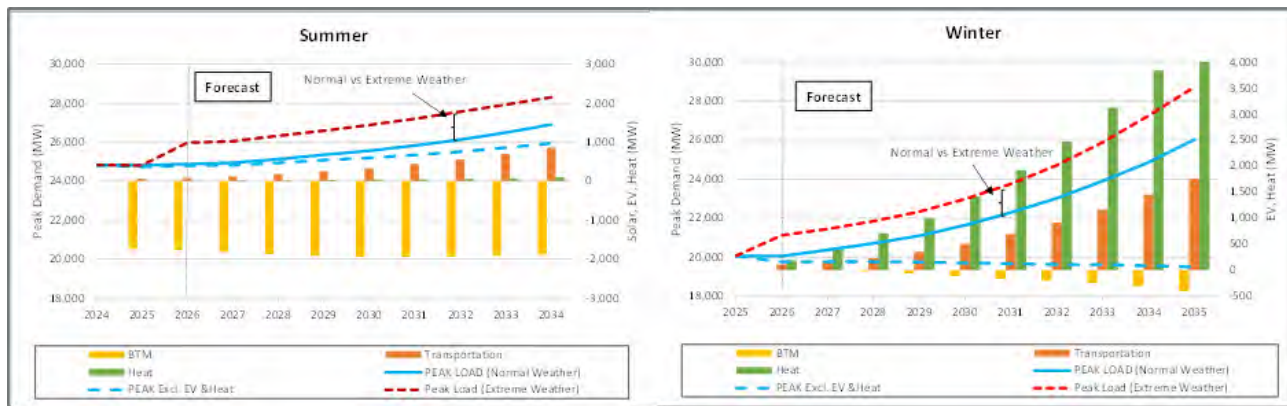
Figure 2-4: Historical and Forecast Average Hourly Load and Major Drivers (BTM solar, EV, and Heat)



ISO-NE projects an increase in average hourly load of 11% between 2025 and 2034, driven by the adoption of electric vehicles as well as extensive electrification of space heating and water heating in the residential and commercial sectors. Transportation and heat electrification are expected to play a pivotal role in the achievement of New England state greenhouse gas (GHG) reduction mandates and goals.

A similar trend is expected for the summer and winter peak loads as shown in Figure 2-5 below.

Figure 2-5: Forecast of Summer and Winter Peaks Under Expected and Extreme Weather Conditions



Summer and winter peak loads are expected to grow between 2025 and 2034 by 8% and ~24%, respectively. Without transportation and heating electrification, the average hourly load, summer, and winter peaks would remain flat or even negative in the case of the winter peak (dotted lines, left axis).

In the summer, the reliability contribution of BTM solar is expected to slow as the marginal impact of reducing the peak will decline as installed capacity grows. In the winter, however, as winter peak time is forecasted to move from evening to morning during the forecast period, the contribution of BTM solar is expected to increase, reducing the winter peak over time. By 2034, the impacts of EV adoption add about 852 MW and 1,450 MW to the summer and winter peak loads, respectively. By

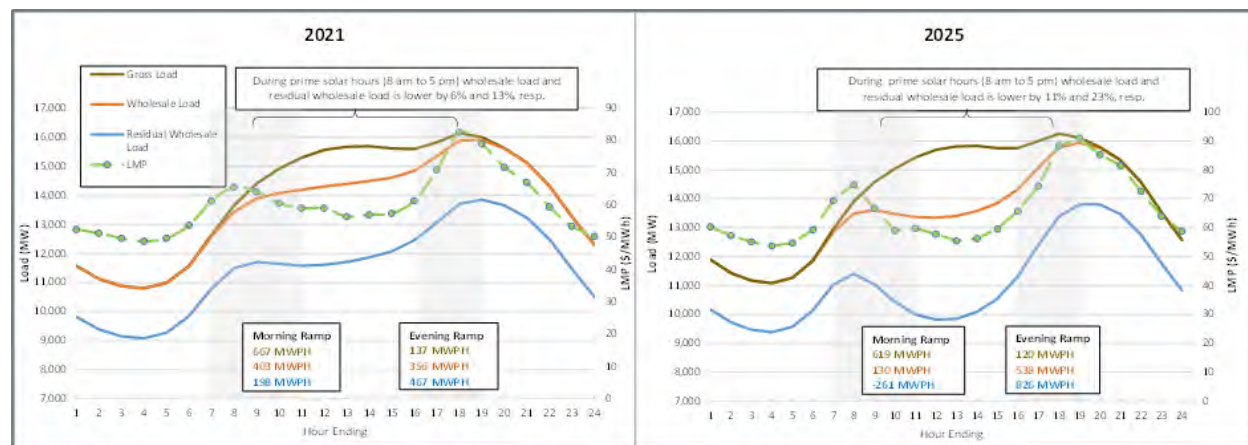
2034, the difference between summer and winter peak loads is expected to shrink from 4,700 MW in 2024 to 1,630 MW. This is because heating electrification will contribute to increasing the winter peak every year, adding up to 3,830 MW of heating load by 2034.

The uncertainty around the expected summer and winter peak load due to extreme hot or cold weather conditions is also captured in the above figure. Summer peak loads under extreme weather conditions are about 1,400 MW higher than the expected peaks. In the summer, the difference between expected and extreme forecast remains close to the average impact during the entire forecast period. However, the impact of extreme weather on winter peaks grows much faster due to the increasing penetration of heat pumps replacing alternative fuels.

2.3 Load and Pricing Profiles

While the overall impact of additional intermittent resources (such as wind and solar) has been relatively small at an annual and seasonal average level, the time-of-day impacts are demonstrably more pronounced. Figure 2-6 below compares the hourly load profiles for 2021 and 2025, with emphasis on the morning (7am to 11am) and evening ramp (4pm to 7pm) periods and the correlation with LMPs.⁷²

Figure 2-6: Hourly Real-Time LMP and Demand Profiles, 2021 vs. 2025



There is a substantial change in the hourly load profiles between 2021 and 2025, with BTM solar moderating wholesale load ramps in the morning and increasing evening load ramps. In particular, the impact on morning and evening ramps has grown; for example, the ramp in “residual wholesale load” during the evening hours has increased from an average of 467 MW per hour to 826 MW per hour between 2021 and 2025.

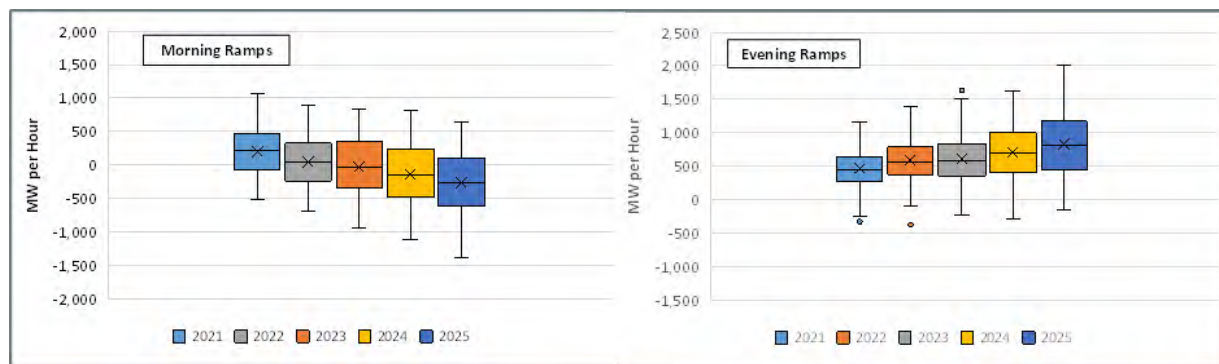
Real-time prices increase early in the morning then dip in mid-morning as solar production increases and consequently load decreases. Energy prices have become higher during the morning

⁷² We do not attempt to quantify the impacts on pricing levels here but rather focus on the time-of-day pricing impacts. However, to allow for a more direct comparison between the two bookend years in this report section, we adjusted 2021 prices to account for differences in natural gas prices (with the important caveat that other supply and demand factors also impact energy prices). The hourly average 2021 LMP is adjusted by the ratio of 2025 average natural gas price to the 2021 average gas price.

ramp, and to a greater extent during the steeper evening ramp, when more expensive supply is dispatched to meet load.

Higher penetration of intermittent resources has not only changed average hourly ramps but also their variability and therefore uncertainty about the amount of dispatchable generation needed to meet the residual wholesale load⁷³ during the morning and evening peaks. Figure 2-7 below shows the daily morning and evening ramps distribution for residual wholesale load between 2021 and 2025.

Figure 2-7: Morning (7am to 11am) and Evening Ramps (4pm to 7pm) Distribution



The interquartile range (IQR) has increased over the period during the evening *upward* ramps, from 375 MW per hour in 2021 to 712 MW per hour in 2025 (or 92% increase) indicating a larger spread in ramp rates in the middle 50% of the distribution. The first and third quartiles (Q1 and Q3) also increased by 69% and 82%, respectively. For example, in 2025, ramps were at least 1,170 MW per hour in 25% of the days; in 2021, that statistic was 643 MW.

The impact of intermittent generation in the morning ramps is increasing *downward* ramping. For example, during half of all days ramps were below *negative* 270 MW per hour (positive 215 MW per hour in 2021) and in 25% of the days, ramps were below *negative* 610 MW per hour in 2025 (but negative 80 MW per hour in 2021). The IQR has increased by 30% from 550 MW per hour (2021) to 712 MW per hour (2025). As the grid transitions to include more intermittent generation, large changes in residual wholesale demand will place a premium on flexible, dispatchable generation.

The wholesale demand “duck curve” has become a common occurrence over the last five years, and with solar capacity projected to double over the next 10 years, it will increasingly present challenges for both markets and system operations. Lower demand in the middle of the day will put downward pressure on real-time prices that could have negative impacts on profitability of dispatchable generation that cannot reduce output. Historically, the lowest demand occurred at night, but there has been a notable increase in the frequency of minimum residual wholesale load occurring later - between 8 am and 3 pm. The frequency has increased from 7% in 2021 to 51% in 2025.

⁷³ The portion of load that cannot be met by intermittent generation.

To date, we have not observed over supply conditions or limited downward flexibility of supply during the high solar output hours that could result in operators curtailing supply and negative energy prices. Further, with lower wholesale prices tracking lower midday load, we have observed changes in flexible demand⁷⁴ shifting consumption from overnight to midday hours, albeit with a quite moderate load impact on an aggregate load. Low energy prices in the early afternoon hours will create opportunities for the growing amount of energy storage resources to charge in anticipation of higher prices during the evening load ramp, thereby smoothing out wholesale load and price changes.

While impacting the load ramp, solar generation has not increased the frequency with which the system is ramp constrained, and the number of ramp-constrained intervals has remained very low in the past five years.

2.4 Load Forecasting and Operational Uncertainties

As the system evolves to comprise more weather dependent supply (including BTM solar and storage), operational uncertainties and challenges due to unanticipated changes in demand are expected to increase. The ISO's multi-year roadmap and annual workplan has a number of important initiatives geared towards aligning market design and systems/tools with operational and reliability challenges, including:⁷⁵

- short-term probabilistic load forecasting methodologies to account for load uncertainty,
- forward-looking intra-day (real-time) market clearing and multi-interval pricing to position and optimize supply to meet changes in net load and load uncertainty,
- evaluating the system's needs for flexible response capabilities and market products to address greater operational uncertainties.

The IMM strongly supports these initiatives, as they reflect a proactive approach to aligning emerging and future reliability needs with wholesale market tools and products. These efforts are critical for price formation and market efficiency, helping to avoid reliance on manual reliability actions that are neither priced nor visible to the market.

While load uncertainty and forecasting challenges are expected to grow in the future, it is worth examining trends in load forecast error in recent years.⁷⁶ To assess this, we reviewed the accuracy of the day-ahead load forecast compared to real-time load and found that there is no discernable deterioration in the accuracy of the load forecast.

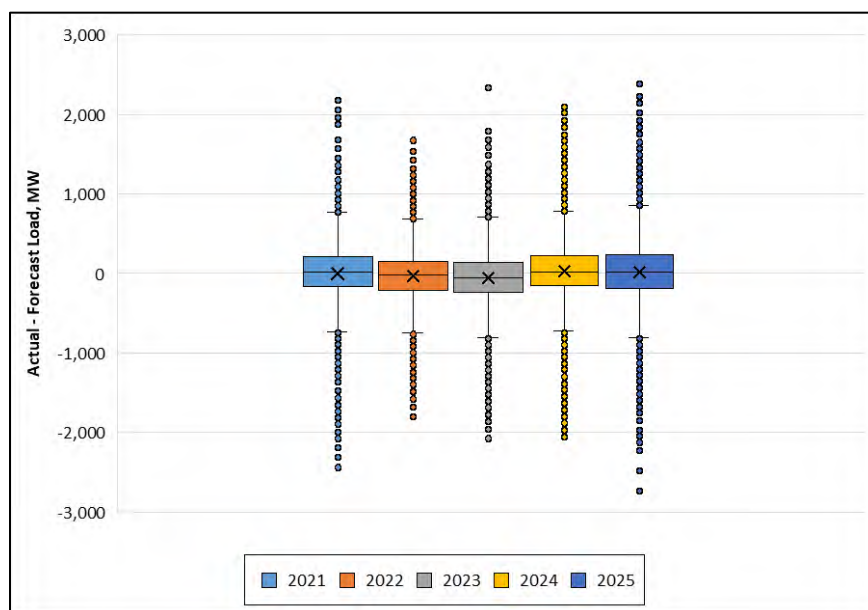
⁷⁴ Pumped and battery storage resources.

⁷⁵ ISO New England Inc., "2024 Open Meeting of the ISO New England Board of Director, Multi-Year Roadmap", November 6, 2024, <https://www.iso-ne.com/static-assets/documents/100017/nov-6-2024-iso-bod-open-meeting-master-slides-final.pdf>.

⁷⁶ In recent years, the ISO has made significant investments to better forecast BTM solar generation. For more information on ISO New England's investment in forecasting behind-the-meter solar generation, see: Energy Systems Integration Group, "Building data intelligence for short-term load forecasting with behind-the-meter PV", March 27, 2019, <https://www.esig.energy/building-data-intelligence-for-short-term-load-forecasting-with-behind-the-meter-pv/>.

The ISO publishes a day-ahead load forecast around 9:30 am as the last load projection prior to the close of the day-ahead market for the next operating day.⁷⁷ Since the implementation of Day-Ahead Ancillary Service in March 2025⁷⁸, the ISO forecast is a direct input into the day-ahead market through the Forecast Energy Requirement constraint. Its publication also provides transparency into operational planning and is often referenced by participants submitting day-ahead demand bids.⁷⁹ Load forecast error historically has a statistically significant impact on day-ahead and real-time price differences. Figure 2-8 below illustrates annual hourly load forecast error with boxplots.⁸⁰

Figure 2-8: Hourly Load Forecast Error



Hourly load forecast error followed a similar distribution in 2025 relative to prior years. Forecast errors remained centered near zero (MW) in both 2024 and 2025, indicating an unbiased forecast on average. In 2025, the middle 50% of errors (IQR) fell between -180 MW to +232 MW. The tails widened in 2025 where hourly errors ranged from about -805 MW to +854 MW, the broadest range in the five-year view. These results show stable typical accuracy with larger extreme deviations in 2025. As discussed in Section 4.4.3, large hourly errors can materially affect price convergence between the day-to-hour operating outcomes.

Forecast error varies by time of day. Morning and evening ramp periods exhibit wider dispersion and fatter tails than the all-hours distribution, reflecting the added uncertainty from behind the

⁷⁷ Twice a day, the ISO produces a three-day load forecast that projects load for the current day and the following two days. The first forecast is typically released around 4:30am and the second, and typically final forecast, is published near 9:30am. ISO New England Inc., “Three-Day System Demand Forecast” webpage, <https://www.iso-ne.com/markets-operations/system-forecast-status/three-day-system-demand-forecast>.

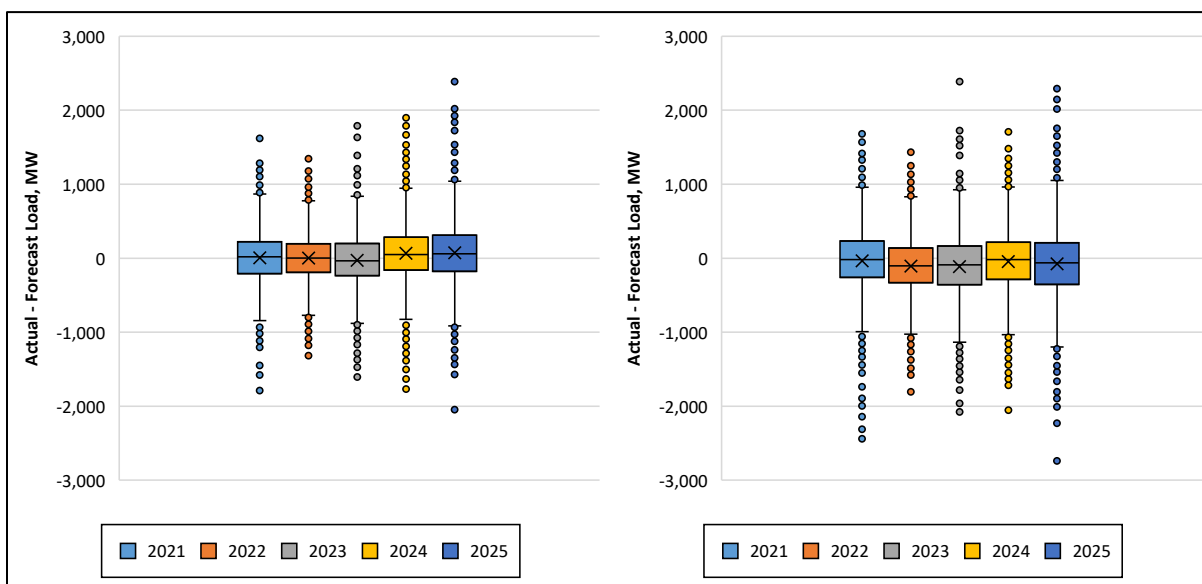
⁷⁸ With Day-Ahead Ancillary Services the load forecast is a direct input and constraint that prices and procures sufficient energy for physical supply in the day-ahead market.

⁷⁹ Load Serving Entities (LSEs) may also rely on their own in-house or third party forecasting tools to inform their day-ahead bidding strategy.

⁸⁰ For this visualization, forecast error is defined as actual load minus forecasted load. Outliers are suppressed in this graph.

meter (BTM) solar during these transitions; morning ramps more often produce negative errors when solar output exceeds expectations, while evening ramps tend to show positive errors as solar production declines. Figure 2-9 illustrates these ramp period distributions.⁸¹

Figure 2-9: Hourly Load Forecast Error during Morning and Evening Ramp Periods



Hourly load forecast error widens during ramp periods. For instance, in the morning ramp, errors stay close to 0 MW but tend to lean positive, and outliers can reach about 2,000 MW in either direction. In the evening ramp, errors also center near 0 MW but lean negative, with tails extending up to roughly 2,300 MW on the high side and 2,700 MW on the low side. In 2025, both ramp periods showed more variation than in earlier years, with more frequent and more extreme outliers. The negative morning skew reflects higher than expected behind-the-meter solar reducing actual load, while the positive evening skew reflects declining solar output and steeper ramps increasing actual load relative to forecast.

2.5 Negative Pricing and Price Volatility

As renewable generation increases over the coming decade, more frequent periods of negative energy prices—driven by supply-side bidding behavior—and greater price volatility are expected. These changes have implications for price formation and revenue adequacy, with a potential shift in revenue reliance for some resources toward the capacity market.

Because many renewable resources are compensated for their real-time output through prices specified in Power Purchase Agreements (PPAs) and are willing to clear at negative prices, this puts downward pressure on energy clearing prices. The Economic Planning for the Clean Energy

⁸¹ The morning ramp period is defined as 7-11 am, and the evening ramp period is defined as 4-7 pm.

Transition (EPCET) study assessed how extended periods of negative LMPs could impact revenues of baseload resources, which cannot ramp down quickly due to operational constraints.⁸²

Negative Prices

The frequency of negative LMPs at the Hub, load zones, and nodes remains very low but increased in 2025. Table 2-2 below presents statistics for 2021-2025.

Table 2-2: Percentage of Five-Minute Intervals with Negative Real-Time Prices

Year	Negative Hub LMPs	Negative Zonal LMPs	Negative Nodal LMPs
2021	0.27%	0.28%	0.42%
2022	0.46%	0.46%	0.56%
2023	0.34%	0.34%	0.39%
2024	0.35%	0.35%	0.40%
2025	0.81%	0.89%	1.19%

Negative real-time Hub LMPs have been infrequent but occurred more than twice as often in 2025 compared to 2024. Despite the increase, negative real-time Hub LMPs occurred at the Hub and load zones in less than 0.9% of hours. For context, the Pathways Study indicated that negative prices might occur in 33% of hours by 2040 under the current energy market construct.⁸³

In 2025, negative nodal LMPs occurred in nearly three times as many intervals as in 2024. Negative nodal LMPs occur more frequently due to export-constrained regions where renewable generation sets the clearing price below zero due to out-of-market revenues like PPAs and Renewable Energy Certificates. We expect zonal and nodal negative pricing intervals to increase in 2026 due to the New England Clean Energy Connect transmission line.

In addition to considering the frequency of negative LMPs, we also assessed the duration of negative prices. Negative prices may ultimately be relatively short-lived depending on the extent to which market participants can respond by increasing exports, reducing generation, or charging storage resources—the latter capability is expected to expand significantly in the coming years. Statistics on the duration of negative real-time LMPs are shown in Table 2-3 below.

⁸² ISO New England Inc., “Economic Planning for the Clean Energy Transition: Illuminating the Challenges of Tomorrow’s Grid”, October 24, 2024, <https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf>. The report discusses how negative LMPs and low loads could impact baseload resources in the following report sections: 1.6.2 Effect of Deep Decarbonization on Energy Markets, and 1.8.1 Challenging Minimum Load Conditions.

⁸³ Analysis Group, “Pathways Study: Evaluation of Pathways to a Future Grid”, April 2022, <https://www.analysisgroup.com/Insights/publishing/pathways-study-evaluation-of-pathways-to-a-future-grid/>. See Table VI-2: Summary Statistics for Energy Market LMPs by Policy Approach, 2040.

Table 2-3: Negative Real-Time Hub LMP Durations, in Minutes

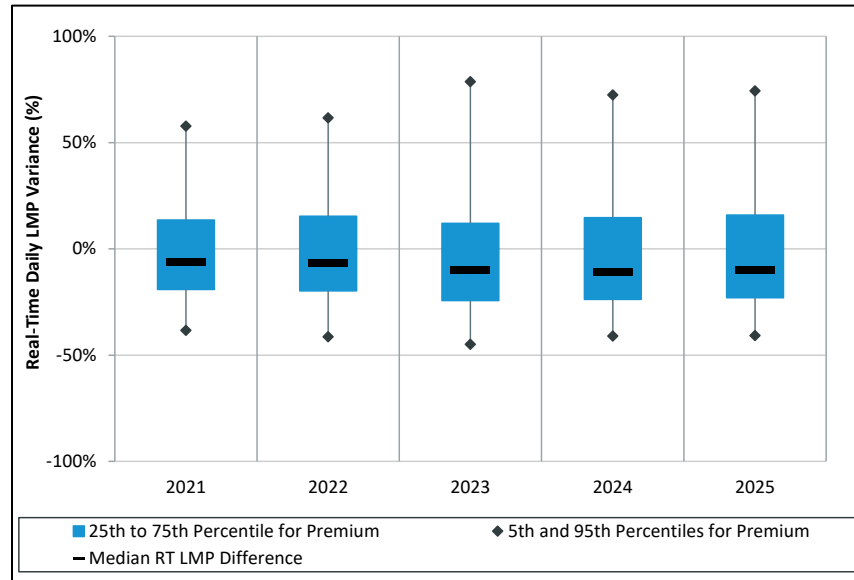
	Mean Duration	Median Duration	Mode Duration	Max Duration
2021	23	15	5	120
2022	24	15	10	190
2023	17	10	10	85
2024	17	10	10	105
2025	25	15	10	240

The median duration of negative real-time Hub LMPs ranged from 10 to 15 minutes over the reporting period, indicating that periods of negative pricing are currently relatively short-lived.

Price Volatility

As renewable generation increases, real-time LMPs are expected to be more volatile. Renewable resources can at times be marginal, setting system prices at or below \$0/MWh, particularly during periods of high solar or wind output. The growth of behind-the-meter generation—especially solar—further suppresses net load during daylight hours, often reducing the amount of dispatchable supply available to set marginal prices. As solar output declines in the evening, net load ramps become steeper, requiring rapid responses from a narrower set of fast-ramping resources. These conditions increase the likelihood of sharper price movements and elevated real-time prices during ramping periods, contributing to wider intraday price swings overall. Figure 2-10 below shows the distribution (box plot) of real-time Hub LMPs as a percentage of the daily average Hub LMP.

Figure 2-10: Real-Time LMP Variance



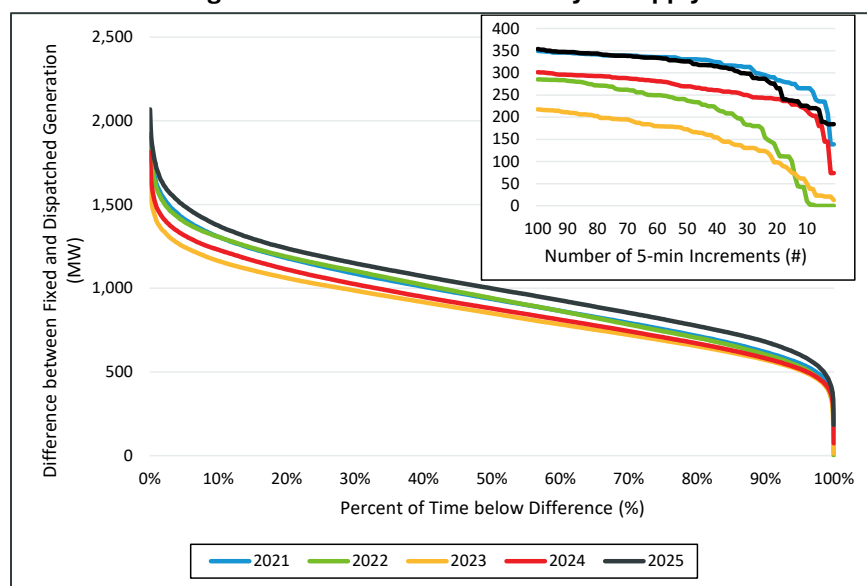
Real-time LMP volatility remained consistent with prior years. Half of all real-time LMPs were 23% lower than or 16% higher than the daily average LMP. As discussed above, negative real-time Hub LMPs occurred at the Hub in less than 1% of real-time intervals and don't influence outcomes shown in Figure 2-10.

2.6 Downward Flexibility of Supply

Minimum generation events, or over supply conditions, occur when fixed (i.e., non-dispatchable) supply is at risk of exceeding load. By 2032, high BTM solar penetration may, under certain scenarios, result in baseload generation levels exceeding wholesale demand, according to ISO-NE's 2024 EPCET study.⁸⁴ In such cases, baseload generation—particularly inflexible nuclear units—may exceed wholesale demand, resulting in the curtailment of renewable resources. While some conventional generators may be able to decommit, their long start-up times can limit flexibility and hinder their ability to respond to later increases in load.

Examining the difference between dispatchable and fixed generation on the system in an interval provides an assessment of the risk of over-supply conditions. Figure 2-11 below shows a duration curve of downward flexibility on the system. Fixed generation is defined as generation up to economic minimum output, plus any energy each generator must produce due to ramp constraints.

Figure 2-11: Downward Flexibility of Supply



Between 2021 and 2025, there has not been a significant downward shift in the duration curves, as we would expect if the risk of minimum generation conditions was increasing. The average downward flexibility of supply in the tightest 1% of intervals in 2025 was 428 MW, higher than the average between 2021 and 2024 of 369 MW. Looking at the tightest 100 intervals (inset chart), 2025 was also on the higher side of the past five years. On May 21, 2022, there were 35 minutes in which there was no downward flexibility of supply in the generation fleet and the ISO declared a minimum generation emergency. There have not been any minimum generation emergencies since.

2.7 Renewable Generation Curtailment

At times, renewable resources must be dispatched below their available maximum output (i.e., curtailed) despite having zero or negative marginal costs and sufficient fuel to produce at levels

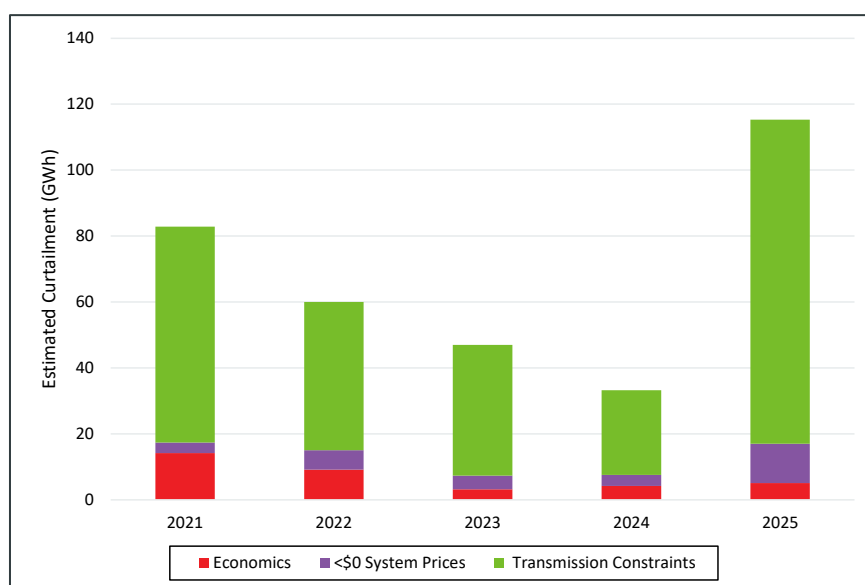
⁸⁴ ISO New England Inc., “Economic Planning for the Clean Energy Transition: Illuminating the Challenges of Tomorrow’s Grid”, October 24, 2024, <https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf>.

exceeding their dispatch. Curtailments result in the loss of low-cost energy, which can increase total system production costs and ultimately raise consumer costs. These outcomes also raise important policy questions about the cost-effectiveness of transmission investments and the value of expanding storage capacity to better integrate renewable generation.

Figure 2-12 below shows renewable curtailment between 2021 and 2025, segmented by the reason for curtailment. Only resources qualified for do-not-exceed dispatch are included in the following analysis.⁸⁵ The curtailment reasons categorized in the chart are:

- **Transmission Constraints:** includes cases when the system price is $> \$0/\text{MWh}$, indicating that $\$0/\text{MWh}$ marginal cost renewable energy would be utilized by the system if it was available. However, in these cases transmission limitations result in a nodal price $\leq \$0/\text{MWh}$ and a dispatch below the unit's full capability.
- **$\leq \$0/\text{MWh}$ System Prices:** includes cases when the system price is $\leq \$0/\text{MWh}$, indicating that system load is being met using only fixed generation (i.e., generation up-to EcoMin) and low-cost, typically renewable, energy. In these cases, only the lowest-cost renewable energy is produced and some $\$0/\text{MWh}$ (or even-lower-priced) energy will be curtailed.
- **Economics:** includes cases when the nodal price is $> \$0/\text{MWh}$ but energy is offered at positive prices and is not dispatched due to economics.⁸⁶

Figure 2-12: Renewable Curtailment by Reason



Curtailment of renewable generation more than tripled between 2024 and 2025 from 34 GWh to 117 GWh. Despite the large increase, curtailment removed low overall; 117 GWh is the equivalent

⁸⁵ Do-not-exceed dispatch allows renewable resources to be dispatched below their maximum potential output by the market-clearing software. Wind and hydro resources have been able to participate since 2016, while solar units were required to begin participating in December of 2023. ISO New England Inc., “Do Not Exceed Dispatch (DNE) Project” webpage, <https://www.iso-ne.com/participate/support/participant-readiness-outlook/do-not-exceed-dispatch>.

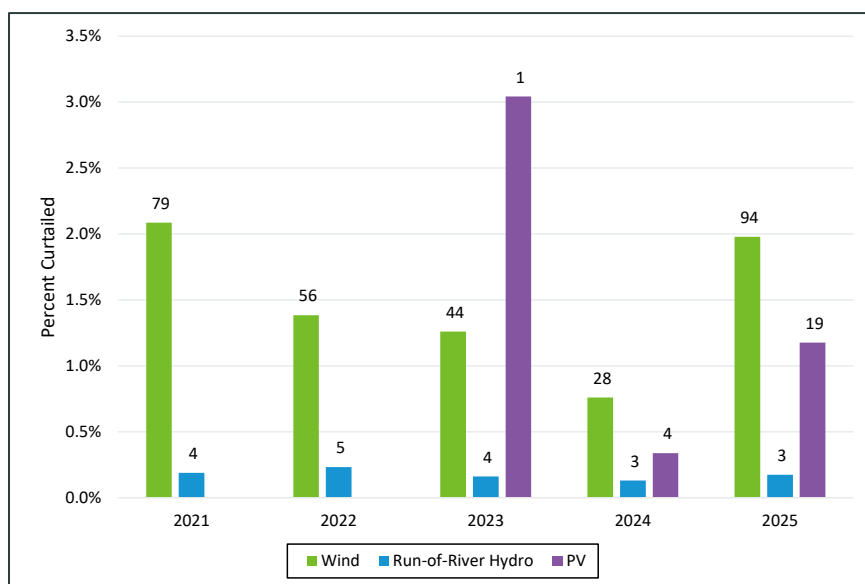
⁸⁶ Related to this observation, in the 2022 AMR, we recommended the ISO expand mitigation to export-constrained areas, which would help reduce market-power concerns introduced by renewable generation offering above marginal cost with limited competition in these areas. We continue to recommend the ISO expand mitigation to export-constrained areas, first proposed in the 2022 Annual Markets Report. ISO New England Inc., Internal Market Monitor, “2022 Annual Markets Report”, June 5, 2025, <https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf>.

of 13.3 MW per hour or less than 0.1% of total energy supply. Transmission constraints have driven about 79% of the curtailed renewables between 2021-2025. Because renewable resources do not have 100% capacity factors, they may be incentivized to build units that exceed the transfer capability of their locally-constrained area to maximize the average output of the generator when fuel is not 100% available.

About 8% of curtailed renewable energy occurs when the system price falls below \$0/MWh, and inexpensive energy from renewables and fixed generation (i.e. generation up-to EcoMin that cannot be backed down) is plentiful. The remaining 13% of curtailed energy was not dispatched despite nodal LMPs exceeding \$0/MWh due to offers exceeding the nodal LMP. These offer segments are subject to mitigation and could be addressed with the outstanding IMM recommendation to expand mitigation to export-constrained areas.

Figure 2-13, below, shows the percentage of potential renewable output that was curtailed in each year, by fuel type.⁸⁷ Labels show the GWhs that were curtailed.

Figure 2-13: Renewable Curtailment by Fuel Type



Wind drives about 80% of curtailed renewable energy, but as a percentage of total wind capability it is low, only about 2% on average in 2025.

The cost of transmission upgrades necessary to eliminate the current minimal volume of curtailed renewable energy are likely more costly than the potential benefits to the system. However, in the future, batteries may be able to reduce curtailment and allow renewables to produce at higher levels when fuel is abundant and deliver the energy when supply and demand conditions are more favorable.⁸⁸

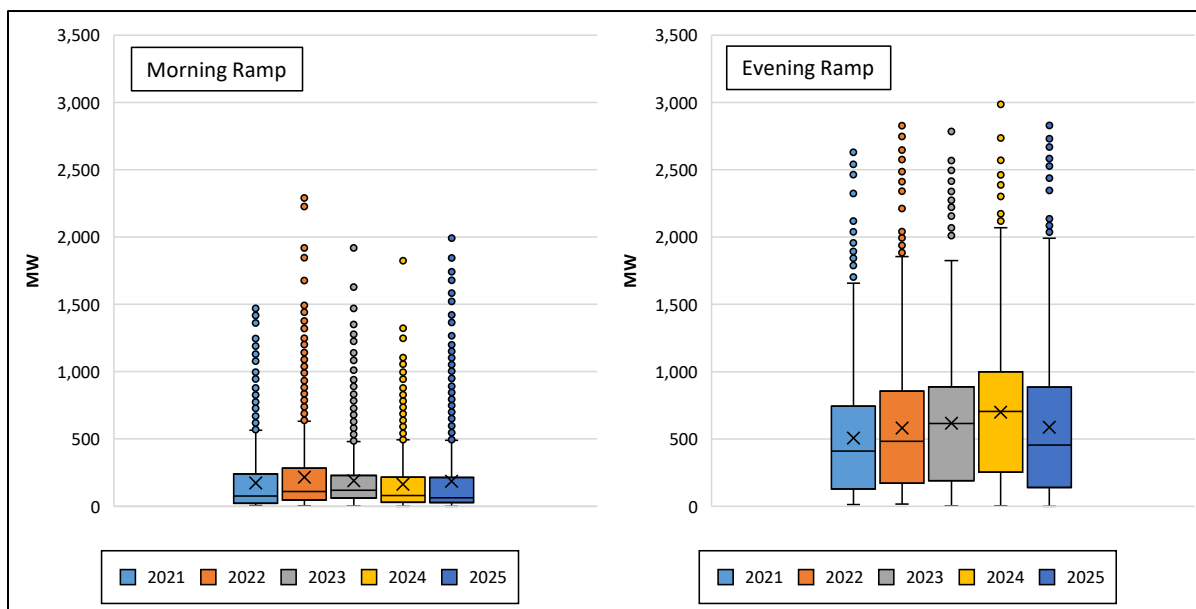
⁸⁷ Photovoltaic output in 2023 is omitted due to the December 2023 implementation date of PV DNE rules. 0.8 GWh of PV, or 3% of available PV participating in DNE, was curtailed in December 2023.

⁸⁸ The Economic Planning for the Clean Energy Transition (EPCET) study discusses the necessary renewable generation, battery capacity, and transmission build required to reduce, or eliminate, carbon in New England. ISO New England Inc., “Economic Planning for the Clean Energy Transition: Illuminating the Challenges of Tomorrow’s Grid”, October 24, 2024, <https://www.iso-ne.com/static-assets/documents/100016/2024-epcet-report.pdf>.

2.8 Reliance on Existing Fast-Start Generation is Increasing during Evening Ramps

Fast-start units provide operational flexibility, which may be relied upon during ramping periods. Figure 2-14 shows the distribution of hourly fast-start generation during morning and evening ramp periods.

Figure 2-14: Fast-Start Generation during Morning and Evening Ramp Periods



Fast-start generation plays a more significant role in the steep evening ramp period than in the morning ramp period. Fast-start generation during the morning ramp (7 am–11 am) declined over 2021–2025, with the median and upper range lower and the distribution narrower in 2025, indicating reduced reliance to manage early day load increases. By contrast, fast-start generation during evening ramps (4 pm–7 pm) increased over time, with higher levels and a higher operating floor than in 2021. Peak evening ramp fast-start generation reached approximately 1,991MW in 2025 (up from 1,825 MW in 2021), reflecting more frequent high magnitude dispatch events. While evening fast-start generation has increased, surplus fast-start capability remains available, as evening ramp generation levels in 2025 continued to remain below total offered fast-start capacity, providing headroom to meet growing ramps.⁸⁹

⁸⁹ Fast-start offered capacity is calculated as the sum of hourly offered economic maximum limits from units that are both fast-start capable and fast-start qualified.

Section 3

Market Structure and Competitiveness Assessment

In this section, we assess the level of competition in the wholesale electricity markets. Competition ensures that the prices consumers pay and that producers receive are the result of competitive forces, and are not unduly influenced by market power. If electricity markets are unable to achieve competitive outcomes due to the potential exercise of market power, mitigation controls are necessary. The IMM performs reviews across various ISO electricity markets to identify these situations and limits their impact through the market power mitigation process and through its monitoring and investigation functions.

The section is structured as follows:

- Energy Market (3.1) followed by energy market mitigation (3.2),
- Ancillary Services Markets (3.3), and
- Financial Transmission Rights (3.4).

In prior years, the IMM has made a number of market design recommendations pertaining to aspects of the market power mitigation framework, including recommendations to review mitigation thresholds in the energy market. The IMM continues to believe that a focused assessment of the mitigation rules is valuable to ensure that these rules provide appropriate safeguards against the exercise of market power while supporting efficient market outcomes.

The Forward Capacity Market is currently undergoing a significant reform process, and no Forward Capacity Auction has been held since FCA 18 (held in 2024). Because there has not been a capacity auction since then, this report does not include an assessment of capacity market competitiveness. An evaluation of auction competitiveness will be included following the completion of the reform effort and the resumption of capacity auctions.⁹⁰

3.1 Energy Market Competitiveness

A number of complementary metrics—intended to be viewed jointly rather than as standalone indicators—are utilized to assess the structure and competitiveness of the energy markets; specifically:

- high-level market concentration measures for supply (3.1.1) and demand (3.1.2) in the real-time market,
- supply-side structural market power tests in the day-ahead and real-time markets (3.1.3): pivotal supplier test (PST) and the residual supply index (RSI),
- supply offer cost mark-up metrics in the day-ahead and real-time markets (3.1.4), and
- the level of capacity economically withheld in the real-time market (3.1.5).

⁹⁰ The IMM's 2023 Annual Markets Report provides an assessment of the competitiveness of prior Forward Capacity Auctions. ISO New England Inc., Internal Market Monitor, "2023 Annual Markets Report", May 24, 2024, <https://www.iso-ne.com/static-assets/documents/100011/2023-annual-markets-report.pdf>.

Key Takeaways

Market outcomes were competitive overall, and the exercise of market power was generally not a concern.

Price Cost Mark-Up: Although price-cost markup metrics in both the day-ahead and real-time markets were higher than in previous years, they remained well below the tightest mitigation threshold of 10%. These results indicate that competition among suppliers effectively limited the ability to inflate LMPs by submitting offers above marginal cost.

Market Concentration: The share controlled by the largest four firms (the "C4" metric) remained consistent with the past five years; approximately 42% on the supply side and 55% on the demand side in the real-time market, with no single firm highly dominant.

Pivotal Suppliers: The frequency of pivotal suppliers was relatively low in the day-ahead market, occurring in ~ 4% of hours. In the real-time market, pivotal suppliers were present in 33% of hours, which was similar to 2024. Over the last five years, the number of pivotal suppliers has increased in both markets due to the decrease in net interchange and an increased reliance on native generation.

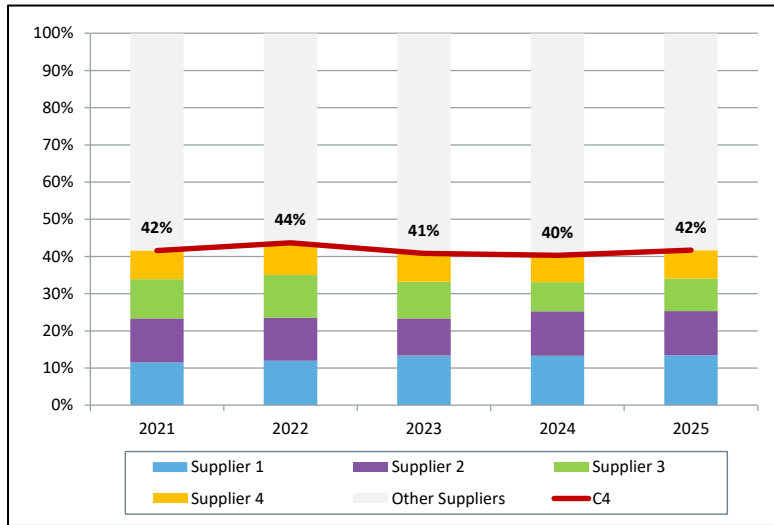
Economic Withholding: We estimate that only 1.3% of capacity was economically withheld in the real-time market on average in 2025. This level of economically withheld capacity was in line with recent years, which had ranged from an average of 1.1% to 1.3%. Levels of economic withholding did not increase when reserve margins were low, suggesting that suppliers did not attempt or did not face incentives to withhold during periods of tight system conditions.

3.1.1 C4 Concentration Ratio for Generation

Supplier market concentration among the largest firms controlling generation and scheduled import transactions is commonly measured by the "C4" index, which represents the combined market share of the four largest firms. This metric is useful for tracking trends in supply concentration over time, as companies enter, exit, or consolidate their positions in the New England market. As shown in Figure 3-1 below, the C4 values in the real-time energy market remained within a narrow range and increased slightly during on-peak hours in 2025.⁹¹

⁹¹ The C4 is the simple sum of the percentages of system-wide market supply provided by the four largest firms in on-peak hours, which are the hours from hour-ending (HE) 8 to HE 23 on non-holiday weekdays, and accounts for affiliate relationships among suppliers. The C4 analyses for both supply and demand do not account for market participants with both load and generation positions. These firms generally have less incentive to exercise market power. Any spot market actions that would tend to raise prices to benefit their generation would come at a cost to their load position. Any actions that would suppress prices to benefit their load would come at a cost to their generation position.

Figure 3-1: Real-time System-wide Supply Shares of the Four Largest Firms



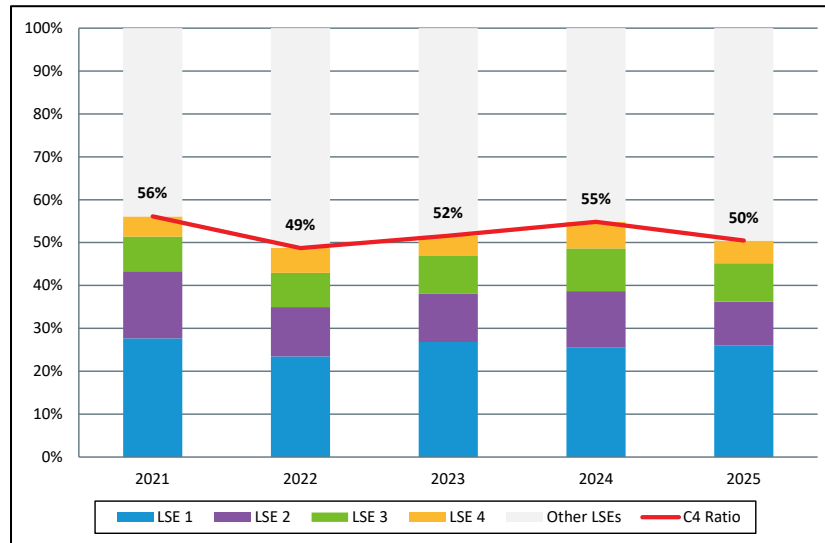
The metric is indicative of low levels of system-wide market concentration, particularly because the market shares are not highly concentrated in any one company. In 2025, 42% of energy supply came from the four largest suppliers, with supply shares relatively evenly distributed among the four largest firms.

3.1.2 C4 Concentration Ratio for Load

The C4 index for load measures market concentration among the four largest load-serving entities (LSEs) in the real-time energy market, as illustrated in Figure 3-2.⁹²

⁹² The C4 load metric accounts for affiliations among different LSEs and includes on-peak hours only. The metric uses Real-time load obligation (RTLO) to measure load. RTLO is measured as all end-use wholesale load in the ISO New England region, along with all exports. The difference between RTLO and real-time generation obligation represents energy losses.

Figure 3-2: Real-time System-wide Demand Shares of the Four Largest Firms⁹³



In 2025, the top four load-serving entities purchased 50% of the total real-time load position in the New England day-ahead market, down from 55% in 2024. There is no evidence to suggest that LSEs exhibited energy market bidding behavior consistent with the exercise of buyer-side market power (deflating price). On average, over 100% of demand cleared in the day-ahead market, and the aggregate demand curve remained relatively price-insensitive around expected LMPs (see Section 4.3.2 on demand bidding).

3.1.3 Residual Supply Index and the Pivotal Supplier Test

The pivotal supplier test (PST)⁹⁴ and the residual supply index (RSI)⁹⁵ are two widely-used structural market tests that provide an indication of opportunities for participants to exercise market power.

⁹³ The firms labeled “LSE 1”, “LSE 2” and so on are not necessarily the same LSE across all years; these are generic labels for the top four firms during a given year.

⁹⁴ Pivotal suppliers are identified for every five-minute pricing interval by comparing the real-time supply margin to the sum of each participant’s total supply that is available within 30 minutes. When a participant’s available supply exceeds the supply margin, they are considered pivotal. The number of five-minute intervals with at least one pivotal supplier are divided by the total number of five-minute intervals in each year to obtain the percentage of intervals with pivotal suppliers.

⁹⁵ The RSI represents the amount of demand that the system can satisfy without the largest supplier’s available energy and reserves. If the value is less than 100, the largest supplier is needed to meet demand and could potentially exercise market power (if permitted). Further, if the RSI is less than 100, there is at least one pivotal supplier. Conversely, when the RSI exceeds 100, there is enough supply available to meet demand without any generation from the largest supplier. In this case, no individual supplier is pivotal and sufficient competition exists in the market. The data used to calculate the RSI come from the ISO’s real-time market software (the Unit Dispatch System, or UDS). Based on these data, the RSI for an interval t is calculated as follows:

$$RSI_t = \frac{Total\ Available\ Supply_t - Largest\ Supplier's\ Supply_t}{Load_t + Reserve\ Requirements_t}$$

Day-Ahead Energy Market

Table below shows the percentage of hours with at least one pivotal supplier.⁹⁶

Table 3-1: Percentage of Hours with Pivotal Suppliers

Year	% of Hours with at least one Pivotal Supplier
2021	0.2%
2022	0.9%
2023	0.1%
2024	2.2%
2025	4.1%

In 2025, tighter supply margins—driven by reduced availability of both imports and native supply—combined with relatively higher projected day-ahead load, led to an increase in the number of hours with pivotal suppliers. The number of hours with pivotal suppliers was lower in the day-ahead market than in the real-time market. This is expected given there is more supply available to the system the day before the operating day, whereas in real time offline long-lead time resources are not included in the PST. In the real-time energy market, the clearing process is more constrained, and the market is exposed to unexpected events that could result in sudden changes in available capacity and demand requirements.

Real-Time Energy Market

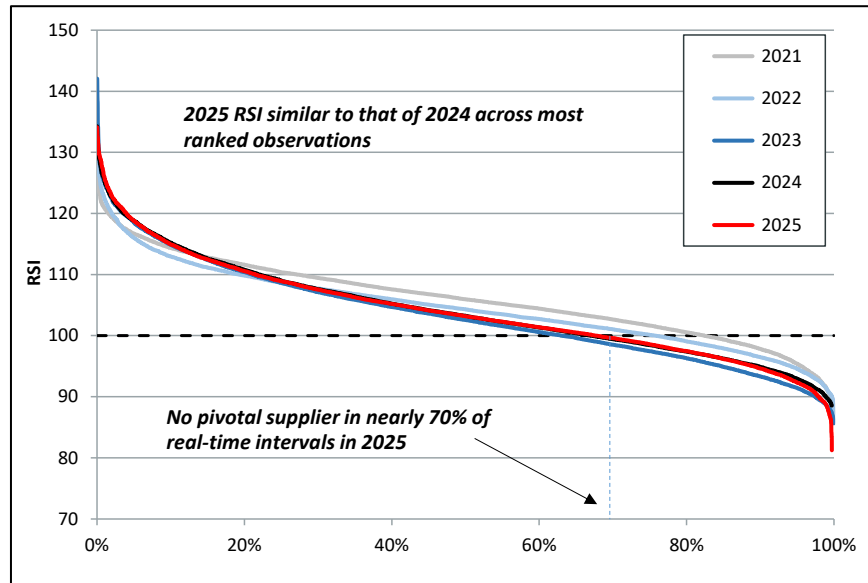
The average RSI for all five-minute real-time pricing intervals and the percentage of five-minute intervals with pivotal suppliers are presented in Table 3-2 below. Duration curves that rank the average hourly RSI over each year in descending order are illustrated in Figure 3-3. The figure shows the percent of hours when the RSI was above or below 100 for each year, indicating the presence of at least one pivotal supplier.

Table 3-2: Residual Supply Index and Intervals with Pivotal Suppliers (Real-time)

Year	% of Intervals with at Least one Pivotal Supplier	RSI
2021	18.0%	106.0
2022	24.9%	104.6
2023	37.3%	103.5
2024	33.3%	104.2
2025	32.6%	104.2

⁹⁶ Pivotal suppliers are identified for each hour by comparing each participant's total available supply to the supply margin. When a participant's available supply exceeds the supply margin, it is considered pivotal. Virtual capacity is excluded. The number of hours with a least one pivotal supplier is divided by the total number of hours in each year to obtain the percentage with pivotal suppliers.

Figure 3-3: System-wide Residual Supply Index Duration Curves



There were more five-minute intervals with pivotal suppliers over the last three years (2023 to 2025) compared to 2021 and 2022. This indicates that suppliers faced relatively less competition in these three years than during the first two years of the reporting period. Since 2023, net interchange has decreased each year meaning that native generation has made up a growing share of generation needed to meet load. Overall, supply margins and intervals with at least one pivotal supplier remained similar to 2024 levels.

3.1.4 Day-Ahead and Real-Time Price-Cost Markups

In a perfectly competitive market, all market participants' energy supply offers would equal their marginal costs. The energy component of the LMP would then be set by the supply offer or demand bid on the margin. However, in practice, participants can raise their supply offers above marginal costs. Uncompetitive offers priced above marginal cost can distort prices and impact generator commitments and dispatch, leading to inefficient market outcomes. Though the IMM administers mitigation rules in the energy market to prevent the exercise of market power, participants are allowed to increase their offers within a certain threshold before mitigation is applied.

The price-cost markup estimates the divergence of the observed market outcomes from the ideal scenario in which all energy supply is offered at marginal cost. The results provide insight into how uncompetitive offer behavior affects the energy markets. A larger price-cost markup means that a larger component of the LMP is the result of inflated supply offers. This analysis used different methods for the day-ahead and real-time price-cost markup calculations. For the day-ahead

metric, we simulated the market clearing using supply offer and marginal cost scenarios.^{97 98} Following ISO-NE’s incorporation of Day-Ahead Ancillary Services (DA A/S), the relevant day-ahead settlement rate for physical energy supply is the sum of the day-ahead LMP and the Forward Reserve (FER) price. The real-time analysis calculated (load-weighted) LMPs by creating supply curves for 1) available generation⁹⁹ by offer price and 2) available generation by marginal cost estimate, and then intersecting real-time demand with each.

The annual price-cost markup values from the day-ahead simulation and real-time analysis are shown in Table 3-3 below.

Table 3-3: Energy Market Price-Cost Markup, %

Year	Day-Ahead Price-Cost Markup	Real-Time Price-Cost Markup
2021	-0.6%	0.2%
2022	-1.8%	-1.7%
2023	-2.2%	-3.6%
2024	2.4%	6.8%
2025	2.7%	5.9%

In the day-ahead market, the price-cost markup increased to 2.7% in 2025, slightly higher than in 2024. This indicates that marginal resources, on average, continued to offer slightly above estimated marginal costs. The resulting increase in the generation-weighted day-ahead price (LMP plus FER price) was modest and remained well below mitigation thresholds, indicating competitive outcomes under the current day-ahead market design.

In the real-time market, annual load-weighted markups were close to zero or negative during 2020–2023, increased to 6.8% in 2024, and remained at a similar level at 5.9% in 2025. The 2025 result therefore does not represent a material change from 2024 conditions. As in 2024, the elevated markup relative to earlier years was primarily due to the offer behavior of gas-fired generators, which have the largest impact on annual markup values in both markets. There continued to be fewer instances of gas-fired generators offering below marginal cost compared with prior years.

Though the markup percentages in both markets were higher than in previous years, the figures still remained below the tightest mitigation threshold (10%). These results indicate that competition

⁹⁷ To perform these simulations, the IMM used an in-house market simulation model, the Integrated Market Simulator (IMS), which replicates the logic of the production day-ahead market and allows for modifications to energy offers and other key inputs. The price-cost markup is calculated using the outcomes of two scenarios: (1) an offer case that uses actual day-ahead energy market supply offers submitted by market participants; and (2) a marginal-cost case that sets generator energy offers at estimates of short-run marginal cost and sets day-ahead ancillary service offer prices at IMM-estimated levels. The price-cost markup is defined as the percentage difference between the annual generation-weighted (LMP + FER price) in the offer case and the marginal-cost case.

⁹⁸ Prior to the 2022 Annual Markets Report, this metric used a different methodology to estimate marginal costs. This is why the values in this report are lower than values for the same years in previous reports.

⁹⁹ Available generation is equal to on-line generation plus generation capacity that can come on-line within 30 minutes. It comes from on-line generators (both long lead-time and fast-start) and off-line fast-start generators.

among suppliers in the day-ahead and real-time markets limited their ability to inflate LMPs by submitting offers above marginal cost.¹⁰⁰

In this assessment, we also reviewed day-ahead price-cost markup values at an hourly level and compared the peak load hour price-cost markup with the forecasted supply margin at peak. Comparing these elements provides insight into whether participants take advantage of tight system conditions, when market power tends to be more of a concern, by increasing offer markups during those times. There was no meaningful correlation between the price-cost markup and the supply margin in 2025, indicating that the day-ahead market remained competitive even when the ISO expected supply margins to be low and market power was present. We also reviewed real-time price-cost markup and reserve margin values at an hourly level. Despite outlier days with high markups and tight conditions, there was no significant correlation between margins and markups over the year.

3.1.5 Real-Time Economic Withholding

Economic withholding refers to suppliers offering their energy above cost. This action can lead to market harm if it results in higher prices that load must pay to purchase energy. Suppliers may engage in this type of behavior if they believe it could be profitable to their portfolio. However, the price impact of this action will depend on the competitiveness of the market. In more competitive markets, the price impact is more likely to be limited. Mitigation, discussed in more detail in Section 3.2, can also limit the market impact of withholding.

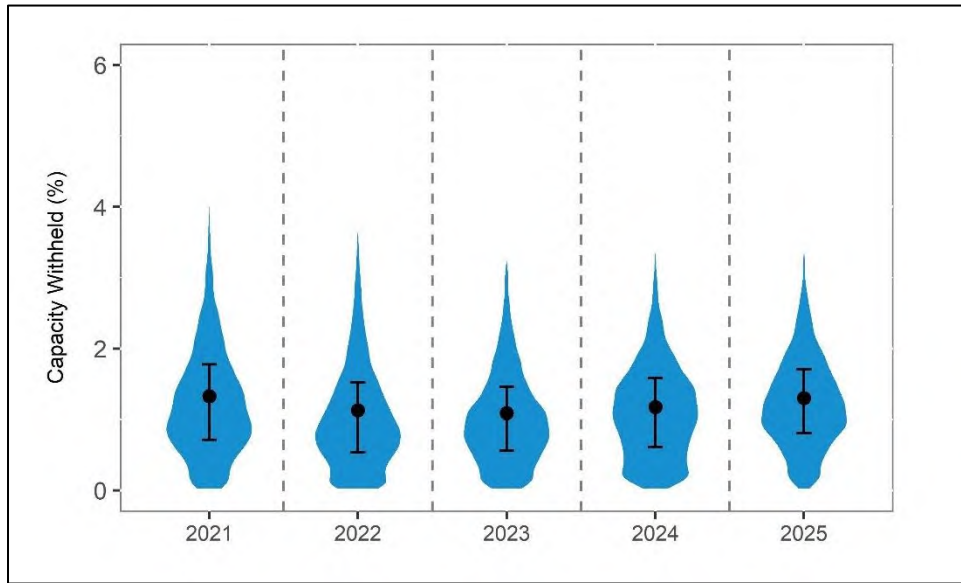
Economic withholding in the real-time market continued to be low in 2025.¹⁰¹ This can be seen in Figure 3-4 below, which shows the distribution of hourly economic withholding (as a percent of capacity) for each of the past five years.¹⁰² The figure also shows, by year, the 25th and 75th percentiles (the black dashes), the interquartile range (the lines between the dashes), and the mean (the black circle).

¹⁰⁰ Differences between the real-time and day-ahead price-cost markups values are due to several factors, including: 1) differences in the methodologies used to calculate the price-cost markup in each respective market; 2) modeling differences between the day-ahead and real-time energy markets; and 3) real-time events that the day-ahead market did not anticipate.

¹⁰¹ We estimate the economically withheld capacity for each generator in every real-time interval as the difference between: a) the quantity that was economic (i.e., the sum of MWs where marginal cost $\leq$ LMP) and b) the actual quantity offered (i.e., the sum of MWs where offer price $\leq$ LMP). In cases where the quantity offered exceeds the quantity that was economic, the withheld MWs are set to zero (i.e., withheld MWs cannot be negative). This analysis considers non-fast-start generators that are online and all fast-start generators (i.e., those that are online or offline); it does not assess potential withholding by offline, non-fast-start generators.

¹⁰² Figure 3-4 presents hourly real-time economic withholding percentages using a violin plot, which combines features of a box plot and a density plot. The curves depict the distribution of hourly withholding, where the widest sections of each curve represent the most-frequently observed levels.

Figure 3-4: Hourly Real-time Economic Withholding



We estimate that only 1.3% of capacity was economically withheld in the real-time market on average in 2025. This level of economically withheld capacity was in line with recent years, which had ranged from an average of 1.1% to 1.3%. In 2025, the middle 50% of observations (the inner quartile range) fell between 0.8% to 1.7%, which was slightly higher than the values from 2024 (0.6% to 1.6%) but still generally in-line with prior years.

Although not presented in the figure, levels of economic withholding did not increase when reserve margins were low, suggesting that suppliers were either unable or did not attempt to take advantage of tight system conditions by economically withholding.

3.2 Energy Market Mitigation

The IMM reviews supply offers in both the day-ahead and real-time energy markets with the objective of identifying and mitigating opportunities for participants to exercise market power.¹⁰³ Under certain conditions, the IMM will mitigate generator supply offers, which results in submitted supply offers (i.e., start-up, no load, and segment energy offer prices) being replaced with “reference” values.¹⁰⁴ In this section we review the level and underlying drivers of the various forms of mitigation in the day-ahead and real-time energy markets.

Key Takeaways

Supply offer mitigation remained low in 2025. There were 399 asset hours of mitigation, representing just 0.02% of all asset hours subject to mitigation, a level similar to past years. This outcome is consistent with the system-level competitiveness metrics discussed above, as well as the limited instances of localized market power (e.g., in import-constrained areas or due to local reliability commitments).

We continue to emphasize the importance of reviewing and strengthening mitigation rules to ensure their robustness under a range of competitive conditions. In prior reports, we issued several recommendations, which can be categorized as follows:

- Review conduct and impact tests and thresholds, including the exemption for non-capacity resources from day-ahead mitigation.
- Enhance indicators of structural market power, both at the system level and for localized areas.
- Improve the accuracy of reference level calculations, with a focus on greater reliance on cost-based reference levels. We also supported the FERC-approved proposal to introduce MW-dependent Fuel Price Adjustments, which will better capture variations in natural gas costs based on quantity.

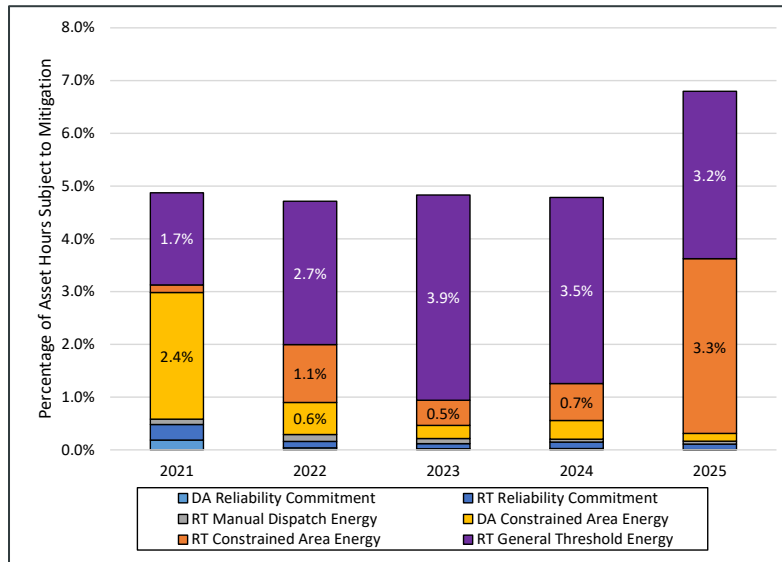
A **structural test** serves as the first indicator of potential market power in the energy markets. The percentage of commitment asset hours in which a structural test failure occurred from 2021 to 2025 is shown in Figure 3-5 below.¹⁰⁵

¹⁰³ This review of supply offers is automated (along with the offer mitigation process) and occurs within the ISO’s energy market software.

¹⁰⁴ The reference values are estimated and maintained by the IMM; these values are used in mitigation to reduce impacts on energy market pricing (LMPs) and uplift payments (NCPC) from participant offers that appear to overstate a generator’s operating costs. Seven mitigation types utilize mitigation tests and are used in ex-ante supply offer mitigation. An eighth mitigation type for dual-fuel generators is performed after-the-fact, when a dual-fuel generator burns a low-priced fuel but submits supply offers based on a higher-cost fuel.

¹⁰⁵ A structural test failure depends on the type of mitigation analyzed. The definitions of the structural test applied in general threshold and constrained area mitigation can be found in the Market Rule. ISO New England Inc., “Transmission, Markets, and Services Tariff (ISO tariff), Section III.A.5.2, Market Rule 1, Appendix A, Market Monitoring, Reporting, and Market Power Mitigation”, http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf. The conditions to pursue manual dispatch energy and reliability commitment mitigation are found in Sections III.A.5.5.3 and III.A.5.5.6.1, respectively.

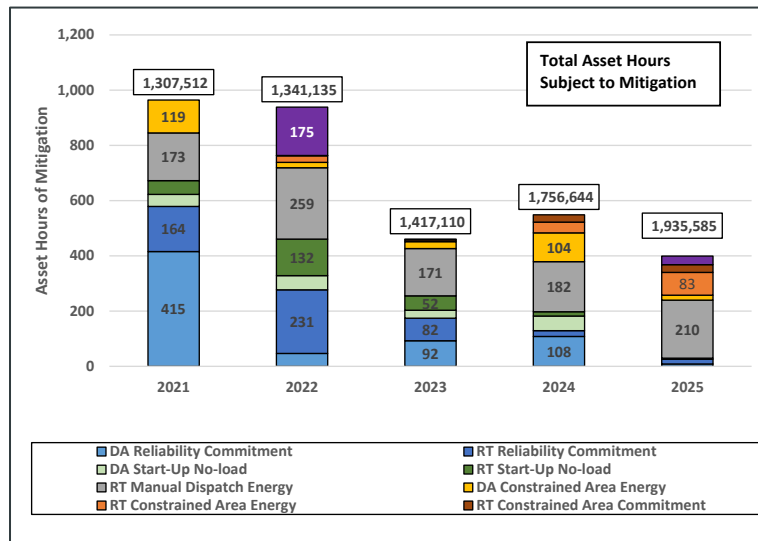
Figure 3-5: Energy Market Mitigation Structural Test Failures



In 2025, the total asset hours subject to mitigation reached 1.9 million asset hours, in which approximately 132 thousand asset hours (7%) failed structural tests.¹⁰⁶ The structural test for general threshold energy mitigation fails the most often and triggers any time a committed generator is owned by a pivotal supplier. Overall, asset hours of structural test failures represent a very small fraction of potential asset hours subject to mitigation and, consequently, lead to an even smaller fraction of asset hours mitigated.

Asset hours of mitigation by type are shown in Figure 3-6 along with the total amount of asset hours subject to mitigation (white boxes).

Figure 3-6: Energy Market Mitigation Asset Hours



¹⁰⁶ The asset hours subject to mitigation are estimated as a committed generator with an economic dispatchable range at or above its economic minimum (eco min). Each such on-line generator during a clock hour represents one asset hour of generation potentially subject to energy market mitigation.

In 2025, there were 399 asset hours of mitigation or just 0.3% of all asset hours subject to mitigation, lower than that of 2024 (548 asset hours).¹⁰⁷

Manual dispatch energy (MDE) mitigation: The ISO will assign manual dispatch points to utilize flexible generation in addressing short-term issues on the transmission grid. As a result, gas or dual-fuel generators receive manual dispatches most often, accounting for 76% of the 1,106 asset hours of manual dispatch in 2025. Due to a relatively tight conduct test (10%), manual dispatch energy mitigation occurs more often than any other mitigation type, reaching a total of 210 asset hours in 2025.

Constrained area (CAE/CACM) mitigation: The frequency of transmission-constrained areas follows the incidence of transmission congestion and import-constrained areas within New England. Day-ahead constrained area mitigations decreased from 104 to 18 between 2024 and 2025, although real-time constrained area mitigations occurred more frequently, increasing from 39 to 83 asset hours of mitigation. In the real-time market, most constrained area energy mitigations occurred in a limited number of instances due to large import constrained areas in southern New England (rather than localized load pockets). In June, the Maine-New Hampshire constraint was binding on two separate days during tight conditions surrounding the pay-for-performance event on June 24. In December, the North-South New England Import Interface was constrained as a result of flows associated with NECEC testing. However, the Maine-New Hampshire and North-East constraints may bind more frequently in 2026 due to additional supply in Maine from the NECEC external interface.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs, and are generally due to routine transmission line outages, outages facilitating upgrade projects, or localized distribution system support.¹⁰⁸ In 2025, reliability commitments totaled 106 asset hours in the day-ahead (a 74% decrease from 2024) and 1,982 asset hours in the real-time markets (an 8% decrease from 2024). About 90% of real-time reliability commitment asset hours occurred in the Southeastern Massachusetts load zone. There were only 25 reliability commitment mitigations in 2025, or just 1% of reliability commitment asset hours.

Start-up and no-load (SUNL) commitment mitigation: This mitigation type addresses grossly overstated commitment costs (relative to reference values), which could otherwise result in very high uplift.¹⁰⁹ SUNL mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate – particularly natural gas. In 2025, only three participants were associated with 68 asset hours of SUNL commitment mitigation.

¹⁰⁷ ISO New England Inc., Internal Market Monitor, “An Overview of New England’s Wholesale Electricity Markets”, May 23, 2025, <https://www.iso-ne.com/static-assets/documents/100023/imm-markets-primer.pdf>. This document is updated periodically, particularly to reflect changes to market design. It includes more information on Energy Market Mitigation types and thresholds.

¹⁰⁸ This mitigation category applies to most types of “out-of-merit” commitments, including local first contingency, local second contingency, voltage, distribution, dual-fuel resource auditing, and any manual commitment needed for a reason other than meeting system load and operating reserve constraints. ISO New England Inc., “Transmission, Markets, and Services Tariff (ISO tariff), Section III.A.5.5.6.1, Market Rule 1, Appendix A, Market Monitoring, Reporting, and Market Power Mitigation”, http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

¹⁰⁹ The conduct test for this mitigation type compares a participant's offers for no-load, start-up and incremental energy cost up to economic minimum to the IMM's reference values for those same parameters. It uses a very high conduct test threshold (200% applied to the start-up, no-load, and offer segment financial parameters).

General threshold energy (GTE) mitigation: Despite having the highest frequency of structural test failures, general threshold energy mitigation occurs with the least frequency of all mitigation types. Across the reporting period, over 60,000 asset hours of pivotal supplier energy were subject to mitigation each year on average; mitigation has occurred for only 206 asset hours, 31 of which occurred in 2025 and 175 in 2022. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators, with six participants accounting for 75% of the structural test failures in 2025.

We continue to emphasize the importance of reviewing and improving mitigation rules to ensure their robustness under changing competitive conditions. To that end we have issued a number of recommendations in prior reports, which are summarized in the Executive Summary and can be categorized as follows:

- Review conduct and impact tests and thresholds, and the day-ahead mitigation exemption for non-capacity resources.
- Improve indicators of structural market power at a system level (accounting for company affiliations, generator ramping) as well as for local market power (export-constrained areas).
- Improve the accuracy of reference level calculations, such as prioritizing reliance on cost-based reference levels. During 2024, we supported the ISO's proposal to introduce MW-dependent Fuel Price Adjustments (FPAs), which will reflect that natural gas costs can vary by quantity, and which FERC ultimately approved.¹¹⁰

¹¹⁰ See the FERC filing regarding MW-dependent FPAs: Federal Energy Regulatory Commission, “*Order Accepting Tariff Revisions, Terminating Show Cause Proceeding, and Directing Informational Filing*”, issued November 21, 2024, https://www.iso-ne.com/static-assets/documents/100017/er24-2584_el23-62_order_accept_revisions_terminate_show_cause_direct_info_filing.pdf.

Also see: ISO New England Inc., Internal Market Monitor, “*Comments of the Internal Market Monitor on Fuel Price Adjustment Modifications*”, https://www.iso-ne.com/static-assets/documents/100014/imm_comments_on_mw-adjusted_fpas.pdf

3.3 Ancillary Services

Below, we review the competitiveness of the Day-Ahead Ancillary Services (DA A/S) market and the regulation market.¹¹¹ The first subsection (3.3.1) provides an assessment of the DA A/S market. The second subsection (3.3.2) reviews available regulation capacity relative to the regulation requirement and indicates the RSI for 2024.

Key Takeaways

Day-ahead ancillary services (DA A/S) outcomes over the review period were broadly consistent with competitive market behavior, with no meaningful evidence of physical or economic withholding affecting costs.

Regulation Market: The regulation market remained structurally competitive in 2025. Available supply consistently exceeded regulation requirements, and no supplier controlled a sufficient share of supply to raise market power concerns.

3.3.1 Day-Ahead Ancillary Services

We conducted a one-year review of the competitiveness of Day-Ahead Ancillary Services in the day-ahead market. The results of this assessment will be published in a standalone report in June 2026¹¹². Here, we summarize our insights on DA A/S competitiveness.

DA A/S market outcomes indicate that costs were broadly consistent with what we would expect from competitive market behavior during the period. We find no evidence that physical withholding materially affected market outcomes. Participation levels have generally increased as market participants gained experience under the new design, and offered capability was typically sufficient to meet both load and reserve requirements. However, participation levels remain an important driver of outcomes, particularly during high-load or stressed system conditions when the availability of flexible resources is most consequential. In these periods, lower participation can contribute to tighter supply conditions and higher prices, although the observed outcomes do not suggest systematic withholding behavior.

In addition, we found little indication of economic withholding affecting overall market costs. Observed DA A/S costs were consistent with simulated outcomes based on competitive offer benchmarks, indicating that offers submitted by participating resources were broadly aligned with competitive, risk-adjusted behavior.

Although structural indicators show that market concentration can arise in certain products and time periods, particularly under tighter system conditions, these conditions did not translate into non-competitive outcomes. Measures of concentration, including pivotal supplier conditions in some reserve products, indicate that the potential for market power exists at times. Nevertheless, observed prices and costs remained consistent with competitive benchmarks, suggesting that suppliers' behavior was disciplined by market design, participation, and mitigation measures.

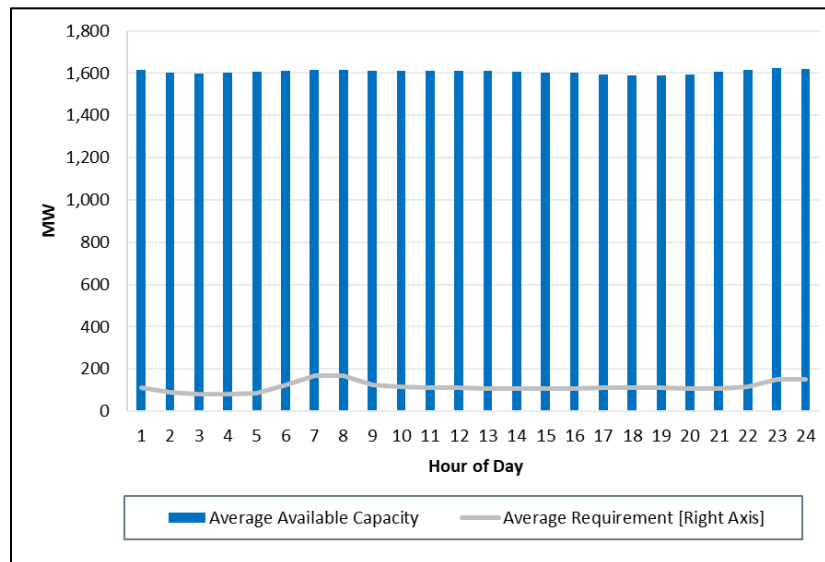
¹¹¹ The DA A/S market went live on February 28, 2025, for the operating day of March 1, 2025. More information about this market can be found in Section 8.2.

¹¹² The report will be available at <https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor>.

3.3.2 Regulation Market

We reviewed the competitiveness of the regulation market by examining market structure and resource availability. The abundance of regulation resources and the relatively unconcentrated control of that supply reduces any opportunity to engage in economic or physical withholding, as indicated in Figure 3-7 below.

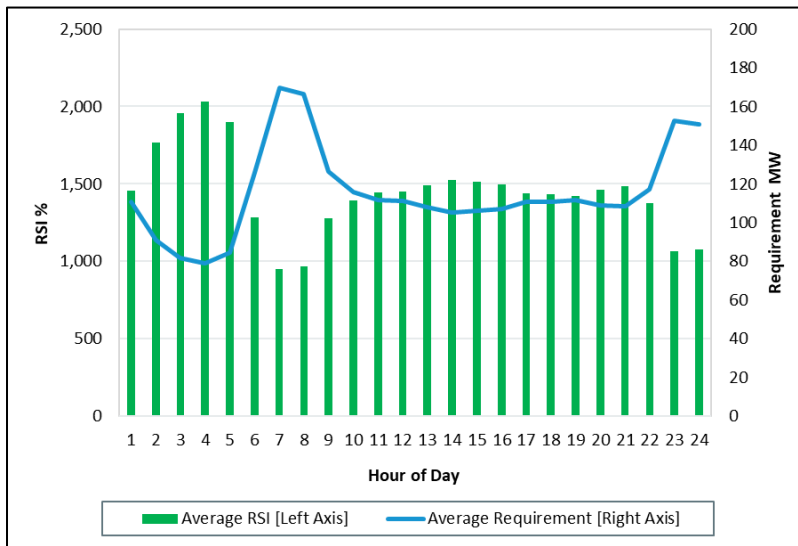
Figure 3-7: Average Regulation Market Requirement and Available Capacity, 2025



On average, during every hour of the day, available supply far exceeds the regulation requirements. However, an abundance of available supply alone is not a dispositive indicator of market competitiveness, as one - or a small number of suppliers - could control the available supply and seek to exercise market power.

The Residual Supply Index RSI provides a better indicator of the structural competitiveness of the regulation market. As shown in Figure 3-8, the regulation requirement (right axis) and RSI (left axis) are inversely correlated (the lower the requirement the higher the RSI).

Figure 3-8: Average Regulation Requirement and Residual Supply Index, 2025



In 2025, the lowest hourly average RSI remained high as in prior years, with values consistently staying above 1,000% except during Hours Ending 7 and 8, when RSI briefly dipped but remained above 900%. Even in those hours, the system still had nine times the regulation requirement available without the largest regulation supplier, meaning the supplier was not pivotal. Accordingly, we find the regulation market was competitive in 2025.

3.4 Financial Transmission Rights Market

In this section, we look at the competitiveness of the Financial Transmission Rights (FTR) market, with a specific focus on market concentration. In this context, market concentration refers to the extent to which FTR MWs are concentrated among market participants.

Key Takeaways

Ownership of FTR paths was relatively concentrated in 2025, with the top four participants holding over 60% of FTR MWs. High concentration levels have been observed in all five years of the reporting period. However, the FTR market remained fairly active in 2025 with over 30 unique participants bidding in the auctions over the course of the year.

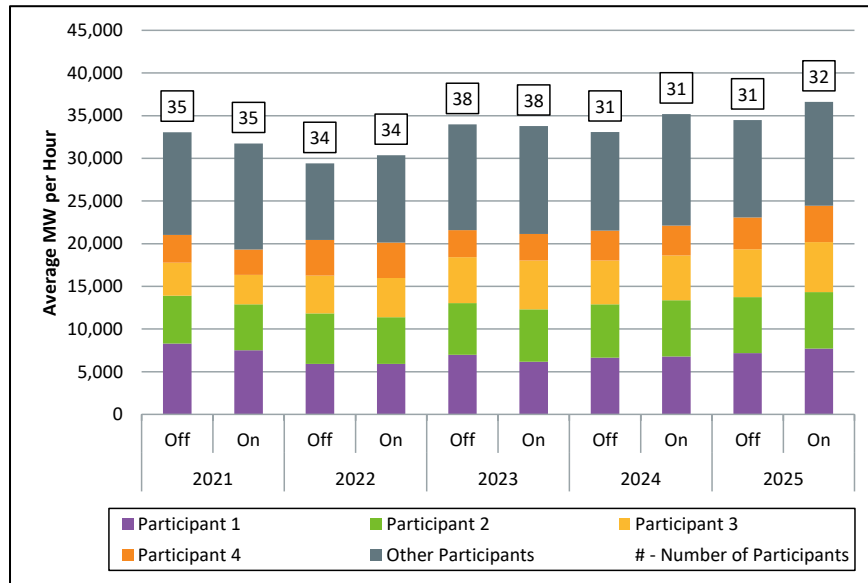
As discussed in Section 9.2, FTRs were profitable in 2025, earning a net profit of \$34 million and reversing a trend of negative or near-zero profitability since 2022. The increase in FTR profits was driven by an increase in system congestion and higher system LMPs throughout the year.

Determining what constitutes a competitive level of FTR ownership is complex, as it is unlikely to align with system-level shares of load-serving or generation ownership. This is because there are not clear commercial motives for all market participants to hold FTR positions – for example, load-serving entities or participants with generation that is not exposed to transmission constraints likely do not have incentives to purchase FTR positions. Even those participants that may benefit from hedging basis risk can have risk preferences that favor exposure to day-ahead congestion over managing that exposure with the purchase of an FTR. Further, FTR market design permits the purchase of FTRs for financial speculation, so many FTR holders have no load or generation position at all.

The concentration of FTR MWs among market participants in 2025 was slightly higher than in prior years. The average amount of FTRs held per hour by the top four participants with the most MWs each year is shown in Figure 3-9 below.¹¹³ This figure also shows the number of different participants that held FTRs each year (indicated by the number above each stacked column). This information is broken down separately for the on-peak and off-peak periods.

¹¹³ The firms labeled “Participant 1,” “Participant 2” and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

Figure 3-9: Average FTR MWs Held per Hour by Top Four FTR Holders by Year and Period



The top four FTR market participants held 67% of both on-peak and off-peak MWs in 2025. This concentration among the top four participants is slightly higher than the five-year average (~65%), coinciding with a slightly smaller count of individual participants in 2024-2025 than in 2021-2023. FTR profits totaled \$34 million in 2025, reversing a trend of negative or near-zero profits since 2022. As discussed in Section 9.2, FTR profits were driven by an increase in overall system congestion, largely attributable to temporary transmission work. Therefore, the increased FTR profits in 2025 do not indicate structural market power concerns as unforeseen congestion patterns were the main driver of FTR profitability.

Section 4

Day-Ahead and Real-Time Energy Market

We examine key trends and drivers of energy market outcomes in this section, which is structured as follows:

- Day-ahead and real-time energy prices across a number of dimensions, including location, time-of-day, and convergence (4.1)
- Factors that influence supply and demand participation (4.2 & 4.3)
- Energy markets and system reliability interactions (4.4)
- Net commitment period compensation (NCPC) payments (4.5)
- Summary of system events during 2025 (4.6)¹¹⁴
- Demand response resource (DRR) participation in the energy markets (4.7)

Day-ahead and real-time energy prices increased significantly in 2025 (83% and 67%, respectively) relative to 2024. These increases were driven primarily by a substantial rise in natural gas prices, which increased by 105% year-over-year. Higher energy prices also reflected increased emissions costs and greater reliance on natural gas-fired generation as net imports declined. During periods of high summer demand, prices were further elevated as dispatch extended into the higher-cost ranges of gas-fired capacity.

Uplift (NCPC) totaled \$42 million in 2025, comprising 0.4% of total energy market costs, the lowest share in at least a decade. Most NCPC payments occurred in the real-time market (\$31 million, 75%). The majority of payments were made to resources committed in economic merit order to meet load and reserve requirements.

4.1 Energy Prices

Below, we evaluate energy prices across a number of dimensions, including by energy market (i.e., day-ahead LMP plus Forecast Energy Requirement, FER, price, and real-time LMP), time-of-day, and location. These perspectives offer useful context for understanding differences in energy prices over the review period.

The first subsection (4.1.1) summarizes energy market pricing over a five-year period, reviews price separation across load zones, and examines load-weighted LMPs, which provide an indication of the effective prices that load-serving entities pay for energy. The second subsection (4.1.2) examines the extent to which prices converged across the day-ahead and real-time energy markets—an important indicator of market efficiency. Finally, the third subsection (4.1.3) estimates the impacts of fast-start pricing rules on LMPs and other market outcomes.

¹¹⁴ For a detailed assessment of system events, see: ISO New England Inc., Internal Market Monitor, “*Quarterly Markets Reports*”, <https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor>

Key Takeaways

Price Levels and Drivers: Day-ahead and real-time energy prices increased by 83% and 67% year-over-year, respectively; the increased energy prices were largely due to higher natural gas prices (up 105%). Prices were nearly \$6/MWh higher in the day-market compared to the real-time market. The day-ahead price includes the Forecast Energy Requirement price (FERP), a new component of energy prices introduced as part of the Day-Ahead Ancillary Services (DA A/S) initiative in March 2025. The FER price is paid to day-ahead cleared physical supply for meeting the ISO's load forecast. The day-ahead LMP and the FERP averaged \$67.86/MWh and \$3.95/MWh, respectively.

- The annual simple average Hub price was \$71.81/MWh in the day-ahead market (incl. \$3.95/MWh FER price) and \$65.87/MWh in real time.
- The day-ahead price premium of \$6/MWh represents the highest average price divergence since the start of the Standard Market Design. We have observed higher day-ahead prices since the addition of the FER.
- There was minimal congestion in 2025. When congestion did manifest, the Connecticut and Maine load zones tended to have the lowest average LMPs compared to the Hub.

Fast-Start Pricing: The fast-start pricing rules in the real-time market are generally achieving their key design objective of improving price formation by better reflecting the production costs of flexible, fast-start resources in energy prices and reducing uplift payments. However, there continued to be significant periods of non-zero reserve pricing and payments even when reserve constraints were not impacting the physical dispatch of resources and there was a physical surplus of reserves. We continue to recommend that the ISO assess this issue.

4.1.1 Day-Ahead and Real-Time Energy Price

Day-ahead and real-time energy prices at the Hub and the eight New England load zones are presented below. These prices are evaluated across a number of dimensions: time-of-use (i.e., peak, off-peak hours), location, and load-weighting.

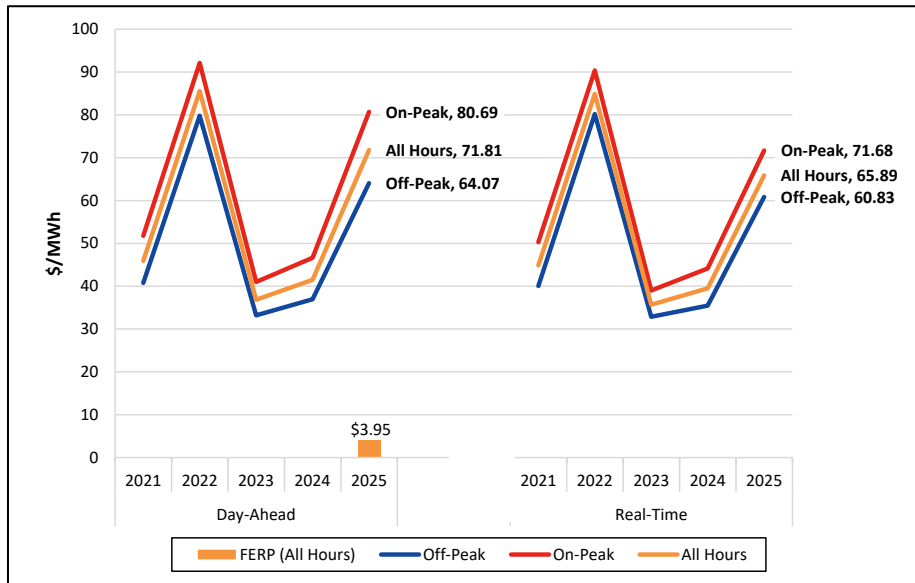
Hub Prices by Time-of-use and Market

First, Figure 4-1 shows simple average Hub prices in the day-ahead (incl. Forecast Energy Requirement price)¹¹⁵ and real-time markets for three time tranches: all hours, peak, and off-peak hours.¹¹⁶

¹¹⁵ Day-Ahead energy prices include the Forecast Energy Requirement (FER) price, which was introduced on March 1, 2025, as part of the Day-Ahead Ancillary Services Initiative. The average FER value includes zeros for January and February 2025.

¹¹⁶ On-peak periods are weekday hours ending 8 to 23 (i.e., Monday through Friday, excluding North American Electric Reliability Corporation (NERC) holidays); the off-peak period consists of all other hours.

Figure 4-1: Annual Simple Average Hub Price



Average Hub prices in 2025 increased compared to 2024 due to higher natural gas prices, especially during the winter. In 2025, the simple annual average Hub price (in *all hours*) was \$71.81/MWh in the day-ahead market¹¹⁷ and \$65.89/MWh in the real-time market. These prices represent increases over the prior year's averages of 73% and 67%, respectively. Time-of-day pricing in 2025 (i.e., on-peak and off-peak) followed a similar upward trend, and on-peak prices remained 26% higher than off-peak prices in the day-ahead market.

These price changes are consistent with observed market conditions, including input fuel costs, load levels, and generator operations. Natural gas prices, which are the primary driver of energy prices in New England, more than doubled in 2025 (up 105%). Additionally, net imports declined significantly for the fourth consecutive year. The decrease in net interchange leads to a shift in the supply curve with greater reliance on more expensive generation.

Prices by Load Zone and Market

At the *zonal* level, price differences were small in 2025 in both the day-ahead and real-time energy markets. Load zone prices were quite close to the Hub price, with an absolute average price difference between the Hub and zones of \$0.76/MWh in the day-ahead market and \$0.71/MWh in real time, reflective of a system that is generally uncongested. As in prior years, the Connecticut and Maine load zones had the lowest average LMPs in both day-ahead and real-time markets (about 2% to 3% lower than the Hub). Upward pricing separation tended to be small in the day-ahead and real-time markets.

Consumer Prices: Load-Weighted Prices

Figure 4-2 below shows the relatively small differences in system-level day-ahead energy prices across the region on a monthly basis.

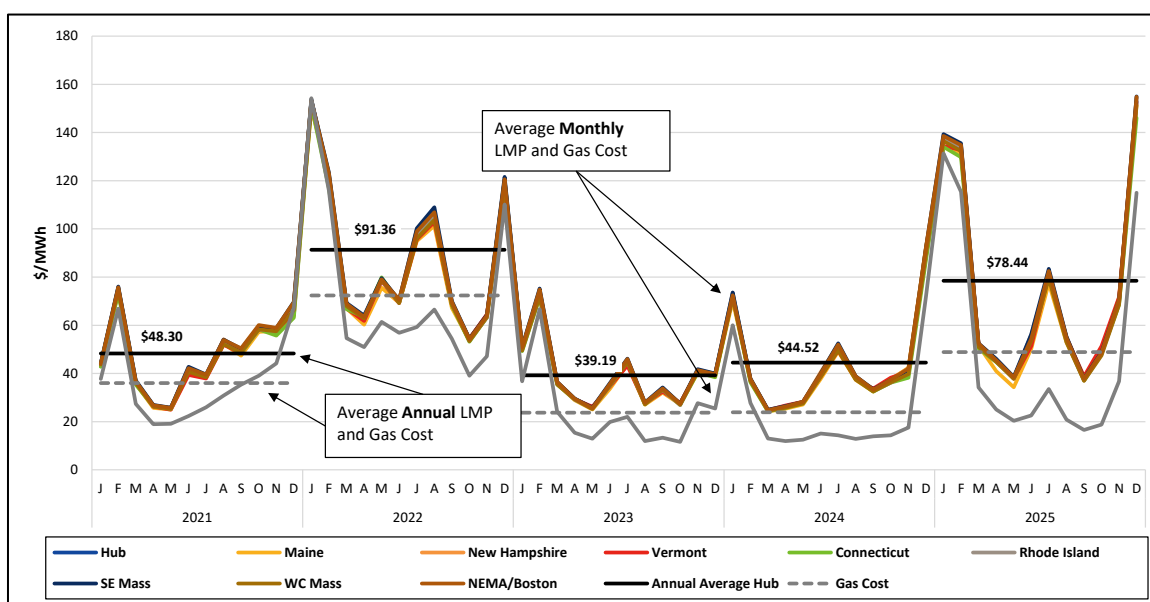
Compared to simple average prices, load-weighted prices provide a more accurate measure of the average energy costs faced by load-serving entities (LSEs). Because energy consumption varies

¹¹⁷ The day-ahead LMP and the Forecast Energy Requirement price (FERP) averaged \$67.86/MWh and \$3.95/MWh, respectively.

significantly by hour, load-weighted prices better capture the cost of meeting demand during peak periods, when higher consumption requires dispatching more expensive generation resources. As a result, load-weighted prices are typically higher than simple averages. In 2025, the average day-ahead load-weighted price was \$78.27/MWh.

Monthly day-ahead load-weighted prices across load zones over the past five years are shown in Figure 4-2 below. The figure illustrates significant monthly variability in LMPs, particularly during winter months with fuel price volatility.

Figure 4-2: Day-Ahead Load-Weighted Prices



Load-weighted energy prices by load zone from 2021 to 2025 indicate a pattern that varies considerably by year and by month, but typically not by load zone. Winter periods with high fuel prices and summer months with elevated load variability typically have the highest load-weighted prices; a similar trend applies to the real-time market. The effect of natural gas prices in 2025 is evident in the figure above, with day-ahead LMPs highest in January, February and December of this year during these cold winter months when gas demand was high.

4.1.2 Energy Price Convergence

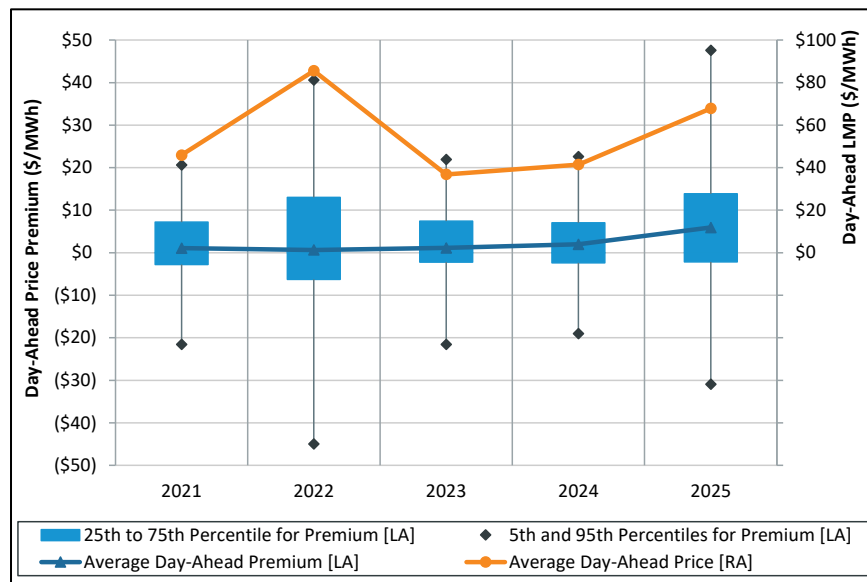
Price convergence refers to the extent to which prices aligned between the day-ahead and real-time energy markets. Price convergence can serve as a metric for market efficiency – which, in this case, means achieving the necessary real-time generator commitments at the lowest possible cost. One way to assess price convergence is to look at the difference between the day-ahead LMP plus the Forecast Energy Requirement price (FERP) and real-time LMPs (i.e., the day-ahead price premium).¹¹⁸ In an efficient market, day-ahead (forward) prices should generally reflect expected real-time (spot) prices. While day-ahead prices will almost never perfectly match real-time prices in any given hour (because real-time conditions will usually differ from expectations), one might expect to see similar average prices between the two markets over time.

¹¹⁸ The day-ahead price premium is defined as the day-ahead LMP plus FER price *minus* the real-time LMP.

Convergence Across all Hours

The average Hub day-ahead price premium increased in 2025 following the beginning of the Day-Ahead Ancillary Services Market (DA A/S) on March 1, 2025. The day-ahead market price now includes the day-ahead LMP and the FERP which is paid to day-ahead cleared physical supply. This constraint ensures day-ahead cleared physical generation is sufficient to meet the ISO's load forecast. Figure 4-3 shows the distribution of the day-ahead price premium (incl. FER price) at the Hub between 2021 and 2025 using a box-and-whiskers diagram.¹¹⁹ This figure also shows the average annual day-ahead price (2021-2024), or the day-ahead LMP plus the FER price (2025).

Figure 4-3: Average Annual Day-Ahead Price Premium at the Hub and Average Day-Ahead Hub LMP



The day-ahead premium at the Hub averaged \$5.93/MWh in 2025, the highest premium over the five-year period. The only two months with higher real-time LMPs were 1) January 2025 (\$1.52/MWh higher), which was prior to the DA A/S market and 2) June 2025 (\$0.66/MWh higher), which included over three hours of capacity scarcity conditions.

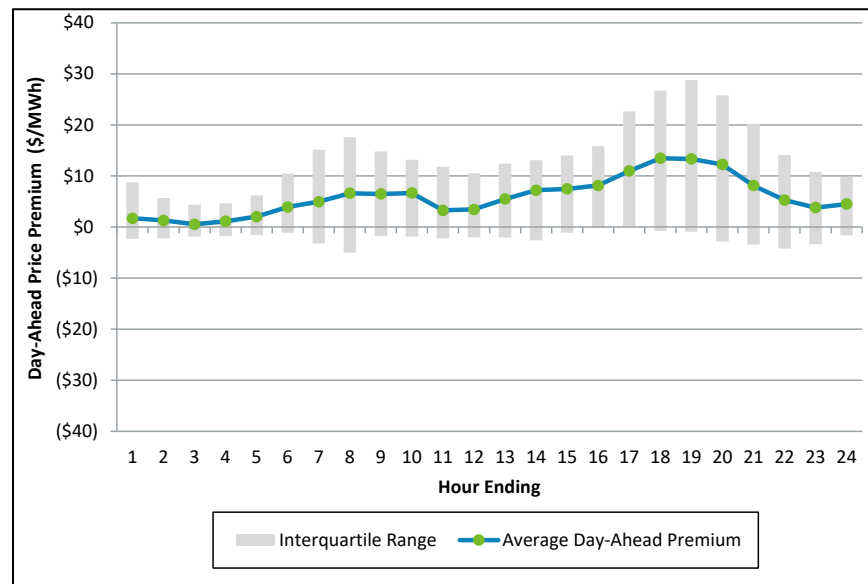
In percentage terms (as a percentage of the day-ahead price), the 2025 price premium (9%) was also the highest in the reporting period. Between 2021 and 2025, the average price premium ranged from as low as \$0.64/MWh (in 2022) up to the high seen this year. The variability in day-ahead price premiums increased in 2025. However, these percentiles generally track the average day-ahead Hub price (orange series, right axis).

Convergence by Time of Day

The average day-ahead price premium (DA LMP + FERP – RT LMP) tended to be higher during the evening peak during 2025. Figure 4-4 below shows, by hour, the average day-ahead price premium at the Hub (blue line). The gray bars show the interquartile range (i.e., the middle 50 percent) of the day-ahead price premium.

¹¹⁹ The day-ahead price premium is measured on the left axis ("LA"), while the average annual day-ahead Hub LMP is measured on the right axis ("RA").

Figure 4-4: Average Hourly Day-Ahead to Real-Time Hub Price Differences, 2025



The average day-ahead price at the Hub exceeded the average real-time price during every hour and ranged from \$0.53/MWh to \$13.47/MWh. The price premium tended to be higher during the peak load hours (HE 17 through HE 20) with the day-ahead premium above \$10/MWh in these four hours. Under the prior market design, virtual supply could clear in the day-ahead market and profit off the day-ahead price premiums; these bids would likely help converge day-ahead and real-time prices. The DA A/S market has largely hampered virtual supply’s price converging ability when the FER constraint is active. If a virtual trader anticipates lower real-time prices, physical supply is still needed to help meet the FER constraint. In this situation, an inframarginal virtual supply bid can lower the day-ahead LMP but would likely lead to a larger FER price.

4.1.3 Fast-Start Pricing: Impact on Real-Time Outcomes

The fast-start pricing rules in the real-time energy market continue to have notable impacts on pricing and market costs. The purpose of fast-start pricing rules is to improve energy price formation when fast-start units are operating. Fast-start pricing rules allow LMPs to better reflect the marginal cost of fast-start resource deployment and, therefore, send more transparent short- and long-term market signals about the cost to operate the system.

We find that fast-start pricing is generally meeting the design’s key objective of improving real-time price formation by better reflecting the production costs of flexible fast-start resources in energy prices.¹²⁰ In 2025, fast-start pricing impacts were similar to prior years. There continued to be significant periods of non-zero pricing (and payments) during times when the reserve constraint was not impacting the physical dispatch of resources and there was a physical surplus of reserves. We recommended that the ISO assess this issue in our 2022 Annual Report.¹²¹

¹²⁰ For more detail on fast-start pricing, see: ISO New England Inc., Internal Market Monitor, “*Summer 2017 Quarterly Markets report*”, December 20, 2017, Section 5.5, <https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf>

¹²¹ A summary of this and other recommendations can be found in the executive summary of this report.

Table 4-1 below compares a number of actual and estimated counterfactual market outcomes. The column labeled *Fast-Start Pricing* details actual pricing and settlement outcomes. The column labeled *Non-Fast-Start Pricing* provides estimates of counter-factual outcomes if fast-start pricing had not been implemented using data produced by the dispatch software.

Table 4-1: Fast-Start Pricing Outcome Summary, 2025

Market Outcome	Fast-Start Pricing (Actual Outcomes)	Non Fast-Start Pricing (Counterfactual Outcomes)	Difference
System LMP (\$/MWh)¹²²	\$65.63	\$61.56	\$4.06 (7%)
Real-Time Energy Payments (\$, Millions)¹²³	\$146.4	\$128.3	\$18.1 (14%)
NCPC Payments (\$, Millions)¹²⁴	\$22.3	\$32.7	-\$10.4 (-32%)
Reserve Prices (\$/MWh)¹²⁵	\$1.78	\$0.94	\$0.85 (90%)
Real-Time Reserve Payments (\$, Millions)¹²⁶	\$27.4	\$12.5	\$14.9 (119%)
Percent of Intervals with Reserve Pricing (%)	6.9%	4.3%	2.7% (62%)
Intervals Fast-Start Resource Marginal¹²⁷	24.2%	10.0%	14.2% (142%)

To summarize the key takeaways, the fast-start pricing mechanics:

- resulted in a higher frequency of fast-start resources setting price, mostly driven by fast-start generator price-setting frequency (+4.9% from asset-related demand, +9.2% from generation)
- increased the average annual system LMP by 7% and increased real-time energy payments by 14%,
- decreased real-time NCPC paid to generators and asset-related demand (ARDs) by 32%¹²⁸, and

¹²² The system LMP shown here is the energy component of the LMP in each interval.

¹²³ This value is different than the real-time payments value reported in the wholesale cost section of the report because, here, real-time load deviations are only considered for locations and customers with physical load (i.e., exports and day-ahead demand that does not correspond to physical load are excluded).

¹²⁴ NCPC payments included in this analysis are Commitment-Out-Of-Merit (COOM), Dispatch-Out-Of-Merit (DOOM), and Rapid Response Pricing Opportunity Cost (RRPOC) payments for generators and asset-related demand resources (ARDs). Due to data limitations, counterfactual LMPs were not available in every interval so estimated payments are slightly less than actual payments. Actual payments (i.e., not based on IMM estimates like the data shown in the table) in 2025 were \$22.9 million.

¹²⁵ These reserve prices represent the average reserve price in every interval – including \$0/MWh reserve price intervals.

¹²⁶ The netting of real-time payments for a participant's forward reserve market obligations is not accounted for in the reported reserve payments. For more information on the impact of fast-start pricing on reserves, see Section 8.1.

¹²⁷ This metric represents the percentage of intervals in which at least one fast-start generator was marginal (i.e., set price).

¹²⁸ Breaking down the reduction further, fast-start pricing reduced commitment-out-of-merit and dispatch-out-of-merit NCPC to generators that did not recover their costs when following ISO dispatch instructions by 41%. The decrease was offset by an increase in Rapid Response Pricing Opportunity Cost (RRPOC) NCPC.

- had a substantial impact on reserve pricing and payments, with non-zero pricing occurring in 62% more intervals. Overall, average reserve prices were 90% higher in the fast-start-pricing case than in the non-fast-start-pricing case, and payments were 119% higher.

4.2 Supply-side Factors

This section explores the key supply factors impacting energy market outcomes. Section 4.2.1 looks at trends in both fuel and emissions costs. Section 4.2.2 examines utilization rates of different generator technologies. Section 4.2.3 summarizes price-setting statistics by resource type. And lastly, Section 4.2.4 looks into priced versus unpriced offer behavior.

Key Takeaways

Fuel and Emissions Costs: Natural gas generation costs rose sharply in 2025, averaging \$49/MWh—up 105% from 2024—driven by elevated winter gas prices, pipeline constraints, and strong heating demand. Production costs peaked during the coldest periods (\$93/MWh in Q1 and \$57/MWh in Q4). Summer conditions supported relatively strong spark spreads (~\$23/MWh in Q3), particularly during peak hours when gas units were operating near full utilization. Although fuel prices eased after winter, average regional hub prices remained above 2024 levels throughout the year.

Emissions compliance costs also increased in 2025, with RGGI adding \$10.21/MWh to combined-cycle production costs and MA EGEL costs more than doubling to \$3.56/MWh. Higher allowance prices reflect tightening emissions limits and growing demand for allowances. As compliance costs rise and allowances become more scarce, less-efficient fossil fuel-fired generators may face increased pressure to reduce output, invest in lower-emitting technologies, or retire entirely.

Generator Utilization Trends: In 2025, generator utilization patterns reflected changing supply conditions and resource availability. Hydroelectric capacity factors declined due to drier weather, while single-fuel combined-cycle units operated at higher utilization following the retirement of the lower-performing Mystic units. Steam turbines also saw increased output, though they continued to operate at low utilization overall, with generation concentrated in winter months and during periods of elevated demand.

Price-Setting: Natural gas continued to play a central role in price formation in 2025; gas generators were marginal for 79% of load in the real-time market.

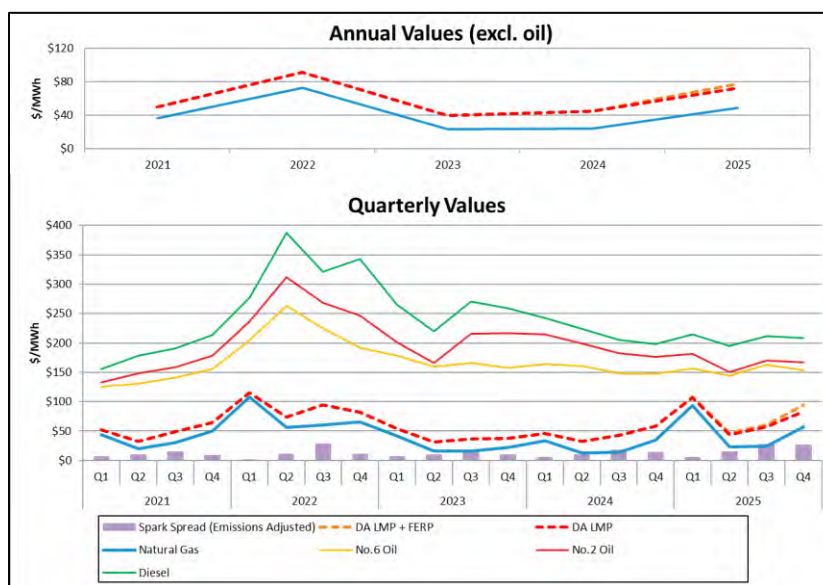
Non-Price-Setting Supply: Approximately two-thirds of total supply in both the day-ahead and real-time markets came from non-price-setting resources, consistent with prior years. The presence of large volumes of non-price-setting supply can lead to low or negative prices, although the frequency of negative prices remained relatively low in 2025.

4.2.1 Generation Costs and Profitability

Day-ahead and real-time electricity prices remain closely correlated with the estimated cost of operating a natural gas-fired generator. In 2025, natural gas-fired generators continued to be the dominant price setters and comprised half of total system supply. The relationship between

electricity prices and generation fuel costs is shown in Figure 4-5 below, alongside the estimated spark spread (gross margin) for an average natural gas-fired generator.¹²⁹

Figure 4-5: Estimated Generation Costs and On-Peak LMPs



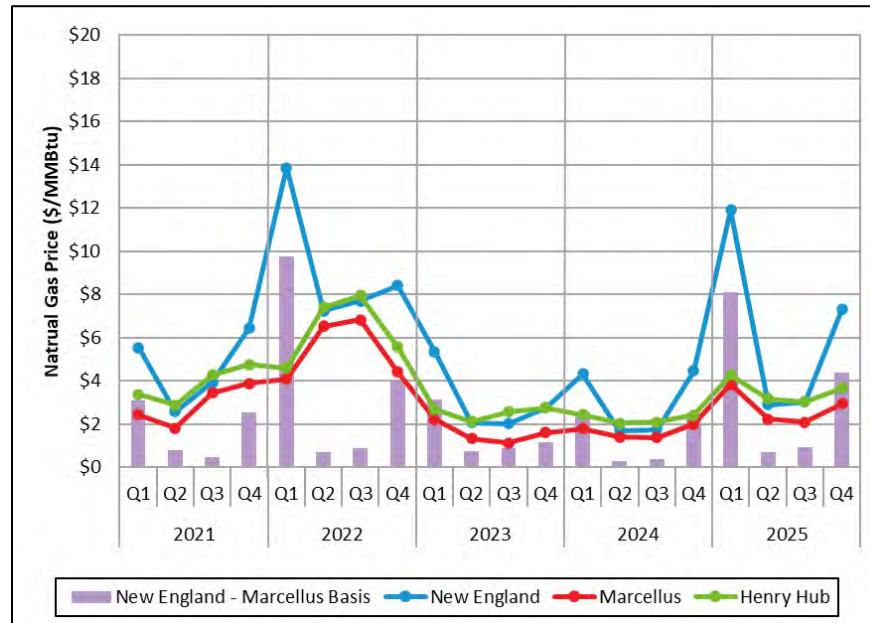
Natural gas generation costs increased sharply in 2025, averaging \$49/MWh (up 105% from 2024). This increase was in part due to elevated winter natural gas prices, with production costs peaking during the coldest months (\$93/MWh in Q1 and \$57/MWh in Q4) as pipeline constraints and strong heating demand tightened regional gas supply. Summer demand conditions supported relatively strong spark spreads (~\$23/MWh in Q3), with higher values occurring during peak load hours when gas-fired generators approached full utilization and higher-cost resources more frequently set marginal prices. Although natural gas costs decreased as winter conditions eased, monthly average regional hub prices remained above 2024 levels. Emissions costs also increased materially, representing a larger share of total gas-fired generation costs in 2025.¹³⁰

The relationship between New England gas prices and Henry Hub and Marcellus prices is shown in Figure 4-6 below.

¹²⁹ Variable generation costs are calculated by multiplying the average daily fuel price (\$/MMBtu) by the average standard efficiency of generators of a given technology and fuel type. Our standard heat rates are measured in MMBtu/MWh as follows: Natural Gas 7.8, Coal – 10.0, No. 6 Oil – 10.7, No. 2 Oil – 11.7. The spark spread is the difference between the day-ahead on-peak LMP and the fuel cost of a gas-fired generator with a heat rate of 7.8, adjusted for the additional estimated emissions costs of a standard gas-fired generator.

¹³⁰ ISO New England Inc., Internal Market Monitor, “Summer 2024 Quarterly Markets Report”, December 18, 2024, Section 4.1, <https://www.iso-ne.com/static-assets/documents/100017/2024-summer-quarterly-markets-report.pdf>.

Figure 4-6: New England vs. Henry Hub and Marcellus Natural Gas Prices



New England natural gas prices closely track upstream benchmark hub prices—particularly Marcellus—while exhibiting significant sensitivity to regional pipeline constraints during periods of elevated demand. In 2025, benchmark prices increased materially relative to 2024 (Henry Hub averaged \$3.53/MMBtu, up 57%; Marcellus averaged \$2.77/MMBtu, up 69%), reflecting tighter national market conditions. During the warmer months (Q2 and Q3), when demand is lower and pipeline capacity is generally unconstrained, basis differentials between New England and Marcellus hubs remained relatively narrow, indicating broad access to regional and national supply. In contrast, during colder months (Q1 and Q4), higher heating demand absorbs much of the available pipeline capacity, resulting in more frequent constraints and wider regional price differentials, consistent with observed winter deliverability limitations into New England.

Industry-Standard Profitability Metrics

Industry-standard profitability metrics for gas-fired generators include implied heat rates and spark spreads. Implied heat rates reflect the efficiency of a generator that would break even at given LMPs and gas prices after adjusting for estimated emission prices. Spark spreads reflect the gross profit margin between LMPs and gas prices for generators of a given heat rate. Notable reference heat rates include 7,800 Btu/kWh, the average heat rate for a typical New England natural gas generator, and 6,451 Btu/kWh, the standard efficiency of a new entrant combined cycle gas-fired generator. Emissions adjusted implied heat rates and corresponding spark spreads across these and other reference heat rates for 2021 through 2025 are shown in Table 4-2, reflecting how rising

natural gas prices and higher day ahead on peak LMPs in 2025 contributed to higher implied margins relative to 2024.¹³¹

Table 4-2: Annual Average On-Peak Implied Heat Rates and Spark Spreads (Clean)

Year	Day-Ahead On- Peak LMP (\$/MWh)	Day-Ahead On-Peak LMP plus FERP (2025, \$/MWh)	Gas Price (\$/MMBtu)	Implied Heat Rate with Emission Costs (Btu/kWh)	Spread (\$/MWh) corresponding to Heat Rate (Btu/kWh) (Emissions-adjusted)					
					6,451	7,000	7,800	8,000	9,000	10,000
2021	51.77	51.77	4.62	9,985	18.32	15.48	11.33	10.29	5.11	-0.08
2022	92.17	92.17	9.28	9,150	27.19	21.66	13.60	11.58	1.51	-8.56
2023	41.02	41.02	3.04	10,710	16.31	14.21	11.15	10.38	6.55	2.72
2024	46.62	46.62	3.06	10,878	18.97	16.62	13.19	12.34	8.05	3.76
2025	75.67	80.69	6.27	10,645	31.79	27.63	21.57	20.05	12.47	4.89

The average natural gas price increased from \$3.06/MMBtu in 2024 to \$6.27/MMBtu in 2025, an increase of about 105%, which largely explains the higher spark spreads observed in 2025 given that fuel cost increases are reflected in marginal energy prices.¹³² Over the same period, the day-ahead on-peak LMP increased from \$46.62/MWh to \$75.67/MWh, an increase of about 62%. The larger percentage increase in gas prices relative to LMPs is consistent with tighter winter pipeline conditions and higher benchmark hub levels in 2025, which increased generator production costs and, in turn, lifted day ahead on-peak prices.

Natural Gas Price-Adjusted LMP

Although there is a significant positive correlation between changes in LMPs and changes in natural gas prices, LMPs are also influenced by other factors such as shifts in the energy supply mix, emissions costs, system demand, and unforeseen events such as unplanned equipment outages. The gas price-adjusted LMP is a high-level metric used to estimate the impact of these non-gas price factors on the energy price and is shown in Figure 4-7 below.¹³³

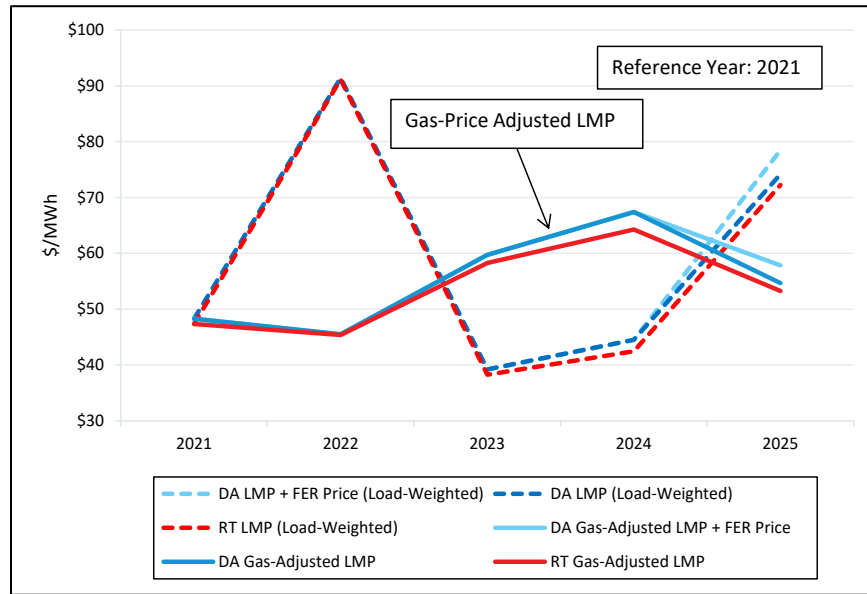
¹³¹ The IMM uses 7,800 Btu/kWh to represent the average heat rate of New England natural gas generators. The estimated new entrant combined cycle heat rate is provided in the ISO-NE Net Cone and ORTP Analysis performed by Concentric Energy Advisors, Inc. and cited in ISO filings to the Federal Energy Regulatory Commission for FCA 16. The analysis estimates that a new entrant combined-cycle unit would have a heat rate of 6,394 Btu/kWh in shoulder seasons, 6,573 Btu/kWh in summer, and 6,429 Btu/kWh in winter. Weighting these estimates by the number of days in a year yields an average heat rate of 6,451 Btu/kWh.

See: ISO New England Inc., “ISO Net CONE and ORTP Analysis – An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction FCA-16 and Forward”, December 2020”, p. 35, https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf

¹³² 2025 IHR and spark spreads reflect Day-Ahead on-peak LMPs inclusive of the Forecast Energy Requirement Price (FERP)

¹³³ The gas price-adjusted LMP is derived by dividing the reference year natural gas price (2020) by the current year natural gas price, then multiplying by the load-weighted LMP.

Figure 4-7: Annual Average Natural Gas Price-Adjusted LMPs



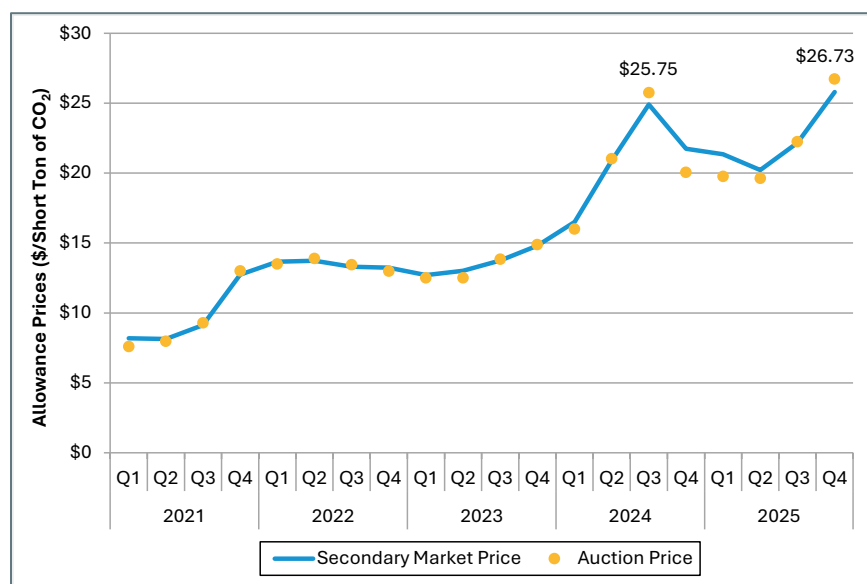
In 2025, gas-adjusted LMPs declined to \$54.68/MWh in the day-ahead market and \$53.26/MWh in the real-time market. The difference between nominal and gas-adjusted LMPs indicates that higher natural gas prices were the primary source of upward pressure on LMPs in 2025. This result is consistent with natural gas continuing to serve as the marginal price-setting fuel in New England, while also indicating that non-fuel factors continued to influence energy price outcomes. The year also continued the pattern of day-ahead LMPs exceeding real-time LMPs (see Section 4.1). While natural gas prices increased in 2025 relative to 2023–2024, the decline in gas-adjusted LMPs indicates that underlying market conditions such as behind-the meter solar generation—separate from fuel price increases—exerted downward pressure on energy prices.

Regional Greenhouse Gas Initiative (RGGI) Prices

The RGGI program is the primary source of emission costs for fossil fuel-fired generators in New England.¹³⁴ Average annual RGGI allowance prices have risen in each of the past 5 years, as shown in Figure 4-8. In 2025, RGGI allowance prices rose slightly (6.5%), from an average of \$21.01 per short ton of CO₂ in 2024 to \$22.38 per short ton in 2025.

¹³⁴ The Regional Greenhouse Gas Initiative, “*Elements of RGGI*” webpage, <https://www.rggi.org/program-overview-and-design/elements>

Figure 4-8: Regional Greenhouse Gas Initiative (RGGI) Prices



Prices increased steadily in the last three quarters of 2025, peaking in the fourth quarter with a secondary market price of \$25.79/short ton of CO₂. The December RGGI auction cleared at \$26.73/short ton, about a dollar more than the previous highest auction clearing price from the third quarter of 2024.

The higher RGGI prices exhibited in 2025 are due to a combination of the following market dynamics:

- Reduced future emissions limits:** The third RGGI program review, completed in July 2025, set stricter emissions limits than those implemented after the 2017 program review.¹³⁵ These stricter limits begin in 2027 when the emissions cap will be 69.8 million short tons of CO₂, compared to 75.7 million short tons under the previous rule. From 2027, the emissions cap will decrease at a steeper rate (10.5% through 2033) than originally planned. By 2037, the allowance cap will be about 9 million short tons of CO₂, with an additional 23.5 million allowances potentially available each year through the Cost Containment Reserve.
- Increased demand for allowances:** While the RGGI CO₂ emissions cap decreases each year, emissions from generators in New England increased by an estimated 3% (to 27 million short tons of CO₂) in 2025 compared to 2024. Generator emissions in all RGGI states increased by about 5% to approximately 87 million short tons of CO₂.¹³⁶
- Allowance cost controls:** The Cost Containment Reserve (CCR), a mechanism to help moderate price spikes by releasing additional allowances, was fully depleted in the first auction of the year.

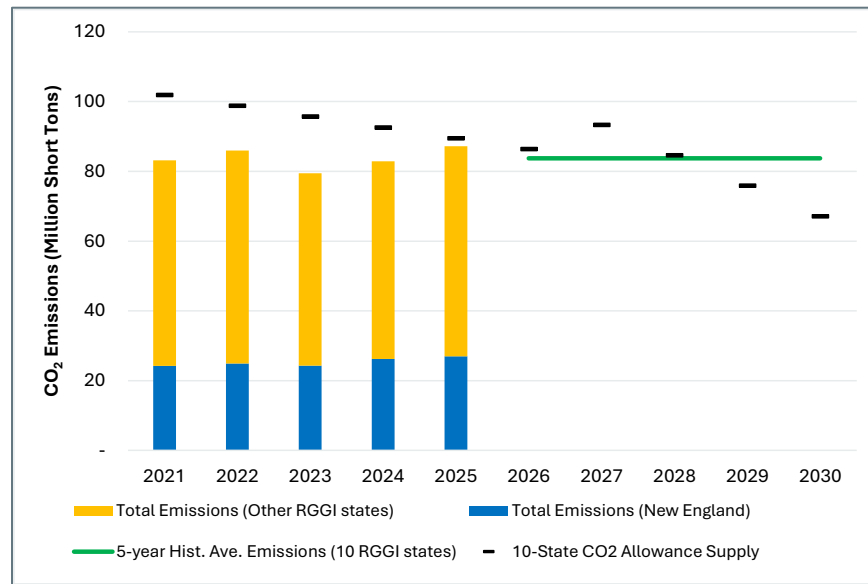
¹³⁵ The Regional Greenhouse Gas Initiative, “Program Review” webpage, <https://www.rggi.org/program-overview-and-design/program-review>.

¹³⁶ Annual emissions data are taken from EPA. Environmental Protection Agency, Clean Air Markets Program Data, “Power plant emissions, compliance, and allowance data” webpage, <https://campd.epa.gov/>.

When prices later in the year exceeded the CCR trigger of \$17.03/short ton, no additional supply was available to moderate the price increase.¹³⁷

Overall, clearing prices reflect electricity generators' compliance needs and market expectations. Decreasing allowance caps will create increased scarcity and put upward pressure on allowance prices. In Figure 4-9 we show the total supply of allowances each year (the allowance cap plus all allowances from the CCR) compared to actual emissions in the RGGI states.¹³⁸

Figure 4-9: RGGI Emissions Levels and Allowance Supply



In 2025, total estimated emissions (approximately 87 million short tons of CO₂) across the 10 RGGI states came close to the total number of allowances available (about 89.5 million allowances, including the CCR). The total allowance supply will increase in 2027, before decreasing in each following year.¹³⁹ The figure shows that by 2029 total emissions from RGGI states could exceed the number of available allowances if emissions levels track closely to the five-year average.

As allowances become increasingly scarce and expensive, generators that are either unable or unwilling to purchase higher-priced allowances will need to reduce emissions—either by investing in more efficient, lower-emitting technologies or by reducing output. Over time, these market dynamics could render some less-efficient fossil fuel-fired generators uneconomic, ultimately leading to their retirement.

¹³⁷ The CCR will be replenished in March 2026. Potomac Economics, “Market Monitor Report for Auction 67”, March 14, 2025, p. 3, https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/67/Auction_67_Market_Monitor_Report.pdf.

¹³⁸ The figure includes only the ten RGGI states that have participated in RGGI continuously since 2021. The CO₂ allowance supply for 2021 to 2023, when Virginia was a member state, has been prorated to exclude Virginia.

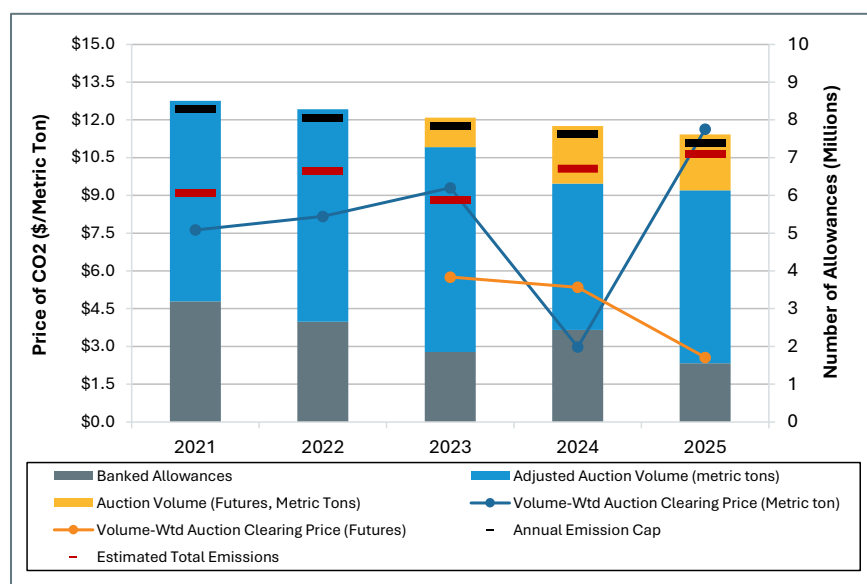
¹³⁹ One outcome of the Third Program Review, completed in July 2025, was an increase in the number of allowances in the CCR. Currently there is one tier of the CCR sized at 10% of the regional allowance cap (in 2025, the CCR contained about 7.8 million allowances). Starting in 2027 there will be two tiers of the CCR, each composed of 11.75 million allowances.

Massachusetts EGEL (MA EGEL) Prices (310 CMR 7.74)

In addition to the RGGI program, Massachusetts generators must also comply with requirements administered by the Massachusetts Department of Environmental Protection (MassDEP).¹⁴⁰ The MA EGEL program places an annual cap on aggregate CO₂ production for the majority of fossil fuel-fired generators within the state.¹⁴¹ The cap will be lowered every year until the target annual CO₂ emission rate is reached in 2050.¹⁴²

The annual quantity and volume-weighted clearing prices for CO₂ allowances sold as current and future vintages during the MA EGEL auctions, as well as the quantity of banked allowances carried over from prior compliance periods, are shown in Figure 4-10 below.¹⁴³

Figure 4-10: Massachusetts EGEL Auction Results



Notes: The volume-weight auction clearing price for futures and the volume of future allowances reflect the price and quantity of allowances sold as futures for the year shown on the x-axis. For example, the auction volume of futures shown in the 2025 column reflects the volume of 2025 allowances sold as futures during the 2024 auctions.

The average 2025 volume-weighted auction price for current vintage allowances increased 290% year-over-year to \$11.63/metric ton of CO₂, the highest average annual auction price observed to date. The average annual prices shown in the figure reflect the clearing price of each of the eight

¹⁴⁰ Massachusetts Department of Environmental Protection (MassDEP), “Electricity Generator Emissions Limits (310 CMR 7.74)” webpage, <https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774>

¹⁴¹ Participating generators are fossil fuel-fired generators with a nameplate capacity of 25 MW or more. Massachusetts Department of Environmental Protection, (MassDEP), “310 CMR 7.00: Air Pollution Control”, <https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download>.

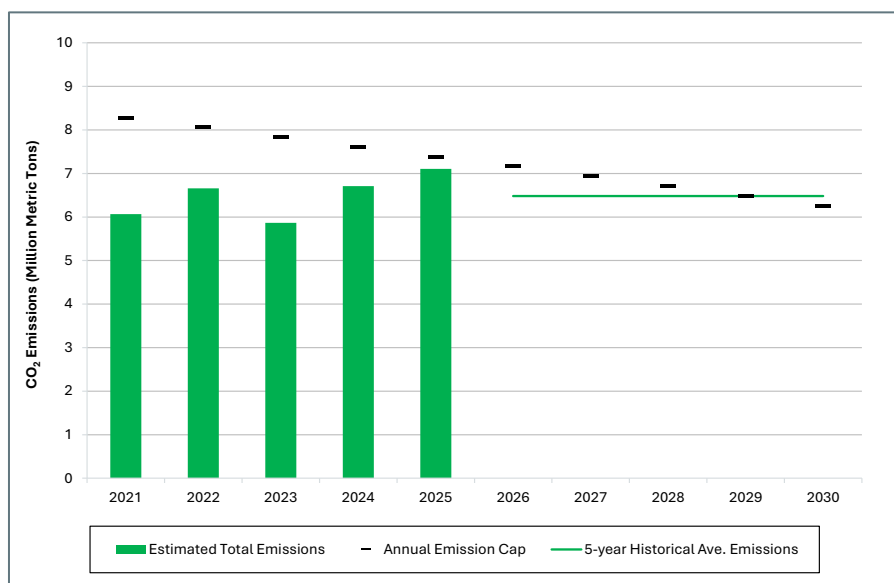
¹⁴² The annual emissions cap for 310 CMR 7.74 will reduce by 223,876 metric tons in each subsequent year, eventually reaching 1,791,019 metric tons in 2050.

¹⁴³ MA EGEL holds auctions in March, June, September, and December of each year. During each auction it sells a certain quantity of the current year’s vintage of allowances as well as (starting in mid-2022) a smaller quantity of the future year’s vintage of allowances. For example, 2025 allowances were sold as futures in the December 2023 and March, June, and September 2024 auctions and as the current vintage in the December 2024 and March, June, and September 2025 auctions.

quarterly auctions in which allowances for a given year are sold. Clearing prices for 2025 allowances in the quarterly auctions ranged from \$1.75-\$5.50/metric ton when sold as futures in the 2024 auctions but jumped to \$6.06-\$15.03/metric ton when sold as the current vintage in the 2025 auctions. Prices for 2026 allowances (not shown in figure) have also increased, selling for \$4.99-\$12.00/metric ton as futures and for \$22.00/metric ton as the current vintage in the December 2025 auction. The \$22.00/metric ton clearing price was the highest observed to date.

Like RGGI, MA EGEL clearing prices reflect electricity generators' compliance needs and market expectations. As noted above, increased emissions in 2025 have likely created some near-term scarcity pressure and an expectation that allowances surpluses will continue to shrink.¹⁴⁴ While generators continue to factor allowance costs into their energy market offers,¹⁴⁵ the thin secondary market could expose participants needing additional allowances to significant price premiums in the future.¹⁴⁶ Figure 4-11 shows the annual emissions cap for the past five years and next five years, compared to actual emissions.

Figure 4-11: MA EGEL Emissions Levels and Cap



In 2025, estimated emissions in Massachusetts from regulated resources reached 96% of the 2025 emissions cap. Assuming future annual emissions equal to the average of the past five years' actual emissions, Massachusetts generators would reach the annual cap in 2029.

¹⁴⁴ Potomac Economics, "Market Monitor Report on the Electricity Generator Emissions Limits Program (310 CMR 7.74): Auction 2026-1", December 12, 2025, <https://www.mass.gov/doc/market-monitor-report-auction-2026-1/download>.

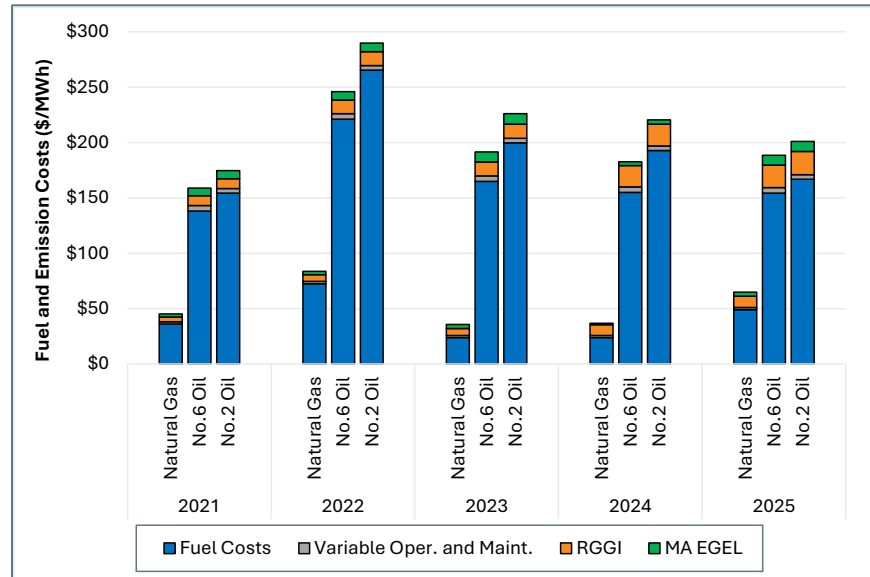
¹⁴⁵ To incorporate the cost of these allowances into generator reference levels, the IMM uses an adder that values the allowances based on recent trades and auction results.

¹⁴⁶ Potomac Economics, "Quarterly Report on the Electricity Generator Emissions Limits Program (310 CMR 7.74) Third Quarter 2025", November 2025, <https://www.mass.gov/doc/market-monitor-quarterly-report-2025-q3/download>.

Impact of Carbon Emissions Programs on Generator Operating Costs¹⁴⁷

Our estimates of the average annual cost of emissions compliance by generator fuel type for both carbon programs are illustrated in Figure 4-12 below.

Figure 4-12: Annual Estimated Average Costs of Generation and Emissions¹⁴⁸



2025 Emissions Costs	Natural Gas	No. 6 Oil	No. 2 Oil
RGGI Costs (\$/MWh)	\$10.21	\$20.44	\$21.08
RGGI % of Generation Costs	17%	11%	11%
MA EGEL Costs (\$/MWh)	\$3.56	\$8.70	\$8.97
Total CO ₂ % of Generation Costs	21%	15%	15%

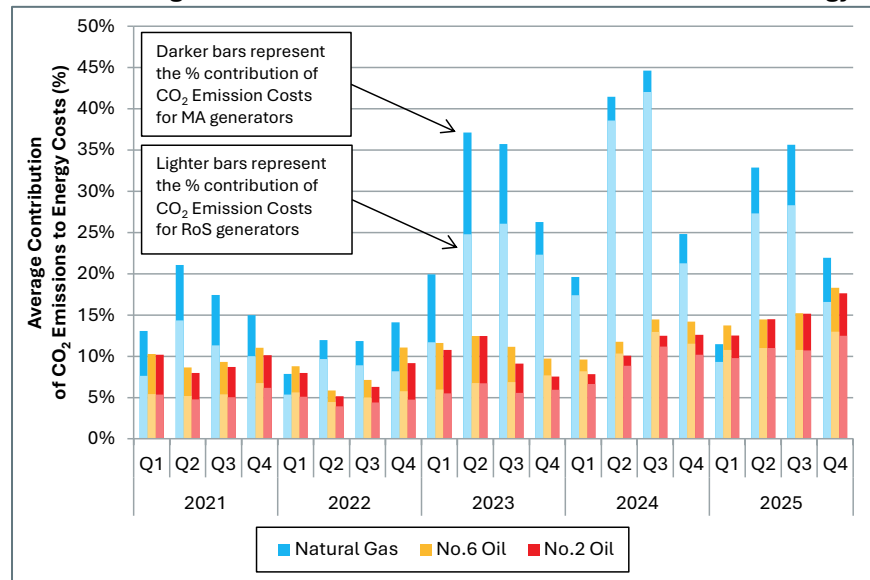
In 2025, RGGI compliance costs added \$10.21/MWh to the production cost of an average natural gas combined-cycle unit, a slight increase from \$9.59/MWh in 2024. MA EGEL compliance costs more than doubled over the same period, reaching \$3.56/MWh for a combined-cycle unit. Despite increased emissions costs, those costs represented a smaller proportion of total generation costs for natural gas generators in 2025 compared with 2024, due to a larger rise in natural gas fuel costs (up 105% year-over-year). The contribution of emissions costs decreased 10 percentage points (from 27% to 17%) for natural gas generators participating only in RGGI, and about 9 percentage points (from 30% to 21%) for natural gas generators in Massachusetts that were subject to both carbon programs.

¹⁴⁷ Fuel, CO₂ emission, and variable operating and maintenance costs are considered when calculating the costs for each generator. Variable operating and maintenance costs represent a small percentage of costs for generators. CO₂ prices in \$/short ton are converted to estimated \$/MWh using average generator heat rates for each fuel type and an emissions rate for each fuel.

¹⁴⁸ IMM standard generator heat rates and fuel emission rates are used to convert \$/ton CO₂ prices to \$/MWh generation costs. The RGGI adder for a coal generator is about \$22/MWh. Due to little remaining capacity, it is no longer shown in these exhibits.

The contribution of CO₂ emission costs to energy production costs at a quarterly level is detailed in Figure 4-13.

Figure 4-13: Estimated Average Percent Contribution of CO₂ Emission Costs to Energy Production Costs



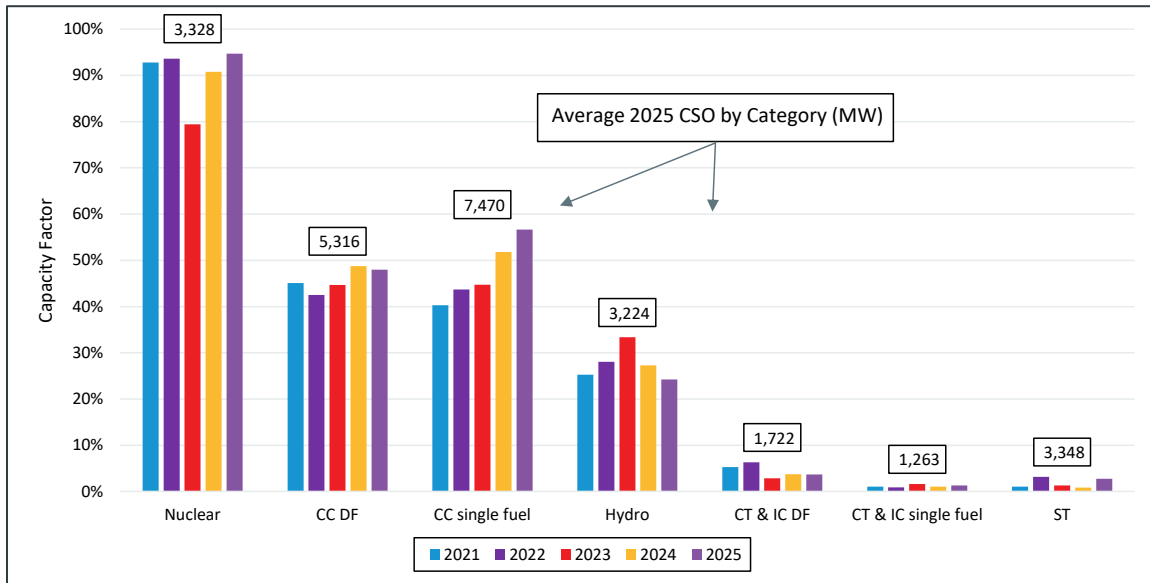
This graph illustrates how the share of total natural gas generator costs coming from emissions costs spikes in the second and third quarters of each year, when natural gas prices tend to be lower. In contrast, because oil prices have declined slightly over the past two years, the contribution of emissions costs to oil generator costs has increased in line with rising emissions costs.

4.2.2 Capacity Factors

Capacity factors provide a high-level view of the relative economics and physical capabilities of generators.¹⁴⁹ Average capacity factors by generator type are shown in Figure 4-14 below.

¹⁴⁹ For the purposes of this section, capacity factor is measured as the ratio of a generator's average hourly output relative to their total capacity supply obligation (CSO). Although this can result in high capacity factors for individual resources with a low portion of their capacity contracted through capacity supply obligations, at the fleet level the results represent the portion of the contracted capacity that is typically operating.

Figure 4-14: Capacity Factor by Generator Type



Hydro capacity factors fell to 24% from 27% in 2025 following drier conditions. Single-fuel combined-cycle capacity factors increased significantly in 2025, from 52% to 57%, primarily due to the retirement of the Mystic generators, which had two of the lowest four capacity factors of any single-fuel combined cycle units in 2023. Steam turbines also saw an increase in capacity factors, from about 1% to about 3% in 2025. Over half of steam turbine generation was in the winter months (about 30% in December and 25% in January) with June and July accounting for an additional third of steam turbine generation.

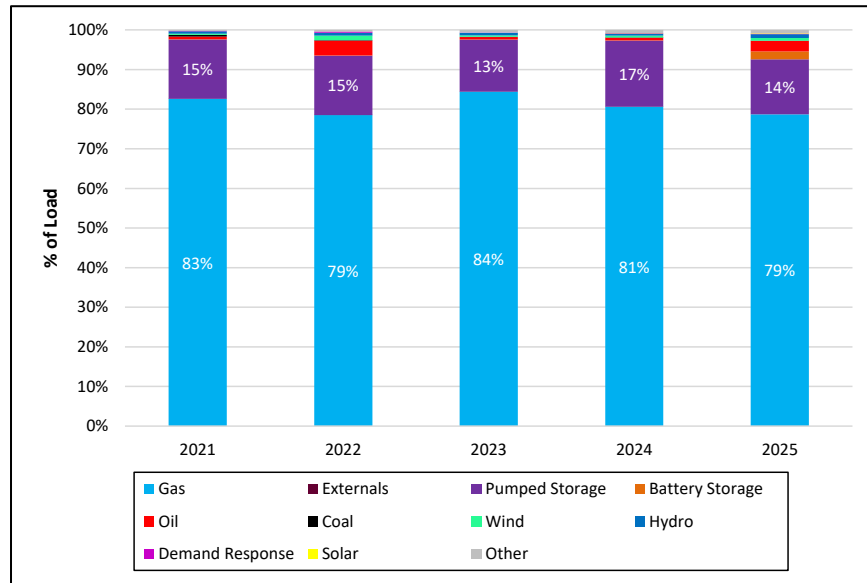
4.2.3 Marginal Resources

The price of energy is largely determined by the marginal resource (i.e., the resource that would provide the next increment of energy). Consequently, trends in marginal resources can provide important insights into changes in energy prices over time. Below, we present statistics on marginal resources by transaction and fuel type in the real-time energy market.¹⁵⁰

The percentage of load for which each transaction type was marginal in the real-time energy market over the last five years is illustrated in Figure 4-15 below.

¹⁵⁰ The statistics presented in this section are calculated on a load-weighted basis. When more than one resource is marginal, the system is typically transmission-constrained and marginal resources likely do not contribute equally to setting price for load across the system. The methodology employed in this section accounts for these differences, weighting the contribution of each marginal resource based on the amount of load in each constrained area.

Figure 4-15: Real-Time Marginal Resource by Transaction Type



Gas-fired generation set price for 79% of real-time load and pumped storage set price for 14% of load, consistent with averages over the last several years. Oil-fired generators were marginal for 3% of load, marking a higher share than the last two years and reflecting winter conditions that were relatively similar to Winter 2022.

Battery storage resources set price for 2% of load. Batteries have increasingly set price throughout 2025 as large battery facilities have come online and have an increasing share of the supply mix. In general, batteries charge when LMPs are low and discharge when LMPs are high. Therefore, batteries are frequently close to the marginal price of supply during daily peak periods.

4.2.4 Supply-Side Participation

Some resources are willing to clear in the energy market at any price (price-taking), while others offer supply at a specific price that is used in the market clearing engine to determine commitment and dispatch. The volumes of price-setting vs. non-setting price supply on the system have important implications for price formation. For example, if most supply cannot set price, there is a higher likelihood of low or negative LMPs.

In 2025, non-price-setting-supply made up 66% of total supply in the day-ahead energy market and 65% in the real-time energy market. Non-price-setting supply consists of offers from suppliers that are willing to sell at any price, as well as offers that cannot set price. Market supply may be insensitive to price for several reasons, including fuel and power contracts, hedging arrangements, unwillingness to cycle (on and off) a generator, or operational constraints. The remaining 34-35% of supply is considered price-setting supply (i.e., it is willing to sell at a specified offer price or higher and can set price).

There are three categories of *non-price-setting* supply: fixed imports, self-scheduled generation, and generation-up-to economic minimum.

- **Fixed imports** are scheduled to flow power into New England on the external interfaces regardless of price.

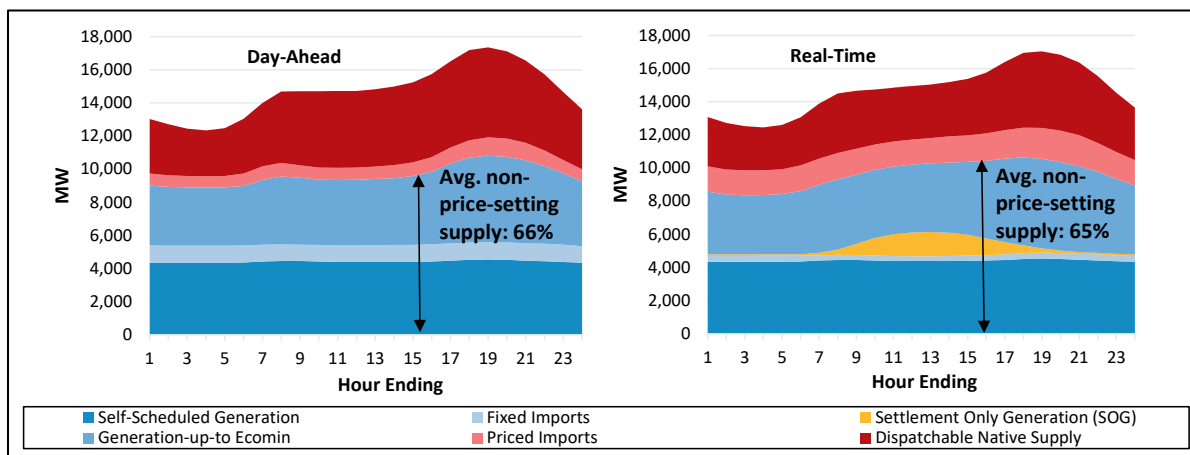
- **Self-scheduled generation** is offered into the energy market as must-run generation. Generators self-schedule at their economic minimum (EcoMin).¹⁵¹
- **Generation-up-to economic minimum** from economically-committed generators is the portion of output that is below EcoMin.¹⁵²

There are two categories of *price-setting* supply that participate in price formation: dispatchable native supply and priced imports.

- **Dispatchable native supply** is energy from generators, demand response resources (DRRs), and virtual transactions (day-ahead market only) that is dispatched economically (based on its offer price). For generators and DRRs, this is energy delivered at levels within the resource’s dispatchable range, above EcoMin.
- **Priced imports** include price-sensitive imports and up-to-congestion transactions.^{153, 154}

An hourly average breakdown of price-setting and non-price-setting supply by category for the day-ahead and real-time markets in 2025 is provided in Figure 4-16 below.

Figure 4-16: Day-Ahead and Real-Time Supply Breakdown by Hour Ending, 2025



On average, non-price-setting supply made up 66% of total supply in the day-ahead market and 65% of total supply in the real-time market. These shares remained similar to 2024. Price-setting supply averaged 35% of total supply over all hours in the real-time market in 2025, with its share peaking in hours ending (HE) 18-22 at 37-38%.

¹⁵¹ The Economic Minimum (EcoMin) is the minimum MW output available from a generator for economic dispatch.

¹⁵² For example, if a unit generating 150 MW has an EcoMin of 100 MW, then its generation-up-to EcoMin is the portion below 100 MW. Generation-up-to EcoMin does not participate in price formation, as the market software cannot dispatch it up or down.

¹⁵³ Up-to-congestion (UTC) transactions are external contracts in the day-ahead energy market that do not flow if the congestion charge is above a specified level. Real-time external transactions cannot be submitted as up-to-congestion contracts. Participants with real-time external transactions are considered willing to pay congestion charges.

¹⁵⁴ There are some nuances to the priced imports category in terms of price-setting ability. While priced imports regularly set price in the day-ahead market, they rarely set price in real-time market. This is because the tie lines are scheduled in advance of the delivery interval in real time and are given a small dispatchable range in the real-time dispatch and pricing algorithm. This prevents the market software from dispatching the tie lines far away from the scheduled amount determined by the transaction scheduling process.

In both markets, the daily ramp-ups in load are typically met by additional supply from *generation-up-to EcoMin* (as additional generators are committed) and *price-setting* supply. In the day-ahead market, the level of supply from *self-scheduled* generation (the largest component of unpriced supply) and *fixed imports* was reasonably stable over the course of an operating day. A majority of unpriced supply tends to be from nuclear generators whose production is stable throughout the day. By contrast, in the real-time market, average hourly self-scheduled generation was higher during midday due to output from settlement-only solar generators (SOGs).¹⁵⁵ In 2025, hourly SOG output averaged 531 MW, or 11% of total real-time self-scheduled generation. SOG generation is higher in the middle of the operating day, peaking at an average of 1,461 MW in HE 13. These smaller generators do not clear in the day-ahead market because they are not modeled in the market nor centrally dispatched by the ISO control room.¹⁵⁶

Unpriced Supply and Price Formation Implications

Large volumes of non-price-setting supply can increase the likelihood of low or negative prices. This may become more common when combined with significant amounts of additional capacity from renewable generation (e.g., wind and solar) with low marginal costs. However, we generally find that energy price formation is robust under current levels of unpriced supply, with prices reflecting the marginal input costs of the highest cost resources dispatched to meet demand.

The combination of lower loads and large amounts of non-price-setting generation can bring about a sudden drop in prices, to low or even negative levels. However, the overall frequency of negative real-time prices at the Hub remains relatively low. Negative prices at the Hub occurred in 0.8% of five-minute real-time pricing intervals in 2025. Even in Maine, which tends to have a higher frequency of negative nodal prices at export-constrained pockets with wind generation, the zonal price was negative in only 1.5% of five-minute real-time pricing intervals in 2025. The frequency of negative LMPs is discussed further in Section 2.5.

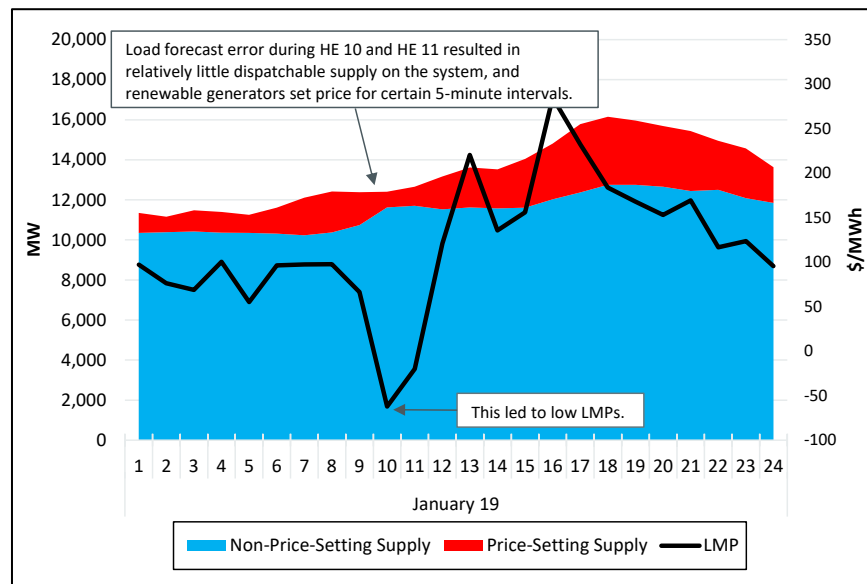
The example shown in Figure 4-17 below illustrates low pricing at a time when a significant amount of non-price-setting supply combined with negative priced energy supply offers to result in low LMPs.¹⁵⁷

¹⁵⁵ See Section 1.6 for a discussion on solar generation and changing demand.

¹⁵⁶ SOGs are passive participants in the real-time energy market only.

¹⁵⁷ Unlike the figure above, this figure includes all imports in the fixed supply category for convenient illustrative purposes.

Figure 4-17: Priced and Unpriced Supply vs. Real-Time LMP, January 19, 2025



On January 19, load-serving entities cleared excess load in the day-ahead market due to warmer than forecasted temperatures. Real-time loads were lower than the ISO’s load forecast, especially during HE 10 and HE 11. As a result, real-time generation needs were less than the amount that cleared in the day-ahead market, and the ISO only had to dispatch a small amount of price-setting generation throughout the morning. The small amount of economically dispatched generation offered into the market at low values, resulting in low prices. The five-minute Hub LMP ranged from -\$99.49/MWh to \$0.00/MWh from 9:00 am to 10:35 am, and the hourly price averaged -\$66.11/MWh and -\$20.00/MWh during HE 10 and HE 11, respectively.

4.3 Demand-side Factors

This section explores key factors influencing demand levels and behavior in the energy markets. Section 4.3.1 analyzes the impact of weather and behind-the-meter solar generation on load. Section 4.3.2 takes a deeper look at the nature of demand-side participation.

Key Takeaways

Demand Trends: Average and peak load levels increased in 2025, with annual load rising from 13,299 MW in 2024 to 13,441 MW in 2025, just a 1% increase. Peak load reached 26,086 MW on June 24, 2025, the highest level since 2013. Weather-normalized load also increased modestly. Behind-the-meter (BTM) solar continued to lower wholesale load during daytime hours and shape intraday load profiles across all seasons, with growing impacts on both morning downward ramps and evening upward ramps.

Demand Bidding: Load Serving Entities (LSEs) continued to clear more demand in the day-ahead market relative to real-time load. Additionally, demand bidding remained mostly insensitive to prices with fixed-priced bids continuing to make up the largest share of day-ahead cleared demand. Virtual demand, exports and asset-related demand continued to provide important price-elasticity to the demand side.

4.3.1 Load and Weather Conditions

Net Energy for Load (NEL) averaged 13,441 MW in 2025, a 1% increase from 2024. The trends in New England’s annual load levels are shown in Table 4-3 below.^{158, 159}

Table 4-3: Average, Peak and Weather-Normalized Load

Demand (MW)	2021	2022	2023	2024	2025	% Change '24 to '25	Sparkline
Load (avg. hourly)	13,561	13,576	13,096	13,299	13,441	↑ 1%	
Weather-normalized load (avg. hourly)	13,419	13,514	13,132	13,236	13,394	↑ 1%	
Peak load (MW)	25,801	24,780	24,043	24,871	26,586	↑ 7%	
Minimum load (MW)	8,646	8,694	8,617	8,775	7,684	→ -12%	

Weather-normalized load averaged 13,394 MW, nearly identical to actual load, indicating that weather conditions were close to seasonal norms throughout the year. Peak load increased to 26,586 MW on June 24 during the PFP event, representing a 7% rise from 2024 and marking the highest level recorded since 2013.¹⁶⁰ Minimum load fell to 7,684 MW on April 20 during mild spring conditions, setting a new record low as strong behind-the-meter (BTM) solar output significantly reduced midday system demand,¹⁶¹ with BTM solar systems lowering demand by an estimated 4,586 MW during the minimum-load hour.

Demand Profiles and Energy Prices

The connection between load levels and energy prices becomes particularly clear when examining hourly operating-day conditions. Figure 4-18 shows the average time-of-day profile for both day-ahead demand and real-time load compared to day-ahead and real-time LMPs, along with average hourly load reductions from behind-the-meter (BTM) solar generation. The figure is broken out into winter, summer, and rest-of-year averages to illustrate seasonal differences in load curves, prices, and solar generation.¹⁶²

¹⁵⁸ In this analysis, load refers to *net energy for load* (NEL). NEL is calculated by summing the metered output of native generation, price-responsive demand and net interchange (imports – exports). It excludes pumped-storage demand.

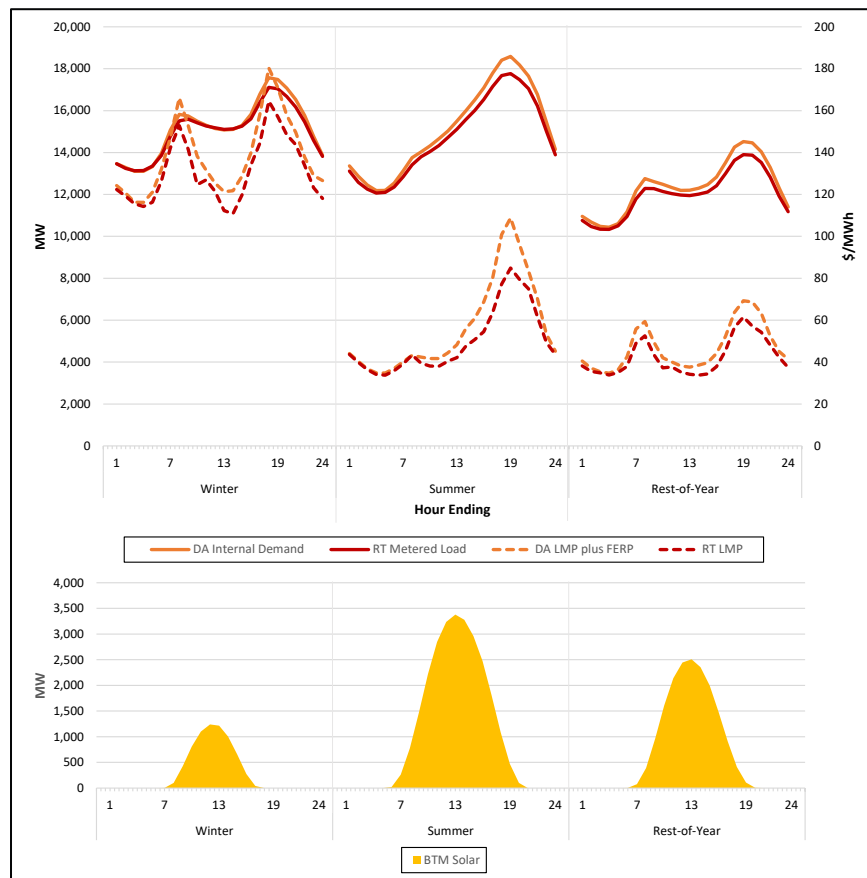
¹⁵⁹ Weather-normalized load estimates what load would be if monthly total heating degree days and cooling degree days were in line with historical averages. The estimate also factors in differences due to non-holiday weekdays and leap days.

¹⁶⁰ The region experienced exceptionally high electricity demand during a July 15–20, 2013 heat wave. The system reached a summer peak of 27,360 MW on July 19, 2013, marking the fourth-highest demand day ever recorded. ISO New England Inc., Internal Market Monitor, “2013 Annual Markets Report”, May 6, 2014, https://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2013/2013_amr_final_050614.pdf.

¹⁶¹ For context, ISO New England has reported historically low system demand, including this new record low. ISO New England Inc., ISO Newswire, “New England grid sees new record low for system demand”, April 22, 2025, <https://isonewswire.com/2025/04/22/new-england-grid-sees-new-record-low-for-system-demand/>

¹⁶² Winter seasons include December, January, and February; summer seasons include June, July, and August.

Figure 4-18: Average Demand and LMP by Hour, 2025¹⁶³



BTM solar generation continued to influence the wholesale load profile even in winter months in 2025, with an average of over 1,000 MW of BTM generation at noon and corresponding dips in midday load.¹⁶⁴ Summer months had both the highest load and ramps, with average peak load well over 18,000 MW. While summer BTM solar typically peaked well over 3,000 MW, peak loads did not typically fall midday in summer as air conditioning demand sharply increased. For “Rest-of-Year” peak loads typically occurred midday with over 2,500 MW of BTM generation.

Across all seasons, day-ahead and real-time prices follow load profiles, with lower LMPs during peak solar hours in winter and rest-of-year and sharply increasing evening LMPs in summer. Figure 4-18 also shows that day-ahead LMPs typically exceeded real-time LMPs as discussed in Section 4.1, and cleared demand typically exceeded real-time load as discussed further in Section 4.3.2.

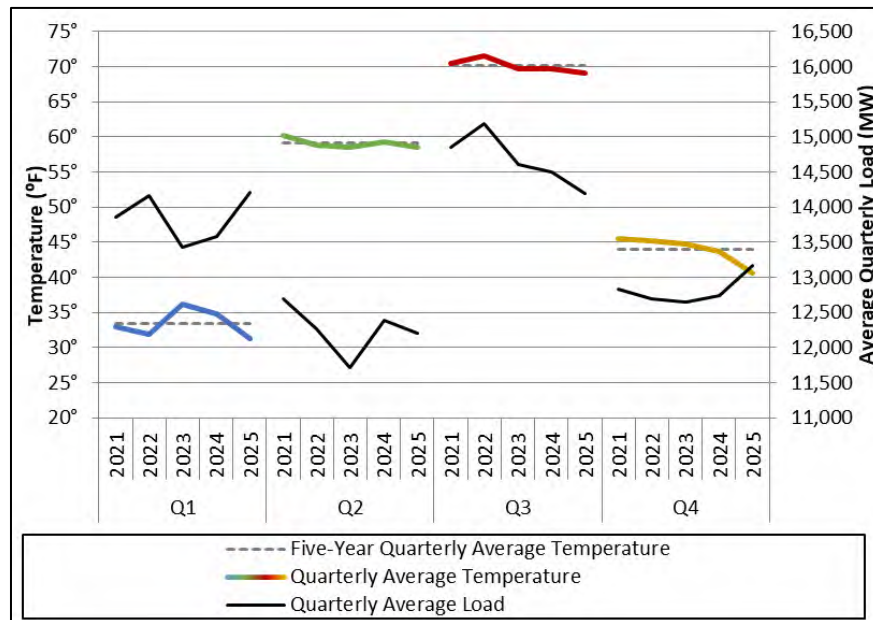
¹⁶³ Day-ahead internal demand is equal to fixed demand + price-sensitive demand + virtual demand. This includes pumped-storage demand and excludes virtual demand at external nodes. Real-time load is the total end-use wholesale electricity load within the ISO New England footprint.

¹⁶⁴ The ISO does not meter output from BTM solar installations or directly measure BTM capacity. For details on behind-the-meter estimation methods, see: ISO New England Inc., “Load Forecast” webpage, <https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/>.

Impact of Weather

Weather is a significant driver of load in New England. Loads are significantly impacted by air conditioning demand in hot weather and electric heating demand in cold weather. Quarterly average and five-year average temperatures for 2021 through 2025 are illustrated in Figure 4-19 below.¹⁶⁵

Figure 4-19: Seasonal vs. Five-Year Average Temperatures



Weather conditions in 2025 were colder than in 2024, contributing to higher average loads in the winter quarters (Q1 and Q4) and lower average loads in Q2 and Q3. Winter conditions in Q1 were 4°F colder than in 2024, with average temperatures just below freezing (31°F). As electrification of heating continues to expand, winter demand levels—and their sensitivity to temperature—are expected to rise. Summer conditions in Q3 were mild on average, although broadly consistent with 2024, with average hourly loads of approximately 14,200 MW. While these averages suggest a milder summer overall, they do not fully capture the variability in actual load during Summer 2025. High temperatures were concentrated in fewer days, with periods of intense heat and humidity surpassing the previous summer.¹⁶⁶

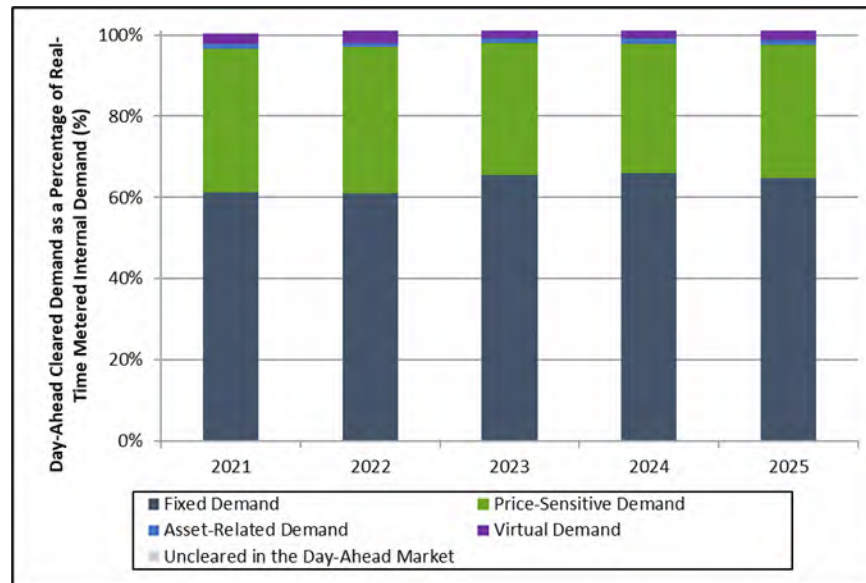
¹⁶⁵ As of July 27, 2023, the ISO calculates New England average temperatures based on new methodology and data collection that incorporates observations from 23 cities. ISO New England Inc., ISO Newswire, “ISO-NE weather forecast improvements aid grid operations”, July 27, 2023, <https://isonewswire.com/2023/07/27/iso-ne-weather-forecast-improvements-aid-grid-operations/>.

¹⁶⁶ ISO New England Inc., Internal Market Monitor, “Summer 2025 Quarterly Markets Report”, November 12, 2025, [2025-summer-quarterly-markets-report.pdf](#)

4.3.2 Demand Bidding

The quantity and pricing of bid-in demand in the day-ahead market have important implications for both price formation and system operations. Day-ahead cleared demand by bid type as a percentage of real-time load is shown below in Figure 4-20.¹⁶⁷

Figure 4-20: Day-Ahead Cleared Demand as a Percentage of Real-Time Load by Bid Type



When real-time demand exceeds day-ahead cleared demand, higher cost resources may need to be dispatched to meet the energy gap, resulting in higher real-time energy prices relative to day-ahead prices. Demand activity can also directly influence price formation. In 2025 Fixed demand declined from 66.0% to 64.9%, while priced demand increased from 31.9% to 32.8%. Asset-related demand decreased slightly from 1.3% to 1.1%. The most notable change was in virtual demand, which increased from 2.6% to 3.7%, indicating a larger role for virtual activity in day-ahead demand outcomes in 2025.¹⁶⁸

Participants cleared 102% of real-time load in the day-ahead market in 2025, continuing a pattern of modest over clearing observed in recent years. Day-ahead fixed demand, priced demand, and asset-related demand together accounted for nearly all of real-time load, indicating that over clearing continues to be driven primarily by virtual demand rather than shifts in underlying physical demand.¹⁶⁹

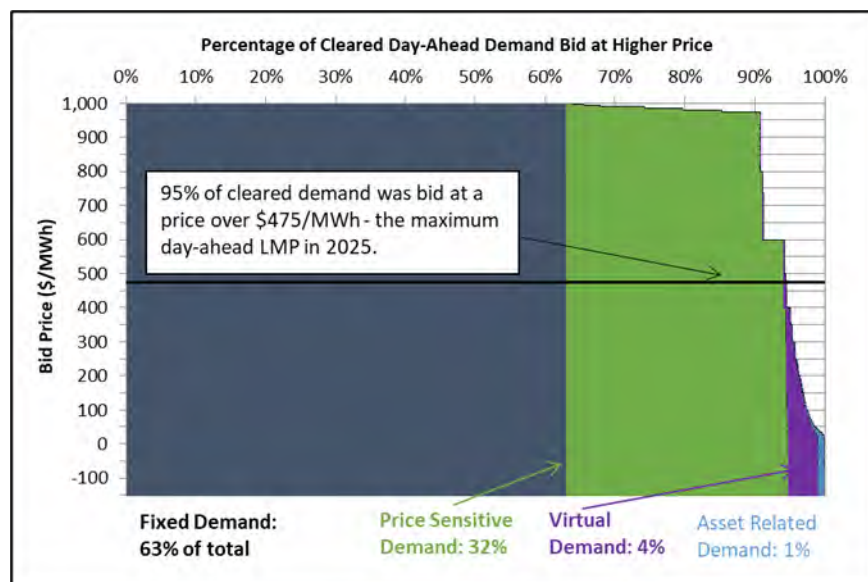
Aggregating cleared demand components by price provides additional insight into bidding behavior and the price sensitivity of demand. Figure 4-21 aggregates annual cleared demand by bid price.

¹⁶⁷ Real-time load is the total end-use wholesale electricity load within the ISO New England footprint. Real-time load is equal to Net Energy for Load – Losses.

¹⁶⁸ See Section 4.2.3 for a discussion of marginal resources and price-setting load.

¹⁶⁹ For more information on virtual demand, see Section 6.

Figure 4-21: Components of Day-Ahead Cleared Demand as a Percentage of Total Day-Ahead Cleared Demand



Internal demand in New England continued to exhibit very limited price responsiveness in 2025. Fixed demand represented 63% of total day-ahead cleared demand, consistent with prior years. Price-sensitive demand accounted for 32% of cleared demand; however, nearly all of these bids were submitted at prices well above expected day-ahead LMPs. As shown in Figure 4-21 95% of all cleared demand was bid at a price above expected LMPs. This bidding pattern indicates that load-serving entities were generally willing to reduce demand only under the highest price conditions.

Virtual demand represented 4% of cleared demand, while asset-related demand from storage and pumping accounted for 1%. Overall, the aggregate day-ahead internal demand curve remained steep around expected LMPs, confirming that internal demand remained largely price insensitive and similar to prior years.

4.4 System Reliability

The ISO is required to operate New England’s wholesale power system to the reliability standards developed by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and in accordance with its own reliability criteria.¹⁷⁰ The energy market may not always produce outcomes that satisfy these reliability criteria, in which case market operators may take out-of-market actions to ensure system reliability. This section of the

¹⁷⁰ These requirements are codified in the NERC standards, NPCC criteria, and the ISO’s operating procedures. North American Electric Reliability Corporation (NERC), “*Reliability Standards*” webpage, <http://www.nerc.com/pa/stand/Pages/default.aspx>.

Northeast Power Coordinating Council Inc. (NPCC), “*Standards*” webpage, <https://www.npcc.org/program-areas/standards-and-criteria>.

ISO New England Inc., “*ISO Operating Procedures*” webpage, http://www.iso-ne.com/rules_proceeds/operating/isone/index.html.

report analyzes these out-of-market actions.

Key Takeaways

In 2025, the day-ahead market generally procured sufficient energy to meet the ISO's load forecast, though there was a higher frequency of small positive energy gaps compared to prior years. These gaps primarily reflected the clearing of Energy Imbalance Reserve (EIR), a product introduced with the Day-Ahead Ancillary Services (DA A/S) market in March 2025. Along with cleared energy, EIR contributes to satisfying forecasted demand, and its increased use represents an intended feature of the updated market design rather than a deterioration in market outcomes.

Following the close of the day-ahead market, the ISO's Reserve Adequacy Analysis (RAA) evaluates whether cleared resources are sufficient to meet forecasted energy and reserve requirements. With the DA A/S market in place, reliance on post-market adjustments and additional commitments declined markedly. Consistent with this objective, no generator commitments originated from the initial RAA run in 2025, indicating improved alignment between day-ahead market outcomes and operational reliability needs.

Local reliability commitments and posturing continued to decline, extending a multi-year trend. The limited reliability commitments made in 2025 were predominantly in-rate, which helped contain reliability-related uplift payments.

Meanwhile, load forecasting accuracy remained stable relative to prior years, despite increasing complexity from continued growth in behind-the-meter solar generation. Ongoing investments by the ISO in forecasting tools have helped maintain forecast performance under these evolving system conditions. Because the load forecast is now a constraint in the day-ahead market with associated financial implications, continued investment in forecasting tools and methodologies remains particularly important for supporting efficient price formation and minimizing unintended cost impacts.

4.4.1 Reserve Adequacy Analysis and the Day-Ahead Energy Gap

The commitment and dispatch outcomes in the *financial* day-ahead market may not always reflect expected *physical* real-time conditions. For example, load-serving entities may clear less demand than the ISO's load forecast, resulting in less physical energy supply clearing in the day-ahead market than is expected to be needed in real time. When this happens, there is a day-ahead "energy gap," which we define here as (1) the expected real-time load less (2) the amount of day-ahead energy awards on physical resources (i.e., excluding virtual supply).

A key design change under the Day-Ahead Ancillary Services Initiative (DASI), which went into effect March 2025, was the explicit incorporation of the ISO's load forecast into the day-ahead market clearing process. The Forecast Energy Requirement (FER) constraint ensures that sufficient physical capability is procured in the day-ahead market to meet forecasted load (absent a violation of the constraint). This requirement may be satisfied through day-ahead energy awards from

physical supply resources as well as awards of Energy Imbalance Reserve (EIR).¹⁷¹ Consequently, while there can still be an “*energy gap*,” there can no longer be a “*capability gap*” as the day-ahead market now clears sufficient physical capability (in the form of energy and EIR) to meet the load forecast.

After the day-ahead market is approved, the ISO performs the Reserve Adequacy Analysis (RAA) to evaluate day-ahead cleared supply against forecasted energy and reserve requirements.¹⁷² If the day-ahead market did not clear enough *physical* supply to meet the ISO’s forecasted demand and reserve requirements, the RAA may rely upon resources to operate at levels above their day-ahead schedules and, infrequently, may require additional generator commitments. This source of commitment should be less common with the DA A/S market in place, and, in fact, there were no commitments that originated from the first RAA run (i.e., the run that takes place shortly after the close of the re-offer period at 2PM the day prior to the operating day) in 2025.

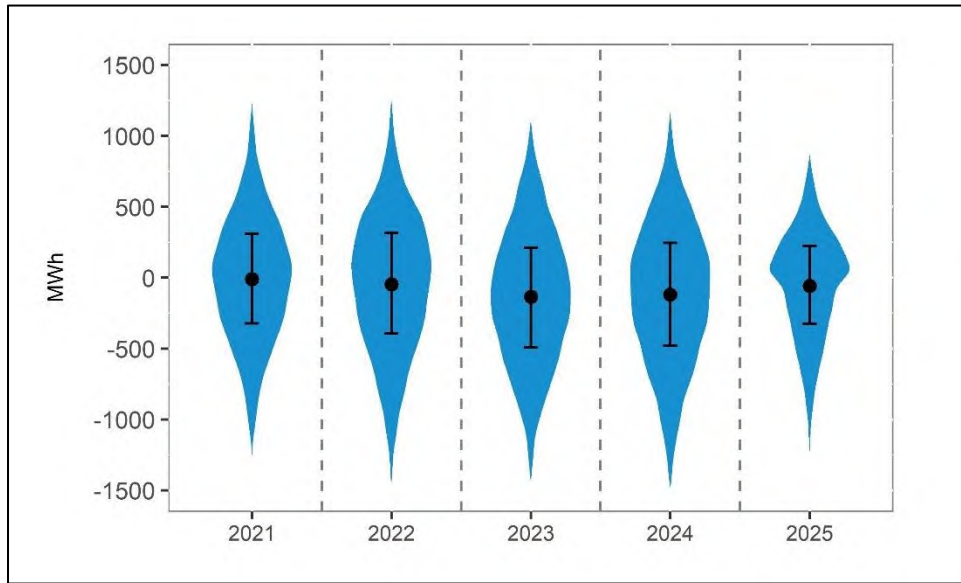
The day-ahead energy gap varied less widely in 2025 than in prior years and, on average, the day-ahead market continued to procure more energy than was expected to be needed in real-time. This can be seen in Figure 4-22 below, which shows the distribution of the day-ahead energy gap for each of the last five years.¹⁷³ The figure also shows, by year, the 25th and 75th percentiles (the black dashes), the interquartile range (the line between the dashes), and the mean (the black circle).

¹⁷¹ For more information about Energy Imbalance Reserves, see Section 8.2.2.

¹⁷² The RAA process is performed several times for each operating day, with the first RAA run taking place shortly after the close of the re-offer period at 2PM the day prior to the operating day. For more information about the RAA, see: ISO New England Inc., “SOP-RTMKTS.0050.0010 - Perform Reserve Adequacy Analysis”, https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/sysop/rt_mkts/sop_rtmkts_0050_0010.pdf

¹⁷³ Figure 4-22 presents the day-ahead energy gap using a violin plot, which combines features of a boxplot and a density plot. The curves depict the distribution of the energy gap, where the widest sections of each curve represent the most-frequently observed levels. A negative value indicates that there was no day-ahead energy gap in a specific hour (i.e., the sum of the cleared physical day-ahead energy awards exceeded the load forecast).

Figure 4-22: Day-Ahead Energy Gap



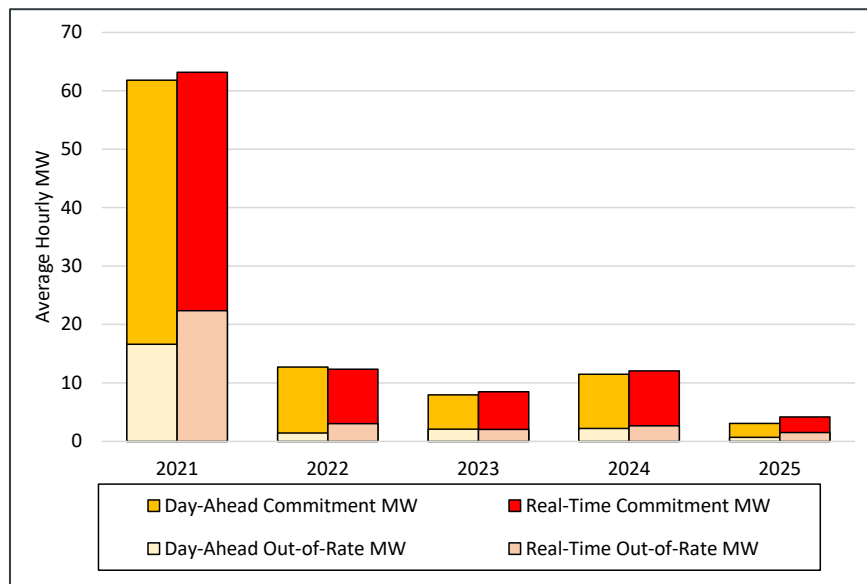
The average day-ahead energy gap in 2025 was -72 MWhs, which indicates that the quantity of cleared physical energy *exceeded* the load forecast on average. In 2025, the middle 50% of hourly observations fell between -334 MWh to 222 MWh, which represented a modest decrease compared to prior years. Notably, the curve for 2025 shows a higher frequency of observations at values slightly above 0 MWh, indicating that small energy gaps were more common in 2025 than in prior years. This is largely the result of the new FER constraint and EIR product. Given that EIR awards can now be used to meet the anticipated next-day load (along with day-ahead energy awards), the day-ahead market may deem it more efficient to satisfy energy gaps via EIR awards than to clear additional energy. During the period of March 2025 through December 2025, the hourly average volume of EIR awards was 125 MWh.

4.4.2 Reliability Commitments and Posturing

Reliability commitments include manual generator commitments for local second contingency protection, voltage support, or other special constraints. System operators direct such commitments for reliability purposes rather than generator economics. Consequently, reliability commitments are often out of merit and may negatively impact price formation for other online generators. Average hourly energy output (MW) from reliability commitments for 2021 through 2025 is shown in Figure 4-23 below.¹⁷⁴ The figure also specifies which portion of the output was out-of-rate, based on offer segments priced above the LMP.

¹⁷⁴ For more information on reliability commitments reviewed by the IMM, see: ISO New England Inc., “*Market Rule 1 Appendix A Market Monitoring, Reporting and Power Mitigation, Section III.A.5.5.6.1*”, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

Figure 4-23: Average Hourly Energy Output from Reliability Commitments



The total amount of reliability commitments decreased substantially in 2025, with an annual hourly average of under 10 MW of reliability commitments, about three quarters of which were local second contingency commitments. At a system level, reliability commitments declined significantly after 2021 when transmission upgrades in Maine and Southeastern Massachusetts (SEMA) were completed. Furthermore, the few reliability commitments were mostly in-rate, limiting reliability uplift payments. The local second contingency commitments occurred throughout the year and were generally in Maine or Southwest New England.

System operators may posture units—reducing their output below economic dispatch levels—to maintain operating reserves under stressed system conditions or to conserve limited stored fuel. When this occurs, resources are compensated through uplift payments for following operator instructions. In 2025, no resources were postured.

4.4.3 Load Forecast and Market Implications

The ISO’s day-ahead load forecast, published around 9:30 am, is the last load projection prior to the close of the day-ahead market for the next operating day.¹⁷⁵ The load forecast was not a direct input into the day-ahead market up until March 2025, when DA A/S incorporated the load forecast as a constraint to be met in the market clearing engine. However, up to that point the ISO load forecast nonetheless informed Load Service Entities’ (LSEs) submission of day-ahead demand bid quantities.^{176, 177} Therefore, LSE day-ahead demand clearing relative to their real-time load generally aligns with the ISO forecast error. Consequently, the day-ahead load forecast error has

¹⁷⁵ Twice a day, the ISO produces a three-day load forecast that projects load for the current day and the following two days. The first forecast is typically released around 4:30am and the second, and typically final forecast, is published near 9:30am. ISO New England Inc., “Three-Day System Demand Forecast” webpage, <https://www.iso-ne.com/markets-operations/system-forecast-status/three-day-system-demand-forecast>

¹⁷⁶ Load Serving Entities (LSEs) may also rely on their own in-house or third-party forecasting tools to inform their day-ahead bidding strategy.

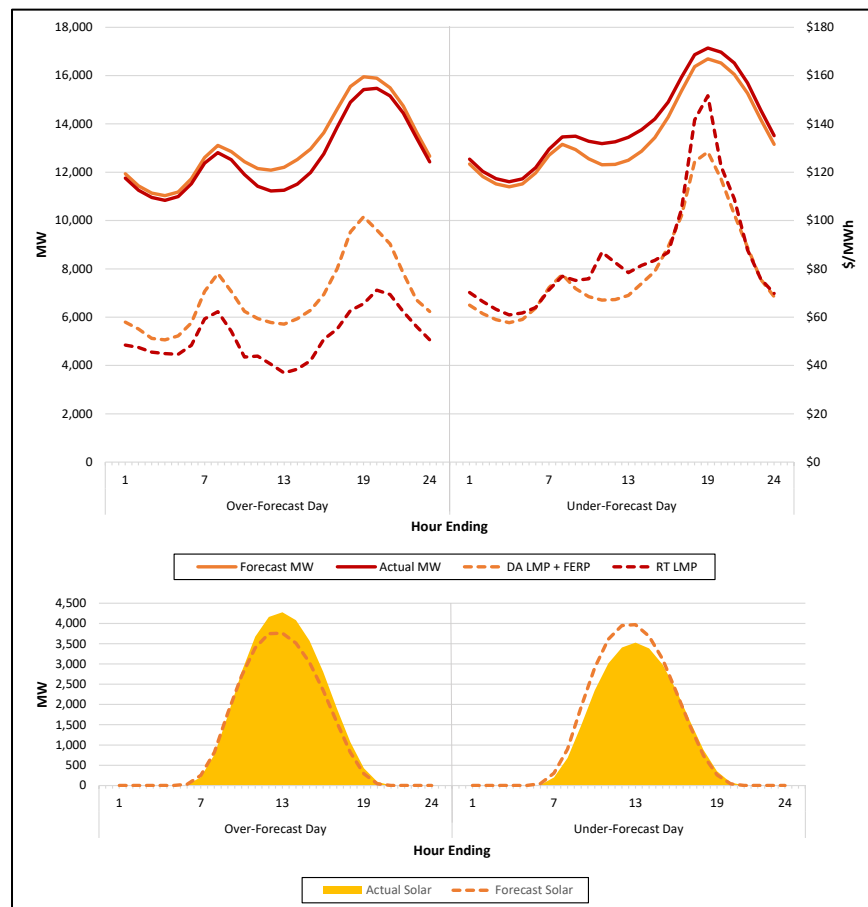
¹⁷⁷ Additionally, as mentioned in Section 4.4, the load forecast is used in the RAA process to finalize the ISO’s next day operating plan.

implications for both generator commitments and price deviations between the day-ahead and real-time markets.

Load Forecast Accuracy

Trends in load forecasting accuracy are covered in Section 1.5 which concludes that the distribution of the load forecast error in 2025 was consistent with prior years. The continued growth in BTM¹⁷⁸ solar generation in recent years adds to the complexity of load forecasting, and the ISO has invested significantly in enhancing its load forecasting tools.¹⁷⁹ Figure 4-24 illustrates the relationship between solar forecast error, load forecasts, and LMP deviations by displaying the load curves of typical over- and under-forecast days, with load on the left axis, LMPs on the right axis, and solar forecasts below.¹⁸⁰

Figure 4-24: Impact of BTM Solar on Load Forecast Error



¹⁷⁸ The ISO includes both behind-the-meter solar and front-of-the-meter settlement-only (SOG) solar in its operational solar forecasts.

¹⁷⁹ In recent years, the ISO has made significant investments to better forecast BTM solar generation. For more information on ISO New England's investment in forecasting behind-the-meter solar generation, see: Energy Systems Integration Group, "Building data intelligence for short-term load forecasting with behind-the-meter PV", March 27, 2019, <https://www.esig.energy/building-data-intelligence-for-short-term-load-forecasting-with-behind-the-meter-pv/>.

¹⁸⁰ The average over-forecast and under-forecast days in the graph are calculated from the days with the top 25% largest over- and under-forecast load deviations in 2024.

Over-forecast days, when the day-ahead load forecast is greater than actual real-time load, are typically driven in part by more load-reducing BTM and settlement-only solar generation than anticipated. This forecast error has a knock-on effect on LMPs, where the high day-ahead load forecast can result in more day-ahead unit commitments and higher LMPs and subsequent low LMPs in real time as units are dispatched down.

The opposite effects occur on under-forecast days, which are typically driven by less load-reducing solar generation than expected. Real-time LMPs are typically higher than day-ahead prices, driven by the costs of dispatching units up to meet unexpected demand, fast-start pricing as more units are committed to meet load, or reserve pricing as upward dispatch reduces available reserves.

4.5 Net Commitment Period Compensation (Uplift)

NCPC are make-whole payments made to generators, external transactions, and virtual transactions when they follow ISO dispatch instructions and experience revenue shortfalls or lost opportunity costs. NCPC payments can provide insight into unpriced energy costs, and higher levels of uplift may be symptomatic of price formation or missing product issues. In this section, we review NCPC in the context of total energy payments, provide a breakdown of payments by category, and show NCPC payments by generator type.

Key Takeaways

Net Commitment Period Compensation (NCPC) totaled \$42 million (\$0.35/MWh of load) in 2025, an increase of \$7 million year-over-year, driven primarily by higher generation production and commitment levels. This increase was largely offset by higher energy prices (LMPs), resulting in NCPC declining as a share of total energy costs to 0.4%.

Approximately \$31 million (75%) of NCPC payments occurred in the real-time market. Most payments were made to resources committed in economic merit order to meet load and reserve requirements, with uplift covering commitment and opportunity costs not fully recovered through LMPs during commitment and dispatch hours.

Overall, NCPC outcomes in 2025 did not indicate persistent or systemic price-formation concerns. However, consistent with last year's report, fast-start oil-fired generators—important for peak reliability and system flexibility—continue to rely on NCPC to recover a significant share (over 40%) of their operating costs. This reliance reflects a combination of out-of-merit operator-initiated commitments and operational constraints, such as minimum run times. The IMM will continue to monitor these drivers and their implications for price formation.

NCPC in the Context of the Energy Market Payments

Tracking NCPC payments relative to energy payments provides a high-level metric capturing reliance on compensation through make-whole payments rather than uniform market clearing prices, as well as the level of costs borne by payers of uplift, which can be difficult to predict and hedge. Energy and NCPC payments are summarized in Table 4-4 below.

Table 4-4: Energy and Uplift Payments

	2021	2022	2023	2024	2025
Energy Payments (\$ millions)	\$6,099	\$11,712	\$4,847	\$5,620	\$9,407
NCPC Payments (\$ million)	\$35.9	\$53.1	\$34.4	\$34.7	\$41.7
NCPC in \$/MWh	\$0.30	\$0.45	\$0.30	\$0.30	\$0.35

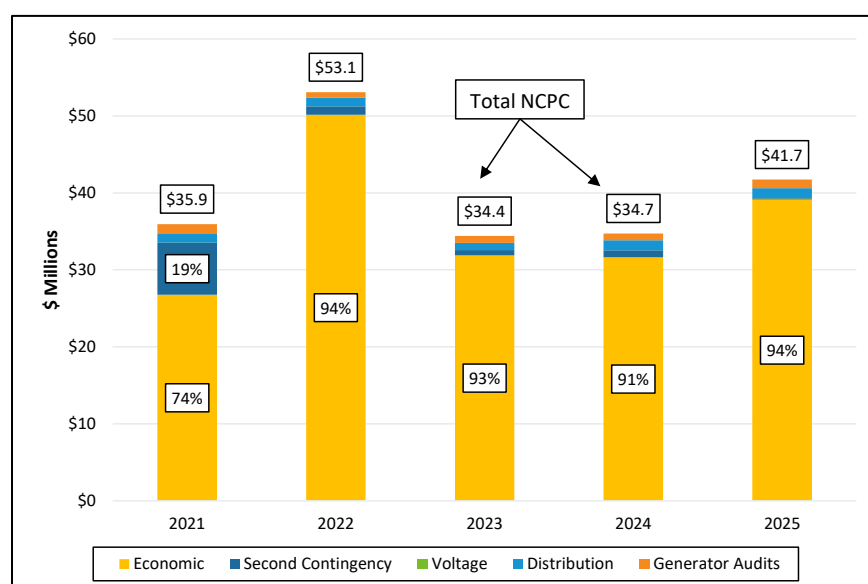
NCPC as % Energy Payments					
Day-Ahead NCPC	0.3%	0.1%	0.1%	0.1%	0.1%
Real-Time NCPC	0.3%	0.3%	0.6%	0.5%	0.3%
Total NCPC as % Energy Costs	0.6%	0.5%	0.7%	0.6%	0.4%

NCPC payments totaled \$41.7 million in 2025, up from \$34.7 million in 2024. The subsections below describe the drivers of increased uplift payments. As load was similar to 2024, NCPC payments increased to \$0.35/MWh of load (up from \$0.30/MWh in 2024). Despite this increase, NCPC payments grew at a lower rate than overall energy market payments. NCPC accounted for just 0.4% of energy market costs, the lowest share over the reporting period. The majority of NCPC continued to be incurred in the real-time market.

NCPC Payments by Category

Below, we sort NCPC payments into categories based on the underlying driver of the commitment or dispatch decision, including meeting system-wide first-contingency requirements (economic NCPC), local second-contingency, distribution or voltage requirements, and dual-fuel auditing requirements. Annual NCPC by category is shown in Figure 4-25 below.

Figure 4-25: Total Uplift Payments by Year and Category

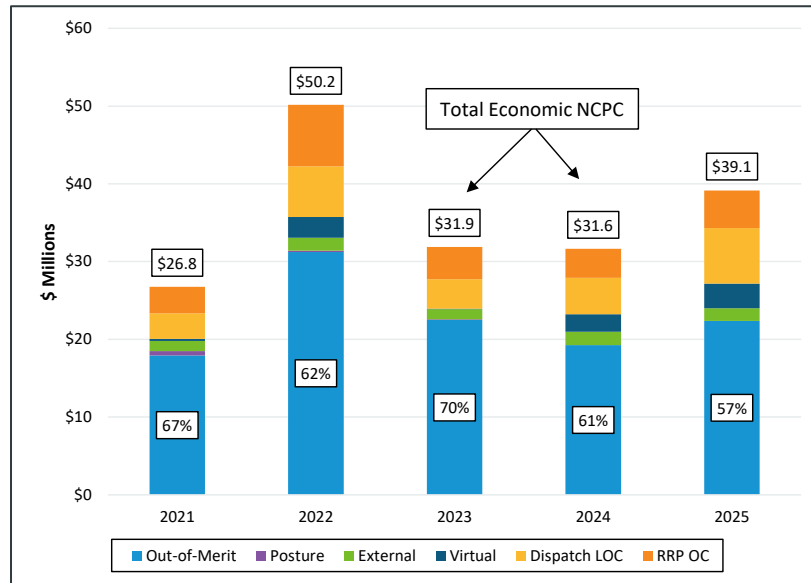


Economic (or First Contingency) NCPC continued to comprise the largest share of uplift payments at \$39 million (94% of total). Economic payments drove the increase in overall NCPC as discussed below. Second contingency payments marked their lowest total in the reporting period (<\$0.2 million), and distribution payments totaled \$1.3 million. Audit uplift totaled just over \$1 million.

Economic NCPC by Subtype

Economic NCPC payments contain sub-categories, including out-of-merit payments for unrecovered generation costs, posturing uplift, external transaction payments, and compensation for lost opportunity costs due to the dispatch or rapid-response pricing process. Economic NCPC by subtype is shown in Figure 4-26 below.

Figure 4-26: Economic Uplift by Sub-Category



Out-of-merit payments covering generators’ operating cost shortfalls totaled \$22 million, or 57% of total economic NCPC. Such payments increased by \$3 million from 2024. As natural gas prices rose in 2025, gas-fired generator operating costs increased. Such increased operating costs can lead to higher out-of-merit payments in cases when LMPs do not fully cover generators’ costs.

Real-time **fast-start commitments** are one such case when LMPs can fail to fully cover generators’ operating costs. This might occur if prices fall while fast-start generators remain in their minimum run time, or if fast-start generation is committed to meet system reliability needs. Economic payments to real-time fast-start generators accounted for 53% of economic out-of-merit NCPC (\$12 million).

Payments to **virtual transactions** increased to \$3 million in 2025, continuing the increase from \$50 thousand to \$2 million in 2024. Payments to virtual and day-ahead external transactions increased due to relatively frequent congestion at external interfaces (see Section 5).¹⁸¹ Such payments maximize total clearing (welfare) without creating additional NCPC charges for load, but rather is a transaction cost paid to the congestion relieving party.

Opportunity cost payments (dispatch and rapid-response pricing) totaled \$12 million, up 42% from 2024. As LMPs increased in 2025, opportunity costs resulting from regular dispatch and fast-start pricing mechanics also increased. Additionally, battery storage generators incur higher opportunity costs in the dispatch process since they can respond immediately to ramping dispatch instructions that are sent in advance.

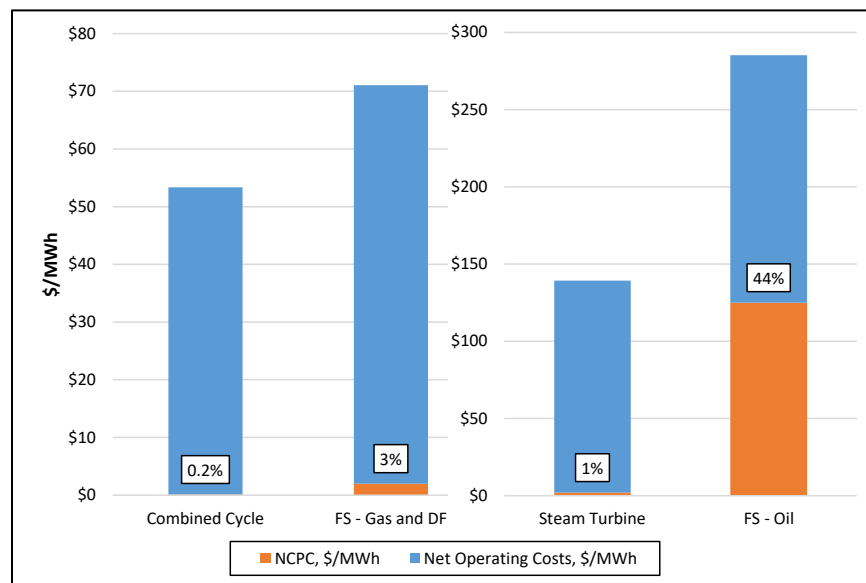
¹⁸¹ For a numerical example of day-ahead virtual or external NCPC driven by congestion at external interfaces, see: ISO New England Inc., “FAQs: Net Commitment-Period Compensation (NCPC)” webpage, <https://www.iso-ne.com/participate/support/faq/ncpc-rmr>.

NCPC Reliance

As discussed above, high reliance on uplift payments for cost recovery might be indicative of poor price formation or might indicate other structural issues that lead to out-of-merit operation, such as out-of-market reliability commitments and dispatch.

Here, we define NCPC reliance as the share of total operating costs recovered through uplift payments.¹⁸² Figure 4-27 below shows NCPC reliance for select fuel types.¹⁸³

Figure 4-27: NCPC Reliance by Fuel Type



Combined cycle generators required uplift to recover less than 1% of their operating costs in 2025. While combined cycle operating costs increased in 2025 due to higher gas prices, NCPC reliance remained low as higher LMPs compensated generator operating costs. Dual-fuel units with fast-start capability relied on NCPC to recover 3% of their operating costs, and steam turbines relied on NCPC to recover 1% of their costs. By contrast, oil-fired fast-start units with high operating costs (\$285/MWh) relied on NCPC to recover 44% of those costs (\$125/MWh). Such units received \$4 million in out-of-merit NCPC throughout 2025. Oil-fired fast-start generators are manually committed by system operators during relatively tight periods (particularly in the summer) to provide capacity or manage ramps and load forecast deviations. The resulting manual fast-start commitments are often either entirely out of merit or partially out of merit over the generator's

¹⁸² For the purposes of calculating NCPC reliance, operating costs (the denominator of NCPC reliance) are calculated as the sum of energy, startup, and no-load costs that are eligible for recovery through either energy market revenues or uplift. Offered costs may be negative, and resources that are self-scheduled are treated as if they have negative offered commitment costs. This calculation sums the maximum of each generator's offered operating costs and zero to only include positive operating costs. Additionally, this calculation includes all day-ahead and real-time incremental NCPC and NCPC costs for non-fast start generators, and only real-time NCPC and NCPC costs for fast-start generators. Day-ahead NCPC and costs for fast-start units are not included since day-ahead commitments for fast-start units are not binding. For more information on NCPC cost calculation rules, see ISO New England Inc., "Section III Market Rule 1 Appendix F Net Commitment Period Compensation Accounting", https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_f.pdf.

¹⁸³ In this figure, NCPC and net operating costs are expressed in \$/MWh of real-time generation. Net Operating Costs represent the share of operating costs that can only be recovered through energy market revenues.

minimum run time, resulting in uplift for cost recovery. We continue to monitor these commitments and their implications for price formation.

In summary, NCPC payments increased in 2025 due to higher generator operating costs throughout the year. As increased operating costs were largely reflected in LMPs, NCPC rose in absolute terms but fell as a share of energy market payments. NCPC payments in 2025 did not indicate persistent price formation concerns.

4.6 Summary of System Events During 2025

System events, such as tight system conditions resulting from generator outages or higher than anticipated loads, can have a significant impact on energy market outcomes. Two events warrant mention in 2025: the June 24 and November 23 capacity scarcity conditions (shortage events). This section details the frequency of system events and abnormal conditions over the past five years and provides a summary of the shortage events.

Key Takeaways

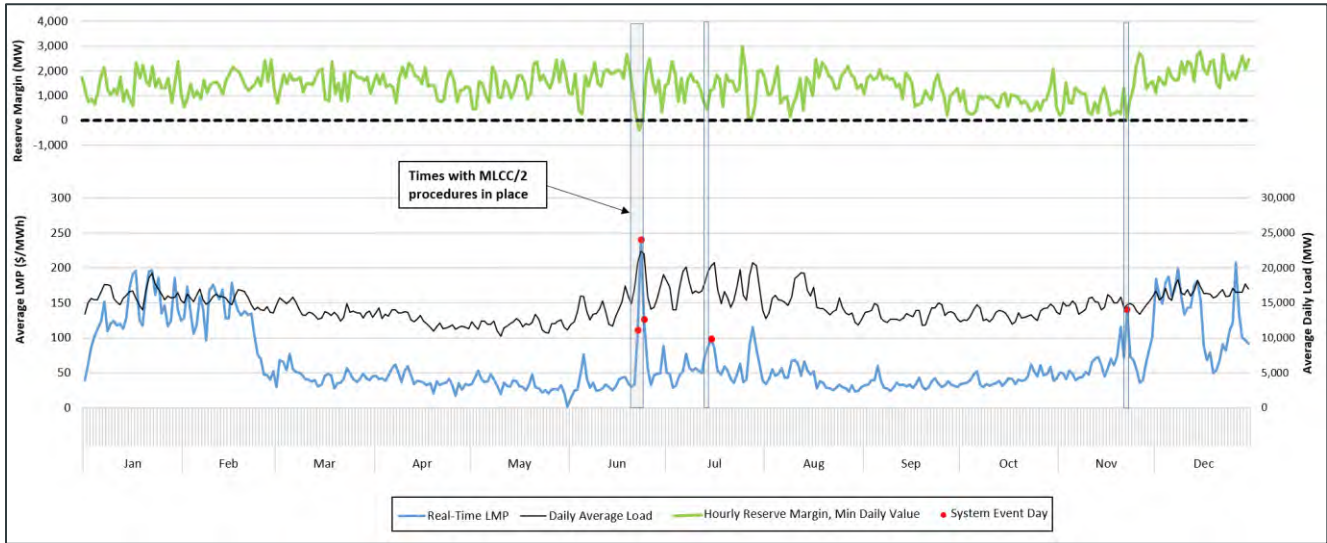
Overall, there were few instances of tight system conditions or scarcity pricing in 2025. These events were transitory in nature, and relatively small operating reserve deficiencies (compared to the requirement) were resolved within a few hours. During these periods, the markets provided transparent and strong price signals that incentivized supply resource performance.

Weather and unplanned supply outages were the main drivers behind notable system events over the last several years. Two reserve shortage events and three M/LCC 2 events occurred during 2025. The first shortage event occurred on June 24 and resulted from a combination of high loads and unplanned generator outages and reductions. The second event occurred on November 23 and resulted from generator outages around the highest loads of the day. These events both occurred simultaneously with M/LCC 2 events. The third M/LCC 2 event occurred in July when temperatures and loads were high.

Overall, these outcomes reflect a system that has had a healthy overall reserve margin with few periods of system stress in the past few years.

To provide context for the events covered in this section, Figure 4-28 below overlays the timing of the two events mentioned above and M/LCC2 (represented by the red dots) events on a series of average daily real-time LMPs and load levels. Also shown is the minimum total reserve margin (for an hour) for each day.

Figure 4-28: Pricing, Demand and Reserve Margin during System Events in 2025



The following metrics illustrate the frequency of abnormal system conditions and extreme market outcomes over the past five years:

- Number of OP-4 and M/LCC 2 Events
- Reserve Deficiency Events
- Frequency of Extreme Hub LMPs

OP-4 and M/LCC 2 Events

The ISO uses the following control room procedures to address issues and alert participants during times of tight or abnormal system conditions:

- **Master Local Control Center Procedure No. 2** (M/LCC 2, Abnormal Conditions Alert)¹⁸⁴
- **Operating Procedure No. 4** (OP-4, Action during a Capacity Deficiency)¹⁸⁵

The number of instances for each type of event is shown in Table 4-5 below.

Table 4-5: OP-4 and M/LCC 2 Event Frequency

Procedure	2021	2022	2023	2024	2025
# of OP-4 Events	0	1	1	2	2
# of M/LCC 2 Events	6	6	6	6	3

¹⁸⁴ M/LCC 2 notifies market participants and power system operations personnel when an abnormal condition is affecting the reliability of the power system, or when such conditions are anticipated. The ISO expects these entities to take certain precautions during M/LCC 2 events, such as rescheduling routine generator maintenance to a time when it would be less likely to jeopardize system reliability. ISO New England Inc., “Master/Local Control Center Procedure No. 2 (M/LCC2) Abnormal Conditions Alert”, https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/mast_satllte/mlcc2.pdf

¹⁸⁵ OP-4 establishes criteria and guidelines for actions during capacity deficiencies. There are eleven actions described in the procedure that the ISO can invoke as system conditions worsen. ISO New England., “ISO New England Operating Procedure No. 4 – Action During A Capacity Deficiency”, https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op4/op4_rto_final.pdf

The ISO implemented three M/LCC 2 events in 2025, down from six in the prior four years. In our assessment of the system events, detailed in the quarterly reports, we generally found that the market performed well during these periods. The table at the end of this section summarizes the high-level causes and outcomes of each system event in 2025.

Reserve Deficiency Events

Reserve deficiency events (i.e., periods when there are negative reserve margins) are indicative of stressed system conditions when there is not enough available supply capable of meeting the region’s 10- or 30-minutes reserve requirements. During such events, reserve product and energy clearing prices reflect the reserve price cap associated with the deficient constraint, known as the applicable Reserve Constraint Penalty Factors (RCPFs). Below, Table 4-6 shows the number of hours during which each reserve margin was negative.

Table 4-6: Frequency of Negative Reserve Margins (System Level) ¹⁸⁶

Year	Hours of Negative Total30 Margins	Hours of Negative Total10 Margins	Hours of Negative Spinning Reserve Margins
2021	0.0	0.0	26.8
2022	1.4	0.1	48.1
2023	0.5	0.3	6.8
2024	2.2	1.1	3.7
2025	3.6	0.3	30.3

Overall, these outcomes reflect a system that has had a healthy reserve margin on average with few periods of system stress in the past few years. The Total30 and Total10 margins fell below zero in each of the last four years when tight system conditions led to capacity scarcity conditions under the Pay-for-Performance construct.

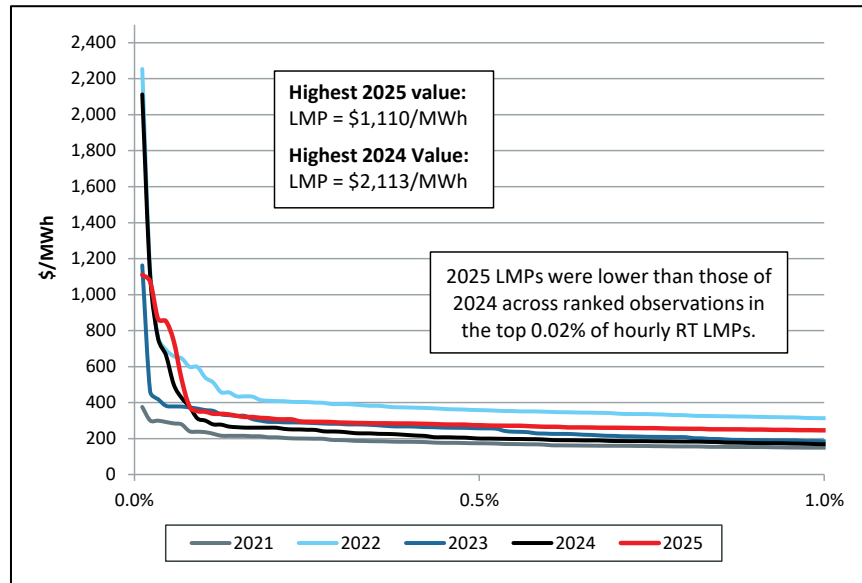
Shortages of ten-minute spinning reserves (with an associated RCPF of \$50/MWh) occur more frequently reflecting demand for both energy and spinning reserves on committed dispatchable generation (mainly combined cycles). The spinning reserve shortages occurred across 46 days throughout the year in 2025 due to a variety of factors, such as tight system conditions caused by higher real-time loads or unplanned outages.

Frequency of Extreme Hub LMPs

High real-time LMPs can also be indicative of stressed system conditions, as higher-cost generation is required to meet load and reserve requirements. The duration curves in Figure 4-29 below show the top 1% of hourly average real-time LMPs ranked from highest to lowest over the past five years.

¹⁸⁶ The calculations in this table come from the LMP calculation processes in the real-time market software. The “Hours of Negative Total30 Margins” column does not include instances where only the replacement reserve margin is negative, because those instances are not associated with the \$1,000/MWh RCPF.

Figure 4-29: LMP Duration Curves for Top 1% of Real-Time Pricing Hour



Real-time LMPs in 2025 were higher than those of 2024 across most ranked observations, consistent with the higher LMPs this year. The six highest hourly real-time LMP values occurred during the two shortage event days; however, the majority of the top 1% of LMPs (83%) occurred during winter months (January, February and December). Elevated energy prices during the winter were driven by high natural gas prices due to cold weather and pipeline constraints. There were no reserve deficiencies during these month.

The highest hourly price of the year (\$1,110/MWh) occurred during HE 19 on June 24, when capacity scarcity conditions resulted in the RCPFs for the total thirty-minute reserve constraint (\$1,000/MWh) being incorporated into LMPs for the entire hour.

Specific days that saw notable market and system outcomes in 2025 are summarized in Table 4-7 below.

Table 4-7: System Events In 2025

Date	Event Type	Driver	Market & System Summary
Jun 23-25	M/LCC 2 (Jun 23-Jun 25), OP4 Actions 1 and through 5 and Shortage Event (Jun 24)	Hot weather, high loads and generator outages and ambient derates	Loads were high due to hot weather. Multiple generator outages occurred throughout the day, while many thermal generators reduced maximum output due to hot weather. Capacity scarcity conditions for over t hours, and five-minute real-time LMPs peaked at \$1,561/MWh.
Jul 16-17	M/LCC 2	Hot weather and high loads	High temperatures and loads led to high energy prices.
Nov 23	M/LCC 2, OP4 Actions 1 and 2, Capacity Shortage Event	Generator Outages	About 5,000 MW of generation was out-of-service; most of these outages were routine maintenance outages often taken during the shoulder months. 900 MW of generation went out-of-service in HE 18, leading to negative reserve margins. Capacity scarcity conditions for 30 minutes, and five-minute real-time LMPs peaked at \$2,666/MWh.

4.7 Demand Response Resources

Demand Response Resources (DRRs) can participate in the day-ahead and real-time energy and ancillary services markets by reducing end-use consumption. The first subsection (4.7.1) analyzes how DRRs participate in the energy market¹⁸⁷ and the second subsection (4.7.2) analyzes their participation in the capacity market. The final section (4.7.3) reviews DRR compensation across all markets.

Key Takeaways

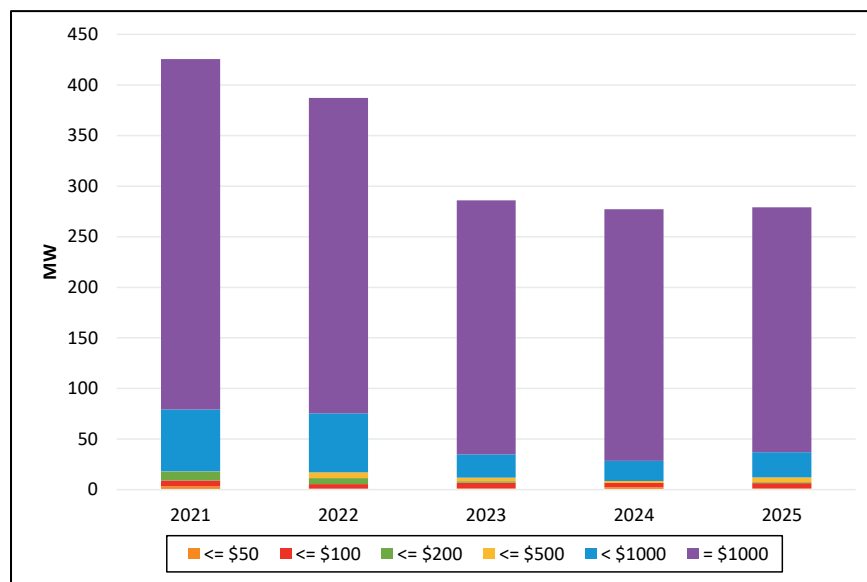
Similar to prior years, Demand Response Resources (DRRs) primarily served as capacity and operating reserve resources in 2025, generally only available for dispatch at very high offer prices. For example, 87% of DRR capacity was offered at \$1,000/MWh in the real-time energy market in 2025. Given these high offer prices, dispatch of these resources occurred infrequently and at low quantities. DRRs mostly provided operating reserves during real-time operations; 5 MW of 10-minute reserves and 191 MW of 30-min reserves per hour on average in 2025.

The capacity market continues to provide DRRs with the majority of their overall market revenues; in 2025, DRRs received \$11 million in capacity payments, which comprised 80% of their total market payments.

4.7.1 Energy Market Offers and Dispatch

By virtue of their high energy offer prices, most DRRs effectively function as reserve resources, providing energy only when prices are extremely high. Figure 4-30 below depicts average hourly demand reduction offer (i.e., energy offer) quantities in the real-time energy market by year and offer price category over the past five years.

Figure 4-30: Demand Response Resource Energy Offers in the Real-Time Energy Market

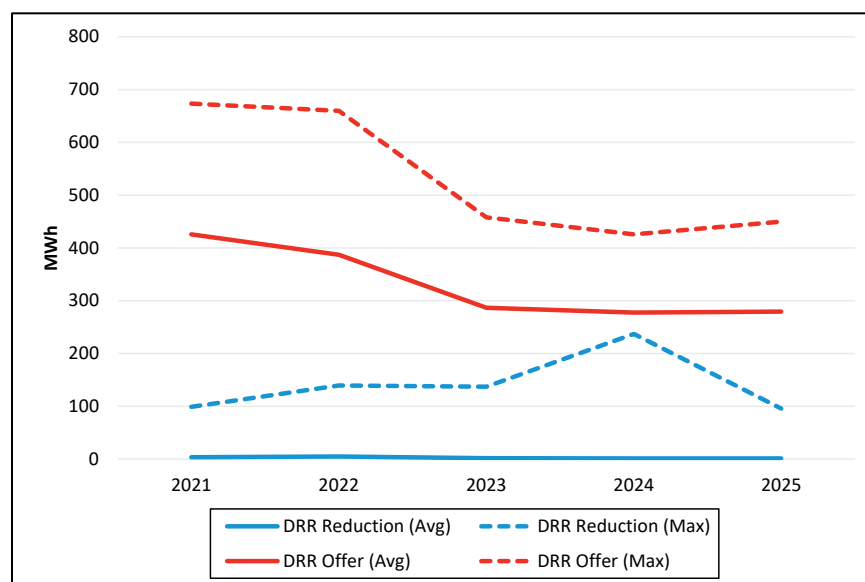


¹⁸⁷ Given the similarity of DRR participation across the day-ahead and real-time energy markets, this section uses only real-time energy offer and dispatch data to illustrate their participation in the ISO's energy markets.

Most DRRs offer their real-time energy at \$1,000/MWh;¹⁸⁸ 87% of offered DRR capacity, on average, was offered at this value in 2025. In most hours, only the lower-priced energy offers (\$200/MWh or less) have a reasonable likelihood of being dispatched in the real-time energy market; these offers averaged just 3% of hourly offered DRR capacity in 2025.

Given the offer price behavior of DRRs, the ISO dispatches relatively small quantities in the energy markets. Figure 4-31 below illustrates the reduction of DRRs in the real-time energy market relative to the resources' offered reductions over the past five years. The blue lines represent actual reductions, while the red lines indicate offered reduction capability.

Figure 4-31: Demand Response Resource Reductions in the Real-Time Energy Market



DRRs were dispatched to reduce consumption infrequently in 2025, averaging only 1.1 MWh of energy reductions. This is in line with average values over the study period. The highest observed DRR energy reduction values in 2025 occurred during the capacity scarcity conditions on June 24, 2025. Aggregate DRR reduction values reached nearly 100 MWh during this period of stressed system conditions. As a group, DRRs under-performed relative to their CSO during this scarcity event, which led to PFP charges of over \$4 million.¹⁸⁹ These observations are reflective of the fact that DRRs are generally not relied upon as a form of energy supply during normal operating conditions. However, they do provide operating reserves in real time. In 2025, DRRs provided an hourly average of 5.3 MWh of ten-minute operating reserves and 190.8 MWh of thirty-minute operating reserves. These reserve designation values are very similar to those from 2024.

4.7.2 Capacity Market Participation

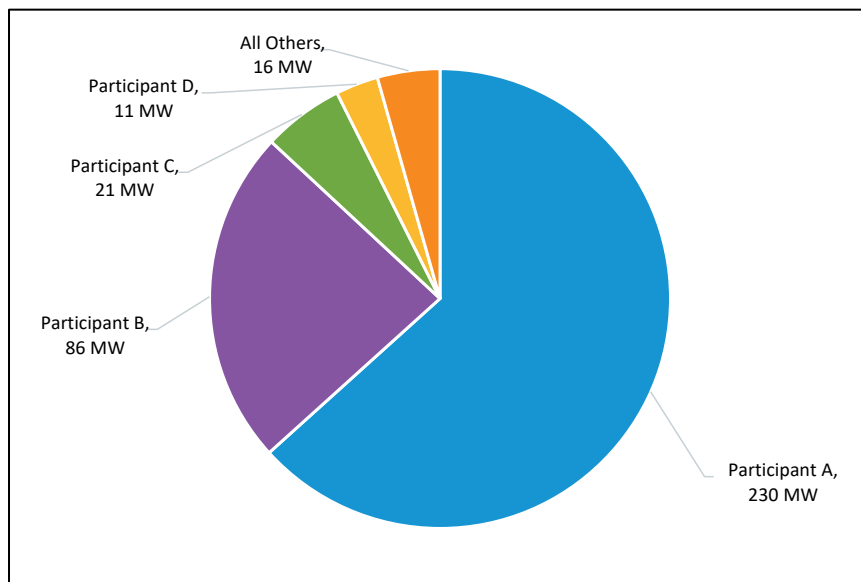
Active demand response participates in the Forward Capacity Market by aggregating one or more DRRs into Active Demand Capacity Resources (ADCRs). All active demand resources with capacity

¹⁸⁸ \$1,000/MWh is the highest energy price offer that can be submitted without additional quantitative support provided by the participant and verification by the ISO. No DRR offered greater than \$1,000/MWh during the study period.

¹⁸⁹ For more information about resource performance during the June 24, 2025, CSC event, see: ISO New England Inc., Internal Market Monitor, "Summer 2025 Quarterly Markets Report", November 12, 2025, <https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf>.

market obligations are required to offer “physically available” capacity into the day-ahead and real-time energy markets.¹⁹⁰ Figure 4-32 indicates the total CSO for ADCRs in 2025 as well as the split by participant.¹⁹¹

Figure 4-32: CSO by Lead Participant for Active Demand Capacity Resources, 2025



In 2025, ADCRs had capacity supply obligations (CSOs) totaling approximately 364 MW. This continues the year-over-year trend of declining capacity market participation by ADCRs and is a reduction of 44 MW (11%) compared to 2024. The largest participant accounted for nearly two-thirds of the total ADCR capacity supply obligations in 2025, which was similar to the percentage held by the largest participant in 2024. Collectively, the two largest participants accounted for approximately 87% of ADCR capacity supply obligations in 2025.

4.7.3 Wholesale Market Compensation

The capacity market continues to be the key driver of DRR compensation with relatively modest levels of revenue coming from the energy and ancillary services markets. Figure 4-33 provides a summary of capacity,¹⁹² energy,¹⁹³ and reserve payments to DRRs by year for the past five years.

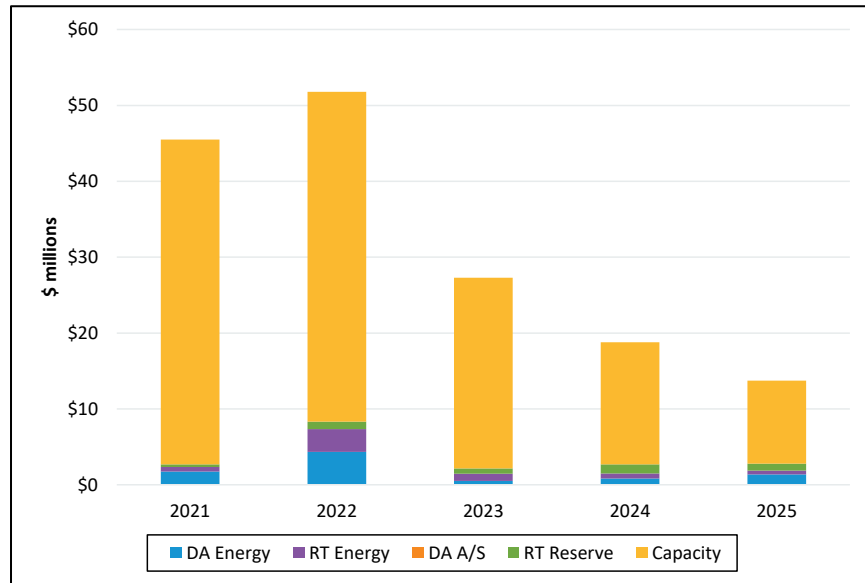
¹⁹⁰ To satisfy the ADCR’s capacity supply obligation, DRRs mapped to an ADCR need to offer demand reductions into the energy market at an aggregate level consistent with the parent ADCR’s capacity supply obligation.

¹⁹¹ The CSO estimate indicates the average capacity supply obligation for the calendar year.

¹⁹² The FCM compensation depicted in this figure is based the results of the primary FCA and does not account for any gains or losses that may have occurred as a result of CSO bilaterals or reconfiguration activities. The compensation does, however, account for Pay-for-Performance payments and penalties assessed to ADCRs.

¹⁹³ NCPD payments to DRRs are included within the DA and RT energy bars in this figure. Additionally, FER credits, which are credits paid to physical resources that have day-ahead energy awards, are also included within the DA energy bar.

Figure 4-33: Wholesale Market Payments to Demand Response Resources



In 2025, capacity market payments to DRRs totaled \$11 million, accounting for 80% of all payments to DRRs. This reflects a decrease in capacity payments relative to prior years, largely as a result of the lower level of CSO held by DRRs. Meanwhile, payments for energy and reserves have remained relatively small. In 2025, total energy payments amounted to \$1.7 million, which includes approximately \$50 thousand in FER credits. Real-time reserve payments totaled \$0.9 million in 2025, and DRRs received no day-ahead ancillary services payments in 2025.

Section 5

External Transactions

External transactions are energy market transactions that allow market participants to transfer power between New England and its neighboring control areas, and represent an important part of the overall supply and demand picture.¹⁹⁴ Transferring power between different control areas can help reduce total production costs across control areas by allowing power to flow from lower priced to higher priced control areas, and provide reliability benefits to the interconnected systems.

This section reviews trends in external transactions in the day-ahead and real-time energy markets. The first section (5.1) provides an overview of external transactions across all external interfaces, while the second section (5.2) looks specifically at the performance of Coordinated Transaction Scheduling (CTS) with New York.

5.1 External Transaction Trends and Drivers

This section on outcomes, trends and drivers of import and export (external) transactions is organized in three subsections: (5.1.1) overall flows between New England and its neighboring control areas, with a breakdown across the six interfaces¹⁹⁵, (5.1.2) the pattern of fixed bidding versus price-sensitive bidding, and (5.1.3) the drivers of uplift (NCPC) payments to external transactions.

Key Takeaways

Interchange Levels and Drivers: Real-time net interchange averaged 932 MW per hour (serving 7% of real-time load), which was the lowest level of net interchange since at least 2011. Net interchange continued to decrease as dry weather in Canada limited sales of hydro generation to New England and a nuclear generator in New Brunswick took an extended outage for the second consecutive year. Nearly 47% of total net interchange came from Canadian interfaces, a decrease from 60% in 2024 and 80% in 2023.

Contribution on High Priced Intervals: Despite falling over the last five years, net interchange continues to play a critical role in helping New England meet energy demand during periods when loads and energy prices increase. During hours where day-ahead energy prices were above \$100/MWh, net interchange averaged nearly 2,700 MW per hour, in line with prior years. However, this relationship loosened late in the year as net interchange fell during Q4 2025, and New England imported an average of 1,421 MW during these high-priced intervals.

Priced vs. Unpriced: At the Canadian interfaces, most day-ahead transactions were priced during 2025. However, nearly all of these priced transactions were not re-offered in real time and

¹⁹⁴ A control area, or balancing authority area, is an area comprising a collection of generation, transmission and load within metered boundaries for which a responsible entity (defined by NERC to be a balancing authority) integrates resource plans for that area, maintains the area's load-resource balance, and supports the area's interconnection frequency in real time.

¹⁹⁵ There are currently seven external interfaces with the addition of the New England Clean Energy Connect in January 2026. This interface began non-commercial testing in November 2025. This section focuses on the six interfaces that were commercial during 2025.

therefore were effectively scheduled as fixed transactions in the real-time market. At the three New York interfaces, external transactions tended to be fixed in the day-ahead and priced in real time due to the mechanics of Coordinated Transaction Scheduling at New York North.

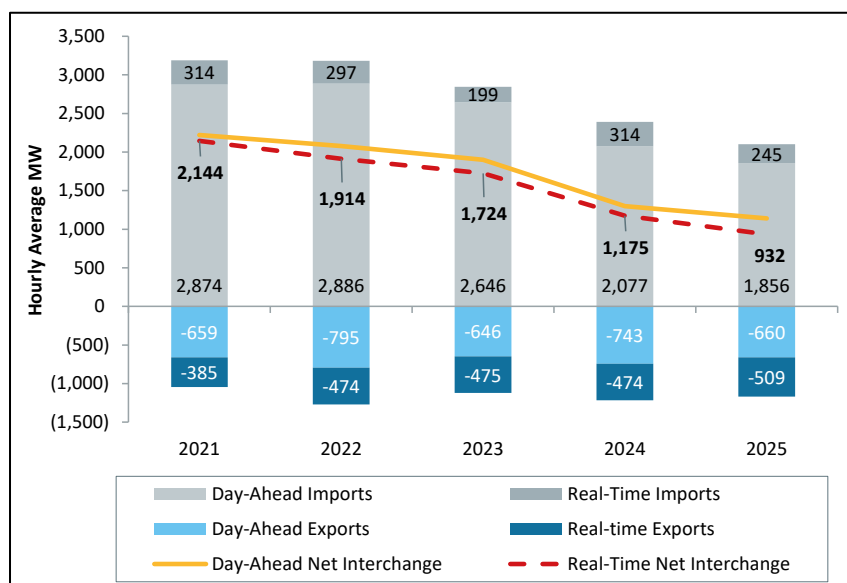
Uplift Payments and IMM Recommendation: External transactions received more uplift payments in the day-ahead market this year, largely due to increased payments to virtual transactions for relieving external congestion at the Highgate interface in the day-ahead market. In the real-time market, uplift payments decreased slightly compared to 2024 as price forecast error at non-CTS interfaces led to reduced clearing of out-of-merit external transactions.

We continue to recommend that ISO-NE review non-CTS external interface clearing rules to ensure participants are incentivized to offer external transactions that reflect expected quantities at the cost or value of the underlying energy (see Recommendation #2025-1 in the Executive Summary).

5.1.1 External Transaction Volumes

The average hourly system-wide net interchange from the day-ahead and real-time markets are shown in the line series of Figure 5-1 below. The bar series chart shows the hourly average imported volume (positive values) and exported volume (negative values), as well as the net interchange in both the day-ahead and real-time markets.¹⁹⁶

Figure 5-1: Hourly Average Day-Ahead and Real-Time Pool Net Interchange



Net interchange continues to decrease between New England and its neighboring control areas. Real-time net imports averaged 932 MW per hour (or 7% of real-time load), the lowest volume of net interchange since at least 2011. In 2025, net interchange fell as dry weather continued in Quebec, and a nuclear unit in New Brunswick took an extended outage for the second consecutive

¹⁹⁶ The real-time import and export volumes are shown as the incremental additions to the amounts cleared in the day-ahead market.

year. Overall, day-ahead and real-time net imports fell by 158 MW and 243 MW on average, respectively.

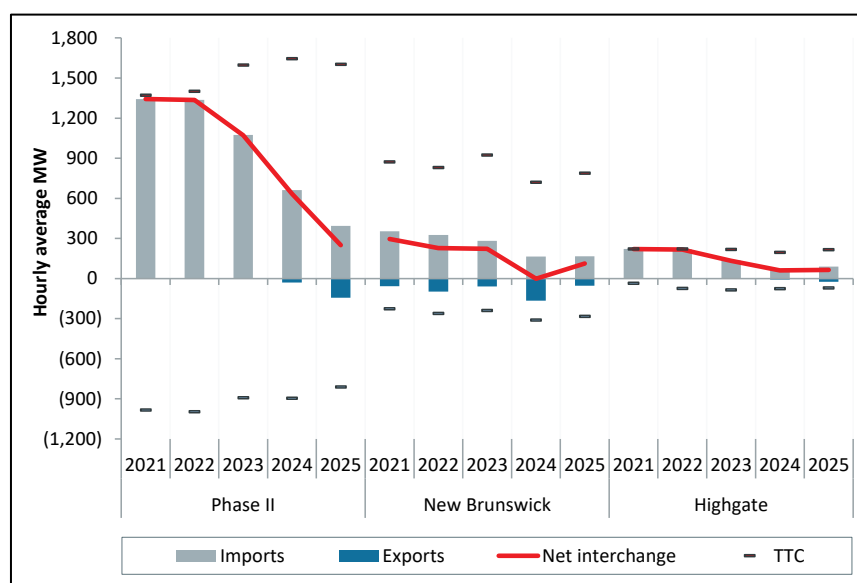
Despite falling over the last five years, net interchange still plays a critical role in helping New England meet energy demand during periods when loads and energy prices increase. During hours when day-ahead LMPs were at least \$100/MWh, net interchange averaged over 2,700 MW per hour in 2025, broadly consistent with the prior four-year average. However, this relationship broke down late in the year. Net interchange during high-priced hours fell sharply in Q4 2025, when average interchange dropped to 1,421 MW—about 50% below the prior four-year average (~2,900 MW).

Day-ahead *net interchange* (orange) remained higher than real-time *net interchange* (red) during 2025. This was due to lower real-time net interchange at the New York North interface where real-time scheduled exports exceeded the volume of additional real-time imports across all interfaces. When net real-time interchange is lower, New England must commit additional real-time native generation which can lead to higher real-time prices.

A Breakdown of Flows across the Canadian Interfaces

Annual hourly average real-time net interchange volumes (red line), as well as the gross import and export volumes, are shown for each Canadian interface in Figure 5-2 below, along with the real-time total transfer capability (TTC) ratings for each interface.¹⁹⁷

Figure 5-2: Real-Time Net Interchange at Canadian Interfaces¹⁹⁸



Canadian exports into New England and neighboring regions have decreased steadily and significantly since 2022, driven by reduced hydro power generation in Canada. Nevertheless, Canada remains an import supplier of electricity to New England, providing 47% of New England's total net imports.

¹⁹⁷ The total transfer capability (TTC) rating is the MW amount of power that can be reliably transferred from one system to the other over the transmission interface.

¹⁹⁸ The New England Clean Energy Connect is not shown in the figure but is included in total net interchange numbers. The interface began testing in late 2025 and began commercial operation in January 2026.

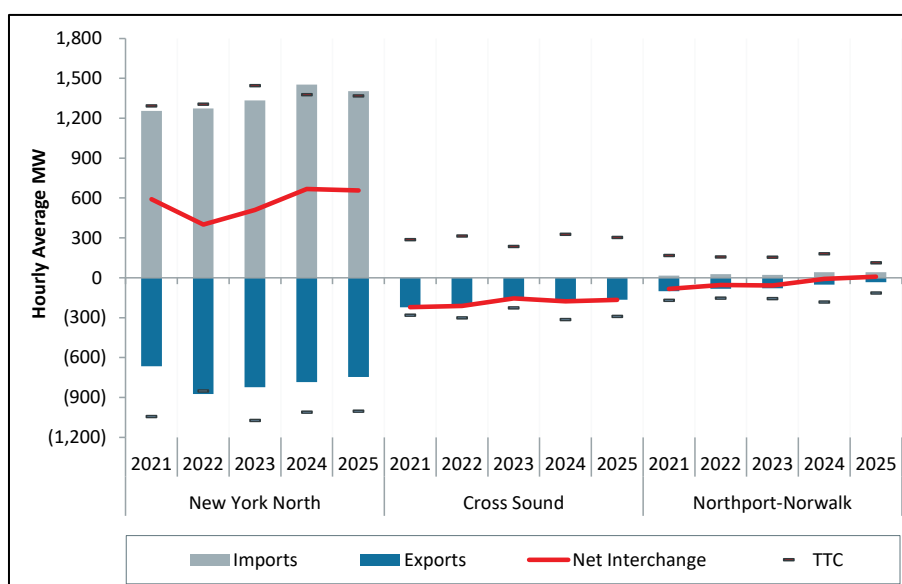
The net interchange between New England and Quebec saw another substantial fall in 2025 as dry weather persisted in Canada, limiting the amount of excess hydroelectric generation available to sell in New England.¹⁹⁹ Phase II saw the highest net imports of any interface from 2021 to 2022, averaging 1,339 MW per hour, which was in line with historical norms. However, in 2025, net imports at Phase II averaged 250 MW per hour, 81% below average levels from 2021 and 2022. Historically, imports at the Highgate interface were close to the maximum import capability of the interface (225 MW) but have decreased in recent years. In 2025, net imports remained lower than normal, averaging just 65 MW per hour. Most import transactions over the Highgate interface in 2025 originated in IESO and were wheeled to New England through Quebec.

Net interchange with New Brunswick rebounded in 2025 but remained below historical levels. A large nuclear generator took a six-month outage (June 2025 to December 2025) for the second consecutive year, limiting the amount of generation and capacity in New Brunswick.²⁰⁰ When the unit was in-service, New England was a net importer over this interface, averaging 189 MW per hour. During the outage, New England exported over 20 MW per hour, on average.

A Breakdown of Flows across the New York Interfaces

Real-time interchange volumes and capabilities for each of the three New York interconnections are shown in Figure 5-3 below.

Figure 5-3: Real-Time Net Interchange at New York Interfaces



On a net basis, New England imports power from New York over the New York North interface and exports power to Long Island via the Cross Sound Cable and Northport-Norwalk interfaces. Combining flows at all three interfaces, ISO-NE's net imports in 2025 averaged nearly 500 MW per hour (or 4% of total real-time load).

¹⁹⁹ For more information on Québec's reduction in exports, see: Hydro-Québec, "Annual Report 2025", <https://www.hydroquebec.com/data/documents-donnees/pdf/hq-rapport-annuel-2025-anglais.pdf>.

²⁰⁰ For more information on the outage of the New Brunswick nuclear generator, see: Énergie NB Power, "Point Lepreau Nuclear Generating Station Returns to Operation", Dec 15, 2025, <https://www.nbpower.com/en/about-us/news-media-centre/news/2025/point-lepreau-nuclear-generating-station-returns-to-operation/>.

At New York North, net interchange (red line) remained similar to levels in 2024, averaging 657 MW per hour. In the day-ahead market, prices remained close between New York and New England with New York prices just \$0.28/MWh higher on average compared to about \$0.70/MWh higher in 2024. External transactions may be willing to flow from New York to New England at a financial loss (based on spot energy price differences) to deliver on contracted energy or to sell Renewable Energy Certificates (RECs) at a higher price in New England.

New England typically exports power to Long Island over the Cross Sound Cable and Northport-Norwalk interfaces. In 2025, net exports to Long Island at Cross Sound Cable averaged 166 MW per hour, 11 MW lower than 2024. At Northport-Norwalk, *net imports* from Long Island averaged 8 MW after exporting an average of 9 MW per hour in 2024. The Northport-Norwalk interface was heavily reduced this year due to transmission work and was only at its full capability (200 MW) in about 10% of intervals.

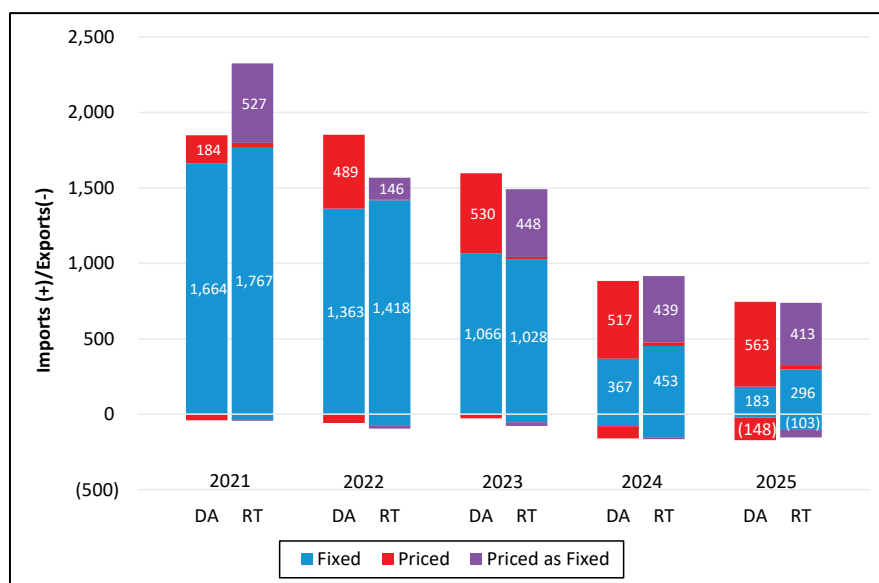
5.1.2 External Transaction Participation

In Section 4, we assess overall market supply and demand-side participation in terms of the extent to which supply offers or demand bids are price-taking (fixed) versus price-making (priced). This can have important implications for price formation in the energy markets. In this section, we present a similar analysis focusing on external transactions, which participate on both the supply and demand sides of the market (i.e., supply offers for imports and demand bids for exports).

Canadian Interfaces

The composition of transactions that *cleared* at the Canadian interfaces in the day-ahead and real-time markets by fixed, priced and “priced as fixed”²⁰¹ is shown in Figure 5-4 below.

Figure 5-4: Transaction Types by Market and Direction at Canadian Interfaces
(Average MW per hour)



²⁰¹ A “priced-as-fixed” transaction is a real-time external transaction that was priced and cleared in the day-ahead market, but not reoffered in the real-time market. When day-ahead priced transactions are not reoffered in the real-time market, they are scheduled as fixed transactions.

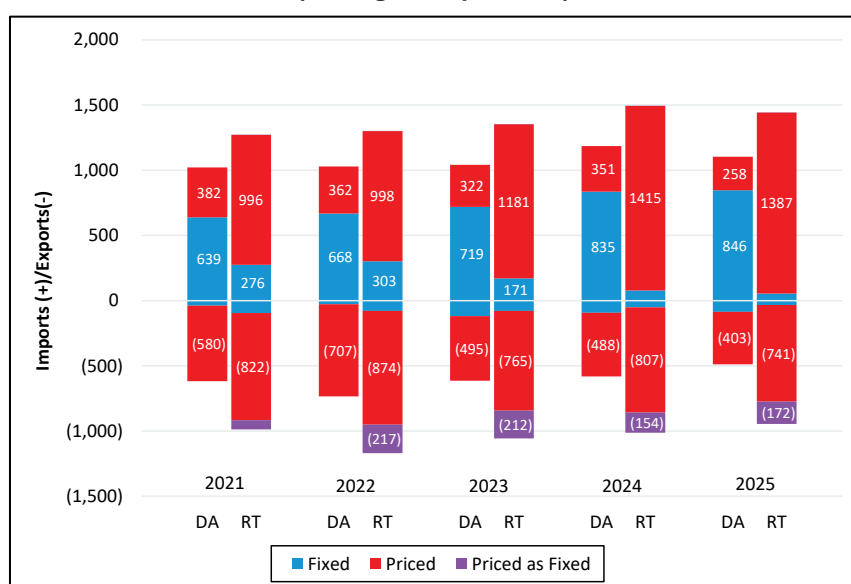
In the day-ahead market external transactions were predominantly fixed at Canadian interfaces prior to 2024. However, levels of fixed import transactions have fallen at Canadian interfaces in recent years in tandem with an overall decline in total import transactions. Day-ahead priced transactions remained relatively consistent over the last four years.

There continues to be very low levels of price-sensitive transactions in the real-time market. At the Canadian interfaces, most priced transactions were not reoffered in real time. Without these transactions being reoffered, nearly all real-time transactions are scheduled as fixed (“Priced as Fixed” label).

New York Interfaces

The composition of transactions that cleared at the New York interfaces in the day-ahead and real-time markets by fixed, priced and “priced as fixed” is shown in Figure 5-5 below.²⁰²

**Figure 5-5: Transaction Types by Market and Direction at New York Interfaces
(Average MW per hour)**



Most day-ahead cleared import transactions at the New York interfaces were fixed while most exports were priced. In 2025, the composition of external transactions at New York interfaces remained similar to 2024 levels. Day-ahead price differences between New York and New England stayed relatively flat year-over-year, with New York prices averaging just \$0.28/MWh higher than New England prices at New York North, the largest interface connecting New York and New England.

In real time, most transactions are priced due to the bidding mechanics of Coordinated Transaction Scheduling (CTS) at the New York North interface. Under CTS, all real-time transactions are evaluated based on price, although participants may offer prices as low as negative \$1,000/MWh, which effectively schedules the import transaction as fixed. Most real-time import transactions that cleared in the day-ahead market continued to be price-insensitive at the

²⁰² Volumes not listed in the figure all averaged less than 100 MW per hour.

interface. Transactions can be fixed in real time at New York North, but these represent wheeled transactions which decreased this year.²⁰³

5.1.3 External Transaction Uplift (NCPC) Payments

External transactions are eligible to receive uplift (or NCPC) payments when revenues are not sufficient to recover their costs. These payments often occur in the real-time market when external transactions clear on an ISO price forecast but are unable to recover as-offered costs through actual settled prices. External transactions (or virtual transactions placed at external nodes) can also receive uplift in the day-ahead market for relieving congestion at non-CTS external interfaces since congestion is not captured in the LMP. These payments occur when a transaction that is out-of-the-money at the system price clears in the direction counter to the constraint (e.g., an export or virtual demand bid when the interface is import-constrained) allowing a counter-party to clear in excess of the interface limit.²⁰⁴ These otherwise uneconomic transactions require uplift in the absence of congestion pricing.

The annual uplift credit totals at all external nodes in both the day-ahead and real-time markets are presented in Table 5-1 below.

Table 5-1: NCPC Credits at External Nodes

Year	Day-ahead credits (\$million)	Real-time credits (\$million)
2021	\$1.0	\$0.5
2022	\$3.1	\$1.2
2023	\$0.1	\$1.3
2024	\$2.4	\$1.6
2025	\$3.9	\$0.9

Typically, total uplift paid at external nodes is very small compared with other types of uplift (see Section 4.5).” In 2025, *day-ahead* uplift credits totaled \$3.9 million, which was the second consecutive increase in day-ahead uplift credits. \$2.8 million was paid to transactions at the Highgate interface for relieving the import-constrained interface. This interface often sees high uplift credits in the day-ahead market as participants compete for clearing priority at the interface by placing virtual demand bids to ensure they clear their full day-ahead import transaction. 90% of day-ahead uplift at Highgate was paid during January 2025 when higher energy prices led to increased competition for clearing priority at the interface.

²⁰³ A wheeled transaction occurs when a participant flows power from one system to another over a third party’s transmission lines. For example, a participant might use these transactions to flow power from PJM through New York and into New England.

²⁰⁴ For example, consider an interface with an import TTC of 100MW and an LMP of \$100/MWh. If there are 200MW of imports offered at \$0/MWh, only 100MW can clear (due to the TTC), unless there is a transaction to offset the remaining 100MW of excess imports. If a 100MW export is offered at \$50/MWh, it can provide counter-flow. The \$50/MWh exports are willing to purchase the \$0/MWh imports. However, because congestion is not captured in the LMP, the energy settlement for the export will result in a loss; the exports are only willing to pay \$50/MWh and the LMP is \$100/MWh. Therefore, these 100MW of exports must be paid \$50/MWh to make them whole, for a total NCPC payment of \$5,000. The NCPC charges are only levied to the participants importing over the interface. NCPC charges and credits are a transfer between participants creating the congestion to participants relieving the congestion.

Real-time uplift credits are driven by transactions scheduled out-of-rate due to price forecast error. In other words, transactions (at non-CTS interfaces)²⁰⁵ were in-rate based on forecasted prices but were out-of-rate based on actual prices that are used in settlements. Accurate price forecasting of LMPs helps reduce NCPC paid to external transactions. In 2025, price forecast error improved and NCPC credits for external transactions fell to less than \$1 million.

²⁰⁵ At the CTS interface, out-of-rate transactions are not entitled to NCPC but also do not incur NCPC charges.

5.2 Coordinated Transaction Scheduling

This section provides an update on the assessment of how coordinated transaction scheduling (CTS) at the New York North interface is functioning. Specifically, we review CTS performance metrics against its high-level performance indicators, including scheduling efficiency, price convergence, and price forecast error. We continue to recommend the ISO assess enhancements to price forecasting to minimize forecast error, or changes to CTS mechanics to minimize the impact of price forecast error.²⁰⁶

Key Takeaways

CTS produced similar outcomes to previous years. Price forecast error continues to dampen the positive impacts of CTS by creating financial risk for participants at the Roseton interface and is likely impacting bid and offer behavior. Specifically, participants often clear day-ahead transactions then offer hedged price-insensitive transactions in the real-time market. Lower price-sensitive offered capacity in real-time reduces the ability of the CTS engine to adjust flows as New England and New York price spreads fluctuate.

On average, the CTS engine could have used 232 MW of unutilized capacity per hour to help converge prices before hitting the most limiting constraint (ramp- or transfer capability-constraint). The CTS engine was often unable to converge prices due to the unwillingness of participants to adjust to real-time price differences.

We encourage ISO-NE to review its price forecasting tools and explore opportunities to improve forecast accuracy. Since price forecast error is unlikely to be completely eliminated, minimizing the impact of price forecast error through changes to CTS mechanics or settlement may better incentivize participants to offer at cost.

5.2.1 CTS Performance

We assess CTS performance against two measures of efficiency: the flow of power from the lower- to higher-cost region and degree of price convergence between New England and New York.

A summary of CTS power flows between the two control areas is shown in Table 5-2 below. The percentage of time power flowed into New England is shown in the *Net Flow* column.²⁰⁷ The percentage of time the flow was directionally correct (i.e., power flowed from lower- to high-cost region, based on actual prices) is shown in the *Correct Flow* column.²⁰⁸ The average New England price premium is shown for context, as a primary driver of flow direction. The correct flow and

²⁰⁶ A summary of this and other recommendations can be found in the executive summary of this report. For a more in-depth analysis of CTS outcomes, see: ISO New England Inc., Internal Market Monitor, “2022 Annual Markets Report”, June 5, 2023, <https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf>.

²⁰⁷ Fixed wheeling transactions at the New York North (NYN) interface are ignored in the analyses contained in this section. These transactions are not cleared in the CTS process. On average, in 2025 there were 20 MW of fixed-wheeling transactions net importing over the NYN interface in each interval.

²⁰⁸ The prices used in this subsection are proxy prices that represent the marginal cost of energy on each side of the NYN interface. The NYISO pricing node is “N.E._GEN_SANDY PD” (Sandy Pond) and the ISO-NE node is “.I.ROSETON 345 1” (Roseton). Congestion pricing is removed from external prices to ensure we are better capturing the marginal cost of energy in each control area at the border. When the ramp or flow limit binds, the prices at the interface reflect the bids and offers that set price based on the forecast, and not necessarily the marginal cost of energy in each control area.

average price spreads including potential revenues from the Renewable Energy Certificate (REC) price spread (the difference between the New England and New York REC prices) are also shown to highlight other incentives participants are presented when flowing power across the NYN interface.²⁰⁹

Table 5-2: Summary of CTS Flows

Year	Net Flow (% of intervals) to ISO-NE	Correct Flow (% of intervals)	Correct Flow (% of intervals, accounting for REC spread)	Average New England Price Premium (\$/MWh, without CTS Congestion)	Average New England Price Premium including REC spread (\$/MWh, without CTS Congestion)	Average New England Price Premium (\$/MWh, with CTS Congestion) ²¹⁰
2021	69%	56%	78%	\$1.96	\$20.03	(\$1.65)
2022	51%	57%	65%	(\$2.92)	\$9.47	(\$4.09)
2023	68%	55%	70%	\$2.04	\$11.23	(\$0.91)
2024	81%	54%	68%	\$2.15	\$10.76	(\$1.03)
2025	83%	55%	77%	\$3.01	\$16.30	(\$2.52)

In 2025, power flowed into New England from New York 83% of the time and the average New England price premium was \$3.01/MWh. However, CTS scheduling moved energy in the correct direction only 55% of the time on a 15-minute basis (i.e., from lower- to higher-cost region, based on the price without CTS congestion)—similar to the prior four years. When REC prices are included in the price spread, about 77% of the time power flowed in the correct direction. REC prices contributed about \$13/MWh to the price spread between New England and New York on a per-MW basis.

Table 5-3 below shows a summary of price convergence between New York and New England and CTS price forecast error.

²⁰⁹ Renewable Energy Certificate prices used in this analysis are the vintage prices from the date of flow. For example, for a transaction flowing on 2/10/2022, the vintage 2022 MA Class 1 REC price and 2022 New York Tier I REC price during the week of 2/5/2022-2/11/2022 is used to reflect the expected value of the RECs at the time of scheduling. In cases where the date falls before the first populated price (e.g., no 2020 NY Tier I REC price data was available before 1/2/2021) the first available price is applied in the analysis.

²¹⁰ The average New England price premium is shown in this table to highlight that although New England prices exceed New York prices (based on the "Average New England Price Premium without CTS Congestion" columns), participants are unable to capture that price spread due to the number of negatively-priced import offers. These negatively-priced import offers often set price, leading to a New York price premium once congestion, caused by these negatively-priced imports, is factored in.

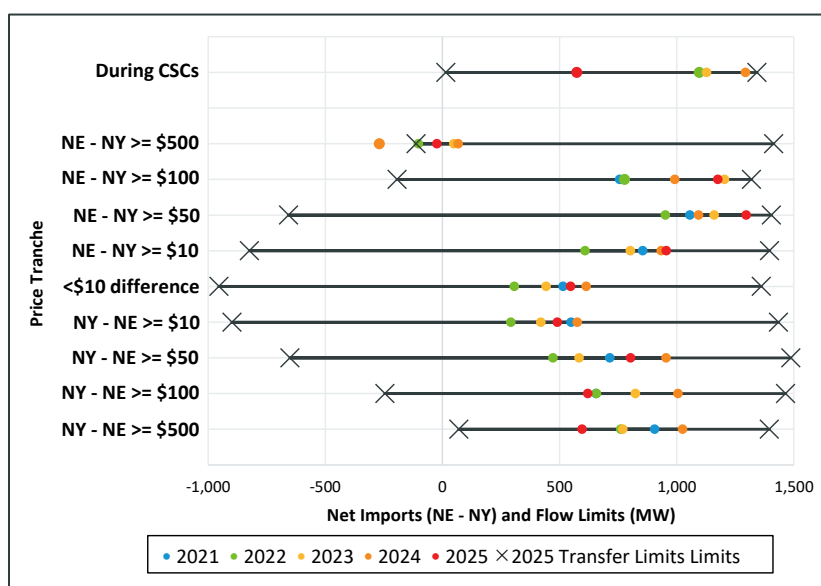
Table 5-3: Summary of Price Convergence and Forecast Error

Year	NY LBMP (\$/MWh)	NE LMP (\$/MWh)	Average Absolute Price Spread (\$/MWh)	Average Absolute Price Spread as % of ISO-NE LMP (%)	Average Absolute Price Spread Forecast Error (\$/MWh)	Average Absolute Price Spread Forecast Error as % of ISO-NE LMP (%)
2021	\$41.07	\$43.03	\$12.76	30%	\$10.78	25%
2022	\$85.78	\$82.86	\$24.50	30%	\$23.31	28%
2023	\$32.63	\$34.67	\$11.98	35%	\$10.10	29%
2024	\$36.01	\$38.15	\$10.69	28%	\$9.72	25%
2025	\$60.61	\$63.62	\$18.16	29%	\$14.77	23%

The average absolute price spread in 2025 was the highest since 2022, although the absolute price difference between New York and New England was 29% of the LMP, similar to previous years. This could indicate that, although the price differences were greater due to overall higher prices, the CTS engine helped converge prices about as efficiently as previous years. Despite the similar price spread outcomes, the CTS price forecast performed slightly better than in previous years. The average absolute price spread forecast error was 23%, compared with values above 25% in the previous four years.

Many variables impact the price spread between New York and New England (e.g., generator and transmission outages, interconnections with other areas, differences in scarcity pricing rules) so the price spread cannot be fully attributed to the efficiency of CTS solutions. Despite the improvement in price forecasts, CTS solutions did not efficiently utilize the New York North interface capacity to converge prices. On average, the CTS engine could have used 232 MW of unutilized capacity to help converge prices before hitting the most limiting constraint (ramp- or transfer capability-constraint). Figure 5-6 below, shows the average net flow of external transactions over the New York North interface, by price spread tranche. Additionally, the net flow of external transactions during capacity scarcity conditions (CSCs) is also shown in the line at the top. The × symbols on the line mark the 2025 import and export limits in the intervals shown. The red dots show the average scheduled net interchange in 2025.

Figure 5-6: Average NYN Flow by NE-NY Price Spread



In 2025, the CTS engine generally utilized more of the interface to converge prices. Most notably, when New England was experiencing a price premium less than \$500/MWh, but greater than \$10/MWh, the CTS engine imported more power than in past years (i.e. the red dot was further to the right). This does indicate that the CTS engine did a better job of converging prices at these times, but is due to a 20% decrease in export bids coupled with a 25% increase in import offers, rather than reductions in forecast error. Over half of cleared CTS transactions were offered at less than -\$50/MWh, similar to 2024. These price-insensitive CTS transactions were often not exposed to real-time prices—and most (about 83%) were backed by a day-ahead transaction in 2025, similar to 87% in 2024. This may indicate that participants are unwilling to rely on the CTS engine to efficiently schedule transactions by submitting economic bids and offers or have other contracts that incent them to bring energy into New England.

During the two CSC events in 2025, New England scheduled about 600 MW of imports over the NYN interface. During the first event on June 24, which lasted three hours, the CTS engine scheduled an average of 540 MW of New England net imports per interval over the NYN interface with an average New England price premium of \$615/MWh. The actual price difference was a New York price premium of \$200/MWh, as NYISO was also resource deficient at the time. This actual price spread sent incentives for participants to export out of New England. During capacity scarcity conditions, participants that are net importers receive the pay-for-performance (PfP) rate of \$9,337/MWh for each MW of net imports. Due to the difference in realized price for net importers and net exporters, different participants can be incentivized to import and export at the same time. The IMM has recommended that the ISO charge exports the PfP rate to align incentives for participants moving power between regions.

During the second 30-minute event, on November 23, NYN was importing power at the limit based on a forecasted \$60/MWh New England price premium, on average, compared with the actual price difference of \$1,916/MWh. Despite the large forecast error, CTS optimized flows as efficiently as was possible given the limits during the event.

Section 6

Virtual Transactions

Participants submit virtual demand bids and virtual supply offers to profit from, or limit exposure to, differences in day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence and help the day-ahead dispatch model to better reflect real-time conditions. In ISO New England, participants can submit virtual supply offers and demand bids at any pricing location on the system: the Hub, load zones, external interfaces, Demand Response Resource (DRR) aggregation zones, and the hundreds of generation and load nodes (network nodes). This section covers our assessment of virtual transaction participation in the day-ahead energy market, including the level of activity and profitability.

Key Takeaways

Average **cleared virtual supply** (1,054 MW per hour) increased to its highest level in the past five years, continuing an upward trend over the reporting period. While there are multiple drivers of participants' virtual supply offer behavior, the increased volume observed in the past several years is mainly due to the growing amount of solar and wind resources on the grid and their limited participation in the day-ahead market. Solar settlement-only generators (SOGs) are ineligible to participate in the day-ahead market, while modeled solar and wind generators (> 5 MW capacity) tend to offer high-priced energy in the day-ahead market due to uncertainty in real-time weather conditions, risk preferences, and outside commercial arrangements. Many virtual participants anticipate additional real-time generation from renewable resources and clear virtual supply in the day-ahead market in their place. These offers support more efficient day-ahead clearing outcomes and contribute to price convergence.

Average **cleared virtual demand** increased at all different location types and reached its highest level in the past five years (595 MW per hour). Clearing at external interfaces rebounded after having decreased in 2024, while several participants drove increased clearing of virtual demand at the Hub, load zone, and nodal level.

Profitability: Virtual demand incurred gross losses of \$3.19/MWh in 2025, the highest level in the past five years. Virtual supply made a gross profit of \$2.67/MWh, which was higher than the previous two years but in line with the first two years of the reporting period.

Overall, consistently higher day-ahead LMPs over the past five years have contributed to these outcomes. In addition, participants often place virtual supply offers in the middle of the day when solar output is high, and profit when that output puts downward pressure on real-time prices. By contrast, participants often place virtual demand bids for reasons other than price arbitrage, such as hedging physical positions or ensuring priority at external interfaces.

Uplift Charge Allocation: The total NCPC charge rate for virtual transactions in 2025 was \$0.59/MWh, continuing a downward trend since 2022, when NCPC costs reached \$0.91/MWh. NCPC credits for virtual demand increased in 2025 due to virtual demand relieving import congestion at external interfaces, while virtual supply received less NCPC credit compared to 2024. After accounting for NCPC charges and credits, virtual supply transactions were profitable (\$2.16/MWh) while virtual demand transactions incurred losses of -\$3.35/MWh.

IMM Recommendation on NCPC Charge Allocation: We continue to recommend that the ISO review the allocation of NCPC charges to virtual transactions to ensure the charges are consistent with principles of cost causation and don't pose an inefficient participation obstacle given the important role that virtual supply plays in converging and lowering day-ahead LMPs. The allocation of uplift and uncertainty regarding the charge can impact virtual supply offers and the day-ahead LMP which drives the vast majority of consumer costs.

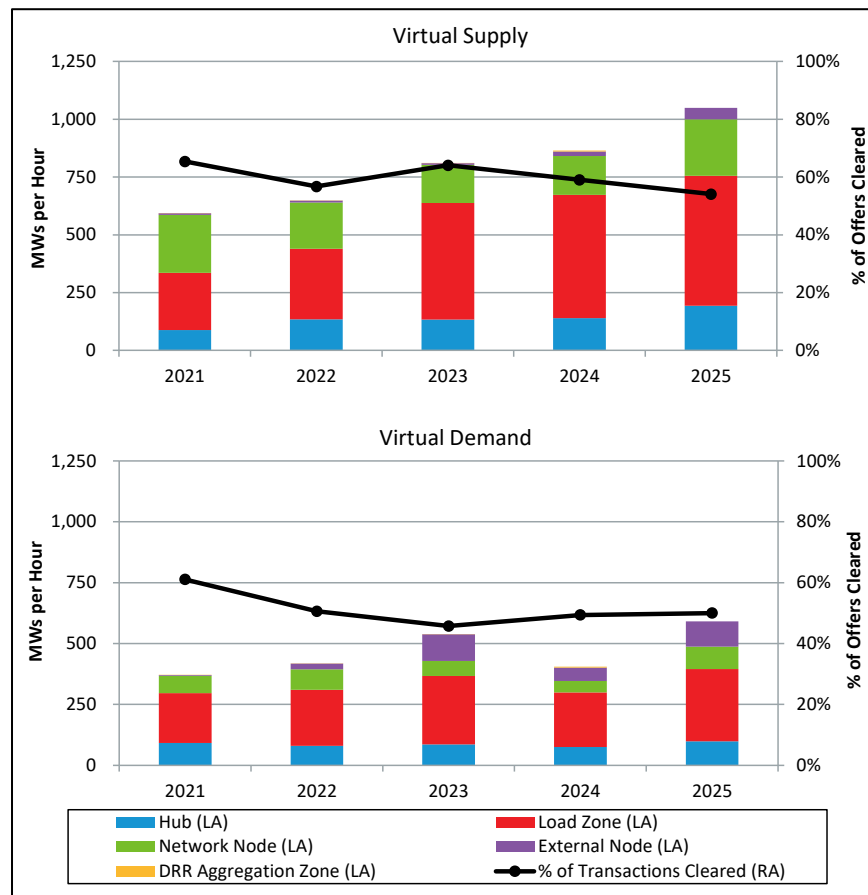
Review of the allocation of NCPC charges to virtual transactions is even more timely in the context of the new Day-Ahead Ancillary Services (DA A/S) market. This change strengthens the case for reassessing whether NCPC charges levied on virtual transactions are reasonable. Under DA A/S, sufficient physical supply is procured in the day-ahead market to meet the ISO's load forecast through the Forecast Energy Requirement (FER), regardless of virtual participation. As a result, virtual supply does not displace physical supply in the day-ahead market to meet the FER nor creates a physical shortfall that must be resolved in real time. Accordingly, traditional cost-causation arguments that attribute uplift to virtual supply deviations are materially less applicable under the current market design.

6.1 Virtual Transaction Volume

In 2025, the average quantity (in MW) of cleared virtual supply and demand per hour increased from 2024 and reached higher levels than in any of the previous four years, as shown in Figure 6-1 below.²¹¹ The percentage of virtual supply offers that cleared declined slightly, while the percentage of virtual demand bids that cleared was about the same as in 2024.

²¹¹ Cleared transactions are categorized based on the location type where they cleared: Hub, load zone, network node, external node, and Demand Response Resource (DRR) aggregation zone. The line graph (right axis) shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

Figure 6-1: Cleared Virtual Transaction Volumes by Location Type and Bid Type



Virtual Supply: Cleared virtual supply averaged 1,054 MW per hour in 2025, up 23% from 2024. This increase was consistent with an upward trend over the past several years and reflects, in large part, the growing amount of solar and wind resources on the grid; real-time solar and wind generation increased by a similar amount (24%) from 2024 to 2025. Virtual supply trends also reflect the limited participation of solar and wind generation in the day-ahead energy market. Solar settlement-only generators (SOGs) are ineligible to participate in the day-ahead market, while modeled solar and wind generators (> 5 MW capacity) tend to offer high-priced energy in the day-ahead market due to uncertainty in real-time weather conditions, risk preferences, and power purchase arrangements.^{212, 213} These offer patterns lead to higher volumes of renewable generation clearing in real-time than in the day-ahead market.

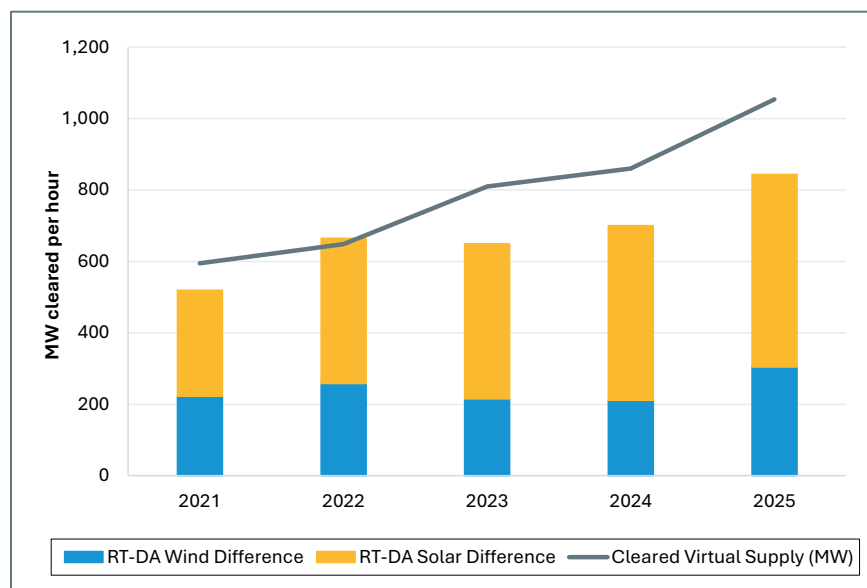
²¹² Settlement-only generators are generating units that produce < 5 MW, are not centrally dispatched by the ISO New England control room, and are not monitored in real time. By the end of 2025, settlement-only photovoltaic and wind generators had an installed capacity of about 2,475 MW and 56 MW, respectively.

²¹³ ISO-NE defines a modeled asset as, “one or more generating units at a single location that is fully visible and controllable by ISO-NE’s control room. Modeled generators bid into the Day-Ahead and/or Real-Time Energy Markets, contribute to price formation, and are therefore dispatched based on price.” At the end of 2025, ISO-NE had about 1,200 MW and 1,750 MW of modeled photovoltaic and wind capacity, respectively.

In this context, virtual supply plays an important role in helping close the gap between day-ahead and real-time markets, partially offsetting limited renewable participation in the day-ahead timeframe and contributing to price convergence.

Figure 6-2 shows how the average hourly quantity of cleared virtual supply compared to the average hourly difference in real-time versus day-ahead front-of-the-meter wind and solar generation over the past five years.²¹⁴

Figure 6-2: Cleared Virtual Supply, Solar, and Wind Volumes



In every year but 2022, the average volume of cleared virtual supply has exceeded the volume of SOG and modeled solar and wind generation that operated in real time but was not cleared in the day-ahead market. Within each year, there is considerable hourly and daily variation in the ratio of virtual supply volumes to solar and wind output, particularly during high-stress periods where the risk of high real-time price spikes tends to dampen willingness to clear virtual supply offers.

However, the overall annual trend indicates that virtual supply contributes to filling the gap between day-ahead and real-time renewable generation, and therefore supports more efficient day-ahead clearing outcomes. The fact that virtual supply volumes typically exceed the renewables gap, on an annual basis, demonstrates that participants also offer virtual supply to capture day-ahead and real-time price differences not related to renewable generation.

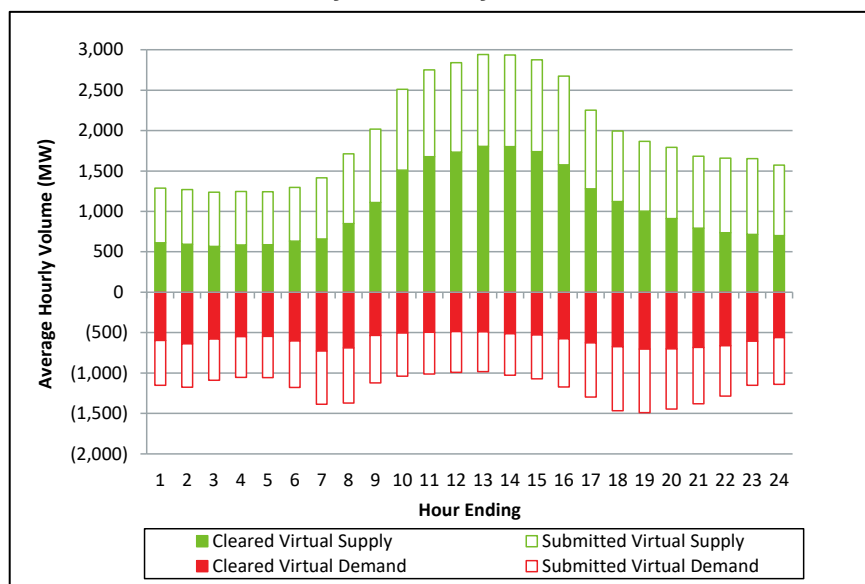
Virtual demand: As shown in Figure 6-1 above, cleared virtual demand averaged 595 MW per hour, a 194 MW or 48% increase from 2024. Volumes increased at all location types, reflecting multiple contributing factors. At external nodes, virtual demand volumes decreased from 2023 to 2024 but rebounded in 2025 due to increased clearing at the Highgate and New York North interfaces (up 35 MW/hr and 18 MW/hr, respectively, from 2024). Cleared virtual demand also increased at all other location types, driven by increases among a handful of participants.

Higher levels of virtual supply tended to be submitted and cleared during the middle part of the day, while higher levels of demand tended to be submitted and cleared during the morning and

²¹⁴ The figure does not include behind-the-meter (BTM) solar generation, which is factored into ISO-NE's load forecast and does not participate in either the day-ahead or real-time energy markets.

evening ramp periods. This can be seen in Figure 6-3 which shows the average hourly volume of submitted and cleared virtual transactions by time of day in 2025. Virtual supply is depicted as positive values, while virtual demand is depicted as negative values.

Figure 6-3: Average Hourly Submitted and Cleared Virtual Transaction Volumes by Time of Day, 2025



More virtual supply clears during the middle of the operating day than in the morning or evenings, reflecting the correlation between virtual supply volumes and output from solar generation. Between hours ending 9 through 17, cleared virtual supply averaged about 1,581 MW per hour compared to 737 MW per hour during the rest of the day.

Meanwhile, the average volume of cleared virtual demand continues to be slightly higher during the morning and evening ramping periods, when loads are higher and prices tend to be more volatile in the real-time market.

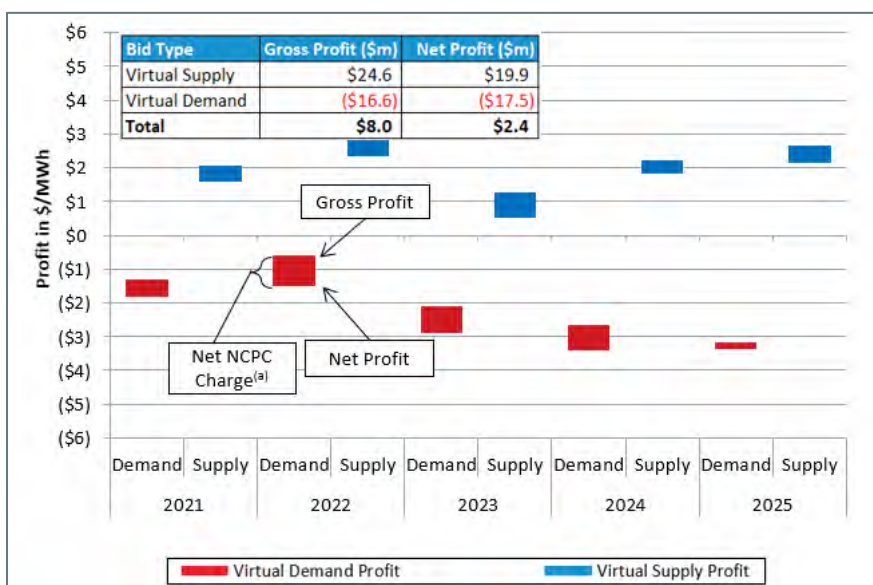
6.2 Virtual Transaction Profitability

Virtual transactions profit from differences between day-ahead and real-time prices, while at the same time contributing to increased day-ahead and real-time price convergence. In this section we present virtual transaction profitability metrics at the system and location level and discuss the impact of NCPC charges on virtual transaction profitability.

Generally, profitable virtual transactions help ensure that day-ahead commitments more accurately reflect real-time requirements, bringing prices across the two markets closer together. This price-converging function is becoming increasingly important as low-marginal cost intermittent generation enters the market and tends to produce more energy in real time compared to the day-ahead market. However, transaction costs in the form of NCPC charges can turn otherwise profitable virtual transactions into unprofitable transactions on a net basis. Figure 6-4 illustrates the profitability of virtual transactions along with the impact of NCPC charges on

profitability. The figure displays the average annual gross and net profit of virtual transactions since 2021.²¹⁵

Figure 6-4: Average Annual Gross and Net Profits for Virtual Transactions



(a) Net NCPC charges are NCPC charges minus NCPC credits, which participants receive for virtual transactions that relieve congestion at external interfaces in the day-ahead energy market.

Virtual demand incurred a gross loss of \$16.6 million, or \$3.19/MWh, on average in 2025, the highest gross loss for virtual demand over the last five years. Virtual supply made a gross profit of \$24.6 million, or \$2.67/MWh, in 2025. Virtual supply profitability increased from 2024 (\$2.21/MWh) and 2023 (\$1.28/MWh), but was in line with average per MWh profits in 2022.

Over the five-year reporting period, virtual demand has lost money on an annual basis while virtual supply has remained consistently profitable. This is because real-time prices have tended to be lower than day-ahead prices, on average. Additionally, the systematic differences in profitability stem from the distinct motivations underlying virtual supply offers and virtual demand bids. Participants offering virtual supply to reflect real-time renewable generation submit more offers in the middle of the day when solar output is high. This is also the time of day when day-ahead prices are typically higher than real-time prices. In 2025 virtual supply offers that cleared between hours ending 9 and 17 accounted for 56% of total virtual supply volume but generated 90% (\$22.2 million) of virtual supply's gross profit for the year.

By comparison, participants submitting virtual demand bids often do so to hedge against price risk in the real-time market.²¹⁶ Participants also clear high volumes of virtual demand at external

²¹⁵ The bars are categorized by year and bid type with virtual demand shown in red and virtual supply shown in blue. The top of each bar represents gross profit, the bottom represents net profit, and the length of the bar represents the per-MWh net NCPC charge. The inset table shows profitability by bid type for 2025.

²¹⁶ While the introduction of the Day-Ahead Ancillary Services (DA A/S) market may motivate DA A/S sellers to hedge close-out exposure through virtual demand bids when performance risk is high, we do not observe a significant or material increase in cleared virtual demand attributable to DA A/S sellers in practice. To date, virtual demand activity appears broadly consistent with prior patterns and does not suggest a systematic shift in participation behavior by DA A/S providers.

interfaces, often to obtain scheduling priority of import transactions.²¹⁷ These strategies differ from purely speculative bidding that aims to profit from day-ahead and real-time price differences.

Another factor affecting virtual profitability is NCPC credits and charges.²¹⁸ Average NCPC charges for virtual supply decreased for the fourth straight year, averaging \$0.55/MWh in 2025, while NCPC credits were smaller than in the prior year. In 2025, virtual supply remained profitable after subtracting net NCPC charges (\$0.51/MWh), making a net profit of \$2.16/MWh, on average. NCPC charges for virtual demand also decreased from prior years, averaging \$0.66/MWh in 2025. NCPC credits allocated to virtual demand were higher than in 2024 as more virtual demand bids relieved congestion at external interfaces, particularly at Highgate.²¹⁹ Virtual demand lost \$3.35/MWh, on average, after accounting for net NCPC charges (\$0.17/MWh).

These NCPC charges can limit the ability of virtual transactions to converge prices by discouraging participation and leading participants to clear bids only when a higher day-ahead and real-time price divergence is expected. The IMM continues to recommend that the ISO review the allocation of NCPC charges to virtual transactions to ensure the charges are consistent with principles of cost causation.²²⁰

Review of the allocation of NCPC charges to virtual transactions is even more timely in the context of the new Day-Ahead Ancillary Services (DA A/S) market. This change strengthens the case for reassessing whether NCPC charges should be levied on virtual transactions. Under DA A/S, sufficient physical supply is procured in the day-ahead market to meet the ISO's load forecast through the Forecast Energy Requirement (FER), regardless of virtual participation. As a result, virtual supply does not displace physical supply in the day-ahead market to meet the FER nor does it create a physical shortfall that must be resolved in real time.

Accordingly, traditional cost-causation arguments that attribute uplift to virtual supply deviations are materially less applicable under the current market design.

²¹⁷ For example, a participant with a large portfolio of generation assets may use virtual demand to hedge against higher real-time prices that might occur if one of their assets goes out of service in the real-time market after clearing in the day-ahead market.

²¹⁸ The ISO allocates the following NCPC charges to cleared virtual transactions: (1) **Real-time Economic NCPC**: all cleared virtual transactions (supply and demand) incur a charge to contribute towards the payment of real-time economic NCPC because they are considered real-time deviations; and (2) **Day-ahead Economic NCPC**: virtual demand bids are also charged day-ahead economic NCPC based on their share of day-ahead load obligation. This charge is typically much smaller because total day-ahead economic NCPC is divided among a much larger quantity of energy.

Virtual transactions can also incur NCPC charges associated with congestion at the non-CTS (coordinated transaction scheduling) external interfaces. Because these NCPC charges do not have a broad market impact or apply to virtual transactions at most locations, they are not considered in much detail in this report.

²¹⁹ For more information on NCPC credits at external interfaces, see Section 5.1.3.

²²⁰ For more information on recommended market design changes, see the table in the Executive Summary.

Most Profitable Locations for Virtual Supply

Table 6-1 details the top 10 most profitable locations for virtual supply in 2025, after accounting for transaction costs and NCPC charges/credits (ranked by total net profit).²²¹

Table 6-1: Top 10 Most Profitable Locations for Virtual Supply, 2025

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit (\$k)	Net Profit (\$k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
.H.INTERNAL_HUB	Hub	2,696,192	1,692,453	\$4,439	\$3,530	\$2.62	\$2.09	40
.Z.SEMASS	Load Zone	944,118	727,188	\$1,872	\$1,470	\$2.57	\$2.02	21
.Z.MAINE	Load Zone	1,112,077	898,426	\$1,892	\$1,367	\$2.11	\$1.52	29
UN.BULL_HL 34.5BLHW	Gen Node	290,988	163,915	\$1,280	\$1,190	\$7.81	\$7.26	23
.Z.CONNECTICUT	Load Zone	583,951	410,089	\$1,154	\$930	\$2.81	\$2.27	21
.Z.NEMASSBOST	Load Zone	994,746	784,763	\$1,322	\$895	\$1.69	\$1.14	19
.Z.RHODEISLAND	Load Zone	560,812	447,574	\$1,108	\$860	\$2.48	\$1.92	17
.Z.NEWHAMPSHIRE	Load Zone	678,355	541,558	\$1,076	\$764	\$1.99	\$1.41	18
.Z.WCMASS	Load Zone	628,592	549,846	\$1,073	\$754	\$1.95	\$1.37	19
.Z.VERMONT	Load Zone	689,612	564,394	\$968	\$628	\$1.72	\$1.11	23

Nine of the top ten locations consisted of the Hub and all eight load zones. High total net profits at these locations were in line with the lower real-time prices at these locations, especially during the middle of the operating day.

The other location is associated with wind power generation in Northeast Maine, a region that is export-constrained. Because wind generators often do not offer their full capacity in the day-ahead market, or offer at high prices, virtual traders can profit when increased real-time wind generation leads to transmission congestion and lower real-time prices behind the export constraint.²²²

Most Profitable Locations for Virtual Demand

Table 6-2 details the 10 most profitable locations for virtual demand in 2025, after accounting for transaction charges and all relevant NCPC charges/credits (ranked by total net profit).

Table 6-2: Top 10 Most Profitable Locations for Virtual Demand, 2025

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit (\$k)	Net Profit (\$k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
UN.OCEAN_ST13.8OS P2	Gen Node	6,271	3,046	\$150	\$142	\$49	\$47	3

²²¹ For more information about the additional charges for virtual transactions, see: ISO New England Inc., “Section IV.A Recovery of ISO Administrative Expenses, Schedule 2 Energy Administration Service”, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_4/section_iva.pdf.

²²² These locations tend to be riskier as well, given the difficulty of forecasting wind generation. For example, if a participant expects high wind output in the real-time market, they might clear virtual supply in the day-ahead market at a low price and expect to profit off negative real-time prices. However, if the wind generation does not meet day-ahead expectations, these locations will likely be unconstrained, and the participant would have to pay its day-ahead obligation back at a higher real-time price.

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit (\$k)	Net Profit (\$k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
UN.BASELINE34.5DNEW	Gen Node	3,999	539	\$28	\$28	\$52	\$52	8
.I.SHOREHAM138 99	Ext Interface	229,851	11,973	\$44	\$28	\$4	\$2	7
LD.BUNKR_HL13.8	Load Node	21,402	16,794	\$34	\$21	\$2	\$1	13
.I.NRTHPORT138 5	Ext Interface	231,345	3,425	\$10	\$19	\$3	\$6	8
.I.SALBRYNB345 1	Ext Interface	164,781	1,894	\$17	\$16	\$9	\$8	7
UN.TUTTLEHL34.5ANTW	Gen Node	1,436	1,436	\$18	\$16	\$13	\$11	2
LD.JOHNSTON12.5	Load Node	3,270	2,852	\$17	\$15	\$6	\$5	5
LD.ELM_WEST13.8	Load Node	3,583	3,583	\$13	\$12	\$4	\$3	4
LD.CONGRESS13.8	Load Node	1,192	1,167	\$12	\$10	\$10	\$9	3

Three of the 10 most profitable locations were external interfaces. .I.SHOREHAM138 99 and .I.NRTHPORT138 5 are external proxy nodes for the two Long Island, New York interfaces, and .I.SALBRYNB345 1 is the external proxy node for the New Brunswick interface. At the Northport-Norwalk interface, about half of net profit came from uplift credits that a small number of participants received for relieving import congestion.²²³ Typically, New England is a net exporter to Long Island via the Northport-Norwalk interface; however, in Q4 2025, New England was a net importer over this interface. Additionally, during Fall 2025 the Northport-Norwalk interface was frequently limited due to transmission work, which created more congestion at the interface than normal. Virtual traders were able to relieve some of that congestion in the day-ahead market and received uplift credit from importers for doing so.

The other seven most profitable locations consisted of generator and load nodes. Overall, none of the 10 nodes had more than 2 MWh of virtual demand clearing, on average.

²²³ For more information on NCPC credits at external interfaces, see Section 5.1.3.

Section 7

Forward Capacity Market

The capacity auction for the delivery period 2028/29 delivery was delayed until 2028 as the Forward Capacity Market (FCM) shifts to a prompt-auction structure as part of the Capacity Auction Reforms (CAR) project.²²⁴ In this section (7.1), we first discuss and provide our current thinking and recommendations on aspects of the CAR design, including comments on the Prompt-Deactivation component of the design (“CAR-PD”) and benefits of the Seasonal-Accreditation component (“CAR-SA”). The CAR-PD phase of the reforms was recently approved by FERC.²²⁵

Finally, since no forward capacity auction occurred in 2025, we focus on secondary market activity and Pay for Performance (PfP) settlement outcomes. Monthly reconfiguration auctions for Capacity Commitment Periods (CCP) 15-16 and annual reconfiguration auctions for CCPs 16-18 were held during the year. Section 7.2 summarizes the outcomes of these reconfiguration auctions. Section 7.3 covers the PfP events on June 24 and November 23, which mark an increase in reserve deficiency hours and total PfP payments relative to prior years.

7.1 Capacity Auction Reforms

The Capacity Auction Reform (CAR) project is a multi-year initiative aimed at overhauling key aspects of the capacity market, including auction timing, seasonal procurement, and capacity qualification and exit (deactivation) rules. The project is split into two components: (1) the CAR-PD project encompasses the prompt-auction timeline and resource deactivation components and (2) The CAR-SA project encompasses the bi-annual seasonal auction and marginal resource accreditation components, including the implementation of a gas-specific resource constraint in winter months to better reflect limited natural gas availability to the power sector when pipelines are constrained.

The FERC approved tariff changes for CAR-PD in early 2026, and as part of this regulatory process, the IMM filed supportive comments on the CAR-PD design.²²⁶ Section 7.1.1 below summarizes these comments. CAR-SA design work continued throughout 2025, and Section 7.1.2 outlines key design features of the proposal.

7.1.1 CAR: Prompt/Deactivations

The two primary components of the CAR-PD proposal are the replacement of the forward capacity auction construct (three years in advance) with a prompt (one month in advance) capacity auction, and associated changes to the resource deactivation process. Other key changes included moving from a descending clock auction to a sealed-bid auction format and the conforming changes to the buyer- and seller-side mitigation rules. While CAR-PD is intended as an intermediate step with changes that will carry through the final CAR design (incorporating both CAR-PD and CAR-SA), we support CAR-PD on its own merits as an improvement on existing capacity market rules.

²²⁴ For more details on the CAR project, see: ISO New England, “Capacity Auction Reforms Key Project” webpage, <https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project>.

²²⁵ Federal Energy Regulatory Commission, “Order Accepting Tariff Revisions, 194 FERC ¶ 61,249, Mar. 30, 2026, Docket No. ER26-925-000, <https://www.iso-ne.com/static-assets/documents/100033/er26-925-000.pdf>.

²²⁶ ISO New England Inc., Internal Market Monitor, “Comments of the Internal Market Monitor of ISO New England”, January 20, 2026, Docket No. ER26-925-000, https://www.iso-ne.com/static-assets/documents/100031/er26-925-000_imm_comments_cars.pdf.

Benefits of Moving the Auction Timing: The prompt-auction structure reduces uncertainty in the capacity market. On the demand side, the capacity market relies on load forecasts, which were made more than three years in advance under existing Forward Capacity Auction (FCA) rules. Under the FCA, ongoing changes to the load forecast are reflected in Net ICR adjustments throughout three Annual Reconfiguration Auctions (ARAs), and these have shown significant variability to date. The prompt-auction design improves forecast certainty through reducing the load forecast window, enhancing market signals and eliminating the need for ARAs.

Prompt auctions similarly reduce uncertainty in supply. The CAR-PD design requires resources to be fully built before they can enter the auction. This eliminates unbuilt “phantom capacity” that might clear a forward capacity auction and fail to complete construction in time for the capacity commitment period, negatively impacting price formation. Additionally, the prompt timeframe should improve participants’ expectations of the net going forward costs in their supply offers.²²⁷

Deactivation Process: The deactivation component of CAR-PD eliminates priced retirement bids in favor of unpriced, irrevocable deactivation notifications due one year before the commitment period. We observe that deactivation decisions are usually based on unit fundamentals and multi-year market outlooks rather than the single-year capacity clearing price implied by the priced retirement bid construct. The one-year notification due date balances the time necessary for the ISO to conduct reliability assessments for the deactivating resource and time for a market participant to form reasonable market expectations relatively near to the commitment period, with flexibility up until the binding one-year deadline.

While deactivations will be unpriced under CAR-PD, the IMM will continue to conduct market power reviews for deactivating resources. A conduct and portfolio benefits test will be applied to all deactivation notices. Should a resource fail these tests, the resource will still exit the market, but a proxy bid will be included in the auction in its place to preserve competitive price formation in the prompt auction.

Future Deactivation Mitigation Enhancements: During the design process, the IMM expressed a preference for adopting a market power charge as a more effective deterrent to uneconomic deactivations than the current and proposed proxy bid approach.²²⁸ We continue to believe this option warrants further consideration. Because deactivations can affect market prices over multiple years—and are heavily influenced by the pace and nature of new entry—the proxy bid approach provides protection only for a single year. A well-designed market power charge would more directly discourage uneconomic deactivations and better protect market outcomes over time.

Future Seller-side Mitigation Enhancements: The IMM has recommended replacing the current Pivotal Supplier Test with a Conduct and Impact (C&I) framework for seller-side mitigation of existing resources offering capacity for a single delivery period. A C&I approach would more accurately assess market power, provide a more consistent and flexible mitigation framework, reduce reliance on rigid conduct thresholds, and offer a conceptual foundation for better

²²⁷ Net going forward costs represent the incremental costs of a resource taking on a CSO. ISO New England Inc., “[Market Rule 1 - Section 13 Forward Capacity Market](https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf)”, Section III.13.1.2.3.2.1.2.A, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

²²⁸ ISO New England, Internal Market Monitor, “*IMM Feedback on Capacity Auction Reforms – Prompt & Deactivations*”, June 10, 2025, https://www.iso-ne.com/static-assets/documents/100024/a03.3a_mc_2025-06-10-11_car-pd_imm_feedback.pdf.

alignment with buyer-side mitigation rules. While this recommendation was not adopted in for the CAR-PD phase, we continue to recommend that the ISO evaluate and adopt these changes in advance of the next capacity auction.²²⁹

Auction Format: The CAR-PD design includes a change to a sealed-bid auction and provides a number of improvements in terms of reducing administrative complexity, providing better alignment with the underlying economic issues that a prompt capacity procurement process is intended to address, and mitigating certain market power concerns. On the latter, the sealed-bid auction format addresses certain market power concerns that arise due to information release in the current descending-clock auction structure.

7.1.2 CAR: Seasonal/Accreditation

The ongoing CAR-SA project encompasses a shift to two seasonal capacity auctions (summer and winter) and a marginal resource accreditation approach.²³⁰ The sections below outline these features at a high level.

Seasonality in Accreditation and Reliability Risk

The CAR-SA proposal includes a shift from one annual capacity auction to two seasonal capacity auctions, one for summer and one for winter. Each auction will be run independently with individual demand curves and supply offers. The primary purpose of the seasonal construct is to enable season-specific marginal resource accreditation; as discussed below, marginal accreditation can improve investment signals in the capacity market, and a seasonal context is necessary to reflect the different (and evolving) summer-winter load profiles and the value of different resource types in meeting summer and winter peaks.

Marginal Resource Accreditation

The resource accreditation reforms aim to align capacity market qualified supply with expected resource contributions toward system reliability by adopting a Marginal Reliability Impact (MRI) approach.²³¹ Current FCM rules generally qualify capacity based on audited resource performance, which can differ materially from the true reliability value provided by a resource if it is not fully available during stressed conditions, such as due to forced outages, gas pipeline limitation, and limited energy.

Shifting the capacity market toward MRI-based capacity improves market efficiency and cost-effectiveness, reducing the procurement of unreliable capacity and rewarding investment in resources that are best positioned to address system reliability needs.

Seasonality is a core consideration in marginal resource accreditation because seasonal conditions determine how effectively different resource types contribute to system reliability. For example, solar resources provide substantially more reliability value in summer, when daylight is abundant, than in winter, when daylight is limited and reliability events often occur during severe weather.

²²⁹ ISO New England Inc., Internal Market Monitor, “2024 Annual Markets Report”, May 2025, Section 6, <https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf>.

²³⁰ For more information on CAR-SA, see: ISO New England Inc., “Capacity Auction Reforms: Seasonal/Accreditation (CAR-SA), Design Kickoff Discussion”, September 9, 2025, https://www.iso-ne.com/static-assets/documents/100027/a02.2a_mc_2025_09_09_10_introduction_car-sa_presentation.pdf.

²³¹ In this context, “system reliability” is defined by the one-day-in-ten-years reliability standard.

Also, short-duration energy storage resources, such as batteries, can provide significant reliability value during brief, high-risk reliability intervals; however, their contribution during prolonged stress events is inherently limited. Given the rapid growth of these technologies, it is increasingly important that resource accreditation accurately reflects their reliability attributes so that market compensation appropriately aligns with system needs.

Natural Gas Resource Constraint

Reliability risks in New England are particularly pronounced during winter periods due to the region's limited natural gas pipeline capability. Cold-weather conditions increase heating demand, which can constrain gas availability to generators at the same time winter peak loads and reliability events are most likely to occur. Looking ahead, projected growth in winter demand over the next decade is expected to further increase these risks (see Figure 2-5). As a result, it is increasingly important to explicitly model natural gas pipeline limitations and their impact on resource deliverability in the capacity market accreditation process, so that resource reliability contributions are accurately reflected and appropriately compensated.

In short, the physical natural gas constraint reduces the expected reliability contributions from gas-only generators in winter. To reflect this reality, the ISO's proposal models the limited gas system as a shared generation constraint for gas-only resources, conceptually and practically similar to a transmission export-constrained zone, which limits the generation behind the constraint in a shared manner.²³² This is because the gas constraint is a shared quantity among generators; on a day when the gas system is fully constrained, a gas-fired generator can only contribute to system reliability by consuming limited gas supplies and limiting reliability contributions from other generators.

Under this design, gas-only generators will face a gas demand curve that values the reliability contributions of gas-only generation at a lower level than other system generation, based on modeled gas system limits during expected shortage conditions. Gas-only units that clear based on this demand curve will receive a lower capacity clearing price than the rest of the system. Notably, gas-fired generators that firm up their fuel supplies are not included with the gas constraint, specifically dual-fuel generators that can switch to oil during winter conditions, and gas-only generators that sign firm contracts that confer priority access to gas regardless of system conditions.²³³

The gas constraint design will improve capacity market signals through aligning gas-only generator compensation with expected reliability contributions, and through limiting the impact of unreliable gas-only generation capacity on the market clearing prices. Gas generators will be incentivized to invest in firm fuel or dual-fuel capability through weighing the costs of such investments against their expected increase in capacity market compensation.

²³² ISO New England Inc., "CAR-SA: Gas Demand Curves Examples", January 2026, https://www.iso-ne.com/static-assets/documents/100031/a04.1.a.iii_mc_rc_2026_01_13-14_follow_up_gas_demand_curve_examples.pdf.

²³³ Since gas availability for electric generators (after heating demand) remains a limited quantity even if a portion of that gas is firm, the CAR-SA proposal will reduce the gas demand curve by the amount of demonstrated firm gas capacity at the time of the auction. Therefore, the gas-only demand curve will reflect the availability of non-firm gas for generation after both heating demand and demonstrated firm gas for generation are accounted. For more information, see: ISO New England Inc., "Overview of Gas Design" December 2025, https://www.iso-ne.com/static-assets/documents/100030/a04.1.a_mc_rc_2025_12_09-10_gas_constraint_design_cont..pdf.

7.2 Reconfiguration Auction Outcomes

This section provides a review of reconfiguration auction outcomes in 2025, with results spanning Capacity Commitment Period (CCP) 15 (2024/25) through CCP 18 (2027/28).

Key Takeaways

Overall traded volumes in secondary capacity auctions remain low relative to total contracted capacity, as most positions are established and held through the primary Forward Capacity Auctions (FCAs). Nevertheless, secondary auction clearing prices provide useful information about market participants' expectations. Notably, reconfiguration auction prices for the 2026/27 and 2027/28 capacity commitment periods were materially higher than the associated FCA clearing prices, suggesting tighter supply-demand fundamentals and potentially heightened expectations of future capacity scarcity conditions and Pay-for-Performance (PfP) exposure.

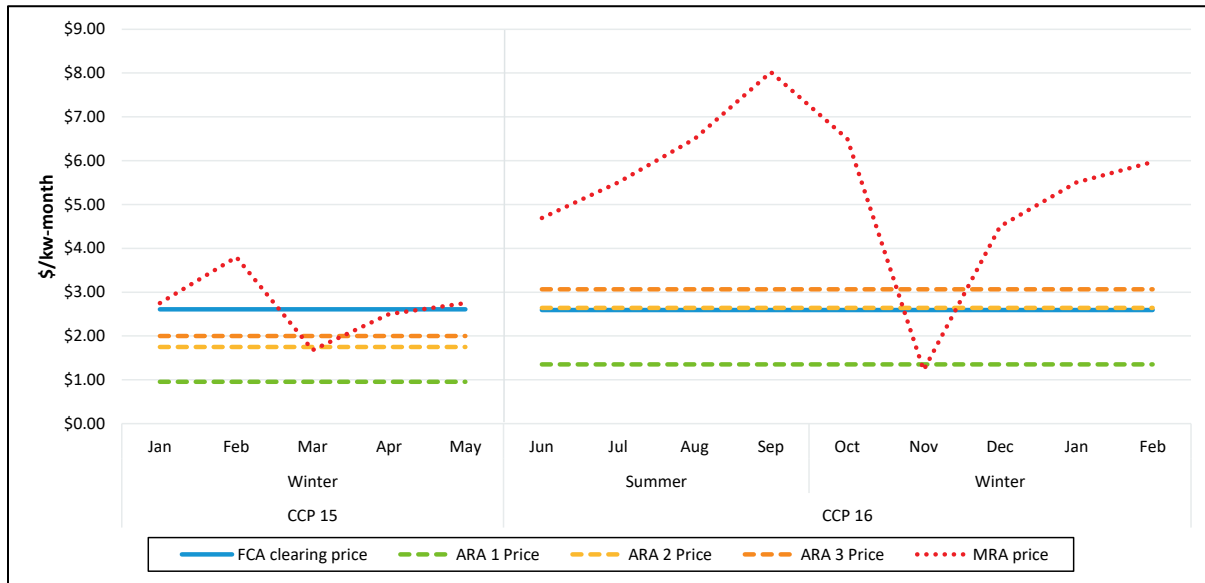
Annual Reconfiguration Auction (ARA) prices for CCPs 15 and 16 were generally similar to or lower than FCA clearing prices. Reduced capacity prices were generally attributable to lowered Net ICR values as load forecasts shifted leading up to the commitment periods. In contrast, prices for ARA 2 of CCP 17 and ARA 1 of CCP 18 reached around \$5/kW-month, marking a significant increase from each FCA. These prices were driven by tighter supply due to CSO terminations and higher prices for remaining supply.

Monthly Reconfiguration Auction (MRA) prices in CCP 15 were similar to the FCA 15 clearing price, but prices in CCP 16 were generally much higher than the FCA 16 price, peaking at \$8/kW-month in September 2025. Clearing prices were driven by relatively tight supply availability in summer months and increased perceived PfP risk throughout the year.

7.2.1 Reconfiguration Auctions: CCP 14 and CCP 15

Monthly reconfiguration auctions covering the CCP 15-CCP 16 (2024/25 and 2025/26) period occurred throughout 2025. Figure 7-1 shows Monthly Reconfiguration Auction (MRA) rest-of-pool prices alongside Forward Capacity Auction (FCA) and Annual Reconfiguration Auction (ARA) rest-of-pool prices.

Figure 7-1: Reconfiguration Auction Prices for CCPs 15 and 16



Annual reconfiguration auction prices were generally near or below FCA clearing prices for CCPs 15 and 16 (June 2024 through May 2026), with falling Net ICR requirements following the forward auctions and closer to the delivery periods. Monthly reconfiguration auctions in the latter half of CCP 15 cleared at prices near the FCA 15 price with minimal price separation.

By contrast, MRAs throughout CCP 16 generally cleared at prices significantly higher than FCA 16, with significant price volatility. MRA prices averaged over \$5/kW-month, with a peak of \$8/kW-month in September 2025. Clearing prices throughout the summer of CCP 16 were influenced by limited supply. On average, only 500 MW of supply offers entered into the auctions, compared to 4,000 MW of demand. In other words, more resources were willing to offload obligations than resource willing to take on obligations.

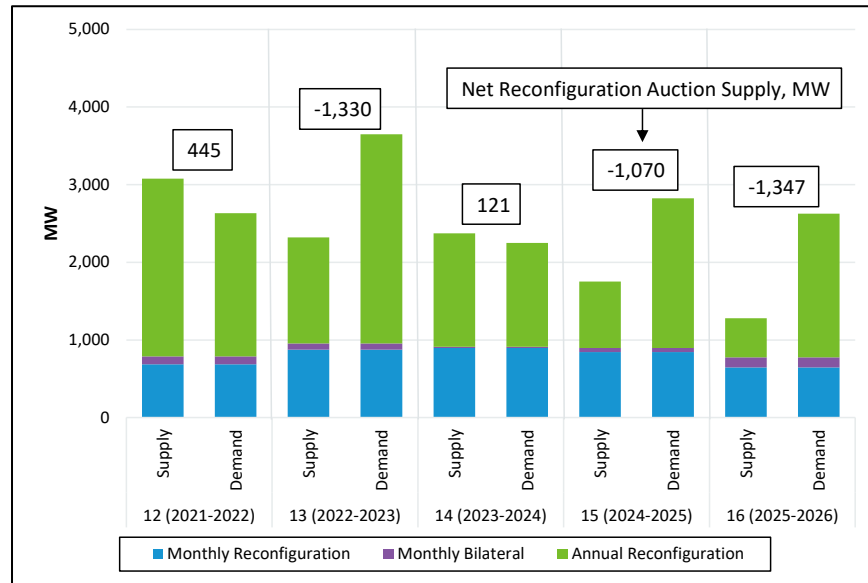
Capacity supply is typically tighter in summer as fossil fuel-fired generators have less qualified capacity due to high ambient temperatures, and therefore demand response resources make up the majority of MRA cleared supply. While a return to the relatively capacity-abundant winter period resulted in a low clearing price in November 2025, high supply offers and demand bids continued to drive high clearing prices through the rest of the year into 2026. Increased supply offers and demand bids may reflect a higher perceived risk of holding a CSO relative to prior years.

Traded volumes in reconfiguration auctions remained low as a share of total volumes acquired in FCAs. Figure 7-2 shows secondary auction volumes from CCP 12-CCP 16, with separate bars showing cleared supply and cleared demand.^{234,235}

²³⁴ The annual reconfiguration bars represent the volume of total capacity added or shed (whichever is greater) across all three ARAs for a commitment period. Volumes are calculated as annual averages. For example, MW traded in ARAs have a weight of 1, while MW traded in MRAs have a weight of 1/12.

²³⁵ ARAs feature an updated Net ICR compared to the base auction. Demand represents a combination of an updated system demand curve and participant bids to shed CSO, while supply represents a price-taking component for CSO that is not participating in the ARA and a priced component for new supply offers. CSO can enter or exit the market on a net basis in an ARA, and this is the only reconfiguration type in which net entry or exit can occur.

Figure 7-2: Traded Volumes in Reconfiguration Auctions

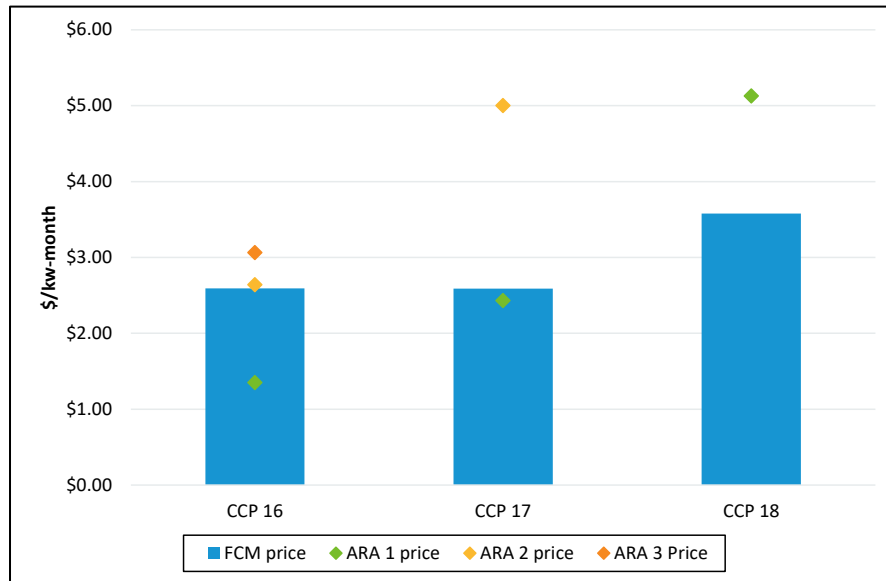


Reconfiguration auction volumes averaged 8% of FCA auction volumes for CCPs 15-16. ARA volumes continued to make up the largest share of secondary auction volume as capacity left the market on a net basis throughout the ARAs in CCP 15-16 as Net ICR requirements fell. Decreased monthly reconfiguration auction volumes are associated with the limited capacity supply in Summer 2025. Bilateral trading accounted for 130 MW of capacity on average in CCP 16, up from only 50 MW in CCP 15.

7.2.2 Annual Reconfiguration Auctions: CCP 16 (2025/26), CCP 17 (2026/27), and CCP 18 (2027/28)

The final ARA for CCP 16, the second ARA for CCP 17, and the first ARA for CCP 18 occurred in 2025. Figure 7-3 shows the rest-of-pool clearing prices for the FCAs 16-18 alongside the ARAs that have occurred so far for each commitment period.

Figure 7-3: Annual Reconfiguration Auction Prices, CCP 16-CCP 18



The third ARA for CCP 16 cleared at \$3.06/kW-month, higher than the \$2.59/kW-month clearing price in FCA 16. Clearing prices rose despite a decline in the Net ICR (30,300 MW in ARA 3 compared to 31,645 MW in FCA 16).

The second ARA for CCP 17 and the first ARA for CCP 18 both cleared at roughly \$5.00/kW-month, marking significant increases from both FCA clearing prices. While the clearing price of CCP 17 ARA 2 was influenced by a slight increase in Net ICR (30,600 MW, up by 300 MW), tighter supply was the primary driver of both outcomes. Increased supply prices were attributable to two factors; first, significant amounts of capacity were terminated between the FCA and ARAs (500 MW in CCP 17; 900 MW in CCP 18).²³⁶ Notably, battery storage generators made up the majority of terminated CSO MW for CCP 17-18 (over 75%). Second, a heightened expectation of more PfP events likely contributed to increased offers for remaining incremental supply.

7.3 Pay-for-Performance Outcomes

Pay-for-Performance (PfP) is a two-settlement mechanism that credits or charges resources based on their performance in meeting energy and operating reserve requirements during periods when the system is deficient in Total 10- or 30-minute reserves. These periods are called Capacity Scarcity Conditions (CSCs).

Two distinct CSCs occurred in 2025, marking just the sixth and seventh occurrences since the PfP market rules were introduced in June 2018. The 2025 CSCs occurred on June 24 and November 23. The June 24 event was driven by high temperatures, peak system loads, and generation trips, while the November 23 event was driven by large generation trips on a comparatively normal operating day.²³⁷ The two events totaled 3.6 hours, mostly driven by the historically long June 24 event. However, CSC hours were slightly under the ISO forecasting models' predictions of reserve deficiency hours for CCP 16 (2025/26).²³⁸

Key Takeaways

Two Capacity Scarcity Conditions (CSCs) occurred in 2025. The June 24 event was the longest CSC since the implementation of Pay for Performance (PfP) rules at just over 3 hours, while the November 23 event lasted only 30 minutes. The June 24 event was driven by the system annual peak load, and generator outages contributed to both events.

The PfP rate increased to \$9,337/MWh for CCP 16 from \$5,455/MWh in CCP 15, significantly impacting total credits and charges in the two-settlement system. PfP transfers totaled \$114.3 million on June 24 and \$32.3 million on November 23. Many resources reached monthly stop-loss limits on June 24, marking the first and only event in which the stop-loss construct

²³⁶ For more information on termination of capacity supply obligations, see: ISO New England Inc., “[Market Rule 1 - Section 13 Forward Capacity Market](https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf)”, Section III.13.3.4A., https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

²³⁷ Detailed analysis of event drivers on both days is available in Section 4.6, and in the Summer and Fall 2025 Quarterly Markets Reports. ISO New England Inc., Internal Market Monitor, “*Internal Market Monitor Reports and other Materials*” webpage, <https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor>.

²³⁸ ISO New England., “*Operating Reserve Deficiency Information – Capacity Commitment Period 2024-2025*”, December 7, 2021, https://www.iso-ne.com/static-assets/documents/2021/12/a00_pspc_2021_12_iso_memo_or_def_fca_16.pdf. FCA 16 cleared at 32,810 MW, a surplus of 1,165 MW over Net ICR (31,645 MW). At this level of capacity, the ISO forecast roughly 4-5 hours of reserve deficiencies.

significantly affected settled outcomes.

Notably, the balancing ratio exceeded 100% on June 24. The high balancing ratio indicated that system CSO was insufficient to meet load and reserve requirements during the event.

Additionally, resources were required to produce more than their CSO to avoid receiving net PfP penalties. Forthcoming market rule changes will cap the balancing ratio at 100% to avoid financial obligations that exceed physical generating capabilities.

Capacity resource performance is assessed based on the energy delivered and operating reserves provided during CSCs relative to the resource's CSO and the system's balancing ratio—the fraction of total contracted capacity needed to meet load and reserve requirements.

The PfP rate is the price at which resources are compensated for providing energy or reserves above their CSO (after weighting by the balancing ratio). The rate increased to \$9,337/MWh in CCP 16, a 70% increase from CCP 15 (\$5,455/MWh). The higher rate contributed to large PfP settlements in 2025 relative to prior years. While the tariff continues to specify a rate of \$9,337/MWh for upcoming CCPs, the ISO has recently proposed a reduction to \$3,500/MWh, which would take effect immediately if accepted.²³⁹

Capacity market settlements for the June 24 PfP event are aggregated by fuel type in Figure 7-4, while Figure 7-5 shows settlements for the November 23 event.²⁴⁰ The green and red bars show PfP credits or charges to resources with CSO by fuel type on a net basis. The yellow bars show PfP credits to resources with no CSO that provided energy or reserves during the event. Monthly base capacity payments are shown by fuel type for comparison.

²³⁹ For current PPR, see: ISO New England Inc., “[Market Rule 1 - Section 13 Forward Capacity Market](https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf)”, Section III. 13.7.2.5, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf. For information on the proposed PPR update, see: ISO New England Inc., “*Pay-For-Performance Revisions: Performance Payment Rate (PPR) Proposed Change*”, March 2026, https://www.iso-ne.com/static-assets/documents/100033/a03_mc_2026_03_10-12_pfp_revisions_ppr.pdf.

²⁴⁰ In these figures, “DF” refers to dual-fuel assets and “CC” refers to combined-cycle generators. “ST – RFO” refers to steam turbine units burning residual fuel oil. Gas- or oil-fired units with fast-start capability are separated from similar units without fast-start capability. The “Other” category includes nuclear, coal, and wood or waste-fired units.

Figure 7-4: Pay-for-Performance Settlements, June 2025

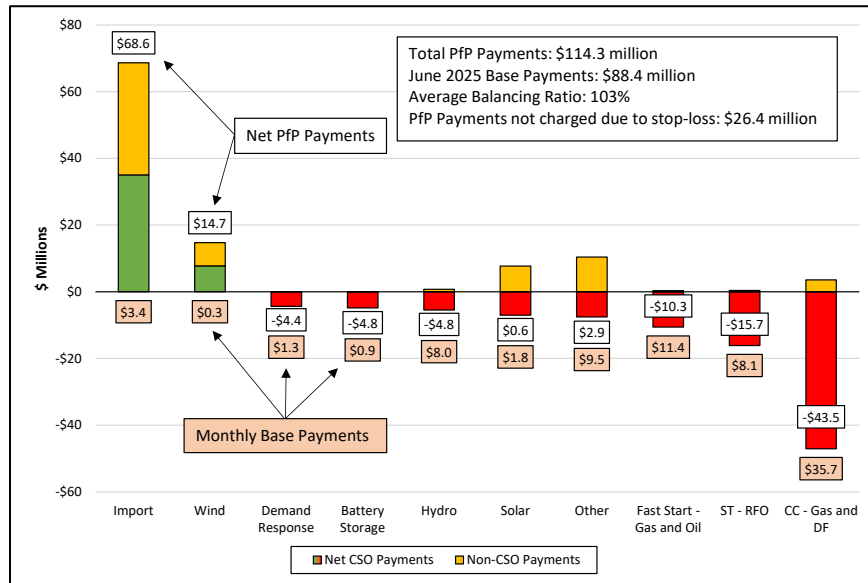
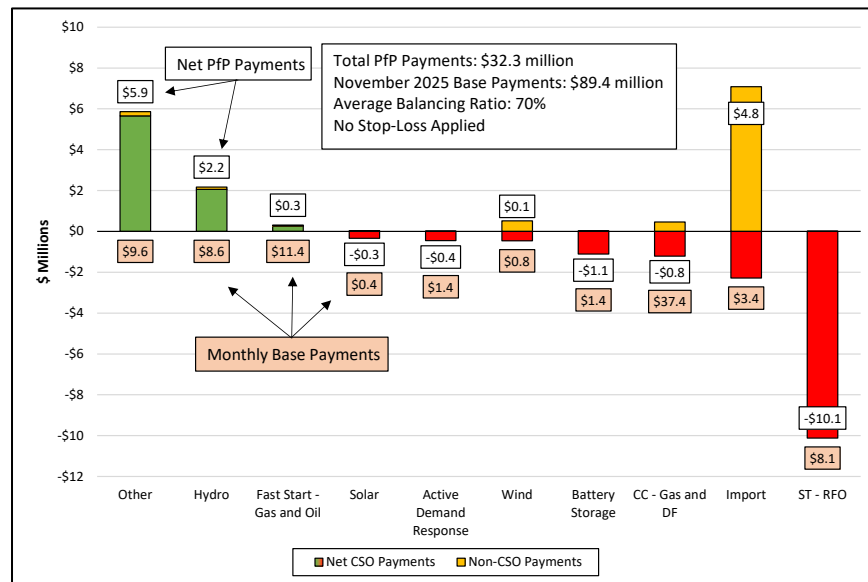


Figure 7-5: Pay-for-Performance Settlements, November 2025



Resource Performance: Aggregated across the year, imports were the best-performing resource type during shortage conditions due to their relative flexibility. Imports with and without CSO earned \$69 million on June 24, and imports without CSO earned \$7 million in credits on November 23.²⁴¹ While most resource types underperformed on June 24 due to the 103% average balancing ratio (discussed below), combined cycle units particularly struggled due to gas pipeline Operational Flow Orders and high ambient temperatures. Resource performance during the November 24 event was largely determined by resource availability in an unexpected and short-

²⁴¹ In contrast, imports with CSO faced \$3.1 million in PFP charges in November. Imports as a group received \$4.8 million in net credits during the event.

duration event, with flexible and already-online units performing well against a low balancing ratio and slower steam turbine units performing poorly since they were unable to come online in time.

Balancing Ratio: The balancing ratio averaged 103% on June 24 and 70% on November 23. The June 24 event marked the first and only time that the balancing ratio exceeded 100% since the implementation of PfP rules. The high balancing ratio indicated that system CSO was insufficient to meet load and reserve requirements,²⁴² and that resources were required to produce more than their CSO to avoid financial PfP penalties. Forthcoming market rule changes will cap the balancing ratio at 100% to eliminate financial obligations in excess of physical capabilities.²⁴³ Additionally, exports occurred during both events and contributed to the reserve deficiency and to the high balancing ratio in June. The assessment of PfP charges to exports would have disincentivized export demand.²⁴⁴

Stop Loss Mechanism: The combination of the high PfP rate, high balancing ratio, and long event duration caused several resources to reach monthly stop-loss limits on June 24. The stop-loss construct resulted in \$26.4 million in reallocations from over-performing capacity resources to cover shortfalls from under-performing capacity resources that reached stop loss limits. Notably, the stop-loss construct limits stop-loss charge exposure to capacity resources rather than reducing PfP credits to non-capacity resources. This is because the stop-loss mechanism functions as a mutual insurance fund for capacity resources, and this construct will continue under the balancing ratio changes. The November 23 event did not result in any additional resources reaching monthly or annual stop-loss limits.

²⁴² Weather on June 24 was unexpectedly extreme, and loads were estimated to be in-line with a 90/10 hotter-than-forecast day in the 2021 CELT report forecast for FCA 16.

²⁴³ Federal Energy Regulatory Commission, “*Order Granting Complaint in Part and Denying in Part*”, 194 FERC ¶ 61,052, Docket No. EL25-106-000, January 22, 2026, https://www.iso-ne.com/static-assets/documents/100031/el25-106-000_order_nepga_complaint_grant_in_part.pdf.

²⁴⁴ For the IMM’s recommendation on PfP treatment of exports, see: ISO New England Inc., Internal Market Monitor, “*2024 Annual Markets Report*”, May 23, 2025, <https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf>.

Section 8

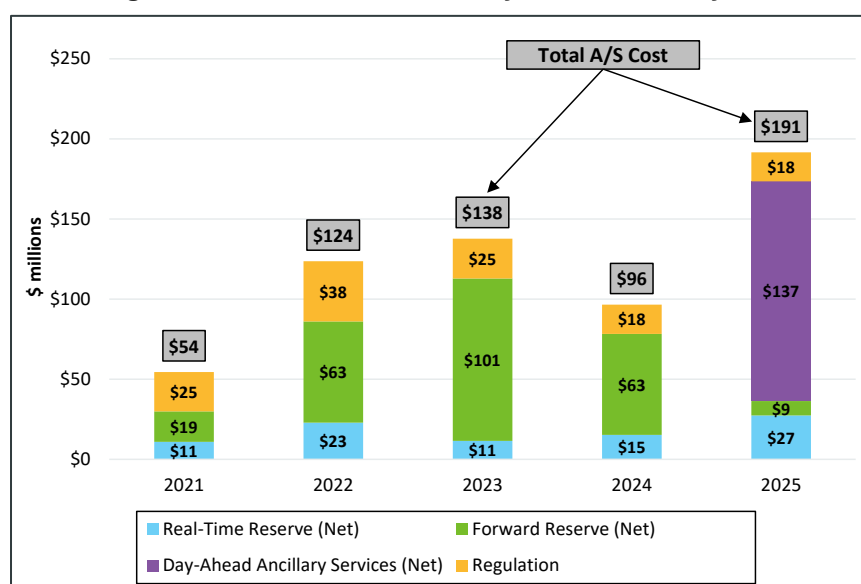
Ancillary Services Markets

This section discusses the performance of ISO-NE's ancillary services markets. These markets are:

- **The real-time reserve market:** a *spot* market that procures and prices operating reserve capability (i.e., fast-start and fast-ramping capability) through a co-optimized process in the real-time energy market. (8.1).
- **The day-ahead ancillary services (DA A/S) market:** a *forward* market that procures and prices ancillary services capability (both operating reserve capability and the capability to meet the load forecast) through a co-optimized process in the day-ahead market (8.2).
- **The regulation market:** a *spot* market that procures and prices the capability of resources to alter their energy output over very short time intervals (minute-to-minute) in order to balance supply and demand and maintain system frequency in the real-time energy market (8.3).

Ancillary service market costs are shown by year in Figure 8-1 below. This figure also includes costs associated with the Forward Reserve Market (FRM), which sunset at the end of February 2025 coincident with the start of the DA A/S market.

Figure 8-1: Market-based Ancillary Service Costs by Year



Market-based ancillary services costs reached their highest level over the reporting period in 2025, totaling \$191 million. This represented an increase of nearly 100% relative to 2024 costs (\$96 million). The largest increase in costs came from the new DA A/S market, whose costs totaled \$137 million in 2025. This increase was somewhat offset by a reduction in FRM costs. The FRM was eliminated at the end of February 2025 as it was incompatible with the new DA A/S market.

While not discussed in this section, the ISO does procure and compensate other ancillary services via non-market mechanisms. Two such ancillary services are: 1) *voltage service*, which helps the ISO maintain an acceptable range of voltage on the transmission system and 2) *blackstart service*, which is provided by generators that are able to start quickly without outside electrical supply and are therefore able to facilitate power system restoration in the event of a partial or complete system blackout. Voltage services costs totaled \$16 million in 2025, which was nearly identical to

the costs for this service in 2024. Meanwhile, blackstart services costs rose from \$44 million in 2024 to \$48 million in 2025.

8.1 Real-Time Operating Reserves

The following section reviews real-time operating reserve products and outcomes. The first subsection (8.1.1) presents the reserve requirements that the ISO maintains in the real-time energy market as well as the typical amount of reserve capability that is available in excess of those requirements. The second subsection (8.1.2) explores the frequency and magnitude of real-time reserve prices, including the frequency of reserve constraint penalty pricing, and summarizes the level of real-time reserve payments.

Key Takeaways

The system generally had ample reserve capability to satisfy reserve requirements throughout 2025, with two notable exceptions during a few days with reserve deficiencies resulting in Capacity Scarcity Conditions under the Pay for Performance rules. The average system reserve requirements in 2025 were effectively unchanged from 2024, and ten-minute spinning margins increased slightly in 2025 relative to 2024 as a result of newly commercial battery capacity.

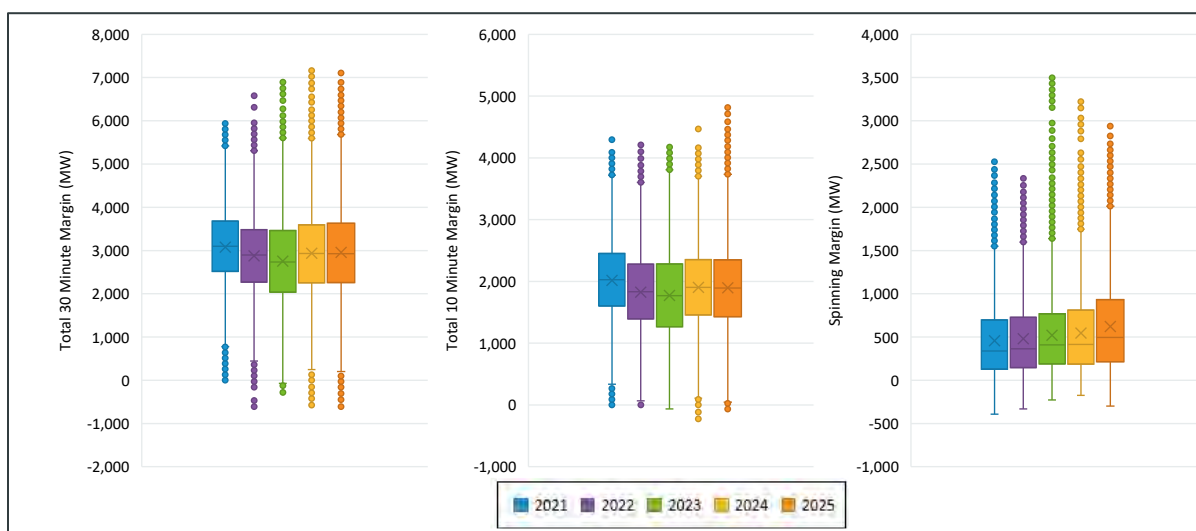
During 2025, net real-time reserve payments totaled \$27.3 million, an 80% increase from 2024. A key driver of these increased payments was the sunsetting of the Forward Reserve Market with the implementation of day-ahead ancillary services. Total real-time credits before forward reserve adjustments only increased 3% year-over-year.

8.1.1 Reserve Requirements and Margins

There are three distinct reserve requirements determined by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council Inc. (NPCC). Reserve requirements are based on the two largest contingencies on the system (commonly known as first and second contingencies). Figure 8-2 shows these system-level requirements, as well as the average reserves designated to satisfy these requirements.²⁴⁵

²⁴⁵ There are also 30-minute local reserve requirements that are not shown or discussed below. These requirements bind infrequently, and thus are not impactful to system operations.

Figure 8-2: Average System Reserve Requirements and Designations



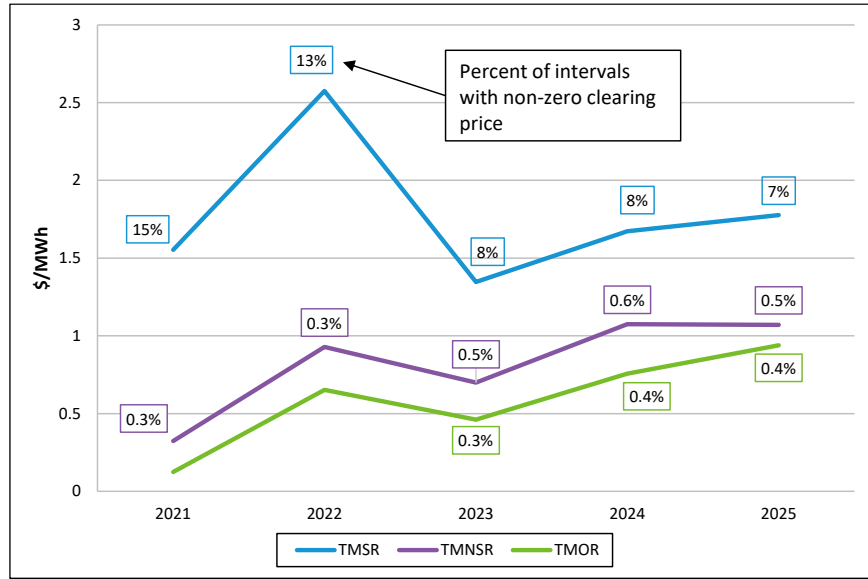
The reserve margin measures the reserve capability available in excess of reserve requirements (i.e., the distance between associated designation lines and bars in the figure above). Total ten-minute and thirty-minute reserve margins in 2025 were effectively unchanged from 2024. The spinning reserve margin increased from 546 MW to 624 MW on average year-over-year, driven by contributions from new battery assets that went commercial in 2025. These assets contributed ~70 MW more per hour to the spinning reserve margin in 2025 than in 2024. In most intervals, the system carries plentiful total-10 and total-30 reserves, with only outlier values dipping below the requirement (i.e. the dots below 0). Spinning reserve margins fall below 0MW more often, due to the lower penalty factor—the market software will only pay a maximum of \$50/MWh to ensure the requirement is met, compared with \$1,500/MWh for the total-10 minute requirement and \$1,000/MWh for the total-30 requirement.

On average, there has been a healthy surplus of reserve capability on the system compared to the requirements, though there were noteworthy periods during 2025 when the region experienced deficiencies of reserves. These instances are included in the discussion of system events in Section 4.6.

8.1.2 Reserve Prices and Payments

Reserve prices occur when there is an opportunity cost of providing reserves rather than energy; in other words, when the market clearing engine re-dispatches resources to maintain reserve requirements. This is an infrequent occurrence in New England, which has a large fleet of offline fast-start resources. Most of the time such re-dispatch is not necessary and, because reserve constraints are not binding, reserve clearing prices are \$0/MWh. Figure 8-3 below shows both the frequency of non-zero reserve prices and the average value of reserve prices for all products at the system level.

Figure 8-3: Reserve Price Frequency and Average Value

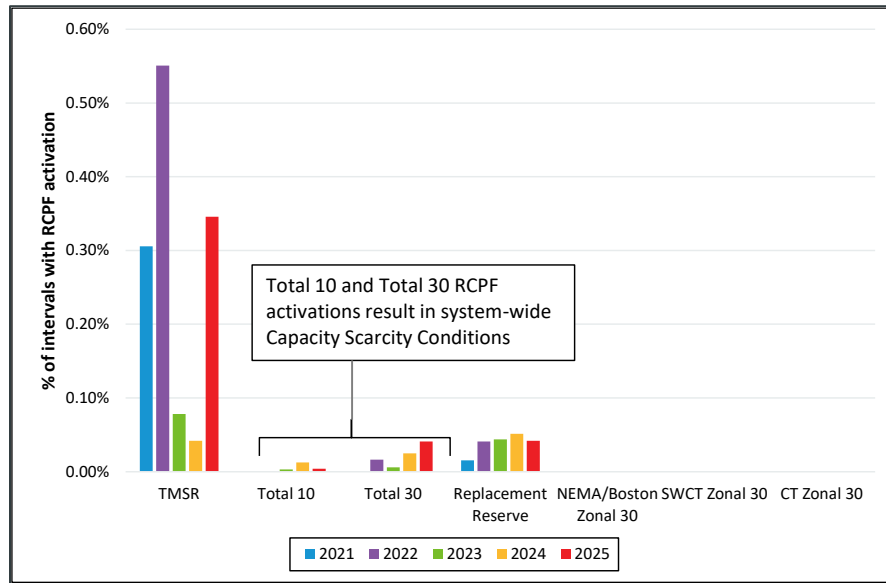


The frequency of non-zero reserve pricing, as indicated by the data labels in the figure above, was consistent with that observed in 2024. Average reserve prices, however, were higher on average in 2025 than in 2024 for the TMOR and TMSR products. This outcome indicates that when reserve constraints did bind, the re-dispatch necessary to maintain reserve requirements was costlier in 2025 than in 2024 (i.e., those resources ‘held down’ to provide reserves incurred greater opportunity costs, on average). A key contributor to higher average reserve prices in 2025 were the Capacity Scarcity Conditions that occurred during June and November. There were about 3.5 hours of CSCs in 2025 (driven primarily by the TMOR RCPF), compared with 2.3 hours in 2024.

Reserve Constraint Penalty Factors (RCPFs)

RCPFs for reserve constraints are “activated” and impact reserve prices when there is insufficient reserve capability to meet the reserve requirements, or when the cost of re-dispatch to satisfy those requirements exceeds RCPF values. The percentage of five-minute intervals during which the RCPF for each reserve constraint was activated is shown in Figure 8-4 below.

Figure 8-4: Reserve Constraint Penalty Factor Activation Frequency



The most significant RCPF activations of 2025 were the total 30-minute reserve requirement RCPFs, which triggered Capacity Scarcity Conditions in June and November. The total 10-minute RCPF (\$1,500/MWh) was active for only 20 minutes, and the total 30-minute RCPF (\$1,000/MWh) was active for 215 minutes. This level of activation is the highest observed in the last five years. These instances are included in the discussion of system events in Section 4.6.

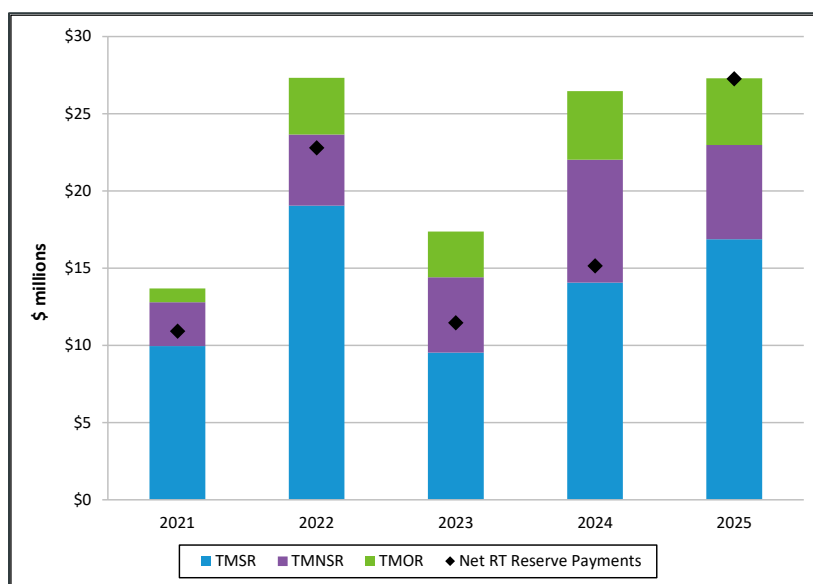
The RCPF for the TMSR requirement (\$50/MWh) activated for 30 hours in 2025, compared with 4 hours in 2024. This RCPF tends to activate more frequently than the RCPFs of other reserve constraints due to its relatively low value.

Reserve Payments

Real-time reserve payments are made to resources designated to provide operating reserves in intervals when reserve clearing prices are non-zero. Total real-time reserve payments are relatively small compared to overall energy market and capacity market payments.

Figure 8-5 below shows the total payments made for real-time reserves over the past five years, as illustrated by the stacked bars. The black diamond shows total net real-time reserve payments, and is reflective of the elimination of real-time reserve credits to forward reserve resources to ensure these resources are not double-compensated.

Figure 8-5: Real-Time Reserve Payments



Total gross real-time reserve payments in 2025 totaled \$27.3 million. With the implementation of DA A/S in March 2025, the Forward Reserve Market was sunset, resulting in only \$26 thousand of forward reserve payment adjustments (the difference between the black dot and the top of the green bar), compared with \$11 million in 2024.

The most notable changes in 2025 relative to 2024 are the increase in TMSR payments, driven by the higher magnitude of TMSR pricing discussed above, and the offsetting decrease in TMNSR payments, which stem primarily from the decrease in TMNSR RCPF activations.

Fast-start pricing has had a significant impact on real-time reserve payments, increasing payments by over 119% in 2025. An assessment of the impact of fast-start pricing is provided in Section 4.1 of this report.

8.2 Day-Ahead Ancillary Services

The day-ahead ancillary services (DA A/S) market is designed to procure sufficient capability to satisfy both the operating reserve requirements and the load forecast through a market construct. This section provides details on the performance of this market between March 1, 2025, and December 31, 2025.^{246, 247}

As a result of our ongoing analysis of DA A/S market outcomes and discussions with market participants, the IMM released a memo on February 4, 2026, that contained three recommended

²⁴⁶ The DA A/S market went live for the operating day of March 1, 2025.

²⁴⁷ For more detailed analysis of the DA A/S market at a quarterly level see the following three IMM Quarterly Reports:

ISO New England Inc., Internal Market Monitor, “Spring 2025 Quarterly Markets Report”, July 16, 2025, <https://www.iso-ne.com/static-assets/documents/100025/2025-spring-quarterly-markets-report.pdf>,

ISO New England Inc., Internal Market Monitor “Summer 2025 Quarterly Markets Report”, November 12, 2025, <https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf>,

ISO New England Inc., Internal Market Monitor “Fall 2025 Quarterly Markets Report”, February 4, 2026, <https://www.iso-ne.com/static-assets/documents/100032/2025-fall-quarterly-markets-report.pdf>.

changes to improve the cost-effectiveness of the day-ahead market.²⁴⁸ The IMM's recommendations are to:

- 1) Increase the Strike Price to better reflect the short-run marginal costs of resources providing ancillary services.
- 2) Reduce the Forecast Energy Requirement (FER) to account for renewable generation.
- 3) Review and potentially lower the non-performance factor (NPF) applied to operating reserve requirements.

Additionally, the IMM plans to publish a report in May 2026 that will provide a comprehensive evaluation of the competitiveness and performance of the DA A/S market during its first year.

Key Takeaways

Flexible Response Services (FRS) capability consistently exceeded requirements. While FRS requirements remained steady throughout the year, offered capability showed seasonal fluctuations, declining during the shoulder seasons (spring and fall), when resources tend to take their planned outages, and rising in summer and winter.

Only small amounts of Energy Imbalance Reserve (EIR) typically cleared, although volumes fluctuated based on market conditions. October had the highest level of average EIR clearing due to high generator outages and reduced net interchange, while July had the lowest level.

DA A/S products accounted for a relatively small share of total Energy and Ancillary Services (E&AS) costs in 2025, amounting to a net settlement of \$137.2 million, or about 2% of overall costs.

Based on its analysis, the IMM has recommended three changes to the DA A/S market and will further evaluate the market's first year in a comprehensive report planned for May 2026.

8.2.1 Flexible Response Services

Under the Day-Ahead Ancillary Services (DA A/S) market, the ISO procures a set of operating reserve capabilities designed to ensure sufficient fast-starting and fast-ramping resources are available to respond quickly to large, unexpected supply losses. These capabilities are procured in the DA A/S market as Flexible Response Services (FRS). The FRS requirements align closely with those in the real-time market and include ten-minute spinning reserve, total ten-minute reserve, and total 30-minute reserve requirements.

To help satisfy these requirements, market participants make offers for the following products:

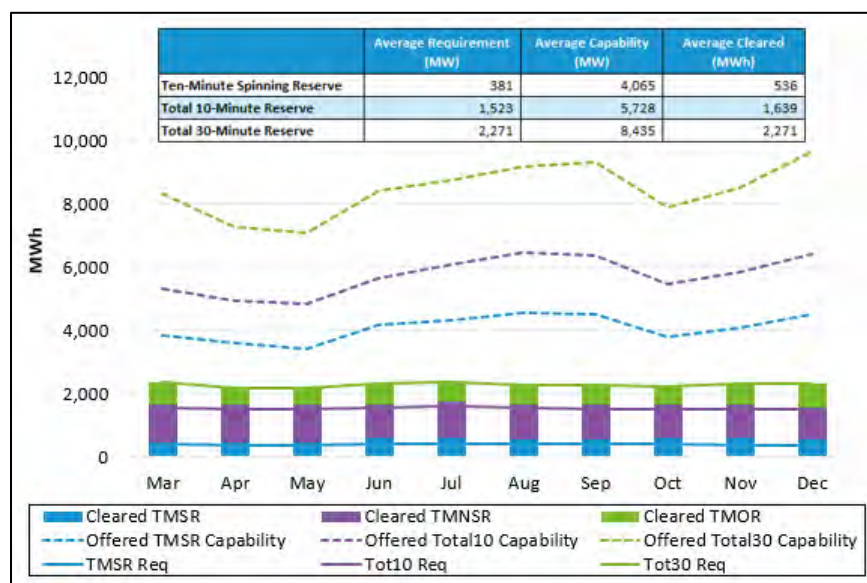
- ten-minute spinning reserve (TMSR)
- ten-minute non-spinning reserve (TMNSR)
- thirty-minute operating reserve (TMOR)

Overall, offered FRS capability has remained well above FRS requirements. This can be seen in Figure 8-6, which shows the average hourly FRS requirements, offered capability, and the cleared

²⁴⁸ ISO New England Inc., Internal Market Monitor, "Recommended Changes to the Day-Ahead Ancillary Services Market", February 4, 2026, https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf

awards, by month.²⁴⁹ This figure also includes hourly averages over the entire period (March 2025 – December 2025) in the inset table.

Figure 8-6: FRS Requirements, Offered Capability, and Cleared Awards



On average, offered TMSR capability exceeded the TMSR requirement by a factor of over ten times the requirement, while offered total 10- and total 30-minute capabilities exceeded requirements by more than a factor of three. The FRS requirements, which are based on the projected first and second contingencies, did not change much during the year. However, the offered capability displayed a seasonality, with participation declining in the spring and fall (when resources tend to undertake planned outages) and then rising in the summer and winter.

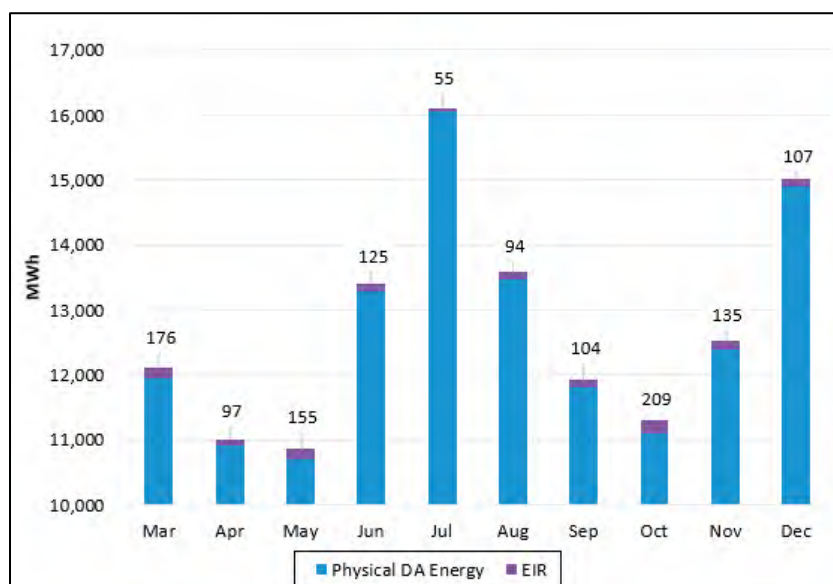
8.2.2 Energy Imbalance Reserves

The other ancillary service procured in the DA A/S market is reserve capability used to help meet the load forecast. Physical supply resources that can provide 60-minute reserve capability are compensated through a new ancillary service product called Energy Imbalance Reserve (EIR). This product is procured by the market clearing engine to meet the Forecast Energy Requirement (FER) constraint, which may be satisfied by a combination of day-ahead energy awards on physical resources and EIR awards. Physical resources with day-ahead energy awards and resources cleared for EIR are both paid the FER Price, as each contributes to satisfying the FER constraint.

Generally, only small amounts of EIR clear as day-ahead energy awards to physical suppliers satisfy the majority of the FER demand. This can be seen in Figure 8-7, which shows the average hourly cleared FER supply by month over the period March 2025 to December 2025.

²⁴⁹ Offered capabilities reflect participant-submitted DA A/S offer quantities limited by physical resource characteristics (e.g., ramp rate, ecomax).

Figure 8-7: Cleared Awards to Satisfy the Forecast Energy Requirement



The average hourly volume of EIR cleared during the period of March 2025 through December 2025 was 125 MWh. However, EIR clearing did vary by month depending on the dynamics of both the supply and demand sides of the market. October had the highest level of EIR clearing on average (209 MWh), which was related to high levels of generator outages and reduced net interchange. Meanwhile, the lowest level of EIR clearing occurred in July (55 MWh on average) when generation outage levels were low, resulting in higher levels of day-ahead energy awards that could cost-effectively satisfy the FER constraint.

8.2.3 Settlements

The four DA A/S products are paid an initial credit at the applicable DA A/S clearing price and incur a closeout charge whenever the real-time Hub LMP exceeds the strike price. For the purposes of calculating the settlement value of the DA A/S market, we sum the initial credit and the closeout charge to calculate a final *net* payment/charge.

DA A/S products represented a relatively small percentage of overall energy and ancillary services (E&AS) costs in 2025.²⁵⁰ This can be seen in Table 8-1, which shows the initial credit, closeout charge, and *net* settlements for the DA A/S products for the period from March 2025 through December 2025.

²⁵⁰ Total energy and ancillary services costs include day-ahead and real-time energy, reserve, regulation, and NCPC costs.

Table 8-1: DA A/S Settlements (\$ millions)

DA A/S	Credit	Closeout	Total
DA TMSR (net)	\$65.2	-\$28.7	\$36.5
DA TMNSR (net)	\$123.8	-\$59.8	\$64.0
DA TMOR (net)	\$65.5	-\$33.2	\$32.3
EIR (net)	\$10.0	-\$5.5	\$4.5
Total (net)	\$264.5	-\$127.2	\$137.2
Total E&AS Costs:			\$7,125
% Total E&AS Cost:			2%

DA A/S credits totaled \$264.5 million over this period, while closeout charges amounted to -\$127.2 million. The net settlement was \$137.2 million, which represented 2% of E&AS costs over this *ten-month* period.

8.3 Regulation

In this section, we examine the participation, outcomes, and competitiveness of the regulation market. Specifically, we review the amount of regulation capability needed by the ISO (8.3.1), and regulation clearing prices and payments (8.3.2).

Key Takeaways

Regulation requirements were stable in both 2024 and 2025, averaging about 93 MW per hour, with the highest needs during morning and evening ramps. Battery storage and other Alternative Technology Regulation Resources (ATRRs) increased their share of the market, supplying more than 80% of cleared regulation capacity in 2024 and increasing to 86% in 2025.

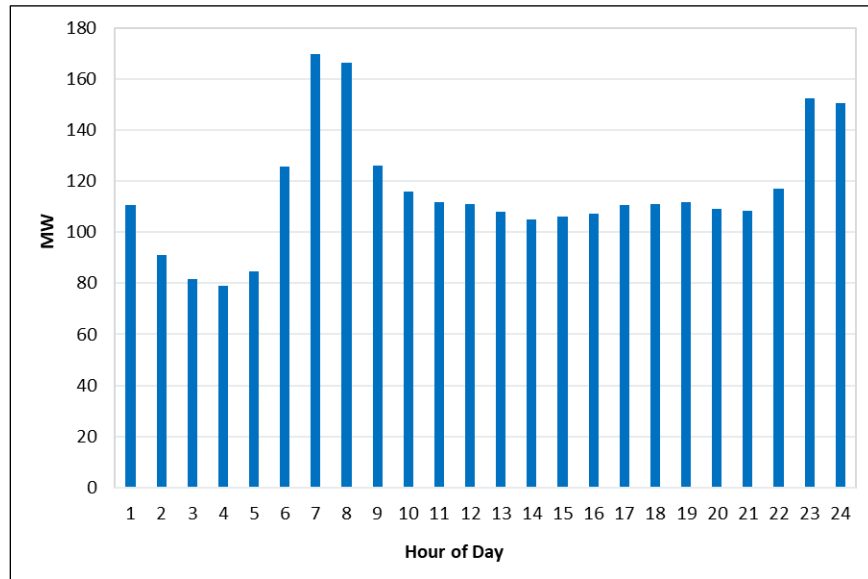
System frequency performance remained strong, with no BAAL violations in 2025, indicating sufficient regulating capability and performance. Regulation capacity clearing prices declined from \$15.30/ MWh in 2024 to \$12.21/ MWh in 2025, while service prices stayed constant at \$0.08 per mile.

Total regulation payments fell slightly from \$18.2 million to \$18 million, reflecting low system stress. Throughout this period, the market remained competitive, and the growing role of battery storage improved efficiency by lowering costs and maintaining reliable frequency control.

8.3.1 Regulation Requirements, Resource Mix, and Performance

The regulation *requirement* in New England varies throughout the day and is typically highest in the morning and the late evening. The higher regulation requirement during these hours is the result of greater load variability (load ramping up in the morning and down in the evening). The average hourly regulation requirement by hour of day for 2025 is shown in Figure 8-8 below.

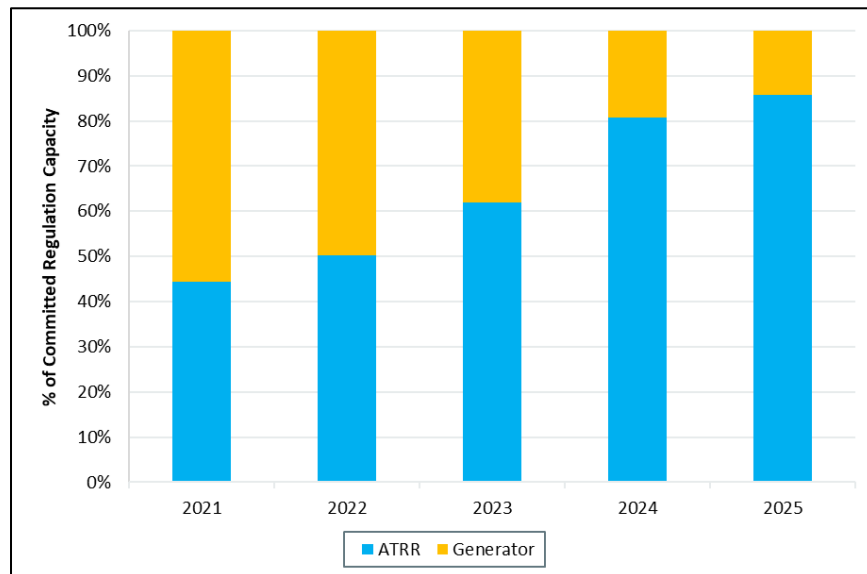
Figure 8-8: Average Hourly Regulation Requirement, 2025



The average hourly regulation requirement in 2025 was 93.4 MW, nearly unchanged from the 93.5 MW requirement in 2024. Regulation service is supplied by two types of resources: traditional generators and Alternative Technology Regulation Resources (ATRRs). Most ATRRs consist of battery energy storage systems that can provide regulation exclusively or operate as multi-use assets by charging, discharging, or doing both while participating in the energy market.

The regulation market resource mix for 2021 to 2025 is shown in Figure 8-9 below.

Figure 8-9: Regulation Resource Mix



The *resource mix* for regulation has changed significantly. In 2021, ATRRs (blue shading) provided 44% of cleared regulation capacity. By 2025, ATRRs provided 86%. This change follows continuing increases in the installed capacity of battery resources. Regulation capacity available from ATRRs has increased from 88 MW to 468 MW over the period. The change in resource mix also supports the finding that battery resources are lower-cost regulation resources (i.e., have lower-cost

regulation market offers), as these ATRRs have increasingly displaced traditional generators in the merit order for regulation market commitment.

8.3.2 Regulation Prices and Payments

Regulation Clearing Prices (RCP) are based on the regulation offer of the highest-priced generator providing the service. There are two types of regulation clearing prices: “service” and “capacity.”²⁵¹ Clearing prices for the past five years are shown in Table 8-2 below.²⁵²

Table 8-2: Regulation Prices

Year	Regulation Capacity Clearing Price (\$/MW per Hour)			Regulation Service Clearing Price (\$/Mile)		
	Min	Avg	Max	Min	Avg	Max
2021	0.00	19.23	732.93	0.00	0.21	10.00
2022	0.00	30.96	2,979.80	0.00	0.27	10.00
2023	0.00	23.48	2,048.15	0.00	0.13	10.00
2024	0.00	15.30	3,812.42	0.00	0.08	10.00
2025	0.00	12.21	4,051.16	0.00	0.08	10.00

Regulation capacity prices decreased by 20% in 2025, reflecting a decline in offer prices as lower-cost ATRRs continued to make up a larger share of the regulation mix. Regulation service prices, on the other hand, showed no change compared to 2024. In 2025, the average service price was \$0.08/mile.

The absence of change in the average regulation service price indicates that system conditions did not produce the higher mileage intensity, ramping volatility, or increased opportunity-cost exposure that typically raises service prices. Regulation mileage patterns, dispatch behavior, and storage state-of-charge dynamics were comparable to the prior year, resulting in a consistent price formation environment and an unchanged annual average. By contrast, the Average Regulation Capacity Clearing Price dropped from \$15.30 to \$12.21/MWh; the lower average, alongside still-elevated upper-tail outcomes, is consistent with continued clearing of low- or zero-priced ATRR capacity in most hours.

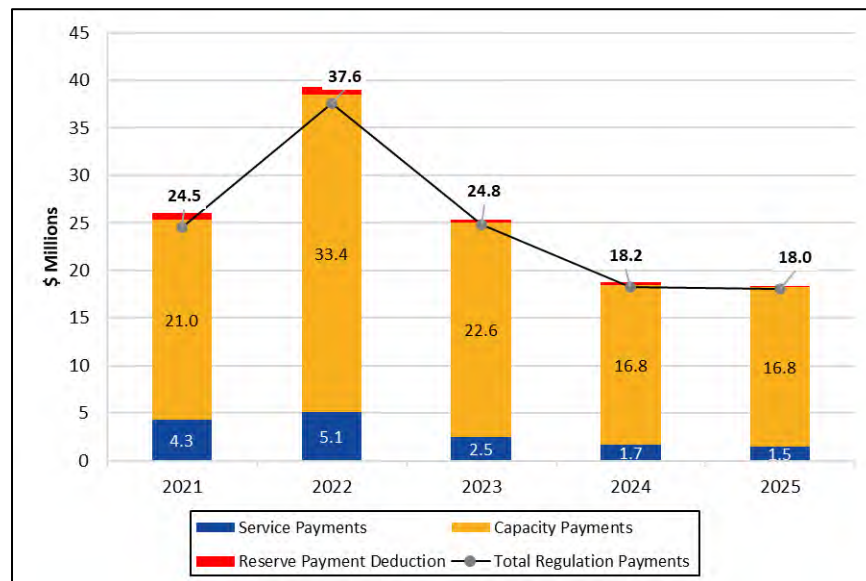
²⁵¹ The service price represents the direct cost of providing the regulation service (also known as regulation “mileage”). Mileage represents the up and down movement of generators providing regulation and is measured as the absolute MW variation in output per hour. These direct costs may include increased operating and maintenance costs, as well as incremental fuel costs resulting from the generator operating less efficiently when providing regulation service. The capacity price may represent several types of costs, including: (1) the expected value of lost energy market opportunities when providing regulation service, (2) the value of intertemporal opportunities that would be lost from providing regulation, (3) elements of fixed costs such as incremental maintenance to ensure a generator’s continued performance when providing regulation, and (4) fuel market or other risks associated with providing regulation.

²⁵² The prices in the table are simple average prices for each year.
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Regulation Payments

Compensation to generators providing regulation includes a Regulation Capacity Payment, a Service Payment, a Make-Whole Payment, and an operating reserve adjustment.²⁵³ Annual regulation payments over the past five years are shown in Figure 8-10 below.²⁵⁴

Figure 8-10: Regulation Payments



Regulation payments saw just a 1% year-over-year decline in 2025, from \$18.2 million in 2024 to \$18.0 million in 2025. This slight reduction reflects continued easing in both capacity and service components, driven by lower clearing prices and fewer high-mileage intervals, though the scale of these changes resulted in only a small shift in total annual payments.

Capacity payments, which consistently represent the majority of total regulation payments, showed no change between 2024 and 2025, remaining at \$16.8 million, as lower-cost ATRRs continued to dominate the regulation mix. Service payments decreased 13%, from \$1.7 million in 2024 to \$1.5 million in 2025, indicating that fewer hours required high-mileage performance or that mileage-related opportunity costs were less pronounced. As a result, capacity payments accounted for 92% of total regulation payments in 2025, while service payments represented only 8%.

As energy storage capacity continues to grow in New England—including the addition of larger-scale facilities—and as the regulation market remains relatively saturated, batteries are

²⁵³ The operating reserve adjustment represents a deduction to regulation payments. Under certain circumstances, part of a regulation resource's regulating range may overlap with the resource's operating reserve range. Since generators do not actually provide operating reserves within the regulating range, reserve compensation needs to be deducted from the resource's market compensation. The reserve payment deduction represents the MW quantity overlap of the regulating range and operating reserve range, multiplied by the operating reserve price.

²⁵⁴ The reserve payment deduction is shown as a negative value in the exhibit; the positive values represent total payments (prior to reserve payment deductions) for the regulation capacity and service (mileage) provided by regulation resources during the period. The make-whole payment is included in capacity payment totals, since it represents an uplift payment when the capacity payments do not fully compensate resources for energy market opportunity costs.

expected to play an increasing role in the energy market. In this environment, battery strategies are likely to increasingly shift toward energy price arbitrage, alongside Massachusetts Clean Peak Energy Program (CPEC) operating strategies.

Section 9

Transmission Congestion and Financial Transmission Rights

This section covers trends in transmission congestion and financial transmission rights (FTRs), ISO-administered tools for managing or taking positions on congestion risk.

Key Takeaways

Congestion: In 2025, congestion revenue totaled \$75 million, representing 0.8% of total energy costs. Congestion revenue increased on a yearly basis due to both higher LMPs and more frequent congestion. Temporary transmission work drove most of the increased congestion in 2025, notably including outages in April-May surrounding interconnection work for the New England Clean Energy Connect (NECEC) line that began operation in early 2026. Overall, levels of transmission congestion are relatively low in New England compared to other ISO markets due to the significant amount of reliability-driven transmission investment over the past decade.²⁵⁵

Financial Transmission Rights: The average number of FTR MWs held in 2025 (35,000 MWs per hour) increased 4% from the prior year. FTRs were fully funded in 2025, meaning there was sufficient revenue collected through the energy markets' congestion revenue fund to pay FTR holders.

FTR positions earned \$34 million in profits throughout 2025, reversing a trend of negative or low profitability since 2022. Profits were driven by a more congested system (due in part to transmission work in Maine to accommodate the NECEC line) and high LMPs, leading to high positive target allocations. The Roseton interface reflected 57% of all FTR purchase costs and 25% of positive target allocations throughout the year. While profits at this location were small, they were profitable for the first time since 2021, contributing to the increase in total FTR profits.

9.1 Transmission Congestion

Below, we examine transmission congestion in New England over the past five years, beginning with overall congestion revenues and then assessing where congestion has emerged across the system.

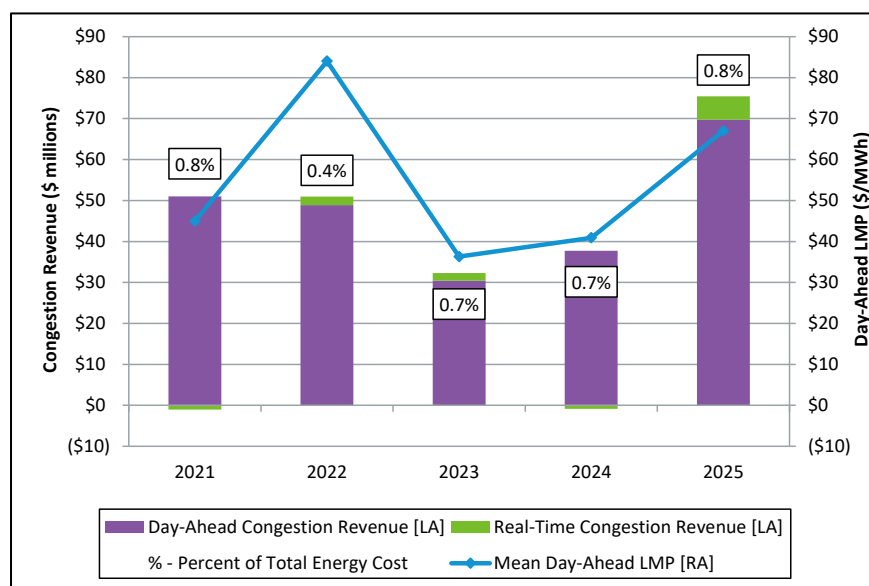
²⁵⁵ Potomac Economics' (the External Market Monitor for ISO-NE) *2024 Assessment of the ISO New England Electricity Markets* showed that ISO-NE had the lowest congestion rate between 2022-2024 (\$0.33/MWh) among a set of RTOs that included ERCOT, ISO-NE, MISO, NYISO, and PJM. However, ISO-NE had the highest transmission rate in 2024 (\$24/MWh) of these RTOs. See Figure 2 in its *2024 Assessment*. Potomac Economics, "2024 Assessment of the ISO New England Electricity Markets", June 2025, https://www.potomaceconomics.com/wp-content/uploads/2025/06/ISO-NE-2024-EMM-Annual-Report_Final.pdf.

Congestion Revenue

Congestion revenue represents the difference between what load pays for energy and what generation receives for energy as a result of transmission congestion.²⁵⁶ A feature of New England's locational energy market is that load pays for energy at the price where it is *consumed*, and generation is paid at the price where it is *produced*. This means that, when there is a binding transmission constraint limiting the production of less expensive generation, load will often pay more for the energy than generation receives for the energy. This resulting congestion revenues form the basis for Auction Revenue Rights (ARRs), which are auctioned through FTRs and ultimately fund payments to the FTR holders as discussed further in Section 9.2.

Over the last five years, congestion revenue has been small relative to total energy market payments and typically moves in line with energy prices. This can be seen in Figure 9-1 below.²⁵⁷

Figure 9-1: Average Day-Ahead Hub LMP, Congestion Revenue Totals as Percent of Total Energy Cost



Total day-ahead and real-time congestion revenue was \$75 million in 2025, representing 0.8% of energy market costs. Congestion revenue is typically correlated with day-ahead energy prices. For export constraints, this occurs because export-constrained zones (such as Maine) often feature inexpensive renewable energy, driving up congestion revenue as Hub LMPs increase relative to low export-constrained LMPs. Conversely, import-constrained zones often require relatively expensive fossil fuel-fired generation, and high input fuel prices raise price differences and congestion revenue relative to hub generation.

Congestion revenue more than doubled relative to 2024, reflecting both higher LMPs and an increase in the frequency of binding transmission constraints, as discussed below. Most

²⁵⁶ For an exact definition of day-ahead and real-time congestion revenue, see: ISO New England Inc., “Section III Market Rule 1 Standard Market Design”, Section III.3.2.1(i), https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

²⁵⁷ The percentages in the figure are the total congestion revenue each year (i.e., the day-ahead congestion revenue plus the real-time congestion revenue) expressed as a percent of total energy market costs. Additionally, the designation ‘LA’ in the legend indicates that the value is measured by the y-axis on the left side, while ‘RA’ indicates that the value is measured by the y-axis on the right side.

congestion revenue accrued in the day-ahead market (\$70 million) since this market accounts for the majority of transaction settlement, while net congestion revenue associated with real-time deviations totaled \$6 million in 2025.

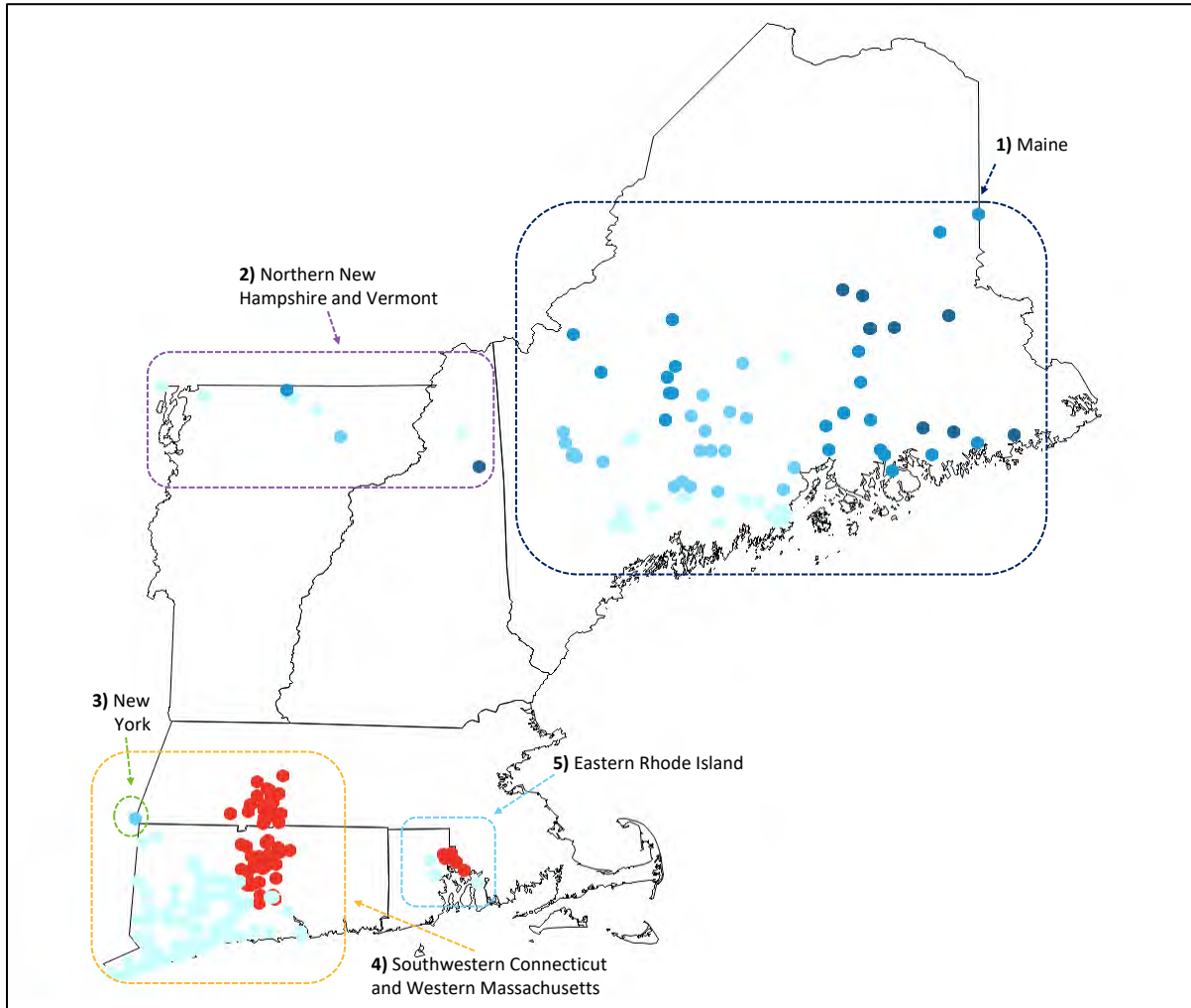
Congested Areas in New England

The New England pricing nodes and areas most affected by transmission congestion in the day-ahead market in 2025 are shown in Figure 9-2 below.²⁵⁸ Locations that are “upstream” of a binding transmission constraint have a negative congestion component, while locations that are “downstream” of a binding constraint have a positive congestion component.²⁵⁹

²⁵⁸ In order to highlight the constrained areas, this figure only includes nodes that had an average day-ahead congestion component in 2025 of greater than or equal to \$0.20/MWh or less than or equal to -\$0.20/MWh.

²⁵⁹ More specifically, a negative congestion component occurs when a location has a positive shift factor to a binding constraint. In simple terms, a shift factor measures how an injection of energy at a location impacts the flow of energy over a transmission constraint. In other words, locations with a positive shift factor indicate that an injection of energy at that location would *exacerbate* transmission congestion. Conversely, a positive congestion component occurs when a location has a negative shift factor to a binding constraint. In other words, locations with a negative shift factor indicate that an injection of energy at that location would *alleviate* transmission congestion.

Figure 9-2: New England Pricing Nodes Most Affected by Congestion, 2025



Many of the congested areas in New England in 2025 were relatively small geographic areas where transmission capacity limited the ability to export power to the rest of the system. Several areas in Figure 9-2 have been highlighted and each of them is discussed in detail below:

- 1) **Maine:** The Maine area features low loads, high amounts of renewable generation, and interconnections with the New Brunswick control area. Congestion can occur as inexpensive energy in Maine flows to the rest of the system over limited transmission, resulting in periodic congestion of interfaces that include Orrington South (“ORR-SO”), Rumford Export (“IRMF-E”), and Keene Road Export (“KR-EXP”). Notably, congestion patterns in Maine increased relative to prior years due to transmission work in certain months. Transmission work to accommodate the NECEC line occurred in April-May, leading to frequent congestion over Orrington South and Coopers Mill-South (“COMI-S”). Additionally, the Rumford Export interface bound frequently in October due to transmission line outages.
- 2) **Northern New Hampshire and Vermont:** Northern New Hampshire and Vermont also feature high amounts of intermittent generation, and imports over the Highgate tie line. Constrained interfaces in this area include Kingdom Wind Generation (“KCW”), Sheffield

Generation (“SHEF”), and Sheffield-Highgate (“SHFHGE”). Overall congestion patterns in this area were similar to prior years.

- 3) **New York:** The lines between New York and New England may become congested when line limits are reduced or price differences between New York and New England strongly incentivize flows in one direction. For example, in cold weather, New York typically has lower energy prices than in New England due to gas pipeline availability, and the New York-New England (“NYNE”) interface binds due to imports reaching line limits.
- 4) **Southwestern Connecticut:** The Southwestern Connecticut region contains several large, efficient gas-fired generators. The local 115-kV transmission system occasionally limits exports to the rest of the system, resulting in local export congestion around the generating units and import congestion in Connecticut and Western Massachusetts. The Berlin 1771 line bound relatively frequently in 2025, particularly in December.
- 5) **Eastern Rhode Island:** Similar to the Southwestern Connecticut region, the Eastern Rhode Island area occasionally experiences congestion due to generation patterns over the local 115-kV system. This can occur in winter months due to gas-fired generator locations; gas generators on the west side of the constraint can be less expensive than those on the east side, since the east-side generators are located on the relatively constrained and expensive G-lateral of the Algonquin pipeline. This can create transmission constraints when more generators are committed on the west side of the constraint since they are less expensive. The Hartford Avenue E105 line was the most frequent binding constraint for this area in 2025.

9.2 Financial Transmission Rights

The assessment of financial transmission rights (FTRs) activity and performance is structured as follows: (9.2.1) FTR auction volumes, (9.2.2) FTR funding, and (9.2.3) FTR profitability at a market level. Given their outsized impact on FTR market outcomes, special attention is given to FTR paths that source from I.ROSETON 345 1 (“Roseton”), which is ISO-NE’s external node for trading across the New York - New England (“NYNE”) interface.²⁶⁰

9.2.1 FTR Volume

The volume of FTRs held by participants reflects several factors, most notably expectations about the magnitude and frequency of day-ahead congestion. When participants anticipate greater congestion than in prior years, they may acquire additional FTR MWs to hedge expected price differences. Conversely, expectations of lower congestion are likely to result in reduced FTR purchases.

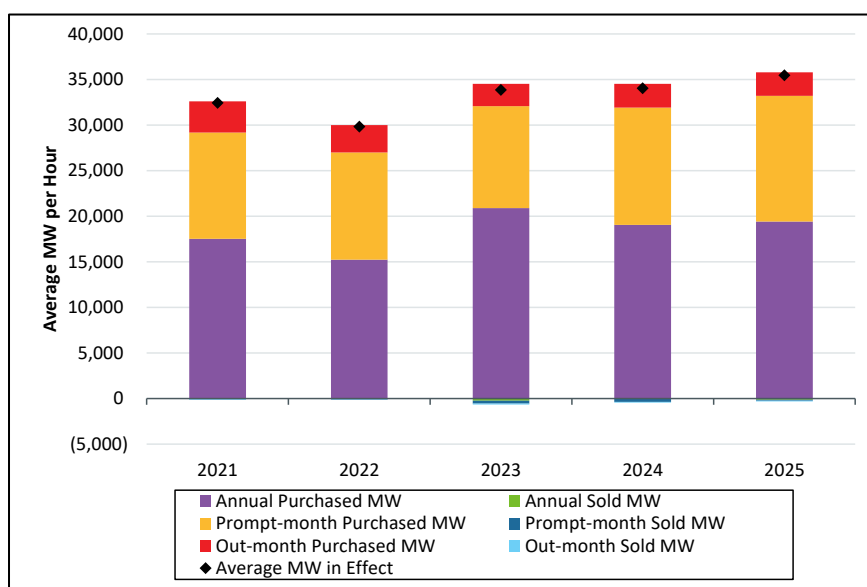
Another important factor is the set of transmission limits that the ISO uses in the auctions it conducts to award FTRs. The ISO performs a market feasibility test in each FTR auction that ensures that the awarded set of FTRs respects the transmission system’s physical and operational

²⁶⁰ I.ROSETON 345 1 is represented by area 3 in Figure 9-2 above.

limits.²⁶¹ Essentially, these limits restrict the MW volume of FTRs that can be purchased in FTR auctions, which helps ensure that the congestion revenue collected from the energy market will be sufficient to pay FTR holders.

Figure 9-3 shows the average MW volume of FTRs in effect each hour by year (black diamonds) for the past five years.²⁶² This figure also shows the average hourly MW volume of FTRs purchased and sold by auction type (i.e., annual, prompt-month, or out-month) during each year.²⁶³ FTR purchases are depicted as positive values, while FTR sales are depicted as negative values.

Figure 9-3: Average FTR MWs in Effect per Hour by Year



Market participants held roughly 35,000 MWs of FTRs per hour in 2025, a 4% increase from 2024. The increase in held FTR MWs was driven by increased purchases both in annual auctions (19,000 MW) and prompt-month auctions (14,000 MW). Out-month FTR purchases averaged 3,000 MW, unchanged from 2024. FTR holders continued to sell very few FTR positions in any auction throughout 2025. Discussed below, FTRs were more profitable in 2025 than in 2024, driving increased participation, particularly in prompt-month auctions.

9.2.2 FTR Funding

FTR funding refers to the ability to pay FTR holders the full value of their positive target allocations. Positive target allocations arise when the congestion component at the sink location (point of

²⁶¹ This test is performed to increase the likelihood of revenue adequacy, which means that there is sufficient congestion revenue collected in the energy market and from FTR holders with negative target allocations to fully compensate all FTR holders with positive target allocations. This is further discussed in Section 9.2.2.

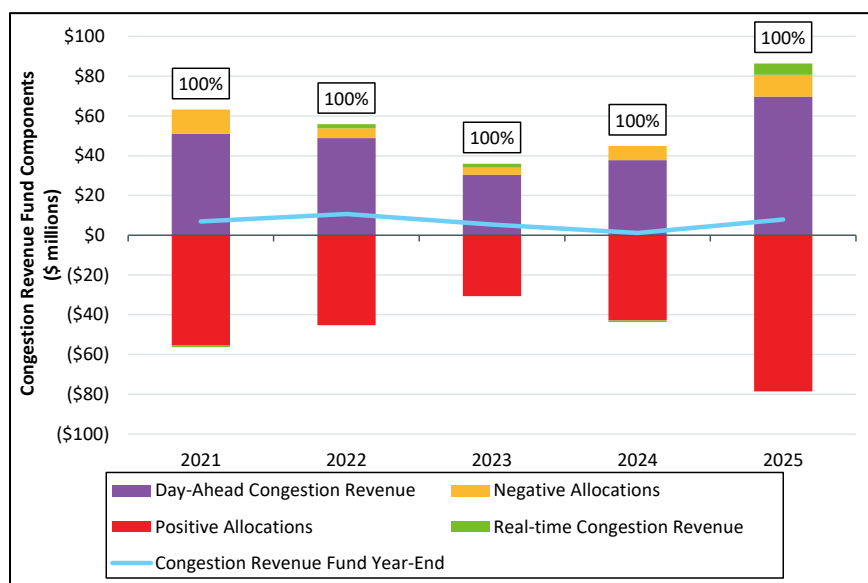
²⁶² The averages are hourly-weighted MW volumes. This weighting accounts for the fact that there are more off-peak hours than on-peak hours in a year. The volume of FTRs in effect each year represents the hourly-weighted average MW volume of FTRs purchased less the hourly-weighted average MW volume of FTRs sold.

²⁶³ An *annual* auction refers to an auction where participants purchase (or sell) FTRs whose term is one calendar year, while both *prompt-month* and *out-month* auctions refer to auctions where participants purchase (or sell) FTRs whose term is one month. *Prompt-month* refers to the monthly auctions for FTRs that are in effect for the month immediately after when the auction takes place, while *out-month* refers the monthly auctions for FTRs that are in effect for any other month remaining in the calendar year (excluding the prompt-month).

delivery) of an FTR path is larger than the congestion component at the source location (point of injection). When there is sufficient revenue to pay all the positive target allocations, FTRs are said to be *fully funded*. Fully funding FTRs is an important aspect of a well-functioning FTR market because it gives market participants confidence that they will receive the full value of their FTRs.

FTRs were fully funded in 2025 and have been in each of the last five years, as can be seen in Figure 9-4 below. The graph shows, by year, the different components of the congestion revenue fund (“CRF”), including: congestion revenue from the day-ahead and real-time energy markets and positive and negative target allocations.²⁶⁴ The balance in the CRF at the end of each year is shown by the blue line.²⁶⁵

Figure 9-4: FTR Funding and Congestion Revenue Fund Components by Year



Day-ahead congestion revenue totaled \$70 million in 2025, up 85% from 2024 following higher average LMPs and more congested average conditions. Real-time congestion revenue reached \$6 million. While day-ahead and real-time congestion revenue alone were not sufficient to cover positive target allocations (\$79 million), negative target allocations (\$11 million) covered the revenue shortfall. Consequently, FTRs were fully funded at the end of year, and the \$8 million surplus was distributed proportionately to entities that paid congestion costs during the year.²⁶⁶

²⁶⁴ The CRF is used to pay FTR holders with positive target allocations. This fund collects money from three sources: (1) day-ahead congestion revenue, (2) real-time congestion revenue, and (3) the holders of FTRs with negative target allocations. For more information about transmission congestion revenue and FTR funding, see: ISO New England Inc., “Section III Market Rule 1 Standard Market Design”, Section III.5, https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

²⁶⁵ The CRF balance is defined here as the $\sum[\text{day-ahead congestion revenue} + \text{real-time congestion revenue} + \text{abs}(\text{negative target allocations}) - \text{positive target allocations}]$. Note that this does not include surplus interest throughout the year. For the final settled CRF values, see: ISO New England Inc., “2025 FTR Monthly Summary”, https://www.iso-ne.com/static-assets/documents/100020/2025_monthly_summary.pdf.

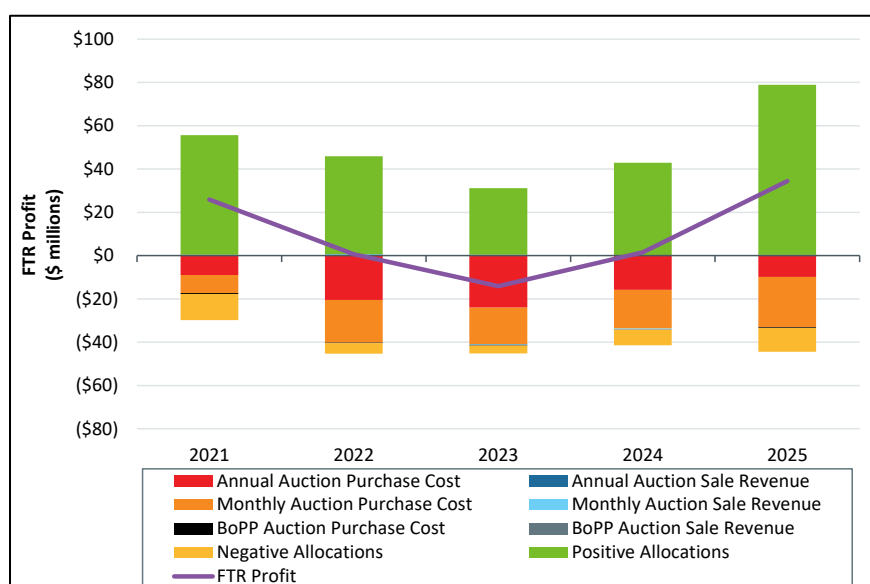
²⁶⁶ For more information about the distribution of excess congestion revenue see: ISO New England., “Section III Market Rule 1 Standard Market Design”, Section III.5.2.6, https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

9.2.3 FTR Profitability

Overall profit in the FTR market is measured as the sum of the positive target allocations and the revenue from FTR sales, minus the negative target allocations and the cost of FTR purchases. In a competitive FTR market, one would not expect to see excessive (risk-adjusted) profits or losses sustained over numerous years. Prolonged periods of high profitability would likely spur the entry of new participants (or at least an increase in FTR bid prices among existing participants), raising the cost to purchase FTRs and reducing FTR profitability. Conversely, prolonged periods of losses might motivate existing participants to exit the market (or at least decrease their FTR bid prices), lowering the cost of purchasing FTRs and increasing FTR profitability.

As a group, FTR holders were profitable in 2025. Figure 9-5 below shows total profit (purple line) as well as each of the different profit components. In this figure, FTR sales revenue and positive target allocations are shown as positive values (as they increase FTR profitability), while FTR purchase costs and negative target allocations are shown as negative values (as they reduce FTR profitability). Further, this figure classifies purchase costs and sales revenues by auction type (i.e., annual, prompt-month, or out-month).

Figure 9-5: FTR Costs, Revenues, and Profits



FTR profits totaled \$34 million in 2025, the highest over the five-year period. Profits were driven by a more congested system (due in part to transmission work in Maine to accommodate the NECEC line) and high LMPs, leading to high positive target allocations (\$79 million). Annual auction purchase costs fell to \$10 million from \$16 million in 2024. Conversely, monthly purchase costs increased to \$23 million, up from \$18 million in 2024. The increase in monthly purchase costs reflected increased volumes in prompt-month auctions.

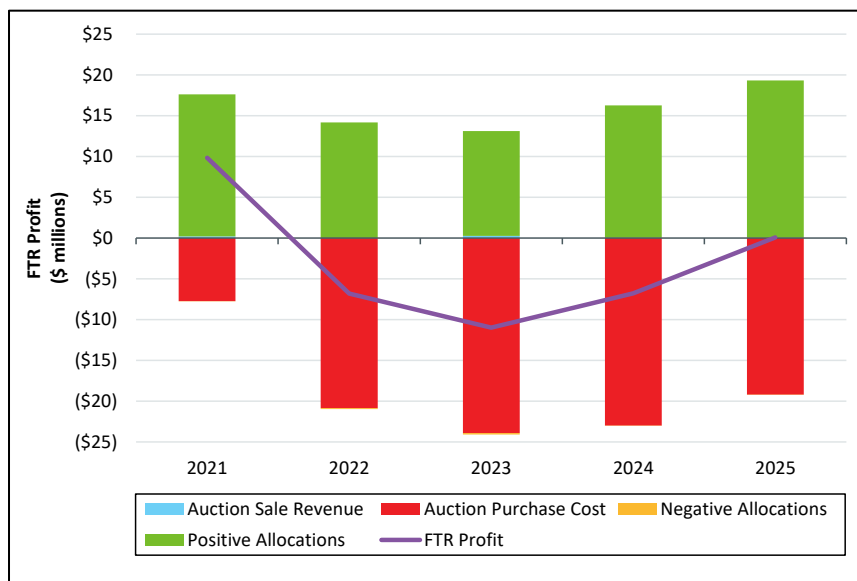
Congestion on the New York – New England Interface

Changes in profitability of FTRs that source from Roseton can contribute significantly to overall FTR market outcomes. This is partly because the NYNE interface tends to be one of the most frequently binding transmission constraints in the day-ahead market. Many of the participants that purchase FTRs that source from Roseton also import power over the New York North interface and use these FTRs to hedge against negative congestion pricing in the day-ahead market. To provide some perspective, the purchase costs for FTRs sourcing from Roseton represented 57% of all the FTR

auction purchase costs in 2025, while the positive target allocations for FTRs sourcing from Roseton represented 25% of all positive target allocations.

FTRs sourcing from Roseton were modestly profitable in 2025. This can be seen in Figure 9-6 below, which shows the total annual profits (purple line) for these FTRs over the last five years. This figure also shows the associated purchase costs, sale revenues, and positive and negative target allocations.

Figure 9-6: FTR Profits and Costs for FTRs Sourcing from Roseton



FTRs sourcing from Roseton generated \$76 thousand in profit on a net basis in 2025. While such profits were modest, this reversed a trend of unprofitability since 2022. Profitability increased from 2024 despite the NYNE interface binding less frequently (6% of hours in 2025, compared to 11% of hours in 2024). Positive target allocations over NYNE (\$19 million) increased, indicating larger price separation between the Roseton node and the rest-of-system in 2025 relative to 2024. At the same time, auction purchase costs (\$19 million) fell 17% year-over-year.

Section 10

Market Design and Rule Changes

This section provides an overview of the major market design and rule changes that were recently implemented²⁶⁷ or are being considered or planned for future years.²⁶⁸ The section also summarizes notable long-term studies that will have market and operational implications for the future grid.

10.1 Major Design Changes Recently Implemented

The following subsections provide an overview of changes recently implemented.

10.1.1 Day-Ahead Ancillary Services Initiative

The Day-Ahead Ancillary Services Initiative (DASI) went live on February 28, 2025, for the operating day of March 1, 2025. This initiative created a day-ahead ancillary services (DAA/S) market that procures and transparently prices specific ancillary services needed for system reliability. Prior to the creation of the DA A/S market, there was no day-ahead reserves market. Instead, ISO-NE procured reserves on a forward basis via the Forward Reserve Market (FRM). The FRM was retired co-incident with the start of the DA A/S market.

The DA A/S market is covered in more detail in Section 8.2.

10.2 Major Design or Rule Changes in Development or Implementation for Future Years

The following market design or rule changes have been (i) completed and the planned implementation date is in the future or (ii) are currently being assessed or are in the design phase.

10.2.1 Capacity Auction Reforms – Prompt Deactivation

On December 30, 2025, ISO-NE filed revisions to its Tariff referred to as the Capacity Auction Reforms – Prompt Deactivation (CAR-PD).²⁶⁹ This set of reforms proposes major changes to the ISO’s capacity market by replacing the primary auction in the Forward Capacity Market, which is held more than three years before the capacity delivery period, with a prompt auction held about one month before the delivery period. Under this new approach only commercial, deliverable resources may participate, eliminating the complexities associated with non-commercial entry. Other reforms in CAR-PD include replacing the descending-clock auction with an administratively simpler sealed-bid format and reducing that retirement notice requirement from four years to one year.

Several design features remain, including monthly settlements, cost allocation rules, and Pay-for-Performance. Existing methods for determining qualified capacity largely stay in place, with some improvements enabled by the shorter timeline. Market power mitigation rules also remain mostly unchanged and changes are conforming in nature with the reduced timeframe. Overall, the reforms

²⁶⁷ ISO New England Inc., “Implemented Key Projects” webpage, <https://www.iso-ne.com/committees/key-projects/implemented>.

²⁶⁸ ISO New England Inc., “Key Projects” webpage, <https://www.iso-ne.com/committees/key-projects>.

²⁶⁹ ISO New England Inc., “ISO New England Inc., Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Establish a Prompt Capacity Market and Deactivation Framework, FERC filing”, Docket No. ER26-925-000, December 30, 2025, https://www.iso-ne.com/static-assets/documents/100030/car-pd_filing.pdf.

are expected to improve the accuracy of auction inputs, enhance supply participation, and support more efficient capacity and reliability outcomes. The transition had broad stakeholder support, and while the ISO plans additional reforms for the 2028/29 auction cycle, the CAR-PD package stands on its own merits.

More information about this topic can be found in Section 7.1.1.

10.2.2 Capacity Auction Reforms – Seasonal Accreditation

The changes associated with seasonal accreditation represent the second set of major reforms that the ISO is undertaking to modernize its capacity market. Referred to as Capacity Auction Reforms – Season Accreditation (CAR-SA), this set of reforms aim to ensure that procured capacity better reflects each resource’s actual contribution to resource adequacy. By procuring capacity in separate summer and winter auctions, the market can more accurately reflect seasonal reliability needs and the changing performance of resources across seasons. The reforms also support the system’s long-term sustainability by aligning investment incentives with how resources contribute to reliability as system conditions evolve. This initiative is currently in stakeholder discussions, and the ISO aims to file the reforms with FERC by the end of 2026.²⁷⁰

More information about this topic can be found in Section 7.1.2.

10.2.3 FERC Order 2222, Distributed Energy Resources

On September 17, 2020, FERC issued Order 2222, which found that existing ISO/RTO market rules were unjust and unreasonable because they contained barriers to the participation of distributed energy resources aggregations (DERAs).²⁷¹ The purpose of Order 2222 is to remove these barriers and allow DERAs to provide all services that they are technically capable of providing. Specifically, the order outlined 11 directives for ISOs/RTOs to follow, including allowing participation of DERAs in the energy, ancillary services, and capacity markets and allowing DER aggregators to register DERAs under one or more participation models.²⁷²

The ISO developed new rules to integrate aggregated distributed energy resources, then worked through several rounds of FERC feedback and compliance filings to refine those rules over the next few years. By late 2025, FERC had accepted the final updates, allowing these resources to participate more fully in the region’s energy and capacity markets. The ISO Tariff now permits

²⁷⁰ ISO New England Inc., “Capacity Auction Reforms Key Project” webpage, <https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project>.

²⁷¹ A Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction. Federal Energy Regulatory Commission, “FERC Order No. 2222: Fact Sheet” webpage, September 28, 2020, <https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet>.

²⁷² A “participation model” refers to rules created for a specific type of resource that has unique physical and operational characteristics. For example, a generator is a type of participation model in ISO-NE. ISO New England Inc., “Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets; Docket No. ER22-983-000” February 2, 2022, p. 5, footnote 7, available at https://www.iso-ne.com/static-assets/documents/2022/02/order_no_2222_filing.pdf.

DERAs to participate in its energy and ancillary service markets effective on November 1, 2026, and its capacity market effective for the 2028-29 Capacity Commitment Period (CCP 19).

10.3 Additional Notable Studies

The following subsection provides an overview of additional notable studies that are not part of any planned market design or implementation work.

10.3.1 2025 Regional System Plan

On December 8, 2025, the ISO published the final version of its 2025 Regional System Plan (RSP25), a comprehensive biennial system planning analysis that provides a 10-year view of New England's grid.²⁷³ The report highlights that demand for electricity is projected to grow significantly between 2025 and 2034, driven mostly by states' clean-energy and electrification policies. These policies are advancing the transition toward renewable generation while increasing adoption of electric vehicles and electric heating, reshaping both the level and timing of electricity consumption.

RSP25 also outlines how the power grid will need to adapt to these changes, including managing the rapid growth of behind-the-meter solar, which will push daytime electricity use to new lows on mild, sunny days. It identifies emerging long-term transmission needs and ongoing regional efforts to prepare the grid for more renewable energy, such as projects aimed at increasing transfer capability through Maine and supporting new generation in northern New England. While not a blueprint for future resource development, RSP25 serves as a broad planning tool that helps policymakers, utilities, and stakeholders anticipate challenges and coordinate investments to ensure continued reliability as the region moves toward cleaner energy.

²⁷³ ISO New England Inc., "2025 Regional System Plan", December 8, 2025, https://www.iso-ne.com/static-assets/documents/100030/final_2025_rsp.pdf

Acronyms and Abbreviations

Acronyms and Abbreviations	Description
°F	degrees Fahrenheit
AC	alternating current
ACE	area control error
ADCR	Active Demand Capacity Resources
AMR	Annual Markets Report
ARA	annual reconfiguration auction
ARD	asset-related demand
ART	Annual Reconfiguration Transaction
AS	ancillary service
BAA	balancing authority area
BAAL	Balancing Area ACE Limits
BAL-001-2	<i>NERC's Real Power Balancing Control Performance Standard</i>
BAL-003	<i>NERC's Frequency Response and Frequency Bias Setting Standard</i>
bbl	barrel (unit of oil)
Bcf	billion cubic feet
BTM	behind-the-meter
Btu	British thermal unit
C4	market concentration of the four largest competitors
CAR	Capacity Auction Reform
CARPD	Capacity Auction Reform: Prompt and Deactivation
CARSA	Capacity Auction Reform: Seasonal and Accreditation
CC	combined cycle (generator)
CCP	capacity commitment period
CDD	cooling degree day
CMR	Code of Massachusetts Regulations
CO ₂	carbon dioxide
CONE	cost of new entry
CPS 2	<i>NERC Control Performance Standard 2</i>
CSC	Cross Sound Cable <i>or</i> capacity scarcity condition
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CT	combustion turbine
CTL	capacity transfer limit
CTS	Coordinated Transaction Scheduling
DAGO	day-ahead generation obligation
DALO	day-ahead load obligation

Acronyms and Abbreviations	Description
DARD	dispatchable asset related demand
DASI	Day-Ahead Ancillary Services Initiative
DA A/S	Day-Ahead Ancillary Services
DDBT	dynamic de-list bid threshold
DDG	do-not-exceed dispatchable generators
DDT	dynamic de-list threshold
Dec	decrement (virtual demand)
DFC	dual fuel commissioning
DG	distributed generation
DLOC	dispatch lost opportunity costs NCPC
DNE	do not exceed
DOE	US Department of Energy
DR	demand response
EGEL	Electricity Generator Emissions Limits (program)
EIA	US Energy Information Administration (of DOE)
EIR	Energy Imbalance Reserve
EMM	External Market Monitor
EMOC	Energy Market Opportunity Cost
EMOF	Energy Market Offer Flexibility
EPA	Environmental Protection Agency
ERS	external reserve support
ETU	Elective Transmission Upgrade
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FER	Forecast Energy Requirement
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
FRS	Flexible Response Services
FSP	Fast-Start Pricing
FTR	Financial Transmission Right
GT	gas turbine
GHG	greenhouse gas
GW	gigawatt
GW-month	gigawatt-month
GWh	gigawatt-hour
GWSA	Global Warming Solutions Act
HDD	heating degree day
HE	hour ending
HQ	Hydro-Québec

Acronyms and Abbreviations	Description
HQICCS	Hydro-Québec Installed Capacity Credit
IBT	internal bilateral transaction
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
ICT	Interim Compensation Treatment
IEP	Inventoried Energy Program
IMAPP	Integrating Markets and Public Policy
IMM	Internal Market Monitor
Inc	increment (virtual supply)
ISO	Independent System Operator, ISO New England
ISO tariff	<i>ISO New England Transmission, Markets, and Services Tariff</i>
kW	kilowatt
kWh	kilowatt-hour
kW-month	kilowatt-month
kW/yr	kilowatt per year
L	symbol for the competitiveness level of the LMP
LA	left axis
LCC	Local Control Center
LEG	limited-energy generator
LMP	locational marginal price
LNG	liquefied natural gas
LOC	lost opportunity cost
LOLE	loss- of-load expectation
LS/ERI	Lower SEMA/Eastern RI Import interface
LSE	load-serving entity
LSCPR	local second-contingency-protection resource
LSR	local sourcing requirement
M-36	<i>ISO New England Manual for Forward Reserve</i>
MA	State of Massachusetts
MAPE	mean absolute percent error
MassDEP	Massachusetts Department of Environmental Protection
MCL	maximum capacity limit
MDE	manual dispatch energy
ME	State of Maine and Maine load zone
M/LCC 2	Master/Local Control Center Procedure No. 2, <i>Abnormal Conditions Alert</i>
MMBtu	million British thermal units
MOPR	Minimum Offer Price Rule
MRA	monthly reconfiguration auction

Acronyms and Abbreviations	Description
MRI	marginal reliability impact
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NCPC	Net Commitment-Period Compensation
NECEC	New England Clean Energy Connect
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NH	State of New Hampshire, New Hampshire load zone
NHME	New Hampshire-Maine Import interface
NICR	net Installed Capacity Requirement
NNE	northern New England
No.	Number
NPCC	Northeast Power Coordinating Council
NY	State of New York
NYNE	New York-New England interface
NYISO	New York Independent System Operator
OATT	<i>Open Access Transmission Tariff</i>
OP 4	ISO Operating Procedure No. 4
OP 7	ISO Operating Procedure No. 7
OP 8	ISO Operating Procedure No. 8
ORTP	offer-review trigger price
PER	peak energy rent
PFP	pay-for-performance
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PPR	pay-for-performance penalty rate
PRD	price-responsive demand
PROBE	Portfolio Ownership and Bid Evaluation
PST	pivotal supplier test
PTO	Participating Transmission Owners
PURA	Public Utilities Regulatory Authority
PV	photovoltaic
Q	quarter

Acronyms and Abbreviations	Description
RA	reconfiguration auction
RA	right axis
RAA	reserve adequacy assessment
RCA	Reliability Coordinator Area
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RFP	Requests for Proposals
RGGI	Regional Greenhouse Gas Initiative
RI	State of Rhode Island, Rhode Island load zone
RMCP	reserve market clearing price
RNL	regional network load
RNS	regional network service
RoP	rest of pool
RoS	rest of system
RRP OC	rapid-response pricing opportunity costs NCPC
RSI	Residual Supply Index
RTDR	real-time demand response
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTR	renewable technology resource
SCR	special-constraint resource
SEMA	Southeast Massachusetts load zone
SENE	southeastern New England
SMD	Standard Market Design
SWCT	Southwest Connecticut
THI	Temperature-Humidity Index
TMNSR	10-minute non-spinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TPRD	transitional price-responsive demand
TTC	total transfer capability
UDS	unit dispatch system
US	United States
UTC	up-to-congestion
VT	State of Vermont and Vermont load zone
WCMA	Western/Central Massachusetts
WRP	Winter Reliability Program
WTI	West Texas Intermediate

Acronyms and Abbreviations	Description

An Assessment of the Day-Ahead Ancillary Services Market

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Internal Market Monitor

JUNE 8, 2026



Preface/Disclaimer

The Internal Market Monitor (“IMM”) of ISO New England Inc. (the “ISO”) has prepared this report on the performance and the competitiveness of the Day-Ahead Ancillary Services (DA A/S) Market.

This report fulfills the requirement of Market Rule 1, Appendix A, Section III.A.17.2.5, *Additional Ad Hoc Reporting on Performance and Competitiveness of Markets*:

In furtherance of its function under Section III.A.2 of this **Appendix A**, including without limitation Sections III.A.2.3(e) and (k) therein, the Internal Market Monitor shall perform independent evaluations and prepare ad hoc reports on the overall competitiveness and performance of the New England Markets or particular aspects of the New England Markets, including the competitiveness and performance of a major market design change. The Internal Market Monitor shall have the sole discretion to determine when to prepare an ad hoc report and may prepare such report on its own initiative or pursuant to a request by the ISO, New England state public utility commissions or one or more Market Participants. However, the Internal Market Monitor will report on the competitiveness and performance of any new major market design change within one to three years, respectively, of the effective date of operation of the market design change, or as soon as adequate data becomes available. While the Internal Market Monitor may solicit or receive input of the External Market Monitor, Market Participants and other stakeholders, including New England state public utility commissions, the methodology and criteria used to conduct its independent analysis shall be at the sole discretion of the Internal Market Monitor. The Internal Market Monitor shall describe its methodology and criteria used in an ad hoc report of its significant findings and, if any, recommendations. The Internal Market Monitor shall file with the Commission and post to the ISO’s website a final version of an ad hoc report. Thereafter, the Internal Market Monitor shall continue to report on the competitiveness and performance of any market design change that has been the subject of an ad hoc report in its quarterly or annual reports under Sections III.A.17.2.2 and III.A.17.2.4.

All information and data presented here are the most recent as of the time of publication.

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Section 1

Executive Summary

The Day-Ahead Ancillary Services Market introduced the most significant reforms to New England's wholesale energy markets in over twenty years. Under this design, the Day-Ahead Market jointly clears energy and Day-Ahead Ancillary Services (DA A/S) to meet expected next-day load and operating reserve requirements. The initiative was launched on February 28, 2025.

This report evaluates the competitiveness and performance of the DA A/S design during its first year of operation. While the analysis is based on a limited period, it provides a comprehensive assessment of market outcomes and will be further supplemented by ongoing quarterly reporting on market performance and a required three-year full performance review.¹

The report begins with an overview of the market design, followed by detailed analysis of market costs, cost drivers, and comparisons with the New York ISO market. We then assess market competitiveness, mitigation effectiveness, and market performance metrics, including reliability impacts. The final section presents results from an IMM survey of market participants, offering qualitative data and additional insight into how the design reforms have been experienced in practice.²

In our assessment, we conclude that DA A/S costs are consistent with competitive market participant behavior. However, competitiveness does not necessarily translate into efficient outcomes. In February 2026, we put forward a set of targeted recommendations to improve the cost-effectiveness of the DA A/S design based on our ongoing monitoring and assessment work.³ These include refinements to the Strike Price methodology, adjustments to the Forecast Energy Requirement (FER), and a review of contingency-response related performance parameters affecting the ten- and thirty-minute reserve requirements. One of these changes (the latter) was implemented on May 1, 2026, while the ISO is currently working with stakeholders on detailed design changes for the remaining two recommendations.⁴ We continue to believe that these changes will meaningfully improve cost-effectiveness and overall market performance.

A number of key findings emerge from this one-year assessment.

¹ Appendix A, Market Rule 1, I.A.17.2.5 requires the IMM to assess the competitiveness of major market design changes within one year (subject to sufficient data) and to evaluate market performance within three years.

² The IMM appreciates the time and thoughtful responses provided by the market participants who participated in the survey.

³ ISO-NE Internal Market Monitor (David Naughton), "Recommended Changes to the Day-Ahead Ancillary Services Market," memo, February 4, 2026, https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf

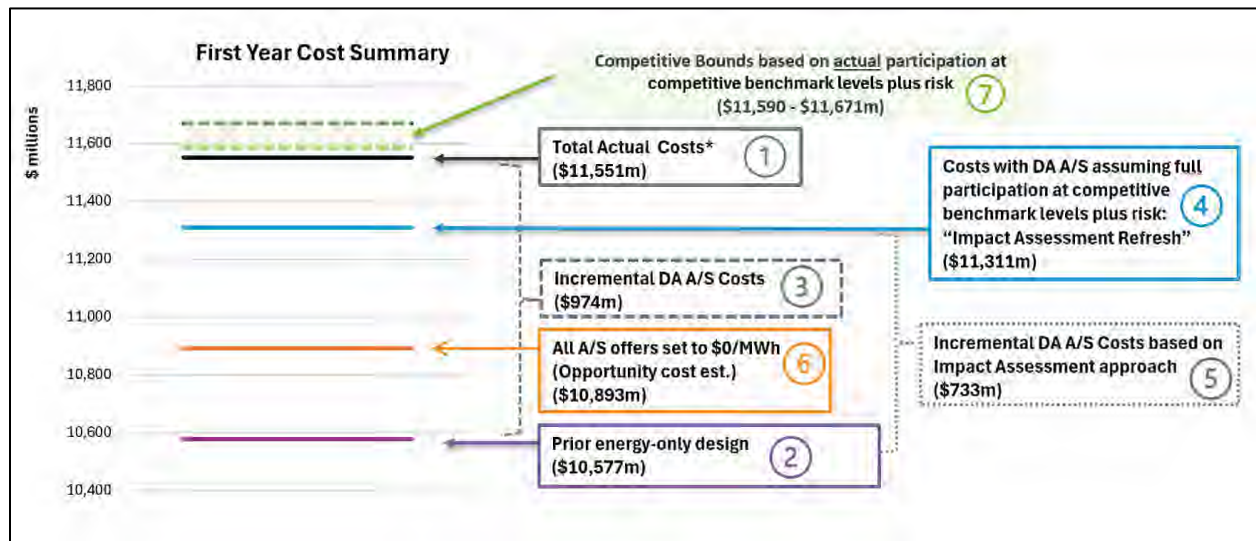
⁴ The report does not quantify the impact of these changes; backcast-based estimates have been provided by the ISO to stakeholders as part of ongoing design discussions. See ISO New England, "Day-Ahead Ancillary Services Post-Implementation Adjustments," presentation to NEPOOL Markets Committee, May 12–14, 2026, https://www.iso-ne.com/static-assets/documents/100035/a06_mc_2026_05_12-14_daas_post_implementation_adjustments_presentation.pdf

Estimated Incremental Costs of DA A/S Totalled \$974 Million in the First Year, with 12 Days Accounting for 50%

The first twelve months of DA A/S operation corresponded to a period of elevated fuel and energy costs, and several multi-day periods of exceptionally high demand and extreme weather events that had not been experienced in some years. Overall, energy and ancillary services (E&AS) costs from March 2025 through February 2026 totaled **\$11,500 million** (\$11.5 billion), the highest since 2022 and the second highest since 2008 in nominal terms.⁵

A core part of this assessment includes a series of simulation studies to evaluate DA A/S costs and identify key cost drivers and assess competitive outcomes. The figure below summarizes total E&AS costs from these simulations. The key values from the simulation studies are labeled with a number and referenced in the narrative below to facilitate interpretation.

Figure 1-1: Day-Ahead Ancillary Services Cost Estimates and Drivers



*Based on simulated DA A/S market rules used as the benchmark for counterfactual comparisons. Total costs modeled in the simulation include LMP, FER, DA Flexible Response Services and EIR net costs, and the cost of real-time incremental energy.

First, we compare outcomes under the new co-optimized energy and ancillary services market to those under the prior energy-only design to estimate incremental costs of the design. Total simulated E&AS costs amounted to **\$11,551 million** ①, closely matching actual costs and reflecting strong model benchmarking performance throughout the study period. We estimate that costs under the prior energy-only market would have been **\$10,577 million** ②, meaning that total incremental costs were **\$974 million** ③, about 9% higher than the prior energy-only design, or \$8.23/MWh of load served.

⁵ Actual total energy and ancillary services costs include day-ahead and real-time energy, reserve, regulation, and NCPD costs.

DA A/S costs were concentrated in a relatively small number of stressed operating days. Specifically, 12 days accounted for roughly 50% of incremental costs, with a five-day winter storm event (Winter Storm Fern) contributing about 40%, and a single day (January 27, 2026) accounting for 18%. These “**Top 12 Days**” are particularly important to analyze because they reflect periods when reliability risks are elevated and strong price signals and performance incentives are most critical. Accordingly, we assess market competitiveness and performance during these days in greater detail throughout the report.

Higher-than-Expected DA A/S Costs Primarily Reflect Changes in Market and System Conditions

DA A/S costs were significantly higher than those estimated in ISO-NE’s original Impact Assessment (IA), which used 2019–2021 data and estimated incremental costs of **\$140 million** (approximately 3% of total E&AS costs). Significantly different market fundamentals and system conditions during the 2025/26 period—including higher natural gas prices, increased energy price volatility, shifts in the supply mix, and more frequent stressed conditions—put upward pressure on costs.

To model these effects collectively, we conducted an “IA Refresh” using the same methodology as the original IA, which assumes full participation and competitive offer pricing (including risk premiums). When developing the IA, the ISO made assumptions about participant behavior and the nature of the competitive environment. Like many economic studies, ISO-NE premised assumptions on market participation on profit-maximizing behavior under competitive conditions. Consistent with that framework, participants were assumed to offer their full physical capability at the estimated cost of meeting the DA A/S obligation. This approach provides a full-participation, competitive-equilibrium benchmark reflecting an expected long-run market outcome.

Under these assumptions, total costs would have been **\$11,311 million** ④, implying incremental DA A/S costs of **\$733 million** ⑤ (\$5.66/MWh). Updated market conditions therefore explain roughly 75% of the observed incremental costs of \$974 million. The remaining **~\$240 million** in incremental costs (not explained by updated market/system conditions) is primarily attributable to lower participation and higher offer prices than benchmark levels.

Higher-than-Expected Costs also Reflect Differences Relative to Assumed Market Behavior and Highlight the Role of Opportunity Costs in Price Formation

In practice, participation has been lower and offer prices higher than assumed in the IA, resulting in tighter supply conditions, higher cross-product opportunity costs, and a higher marginal cost of meeting energy and ancillary service requirements.

Under these conditions, opportunity costs play a key role in price formation by ensuring that resources are indifferent between providing energy and ancillary services in the co-optimized market. Although difficult to quantify opportunity costs precisely, simulation results show that even if all DA A/S historically-offered capability were offered at \$0/MWh, total E&AS costs would be **\$10,893 million** ⑥, indicating that the system would still incur **\$316 million** (\$2.67/MWh) in incremental costs to satisfy FER and FRS constraints.

Ultimately, market participation decisions depend on a myriad of factors, including commercial strategy considerations, physical and operational constraints, and perceptions of market risk.

Importantly, our survey results suggest market complexity also played a role in participation decisions. Some participants indicated that they adjusted their offer behavior over time as they became more familiar with the market, but many indicated that they wanted additional training to enhance their understanding and comfort with specific market features. These findings are consistent with the broader analysis in this report, which shows that risk, uncertainty, and market design features play a significant role in shaping offer behavior and market outcomes.

- ➔ We recommend that the ISO provide additional and ongoing technical training related to DA A/S to facilitate and accelerate market participation.

DA A/S Costs were Consistent with Competitive Market Participant Behavior

Our competitiveness analysis indicates that DA A/S market outcomes were broadly consistent with competitive behavior. Specifically, we find that:

- Participation levels have generally not raised **physical withholding** concerns that would impact overall competitive cost estimates. Participation levels continue to trend upwards with market experience. While there has generally been sufficient offered capability to meet the load and reserve requirements, we find that the level of participation is particularly impactful on market costs and prices on high load/stress days. The IMM continues to consult with participants regarding their participation levels to guard against potential physical withholding.
- There is also no indication of impactful **economic withholding** on overall costs. Observed market costs were consistent with simulated costs using competitive offer benchmarks, indicating that offer levels from participating resources were broadly consistent with competitive, risk-adjusted offer behavior. To assess whether market outcomes are consistent with competitive offer behavior, we conducted two simulations in which DA A/S offers are set at IMM benchmark levels, differing only in how the risk premium is defined. Together, these risk methodologies provide a range of competitive outcomes: one based on a return-per-unit-of-risk metric (Sharpe) and one based on a more conservative tail-risk measure (conditional Value at Risk). Market costs of **\$11,551 million** ① are consistent with, and even slightly below, the IMM's **competitive bounds of \$11,590 and \$11,671 million** ②, although that result is driven largely by a small number of high-cost days; for most of the year, costs were closely aligned with the IMM's competitive benchmarks.
- **DA A/S offer mitigation** occurred infrequently and effectively addresses circumstances where offers both materially exceeded benchmark expectations and had a measurable effect on clearing prices. One notable exception arises when price impact thresholds fell below \$3/MWh, which occur during times when system conditions were generally unstressed and market power is not a concern. Almost thirty-percent of mitigations occurred under these conditions. The ISO plans to address as part of their DA A/S market enhancements work in 2026 by incorporating a \$3/MWh price impact floor, a sensible measure that will address these observed instances of over-mitigation.
- DA A/S markets exhibit moderate concentration, and some realized outcomes—particularly for DA TMSR—show tight post-clearing reliance on a relatively small set of suppliers when capability is assessed after commitment. These “ex-post” measures can

help identify intervals that warrant closer monitoring. However, they likely overstate the extent of market power. In the day-ahead market, clearing reflects the joint satisfaction of multiple requirements, so there is not a single marginal unit that can be isolated; changes in any binding constraint generally affect the dispatch and reserve provision of multiple units and this inherent substitutability can mitigate market power concerns.⁶

The Strike Price and Expected Closeout Cost Calculator (the “GMM”) Showed Systematic Bias

The ISO’s Gaussian Mixture Model (GMM) model for determining key DA A/S values—specifically the strike price and expected closeout—exhibited systematic bias in its first year of operation, understating real-time LMPs on average. This under-forecasting bias is evident in actual outcomes falling frequently in the upper tail of the predictive distribution and carried through to expected closeout charges, which were also systematically understated relative to actual closeout charges.

These findings have two important implications. First, when the model produces Strike Prices and expected closeout values that are below prevailing market expectations, the IMM may need to adjust mitigation values to offset this misalignment, potentially leading to higher offer prices and increased day-ahead market costs.⁷ Indeed, the IMM performed such adjustments during many high-stress days. Second, implementing a Strike Price floor—consistent with our recommendation to better align the strike price with the short-run marginal costs of resources providing ancillary services—offers a meaningful secondary benefit by eliminating forecasting errors below the marginal cost of a combustion turbine.

- ➔ Even with the IMM’s recommended strike price adjustments, we encourage the ISO to continue to invest in its modeling tools and processes to ensure that expected real-time energy prices and closeout costs better track prevailing market conditions.

Evidence of Reliability Benefits is Promising but Preliminary

We have considered stakeholder interest in the reliability benefits of DA A/S, particularly in light of higher-than-expected costs. Accordingly, we developed a framework that combines empirical analysis with survey responses to evaluate changes in resource performance and commitment patterns. Given that this assessment is based on a single year of operation, the results should be interpreted with caution, and the framework will continue to evolve as additional data and stakeholder feedback become available.

The DA A/S design incorporates features that support reliability—most notably transparent pricing and stronger performance incentives—but participant behavior also reflects the combined influence of energy, capacity, and ancillary services market incentives. Therefore several observed

⁶ In addition, efficient market outcomes need not include surplus TMSR capability, and the market can re-optimize commitment and reserve awards in response to offers.

⁷ The relationship between strike price levels and market outcomes is nuanced and requires further study. In particular, while lower strike prices relative to prevailing market conditions increase expected closeout costs and likely increases overall day-ahead costs, however this effect is at least partially offset by higher realized closeout costs.

reliability effects remain preliminary and cannot yet be treated as causal, and therefore care should be taken in attributing observed performance improvements to DA A/S alone.

Early indications are encouraging but mixed.

- **Outage rates:** Combustion turbine availability has improved, reflected in lower outage rates which have fallen from 18% to 11% for resources taking on DA A/S obligations.
- **Natural gas procurement:** We measured if gas-fired generators scheduled additional natural gas day-ahead to meet DA A/S positions, in the context of stronger incentives to be prepared to perform. We did not find a measurable change in the amount of natural gas scheduled to meet real-time needs, even during winter months when intraday gas procurement is more uncertain. About 97% of natural gas needs continue to be scheduled day-ahead.
- **Operational changes:** On the other hand, survey responses indicate that DA A/S awards influence operational decisions; 71% of respondents reported taking actions in response to awards, most commonly procuring fuel.
- **Day-ahead commitments:** More commitments of long-lead time resources occur under DA A/S, with no commitments made through the out-of-market next-day Reserve Adequacy Analysis (RAA) process; under DA A/S such commitments face financial obligations and stronger performance incentives, and create additional responsive capability in real-time.

Potential Cost Implications for the Capacity Market and Uplift

DA A/S has introduced a market-based revenue stream for flexible, fast-start combustion turbines, which comprise the majority of cleared resources, and therefore has implications for how costs are recovered across wholesale markets. First-year DA A/S revenues averaged approximately \$3.50/kW-month fleetwide, compared to about \$1.30/kW-month under the former Forward Reserve Market in 2023 and 2024. These additional revenues reduce the reliance on out-of-market uplift payments and contribute to a shift in cost recovery toward market-based mechanisms. They also have implications for capacity market pricing by offsetting a portion of the “missing money” reflected in competitive capacity offers and, over time, are expected to be incorporated into Net Cost of New Entry estimates, placing downward pressure on future capacity market costs.

Absent DA A/S, additional commitments of long-lead-time generation would likely have been required after the day-ahead market to meet expected load and reserve requirements. As a result, DA A/S may reduce NCPC by limiting reliance on post-day-ahead (RAA) commitments. However, the magnitude of these reductions is highly uncertain and sensitive to assumptions about operator behavior. Estimated savings are bounded at approximately \$35 million annually, with more realistic outcomes likely significantly lower (e.g., roughly \$11 million under peak conditions).

Continued Monitoring and Openness to Refinements Will Be Important

The new market design has been in operation for only one year. Given the magnitude of the design change, it is not surprising that refinements are being considered based on early experience to improve or balance cost-effectiveness. While we do not include additional design recommendations in this assessment, further changes may be warranted for ISO and stakeholder

consideration as more data become available and our monitoring and assessment work continue. Future analysis will help determine whether the patterns observed in the first year reflect long-run outcomes or transitional effects.

Section 2

Introduction and Assessment Scope

In fulfillment of its obligations under the ISO-NE tariff, the Internal Market Monitor (IMM) has prepared this report on the performance and the competitiveness of the Day-Ahead Ancillary Services (DA A/S) Market. This report is filed with the Federal Energy Regulatory Commission pursuant to Appendix A, Market Rule 1, I.A.17.2.5, which requires the IMM to assess the competitiveness of major market design changes within one year (subject to sufficient data) and to evaluate market performance within three years.

This report goes beyond a narrow assessment of “competitiveness” and instead evaluates the first year of operation of the DA A/S market and the broader day-ahead market. A subsequent review will be conducted in 2028, after the DA A/S design has been in place for three years.

Prior to this report, the IMM has already put forward a set of targeted recommendations to improve aspects of the DA A/S design.⁸ These include refinements to the strike-price methodology, adjustments to the Forecast Energy Requirement (FER), and a review of parameters affecting the quantity of reserve procurement. This report does not attempt to quantify the impact of these recommended changes. Rather, the analysis is intended to inform these recommendations and to highlight areas where adjustments may improve certain aspects of design performance.

The implementation of DA A/S represents one of the most significant changes to the ISO New England market design in recent years. Prior to DA A/S, the day-ahead market committed resources to satisfy operating reserve requirements but did not create financial obligations nor compensate resources for these ancillary services capabilities. Instead, reserve providers were primarily compensated for these capabilities through the Forward Reserve Market (FRM) or infrequent real-time reserve pricing. In addition, the process for managing differences between day-ahead schedules from physical resources and expected real-time operating conditions relied on actions that took place after the day-ahead market clearing was complete.

That prior energy-only design created several challenges. First, because the day-ahead market was not transparently procuring operating reserves, resource owners were not explicitly aware that the ISO was relying on them for these services in its operating plan. Second, the value of reserve capability was not clearly reflected in day-ahead market prices. Third, when the set of resources committed through the day-ahead market proved insufficient to satisfy reliability needs, the ISO relied on out-of-market actions to ensure reliability.

The DA A/S reforms were developed to address these limitations, but, at the same time, these reforms have made certain costs more visible through marginal pricing principles. Under the prior market structure, some of the costs associated with maintaining reserve capability and operational

⁸ The memo titled *Recommended Changes to the Day-Ahead Ancillary Services Market* is available here: https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf

flexibility were reflected through mechanisms such as the FRM or uplift payments rather than through explicit day-ahead ancillary service payments.

Under the new design, reserve procurement costs are incorporated more directly into market settlements. As a result, one of the most prominent features of the first year of DA A/S has been the magnitude of the increase in energy and ancillary services costs associated with the initiative. Stakeholders have focused on these costs and raised a central question: what benefits does the market produce in return?

We start to answer that question in this report. Because a new market design that visibly increases market payments will inevitably be judged against its costs, the evaluation in this report places emphasis on benefits as well as costs. However, some of the expected benefits of DA A/S — particularly those associated with increased participant incentives and improved system preparedness — are inherently more difficult to measure than the costs. Market payments can be directly observed in settlement data, while benefits are not as easily captured. For this reason, the report evaluates a broader set of metrics that are closely tied to the objectives of the reform. These include changes in fuel scheduling, day-ahead commitment, and unit availability and performance.

The report is organized around three broad analytical questions.

1. **What was the incremental cost of this initiative?** This includes a review of energy and ancillary services settlements, a structured assessment of incremental cost, and a benchmarking to ancillary services costs in the New York ISO market.
2. **What factors drove these costs?** This includes an analysis of the role of system conditions and participant behavior. The analysis of participant behavior includes a review of market participation, an evaluation of the market structure and offer behavior, and an assessment of mitigation effectiveness.
3. **What benefits has this initiative produced?** This includes a review of the market's performance as well as a high-level evaluation of preliminary reliability benefits.

To address these questions, the report uses several complementary methods, including analysis of observed market outcomes, simulation-based counterfactual analysis, and survey evidence from market participants.

The first year of any major market reform will inevitably involve adaptation. Participants are still learning the details of the market, the ISO is accumulating experience with the new design, and the data from a single year may reflect system conditions that are not representative of long-run outcomes. For these reasons, this report should be understood as a first-year review rather than a final assessment of the long-run performance of the market.

Section 3

Market Design Overview

The Day-Ahead Ancillary Services Market represents a set of reforms to the day-ahead market with the objectives of procuring the ancillary service capabilities necessary to meet reliability requirements, pricing those capabilities in a transparent manner, and compensating the resources that provide those capabilities.⁹

These market reforms impacted both the energy and ancillary services markets. The introduction of the DA A/S market was accompanied by a significant alteration to the energy market with a new market constraint that ensures that enough physical

capability is procured day-ahead to satisfy the ISO's load forecast. Importantly, the DA A/S market and the existing day-ahead energy market collectively form the day-ahead market, which jointly clears energy and ancillary services in a co-optimized process that determines the optimal allocation of energy and ancillary services to satisfy the system's requirements.

Glossary

DA A/S: The ancillary services products that are procured in the DA A/S market

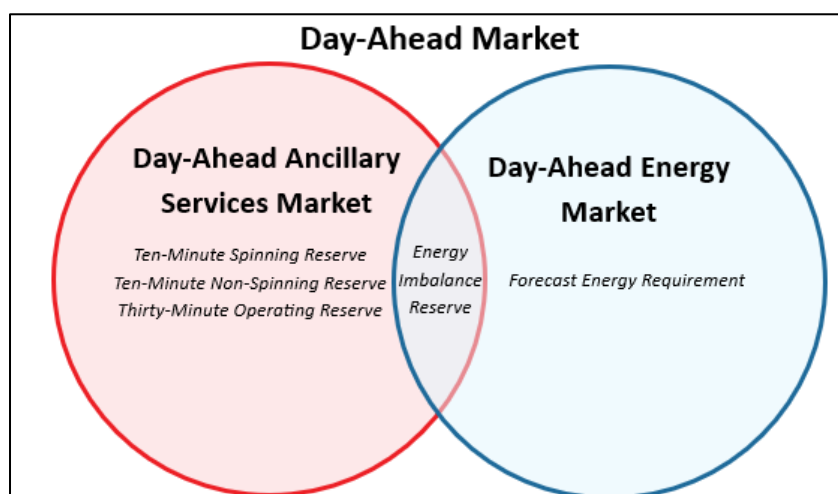
DA A/S market: The day-ahead ancillary services market

DA energy market: The day-ahead energy market

DA market: The jointly optimized DA energy and DA A/S market

A conceptual representation of the DA A/S market reforms is depicted in Figure 3-1 below.

Figure 3-1: Conceptual Representation of DA A/S Market Reforms



⁹ See Page 16 of the testimony of Dr. Matthew White in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

An overview of these market reforms is provided below in order to set the groundwork for the discussion of market costs and performance that follows.

3.1 Day-Ahead Ancillary Services Market

The DA A/S market is a voluntary market in which the ISO procures certain ancillary service capabilities one day in advance of when they are needed. Resources that have these capabilities can receive compensation for them in return for taking on a financially-binding obligation that is linked to the real-time LMP.

3.1.1 Requirements and Products

Flexible Response Services

Flexible Response Services (FRS) provide the fast-starting and fast-ramping capability needed for the ISO to respond quickly to large supply losses. These services correspond to operating reserves and are based largely on the system's largest contingencies, consistent with analogous requirements in the real-time market.¹⁰ These requirements are:

- The **Ten-Minute (Total 10) Reserve Requirement** is the amount of 10-minute reserve capability (spinning or non-spinning) that is required by the system. It is based on the system's first contingency multiplied by a non-performance factor, which changed from 120% to 115% on May 1, 2026.¹¹
- The **Ten-Minute Spinning Reserve (TMSR) Requirement** represents the amount of the Total 10 requirement that must be met through spinning reserves. This amount is generally set at 25% of the Total 10 requirement but can range between 25% to 100%.
- The **Total Reserve (Total 30) Reserve Requirement** is the total amount of 10-minute and 30-minute reserve capability required by the system. The amount in excess of the Total 10 reserve requirement is generally 50% of the system's second contingency plus an additional amount known as Replacement Reserves, which varies between 160 MW and 180 MW depending on the season.

To help satisfy these requirements, resources may make offers for the following products:¹²

- **Ten-Minute Spinning Reserve (TMSR):**
 - This is capability that is synchronized to the grid and capable of responding within ten minutes.

¹⁰ For more information about the determination of operating reserve requirements, see ISO-NE Operating Procedure No. 8: https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op8/op8_rto_final.pdf

¹¹ This change took effect for the operating day of May 1, 2026. For more information about the motivation behind this change, see: https://www.iso-ne.com/static-assets/documents/100034/a05_reserve_nonperformance_factor_updates.pdf.

¹² There are some exceptions to the general reserve capability descriptions provided here. For information about the calculation of reserve capability, see Section III.1.7.19.2 of the ISO-NE Tariff, available here: https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

- This reserve product can be used to satisfy the TMSR, Total 10, and Total 30 requirements.
- **Ten-Minute Non-Spinning Reserve (TMNSR):**
 - This is capability that is not synchronized to the grid but can start and respond within ten minutes.
 - This reserve product can be used to satisfy the Total 10 and Total 30 requirements.
- **Thirty-Minute Operating Reserve (TMOR):**
 - This is capability that may or may not be synchronized to the grid but is capable of responding within thirty minutes.
 - This reserve product can be used to satisfy the Total 30 requirement.

Energy Imbalance Reserves

Energy Imbalance Reserve (EIR) provides reserve capability used to help meet the load forecast. Physical supply resources with 60-minute reserve capability can be compensated by clearing EIR awards. The market clearing engine procures EIR to help satisfy the **Forecast Energy Requirement (FER)**, which ensures that expected next-day demand is met through a combination of day-ahead energy awards on physical resources and EIR awards.¹³

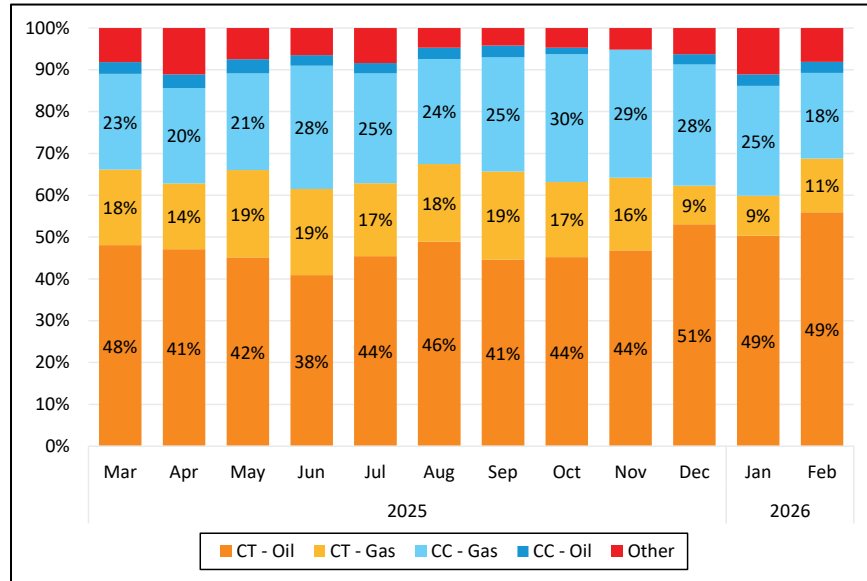
Observed DA A/S Clearing

Combustion turbine (CT) and combined-cycle (CC) resources accounted for most DA A/S clearing during the first year of the market. These resources were primarily fueled by natural gas and oil.¹⁴ Figure 3-2 shows monthly DA A/S clearing by technology and fuel type, expressed as shares of total clearing (MWh), with each column summing to 100%.

¹³ The FER is discussed in much more detail in Section 3.2.

¹⁴ While some of these resources can run on multiple fuels (i.e., are dual-fuel capable), when they do run, they generally run exclusively on one fuel. For these “dual-fuel” resources, we use the fuel underlying the energy offer for a specific hour.

Figure 3-2: DA A/S Clearing by Technology and Offered Fuel



Combustion turbines dominated DA A/S clearing each month over this period. Oil-fired CTs typically accounted for roughly 40–50% of cleared awards, while gas-fired CTs contributed an additional 10–20%. CT resources supplied nearly all TMSR awards in every month and also made meaningful contributions to TMOR and EIR clearing.

Combined-cycle units offering on gas also represented a substantial share of DA A/S clearing, generally in the range of 20–30% each month. These units were the primary suppliers of TMSR throughout the year.

Other resource types had only a limited role. Pumped-storage hydro and pondage hydro were the only other resource types to account for more than one percent of cleared DA A/S awards during the first year of the DA A/S Market.

3.1.2 Settlement

DA A/S awards are settled using a two-part call option settlement design. The first settlement depends on the day-ahead market; resources that receive a DA A/S award earn a credit at the ancillary service clearing price and the MWh quantity of awards. The second settlement depends on the real-time market; resources with a DA A/S award incur a closeout charge as follows:

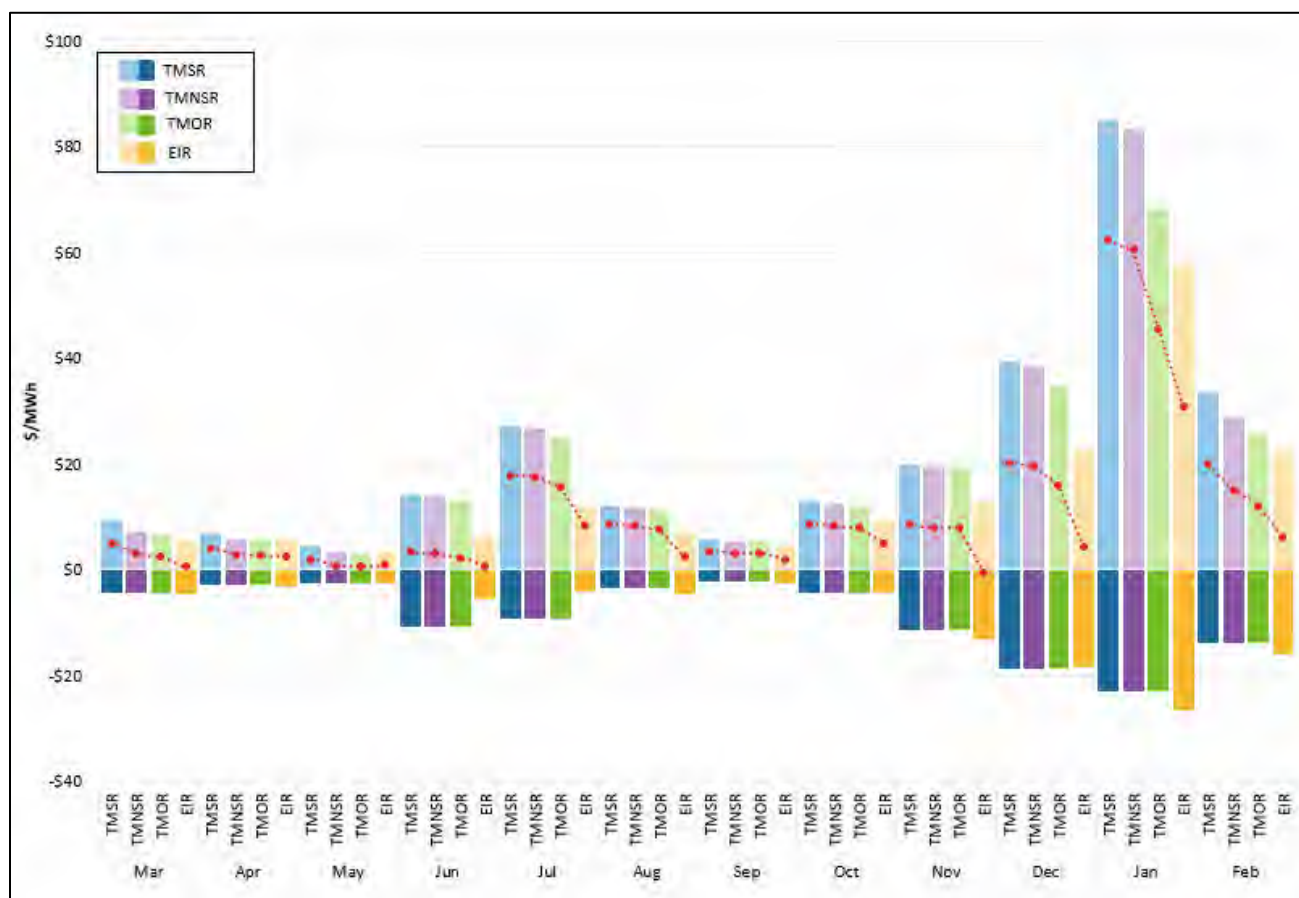
$$\text{Closeout charge} = \text{Award MW} \times \max(LMP_{Hub}^{RT} - \text{Strike Price}, 0)$$

This equation is an important part of the DA A/S market design as it creates a new financial link to the real-time energy market for a resource with a DA A/S award. If the real-time Hub LMP exceeds the strike price (often denoted by K), then resources with a DA A/S award incur a closeout charge. However, if the real-time Hub LMP is less than the strike price, then resources with DA A/S awards incur no charge. The current design sets the hourly strike price at the expected real-time Hub LMP plus a \$10 adder.

Observed DA A/S Clearing Prices

Figure 3-3 below captures this two-part settlement over the first year of DA A/S. This figure shows the average hourly DA A/S clearing prices as positive values and realized closeout charges as negative values by product and month.¹⁵ This figure also depicts the clearing price less the realized closeout charge, which we refer to as the *net* clearing price, with a red circle.

Figure 3-3: Average Hourly DA A/S Clearing Prices by Product and Month



The DA A/S clearing prices were highest in the summer (specifically, July 2025) and winter months (specifically, December 2025, January 2026, and February 2026). These are months when the power system tends to experience more stressed conditions, which can lead to higher and more volatile energy prices. We provide additional information on several acute periods during the first year of DA A/S throughout this report in order to provide additional insight into the drivers of the higher costs observed during these months.

Given their price formation mechanics, the clearing prices of the three FRS products (TMSR, TMNSR, and TMOR) were closely aligned, while the clearing price for EIR (i.e., the Forecast Energy

¹⁵ The EIR values depicted in this figure are the average hourly values for only the hours when cleared EIR MWs were greater than zero.

Requirement Price or FERP) was lower nearly every month.¹⁶ In general, realized closeouts were lower than DA A/S clearing prices, resulting in positive net clearing prices for all products in every month with the exception of EIR in November 2025.

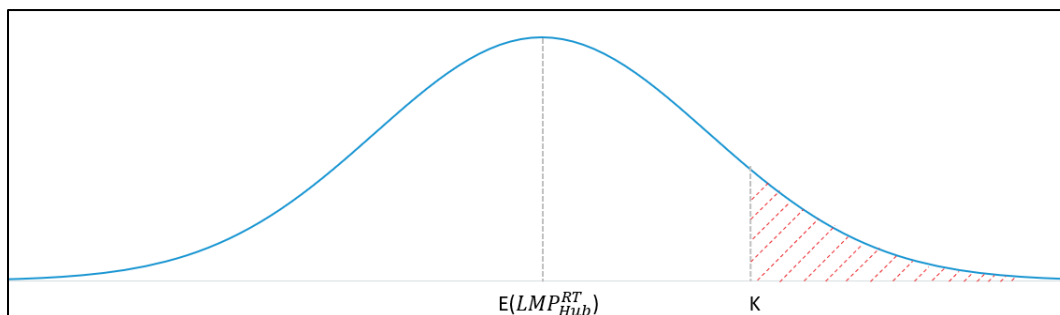
3.1.3 Offer Formulation

The settlement structure described above is foundational to the formulation of a DA A/S offer. This is because, by virtue of receiving a DA A/S award, a resource incurs an (otherwise avoidable) cost in expectation due to the closeout charge. Under the DA A/S design, this cost is referred to as the **Expected Closeout (charge)**. The expected closeout is a critical element of the design because it underpins a competitive DA A/S offer and forms the basis of the mitigation framework.

Conceptually, the expected closeout exists because the real-time LMP could fall between a range of possible values depending on the actual system conditions that occur. For example, lower-than-expected loads could lead to reduced real-time LMPs, while the unexpected trip of a large generator could lead to heightened real-time LMPs. The former scenario is unlikely to create a closeout charge for a resource with a DA A/S award but the latter scenario might.

A simplified graphical representation of this idea is presented in Figure 3-4 below. The x-axis in this figure depicts all the possible values of the real-time LMP that could occur and the blue line defines the likelihood of each of those values; more extreme values of the real-time LMP are less likely to occur (as indicated by the lower level of the blue line at those values), and less extreme values are more likely to occur (as indicated by the higher level of the blue line at those values). This figure depicts the expected value of the real-time LMP as $E(LMP_{Hub}^{RT})$ and the strike price as K. All values of the real-time LMP above K would lead to a closeout charge; this range is indicated in the figure with the dashed red line.

Figure 3-4: Distribution of Real-Time Energy Prices



A central goal of the design is to create strong incentives for resource owners to be prepared to cover their DA A/S positions with physical generation (consistent with a covered call framework).

¹⁶ Specifically, FRS clearing prices “cascade up.” This means, for example, that the shadow price of the Total 30 requirement will appear not only in the TMOR clearing price, but will also “cascade up” into the TMNSR and TMSR clearing prices because these products also help satisfy this requirement. The result is the following relationship between clearing prices for the FRS products: $CP_{TMSR} \geq CP_{TMNSR} \geq CP_{TMOR}$.

Otherwise, the resource effectively buys out of its position at the market's replacement cost reflected in the real-time LMP, potentially incurring net losses.

In addition to the expected closeout, which is relevant to all resource types, there are two other components to a competitive DA A/S offer as defined by the ISO. The first, which is called the **Avoidable Input Cost (AIC)**, represents input energy-related costs incurred by a subset of DA A/S providers (gas and energy storage) that could otherwise be avoided but for the DA A/S award. And the second is a **risk premium**, which captures the uncertainty in net revenues associated with clearing a DA A/S award.

3.1.4 Mitigation

To safeguard competitiveness, DA A/S incorporated a new mitigation framework.¹⁷ This framework is designed to reduce price-impactful exercises of market power while preserving room for competitive offers that reflect reasonable expected values for closeout costs, avoidable input costs and risk. It utilizes the same conduct-and-impact approach that is commonly employed to mitigate market power throughout New England's wholesale markets. The conduct test identifies offers that may be inconsistent with competitive behavior, while the impact test assesses the effect of those flagged offers on market clearing prices. If a DA A/S product offer fails the conduct test, and the impact test fails in any hour, the submitted offer price is replaced during market clearing with a reference price that is intended to represent a competitive offer.¹⁸ This reference price, referred to as a **Benchmark Level** under the DA A/S design, is equal to the sum of the expected closeout and, as applicable, the AIC.

¹⁷ For more information about DA A/S mitigation, see Section III.A.8 of the ISO-NE Tariff, available here: https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

¹⁸ One unique aspect of the DA A/S mitigation design is that a DA A/S product offer is mitigated in a given hour if the offer fails the conduct test in that hour and there is a price impact failure in any hour of that same day (i.e., the impact test failure does not need to occur in the same hour as the conduct test failure for DA A/S mitigation to occur).

The conduct test compares the DA A/S offer price to an estimate of an upper-end competitive price. This latter price is referred to as the **Conduct Test Threshold Price**, and all offer prices that exceed this value are flagged for possible mitigation. The conduct test threshold price is defined as the sum of:

1. 200% of the expected closeout charge;¹⁹ and
2. 150% of the AIC.²⁰

The impact test used for the DA A/S market determines whether DA A/S offers that are flagged by the conduct test have a material effect on increasing DAM clearing prices beyond acceptable levels.²¹ For this purpose, materiality is defined by the **Impact Test Threshold**, which is set at 150% of the median difference between (1) the conduct test threshold prices for all Day-Ahead Ancillary Services offers submitted for the offer-hour and (2) the Benchmark Levels for all Day-Ahead Ancillary Services offers submitted for the offer-hour.²² In the majority of hours, this means the threshold is 150% of the expected closeout.

3.2 Day-Ahead Energy Market

Prior to DA A/S, the market clearing outcomes in the day-ahead market did not always align with expected real-time conditions. For example, less physical energy supply could clear than was expected to be needed in real time.²³ When that happened, there was a day-ahead “energy gap” (i.e., the amount of day-ahead energy awards on physical resources was less than the expected real-time load.)

¹⁹ The 200% multiplier was intended to give suppliers reasonable room to reflect risk premiums, forecasting error in estimated closeout values, and expected differences between Day-Ahead and Real-Time outcomes. The ISO concluded that this level captured a reasonable range of competitive offer behavior without materially weakening market power protections. For additional discussion on this topic, please see pages 90-92 of the testimony of Dr. Parviz Alivand in support of DA A/S contained within the ISO’s filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

²⁰ The 150% multiplier was intended to allow for resource-specific variations in fuel and charging costs, as well as potential inaccuracies in the ISO’s standard cost formulas. The ISO concluded that this level provided a reasonable allowance for competitive cost variation while maintaining an effective conduct screen. For additional discussion on this topic, please see pages 101-102 of the testimony of Dr. Parviz Alivand in support of DA A/S contained within the ISO’s filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

²¹ This evaluation is performed for each hour using all resources that submitted DA A/S offers for that hour, and it measures whether conduct-test-flagged offers increase any Day-Ahead Market price, including the DA LMP and each of the four DA A/S clearing prices.

²² The 150% factor provides a 50 percent buffer above the base threshold measure to account for the limitations of using a single mitigation run and to avoid unnecessary mitigation of offers that may be flagged in that run but, on their own, would not materially affect market prices. Based on its market simulations, the ISO concluded that this level appropriately balances avoiding over-mitigation and preventing under-mitigation. For additional discussion on this topic, please see pages 104-111 of the testimony of Dr. Parviz Alivand in support of DA A/S contained within the ISO’s filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

²³ Physical energy supply refers to generators, demand response resources, and imports.

3.2.1 Forecast Energy Requirement

To address this “energy gap,” the day-ahead market introduced a new constraint—the **Forecast Energy Requirement (FER)**—which requires sufficient capability from physical resources to meet the ISO’s load forecast. The market satisfies the FER through a combination of day-ahead energy awards on physical resources and EIR awards.²⁴

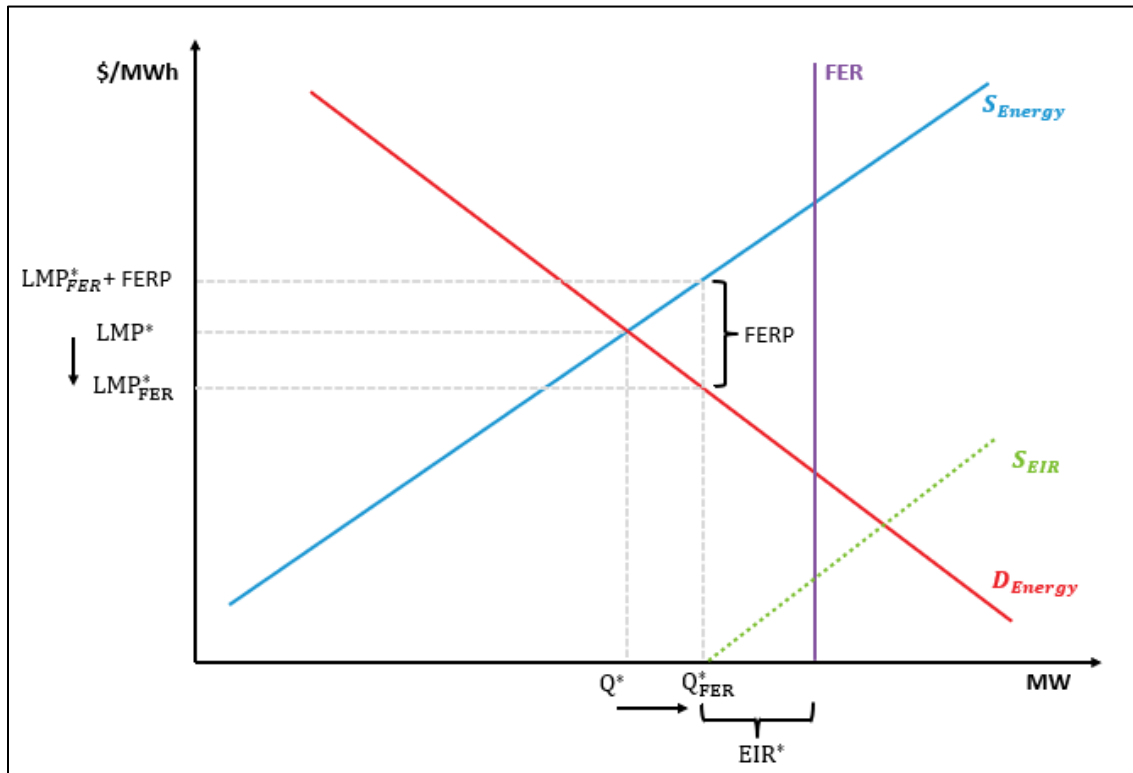
For their contribution to satisfying the FER constraints, physical supply resources with day-ahead energy awards and EIR awards are paid the **FER Price (FERP)**. Notably, the addition of the FER constraint fundamentally changed the paradigm for energy compensation to physical resources in the day-ahead market; physical resources are now compensated for their energy via a combination of the LMP and FERP, whereas prior to DA A/S they received energy compensation solely via the LMP. The **FER credit** represents the payment to physical supply resources with day-ahead energy awards for their contribution to satisfying the FER constraint. The FER credit is allocated as a charge primarily to real-time load obligation (RTLO) on a pro-rata basis.²⁵

A simplified graphical representation of the impact that the FER has on day-ahead energy market clearing is presented in Figure 3-5 below.

²⁴ For more information about Energy Imbalance Reserves (EIR), see Section 3.1.1.

²⁵ For more information on how the FER credit is charged, see Section III.3.2.1(q)(4)(iii) of the ISO-NE Tariff: https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

Figure 3-5: The Impact of FER on Day-Ahead Energy Market Clearing



Prior to DA A/S, the intersection of the energy supply curve (blue line) and energy demand curve (red line) determined the quantity of cleared energy (Q^*) and the clearing price for that energy (LMP^*). With the introduction of the FER (purple line), the market clearing changes. The market clearing engine must find a combination of energy on physical resources and EIR (dashed green line) to satisfy the FER. In the figure above, the market now clears a higher quantity of energy (Q_{FER}^*) and the remainder of the FER is satisfied via cleared EIR (EIR^*) such that $Q_{FER}^* + EIR^* = FER$.

Importantly, the LMP with the FER included (LMP_{FER}^*) is lower than the LMP without it (LMP^*).

However, physical resources with energy awards as well as resources that clear EIR awards receive the FERP because of their contribution to satisfying the FER.²⁶ As such, physical resources with energy awards now receive $LMP_{FER}^* + FERP$ as energy market compensation, which covers the marginal cost of energy supply.

²⁶ In this example, the FERP is set by energy supply and demand rather than by EIR, although that can and frequently does occur.

Section 4

Market Costs

This section presents the settlement costs associated with DA A/S in its first year as well as an estimate of the incremental costs of DA A/S relative to an energy-only design intended to replicate the day-ahead market design prior to DA A/S. As such, this analysis distinguishes between *settlement costs* and *incremental economic cost*.

Settlement costs measure the credits and charges created by the DA A/S design, including DA A/S credits and closeout charges, and FER credits and charges. Although these items determine who pays and who receives money, they do not, by themselves, measure the incremental cost of the new market design because the same market design change also affects other settlement-related factors (e.g., day-ahead LMPs).

For this reason, we also present a simulation-based estimate of incremental economic cost. Importantly, the simulations do not measure all offsetting or interactive effects, including the retirement of the Forward Reserve Market (FRM), potential reductions in NCPC, future effects on capacity-market offer behavior and Net CONE, or changes in investment and retirement incentives. Consequently, the simulation-based results can be best understood as measures of the incremental day-ahead and deviation-settlement effects of introducing the FER and FRS requirements, not as a full cost-benefit analysis of the initiative.

Key Takeaways

During the first year, net DA A/S payments totaled \$261.7 million (\$2.21/MWh of load served) and were heavily concentrated in winter months, which accounted for roughly 60% of the total. FER credits were much larger at approximately \$1 billion (\$8.49/MWh), also showing strong seasonality with nearly two-thirds occurring in winter. Therefore, total year one settlement payment/costs totaled over **\$1.25 billion**, or \$10.70/MWh of load served.

Simulation results indicate that the implementation of the DA A/S market increased total incremental costs relative to the prior day-ahead design by about **\$974 million** in its first year (\$8.23/MWh of load served), a lower amount than settlements costs primarily reflecting the interplay between the FERP and (lower) DA LMP. A small number of high-cost days drove a disproportionate share of this increase: just 12 days accounted for roughly 50% of incremental costs, with a five-day winter storm event alone contributing about 40%, and a single day (January 27, 2026) responsible for 18%.

Net costs for the Flexible Response Services in New England averaged \$2.10/MWh of load, which was higher than the costs of similar products in a comparable market (NYISO). These higher prices in New England reflect both system characteristics (e.g., high reserve requirements relative to load) and design features, in particular the DA A/S call-option settlement design, which is intended to enhance reliability through stronger performance incentives than a forward sale construct as exists in New York.

4.1 Settlement Costs

The DA A/S products represent a small percentage of overall energy and ancillary services (E&AS) costs.²⁷ This can be seen in Table 4-1, which shows the *net* settlements for the DA A/S products by season for the first year.^{28,29}

Table 4-1: DA A/S Settlements (\$ millions)

DA A/S	Spring 2025	Summer 2025	Fall 2025	Winter 2026	Total
DA TMSR (net)	\$3.7	\$16.6	\$8.5	\$45.6	\$74.4
DA TMNSR (net)	\$6.3	\$26.1	\$16.1	\$65.1	\$113.6
DA TMOR (net)	\$2.9	\$13.3	\$7.8	\$36.3	\$60.3
EIR (net)	\$0.2	\$1.4	\$1.7	\$10.1	\$13.4
Total (net)	\$13.1	\$57.4	\$34.1	\$157.1	\$261.7
Total E&AS Costs	\$1,284	\$2,346	\$1,610	\$6,261	\$11,500
% Total E&AS Cost	1%	2%	2%	3%	2%

Net DA A/S payments totaled \$261.7 million during the first year, representing about 2% of total E&AS costs over the period, or \$2.21/MWh of load served.³⁰ TMNSR payments represented the largest component at \$113.6 million, followed by TMSR at \$74.4 million, and TMOR at \$60.3 million. EIR payments were relatively small at \$13.4 million in total, contributing little to overall costs. Importantly, while the total DA A/S payments are highly seasonal—with Winter 2026 accounting for the majority these payments (60%)—they tended to move in-line with overall E&AS markets costs, generally accounting for 1 to 3% of these overall E&AS market costs.

FER credits have accounted for much larger share of total E&AS costs throughout the first year. This can be seen in Table 4-2 below, which shows total FER credits by quarter.

²⁷ Total energy and ancillary services costs include day-ahead and real-time energy, reserve, regulation, and NCPC costs.

²⁸ The months included in each season are: Spring: Mar-May, Summer: Jun-Aug, Fall: Sep-Nov, Winter: Dec-Feb

²⁹ For the purposes of calculating the settlement value of the DA A/S market, we sum the initial credit and the closeout charge to calculate a final *net* payment/charge.

³⁰ Load served, or Net Energy for Load, during the one-year period totaled 118,400 GWh, or 13,516 MW on average per hour.

Table 4-2: FER Settlements (\$ millions)

	Spring 2025	Summer 2025	Fall 2025	Winter 2026	Total
FER Credit	\$74.4	\$122.2	\$166.9	\$641.6	\$1,005.1
Total E&AS Costs	\$1,284	\$2,346	\$1,610	\$6,261	\$11,500
% Total E&AS Cost	6%	5%	10%	10%	9%

FER credits totaled approximately \$1 billion during the first year of DA A/S, accounting for approximately 9% of total E&AS costs over the period, or \$8.49/MWh of load served. The average annual FER price was \$7.13/MWh (including all hours, even when the FERP was zero). Like DA A/S payments, FER credits vary by season with the largest value occurring in winter; FER credits during the winter accounted for \$641.6 million, or roughly 64% of total FER credits. FER credits represented between 5-6% of total E&AS costs during spring and summer before climbing to 10% for both the fall and winter. The increase during the fall was related to the high level of generator outages and a reduction in net interchange in the day-ahead market,³¹ while the winter increase was related to increased payments during a multi-day period of stressed system conditions.

4.2 Incremental Costs

We performed market simulations to better understand the incremental impact of DA A/S on market outcomes relative to the day-ahead market (DAM) design that was in place prior to March 1, 2025. To perform these simulations, we used an in-house market simulation tool that both replicates the logic of the day-ahead market (DAM) that exists in production today and also provides the flexibility to modify constraints and other key inputs.^{32,33}

The simulations indicate that the initiative increased total day-ahead and deviation-settlement costs relative to the prior energy-only design, but the increase appears through different settlement components than the underlying economic driver may suggest. In the full DA A/S case, the large share of the incremental payments appears as FER credits and net DA A/S credits. In a no-FER simulation, similar underlying FRS-procurement costs tend to appear through higher DA LMPs instead.

³¹ For more in-depth coverage of this period, see the IMM's Fall 2025 Quarterly Markets Report, available here: <https://www.iso-ne.com/static-assets/documents/100032/2025-fall-quarterly-markets-report.pdf>.

³² Importantly, while the IMS benchmarks very well against the GE market clearing engine (MCE) that is used in production at ISO-NE, the simulation results should be viewed as indicative rather than exact. The market simulator captures the main co-optimized commitment, scheduling, constraint, and pricing logic that has been benchmarked to production-market outcomes, but it does not reproduce every production-engine feature.

³³ Due to simulation-related constraints, December 5, 2025, and January 3, 2026, are not reflected in any of the simulation results.

Incremental Cost of DA A/S

In order to estimate the impact of DA A/S on market costs, the following scenarios were simulated:

- 1) **No DA A/S:** a scenario in which all DA A/S constraints (FER, FRS) are ‘turned off.’ This scenario is intended to reflect the pre-March 2025 day-ahead market.³⁴
- 2) **DA A/S:** a scenario in which all DA A/S constraints are ‘turned on.’ This scenario is intended to reflect the current day-ahead market.

The following table provides a high-level comparison of these two scenarios.

Table 4-3: Estimated Change in Market Costs

Category	No DA A/S (\$M)	DA A/S (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$10,437	\$11,153	\$716	6.9%
<i>LMP</i>	\$10,437	\$10,127	-\$309	-3.0%
<i>FER Price</i>	\$0	\$1,026	\$1,026	
DA A/S	\$0	\$261	\$261	
<i>Credits</i>	\$0	\$453	\$453	
<i>Closeouts</i>	\$0	-\$192	-\$192	
Total Charges/Credits	\$10,437	\$11,415	\$978	9.4%
Cost of Incremental RT Energy	\$140	\$136	-\$4	-2.9%
Total Cost/Revenue Change	\$10,577	\$11,551	\$974	9.2%

We estimate that DA A/S resulted in an increase of \$974 million (9.2%) in total costs over the first year. The majority of the incremental cost increases are in the form of higher day-ahead energy market payments, where we estimate an increase of \$716 million relative to the ‘No DA A/S’ scenario. While energy payments via the day-ahead LMP decreased by \$309 million relative to the ‘No DA A/S’ scenario, this is more than offset by a \$1,026 million FER credit.³⁵ Net payments to the new DA A/S awards (\$261 million) represent all of the remaining estimated cost increase. The simulations indicate very little change in incremental real-time energy purchases between the two scenarios.³⁶

³⁴ The IMM did *not* adjust energy offers in this scenario in any way (e.g., there was no adjustment to reflect the way participants with FRM obligations were required to offer in the real-time market under that market design).

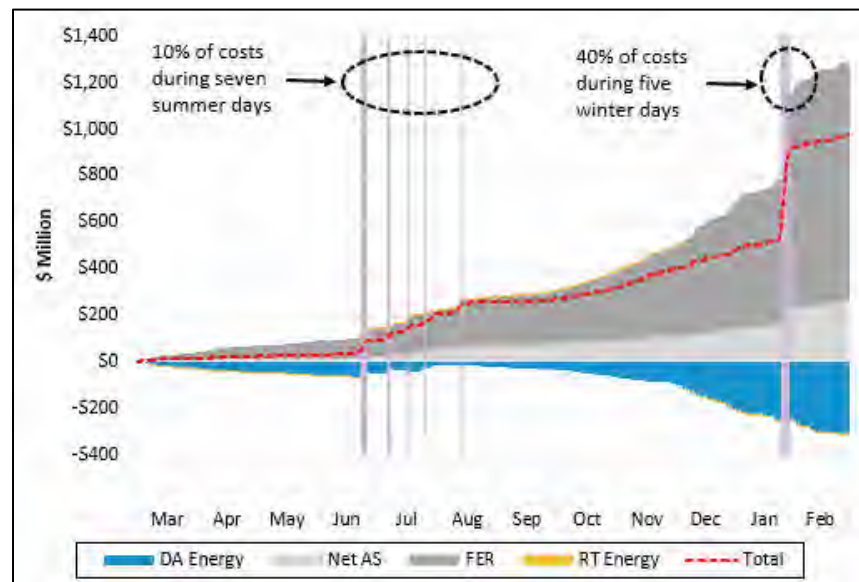
³⁵ See Figure 3- and the associated text for an explanation of this impact this design has on the day-ahead LMP.

³⁶ We calculate the cost of incremental real-time energy as (real-time load obligation – day-ahead load obligation) * real-time LMP, mimicking the deviation settlement logic. These costs can differ because one scenario may clear more energy supply in the day-ahead market relative to another and therefore need to procure less energy supply in real-time market. Importantly, we assume no changes in the real-time LMP between the two scenarios, which is a conservative assumption in hours where DA A/S improved the day-ahead operating plan and reduced the likelihood of moving up a steep real-time supply curve.

High-Cost Days

It is important to call out the outsized impact that a small set of high-cost days had on the incremental costs of DA A/S during its first year. This can be seen in Figure 4-1, which shows the cumulative total incremental change in market cost broken down by cost component over the first year of DA A/S.

Figure 4-1: Cumulative Incremental Change in Market Costs



We found that 12 days, most of which were associated with multi-day periods of stressed system conditions, accounted for approximately 50% of incremental costs of DA A/S in its first year (we note these in the figure above with light purple bars). These 12 days include a five-day period from January 25, 2026, to January 29, 2026, that coincided with Winter Storm Fern, as well as the following seven days in Summer 2025: June 23 through June 25,³⁷ July 7, July 17, July 25, and August 13. We estimate that one day alone, January 27, 2026, accounted for 18% of the incremental DA A/S costs and that the five-day period between January 25, 2026, to January 29, 2026, accounted for 40% of these incremental costs.

To provide some idea of the impact of these high-cost days on incremental costs, we present Table 4-4, which shows the estimated incremental DA A/S costs for only the 12 highest-cost days within the year as well as the costs for all other days of the year. For reference, the table also shows the full year costs (in gray).

³⁷ The three-day period in June was characterized by hot and humid leading to very high peak loads.³⁷ Events during this period culminated on June 24 when the grid experienced capacity scarcity conditions (CSC). For more coverage on this period, see the IMM's Summer 2025 Quarterly Markets Report, available here: <https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf>.

Table 4-4: Comparison of Incremental DA A/S Costs: High-Cost Days to All Other Days

Category	Incremental Cost (\$M) <i>12 Highest-Cost Days</i>	Incremental Cost (\$M) <i>All Other Days</i>	Incremental Cost (\$M) <i>Complete Year</i>
DA Energy	\$386	\$331	\$716
<i>LMP</i>	\$44	-\$353	-\$309
<i>FER Price</i>	\$342	\$684	\$1,026
DA A/S	\$93	\$169	\$261
<i>Credits</i>	\$134	\$319	\$453
<i>Closeouts</i>	-\$41	-\$151	-\$192
Total Charges/Credits	\$478	\$500	\$978
Cost of Incremental RT Energy	\$11	-\$15	-\$4
Total Cost/Revenue Change	\$489	\$485	\$974

Day-ahead energy costs represent the majority of the incremental costs for both the 12 highest-cost days (\$368 million of \$489 million, or 79%) and all the other days (\$331 million of \$485 million, or 68%). Notably, while we see the \$684 million increase in FERP-based energy payments for the other days being offset by a \$353 million reduction in LMP-based payments, we see the \$342 million dollar increase in FERP-based energy payments for the 12 highest-cost days associated with an *increase* in LMP-based payments of \$44 million. Additionally, we see a higher percentage of the DA A/S credits being offset by closeouts in the other days (\$151 million of \$319 million, or 47%) than we do for the 12 highest-cost days (\$41 million of \$134 million, or 31%).

4.3 Cost Benchmarking

In this section, we compare day-ahead reserve costs for ISO-NE against those for the New York Independent System Operator (NYISO), which has comparable loads and reserve requirements. Importantly, while both New England and New York procure ancillary services through a co-optimized market-based mechanism, there are important design differences: ISO-NE utilizes a call-option settlement approach based around the real-time price of energy, while NYISO uses a forward sale settlement approach, in which day-ahead reserve positions are settled against real-time reserve prices.³⁸

Day-ahead reserve costs for ISO-NE and NYISO are shown in \$/MWh of load in Table 4-5 below, alongside metrics that illustrate the comparability of the two regions.

³⁸ For example, if a NYISO generator cleared day-ahead reserves at \$10/MWh but did not provide reserves in real time when reserve prices were \$2/MWh, the reported net day-ahead reserve cost would be \$8/MWh (\$10/MWh - \$2/MWh). This includes scenarios when the generator did not provide real-time reserves because it was dispatched up for energy.

Table 4-5: Day-Ahead Ancillary Services Costs in ISO-NE Compared to NYISO

Concept	ISO-NE	NYISO
DA Reserve Costs, ^{39,40} <i>\$/MWh of Load</i>	\$2.10	\$1.39 ⁴¹
Average Load, MW	13,516	17,329
Largest Contingency, ⁴² <i>MW</i>	1,261	1,310
Largest Contingency, % Share of Load	9%	8%

When measured on a \$/MWh of load basis, ISO-NE features higher day-ahead reserve costs than NYISO, with a premium of roughly \$1/MWh of load. While FER credits are not directly accounted for in the \$2.10/MWh of load, the FER constraint indirectly impacts this total as it contributes to overall scarcity in the day-ahead market. Based on counterfactual simulations, the ISO-NE day-ahead reserve cost would have been \$1.82/MWh of load in the absence of the FER constraint.⁴³ This indicates that the ISO-NE reserve premium is largely a function of market design. The call-option settlement approach in ISO-NE is designed to provide stronger real-time performance incentives, and the premium for these incentives must be weighed against their reliability benefits.⁴⁴

³⁹ The *DA Reserve Cost* for ISO-NE represents the net FRS costs (i.e., the FRS credits less the realized closeout charges).

⁴⁰ The reserve cost data for NYISO were provided by Potomac Economics. The products included in this calculation are 10-minute, 30-minute, and spinning reserves. We thank Potomac for their data contributions.

⁴¹ Note that \$1.39/MWh of load represents the *Gross* DA reserve costs for NYISO. This is the sum of DA reserve credits, and ignores scenarios where resources might be dispatched up to provide energy and therefore buy back real-time reserves in the two-settlement system. *Net* reserve costs would deduct the costs of purchasing real-time reserves in these scenarios, and would be a useful comparison to the ISO-NE FRS credits less closeout charges. To bound this estimate, we also calculate the difference between NYISO day-ahead reserve prices and real-time reserve prices, regardless of whether assets were truly buying back real-time reserves or not. This yields a lower-bound estimate of \$0.48/MWh of load. We estimate NYISO net day-ahead reserve costs to fall between \$0.48/MWh-\$1.39/MWh; in any scenario, ISO-NE FRS products come at a price premium when compared to NYISO day-ahead reserves.

⁴² The *Largest Contingency* for NYISO was estimated based on technical documentation ([Link](#)) alongside public information on generator sizes.

⁴³ See Section 0 for more information on the counterfactual simulation that does not include the FER,

⁴⁴ See Section 10 for a discussion of the reliability benefits observed over the first year of DA A/S.

Section 5

Assessment of Cost Drivers

In this section we explore the impact that changes in system conditions and observed participant behavior have had on DA A/S costs. We also attempt to disentangle the relationship between reliability requirements (i.e., FRS requirements, FER) to better understand the cost drivers during the first year of this new market design.

Key Takeaways

We find that changing system conditions and differences between assumed and actual market behavior explain a large percentage of the observed cost increase relative to the ISO's 2023 DA A/S Impact Assessment, which was an important component of the market design process.

Specifically, we find that an update of the ISO's 2023 Impact Assessment, which assumes full participation and competitive offer formulation, would have resulted in incremental costs of \$733 million based on actual data from the first year of DA A/S. Again, a small number of high-stress days disproportionately influenced results: just 13 days accounted for roughly half of total incremental costs, and without them, DA A/S impacts would have been closer to original expectations, underscoring the impact of system stress events on overall DA A/S costs.

We also find that the FRS constraints are the primary underlying driver of incremental costs: absent the FER constraint, roughly \$613 million (about 65%) of total incremental DA A/S costs would persist. The addition of the FER constraint largely changes the clearing prices in which these costs manifest, rather than their root cause.

Opportunity costs have played a role in price formation although it is difficult to precisely quantify their overall impact. However, simulation results show that even if all historically-offered DA A/S capability were offered at \$0/MWh, the system would still incur \$316 million (\$2.67/MWh) in incremental costs to satisfy FER and FRS constraints.

5.1 System and Market Conditions

System and market conditions have changed in meaningful ways since ISO-NE brought the market reforms associated with DA A/S through the stakeholder process and ultimately filed the design changes with the Federal Energy Regulatory Commission (FERC) in October, 2023.⁴⁵ These changes, which include higher natural gas prices, more extreme weather events, and changes in the supply mix, have applied upward pressure on both energy and ancillary service costs.

Additionally, market participation levels and offer prices are materially different from the assumptions made by ISO-NE in their Impact Analysis (IA) work to estimate indicative costs for DA

⁴⁵ The ISO's filing to FERC is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

A/S.⁴⁶ In practice, participation has been lower and offer prices higher than was assumed in the IA. These differences have resulted in tighter market supply conditions, high cross-product opportunity costs, and ultimately a higher marginal cost of meeting both energy demand and operating reserve requirements.

Given these differences, the IMM conducted a “refresh” of the IA (which we refer to as the “IA Refresh”) to better understand what the costs of DA A/S might look like under the same full participation and competitive offer assumptions used in the original IA but based on actual data from the first year of the initiative.

The Original IA

In order to capture a range of market conditions, the original IA was performed over a three-year historical period from January 1, 2019, to December 31, 2021. ISO-NE premised market participation and offer price assumptions in the IA on a model of profit-maximizing behavior under competitive conditions. Consistent with that framework, participants were assumed to offer their full physical capability at an estimated competitive cost of meeting the obligation.

The estimated incremental costs associated with DA A/S from the IA are presented as totals and as percentages of total E&AS costs by year in Table 5-1 below.⁴⁷

Table 5-1: Estimated Incremental Costs from DA A/S (ISO-NE Impact Analysis)

Year	Incremental Costs (\$M)	E&AS Costs (\$M)	% E&AS Costs
2019	\$127	\$4,207	3.0%
2020	\$104	\$3,704	3.4%
2021	\$188	\$6,189	3.0%
Average	\$140	\$4,490	3.1%

The IA estimated that DA A/S costs would have averaged \$140 million per year from 2019 to 2021, representing about 3.1% of total E&AS costs. While total E&AS costs varied meaningfully by year, the IA results indicated that DA A/S costs would remain a relatively small and stable share of the overall market.

A more granular summarization of the IA results is presented in Table 5-2 below. This table compares average actual market values from the three-year period (2019-2021) against estimated market values assuming DA A/S had been in place for the same three-year period.

⁴⁶ For more information on the IA, see ISO-NE’s presentation titled *Day-Ahead Ancillary Services (DASI)* from the April 11-13, 2023, NEPOOL Markets Committee meeting, available here: https://www.iso-ne.com/static-assets/documents/2023/04/a07a_mc_2023_04_11-13_dasi_design_r1.pdf

⁴⁷ It is important to note that ISO-NE presented the estimated DA A/S costs relative to total wholesale market costs, which includes Forward Capacity Market (FCM) and transmission costs. We present the estimated DA A/S costs relative to just energy and ancillary services costs as this is our common way to “standardize” costs throughout the document.

Table 5-2: Estimated Change in Market Costs from DA A/S, 2019-2021 (ISO-NE IA)

Category	No DA A/S (\$M)	DA A/S (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$4,405	\$4,588	\$183	4.2%
<i>LMP</i>	\$4,405	\$4,462	\$58	1.3%
<i>FER Price</i>	\$0	\$125	\$125	
DA A/S	\$0	\$22	\$22	
<i>Credits</i>	\$0	\$90	\$90	
<i>Closeouts</i>	\$0	-\$69	-\$69	
Total Charges/Credits	\$4,405	\$4,609	\$205	4.6%
Cost of Incremental RT Energy	\$104	\$40	-\$65	-62.0%
Total Cost/Revenue Change	\$4,509	\$4,649	\$140	3.1%

In the ISO's IA, the increase in markets costs occurred primarily in the day-ahead energy market where costs increased by \$183 million (4.2%). Meanwhile, DA A/S costs were estimated to add only \$22 million to market costs, with \$90 million of DA A/S credits being offset by \$69 million in closeout charges. Notably, the IA estimated a significant reduction (62%) in real-time energy payments.⁴⁸

The “Refreshed” Impact Assessment

System conditions and competitive offers changed considerably between the 2019-2021 period used by the ISO for its impact analysis and the first year of DA A/S. Some of the relevant changes are listed in Table 5-3 below.

⁴⁸ This reduction is likely the result of a “market response” assumption that the ISO incorporated into their simulation work. The ISO assumed that lower day-ahead LMPs under the new design would induce additional priced demand bids, increasing day-ahead cleared energy and supporting price convergence with expected real-time LMPs. The IA therefore added additional energy demand bids to the simulation. This assumption is best understood as a long-run equilibrium response, not as evidence that such behavior was expected to occur in the first year. However, this action increased the amount of demand cleared day-ahead, resulting in smaller real-time deviations and therefore smaller real-time charges/credits. For more information about this modeling assumption, See Page 84 of the testimony of Ben Ewing in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

Table 5-3: Differences in System Conditions and Competitive Offer Components

Index	(1/1/2019 – 12/31/2021) Average	(3/1/2025 – 2/28/2026) Average	Delta (%)
DA Gas Price⁴⁹ (\$/MMBtu)	\$3.24	\$6.82	110.5%
DA Hub LMP (\$/MWh)	\$33.48	\$71.44	113.4%
DA Load Forecast (MW)	13,151	13,019	-1.0%
Summer Peak Load⁵⁰ (MW)	25,095	26,586	5.9%
Winter Peak Load⁵¹ (MW)	19,512	20,221	3.6%
Competitive Offer⁵² (\$/MWh)	\$10.00	\$12.78	27.8%
Expected Closeout (\$/MWh)	\$3.20	\$7.74	141.9%
AIC (\$/MWh)	\$0.48	\$3.35	597.9%
Risk Premium (\$/MWh)	\$6.33	\$1.70	-73.1%

Notably, the average price of gas increased by over 100% between the years covered in the IA (\$3.24/MMBtu) and the first year of DA A/S (\$6.82/MMBtu). This resulted in a commensurate increase in the day-ahead Hub LMP, which rose from \$33.48/MWh to \$71.44/MWh. While there was little change in the average day-ahead load forecast between the two periods, the system experienced higher summer and winter peak loads during the first year of DA A/S.⁵³

Meanwhile, compared with ISO-NE’s original IA, the “IA Refresh” produced a higher average competitive offer (\$12.78/MWh compared with \$10.00/MWh), but the mix of components changes: expected closeout and AIC are higher, while the risk premium is lower. The increase in expected closeout was generally in-line with that observed for energy market prices, while the marked increase in the AIC largely stemmed from the extreme natural gas prices observed during Winter Storm Fern. The reduction in the (Sharpe-based) risk premium reflects changes in total profit

⁴⁹ The gas price is the Intercontinental Exchange next-day index price for Algonquin Non-G.

⁵⁰ This represents the maximum peak hourly load observed in June, July, or August. For the 2019-2021 period, this represents the average of the three summer maximums. This information comes from: https://www.iso-ne.com/static-assets/documents/2023/08/enepk_report.xlsx.

⁵¹ This represents the maximum peak hourly load observed in December, January, or February. For the 2019-2021 period, this represents the average of the three winter maximums. This information comes from: https://www.iso-ne.com/static-assets/documents/2023/08/enepk_report.xlsx.

⁵² The values shown for the competitive offer and its components (Expected Closeout, AIC, and Risk Premium) are simple (unweighted) averages across all resources and hours within each study period/day set. The averages are based on all submitted offers rather than the subset selected by the market-clearing engine to provide DA A/S.

⁵³ The peak load observed in summer 2025 was the highest recorded load in New England in over 10 years. See the IMM’s Summer 2025 Quarterly Markets Report for more information: <https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf>.

variability (relative to the real-time-only alternative) from taking on a DA A/S award for participating resources.⁵⁴

The high-level results of a comparison between the IMM’s “IA Refresh” and the simulated “No DA A/S” scenario are provided in Table 5-4 below.

Table 5-4: Estimated Change in Market Costs from DA A/S (IMM “IA Refresh”)

Category	No DA A/S (\$M)	IMM Refresh (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$10,437	\$11,029	\$592	5.7%
<i>LMP</i>	\$10,437	\$10,214	-\$222	-2.1%
<i>FER Price</i>	\$0	\$815	\$815	
DA A/S	\$0	\$146	\$146	
<i>Credits</i>	\$0	\$340	\$340	
<i>Closeouts</i>	\$0	-\$194	-\$194	
Total Charges/Credits	\$10,437	\$11,175	\$738	7.1%
Cost of Incremental RT Energy	\$140	\$136	-\$5	-3.3%
Total Cost/Revenue Change	\$10,577	\$11,311	\$733	6.9%

We estimate that the incremental cost of DA A/S using the similar assumptions to those used in the original IA would have resulted in an increase of \$733 million (6.9%) in total costs over the first year.⁵⁵ This is an indication that changes in system and market conditions explain a large share (75%) of the total estimated incremental costs of DA A/S during its first year. Notably, the “IA Refresh” shows that not only did the level of incremental costs (\$733 million) increase substantially relative to the original IA (\$140 million) but so did the ratio of these costs relative to total market cost (6.9% in the “IA Refresh” versus 3.1% in the original IA).

As was the case with the estimated incremental costs of DA A/S discussed in Section 4.2, we observe a similar phenomenon of high-cost days playing a large role on incremental costs in the “IA Refresh”. We estimate that 13 days, most of which were the same as those noted in Section 4.2, accounted for approximately 50% of incremental costs of DA A/S in the “IA Refresh.”⁵⁶ Absent

⁵⁴ This could happen if the composition of participating resources shifts over time toward units for which DA A/S participation adds less incremental variance, or more generally where real-time energy margins frequently offset closeout exposure.

⁵⁵ The “IA Refresh” uses actual values from the first year of DA A/S while maintaining the following assumptions of the original IA: (1) all generators make DA A/S offers at their Economic Maximum (EcoMax) and all DARDs at their Max Consumption; (2) all generators and DARDs make DA A/S offers priced at their Benchmark Level plus a risk premium determined by the Sharpe ratio (see Section 6.3 for more information); (3) Wind, solar, and demand response resources do not make DA A/S offers; (4) the Maximum Daily Award Limit (MDAL) for all resources was set such that they could not bind. The “IA Refresh” did not include any additional energy demand bids as were done in the original IA (noted in Footnote 4848). Additionally, all DA A/S offers were based on Benchmark Levels that incorporated participant-submitted values that were approved by the IMM as well as any interventions the IMM made to expected closeouts, reflecting the assumption that these adjusted values most accurately represented competitive offers.

⁵⁶ The days were: June 23-24, 2025; July 6-7, 2025; July 17, 2025; July 29-30, 2025; August 12-13, 2025, and January 25-28, 2026.

these 13 days, the incremental costs of DA A/S in the “IA Refresh” would have represented only 4.0% of total market costs, making it more in-line with the original IA (3.1% of total market costs). These results suggest that market performance during periods of system stress crucially impacted program costs in a way they did not during the years covered in the IA. In fact, there were eight days in the “IA Refresh” when the incremental DA A/S costs exceeded two percent of the total annual incremental DA A/S costs, while there was only one such day in three years when this occurred in the IA.

If changes in system and market conditions account for \$733 million of the total \$974 million that we estimate for the incremental costs of DA A/S, a natural follow-up question is: what explains the remaining \$241 million? The most important differences between the “IA Refresh” and observed first-year outcomes are likely to be (1) participation and (2) differences between observed DA A/S offer prices and estimated competitive offer prices (including risk premiums).

The IA assumed broader participation of eligible capacity than was actually observed during the first year of the new design. These quantity-side decisions reduce market liquidity, raise inter-product opportunity or “redispatch” costs, and can amplify tight-hour price effects. Market participation is looked at in more detail in Section 6.1.

Additionally, differences between observed DA A/S offer prices and cost-based benchmarks also likely contributed to higher prices. Additional coverage of DA A/S offer prices is provided throughout this document, including an analysis of marginal DA A/S offers (Section 5.3), a discussion of risk premia (Section 6.3), comparison of DA A/S offer prices relative to benchmark levels (Section 7) and an evaluation of expected closeout accuracy (Section 8.2).

5.2 Impact of New Market Constraints

DA A/S introduced several new constraints into the day-ahead market at the same time, which has made it challenging to determine the extent to which each constraint has driven observed outcomes. In this section, we analyze the relationship between specific constraints and costs to determine the key drivers of observed costs in the first year of the new market design.

5.2.1 Flexible Response Services

The FRS constraints are the set of constraints that were added in DA A/S to ensure that the ISO has enough fast-starting and fast-ramping capability to quickly respond to a large supply loss. One important insight related to the incremental cost of DA A/S that the IMM first made in its Summer 2025 Quarterly Markets Report (QMR) is that, while the costs primarily manifest themselves in the FER payment, they primarily originate from the FRS requirements.⁵⁷ To arrive at that conclusion, we used the Integrated Market Simulator to run the following scenario:

- 1) **FRS Only:** a scenario in which the FER constraint is ‘turned off’ but the FRS constraints remain ‘turned on.’ This scenario is intended to reflect a modified version of the current DAM that doesn’t have the FER constraint.

We re-ran this FRS Only scenario using a full year of market data and the results are compared against the No DA A/S case in the table below.

Table 5-5: Estimated Change in Market Costs with only the FRS Constraints

Category	No DA A/S (\$M)	FRS Only (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$10,437	\$10,805	\$368	3.5%
<i>LMP</i>	\$10,437	\$10,805	\$368	3.5%
<i>FER Price</i>	\$0	\$0	\$0	
DA A/S	\$0	\$216	\$216	
<i>Credits</i>	\$0	\$397	\$397	
<i>Closeouts</i>	\$0	-\$181	-\$181	
Total Charges/Credits	\$10,437	\$11,020	\$84	5.6%
Cost of Incremental RT Energy	\$140	\$170	\$30	21.1%
Total Cost/Revenue Change	\$10,577	\$11,190	\$613	5.8%

We estimate that incremental DA A/S costs would have been \$613 million if only the FRS constraints had been incorporated into the market clearing process and there was no FER constraint. This equates to 65% of the estimated total incremental DA A/S costs (\$974 million). Notably, the incremental cost increases shift from FERP-based payments when the FER is included to LMP-based payments when the FER is removed. This finding highlights the distinction between a settlement channel (the FERP), and the main cost driver (the FRS requirements). Because energy,

⁵⁷For more information, see section 3.5.7 of our Summer 2025 QMR, available here: <https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf>.

EIR, and FRS awards compete for the same scarce resource capability in the co-optimized market, FRS scarcity can raise the marginal cost of satisfying the FER. When the FER constraint is removed, the same underlying scarcity is reflected more directly in the day-ahead LMP.

Co-optimization of energy and reserves has several important cost implications. The first is that energy prices are likely to rise. This happens because some low-cost supply that would otherwise be dispatched to provide energy may instead be used to satisfy one of the reserve requirements, which may result in higher-cost supply at the margin and consequently a higher energy price. The second is that clearing prices now incorporate cross-product opportunity costs, which are the costs incurred by resources (in the form of foregone profits) when the market clearing engine schedules them to satisfy one requirement when it would have been more profitable to meet another.

We can get a sense of the order of magnitude of these cost implications in Table 5-5. For example, day-ahead LMP-based payments increased by **\$368 million** (3.5%) between the No DA A/S and the FRS Only scenarios. This increase in energy market costs should be generally indicative of the cost associated with the “redispatch” of energy to satisfy reserve requirements and any opportunity costs that show up in the LMP.⁵⁸

Another way to assess the scale of opportunity costs is to set all DA A/S offer prices for resources that historically offered into the market to \$0/MWh and then determine the cost of meeting day-ahead market constraints—energy balance, FER, and operating reserve requirements—based on offered capability.⁵⁹ Any non-zero DA A/S clearing prices that result from this approach are in theory a result only of cross-product opportunity costs, because DA A/S offer prices play no role (as they are set at \$0/MWh). Under this simulation, total E&AS costs amount to \$10,893 million, implying incremental costs of **\$316 million** (\$2.67/MWh). This approach is somewhat analogous to real-time reserve prices, which are based solely on opportunity cost (or administrative penalty factors).

5.2.2 Forecast Energy Requirement

The *incremental* impact of the FER constraint (*incremental* to a scenario that already includes the FRS constraints) must account for the remaining 35% (\$361 million) of the estimated total incremental DA A/S costs (\$974 million). It is likely that using the market simulator to assess the impact of the FER constraint alone would result in a substantially lower incremental cost estimate given the interaction of FER constraint and the FRS constraints disappears when only the FER constraint is modeled. In other words, the costs of constraints are not additive; the incremental cost of satisfying the FER increases as ancillary service capability becomes scarcer.

For the year, the FER constraint represents a larger share of the estimated incremental DA A/S costs than when we looked at it over the first six months in our Summer 2025 QMR (at that time it

⁵⁸ The term “redispatch” is a common shorthand for the co-optimized displacement of energy by reserve awards. Strictly speaking, however, the market clearing engine only produces a single co-optimized dispatch (i.e., there is no initial “dispatch” and then subsequent “redispatch”).

⁵⁹ An important caveat here is that setting EIR offer prices to \$0/MWh in this simulation has the effect of clearing more “cheap” EIR awards than relatively more expensive energy from physical supply.

accounted for ~19%). This is largely the result of two days: January 26 and January 27, 2026. We estimate that the incremental impact of the FER constraint on these two days added \$165 million to incremental DA A/S costs. In other words, absent these two days, the incremental impact of the FER constraint would have only been \$195 million (rather than \$361 million), representing about 28% (rather than 35%) of estimated total incremental DA A/S costs (\$702 million, which represents the incremental costs of DA A/S with January 26, 2026, and January 27, 2026, removed).

5.3 FRS Costs Examined

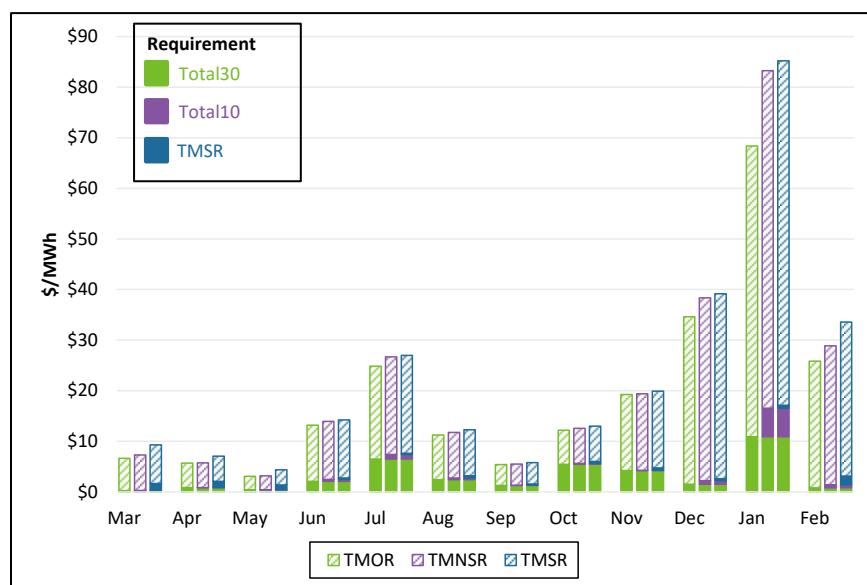
The following section explores how opportunity costs and the various cost components of a DA A/S offer may have impacted FRS clearing prices.

5.3.1 Opportunity Costs

To estimate the extent to which opportunity costs impacted FRS clearing prices, we assumed that highest offer price of a DA A/S product cleared to satisfy that requirement was the “marginal” offer. The difference between this offer price and the ancillary services clearing price is our estimate of the opportunity cost for a specific FRS requirement in that hour. This approach indicated that opportunity costs were \$77 million, which represents a low-end estimate of the opportunity costs given that the *true* marginal DA A/S offer may have a lower offer price.

The impact of opportunity costs associated with each FRS requirement impacted average hourly FRS product clearing prices is depicted by month in Figure 5-1 below. The portion of each column reflects the opportunity cost associated with a specific FRS constraint (e.g., the shaded green series reflects opportunity cost of satisfying the Total 30 requirement) while the total height of the column is the average monthly clearing price for the specific FRS product.⁶⁰

Figure 5-1: Impact of Opportunity Costs on FRS Clearing Prices



Opportunity costs made up a small but, at times, meaningful portion of FRS clearing prices during the first year of DA A/S. The most impactful requirement on FRS clearing prices was the Total 30 requirement, which binds in every hour under this design, although its impact did vary considerably by month. Interestingly, the months with high Total 30-related opportunity costs coincide with

⁶⁰ As mentioned in Section 3.1.2, the clearing price of the FRS products tend to be closely aligned given their price formation mechanics. Specifically, FRS clearing prices “cascade up,” which produces the following relationship between the product clearing prices: $CP_{TMSR} \geq CP_{TMNSR} \geq CP_{TMOR}$.

periods of system stress (July and January) or high levels of generator outages (October and November). Of additional relevance is the finding that four of the five days with the highest average hourly Total 30-related opportunity costs occurred during the four-day period from January 26-29, 2026. Section 5.3.3 examines the drivers of outcomes on the highest DA A/S cost days, including those observed in January.

Opportunity costs associated with the Total 10 requirement, which bound in 33% of hours over the first year, impacted TMNSR and TMSR clearing prices to various degrees over the course of the year. These costs can be seen most visibly in January 2026. Similar to the observation above, the four-day period from January 26-29, 2026, had four of the five days with the highest Total 10-related opportunity costs.

Lastly, the opportunity cost associated with the TMSR requirement, which bound in only 20% of hours in the first year, generally did not have a significant impact on TMSR clearing prices. TMSR-based opportunity costs played no role in clearing prices on 11 of the top 12 high-cost days.⁶¹

5.3.2 Offer Costs

This section explores how the various cost components of a DA A/S offer may have impacted FRS clearing prices. Specifically, this section examines the relationship between the expected closeout, the Avoidable Input Cost (AIC), and the offer price of the “marginal” offer for the Total 30 requirement.^{62,63}

It is important to note that it is not possible to separate the offer price of the “marginal” offer into its distinct components (i.e., expected closeout, the AIC, and risk) given that participants do not submit offer prices at this granularity. For this reason, in Figure 5-2 below, we simply overlay the monthly average “marginal” offer price for the Total 30 requirement (shown as green columns) with two line series: (1) a red line that shows the monthly average expected closeout and (2) a black line that shows an estimate of the AIC component of the “marginal” offer, also averaged by month.⁶⁴

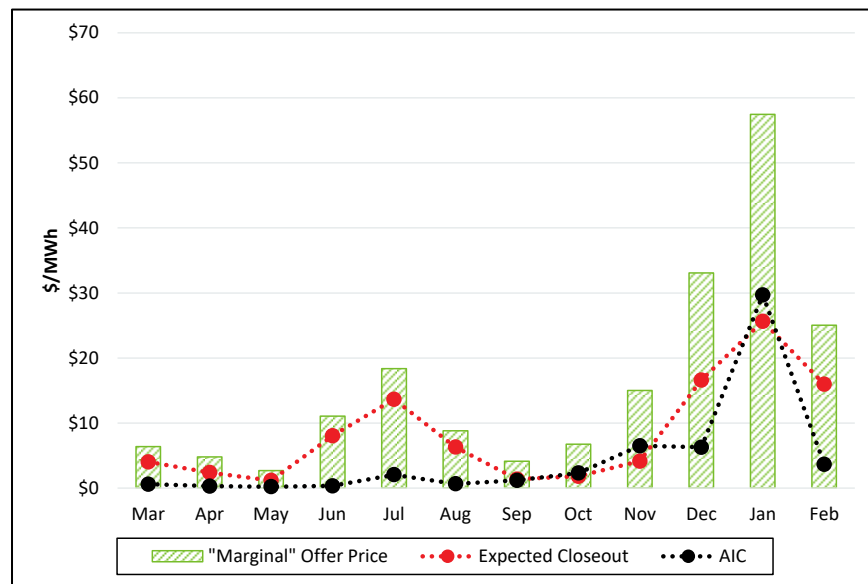
⁶¹ The 12 high-cost days are defined in Section 4.2.

⁶² As discussed in Section 5.3.1, we use the offer with the highest offer price for any DA A/S product cleared to satisfy that requirement as the proxy for the “marginal” offer.

⁶³ We only look at the Total 30 requirement here because it is the most impactful FRS requirement in regard to FRS product price formation as well as the most straight-forward to assess.

⁶⁴ Our estimate of the AIC assumes that the AIC was fully reflected in a resource’s offer price. As such, it can be viewed as an upper limit on the extent to which this offer component may have appeared in FRS offer prices.

Figure 5-2: “Marginal” Offer Price for Total 30 Requirement with Offer Components



The offer price of the “marginal” offer for the Total 30 requirement shows a strong positive relationship with the expected closeout value, rising during periods when the expected closeout was higher (e.g., July, December, January, and February) and falling during other periods when the expected closeout was lower. Meanwhile, the AIC component displays a clear seasonality, appearing to have very little relevance outside of the winter. This likely stems from how the AIC is determined for gas resources, where the AIC is intended to reflect the portion of the gas purchase cost that is not expected to be covered by energy production in the real-time market.⁶⁵

During the winter, high gas prices can create large AIC components particularly in conditions where lower-price resources are expected to set the price of energy in the real-time market. Using this approach for estimating the AIC, we find that the five days where the AIC may have had the largest impact on the shadow price of the Total 30 requirement (and therefore on the clearing prices of all the FRS products) were the five days from January 25-29, 2026.

5.3.3 Key Drivers and Outcomes for the 12 Highest-Cost DA A/S Days

When examining the relationship between fixed and priced demand—defined here as demand expected to be met through real-time energy—and the load forecast in the day-ahead market, we find no evidence of systematic underclearing. On average, the sum of cleared fixed and priced load exceeded the load forecast by approximately 1.4% both during the first year of DA A/S and in the year prior (March 1, 2024, to February 28, 2025). However, on the 12 highest-cost DA A/S days, the

⁶⁵The AIC for a gas resource = $\max\{0, (\text{Gas Price} \times \text{Resource Average Heat Rate}) - \text{Expected Realtime LMP}\}$. For more information, see Section III.A.8.2.2.(a) of the ISO-NE Tariff: https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

level of offered and cleared demand relative to the load forecast appears to play a more prominent role in FER outcomes.

In Table 5-6 (Summer) and Table 5-7 (Winter), we examine the drivers of the FER price outcomes observed across these 12 days, including the role of load clearing relative to the DA load forecast and broader system conditions.

Table 5-6: Summer Highest-Cost DA A/S Days

	23-Jun	24-Jun	25-Jun	7-Jul-25	17-Jul	25-Jul	13-Aug
Forecasted Load	23,800	25,310	23,960	22,800	24,200	23,000	24,100
Temp (min)	69	74	74	72	74	72	67
Temp (max)	90	97	89	86	88	89	88
Natural Gas Price	\$4.37	\$5.75	\$5.01	\$3.26	\$11.30	\$4.92	\$4.27
DA LMP	\$111.14	\$156.73	\$83.79	\$103.56	\$125.64	\$115.31	\$84.95
TMSR Price	\$81.30	\$113.66	\$62.62	\$62.60	\$69.15	\$65.02	\$70.68
TMNSR Price	\$81.30	\$113.66	\$62.62	\$62.60	\$69.15	\$65.02	\$70.68
TMOR Price	\$73.52	\$107.99	\$57.81	\$56.13	\$51.33	\$62.28	\$62.03
FER Price	\$0.20	\$3.24	\$24.75	\$0.00	\$15.99	\$0.27	\$23.49
Net Interchange	1,898	2,236	2,442	2,468	3,706	2,081	2,643
Outages	1,504	2,131	1,827	2,017	1,504	1,442	1,169
DA A/S Offered MWs	8,755	8,848	8,949	6,910	8,780	9,043	9,100
Cleared load as % of RT Load Obligation	95%	93%	94%	100%	96%	102%	101%
Cleared load as % of DA Load Forecast	101%	99%	95%	101%	97%	105%	99%

Table 5-7: Winter Highest-Cost DA A/S Days

	25-Jan	26-Jan	27-Jan	28-Jan	29-Jan
Forecasted Load	19,500	19,650	19,700	19,600	19,550
Temp (min)	4	14	5	2	3
Temp (max)	19	22	19	21	21
Natural Gas Price	\$45.22	\$45.22	\$89.84	\$99.32	\$60.99
DA LMP	\$433.96	\$436.01	\$639.14	\$423.31	\$346.81
TMSR Price	\$219.08	\$365.43	\$750.60	\$327.92	\$141.32
TMNSR Price	\$219.08	\$365.43	\$750.60	\$327.92	\$131.27
TMOR Price	\$214.49	\$328.24	\$423.16	\$313.78	\$105.73
FER Price	\$60.82	\$231.18	\$349.80	\$32.88	\$15.74
Net Interchange	106	1,076	1,900	2,936	2,400
Outages	3,934	4,553	4,295	4,416	4,286
DA A/S Offered MWs	9,788	8,662	8,599	9,227	9,315
Cleared load as % of RT Load Obligation	93%	98%	97%	99%	99%
Cleared load as % of DA Load Forecast	96%	94%	94%	97%	97%

For these 12 days, load clearing outcomes exhibit clear seasonal differences when compared to the day-ahead load forecast. During the summer high-load periods, cleared load generally remains close to the forecast and at times exceeds it, indicating a mix of under- and overclearing. By contrast, the tight winter days are characterized by consistent underclearing, with cleared load falling below the DA forecast on all observed days.

These differences in clearing behavior are reflected in FER pricing outcomes. For the summer tight days, FER prices are relatively low and tend to increase when the system underclears relative to the forecast, while remaining near zero on days when the system overclears. For the winter tight days, FER prices are significantly higher; however, their magnitude does not vary in a clear way with how much the system underclears. Similar levels of underclearing on some tight winter days correspond to a wide range of FER outcomes, indicating that underclearing alone does not explain the size of FER prices for these days.

Other system conditions distinguish the winter period from summer. Winter days are associated with higher outage levels and, at the onset of the higher FER period, reduced net interchange. These conditions coincide with the period in which FER outcomes are elevated, suggesting tighter overall system conditions. Natural gas prices are also notably higher in winter, aligning with the broader increase in FER prices, although differences in gas prices across individual winter days do not closely track the variation in FER outcomes.

It is difficult to attribute the high FER prices alone to any one factor, and indeed evidence to date indicates that supply-side (e.g., outages and interchange over the fall season) as well as demand-side factors impact the FERP. However, during the high-stressed winter period the data indicates that LSE under-clearing (compared to the load forecast) likely had significant impact on the high FER pricing outcomes.

Section 6

Assessment of Market Competitiveness

This section evaluates whether DA A/S market outcomes are consistent with competitive behavior. In so doing, this section serves as the IMM’s competitiveness assessment that is required under Section III.A.17.2.5 of the ISO-NE Tariff.

An accurate assessment of the level of competition is crucial because it helps indicate the extent to which the costs incurred by load for these services reflect competitive market outcomes rather than the exercise of market power. A fundamental feature of competitive markets is the presence of both multiple buyers and multiple sellers, which limits the ability of any individual participant to influence price. While this describes the day-ahead energy market,⁶⁶ the DA A/S market deviates from this idealized version in a very notable way: the market has only one buyer, the ISO, who is purchasing these services on behalf of load.

Accordingly, the objective of this assessment is not to test whether the DA A/S market satisfies the conditions of perfect competition. Rather, the goal is to evaluate whether the observed market outcomes are consistent with the outcomes one would observe in a competitive market. Given the characteristics of the market, this assessment requires a close examination of the supply side of the DA A/S market.

Consequently, the subsequent analysis focuses on the supply side of the market. The first section examines the overall level of market participation. The second section explores the structure of the supply, looking specifically at the level of market concentration and estimating the extent to which the exercise of market power is possible. The third section evaluates how observed DA A/S outcomes compare against outcomes produced using IMM-estimated competitive offers.

Key Takeaways

DA A/S market outcomes indicate that costs were broadly consistent with competitive market conditions during the period.

Offered FRS capability consistently exceeded requirements and increased over the first year of DA A/S, though available supply is more constrained after accounting for market clearing effects—particularly for TMSR, which exhibits relatively tight margins, while Total 10 and Total 30 maintain larger margins. EIR plays a limited role, with generally low cleared volumes that increase during tighter system conditions. Despite rising participation, some capability remains unoffered due to commercial, operational, and risk considerations. Overall, participation has not raised concerns about physical withholding, though it remains an important driver of outcomes particularly during stressed system conditions.

⁶⁶ The IMM found that day-ahead energy market exhibited competitive outcomes in 2025. For more information, see its 2025 Annual Markets Report, available here: <https://www.iso-ne.com/static-assets/documents/100035/2025-annual-markets-report.pdf>.

DA A/S markets exhibit moderate levels of structural concentration, which increase when capability is measured on an ex-post basis due to market clearing effects (e.g., when demand for energy is considered). Concentration is highest for TMSR, reflecting the more limited set of resources capable of providing fast-response reserves, while Total 10 and Total 30 markets are less concentrated.

Despite this structural concentration, DA A/S offer behavior appears broadly consistent with competitive, risk-adjusted benchmarks. Simulations using both Sharpe-based and CVaR-based risk premia produce cost outcomes that are close to, or modestly above, those observed with participant offers. The Sharpe-based framework yields results very similar to observed outcomes, suggesting that participants are embedding risk premiums consistent with managing overall profit variability. The CVaR framework, which places greater weight on tail-risk exposure, results in somewhat higher costs, particularly under stressed conditions. On balance, observed outcomes indicate that participant offers incorporate reasonable, but not excessive, compensation for risk.

6.1 Market Participation

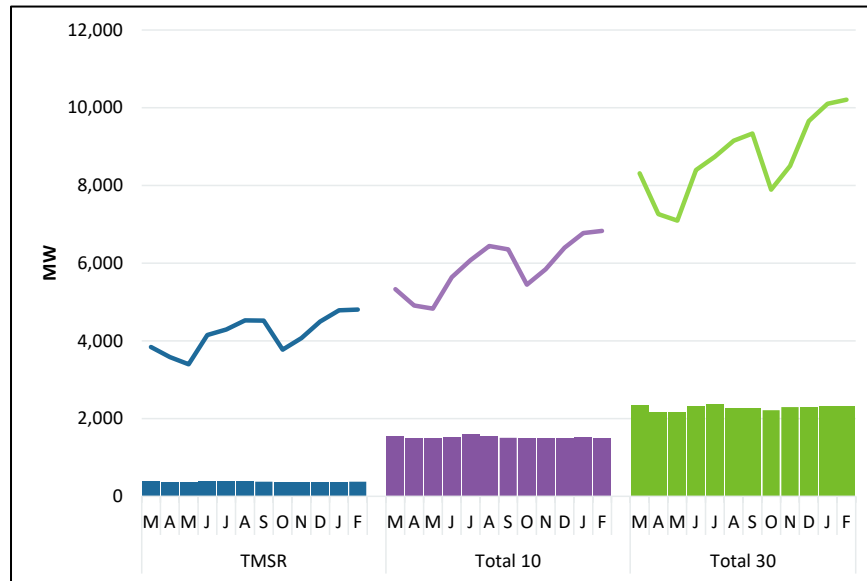
The first section examines the level of participation in the FRS markets over the first year of DA A/S, the second section examines EIR participation, and the last section discusses observations related to unoffered capability.

6.1.1 Flexible Response Services

The offered FRS capability was typically several times larger than the corresponding requirement, and this offered capability generally increased over the first year of the program. This can be seen in Figure 6-1, which shows the average hourly FRS requirements (as bars) and offered capability (as lines) by month.⁶⁷

⁶⁷ Offered capabilities reflect participant-submitted DA A/S offer quantities limited by physical resource characteristics (e.g., ramp rate, EcoMax). Importantly, this figure does not account for the use of Maximum Daily Award Limit (MDAL) parameter by resources as a way to manage the amount DA A/S awards they can clear over the 24-hour day-ahead market clearing. We have seen this parameter commonly used by resources such as limited energy generators (e.g., oil, pondage hydro, pumped storage, and battery storage), which marks an important difference relative to the assumptions used in the Impact Assessment discussed in Section 5.1.

Figure 6-1: Offered FRS Capability relative to Requirements, Ex-ante



Between March 2025 and February 2026, offered TMSR capability rose by roughly 1,000 MW (from 3,800 MW to 4,800 MW), offered Total 10 capability rose by roughly 1,500 MW (from 5,300 MW to 6,300 MW), and offered Total 30 capability rose by roughly 1,900 MW (from 8,300 MW to 10,200 MW). However, the offered capability displayed a seasonality, with participation declining in the spring and fall (when resources tend to undertake planned outages) and then rising in the summer and winter. Meanwhile, the average FRS requirements did not change much by month. The average TMSR requirement was 380 MW, the average Total 10 requirement was 1,521 MW, and the average Total 30 reserve requirement was 2,278 MW.

Several elements of the co-optimized day-ahead market clearing process can limit the DA A/S capability that can be used to satisfy the FRS requirements. Overlooking these limits may lead to an incomplete understanding of the DA A/S market structure. For example, some offered DA A/S capability may be: (1) more valuable to the system when cleared as energy, (2) accessible only from an online state (and the resource may not receive a day-ahead commitment), or (3) limited due to binding transmission constraints.

Consequently, throughout this assessment we use two definitions of supply: *ex-ante* capability (i.e., offered capability) and *ex-post* capability (i.e., offered capability that has been adjusted to account for the factors noted above).⁶⁸

- *Ex-ante* capability is calculated from the resource’s offered DA A/S quantity and physical parameters before market clearing. For online capability, the measure reflects the lesser of (1) headroom between EcoMax and EcoMin and the (2) relevant ramp capability over the

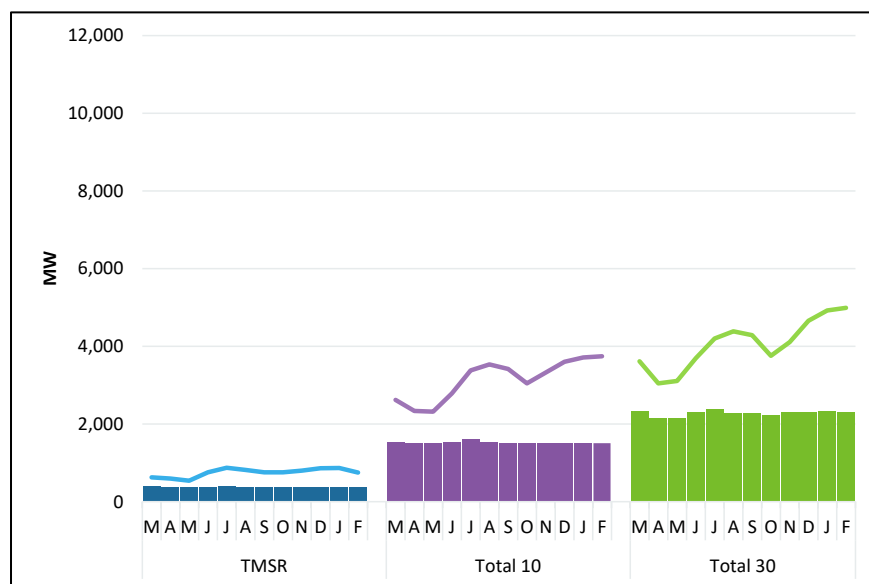
⁶⁸ Specifically, we adjust the offered DA A/S capability downward by the amount of capability that (1) cleared for energy, (2) was offered by non-fast start resources that did not receive a DA commitment, and (3) was behind a binding transmission constraint.

response period. For offline fast-start capability, it reflects the lesser of EcoMax and the applicable Claim10 or Claim30 value.

- *Ex-post* capability starts from the same offered capability but reduces it for capacity that clears for energy, capacity that is not available because the resource was not committed, and capacity limited by binding transmission constraints.⁶⁹

Ex-ante measures can overstate supply because they ignore these clearing effects, while ex-post measures can understate supply because they evaluate capability after the day-ahead market has produced an efficient day-ahead schedule. However, when viewed together, these measures can provide a more complete supply picture. The ex-post perspective of offered FRS capability is illustrated in Figure 6-2 below. Similar to the chart above, this figure shows the average hourly offered FRS capability (as lines) and FRS requirements (as bars) by month.⁷⁰

Figure 6-2: Offered FRS Capability relative to Requirements, Ex-post



As can be seen above, FRS capability becomes more constrained when viewed from a post market clearing perspective. Ex-post TMSR capability tracked tightly with the TMSR requirement over the first year of DA A/S, with an average margin of about ~370 MW per hour. This makes intuitive sense when we consider TMSR procurement in the context of the cost-minimization objective of the day-ahead market. Given that spinning reserve is mostly provided by resources that must be committed

⁶⁹ This ex-post supply assessment is further utilized in the market structure assessment in section 6.2 below.

⁷⁰ Offered capabilities reflect participant-submitted DA A/S offer quantities limited by physical resource characteristics (e.g., ramp rate, EcoMax). Importantly, this figure does not account for the use of Maximum Daily Award Limit (MDAL) parameter by resources as a way to manage the amount DA A/S awards they can clear over the 24-hour day-ahead market clearing. We have seen this parameter commonly used by resources such as limited energy generators (e.g., oil, pondage hydro, pumped storage, and battery storage), which marks an important difference relative to the assumptions used in the Impact Assessment discussed in Section 5.1.

at a cost to provide energy (i.e., have non-zero startup commitment costs), one would not expect an excess of this capability when the market is viewed from a post-clearing perspective.

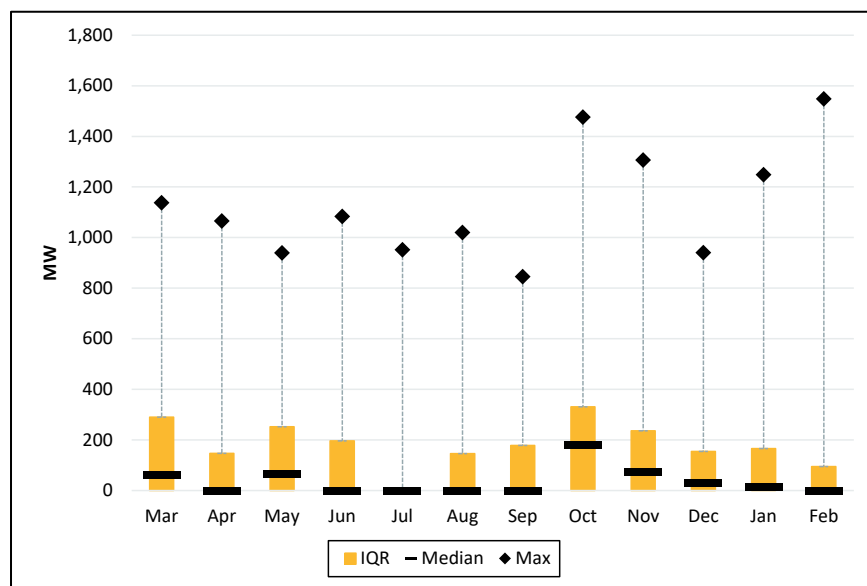
In contrast, ex-post Total 10 and Total 30 capabilities generally had larger margins relative to their respective requirements and these margins are more reflective of the seasonal effects described earlier. Additionally, these ex-post capabilities display clearer upward movement over time as additional resource capability entered the market. The ex-post Total 10 and Total 30 margins tend to be larger than the TMSR margin given that these requirements can be met by both online and *offline* resources.

6.1.2 Energy Imbalance Reserves

There is no strict requirement on the level of EIR that must clear per hour. Instead, the market clearing engine will determine the level of cleared EIR in tandem with its determination of the level of cleared day-ahead energy awards on physical resources, ensuring that, collectively, the two values satisfy the FER. Meanwhile, the supply side of the market is the largest for all the DA A/S products as EIR capability reflects the increase in energy output that resources can achieve in 60 minutes.⁷¹

In general, only small amounts of EIR are cleared to satisfy the FER, but clearing does vary by hour. This can be seen in Figure 6-3, which shows the hourly distributions of cleared EIR MW by month over the first year of DA A/S, highlighting the interquartile range (IQR), median, and maximum values.

Figure 6-3: Cleared EIR MW



⁷¹ Given that there is no strict requirement for EIR and that the supply pool is the largest of all the DA A/S products, the FRS products receive the majority of the focus in our assessment of DA A/S market competitiveness.

Across the year, median cleared EIR volumes were relatively low (generally under ~100 MW) and, in many months, the median value was 0 MW. However, there was a modest uptick in the fall when generators took winter readiness outages and the level of imports generally decreased. Maximum values (black markers) exhibit greater volatility, with pronounced spikes in October, November, January, and February.

6.1.3 Unoffered Capability

It is important to note that some capability chooses not to participate in the voluntary DA A/S market.⁷² In fact, while offered capability has far exceeded the FRS requirements, and participation has trended upwards, participation rates have peaked around an estimated 70% for 60-minute (i.e., EIR) capability, although participation has varied by resource type and fuel. Participants that choose not to participate, or to participate at reduced levels, in the DA A/S market have generally provided three reasons: commercial strategy, physical/operational constraints, and risk considerations. Each of these is discussed briefly below.

- Some participants indicated commercial strategy considerations influenced their decision not to participate in the DA A/S market. A few of these participants cited a focus on alternative, non-market-based revenue streams, most notably those attainable through Massachusetts Clean Peak Energy program. Power Purchase Agreements (PPAs) are likely influencing DA A/S offer behavior as well by prioritizing energy market participation.
- Physical and operational constraints also impacted certain resources decisions to limit their participation in the DA A/S market. Some participants described limitations related to fuel management, making reserve provision impractical. Other participants, particularly those with hydroelectric resources, cited that generation decisions can affect downstream operations and water management schedules.
- Finally, some participants indicated that risk considerations played a role. These participants generally cited the view that a DA A/S award can expose certain resources to additional financial risk because these resources cannot rely on inframarginal real-time energy market revenues to offset potential losses.⁷³ This reasoning applied both to broad classes of resources as well as certain energy segments, such as upper block or duct firing ranges, which tend to have significantly higher marginal costs.

The IMM has consulted with participants regarding their participation levels in the DA A/S market, particularly around periods of stressed system conditions such the five-day period from January 25, 2026, to January 29, 2026, that coincided with Winter Storm Fern. Participation levels have generally not raised physical withholding concerns that would impact overall competitive cost

⁷² There is no must-offer rule in the DA A/S market. For discussion on this topic, please see pages 111-113 of the testimony of Dr. Matthew White in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

⁷³ For a discussion of this risk, see Section 6.3.

estimates. We will continue to monitor participation levels on an ongoing basis and require legitimate justification when lack of participation exceeds the Tariff-defined thresholds.⁷⁴

6.2 Market Structure

Market structure refers to the organization of a market, including the number and relative size of participating firms offering their ancillary services capability into the day-ahead market. Given that the capabilities needed to satisfy the various requirements are different, the natural lanes for this analysis are the requirements: ten-minute spinning reserve (TMSR), total 10-minute reserve (Total 10), and total 30-minute reserve (Total 30).⁷⁵

As mentioned in Section 3.1, the day-ahead market formulation includes nested FRS demand quantities (TMSR, Total 10, and Total 30). TMSR awards can satisfy each of the three FRS requirements; TMSR can satisfy the Total 10 and Total 30 requirements; and TMOR awards can satisfy only the Total 30 requirement. In the text, we refer to TMSR, Total 10, and Total 30 as shorthand for these nested requirements.

As discussed earlier, ex-ante measures can overstate supply and therefore underestimate market power because they ignore the co-optimization effects, while ex-post measures can understate supply and overstate market power because the day-ahead market can re-optimize commitment and reserve awards in response to offers.

Concentration Ratios

A concentration ratio measures the percentage of total capability accounted for by a set of the largest participants. Lower concentration ratios are indicative of more structurally competitive markets, while higher concentration ratios are indicative of less structurally competitive markets that are more susceptible to exercise or market power. In this analysis, CR4 refers to the share of total capability accounted for by the four largest participants, and CR8 refers to the share accounted for by the eight largest participants.

The DA A/S markets exhibit moderate levels of concentration, and these concentration levels increase across all markets when capability is measured on an ex-post basis. This can be seen below in Table 6-1, which shows the average CR4 and CR8 over the study period.

⁷⁴ See Section III.A.4 of the ISO-NE Tariff for more information on physical withholding.

⁷⁵ This assessment does not consider Energy Imbalance Reserve (EIR), which has no explicit requirement and has the largest supply of the DA A/S products given its 60-minute definition.

Table 6-1: DA A/S Market Concentration Ratios

Requirement	CR4		CR8	
	Ex-ante	Ex-post	Ex-ante	Ex-post
TMSR	61%	75%	79%	94%
Total 10	56%	60%	75%	82%
Total 30	50%	54%	72%	79%

On an ex-ante basis, the top four participants accounted for over 50% of the offered supply for all DA A/S requirements. Intuitively, the levels of concentration decreased as the response period increased (i.e., the concentration ratios for 30-minute capability are lower than those for 10-minute capability). Concentration levels increased across all requirements when capability is measured on an ex-post basis, reflecting the effects of joint optimization in day-ahead energy and ancillary services market. This pattern is most pronounced in the TMSR requirement, where CR4 rose from 61% percent under ex-ante capability to 75% under ex-post capability. When considering the eight largest participants, the concentration ratios for all three markets ranged between 72%-79% on an ex-ante basis and between 79%-94% on an ex-post basis.

It is important to recognize that the structure of supply for the DA A/S requirements differs from that in the energy market because only a subset of resources possesses the fast-start (i.e., Claim10 or Claim30) or fast-ramp capability needed to provide the requisite ancillary service. As a result, the supply of reserve capability is inherently more limited than the supply of energy, increasing the potential for concentration.^{76, 77}

Herfindahl-Hirschman Index

The Herfindahl-Hirschman Index (HHI) is a measure of market concentration that gives more weight to larger participants and considers the market shares of all participants.⁷⁸ Similar to concentration ratios, lower values are indicative of more competitive markets and higher values are indicative of less competitive markets.⁷⁹

⁷⁶ The IMM estimates that the real-time energy market had an annual average C4 during the on-peak hours that ranged between 40%-45% over the five-year period between 2020-2024. For more information, see Section 2.1.1 in our 2024 Annual Markets Report (AMR) (<https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf>). Please note that the C4 for energy reported in the 2024 AMR is based on *cleared* energy awards and the concentration ratios for DA A/S presented in this assessment are based on *offered* MWs.

⁷⁷ This comparison is intended only as a directional reference. Energy-market concentration measures are often based on cleared energy MW, while DA A/S concentration measures are based on offered or available reserve capability. The two measures therefore answer different questions, but the comparison is useful for illustrating that reserve-capability supply is inherently narrower than the broader energy supply base.

⁷⁸ The HHI is calculated as follows: $HHI = \sum_{i=1}^n (C_i)^2$; where C_i is the market share of the i -th largest participant (e.g., 25%) and n is the number of all participants that offer their capability.

⁷⁹ The highest possible HHI value is 10,000, which would occur when one firm accounted for 100% of the market.

The HHI values were consistent with the CR4 and CR8 values, indicating a range of concentration from low to moderate.⁸⁰ This can be seen below in Table 6-2, which shows the average HHI values over the study period.

Table 6-2: DA A/S Market Herfindahl-Hirschman Indices

Requirement	HHI	
	Ex-ante	Ex-post
TMSR	1,560	2,203
Total 10	1,320	1,368
Total 30	943	1,111

The HHI values reveal much of the same insight as the concentration ratios above. According to the Antitrust Division of the U.S. Department of Justice, the ex-ante TMSR and Total 10 markets are moderately concentrated while Total 30 is unconcentrated. Of specific note is the HHI for TMSR, which increased from an ex-ante value of 1,560 (moderately concentrated) to an ex-post value of 2,203 (highly concentrated). Ex-post Total 10 and Total 30 are both moderately concentrated according to those standards.

The concentration ratio and HHI measures provide useful summaries of structural concentration by describing how offered (or ex-post) capability is distributed across suppliers. However, these measures do not, by themselves, indicate whether concentration is competitively consequential in each hour, i.e., whether the DA A/S requirement could be met using capability outside a particular supplier or small set of suppliers, especially after accounting for the capability that is available. To evaluate when concentration can translate into potential market power, we therefore apply more insightful and dynamic metrics, the pivotal-supplier tests (PST) and the residual supply index (RSI), which explicitly compare residual (non-supplier) capability to the requirement on an hour-by-hour basis and identify periods when one or more suppliers are necessary to satisfy the requirements.

Pivotal Suppliers and Residual Supply Index

A pivotal supplier is a participant without whose offered capability a requirement could not be met. Periods when a market has a pivotal supplier are noteworthy because they can provide a useful screen identifying that a participant may have the ability to increase clearing prices. A related concept is the residual supply index (RSI), which is the proportion of a requirement that can be satisfied without the capability of the largest supplier.

⁸⁰ The Antitrust Division of the U.S. Department of Justice generally considers markets with HHI values below 1,000 as unconcentrated markets, HHI values between 1,000 and 1,800 as moderately concentrated market and HHI values >1,800 as highly concentrated markets. <https://www.justice.gov/atr/herfindahl-hirschman-index>

Statistics related to pivotal suppliers and the RSI are presented by requirement in Table 6-3 below.

Table 6-3: DA A/S Market Pivotal Supplier and RSI Statistics

Requirement	% of Hours with at least one Pivotal Supplier		RSI ⁸¹	
	Ex-ante	Ex-post	Ex-ante	Ex-post
TMSR	0%	38%	729	124
Total 10	0%	1%	271	147
Total 30	0%	3%	303	136

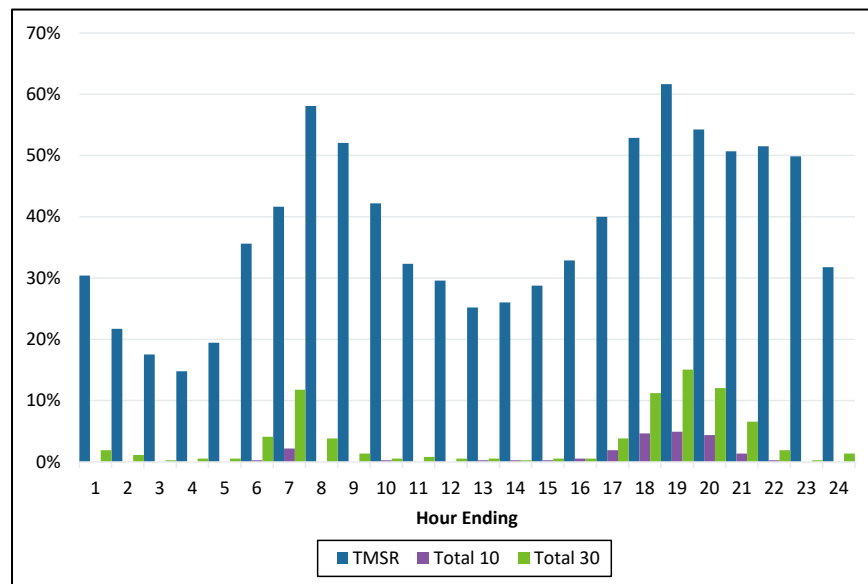
There were no hours with a pivotal supplier for any reserve market when capability is defined on ex-ante basis. By contrast, when ex-post capability is considered, at least one pivotal supplier is present in 38% of the hours in the TMSR market, while pivotal supplier occurrences remain infrequent in the 10- and 30-minute markets.

Consistent with the pivotal supplier results, average RSI values under the ex-ante capability definition suggest a generally robust supply picture with the values across all markets coming in well above 100. However, when capability is measured on an ex-post basis, RSI values decline across all markets. The decline is most significant for the TMSR requirement, which fell from over 700 to 124.

On an ex-post basis, the share of hours with at least one pivotal supplier varies significantly, rising during the morning and evening peak periods when reserve capability is converted to energy to satisfy higher loads. This can be seen in Figure 6-4 below, which shows the percentage of hours with at least one pivotal supplier by hour and market.

⁸¹ The residual supply index (RSI) represents the amount of demand and reserves that the system could satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier would be needed to meet demand and could exercise market power if permitted. Further, if the RSI is less than 100, there is one or more pivotal suppliers.

Figure 6-4: Percentage of Hours with at least One Pivotal Supplier (Ex-post) in the DA A/S Market



The percentage of hours with at least one pivotal supplier for the TMSR market rises from as low as 15% in hour ending (HE) 4 to 58% in HE 8 and 62% in HE 19. The pattern is similar, although more muted, for the Total 10 and Total 30 requirements; the share for Total 10 peaks at 5% in HE 19 while the share for Total 30 peaks at 15% during the same hour.

It is important to consider the TMSR market results in the context of the cost-minimization objective of the day-ahead market. Given that spinning reserve is mostly provided by resources that must be committed at a cost to provide energy (i.e., have non-zero startup commitment costs), one would not expect an excess of this capability when the market is viewed from an ex-post perspective. This effect is likely to raise the appearance of pivotality, especially to the extent that the resources that commonly clear TMSR awards have the same owner. Meanwhile, the Total 10 and Total 30 requirements can be met by both online and offline resources, which do not incur commitment costs, and therefore their ex-post market structure metrics tend to appear lower.

Further, the results above should also be considered in the context of FRS price formation. As noted in Section 5.2.1, in the majority of hours the TMSR clearing price is determined by the marginal offer for the Total 30-minute reserve constraint, which binds in every hour and whose price cascades up to influence the TMSR clearing price.⁸² This means that TMSR is generally competing with all 30-minute capability to set price.⁸³ Put differently, TMSR structural tightness

⁸² The ten-minute spinning reserve constraint bound in only 20% of hours during the first year of DA A/S.

⁸³ Additionally, the relatively low Reserve Constraint Penalty Factor (RCPF) for the TMSR (\$50/MWh) provides a form of safeguard against the exercise of market power in this market (when only the TMSR requirement is binding). This does not mean TMSR clearing prices are capped at \$50/MWh. Because FRS requirements are nested, TMSR awards can also satisfy Total 10 and Total 30 requirements, and the TMSR price can include the shadow prices of those broader constraints. The RCPF is therefore a useful safeguard against TMSR-specific market power, but it does not eliminate the need to monitor broader reserve scarcity and ex-post pivotal conditions.

does not necessarily imply that TMSR clearing prices are not determined by competitive market forces.

6.3 Offer Behavior

To assess whether market outcomes are consistent with competitive offer behavior, we conduct two simulations in which DA A/S offers are set at IMM benchmark levels, differing only in how the risk premium is defined. Together, these risk methodologies provide a range of competitive outcomes: one based on a return-per-unit-of-risk metric (Sharpe) and one based on a more conservative tail-risk measure (conditional Value at Risk).

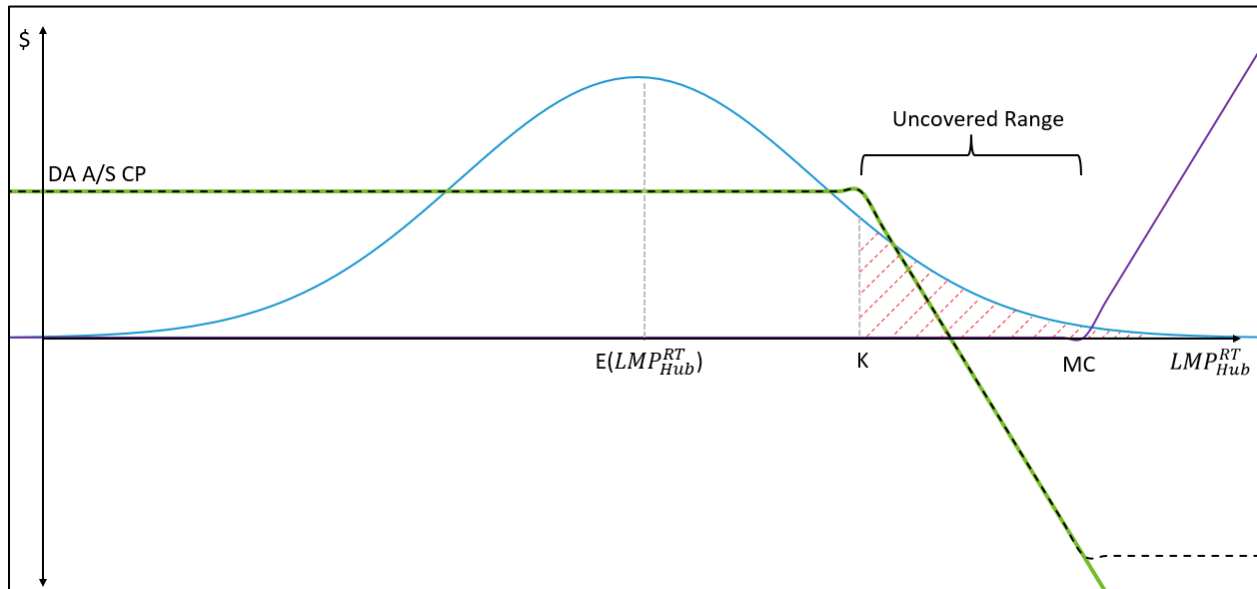
Indeed, both approaches are somewhat conservative in that they treat risk as something participants evaluate asset-by-asset and over short horizons. In practice, resource owners manage risk at the portfolio level and over longer horizons, so diversification and intertemporal balancing can reduce the risk that must be priced into any single asset's DA A/S offer in any given hour. While participant risk tolerance and hedging capability are heterogeneous and not directly observable, we use these two transparent benchmark frameworks to bound plausible risk-premium levels and to evaluate whether risk premiums can materially impact market outcomes.

We start by laying out the underlying cost components of a DA A/S award, before turning to how the Sharpe and CVaR frameworks translate risk exposure into a premium. Recall from Section 3.1.3 that the primary cost associated with a DA A/S award is the expected closeout, which represents the probability-weighted charge that a resource could otherwise avoid by not taking on a DA A/S award. Other costs include the fuel-related costs incurred by a subset of DA A/S providers (gas and energy storage); under this design, these are referred to as avoidable input costs.⁸⁴

Risk arises for resources with DA A/S awards because these obligations exchange a fixed premium (the DA A/S clearing price) for exposure to uncertain (and potentially severe) real-time closeout charges. An illustrative example that describes some of the important factors related to this risk is presented in Figure 6-5 below. In this figure, the x-axis represents possible values of the real-time LMP and the y-axis represents payoff in dollars.

⁸⁴ For more information about the various components of a DA A/S offer, see Section 3.1.3.

Figure 6-5: Payoff Diagram



The payoff associated with the DA A/S award is shown by the green line; the resource receives the DA A/S clearing price until the real-time LMP exceeds the strike price, K , at which point it decreases one-for-one with the real-time LMP. This figure also incorporates the resource's payoff from producing energy in real time (purple line); there is no payoff until the real-time LMP exceeds the asset's short-run marginal cost, denoted MC , at which point it increases in value one-for-one with the real-time LMP.⁸⁵ Finally, the figure also shows the combined payoff of a DA A/S award *and* producing energy in real time (black dashed line). The combined payoff matches the DA A/S payoff until the real-time LMP exceeds the asset's marginal cost; once the unit is in merit, incremental real-time energy margins offset the increasing closeout exposure if the unit can run (i.e., is not on outage), so the combined payoff becomes approximately flat over that range.⁸⁶

While the payoff will vary by resource depending on its marginal cost and its performance, the resource depicted in the figure above is one whose short-run marginal cost exceeds the strike price and so is not able to offset the closeout charge with real-time energy production through a wide range of possible real-time LMPs (labeled as "Uncovered Range" in the figure). In fact, this resource begins incurring a loss at some value of the real-time LMP above the strike price, and even when the resource produces energy, it does not eliminate the loss but instead only prevents it from increasing. More generally, the figure highlights that DA A/S exposure is most acute in states where

⁸⁵ The dollar-for-dollar increase in the real-time margin holds when the resource is available to run once prices exceed short-run marginal cost.

⁸⁶ For exactly the reason outlined in footnote 85, the apparent hedge in combined payoffs holds when the resource is available to run once prices exceed short-run marginal cost. Because outages occur with nonzero probability, there are high-price states in which the unit cannot produce and therefore cannot offset closeout exposure; these states drive residual downside risk and contribute to both overall profit volatility and tail outcomes.

real-time prices are high, but the resource cannot (or does not) provide offsetting real-time energy—whether because it remains out of merit or because it is unavailable.

The risk calculation that a resource owner makes in relation to taking on a DA A/S award depends on numerous factors captured in the illustrative example above (e.g., the expected DA A/S clearing price, the strike price, the resource’s marginal cost, the distribution of real-time LMPs) as well as other considerations not shown (e.g., portfolio-level risk tolerances and resource outage risk).

Different methodologies formalize the tradeoff between risk and return in different ways. In this section we utilize two common methodologies—the Sharpe ratio, which is based on overall profit variability, and CVaR, which focuses on tail losses (extreme downside exposure)—to estimate benchmark measures of risk associated with a DA A/S award.⁸⁷ We then perform market simulations that make use of these risk estimates and compare the results from these simulations to the one based on actual participant offers. This comparison allows us to assess the extent to which market outcomes may reflect competitive offers that incorporate benchmark risk premiums.⁸⁸

Sharpe Ratio

Under the Sharpe ratio approach, the risk premium for selling DA A/S is determined by comparing risk-adjusted expected profits from two alternatives: (i) selling both DA A/S and real-time energy, and (ii) selling real-time energy only. Risk is summarized by the *standard deviation of net revenues*, and the guiding condition is that the Sharpe ratio (expected profit divided by standard deviation) from DA A/S participation must be at least as large as that of the next-best alternative. We compute expected net revenues and profit volatility under each alternative using simulated real-time price distributions (derived from ISO-NE’s Gaussian Mixture Model), along with resource-specific outputs such as marginal costs and outage rates. The DA A/S offer price is then solved as the minimum offer that equalizes these risk-adjusted returns.⁸⁹

Within this framework, the Sharpe-based risk premium is the increment above fair value, defined as expected closeout costs plus any avoidable input costs (AIC), required to satisfy the Sharpe condition. This framework yields a clear decomposition of competitive offers. All suppliers must recover expected DA A/S closeout costs (and any avoidable fuel or storage costs), while a positive risk premium appears only if DA A/S participation *increases* profit volatility relative to real-time-only operation.

Importantly, low volatility does not necessarily imply low downside exposure. A resource with a very high short-run marginal cost, for example, may have stable profits simply because it is rarely in merit and seldom operates. Under a Sharpe metric, DA A/S participation may appear to add little incremental variance. Yet such a resource still faces large closeout charges in high-price states

⁸⁷ The distinction matters most in periods of scarcity, where non-linear price behavior drives economic risk.

⁸⁸ Our risk premium metrics are intended to capture certain salient features of the exposure faced by DA A/S suppliers. These approaches do not capture the likely wide range of risk tolerances across market participants.

⁸⁹ We follow the approach developed during the DASI stakeholder process: https://www.iso-ne.com/static-assets/documents/2023/06/a03a_mc_2023_06_06_dasi_competitive_offer_formulations_memo.pdf

and has little operational ability to profitably offset them through real-time production. Conversely, flexible gas or storage resources may exhibit higher gross variability but also stronger natural hedges—profits from real-time operation that rise exactly when closeouts are large—so that DA A/S participation can leave their overall volatility unchanged or even lower, satisfying the Sharpe condition with little or no additional premium.

In Sharpe-ratio terms, the key question is therefore whether adding the DA A/S position increases the overall dispersion of profits relative to real-time-only operation; that increase can be material even if the Uncovered Region in Figure 6-5 is narrow, depending on how frequently the unit is out of merit in tight hours and how often outages prevent the unit from running when prices are high.

As mentioned above, we performed the following simulation:

- **Sharpe:** a scenario in which all DA A/S constraints are ‘turned on’ but DA A/S offers are based on expected closeout, any avoidable input costs, and a resource-specific risk premium derived using the Sharpe methodology outlined above.

Table 6-4 below provides a high-level comparison of this Sharpe scenario to the DA A/S scenario (initially presented in Section 4.2).

Table 6-4: Comparison to Outcomes with Competitive Offers plus Sharpe Ratio Risk Premia

Category	DA A/S (\$M)	Sharpe (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$11,153	\$11,194	\$40	0.4%
<i>LMP</i>	\$10,127	\$10,081	-\$47	-0.5%
<i>FER Price</i>	\$1,026	\$1,113	\$87	8.5%
DA A/S	\$261	\$259	-\$2	-0.9%
<i>Credits</i>	\$453	\$450	-\$4	-0.8%
<i>Closeouts</i>	-\$192	-\$191	\$1	-0.7%
Total Charges/Credits	\$11,415	\$11,453	\$38	0.3%
Cost of Incremental RT Energy	\$136	\$138	\$1	0.9%
Total Cost/Revenue Change	\$11,551	\$11,590	\$39	0.3%

The simulation results using the Sharpe approach for calculating risk show modest cost increases relative to the simulation based on participant offers. The cost increases are most notable for the FER-related credits (labeled ‘FER Price’ in Table 6-4), which increases by \$87 million. However, these increases are partially offset by a decrease in LMP-based payments of \$47 million, resulting in a modest increase in total day-ahead energy market payments (\$40 million). Payments in the DA A/S market and the real-time energy market were largely unchanged, and the result was an overall increase in costs of \$39 million.

As an additional diagnostic, we isolate the **12 highest-cost days** (largely clustered in multi-day stress events) that together account for roughly half of the incremental first-year DA A/S costs. In this subset, costs under the participant-offer baseline (the DA A/S scenario) amount to \$1,900 million (\$158 million per day) compared to \$2,017 million (\$168 million per day) under Sharpe-based competitive offers, implying that costs on these 12 days were 5.8% below what they would have been had active participants offered according to our Sharpe-based competitive benchmarks. By contrast, across the remaining days of the year, DA A/S costs were \$9,651 million (\$27.50

million per day) versus \$9,573 million (\$27.27 million per day) under the Sharpe-based competitive benchmark, indicating that in normal conditions, participants are broadly consistent with Sharpe-implied premia.

CVaR

A CVaR (Expected Shortfall) approach reframes the same problem in explicitly *tail-risk* terms. Instead of focusing on overall revenue volatility, risk is defined as the average loss in the worst 5 percent of outcomes. For DA A/S positions, these tail losses arise in scenarios where real-time prices exceed the strike price and the resource is unable to offset the resulting closeout charge through real-time operation, leading to losses. This can occur either because the unit is economically out-of-merit (e.g., due to high short-run marginal cost) or because it is physically unavailable (e.g., on outage). In both cases, the defining feature of tail risk is the lack of an effective operational hedge precisely in the states where closeout charges are largest.

Under this approach, tail losses are computed directly from simulated profit distributions, and the risk premium is set as the incremental compensation required to cover the incremental economic capital needed to absorb those losses. A fixed capital charge rate converts required tail-risk capital into a \$/MWh premium. Relative to a Sharpe-ratio method, CVaR places much greater weight on asymmetric downside exposure, focusing on states where high RT LMPs coincide with an inability to hedge closeout charges through real-time production. These states arise not only from physical outages, but also from high short-run marginal costs that keep units out of merit. By explicitly conditioning on such stress scenarios, CVaR captures economically relevant risk that variance-based measures tend to smooth over, making it well suited for participants whose binding constraints are liquidity, collateral, or internal risk limits defined by severe but infrequent losses, rather than by average profit volatility.⁹⁰

In CVaR terms, the Uncovered Region in Figure 6-5 matters disproportionately (especially when coincident with resource outages) because it determines the worst-tail outcomes—high-price intervals in which the closeout exposure is large, and the operational hedge is ineffective.

As mentioned above, we performed the following simulation:

- **CVaR:** a scenario in which all DA A/S constraints are ‘turned on’ but DA A/S offers are based on expected closeout, any avoidable input costs, and a risk premium derived using the CVaR methodology outlined above.

Table 6-5 below provides a high-level comparison of this CVaR scenario to the DA A/S scenario (initially presented in Section 4.2).

⁹⁰ The tradeoff is complexity: CVaR requires careful specification of tail thresholds, capital charges, and, for resources with avoidable input costs, a specification of the dependence between various profit components like RT LMP and input prices.

Table 6-5: Comparison to Outcomes with Competitive Offers plus CVaR Risk Premia

Category	DA A/S (\$M)	CVaR (\$M)	Delta (\$M)	Delta (%)
DA Energy	\$11,153	\$11,247	\$94	0.8%
<i>LMP</i>	\$10,127	\$10,059	-\$69	-0.7%
<i>FER Price</i>	\$1,026	\$1,188	\$162	15.8%
DA A/S	\$261	\$287	\$26	9.9%
<i>Credits</i>	\$453	\$477	\$24	5.3%
<i>Closeouts</i>	-\$192	-\$190	\$2	-0.9%
Total Charges/Credits	\$11,415	\$11,534	\$119	1.0%
Cost of Incremental RT Energy	\$136	\$137	\$1	0.5%
Total Cost/Revenue Change	\$11,551	\$11,671	\$120	1.0%

Compared to the DA A/S scenario, the simulation results based on the CVaR approach depict overall cost increases. The largest cost increase occurs in the FERP-based payments (labelled ‘FER Price’ in Table 6-5), which rose by \$162 million. However, these cost increases were partially offset by a reduction in LMP-based payments of \$69 million. The combined impact was an increase in day-ahead energy market payments of \$94 million relative to the DA A/S scenario. Unlike the Sharpe scenario, costs also increased in the DA A/S market under this approach, rising by \$26 million. With the minor increase in real-time energy payments (\$1 million), the overall increase in costs amounts to \$120 million.

We also perform the same **high-risk-day breakout** under the CVaR framework, which by construction places greater weight on the severe but infrequent outcomes that characterize stressed system conditions. On the 12 highest-incremental-cost days, costs under the participant-offer baseline (the DA A/S scenario) amount to \$1,900 million (\$158 million per day) compared to \$2,051 million (\$170.95 million per day) under CVaR-based competitive offers, implying that costs on these 12 days were 7.4% below what they would have been had active participants offered according to our CVaR-based competitive benchmarks. On the remaining days of the year, DA A/S costs were \$9,651 million (\$27.50 million per day) compared to \$9,619 million (\$27.41 million per day) under the CVaR-based competitive benchmark, again suggesting close alignment in normal periods but a materially larger gap during system stress.

Over the full year, simulated costs fall slightly below the costs produced by the Sharpe- and CVaR-based competitive benchmarks. That full-year comparison, however, is driven primarily by a small number of high-cost stress days: on the 12 highest-incremental cost days, participant-offer outcomes were 5.8% below the Sharpe benchmark and 7.4% below the CVaR benchmark, while on the remaining days, participant-offer outcomes were closely aligned with both benchmarks. This pattern suggests that observed offers were broadly consistent with competitive, risk-adjusted behavior in normal conditions, and somewhat below these benchmark levels during stressed conditions. At the same time, both the Sharpe and CVaR frameworks are conservative benchmarks because they evaluate risk largely on a unit-by-unit basis and over relatively short horizons and therefore do not fully reflect the benefits of diversification across assets or intertemporal risk management within participant portfolios. Accordingly, the fact that participant-offer outcomes fall at or below these benchmarks is consistent with offers reflecting “reasonable” risk premia.

Section 7

Mitigation Performance

This section evaluates whether observed mitigation outcomes during the first year of DA A/S market operations are consistent with the intended two competing objectives: limiting the risk that uncompetitive offers materially affect market outcomes, while avoiding unnecessary intervention of offers based on a resource's legitimate competitive costs; with particular attention to the frequency, context, and system conditions under which mitigation occurred.

Key Takeaways

Overall, mitigation outcomes observed during the first year of DA A/S market operations are largely consistent with the stated objectives of the mitigation framework. Mitigation occurred infrequently, was generally limited to circumstances where offers both materially exceeded benchmark expectations and had a measurable effect on clearing prices, and did not appear to constrain competitive offer behavior during periods of heightened system stress.

One notable exception arises when price impact thresholds fell below \$3/MWh, which occurs during times when system conditions are generally unstressed and market power is not a concern. Almost thirty-percent of mitigations occurred under these conditions. The ISO plans to address as part of their DA A/S market enhancements work in 2026 by incorporating a \$3/MWh price impact floor, a sensible measure which will address these observed instances of over-mitigation.

As described in the ISO's filing, the mitigation framework is explicitly designed to intervene only in clear and impactful instances of uncompetitive behavior.⁹¹ To achieve this balance, the DA A/S mitigation framework applies a sequenced evaluation consisting of a conduct test to identify offers that materially exceed benchmark levels, a price impact test to assess whether such offers meaningfully affect market clearing prices, and mitigation that is limited to offers failing conduct test thresholds. This structure reflects a deliberate design choice to preserve pricing flexibility under most conditions while providing targeted safeguards when competitive outcomes may otherwise be distorted.

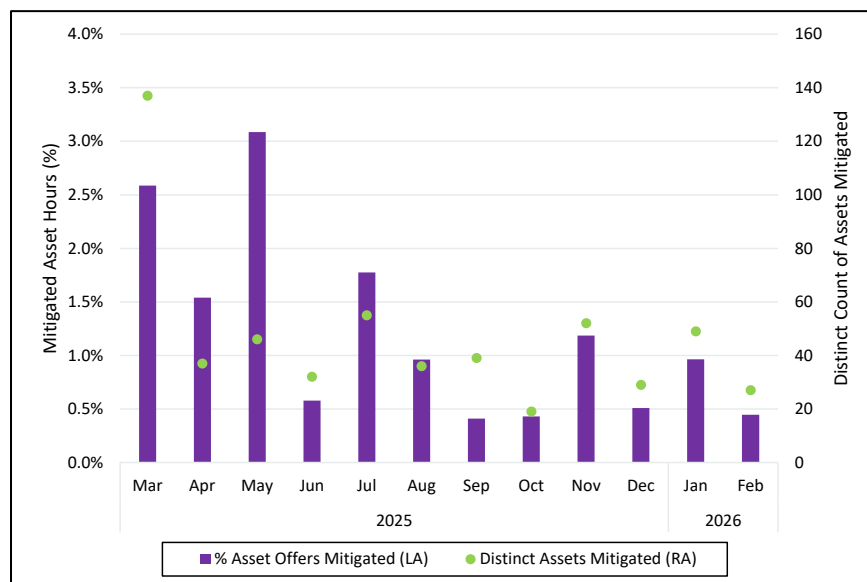
Frequency of Mitigation

In general, there has been a low frequency of DA A/S mitigation indicating that mitigation has not played a prominent role in determining market outcomes. The occurrence of DA A/S mitigation can

⁹¹ See Dr. Alivand's testimony in https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf

be seen in Figure 7-1 below, which shows the percentage of DA A/S offers that were mitigated on the left axis (LA) and the count of the distinct assets that were mitigated on the right axis (RA).⁹²

Figure 7-1: DA A/S Mitigations



Over the course of the first year, 1.2% of all asset-product-hours were mitigated. The count of distinct assets that were mitigated in any month ranged from 19 in October 2025 to 137 in March 2025.⁹³ It is likely that a growing familiarity with the market design reduced both the frequency of mitigation and the number of assets that were mitigated.

Mitigation Performance During Periods of System Stress

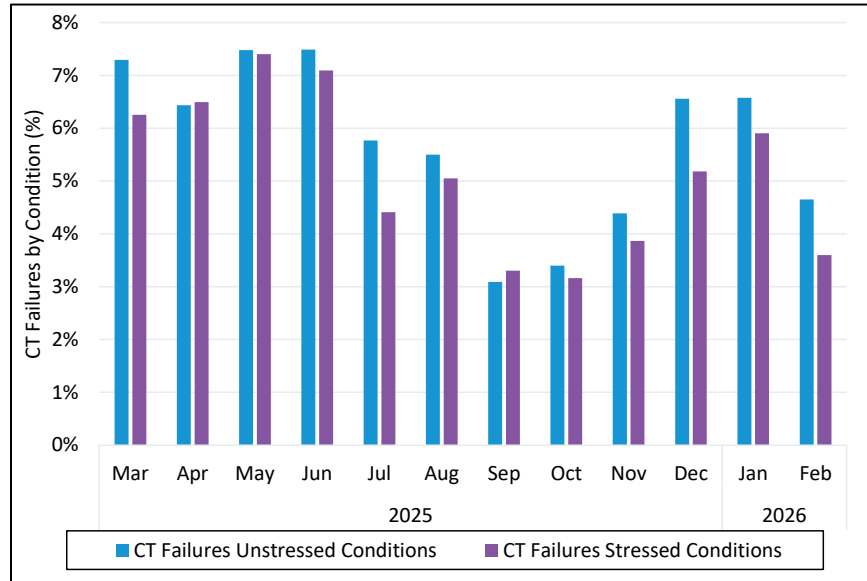
The IMM has found that, in general, participants do not increase their offers beyond the conduct test threshold more frequently when the system is stressed, and, if anything appear more likely to remain within conduct test thresholds during these periods. This can be seen in Figure 7-2 below, which compares conduct test failure rates during periods of stressed system conditions and unstressed periods.⁹⁴

⁹² Given that one asset can make offers on up to four DA A/S products per hour, this percentage represents the count of mitigated asset-product-hours relative to the total count of asset-product-hours in the period.

⁹³ For example, in October, the 19 distinct assets could have been mitigated on different days or the same day, and in different hours or the same hour. Using the combination of the percent of all asset-offers, along with the distinct number of assets mitigated in a month, explains the market-wide impact of mitigation.

⁹⁴ Hourly reserve margins are defined as the difference between ex-post capability and the associated FRS requirement. If any of the three reserve margins was in the bottom 10th percentile for the month, that hour was flagged as a stressed condition hour. Otherwise it is considered unstressed.

Figure 7-2: Conduct Test Failures Across FRS Products

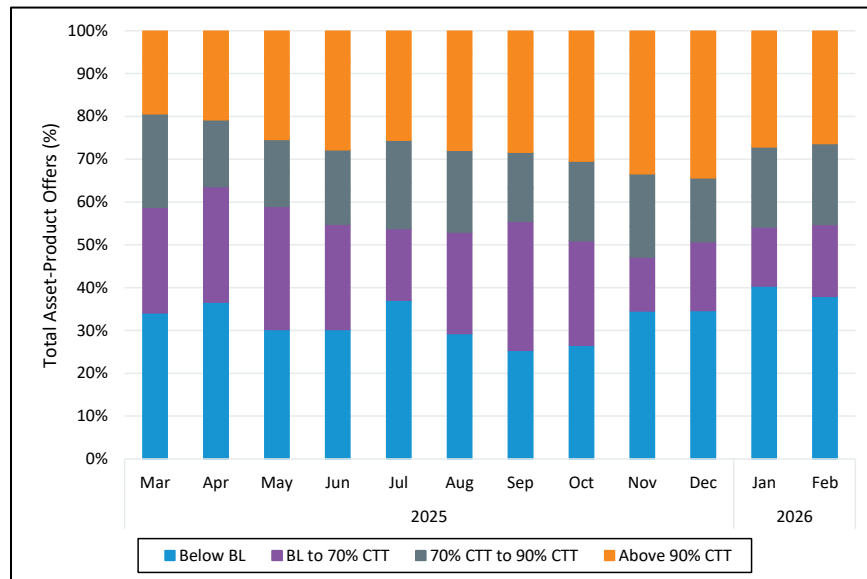


The results indicate that conduct test failure rates exhibit little change—and in several months are modestly lower—during stressed system conditions. One plausible explanation is that the conduct test threshold prices do a reasonable job defining the upper limit for competitive price ranges. Another plausible explanation is that participants adjust their offers to avoid failing the conduct test. As a result, participants may limit conduct test exposure rather than risk mitigation.

Participant Offers Relative to Mitigation Values

Figure 7-3 below represents participant offer bands across all products relative to benchmark levels and the conduct test threshold.

Figure 7-3: Offers Relative to Mitigation Values



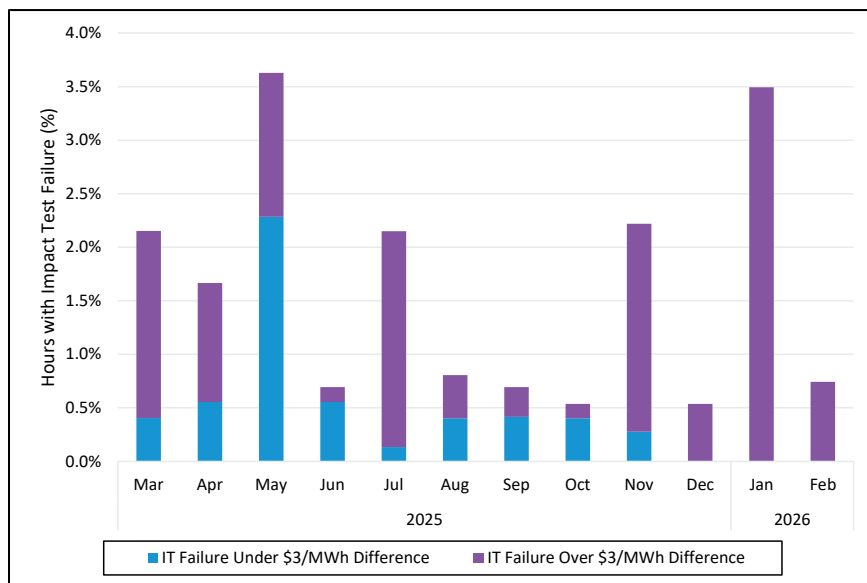
The blue and purple categories, representing offers below the benchmark level or only modestly above it, account for 55% of offers. The gray category, representing offers between 70% and 90% of the conduct test threshold, accounts for 18% of offers. These offers approach the conduct test threshold without exceeding it and may reflect situations in which participants incorporate their own assessment of system conditions or operational risk into pricing decisions, resulting in offers that move meaningfully above benchmark levels while remaining below the conduct test threshold. This behavior is consistent with the intended design of conduct test threshold multipliers, which allow some upward pricing flexibility while discouraging excessive departures from benchmark levels.

The remaining 27% of offers fall at or above 90% of the conduct test threshold, including approximately 6% of offers that fail the conduct test. Offers above the conduct test threshold that occur on days with impact test failures are subject to mitigation and are reduced to benchmark levels when mitigation occurs. Participants whose offers fall into these higher bands may have legitimate concerns that existing conduct test thresholds do not fully reflect their operational or business conditions. In such circumstances, participants are encouraged to engage with the IMM to discuss potential adjustments, including benchmark overrides, as described in Appendix A of the ISO-NE Tariff.

Over-mitigation

One area where the mitigation design shows fault arises when price impact thresholds fell below \$3/MWh. In these instances, mitigation tended to occur under relatively benign system conditions when market power is typically not a concern, suggesting a risk of over-mitigation that does not advance the core objectives of the framework. These outcomes indicate that very low impact thresholds are less effective at distinguishing between competitively meaningful and inconsequential price effects. Instances of impact test failures at impact prices below \$3/MWh (blue) and above \$3/MWh (purple) are shown in Figure 7-4.

Figure 7-4: Percent of Hours with Impact Test Failure



During the first year, there were impact test failures in 1.6% of hours, leading to mitigation on 63 days. Of those hours, 28% occurred when the impact test threshold and evaluated price difference were below \$3/MWh. Hours with price impact violations occurring at thresholds of \$3/MWh or less were associated with expected real-time LMPs below \$29/MWh.⁹⁵ This pattern suggests these conduct/impact violations occurred during relatively benign system conditions, when the exercise of market power was less likely to raise concerns. For reference, in hours where the violations occurred at thresholds greater than \$3/MWh, the expected real-time LMP averaged \$111/MWh.

⁹⁵ The ISO started producing an expected real-time LMP as part of the implementation of the DA A/S market.

Section 8

GMM Performance

This section assesses the performance of the ISO’s statistical model that is used to estimate several key values associated with the DA A/S market.

Key Takeaways

Over the first year of DA A/S, the GMM understated real-time LMPs on average. Model performance reflected systematic under forecasting bias, with observed values frequently falling in the upper percentiles of the predictive distributions. This bias carried through to expected closeout values, which were also understated relative to realized outcomes.

We encourage the ISO to continue to invest in its modeling tools and processes to ensure that expected real-time energy prices and closeout costs better track prevailing market conditions.

8.1 Expected Real-time LMP

To calculate key DA A/S market values, the ISO developed a statistical model of real-time LMPs that depends on a set of explanatory variables known in advance of the day-ahead market (e.g., load forecast, gas price).⁹⁶ The statistical model is a Gaussian Mixture Model (GMM), which produces a set of normal (i.e., Gaussian) distributions whose means and variances change depending on the values of these explanatory variables.

The GMM distributions are used to compute both the expected real-time LMP, which is used to set the Strike Price, and the expected closeout charge, which forms a key part of a resource’s benchmark level that is used in DA A/S mitigation. These values represent means that are determined by integrating over the full range of price outcomes. Therefore, these values are not expected to match realized outcomes on an hour-by-hour basis. However, for a well-calibrated model, the *average* expected values should converge to the *average* realized values over a sufficiently large sample period.

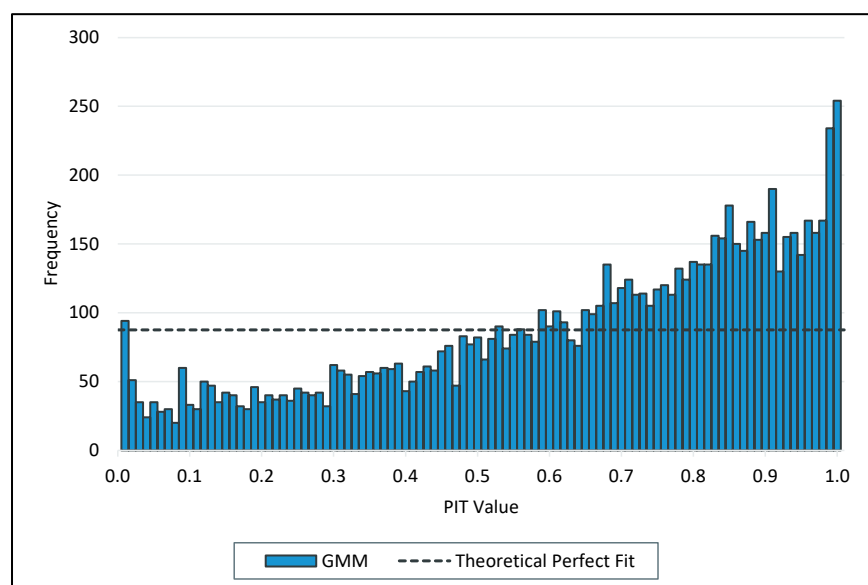
Over the first year of the DA A/S market, we found that the GMM tended to underestimate the real-time LMP. Over this period, the average expected real-time LMP from the GMM was \$60.06/MWh, while the average realized real-time LMP was \$67.63/MWh, indicating a \$7.57/MWh average underprediction bias.

This bias is consistent with evidence that the GMM underestimated the right tail of the real-time LMP distribution. To evaluate the fit of the GMM distributions (which produce the expected real-time LMP) to the true distribution of observed pricing outcomes (realized real-time LMP), we use a probability integral transform (PIT) histogram. The PIT value is defined as the percentile of the

⁹⁶ More information about the model that the ISO uses to forecast the real-time LMP can be found in the ISO’s Day-Ahead Ancillary Services Monthly Real-Time LMP Modeling Memo, available at <https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/DA-A/S-monthly-memo>.

realized outcome under the GMM forecast distribution.⁹⁷ Figure 8-1 shows the histogram of PIT values for all hours during the first year of DA A/S.

Figure 8-1: Probability Integral Transform (PIT) Histogram, All Hours



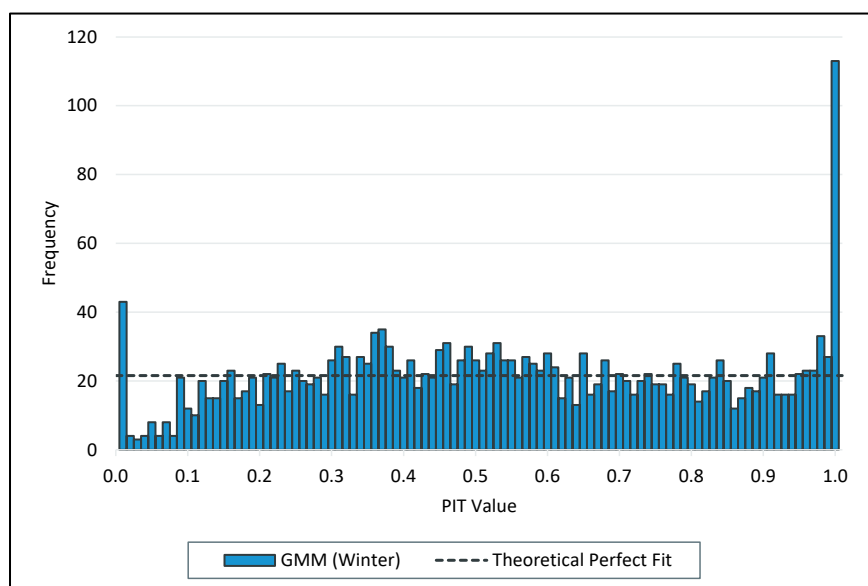
The empirical distribution of PIT values in Figure 8-1 provides a visual assessment of the model fit. The dashed line represents the uniform expected height of the histogram bars for a theoretical model that is perfectly well-calibrated at every percentile.⁹⁸ In contrast, the GMM distribution exhibits a pronounced right skew, with the bulk of the histogram mass falling in the higher percentiles. In particular, approximately 250 hours fell above the 99th percentile of the GMM distribution, over twice as many as expected under a model that perfectly captures the likelihood of observed outcomes. This heavy concentration of prices at high PIT values (and corresponding deficiency of observations at low PIT values) suggests that the GMM understated the probability of high-price outcomes.

Seasonal analysis shows similar patterns throughout most of the year, except for winter. Figure 8-2 shows that winter PIT values were more consistent with a uniform distribution in the middle percentiles but exhibited pronounced spikes in both tails. This increased frequency of observations at PIT ~ 1 ($n=113$) and PIT ~ 0 ($n=43$) indicates that, during winter, the model produced distributions that were too narrow to capture the actual variability in real-time LMPs. As a result, the model frequently underpredicted extreme high-price outcomes. It also occasionally produced severe overpredictions of low-price outcomes. Of these 156 extreme percentile outcomes, 51% occurred during Winter Storm Fern.

⁹⁷ For example, if an observed real-time LMP falls at the 50th percentile of the hour's GMM distribution, its PIT value is 0.5.

⁹⁸ A model is well-calibrated if, for any predicted probability, p , the empirical probability of the event actually occurring matches p . In the language of PIT values, a model is well-calibrated at the 50th percentile if 50% of observations have PIT values less than or equal to 0.5 over a sufficiently large sample, i.e., if 50% of the histogram mass falls below PIT 0.5.

Figure 8-2: PIT Histogram, Winter Hours



8.2 Expected Closeouts

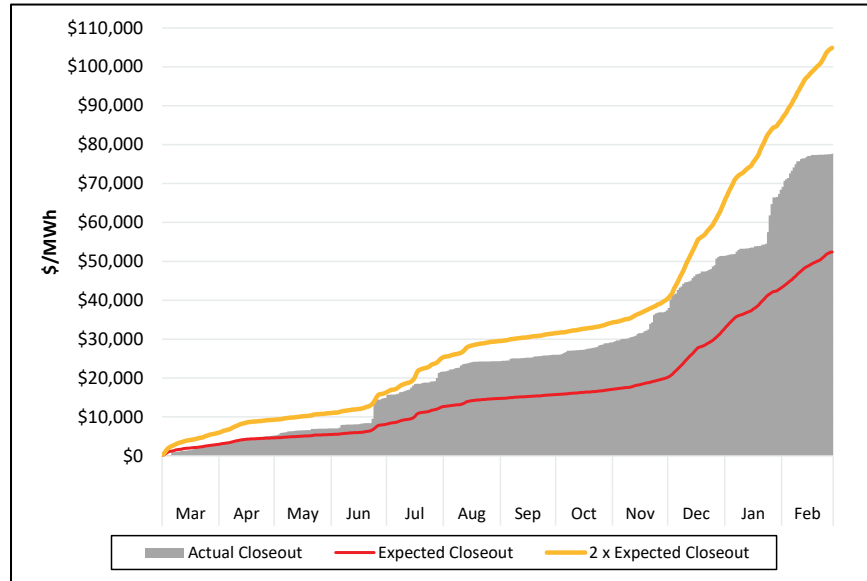
The ISO computes expected closeout charges as the probability-weighted average of potential closeout outcomes, with these probabilities derived from the GMM. Given the model’s tendency to underestimate the upper tail of real-time prices, this bias is expected to be carried through to underestimate expected closeouts as well.

Consistent with this expectation, we found that the GMM underestimated the expected closeouts relative to realized values when viewed on a cumulative basis. This is shown in Figure 8-3 below, which shows the cumulative actual closeout with gray bars and the cumulative expected closeout value produced by the GMM as a red line.⁹⁹ The figure also depicts, in orange, a value that is twice the expected closeout (labeled as ‘2 x Expected Closeout’); this represents the expected closeout portion of the conduct test threshold price that is used in mitigation.¹⁰⁰

⁹⁹ In order to illustrate GMM performance, this expected closeout series does not include any IMM overrides.

¹⁰⁰ For more information about the conduct test threshold price and mitigation, see Section 3.1.4.

Figure 8-3: Actual and Expected Closeouts, Cumulative



We can see that the cumulative actual closeouts, which tend to be more volatile, exceeded the cumulative ISO-produced expected closeouts by a significant margin at the end of the first year of the DA A/S market. Actual closeouts totaled \$78,000/MWh while expected closeouts totaled only \$52,000/MWh. This means that a hypothetical asset that cleared one MWh of DA A/S awards in every hour would have incurred a loss of over \$25,000 if DA A/S clearing prices had been exactly equal to the expected closeouts from the ISO's model.¹⁰¹

To account for estimation error, as well as for reasonable variation in participant expectations of real-time outcomes and in risk premiums, the DA A/S offer mitigation design allows participants to offer up to twice the expected closeout without triggering mitigation. We can see that the cumulative twice expected closeout series does exceed the cumulative actual closeout series at the end of the first year, reaching a year-end total of \$105,000/MWh.

These findings have two important implications. First, when the model produces Strike Prices below prevailing market expectations, the resulting expected closeout values will also be lower, which may prompt the IMM to adjust mitigation values to correct this misalignment, potentially increasing offer prices and day-ahead market costs.¹⁰² Indeed, the IMM performed such adjustments during many high-stress days. Second, implementing a Strike Price floor—consistent with our recommendation to better align the strike price with the short-run marginal costs of

¹⁰¹ It is worth noting that DA A/S clearing prices are not expected to equal the expected closeout for a variety of reasons, one significant cost driver to date being that clearing prices reflect significant opportunity costs.

¹⁰² The relationship between strike price levels and market outcomes is nuanced and requires further study. In particular, while lower strike prices relative to prevailing market conditions increase expected closeout costs and likely increases overall day-ahead costs, however this effect is at least partially offset by higher realized closeout costs.

resources providing ancillary services—offers a meaningful secondary benefit by eliminating forecasting errors below the marginal cost of a combustion turbine.

Even with this change, we continue to encourage the ISO to invest in its modeling tools and processes so that expected real-time energy prices and closeout costs more closely reflect prevailing market conditions. When the expected real-time LMP (plus the \$10/MWh adder) exceeds the proposed floor and determines the Strike Price, it is important that these inputs to option pricing remain aligned with current market conditions.

Section 9

Market Performance Metrics

While previous sections evaluated market costs and competitiveness, this section assesses market performance. Specifically, this section focuses on how well the day-ahead market is preparing the system for what is needed in real time. Consequently, focus in this section is given to price convergence (as an indicator of market efficiency), out-of-market actions, and Net Commitment Period (NCPC) costs. We conclude with an assessment of how DA A/S impacts wholesale revenues streams and potential implications for cost recovery allocation between the E&AS and capacity markets.

Key Takeaways

The first year of DA A/S was associated with a modest increase in the average day-ahead price premium, rising to \$3.81/MWh from \$1.18/MWh, while the median remained largely unchanged, indicating that a small number of high-price events, particularly during stressed periods like July 2025 and January 2026, drove the increase.

Out-of-market commitments have been infrequent in recent years, even before DA A/S, and in the past year have further declined slightly and remained rare.

DASI did not lead to a clear reduction in day-ahead NCPC, as higher revenues from FER and reserves were offset by lower energy prices and ongoing cost recovery needs for marginal units. While DASI may reduce NCPC by avoiding some manual RAA commitments, these potential savings are highly uncertain and likely modest relative to an upper-bound estimate of approximately \$35 million annually. Real-time NCPC declined in categories associated with out-of-merit actions, suggesting improved system preparedness, but the overall impact is relatively small.

Over time, DA A/S revenues may therefore reduce the “missing money” that some resources seek to recover through the capacity market. This is particularly the case for combustion turbine resources. As a result, these revenues are expected to influence capacity-market offer behavior and, ultimately, capacity-market outcomes. Future estimates of energy and ancillary services revenues should also affect Net CONE estimates and the setting of the capacity market’s administrative demand curve. These longer-run effects are not measured in our first-year incremental-cost estimates but are important to understanding the design’s broader economic implications.

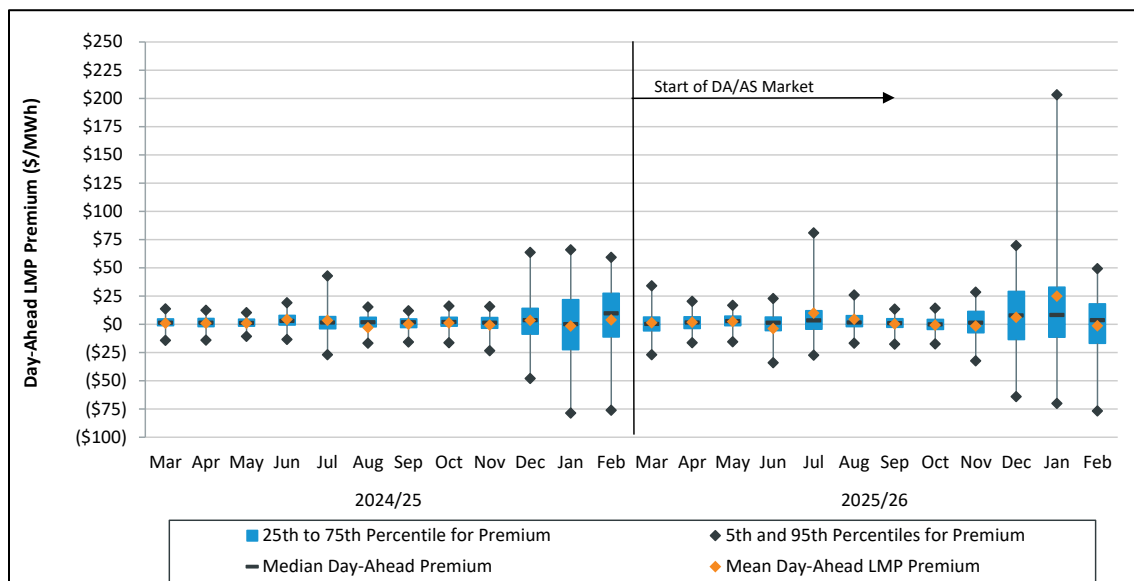
9.1 Price Convergence

Price convergence describes the degree to which prices in the day-ahead and real-time markets align. It is commonly used as an indicator of market efficiency, defined here as achieving the necessary real-time resource commitments at the lowest possible cost. Strong price convergence can indicate that the day-ahead market is effectively anticipating real-time conditions to facilitate efficient and reliable scheduling outcomes.

While both the day-ahead and real-time markets are now co-optimized markets that procure energy and operating reserves, they differ in important ways that can impact price convergence. Reserve procurement in the day-ahead market is based on voluntarily-submitted ancillary services offers, while procurement in the real-time market considers all reserve-capable resources (i.e., is not strictly voluntary) and determines reserve clearing prices solely based on opportunity costs (i.e., there are no reserve offers). Additionally, the incorporation of the Forecast Energy Requirement Price (FERP) as a second price for (physical) energy adds complexity to what had previously been a comparison simply between LMPs.¹⁰³

LMP convergence can be seen in Figure 9-1, which shows the distribution of the day-ahead price premium (i.e., day-ahead LMP minus real-time LMP) at the Hub by month between March 2024 and February 2026 using a box-and-whiskers diagram. This figure also shows the average monthly day-ahead LMP premium (orange marker).

Figure 9-1: Day-Ahead vs. Real-Time LMP Convergence



The day-ahead premium averaged \$3.81/MWh over the first year of DA A/S, up from \$1.18/MWh in the year prior. However, the median day-ahead premium remained similar, increasing from \$1.84/MWh to \$1.93/MWh over the same period. The difference between the average and median highlights that the day-ahead premium was right-skewed, with some high observations pulling the mean up. This can be seen in the figure above; in fact, the average day-ahead premiums in July 2025 and January 2026 were the two months with the highest premiums since the beginning of the Standard Market Design.

¹⁰³ ISO-NE expected that, over time, the day-ahead and real-time LMP would converge under this new market design as load-serving entities cleared more demand in the day-ahead market to take advantage of lower day-ahead LMPs when the FERP bound. See pages 54-56 of the testimony of Ben Ewing in support of DASI contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

While the day-ahead premium increased in the year following the implementation of DA A/S, it is important to consider the factors that contribute to a day-ahead premium:

- Under DA A/S, the day-ahead market produces a more robust and flexible operating plan for real time than with the previous market construct. The cost of procuring this additional flexibility is reflected in day-ahead energy and ancillary service prices.
- Because not all operating reserve capability is offered into the day-ahead market, there can be less economic capacity available to meet load and reserve requirements than in real time. Co-optimization can further raise day-ahead LMPs when efficient generators are used to satisfy reserve requirements rather than energy, resulting in higher-cost resources setting the price. This effect becomes more pronounced under stressed conditions, when the energy supply curve is steeper.
- Renewable resources often offer in a way that results in only a portion of expected real-time output clearing day-ahead. As a result, higher-cost generation may be dispatched in the day-ahead market to meet the FER (also impacting the LMP) and later displaced by lower-cost renewable generation in real time.
- Increased long-lead time commitments and stronger performance incentives under DA A/S place downward pressure on real-time LMPs, reducing reliance on higher-cost real-time-only generation.

9.2 Out-of-Market Actions

Out-of-market actions can reflect both market performance and reliability. If DA A/S improves the day-ahead operating plan, one expected benefit is fewer supplemental commitments through the reserve adequacy analysis (RAA) process or manual operator actions.¹⁰⁴ Because these actions are infrequent, annual averages can obscure the magnitude of actions taken on stressed days. We therefore report a time series, highlighting commitments on the top 12 highest cost DA A/S days¹⁰⁵, all of which occurred during Winter Storm Fern.

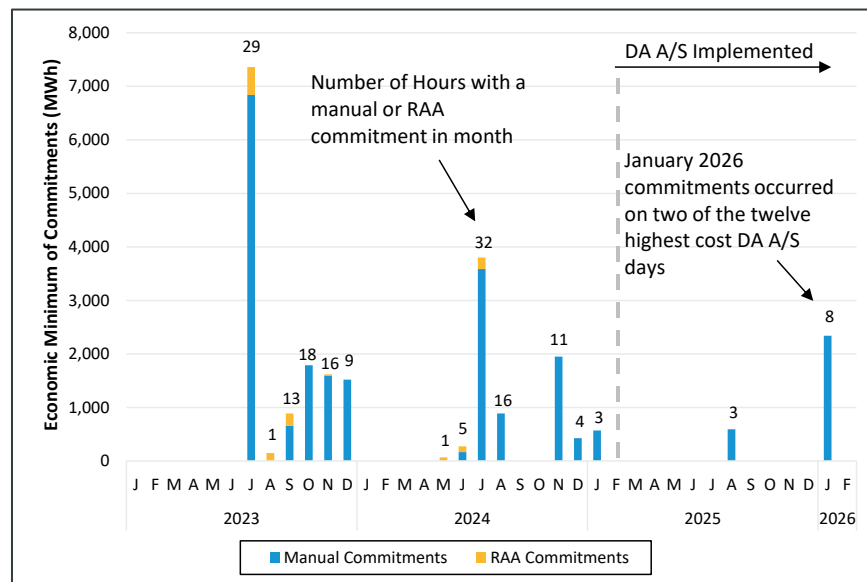
Our evaluation indicates that DA A/S has potentially reduced manual commitments and RAA commitments, although the impact is slight due to the low quantity of these committed MWs pre-DA A/S.¹⁰⁶

¹⁰⁴ RAA commitments include commitments made post-day-ahead clearing to ensure adequate reserves. These commitments can happen during the operating day or the previous day after the day-ahead market is run. For more information, see ISO-NE operating procedure titled *Perform Reserve Adequacy Analysis*, available here: https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/sysop/rt_mkts/sop_rtmkts_0050_0010.pdf

¹⁰⁵ Twelve days, most of which were associated with multi-day periods of stressed system conditions, accounted for approximately 50% of incremental costs of DA A/S in its first year. See Section 4.2.

¹⁰⁶ Manual commitments for capacity and locational support are included in this analysis. Excluded commitments include manual commitments for auditing, special constraint resources that are requested by transmission owners or distribution companies, and manually-initiated economic commitments.

Figure 9-2: RAA and Manual Capacity and Locational Commitments



Manual and RAA commitments to provide capacity or local reliability support remained rare in both the pre- DA A/S and DA A/S periods. Despite the small number of manual and RAA commitments, there was a decrease when DA A/S was implemented. Since then, manual commitments have occurred in only 11 total hours, adding up to only 2,900 total MWh of committed energy (at EcoMin). About 2,300 MWh of those commitments occurred during two of the twelve highest cost DA A/S days, both in January of 2026. In 2024, there were 7,400 MWh of energy at EcoMin committed either manually (7,000 MWh) or in the RAA process (400 MWh). As a result, while DA A/S appears directionally consistent with fewer out-of-market commitments, the effect is relatively small in the context of prior years' performance.

9.3 Impact on NCPC (Uplift)

This section evaluates the impact of DA A/S on Net Commitment Period Compensation (NCPC) through both direct day-ahead effects and indirect real-time effects. The analysis yields three key takeaways:

- **No clear reduction in day-ahead NCPC from increased revenues:** Higher FER payments did not translate into lower day-ahead uplift, as they were largely offset by lower day-ahead LMPs and ongoing cost recovery needs for marginal units; day-ahead NCPC increased modestly in nominal terms following the implementation of DA A/S.
- **Potential reductions from avoided manual commitments are limited and uncertain:** While DA A/S may reduce NCPC by limiting reliance on RAA commitments, estimated reductions are highly sensitive to assumptions and are bounded at approximately \$35 million annually, with more realistic outcomes likely significantly lower (e.g., roughly \$11 million if limited to peak conditions).
- **Real-time NCPC declined in plausibly affected categories:** Payments associated with out-of-merit actions fell following DA A/S implementation, consistent with improved system preparedness; simple counterfactual estimates suggest roughly \$3 million in real-

time NCPC reductions over the first year, although these results are based on correlations rather than a true counterfactual.

Together, these findings indicate a shift in how system costs are recovered—from out-of-market uplift, as well as Forward Reserve payments, to market-based mechanisms—with total NCPC reductions estimated to be no more than approximately \$38 million in the first year.

Day-Ahead NCPC Impacts

In theory, DA A/S affects day-ahead NCPC through two related channels: increased generator revenue streams and changes in commitment patterns.

First, DA A/S introduces additional compensation through the Forecast Energy Requirement price (FERP) and FRS revenues, which increase total day-ahead revenues to generators. To the extent that compensation under the combined DA LMP, FERP, and FRS revenue exceeds what generators would have earned under DA LMP alone, DA A/S may reduce the need for economic uplift payments.

Second, the FER constraint modifies commitment outcomes in the day-ahead market. When the market clears with insufficient physical supply to meet forecast load, the FER constraint induces additional generator commitments. These commitments can improve system preparedness and reduce the need for manual commitments through the Reserve Adequacy Analysis (RAA) process. In principle, this mechanism can reduce NCPC by shifting compensation from uplift to market-based revenues (DA LMP + FERP).

In practice, observed outcomes do not show an immediate reduction in day-ahead NCPC following the implementation of DA A/S. In the year prior to implementation, day-ahead economic NCPC payments totaled approximately \$4.4 million (0.06% of energy market payments), compared to approximately \$5.4 million (0.07%) in the first year of DA A/S. While this is not a full counterfactual analysis of what DA NCPC would have been absent DA A/S, the nominal increase in NCPC indicates that any moderating effects from enhanced revenue streams were offset by other factors.

Several factors help explain the lack of an immediate decline in day-ahead NCPC. First, generator operating costs were generally higher after DA A/S than before due to higher fuel prices in 2025, pushing up NCPC payments for reasons unrelated to DA A/S. Second, economic NCPC payments are often driven by units that are only marginal for part of their commitment periods. These units require uplift to recover startup costs, no-load costs, and unrecovered costs during non-marginal intervals. While DA A/S changes pricing and commitment decisions, it does not eliminate these cost recovery dynamics.

In addition, DA A/S -induced commitments may increase exposure to uplift in some cases. Incremental commitments driven by the FER constraint tend to involve relatively higher-cost units. If these units do not fully recover their costs through energy and reserve revenues, they may require larger NCPC payments. As a result, DA A/S may simultaneously reduce and increase uplift through different mechanisms, leading to ambiguous net effects on day-ahead NCPC.

Averted RAA Commitments

A second potential source of day-ahead NCPC reductions arises from the avoidance of manual commitments through the RAA process. To evaluate this effect, we identify incremental DA A/S commitments—defined as commitments present in the “DA A/S” simulation that do not occur in a counterfactual “No DA A/S” simulation¹⁰⁷—and estimate their total cost based on startup, no-load, and energy-to-EcoMin costs.¹⁰⁸

To translate these costs into potential NCPC reductions, we assume that all incremental DA A/S commitments would otherwise have been manually committed through the RAA process. Under this assumption, the relevant comparison is between (1) their realized compensation under day-ahead markets and real-time energy revenues, and (2) the uplift that would have been required if these commitments had been made manually.

This approach yields an upper bound on the NCPC reductions attributable to DA A/S. Importantly, the underlying assumption is likely generous. The FER constraint tends to understate expected real-time renewable generation and may therefore induce more commitments than operators would have implemented manually. In addition, historical RAA commitment levels have been low even prior to DA A/S, suggesting that not all incremental commitments would have been necessary in practice.

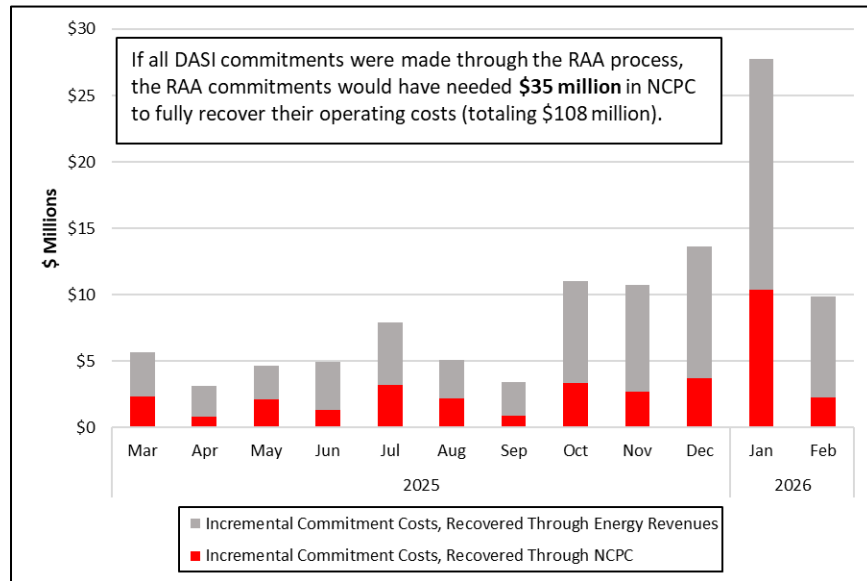
Under this bounding assumption, the total cost of incremental DA A/S commitments was approximately \$108 million in the first year. After accounting for roughly \$72 million in real-time energy revenues, the implied NCPC that would have been incurred under manual commitments is approximately \$35 million. This represents the maximum potential real-time NCPC reductions from avoiding RAA-based commitments.

In Figure 9-3 below, we show the estimated reductions in RAA commitment-driven NCPC. A large share of these estimated reductions is concentrated in a limited number of high-cost days, particularly during Winter 2026 when generator operating costs were elevated. The twelve most expensive DA A/S days account for approximately 30% of total estimated NCPC reductions under this framework. If operators would only have undertaken manual commitments during such high-stress conditions, then the realized NCPC reductions would be substantially lower—on the order of approximately \$11 million.

¹⁰⁷ See Section 4.2 for more information about these simulations.

¹⁰⁸ Note that the DA A/S influence on the commitment mix is not simple – it is not generally true that, for every generator committed under DA A/S, the same generator would have been committed without DA A/S. This analysis identifies the incremental manual commitments that would have been needed without DA A/S to ensure that *at least* the same DA A/S-driven generator mix was online in every hour.

Figure 9-3: Estimated NCPC Cost of Averted RAA Commitments



Taken together, these results suggest that while DA A/S has the potential to reduce NCPC through avoided manual commitments, the magnitude of these reductions is highly sensitive to assumptions about operator behavior. Given historically low levels of RAA commitments, the realized reductions are likely significantly smaller than the upper-bound estimate.

Other Real-Time NCPC Impacts

DA A/S may also affect NCPC outcomes indirectly through changes in real-time system conditions. By increasing day-ahead commitments, DA A/S can improve system preparedness and reduce the likelihood of tight operating conditions that require out-of-market interventions.

The categories of real-time NCPC most likely to be affected include: (1) out-of-merit fast-start commitments, (2) manual dispatches to create “eco surplus,”¹⁰⁹ and (3) real-time manual commitments of long lead-time units. These actions are typically undertaken to maintain sufficient operating reserves or manage system reliability during periods of tight supply-demand balance.

Following DA A/S implementation, NCPC payments and associated out-of-merit generation in these categories declined. Average seasonal NCPC payments across these categories fell from approximately \$3.8 million before DA A/S to \$2.9 million after implementation, corresponding to a 34% reduction. This decline coincided with a reduction in out-of-merit generation, from approximately 42 MW per hour to 33 MW per hour on average.

¹⁰⁹ When system reserves are tight, operators may manually dispatch long lead-time units up in advance of peak load hours to create additional reserve capability; this is referred to as creating “Eco Surplus.” Such out-of-merit dispatches incur significant NCPC credits but are less likely to occur when DA A/S clears such long-lead time units at higher levels in the day-ahead market.

Although these changes are consistent with expected DA A/S outcomes, they reflect correlation rather than causation. Real-time NCPC outcomes depend on a wide range of factors, including load realizations, generator outages, fuel prices, and system conditions more broadly. In the absence of a true real-time counterfactual, it is not possible to attribute these changes solely to DA A/S.

Nevertheless, a simple counterfactual framework can be used to estimate the potential magnitude of real-time impacts. Assuming that out-of-merit generation would have continued at pre- DA A/S levels in the absence of DA A/S, and holding NCPC rates (\$/MWh) constant, estimated NCPC payments for these categories would have been approximately \$14.4 million over the first year, compared to \$11.5 million of actual payments. This implies a roughly \$3.0 million reduction in NCPC attributable to changes in commitment patterns associated with DA A/S.

Summary

Overall, the impact of DA A/S on NCPC payments is mixed and reflects the interaction of several offsetting mechanisms. There is no clear evidence that DA A/S reduced day-ahead NCPC through increased revenue streams alone, as higher FER payments were partially offset by lower day-ahead LMPs and continued cost-recovery needs for marginal units. While DA A/S may not have substantially reduced aggregate NCPC, it changes how costs are recovered by shifting compensation from out-of-market uplift to market-based pricing mechanisms, which represents an important economic benefit of the design.

Notably, other RTOs experienced significant uplift during Winter 2026, while uplift declined in New England during the same period—coinciding with the first winter of DA A/S implementation.¹¹⁰ However, differences in uplift rules, operating conditions, and market structures across regions limit direct comparisons. This analysis suggests that New England could have achieved a similar commitment mix through manual interventions at an estimated annual cost of approximately \$35 million in NCPC (including roughly \$10 million in January 2026). At the same time, given historically low levels of manual commitments and relatively stable system conditions, it is unlikely that New England would have experienced the more extreme uplift outcomes observed in other RTOs even in the absence of DA A/S.

9.4 Revenues Source Mix and Implications

The introduction of the DA A/S market provides explicit compensation for reserve capability, with implications for longer-term resource incentives. While it is too early to observe direct impacts on long-term resource economics (entry, exit, retention), IMM analysis indicates that DA A/S revenues represent a meaningful share of total revenues for fast-start resources, improving the economics of such resources by explicitly rewarding flexibility.

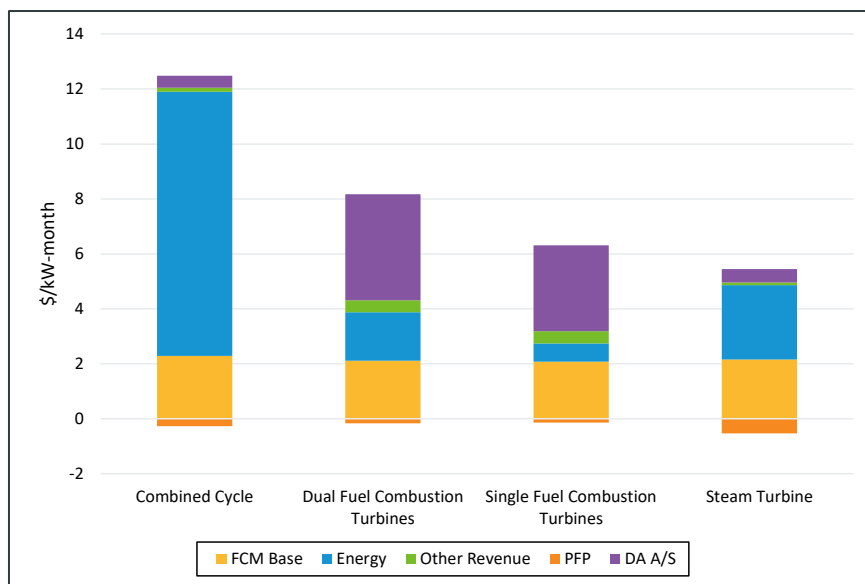
Over time, DA A/S revenues may therefore reduce the “missing money” that some resources seek to recover through the capacity market. As a result, these revenues are expected to influence

¹¹⁰ For example, PJM had over \$750 million in uplift in January 2026 alone. See the PJM markets report for January 2026, available at <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2026/20260219/20260219-item-07a---1-pjm-market-operations-report---presentation.pdf>.

capacity-market offer behavior and, ultimately, capacity-market outcomes. Future estimates of energy and ancillary services revenues should also affect Net CONE estimates and the setting of the capacity market's administrative demand curve. These longer-run effects are not measured in our first-year incremental-cost estimates but are important to understanding the design's broader economic implications.

Figure 9-4 below shows the net revenue for different technology types categorized by the following revenue sources: base capacity from the Forward Capacity Market, PFP, energy, DA A/S, and other revenue.

Figure 9-4: Net Revenue by Technology Type



DA A/S did not contribute significantly to combined-cycle profitability given that they primarily earn revenues by providing energy rather than reserves. Steam turbines also did not have significant DA A/S revenue because they are non-fast-start and cannot provide reserves from an offline state. Combustion turbines received about half of their revenues from DA A/S during the year (combined, \$3.53/kW-mo of a total of \$7.19/kW-mo). DA A/S payments exceed revenues from the now defunct Forward Reserve Market, which averaged about \$1.30/kW-month in 2023 and 2024.

Section 10

Reliability Outcomes

The evaluation of reliability outcomes during the first year of DA A/S is based on a structured set of metrics designed to assess whether the design has led to improved system preparedness and performance. Because reliability outcomes are influenced by system conditions, fuel and energy prices, and a broad range of market-based incentives (e.g., energy prices, Pay-for-Performance), it is difficult to assign causality to DA A/S incentives. This analysis focuses on behavioral and operational indicators that are consistent with the design objectives, including resource availability, day-ahead plan flexibility, and gas scheduling. These indicators are designed to provide a framework for evaluating reliability value over time.

Key Takeaways

Although it is difficult to assign causality to DA A/S given the broad range of market incentives at play over the first year, certain reliability-based metrics for DA A/S resources appear promising.

Additional revenue sources to combustion turbines providing day-ahead reserve products has coincided with improvements to availability. Additionally, more fast-starts are allocated DA A/S obligations, rather than energy, resulting in a day-ahead schedule that has more longer-lead-time units, and fast-start units ready to respond to unexpected events.

Finally, we did not observe any strong gas scheduling behavioral response to DA A/S incentives, although the majority of participants who responded to our survey indicated that DA A/S has influenced their fuel procurement decisions across several fuel types.

10.1 Commitment Differences

The commitment and dispatch outcomes in the day-ahead market may not always reflect expected physical real-time conditions. For example, load-serving entities may clear less demand than the ISO's load forecast, resulting in less physical energy supply clearing in the day-ahead market than is expected to be needed in real time. When this happens, there is a day-ahead "energy gap," which we define here as (1) the expected real-time load less (2) the amount of day-ahead energy awards on physical resources (i.e., excluding virtual supply).¹¹¹

A key design change under DA A/S was the explicit incorporation of the ISO's load forecast into the day ahead market clearing process. The Forecast Energy Requirement (FER) constraint ensures that sufficient physical capability is procured in the day ahead market to meet forecasted load. This requirement may be satisfied through day-ahead energy awards from physical supply resources as

¹¹¹ Under this definition, a negative "energy gap" value indicates that the quantity of cleared physical energy *exceeded* the load forecast.

well as awards of Energy Imbalance Reserve (EIR). Consequently, “the energy gap is closed by procurement of additional energy and EIR.

Day-Ahead Energy Gap

Our evaluation indicates that DA A/S has likely decreased the energy gap, especially at the tail end of the distribution (i.e., DA A/S appears to reduce the incidence of extreme energy gaps). The following table shows energy gap statistics comparing pre-DA A/S times (March 1, 2023-February 28, 2025) with Post-DA A/S implementation (March 1, 2025-February 28, 2026).

Table 10-1: Energy gap statistics pre- and post-DA A/S implementation, in MW

Time Period	Mean	75th Percentile	90th Percentile	95th Percentile	99th Percentile
DA A/S	(94)	198	395	540	800
Pre-DA A/S	(132)	234	542	721	1,079
Difference	38	(36)	(147)	(181)	(278)

Consistent with expectations, DA A/S has reduced the frequency of extreme energy gaps. Pre-DA A/S, the 90th percentile was about 540 MW – a level corresponding to the 95th percentile post-DA A/S implementation. This outcome is expected because the FER constraint enforces a physical supply constraint that ensures physical supply cleared plus EIR in the day-ahead market is adequate to deliver forecasted real-time energy. The enforcement of the additional constraint results in lower energy gaps since DA A/S was implemented.

Fast-Start Commitment in the Day-Ahead Energy Mix

We find that fast-start units made up a smaller portion of the day-ahead generation mix, in favor of longer-lead-time generators, since DA A/S was implemented. The shift indicates that fast-start units are being held for reserves more often after DA A/S implementation, an outcome that is also evident in our simulation studies.¹¹² The following table shows the percentage of day-ahead cleared MWs for energy by startup + notification time, comparing pre- DA A/S times (March 1, 2023-February 28, 2025) with post- DA A/S implementation (March 1, 2025-February 28, 2026).

¹¹² Fixed generation mix is estimated using the percentage of the total Economic Minimums of units committed in the day-ahead market. Calculations using Economic Maximum were similar.

Table 10-2: Day-Ahead Generation by Startup plus Notification Time

Startup plus Notification Time	All Hours			Top 3% Load Hours			Top 12 Days
	Pre- DA A/S	DA A/S	Delta (% Points)	Pre- DA A/S	DA A/S	Delta (% Points)	
Less Than 30 Minutes	30%	19%	-11	25%	18%	-7	16%
Between 30 Minutes and 1 Hour	2%	1%	-1	2%	2%	0	1%
Between 1 and 2 Hours	1%	1%	0	1%	1%	0	1%
Between 2 and 4 Hours	0%	0%	0	0%	0%	0	0%
Between 4 and 8 Hours	44%	52%	8	46%	49%	4	51%
Between 8 and 16 Hours	10%	12%	1	16%	19%	3	19%
Longer than 16 Hours	12%	15%	3	10%	11%	0	12%

Since DA A/S was implemented, the percentage of fixed (i.e., up-to EcoMin) generation from fast-start units has decreased by about 11 percentage points across all hours as some generators now clear DA A/S awards. The fast-start fixed MWs have been offset by longer-lead time generation, with startup + notification time greater than 4 hours. In the highest load hours, as well as the twelve days with the highest DA A/S costs, fast-start generation makes up a smaller percentage of fixed generation, with the longer-lead time generation increasing, when compared with all hours. This indicates that, post- DA A/S, the day-ahead schedule may be more flexible, with more flexible units held in reserve to help respond to unexpected real-time events.

Long Lead-Time Commitment Differences in Simulated Outcomes

Simulated day-ahead market clearing results without DA A/S constraints can directly show the impacts of DA A/S on the day-ahead supply mix. In particular, this can be used to show how DA A/S increased the commitment and dispatch of long-lead time units in the day-ahead market to create reserve availability. Table 10-2 below shows the commitment of economic, long-lead-time units between DA A/S outcomes and simulated non-DA A/S counterfactuals.^{113,114}

Table 10-3: Economic Long Lead-Time Commitments With and Without DA A/S

Time	Average Long Lead-Time Generator MWh		
	Non-DA A/S	DA A/S	Difference
All Hours	5,283	5,359	+ 76 (1%)
Top 12 Days	6,766	6,865	+ 99 (1%)

¹¹³ For this table, we define long lead time units as any generator that offered a combined startup and notification time greater than 4 hours. We include only economic generation, excluding self-schedules or other must-run generation.

¹¹⁴ While the table uses the terms “Non-DA A/S” and “DA A/S” to denote scenarios, note that the “DA A/S” scenario does not reflect the actual DA A/S outcomes, but rather reflects the benchmark scenario in our simulation software. Using this scenario as a comparison rules out any outcomes that are driven by differences in market clearing software. However, note that the DA A/S benchmark scenario performs well and accurately reflects true DA A/S outcomes.

DA A/S increased the amount of long lead-time generation that cleared the day-ahead market, with an average increase of 76 MW (1%) relative to day-ahead market results without DA A/S constraints. Notably, while this table shows *all* cleared long lead-time energy, this result holds even when considering only *commitment* energy up to generators' economic minimum limits. Therefore, DA A/S materially increased committed long lead-time generation ahead of real-time operating conditions.

The impacts of DA A/S on the commitment and dispatch of long lead-time generation were relatively high on the Top 12 days. On average across these days, DA A/S resulted in a 99 MW increase in economic long lead-time generation that cleared the day-ahead market.

10.2 Fuel Scheduling and Management

The DA A/S market strengthens preparedness incentives in the period between day-ahead clearing and real-time operations with an expectation that resource owners are more likely to ensure fuel is available when needed to cover their DA A/S obligation. For gas-fired resources, DA A/S positions can increase the value of securing fuel in advance.¹¹⁵

This analysis focuses on:

- gas nominations pre- and post-DA A/S implementation,
- the share of gas nominated day-ahead, and
- energy preservation for batteries and pump storage units.

The empirical results suggest that, at a system level, resources have not altered their approach to securing fuel based on DA A/S positions. The following table shows scheduled gas generation, estimated expected gas consumption associated with the day-ahead cleared energy offer, and DA A/S positions, across all seasons, and in the top 12 days with the highest DA A/S costs.¹¹⁶

¹¹⁵ Specifically, a resource has an incentive to procure fuel in advance when the expected reduction in closeout exposure exceeds the incremental cost of arranging fuel, including the risk that the gas is not needed and must be resold or otherwise managed.

¹¹⁶ Gas required to deliver day-ahead energy awards is estimated using generator input-output curves and startup gas estimates associated with the day-ahead schedules. Scheduled gas represents timely and evening gas nomination estimates from an external vendor. Both the estimated gas required to deliver day-ahead energy and the hourly scheduled gas are estimates based on the best available data.

Table 10-4: Gas scheduling pre- and post-DA A/S implementation

Time Period	DA A/S Status	Hourly Day-Ahead Cleared Gas Generation (MW/hour)	Hourly DA A/S Position (MW/hour)	Hourly Estimate Gas Required to Deliver Day-Ahead Energy (MMBtu)	Hourly Scheduled Gas (MMBtu)	(Scheduled Gas) / Gas Required to Deliver Day-Ahead Energy
Spring	Pre-DA A/S	5,324		39,852	43,274	109%
	DA A/S	5,416	834	40,649	43,868	108%
Summer	Pre-DA A/S	8,258		62,363	62,296	100%
	DA A/S	8,741	989	65,949	67,799	103%
Fall	Pre-DA A/S	6,968		52,399	53,251	102%
	DA A/S	7,139	1,052	53,384	49,954	94%
Winter	Pre-DA A/S	5,474		40,617	40,308	99%
	DA A/S	6,993	788	50,867	48,056	94%
All Seasons	Pre-DA A/S	6,510		48,831	49,806	102%
	DA A/S	7,072	916	52,720	52,443	99%
Top 12 Days		8,611	1,117	64,903	66,115	102%

In the two years before DA A/S, gas generators scheduled 2% more gas than estimated gas consumption of their day-ahead schedules (All Seasons, Pre-DA A/S, rightmost column). This number declined slightly, to 99% of estimated gas in the first year of DA A/S despite DA A/S positions that amounted to about 13% of day-ahead energy positions. Summer was the only season in which gas generator scheduled more per MMBtu of estimated day-ahead gas consumption after DA A/S implementation than in pre-DA A/S periods.

In the top 12 days, gas generators scheduled 2% more fuel than was necessary to cover their day-ahead energy position. DA A/S did not necessarily cause the subtle shifts in gas scheduling we observed; it is likely that changes in gas costs, OFOs, gas constraints and overall increases in demand in all of the seasons led to the shift. However, we did not find strong evidence that gas generators scheduled additional gas to cover their DA A/S positions, with similar amounts of scheduled gas per day-ahead cleared generation MW pre- and post-DA A/S implementation.

As a counter point to the above empirical analysis, we note that in response to our survey, six out of 16 respondents with gas generators in their portfolios indicated that they procured fuel in response to a DA A/S positions.

For **stored-fuel resources**, including batteries and pumped storage resources, the design may impact both generation timing and fuel preservation incentives. Resources may be incentivized to defer generation in earlier hours to maintain flexibility for periods when DA A/S-related obligations introduce risk of fuel-related outages. During its first year, the impact of DA A/S on overall storage generation profiles appears small given that about 89% of storage generation is produced by assets that do not have a DA A/S obligation during the day and another 5% is produced on days in which

the DA A/S obligation occurs earlier in the day (so generators are available to cover if needed without altering their optimal schedule).

Despite these data limitations, the average storage generator without a DA A/S obligation ran more often during the morning ramp in hours ending 7-9 (13% of generation) than those with a late-day DA A/S obligation (3%).¹¹⁷ On the twelve highest-cost DA A/S days, the difference was more pronounced; storage generators with late-day DA A/S obligations produced zero MWs in hours ending 7-9, compared with 8% of generation for resources without a DA A/S obligation.

10.3 Resource Availability and Performance

Our evaluation of resource availability and performance focuses on outages rates across different technology types. The following table shows the total percentage of seasonal claimed capability out-of-service. The outages include planned and forced outages. The column on the far right shows estimated capacity out of service due to oil or gas availability during the Top 12 days with the highest incremental cost from DA A/S.¹¹⁸

Table 10-5: Total Percentage of Accredited Capacity Out-of-Service

Technology	Pre-DA A/S	DA A/S	Difference (% Points)	Top 12 Days	Top 12 Days – Due to Fuel Availability
Steam Turbines	21%	25%	4	20%	0%
Combustion Turbines	18%	11%	-7	11%	3%
Combined Cycles	12%	14%	2	9%	2%
Total: Above Technology Types	14%	15%	1	11%	2%

The combined outage rates of steam turbines, combustion turbines, and combined cycles across all hours was similar pre- and post-DA A/S, from 14% of claimed capability to 15% of claimed capability.

Outage rates decreased substantially for combustion turbines (an average of 18% of capacity out-of-service vs. 11% post DA A/S implementation). While it is difficult to isolate the incremental effect of DA A/S from other market incentives, it is likely that DA A/S revenues played a part in the reduction for combustion turbines, which receive over half of their net revenue from DA A/S between (discussed in the next section). The availability incentives could also have been influenced by higher energy prices; however, energy price incentives are shared by combined cycles and steam turbines, which did not see an increase in availability.

The design provides incentives for timely return to service by providing a revenue stream for units that are less often called upon for energy but are willing to provide reserves. Despite the additional incentives to procure fuel, about 3% of combustion turbine capacity was out of service during the

¹¹⁷ Late day in this context is a generator that has a DA A/S obligation in hour ending 17 or later.

¹¹⁸ The IMM estimated out of service MWs using outage data reported to the ISO. The values represent estimates due to the nature of the data.

12 highest cost DA A/S days due to depleted oil inventories, and 2% of combined cycle capacity was unavailable due to gas availability. Due to the energy dynamics in this especially-tight winter it is not possible for us to conclude at this time that DA A/S improved fuel procurement or fuel retention.

While the reduction in combustion turbine outage rates is directionally consistent with DA A/S incentives and revenues, the evidence is insufficient to attribute causality. One hypothesis is that higher DA A/S revenues may have led some fast-start resources to defer maintenance, improving short-run availability. Continued monitoring is needed to distinguish such maintenance timing effects from other drivers, e.g., weather, dispatch patterns, etc.

Section 11

Survey Results

The IMM conducted an online survey of market participants in February 2026 to better understand how the market reforms under DA A/S were being experienced by participants firsthand. The survey covered topics including participant understanding of the market, offer behavior, risk perceptions, and views on market performance. In total, 42 respondents completed the survey, yielding a 36% response rate. Of those, 76% indicated they were active in the DA A/S market. The survey therefore includes the perceptions of some participants not offering into the DA A/S market but primarily reflects the experience of those actively engaged in the market.

Key Takeaways

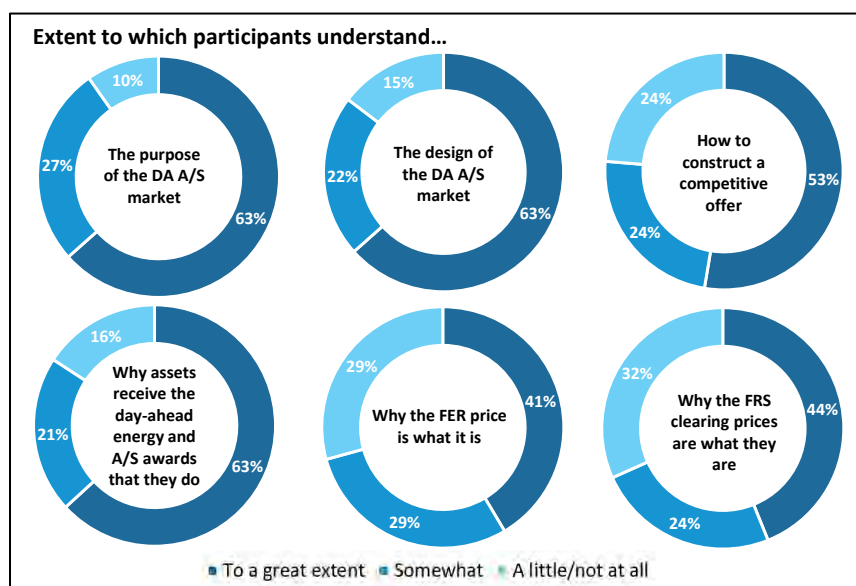
The survey results suggest that many participants are responding to the incentives embedded in the design, particularly with respect to fuel procurement and operational readiness. However, market complexity and uncertainty continue to influence behavior. Some participants have adjusted their offer behavior over time as they've become more familiar with the market, but many indicated that they want additional training to enhance their understanding and comfort with specific market features. These findings are consistent with the broader analysis in this report, which shows that risk, uncertainty, and market design features play a significant role in shaping offer behavior and market outcomes.

Below, we provide a high-level summary of the survey results.

Market Understanding

Participants generally understand the purpose and high-level design of the DA A/S market but have less confidence in constructing offers and understanding clearing prices, as shown in Figure 11-1.

Figure 11-1: Participant Understanding of the Market (Survey)



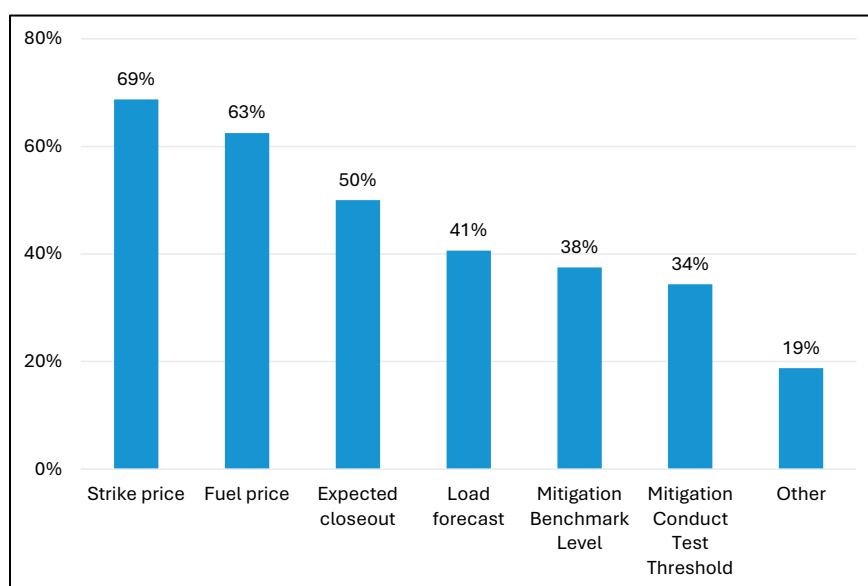
Approximately two-thirds of respondents reported a strong understanding of the market’s purpose and design. However, only about 41–44% reported a strong understanding of FRS and FER price formation, and just over half reported confidence in their ability to construct competitive offers. About 16% reported no confidence in constructing offers. These results suggest that while the design is understood conceptually, translating that understanding into effective participation remains challenging. Additionally, over two thirds of respondents indicated that additional training, particularly on offer formulation, would be beneficial.

Market Participation and Offer Behavior

Some participants indicated that they have changed the frequency or quantity of their offers over time, citing changes in commercial strategy, improved understanding of the market, and changes in fuel prices and asset availability as the main reasons for varying offer behavior.

Participants who do participate in the DA A/S market generally incorporate multiple inputs into their offers, including strike prices, fuel costs, and expected close-outs, as shown in Figure 11-2.

Figure 11-2: Inputs to DA A/S Offers (Survey)



Note: Sample size = 32. Excludes “prefer not to respond” and “not applicable” responses.

A notable share of respondents (31%) reported that they do not explicitly incorporate strike prices in their offers, relying instead on fuel prices, expected closeouts, and/or load forecasts. At the same time, multiple respondents cited uncertainty related to strike prices, expected close-outs, and real-time exposure. These concerns are consistent with the broader finding that risk and uncertainty contribute to higher offer prices and variability in offer strategies.

Operational Impact

Survey results also indicate that DA A/S awards influence operational decisions. Approximately 71% of respondents reported taking actions in response to awards, most commonly procuring fuel.

Risk Perceptions

Participants were evenly split in their ability to account for risk in offers. One-third agree to a great/very great extent that they can sufficiently account for risk, one-third agree to some extent, and one-third agree a little or not at all. Despite this, approximately 75 percent indicated that DA A/S revenues generally cover the costs of providing reserves.

Mitigation and Benchmarking

Participants are generally aware of the mitigation design and many engage with the IMM to revise their benchmark levels. Most respondents who have revised their benchmark level with the IMM agree that the new level accurately reflects costs. However, some highlighted the administrative burden of frequently updating their benchmark level. These results underscore the importance of maintaining a mitigation framework that is both effective and operationally workable.

Perceived Benefits and Challenges

Participants most frequently cited increased revenue and improved compensation for reserve capability as key benefits of the DA A/S market. Other benefits include improved fuel planning and more transparent reserve pricing.

The most commonly cited challenges include:

- market complexity and difficulty forecasting outcomes,
- uncertainty in strike prices and closeout charges, particularly during stressed periods,
- challenges in constructing offers and managing risk, and
- administrative burden associated with mitigation.