Spring 2025
Quarterly Markets Report

By ISO New England's Internal Market Monitor

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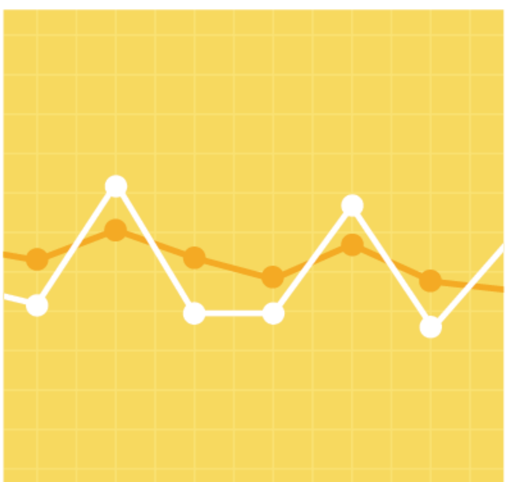
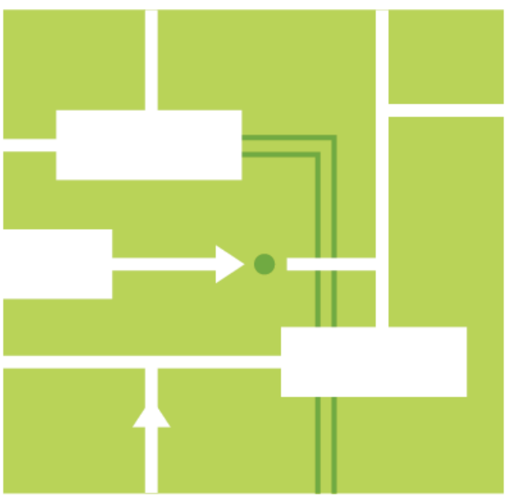
ISO-NE PUBLIC


Preface/Disclaimer

The Internal Market Monitor ("IMM") of ISO New England Inc. (the "ISO") publishes a Quarterly Markets Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. The report addresses the development, operation, and performance of the wholesale electricity markets 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.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation*:

> The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this *Appendix A* and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this *Appendix A.*

All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.[1]

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

[1] Capitalized terms not defined herein have the meanings ascribed to them in Section I of the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the "Tariff").

[2] Available at http://www.theice.com.

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Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Spring 2025 (March 1, 2025 through May 31, 2025).

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.64 billion, up 48% from $1.11 billion in Spring 2024. This increase was driven by higher energy and capacity costs.

Energy costs totaled $1.26 billion, up 67% (or $0.5 billion) from Spring 2024. The increase was primarily due to higher natural gas prices, which rose by 112% year-over-year. Lower loads and an increase in net imports partially muted the impact of higher natural gas prices on LMPs.

Capacity costs totaled $358 million, up 38% (by $99 million) from last spring. Beginning in Summer 2024, higher capacity clearing prices from the fifteenth Forward Capacity Auction (FCA 15) led to greater wholesale costs relative to the previous FCA. Last year, the capacity payment rate for all new and existing resources was $2.00/kW-month. This year, the payment rate for new and existing resources increased to $2.61/kW-month.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $41.19 and $39.25 per megawatt hour (MWh), respectively—both up 60% from Spring 2024. The increase in prices followed higher fuel costs.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $3.40/MMBtu in Spring 2025, 112% higher than the Spring 2024 price of $1.60/MMBtu. Natural gas costs increased in line with higher prices in natural gas supply regions and lower national storage levels.
- Hourly net interchange increased by 46% year-over-year due to more imports from New York. This somewhat offset the impact of higher natural gas prices on LMPs.
- From Spring 2024 to Spring 2025, the RGGI CO_2 adder for natural gas generator costs rose from $8.81 to $9.35/MWh. However, its contribution to the cost of gas-fired generation fell from 38% to 25% because of the larger increase in natural gas prices.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $6.8 million, up $2.1 million compared to Spring 2024. NCPC comprised 0.6% of total energy costs, a similar share to other quarters over the reporting period. The majority of NCPC payments, $6.6 million, were first contingency (also known as "economic") payments.

Day-Ahead Ancillary Services: On March 1, 2025, ISO New England launched a new suite of day-ahead ancillary services (DA A/S) designed to procure operating reserves and ensure sufficient supply to meet the ISO's load forecast through market mechanisms. These services include ten-minute spinning (TMSR), ten-minute non-spinning (TMNSR), thirty-minute reserves (TMOR), and Energy Imbalance Reserve (EIR). The total DA A/S settlement cost over the three-month period was $88 million with the FER credit paid to physical day-ahead energy supply accounting for 85% of that total.

Clearing prices for DA A/S products declined over the period, tracking lower expected closeout values driven by seasonal load reductions and falling natural gas prices. Expected closeout values—used both for offer formulation and mitigation thresholds—generally aligned with actual closeouts on a cumulative basis, although individual hours showed divergence. Finally, mitigation occurred in 27% of hours but only affected 3% of eligible asset hours, with a moderate average reduction in clearing prices by $1.76/MWh.

Real-time Reserves: Payments totaled $0.7 million, similar to 2024 ($0.6 million), driven by increased TMSR scarcity and more frequent non-zero pricing intervals. TMNSR and TMOR prices were rarely non-zero during Spring 2025 reflecting the ample supply of total 10-minute and 30-minute reserves that were available to the system during this season.

Regulation: Regulation market payments were $1.8 million, down 27% from Spring 2024. This decrease primarily reflected lower capacity prices (down 46%), however, regulation service prices increased from $0.03/mile in Spring 2024 to $0.05/mile in Spring 2025.

Financial Transmission Rights (FTRs): Spring 2025 featured the highest congestion-related totals relative to the day-ahead LMP over the reporting period. Day-ahead congestion revenue totaled $19.4 million and real-time congestion revenue totaled $1.0 million. FTRs were highly profitable with $22.1 million in positive target allocations and $4.5 million in negative target allocations. Congestion and price separation were largely driven by transmission outages and corresponding export congestion in Maine. These outages were related to maintenance and upgrades to accommodate future construction of the New England Clean Energy Connect (NECEC) line. While there were high positive target allocations in Spring 2025, the Congestion Revenue Fund (CRF) was fully funded in each month.

Energy Market Competitiveness: The residual supply index for the Real-time energy market in Spring 2025 was 105.7, indicating that the ISO could meet the region's load and reserve requirement without energy and reserves from the largest supplier, on average. There was at least one pivotal supplier present in the real-time market for 25% of five-minute pricing intervals in Spring 2025, slightly down from the previous spring (29%). The year-over-year decrease was due to lower loads and reserve requirements.

There was a total of 65 mitigation asset hours in Spring 2025, which was similar to the Spring 2024 value of 75 asset hours. Real-time manual dispatch energy (MDE) mitigation occurred most frequently with 27 asset hours of mitigation. In addition, there were eight reliability commitments, an increase from zero asset hours in Spring 2024. The increase in reliability commitments this spring reflected more impactful transmission outages than in the prior spring.

Section 2
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes. Selected key statistics for load levels, day-ahead and real-time energy market prices, and fuel prices are shown in Table 2-1 below.

Table 2-1: High-Level Market Statistics

Market Statistics	Spring 2025	Winter 2025	Spring 2025 vs Winter 2025 (% Change)	Spring 2024	Spring 2025 vs Spring 2024 (% Change)
Real-Time Load (GWh)	25,963	32,080	-19%	26,206	-1%
Peak Real-Time Load (MW)	17,353	19,637	-12%	17,354	0%
Average Day-Ahead Hub LMP ($/MWh)	$41.19	$116.73	-65%	$25.66	61%
Average Forecast Energy Requirement Price ($/MWh)	$2.66	-	-	-	-
Average Real-Time Hub LMP ($/MWh)	$39.25	$114.80	-66%	$24.64	59%
Average Natural Gas Price ($/MMBtu)	$3.40	$13.58	-75%	$1.60	112%
Average No. 6 Oil Price ($/MMBtu)	$13.77	$14.69	-6%	$15.74	-13%

Key observations from the table above:

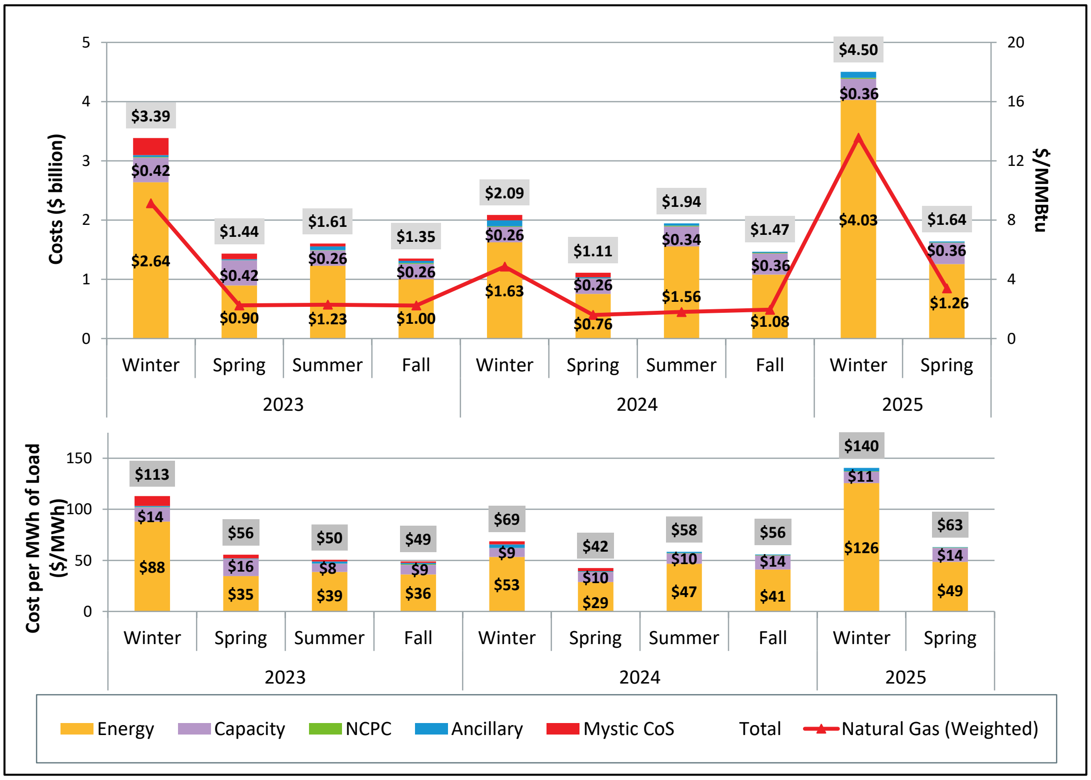
- Day-ahead LMPs averaged $41.19/MWh in Spring 2025, up 61% from Spring 2024. Higher gas prices in Spring 2025 ($3.40/MMBtu) relative to Spring 2024 ($1.60/MMBtu) put upward pressure on LMPs.
- The average premium paid in the day-ahead market to physical suppliers of day-ahead energy during Spring 2025 was $4.60/MWh greater than the real-time LMP. This premium reflects both the day-ahead LMP and the Forecast Energy Requirement (FER) Price, which is produced by the day-ahead market as a result of the implementation of day-ahead ancillary services on March 1, 2025. This represents a larger premium than in Spring 2024 ($1.02/MWh) or in Winter 2025 ($1.93/MWh), and reflects the costs of jointly satisfying bid-in day-ahead demand as well as the ISO's load forecast.[3]
- Load, natural gas prices, and LMPs decreased in Spring 2025 relative to Winter 2025, consistent with increased temperatures and the associated decrease in energy demand.
- Total load in Spring 2025 was effectively unchanged from Spring 2024.

[3] See Section 2.2 for further discussion on load in the day-ahead market.

2.1 Wholesale Cost of Electricity

The estimated wholesale cost of electricity (in billions of dollars), categorized by cost component, is shown by season in the upper panel of Figure 2-1 below.[4] The upper panel also shows the average price of natural gas (in $/MMBtu) as energy market payments in New England tend to be correlated with the price of natural gas in the region.[5] The bottom panel in Figure 2-1 depicts the wholesale cost per megawatt hour of real-time load.

Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Season

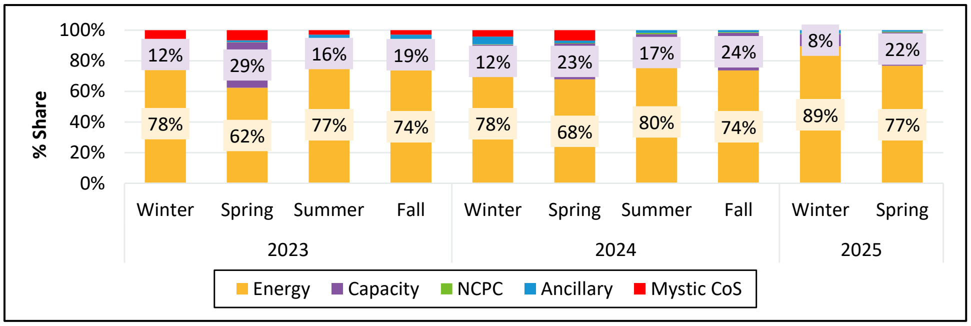


In Spring 2025, the total estimated wholesale cost of electricity was $1.64 billion (or $63/MWh of load), a 48% increase compared to $1.11 billion in Spring 2024 and a 64% decrease compared to $4.50 billion in Winter 2025. The increase from Spring 2024 was driven by increased energy and capacity costs. The share of each wholesale cost component since Winter 2023 is shown in Figure 2-2 below.

[4] In previous reports, we used system load obligations and average hub LMPs to approximate energy costs. Beginning with the Winter 2022 report, we updated the methodology to reflect energy costs based on location-specific load obligations and LMPs. These changes are reflected in all 11 seasons of data. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of quarterly wholesale costs.

[5] 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, Maritimes and Northeast, and Tennessee gas pipeline Z6 north and south. 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.

Figure 2-2: Percentage Share of Wholesale Costs



Energy costs, which comprised 77% of the total wholesale cost, were $1.26 billion ($49/MWh) in Spring 2025, 67% higher than Spring 2024 costs, driven by a 112% increase in natural gas prices. Natural gas prices continued to be a key driver of energy prices. Lower loads and an increase in net imports[6] partially muted the impact of higher natural gas prices on LMPs. Additionally, the energy costs include the cost of the new Forward Energy Reserve (FER) payments made to day-ahead cleared physical generation. FER payments totaled $74.4 million ($2.86/MWh) or 6% of total energy costs.

Capacity costs are determined by the clearing price in the primary Forward Capacity Auction (FCA). In Spring 2025, the FCA 15 clearing price resulted in capacity payments of $358 million ($13.79/MWh), representing 22% of total costs. The current capacity commitment period (CCP15, June 2024 – May 2025) cleared at $2.61/kW-month. This was 31% higher than the primary auction clearing price of $2.00/kW-month for the prior capacity commitment period.

At $6.8 million ($0.26/MWh), Spring 2025 Net Commitment Period Compensation (NCPC) costs represented 0.4% of total wholesale costs, a similar share to other quarters over the reporting period.

Ancillary service costs, which include payments for reserves (DA and RT) and regulation, totaled $15.6 million ($0.60/MWh) in Spring 2025, representing less than 1% of total wholesale costs and down 15% from Spring 2024. Reserve payments associated with the Day-Ahead Ancillary Services (DA A/S) market accounted for 84% of total ancillary services payments.[7]

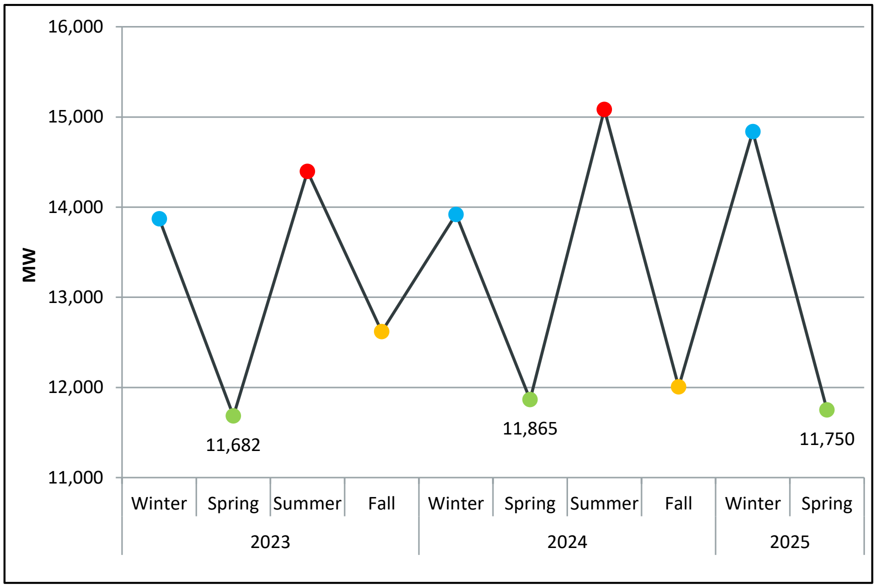
[6] See Section 2.3.2 for more information on imports and exports.

[7] See Section 3.5 for more information on the Day-Ahead Ancillary Services Market.

2.2 Load

New England average loads typically fall in spring as heating demand falls and behind-the-meter (BTM) solar output increases following the winter season.[8] Average hourly load by season is illustrated in Figure 2-3 below.

Figure 2-3: Average Hourly Load by Quarter



Spring 2025 hourly loads averaged 11,750 MW, slightly lower than Spring 2024 loads. As discussed below, weather conditions in Spring 2025 were similar to 2024. Behind-the-meter (BTM) generation increased to 830 MW on average, up 12% from Spring 2024 and contributed to the slightly lower loads.

[8] In this section, the term "load" typically refers to net energy for load (NEL), while "demand" typically refers to end-use demand. NEL is generation needed to meet end-use demand (NEL – Losses = Metered Load). NEL is calculated as Generation + Settlement-only Generation – Asset-Related Demand + Price-Responsive Demand + Net Interchange (Imports – Exports).

Peak Load and Load Duration Curves

New England's system load over the past three spring seasons is shown as load duration curves in Figure 2-4 below with the inset graph showing the 5% of hours with the highest loads.[9]

Figure 2-4: Load Duration Curves

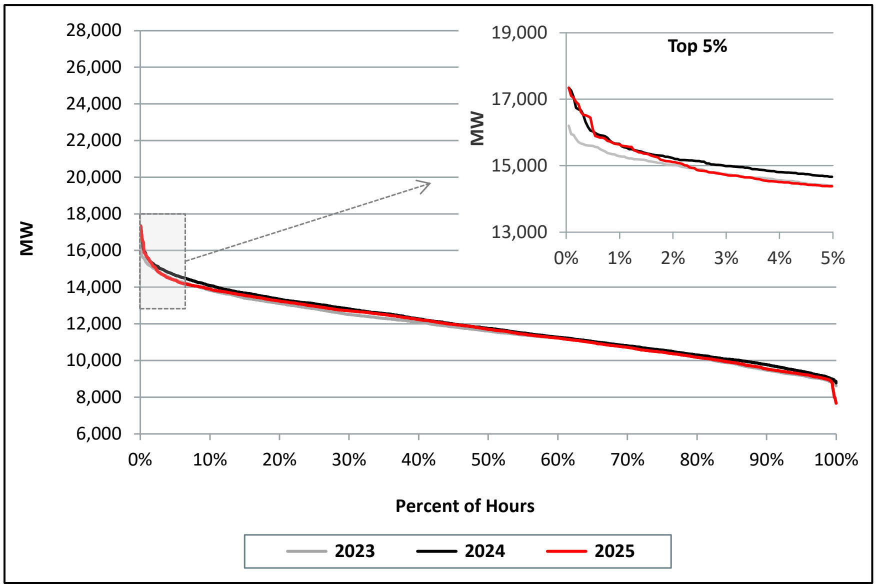


Figure 2-4 shows that loads were generally similar between Spring 2025 and the prior two years. Peak load in Spring 2025 was 17,300 MW. Historically low hourly loads occurred during Spring 2025 due to mild weather and high BTM solar generation; the lowest hourly average load was 7,665 MW on Easter, April 20.[10] There were no reliability issues that resulted from the record low loads in Spring 2025. This spring was notable not only for recording the lowest load, but also for showing duck curves on roughly 45% of the days between January 20 and May 31.[11] The deepest curve occurred also on April 20, highlighting solar's impact mid-day demand.

[9] A load duration curve depicts the relationship between load levels and the frequency in which loads occur at that level or higher.

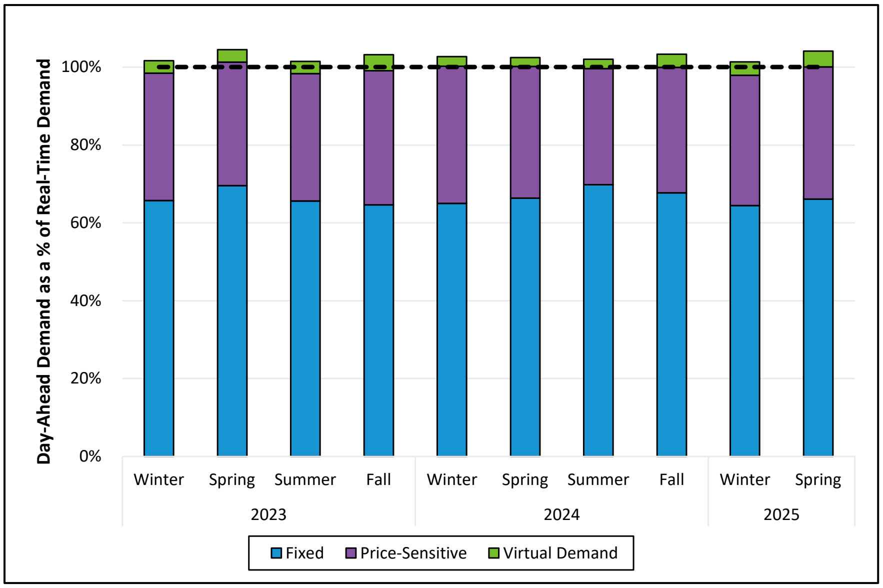
[10] For more information on the record low loads during Spring 2025, see the ISO Newswire article *New England Grid Sees New Record Low for System Demand* (April 22, 2025), available at https://isonewswire.com/2025/04/22/new-england-grid-sees-new-record-low-for-system-demand/. Note that the graph above shows net energy for load, which includes settlement-only generation (SOGs). This is different from the definition used by the ISO, which excludes SOGs.

[11] For more information on duck curves during Spring 2025 see the ISO Newswire article *Sunny Spring Days Push Grid Demand to New Lows* (June 18, 2025), available at https://isonewswire.com/2025/06/18/sunny-spring-days-push-grid-demand-to-new-lows/?utm_source=isone&utm_medium=newsfeed

Load Clearing in the Day-Ahead Market

The average amount of load that participants cleared in the day-ahead market as a share of actual real-time load over the past two years is shown in Figure 2-5 below.

Figure 2-5: Day-Ahead Cleared Demand as Percent of Real-Time Demand, by Quarter



Participants cleared 104% of real-time load in the day-ahead market in Spring 2025, up from 102% in Spring 2024. This marks the highest amount of over-clearing since Spring 2023. Participants cleared 66% of demand as fixed bids and 34% of demand as priced bids. Priced demand bids were typically priced well above expected LMPs, illustrating that demand is largely price-insensitive and that most priced bids are functionally similar to fixed bids. Virtual demand clearing accounted for 4% of cleared demand, and drove the net over-clearing that occurred in Spring 2025.[12]

[12] See 3.3 for more information on virtual demand.

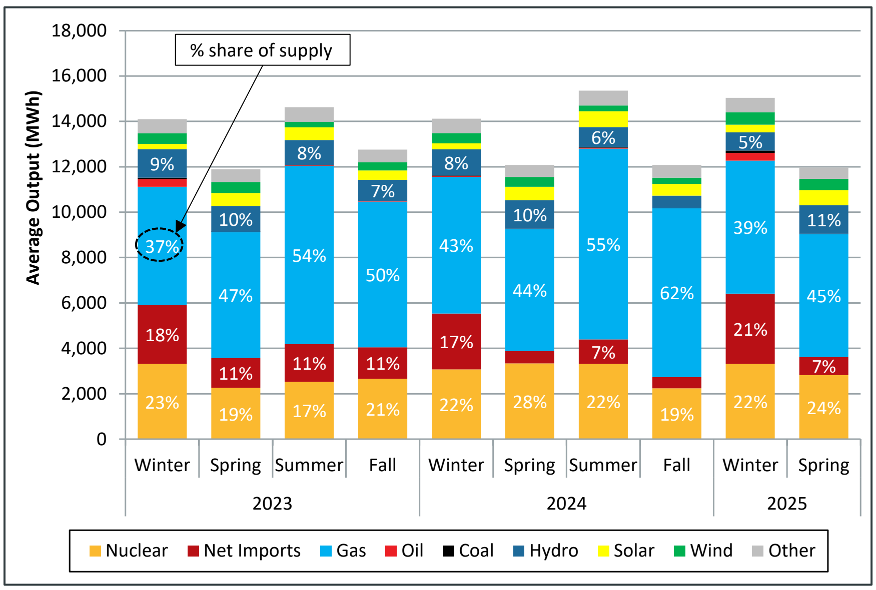
2.3 Supply

This subsection summarizes actual energy production by fuel type, and flows of power between New England and its neighboring control areas.

2.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The energy production by generator fuel type for Winter 2023 through Spring 2025 is illustrated in Figure 2-6 below. Each bar's height represents the average electricity generation from that fuel type, while the percentages represent the share of generation from that fuel type.[13]

Figure 2-6: Share of Electricity Generation by Fuel Type



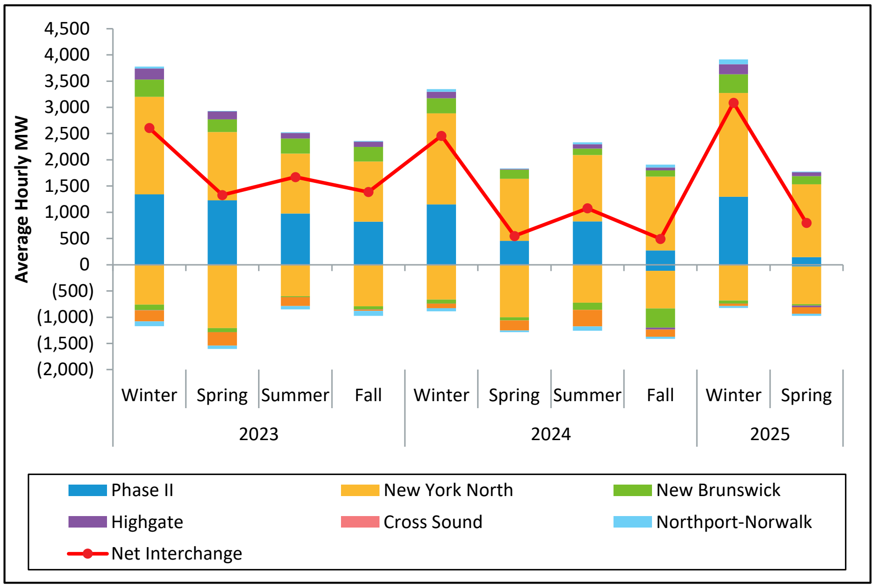
Average output in Spring 2025 (11,961 MWh) was similar to Spring 2024. Lower nuclear generation in Spring 2025 was driven by planned refueling outages. A 250 MW increase in average net imports, which provided 7% of the region's energy supply, offset a portion of the reduction in nuclear generation. The majority of New England's energy continued to be provided by nuclear generation and gas-fired generation. Together, these categories accounted for 69% of total average production in Spring 2025.

[13] Electricity generation equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, wood, and demand response.

2.3.2 Imports and Exports

On average, New England was a net importer of energy, importing nearly 800 MW per hour from the neighboring control areas in Canada and New York.[14] Total net interchange represented 7% of load (NEL), up from 5% in Spring 2024. The average hourly import, export, and net interchange power volumes by external interface for the last 10 seasons are shown in Figure 2-7 below.

Figure 2-7: Average Hourly Real-Time Imports, Exports, and Net Interchange



Hourly net interchange decreased by 74% compared to Winter 2025. Net interchange increases during the winter when cold weather leads to a constrained natural gas system in New England. During the winter, natural gas-fired generators compete with heating demand for limited natural gas supply. This leads to upward pressure on natural gas and LMPs and incentivizes higher volumes of imports from neighboring regions. These conditions are infrequent during the spring, leading to less power delivered into New England from neighboring areas. Outages of transmission elements often increase during the spring, which further contributes to the lower volumes of net interchange compared to winter.

Compared to Spring 2024, hourly net interchange increased by 46% year-over-year due to more imports from New York. After exporting to New York last spring, New England returned to importing over the New York interfaces in spring 2025, averaging 522 MW per hour. The increase in New York imports more than offset the continued decline in imports from Canadian interfaces. Imports from Canada averaged just 276 MW per hour, down from 582 MW in Spring 2024.

New York Interfaces

At the New York interfaces, New England typically imports power over the New York North interface and exports power over the two interfaces with Long Island, Cross Sound Cable and

[14] There are six external interfaces that interconnect the New England system with these neighboring areas. The interconnections with New York are the New York North interface, which comprises several AC lines between the regions, the Cross Sound cable, and the Northport-Norwalk cable. These last two run between Connecticut and Long Island. The interconnections with Canada are the Phase II and Highgate interfaces, which both connect with the Hydro-Québec control area, and the New Brunswick interface.

Northport-Norwalk. The increase in net imports with New York was largely due to increased imports at the New York North interface. Net imports at New York North averaged 675 MW per hour, up from 182 MW per hour in Spring 2024. Net imports increased despite New York prices increasing by more than New England prices this quarter. Some participants may be willing to flow energy into New England even when New England prices are lower. These external transactions would typically be renewable-backed and sell renewable energy certificates (RECs) at a higher price in New England, or have out-of-market contracts (such as a Power Purchase Agreement) requiring the flow of energy even if spot market prices do not align with the direction of the transaction.

New England exported less energy to Long Island due to seasonal transmission work at the Cross Sound Cable interface. In Spring 2025, New England exported 67 MW less per hour over the Cross Sound Cable interface compared to the prior spring (121 vs. 188 MW per hour). This interface was either out-of-service or operating at a reduced Total Transfer Capability for almost one month this spring, limiting the volume of exports to Long Island and increasing the total net interchange New York. At the Northport-Norwalk interface, New England exported an average of 31 MW per hour, similar to the levels in Spring 2024.

Canadian Interfaces

In Quebec, normally abundant water resources and hydro generation provide excess electricity supply, which can be sold to neighboring control areas. However, drier weather over the last few years has reduced the excess energy available in Quebec and limited electricity sales into New England. At the Phase II interface, New England imported an average of 110 MW per hour this spring, the lowest level of imports over the prior 10 quarters. New England has periodically exported energy over the Phase II interface, particularly on days with mild weather and lower energy prices. In March 2025, New England exported an average of 676 MW per hour over Phase II during a four-day period. At the Highgate and New Brunswick interfaces, net imports averaged 39 MW and 127 MW per hour, respectively. Both these import levels were roughly a 20 MW per hour increase from the prior spring.

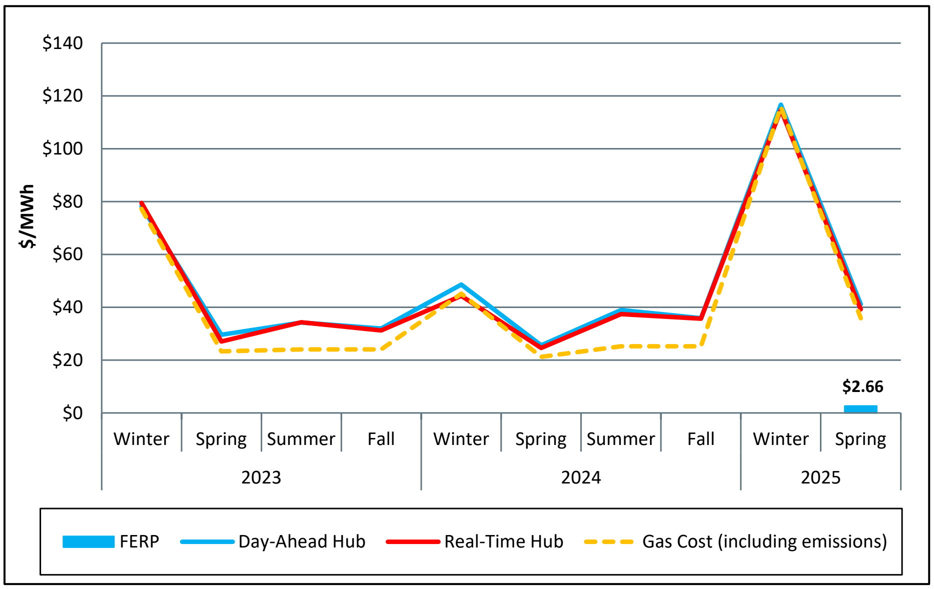
Section 3
Day-Ahead and Real-Time Markets

This section explores the trends and driving factors influencing market outcomes for energy, operating reserves, and regulation products.

3.1 Energy Prices

In New England, seasonal movements of energy prices are generally consistent with changes in natural gas generation costs. These trends can be seen in Figure 3-1 which shows the average day-ahead and real-time energy prices, along with the estimated fuel and emissions costs of generating electricity using natural gas in New England.[15] The figure includes the Forecasted Energy Requirement Price (FERP), which is a payment to day-ahead cleared physical generation and charged to load obligation.

Figure 3-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



As Figure 3-1 illustrates, the seasonal movements of energy prices (solid lines) are generally consistent with changes in natural gas generation costs (dashed line). The spread between the estimated cost of a typical natural gas-fired generator and electricity prices tends to be highest during the summer months as less efficient generators, or generators burning more expensive fuels, are required to meet the region's higher demand.

Day-ahead and real-time Hub prices averaged $41.19/MWh and $39.25/MWh respectively in Spring 2025, both increasing by roughly 60% compared to Spring 2024. The increase was due to higher natural gas costs, which averaged $35.88/MWh in Spring 2025, increasing by nearly $15/MWh compared to the previous spring. Natural gas costs increased in line with higher prices in natural gas supply regions and lower national storage levels. The new Day-Ahead Ancillary Services

[15] The natural gas cost is based on the seasonal average natural gas price and a generator heat rate of 7,800 Btu/kWh, which is the estimated average heat rate of a combined cycle gas turbine in New England. The natural gas cost includes estimated emissions costs.

market began on March 1, 2025. This market includes the FERP, a day-ahead payment made to physical energy suppliers. The average FERP was $2.66/MWh, leading to a total day-ahead premium (DA LMP + FERP – RT LMP) of $4.60/MWh.

In other recent quarters, we found that rising Regional Greenhouse Gas Initiative (RGGI)[16] costs contributed significantly to the cost of generating on natural gas. However, in Spring 2025, the cost of fuel increased more significantly than RGGI costs. From Spring 2024 to Spring 2025, RGGI prices rose, slightly increasing the emissions costs for a standard gas-fired generator from $19.31 to $20.49/short ton of CO_2. This increased the RGGI adder for natural gas generator costs from $8.81 to $9.35/MWh. While carbon costs increased, their contribution to the cost of gas-fired generation fell from 38% to 25% because of the larger increase in natural gas prices.

At the zonal level, only the Maine load zone saw significant price separation from the Hub prices. In the day-ahead and real-time markets, average prices in Maine were 8% and 9% lower than the Hub price, respectively. This price separation occurred due to planned transmission outages related to the New England Clean Energy Connect project and new wind generators in export-constrained areas.

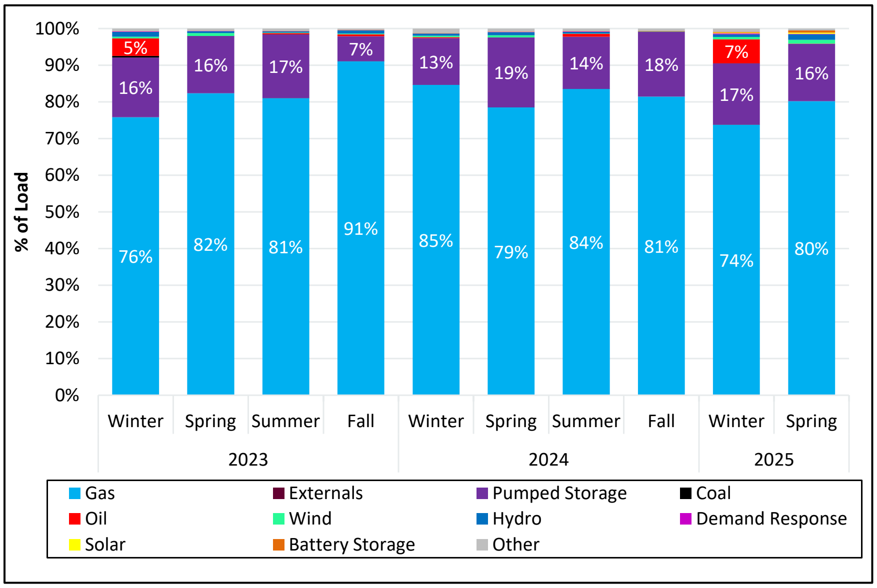
[16] RGGI is a marketplace for CO_2 credits that covers all six New England states as well as other states in the Northeast and Mid-Atlantic regions. It operates as a cap-and trade system, where fossil fuel generators must purchase emission allowances equal to their level of CO_2 emissions over a specific compliance period. See RGGI's *Elements of RGGI page*, available at https://www.rggi.org/program-overview-and-design/elements

3.2 Marginal Resources and Transactions

This section reports marginal units by transaction and fuel type on a load-weighted basis. When more than one resource is marginal, the system is generally constrained and the 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.

The percentage of load for which each fuel type set price in the real-time market since Winter 2023 is shown in Figure 3-2 below.

Figure 3-2: Real-Time Marginal Units by Fuel Type



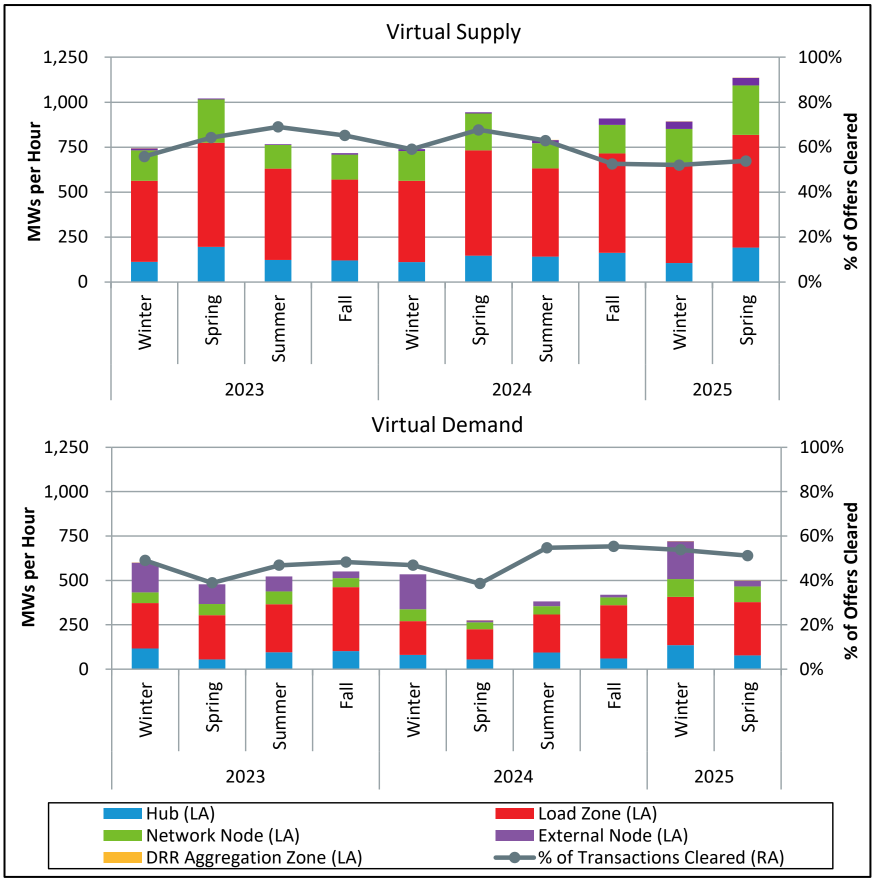
Natural gas generators continued to be the primary real-time marginal resource in Spring 2025, setting price for 80% of load. Pumped-storage generators set price for 16% of real-time load, similar to prior quarters. Wind generators set price for 1% of real-time load, marking the highest frequency of marginal wind generation over the sample period. The frequency of marginal wind generation was driven by relatively frequent export congestion in areas with high wind generation during Spring 2025 as discussed in 5.2.

3.3 Virtual Transactions

In the day-ahead energy market, participants submit virtual demand bids and virtual supply offers to profit from differences between day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence and help the day-ahead dispatch model better reflect real-time conditions.

The average volume of cleared virtual supply (top graph) and virtual demand (bottom graph) are shown on the left axis in Figure 3-3 below. 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 3-3: Cleared Virtual Transactions by Location Type



Cleared virtual supply averaged 1,136 MW per hour in Spring 2025, up 20% from Spring 2024 (944 MW per hour). Virtual supply has continued to increase due to the growing impact of growing settlement-only generation (SOG), particularly growing solar SOGs which do not offer into the day-ahead market but generate in real time. In Spring 2025, cleared virtual supply increased by more than the increase in generation from solar SOGs.

Participants also frequently use virtual supply to try to capture differences between day-ahead and real-time prices in export-constrained areas, particularly areas with wind and solar generation. Beginning in December 2023, the Do-Not-Exceed (DNE) Dispatch Project expanded to include utility-scale (at least 5 MW installed capacity) solar generation. Typically, these wind and solar generators offer high-priced energy in the day-ahead market, but produce energy at low, or even negative, prices in the real-time market.[17] In Spring 2025, there was increased wind generation which led to an increase in virtual supply cleared at network nodes. For cleared virtual supply at network nodes increased from 205 MW to 274 MW per hour, the largest increase at any location type.

Cleared virtual demand averaged nearly 500 MW per hour, the highest volume of cleared virtual demand over the prior nine quarters. The highest increase in cleared virtual demand occurred at

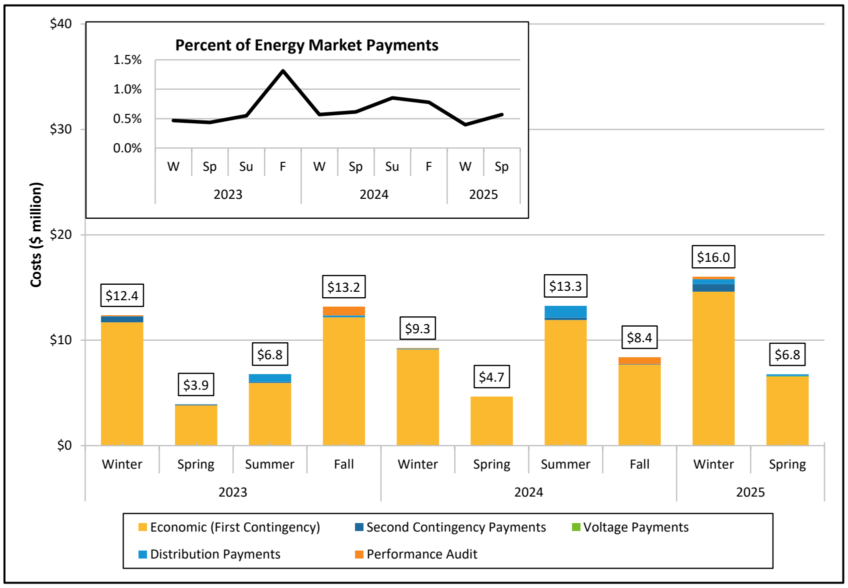
[17] In Spring 2025 wind generation averaged 229 MW per hour in the day-ahead market, while real-time wind generation averaged 491 MW hour.

the load zones, especially NEMA Boston and Connecticut. At these locations, the overall increase was largely driven by one participant submitting and clearing more virtual demand.

3.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) credits are make-whole payments to generators, external transactions, or virtual participants that incur uncompensated costs when following ISO dispatch instructions. NCPC categories include first- and second-contingency protection, voltage support, distribution system protection, and generator performance auditing.[18] Figure 3-4 below shows quarterly NCPC by category and season for 2023-2025. The inset chart shows NCPC as a percentage of energy market payments.

Figure 3-4: NCPC by Category

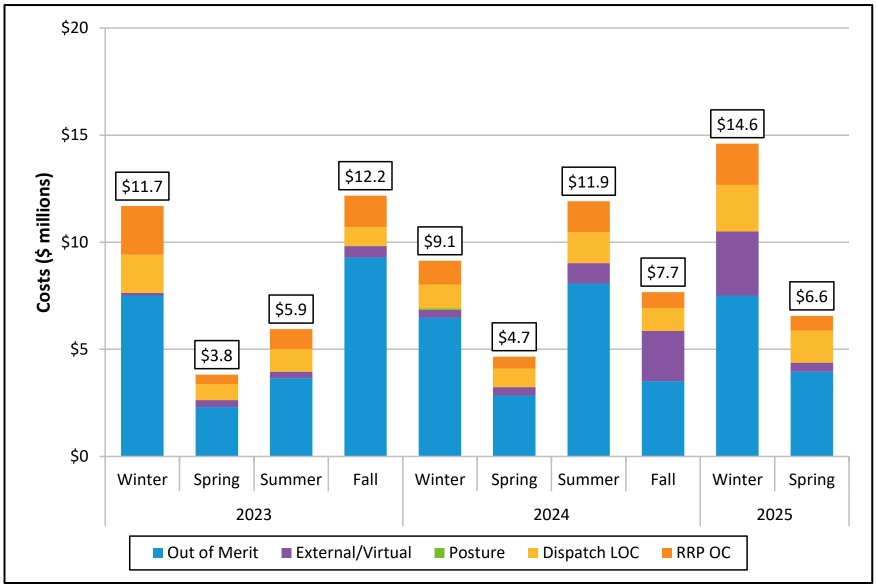


NCPC payments totaled $6.8 million in Spring 2025, up from $4.7 million in Spring 2024. Economic payments made up the majority of total NCPC at $6.6 million. Second contingency, voltage, and special constraint resource payments for distribution comprised the remainder of NCPC at $0.2 million. The minimal amount of non-economic NCPC in Spring 2025 illustrates that few out-of-market reliability commitments occurred throughout the season. In total, NCPC costs represented 0.6% of energy market payments.

Economic uplift includes payments made to resources providing first-contingency protection as well as resources that incur opportunity costs by operating at an ISO-instructed dispatch point below their economic dispatch point (EDP). Figure 3-5 below shows economic payments by sub-category.

[18] NCPC payments include economic/first contingency NCPC payments, local second -contingency NCPC payments (reliability costs paid to generators providing capacity in constrained areas), voltage reliability NCPC payments (reliability costs paid to generators dispatched by the ISO to provide reactive power for voltage control or support), distribution reliability NCPC payments (reliability costs paid to generators that are operating to support local distribution networks), and generator performance audit NCPC payments (costs paid to generators for ISO-initiated audits).

Figure 3-5: Economic NCPC by Reason



Out of merit uplift continued to comprise the largest share of economic NCPC, totaling $4.0 million in Spring 2025. Dispatch lost opportunity cost payments totaled $1.5 million, while opportunity cost payments due to fast-start pricing and dispatch mechanics totaled $0.7 million. External and virtual transactions received $0.4 million in economic uplift, down significantly from Fall 2024 and Winter 2025 due to less frequent congestion at external interfaces.

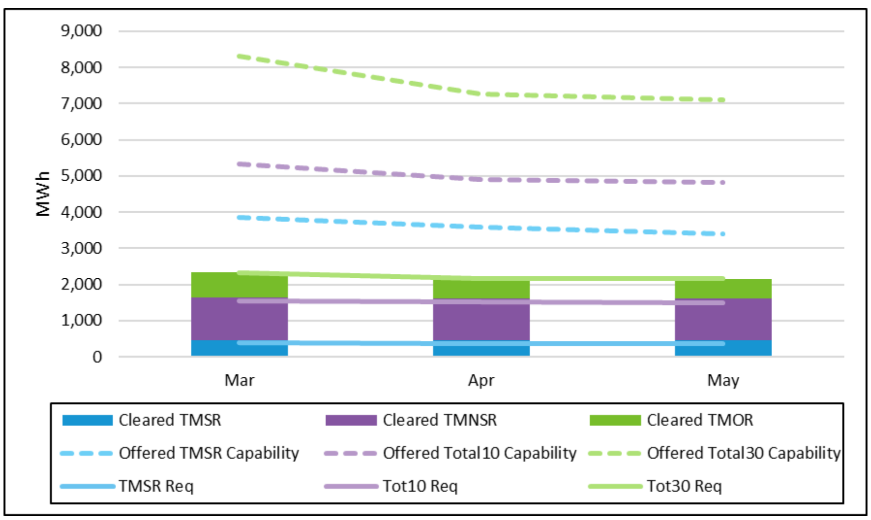
3.5 Day-Ahead Ancillary Services

This section provides details on day-ahead ancillary services (DA A/S) requirements and market outcomes. Beginning March 1, 2025, ISO-NE began procuring ancillary services in the day-ahead market to acquire the capability necessary to satisfy both the load forecast and operating reserve requirements through a market construct. DA A/S products include a suite of operating reserve-style products, collectively referred to as Flexible Response Services (FRS), which include (1) day-ahead ten-minute spinning reserve (DA TMSR), (2) day-ahead ten-minute non-spinning reserve (DA TMNSR), and (3) day-ahead thirty-minute operating reserve (DA TMOR). In addition, Energy Imbalance Reserve (EIR) is a DA A/S product that may be procured to help satisfy the load forecast, as modeled in the Forecast Energy Requirement (FER) constraint. All DA A/S products are settled as call options on real-time energy via a standard two-settlement design: a credit, paid to awards at the applicable clearing price, and a closeout charge, which is based upon the difference between the prevailing hourly RT Hub LMP[19] and a predetermined strike price.

Requirements, offered capability, and cleared awards

Figure 3-6 below shows the 10- and 30-minute DA A/S capability offered into the market relative to the requirements for that capability, averaged across each month. Requirements are determined by the projected first and second contingencies; offered capabilities reflect participant-submitted DA A/S offer quantities limited by physical resource characteristics (i.e., ramp rate, ecomax, etc.).

Figure 3-6: Ex-ante FRS Offered Capability, Requirements, and Cleared Awards



The DA A/S capability made available to the system is generally several times the FRS requirements. For example, the average TMSR requirement across the three-month period was 380 MWh, while the average TMSR capability offered to the market was 3,600 MWh, nearly ten times the requirement. Offered total 10- and total 30-minute capabilities exceed requirements by more than a factor of three. Requirements were relatively flat over this three-month period, while offered FRS capability showed a slight downward trend. This trend aligns with the spring outage season, with resource maintenance in advance of summer operations.

[19] The hourly real-time Hub LMP is the average of the twelve 5-minute real-time Hub LMPs across the hour.

It is important to consider the fact that some portion of offered DA A/S capability may provide greater value to the system when cleared as day-ahead energy, and if so will clear as such. Additionally, some DA A/S capability is offered on resources that can only provide that capability from an online state, and these resources may or may not receive a day-ahead commitment. Finally, some DA A/S capability may be offered on resources that prove unable to provide the service due to binding transmission constraints. Figure 3-7 below shows the same requirements and cleared quantities as Figure 3-6 above, but adjusts the offered capability downward by the amounts of DA A/S capability cleared for energy, DA A/S capability on non-fast start resources that did not receive a DA commitment, and DA A/S capability on resources behind binding transmission constraints. The intent is to provide an 'ex-post' view of available DA A/S capability.

Figure 3-7: Ex-post FRS Offered Capability, Requirements, and Cleared Awards

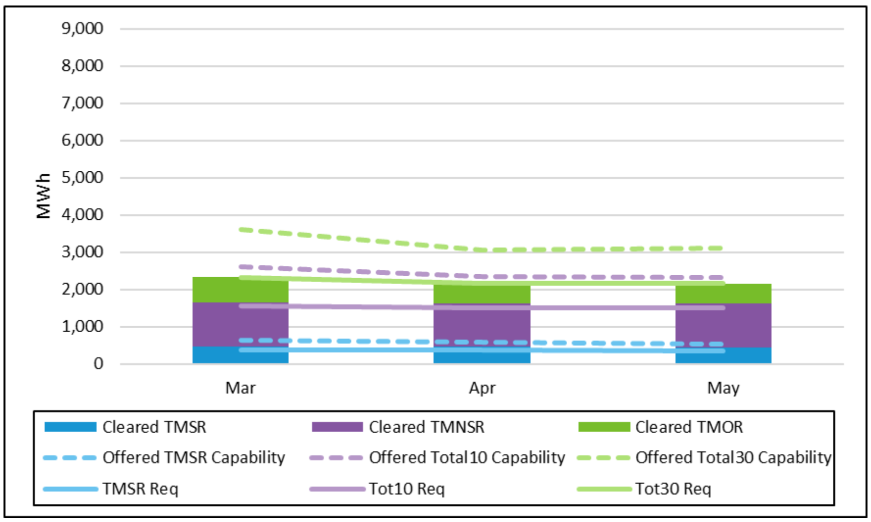
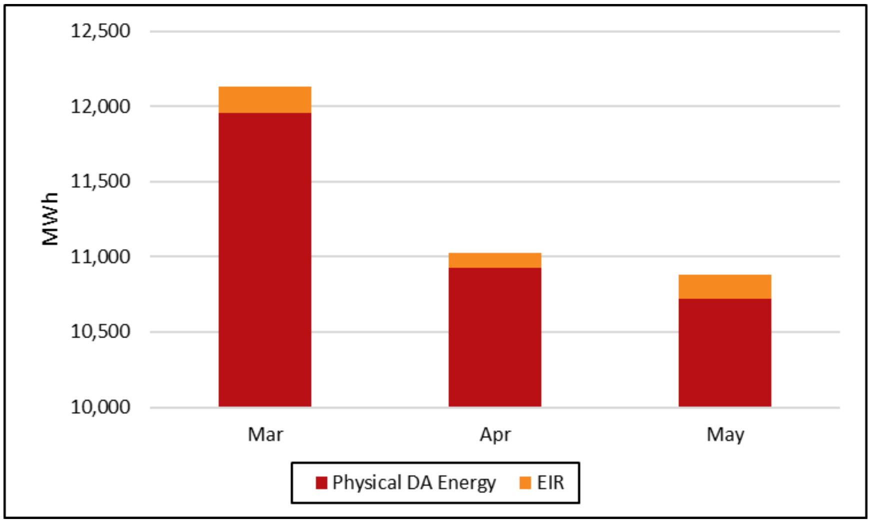


Figure 3-7 shows far less DA A/S capability available from an ex-post perspective, particularly for the capability able to satisfy the TMSR requirement. This tighter supply can contribute to opportunity costs being reflected in DA A/S clearing prices, most notably for TMSR. This dynamic is discussed further below. The FER constraint incorporates the ISO's load forecast into the clearing of the day-ahead market, and ensures that the load forecast can be satisfied by a mix of day-ahead energy awards cleared on physical resources and EIR awards. Figure 3-8 below shows the monthly average cleared FER supply.

Figure 3-8: Forecast Energy Requirement Cleared Awards



Day-ahead energy awards to physical suppliers satisfy the vast majority of the FER demand, with small amounts of EIR cleared periodically. The downward trend in supply cleared to satisfy the FER reflects the decline in load from March to May. EIR is not cleared in all hours; in many hours, sufficient physical energy supply to meet the load forecast is cleared, and as a result no EIR is needed. Table 3-1 provides key statistics related to cleared EIR quantities.

Table 3-1: EIR statistics

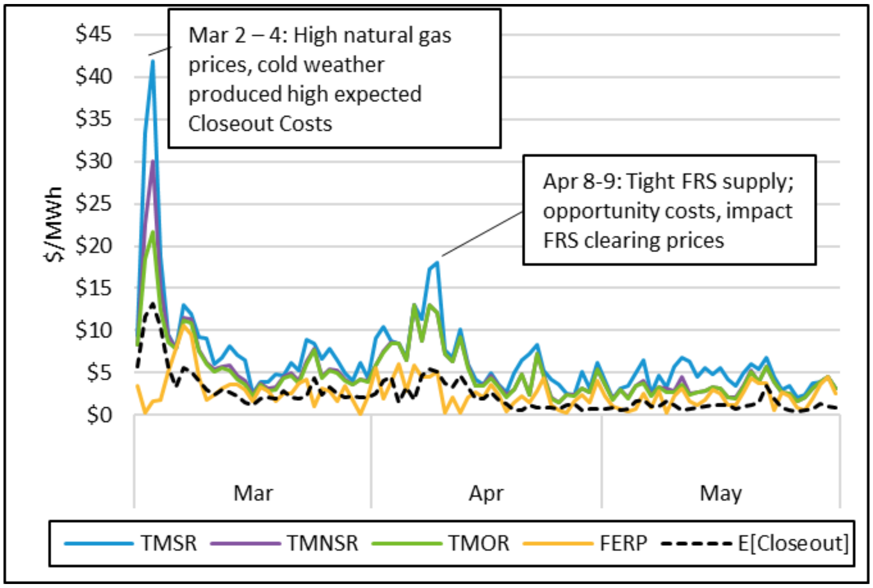
Month	Count of hours with non-zero EIR cleared quantity	% of hours with non-zero EIR cleared quantity	Min Cleared EIR (MWh)	Average Cleared EIR (MWh)	Max Cleared EIR (MWh)
Mar	450	61%	0	176	1,138
Apr	328	46%	0	97	1,066
May	470	63%	0	155	940

EIR is procured in 46% - 63% of hours, depending on the month, and across all hours EIR awards average approximately 140 MWh. In certain hours much more EIR is required, with the maximum cleared EIR quantities ranging between 940 MWh and 1,138 MWh depending on the month. The need for EIR can depend on dynamics on both the supply and demand sides of the market. On the demand side, if load collectively bids less than the ISO forecast, procurement of EIR may be necessary to satisfy the load forecast. On the supply side, a combination of competitively priced INCs and EIR awards may prove to be the most cost-effective solution for satisfying the day-ahead market's requirements.

DA A/S Clearing Prices

DA A/S clearing prices reflect the offer prices of the resources that are on the margin for satisfying a given reserve constraint. DA A/S offer prices generally reflect three components: (1) the expected closeout charge, which is a cost that resources expect to incur as a result of taking on a DA A/S award, (2) avoidable input costs, which are applicable to natural gas-fired generators and storage resources, and (3) risk premiums. Clearing prices can also reflect inter-product opportunity costs, which occur when a resource is cleared to provide one product (such as DA A/S) when it would be more profitable for that resource to provide a different product (such as day-ahead energy). Figure 3-9 below shows daily average clearing prices and expected closeout values for Spring 2025.

Figure 3-9: DA A/S Clearing Prices



DA A/S clearing prices have trended downward since the market's inception, a trend that aligns with an observed decline in expected closeout values. This trend in expected closeouts, in turn, is driven by declining loads and natural gas prices over the three-month study period. We observe opportunity costs to be impactful to DA A/S clearing prices, most frequently for the TMSR clearing price. This generally occurs during morning and evening peaks when the system's energy needs are greatest and less offered TMSR capability is available to clear as TMSR, resulting in 're-dispatch' and associated opportunity costs. Table 3-2 provides monthly average clearing prices and expected closeout values, and provides a further illustration of this downward trend.

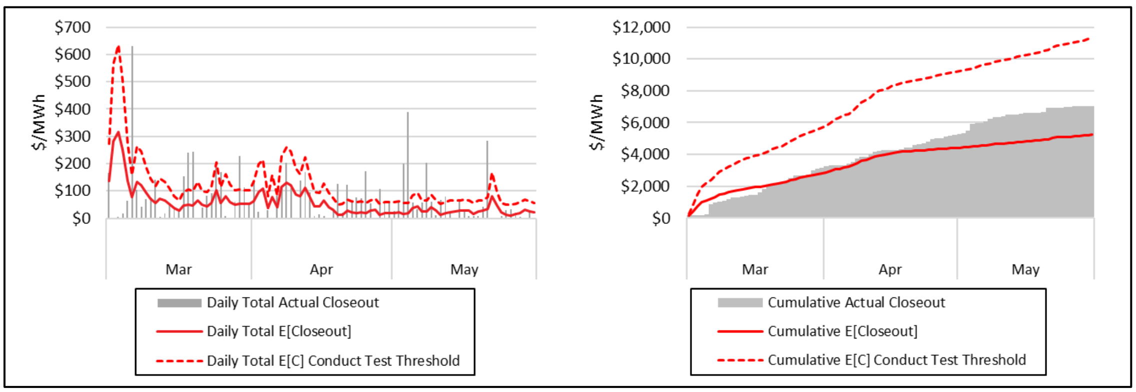
Table 3-2: DA A/S Clearing Price Statistics

Concept	Average Value ($/MWh)		
	Mar	Apr	May
DA Hub LMP	$46.97	$41.41	$35.21
DA TMSR Clearing Price	$9.28	$7.08	$4.38
DA TMNSR Clearing Price	$7.32	$5.75	$3.20
DA TMOR Clearing Price	$6.62	$5.68	$3.10
FER Clearing Price	$3.25	$2.66	$2.06
Expected Closeout	$3.76	$2.24	$1.10

Expected Closeout and Mitigation

The ISO's Gaussian Mixture Model (GMM) produces expected closeout values for each hour of each operating day. These expected closeout values are one component of a participant's competitive costs, and are consequently reflected in DA A/S benchmark levels. The expected closeout values are also considered in DA A/S mitigation; the DA A/S conduct test threshold price allows for offering the greater of $2/MWh and two times the expected closeout. This threshold is intended to allow inclusion of risk premiums in DA A/S offers. Figure 3-10 below provides two visualizations of expected closeout values relative to actual observed closeout values. The left pane shows daily totals of expected closeouts, actual closeouts, and closeout-related conduct test threshold values, while the right pane shows these values cumulatively over time.

Figure 3-10: Expected Closeout vs. Actual Closeout



Individual observations of expected closeout costs and actual closeout costs are not expected to align precisely; the former is a probabilistic expectation based upon a range of possible real-time outcomes, while the latter is a single realized outcome from this range of possibilities. The left pane above highlights this fact. While expected closeouts and the associated conduct test threshold frequently meet or exceed actual closeouts, there are instances when actual closeout costs exceed both expected closeout costs and the associated conduct test threshold. This is evident when the gray bars exceed the red lines, and reflects circumstances in which the bandwidth provided by the conduct test threshold was insufficient to allow DA A/S offers that would cover the actual closeout costs in individual hours.[20]

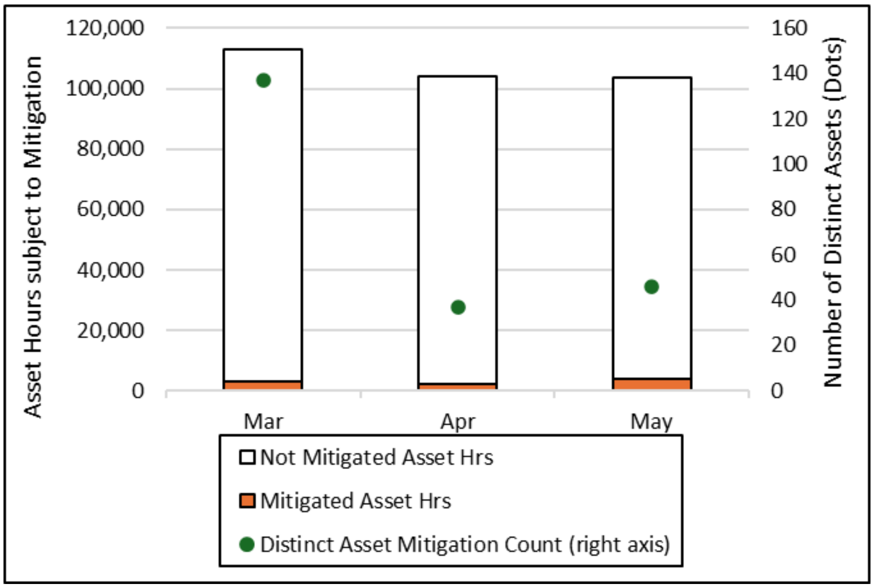
It is reasonable to expect that expected closeouts and actual closeouts will align cumulatively over time. This relationship is observed to some degree in the right pane of the figure above, in which the red line (cumulative expected closeout) and the gray bars (cumulative actual closeout) align quite well until late April, at which point the expected closeouts flatten while the actual closeouts continue to increase. This dynamic is the result of very low expected closeout values produced by the GMM beginning in late April, which in turn stem from low expected loads and natural gas

[20] It is important to note that participants are free to establish their own expected closeout values if those values differ from the ISO's GMM-produced values. Through the IMM consultation process, participants may have these quantitatively-supported expected closeout values utilized in the IMM's benchmark levels and the conduct test threshold.

prices.[21] It is worth noting that, on a cumulative basis, the expected closeout component of the conduct test threshold allows sufficient bandwidth to cover cumulative observed closeouts (i.e., the dashed red line always exceeds the gray bars).

DA A/S mitigation occurs when DA A/S offer prices exceed conduct test thresholds, and the impact of those offers on clearing prices is determined to exceed Tariff-specified impact test thresholds.[22] Figure 3-11 illustrates the frequency of DA A/S mitigation.

Figure 3-11: DA A/S Mitigations



While DA A/S impact test violations occurred in roughly 2% of hours, one or more instance of DA A/S mitigation occurred in 27% of hours during Spring 2025.[23] As shown in the figure above, a very small share of asset hours that were subject to DA A/S mitigation were actually mitigated (3%, on average). On average, DA A/S mitigation served to reduce clearing prices by $1.76 (12%) on average in the hours when mitigation occurred.

DA A/S and FER Settlements

The four DA A/S products are paid an initial credit at the applicable DA A/S clearing price, and face a closeout charge whenever the real-time hub LMP exceeds the strike price. In addition, day-ahead energy awards to physical supply resources (i.e., generators, DRRs, and imports) are paid the FER price, as these energy awards are able to contribute to satisfying the load forecast. Table 3-3 shows these settlements for Spring 2025.

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[21] Expected loads and natural gas prices are the two most impactful covariates in the GMM, and low values tend to produce very tight distributions of expected real-time LMPs. These tight distributions, in conjunction with the $10/MWh strike price adder, result in very little ‘weight’ to the distribution to the right of the strike price, and as a result the expected closeout charges are very low. In such instances, the DA A/S conduct test threshold tends to be set at $2/MWh, the ‘floor’ value on the conduct test threshold price incorporated in the DA A/S design, rather than at two times expected closeout.

[22] See Tariff Section III.A.8.1 for detailed rules regarding DA A/S conduct and impact tests.

[23] This dynamic stems from the DA A/S mitigation design, which mitigates all DA A/S offers that violate the conduct test in any hour of the day if an impact test violation is observed in any single hour of that same day.

Table 3-3: DA A/S and FER Settlements ($millions)

Concept	Mar	Apr	May	Total	% of Total
TMSR (net)	$1.8	$1.3	$0.6	$3.7	4%
TMNSR (net)	$3.0	$2.6	$0.6	$6.3	7%
TMOR (net)	$1.5	$1.1	$0.3	$2.9	3%
EIR (net)	-$0.1	$0.2	$0.1	$0.2	0%
FER	$33	$24	$18	$74	85%
Total	**$39**	**$29**	**$19**	**$88**	**100%**
Total E&AS Costs[24]	$535	$409	$336	$1,281	
% Total E&AS Cost	7%	7%	6%	7%	

The FER credit paid to physical suppliers of day-ahead energy ($74 million) represents the largest share of DA A/S-related settlements (85%). While FER prices are the lowest of all DA A/S prices, the quantity of physical energy supply is large, resulting in the FER credit being the most costly component of the DA A/S design. FRS and EIR net credits totaled $13.3 million across the period. Settlement results show a downward trend across the three months in Spring 2025, aligning with the observed decline in DA A/S clearing prices.

[24] Total Energy and Ancillary Services costs include day-ahead and real-time energy, reserve, regulation, and NCPC costs.

3.6 Real-Time Operating Reserves

This section provides details about real-time operating reserve pricing and payments. ISO-NE procures three types of real-time reserve products: (1) ten-minute spinning reserve (TMSR), (2) ten-minute non-spinning reserve (TMNSR), and (3) thirty-minute operating reserve (TMOR). Real-time reserve prices have non-zero values when the ISO must re-dispatch resources to satisfy a reserve requirement.[25] Resources providing reserves during these periods receive real-time reserve payments.

Real-time Reserve Pricing

The frequency of system-level non-zero reserve pricing for each product, along with the average price during these intervals, for the past three spring seasons is provided in Table 3-4 below.[26]

Table 3-4: Hours and Level of Non-Zero Reserve Pricing

Product	Spring 2025		Spring 2024		Spring 2023	
	Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	$6.87	175.3	$6.98	173.5	$9.16	148.8
TMNSR	$54.49	1.2	$29.90	0.3	$84.76	1.8
TMOR	$168.77	0.3	$0.00	0	$0.00	0

The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 175 hours during Spring 2025, similar to Spring 2024. TMNSR and TMOR prices were rarely non-zero during Spring 2025. These pricing outcomes reflect the ample supply of total 10-minute and 30-minute reserves available to the system during this season.

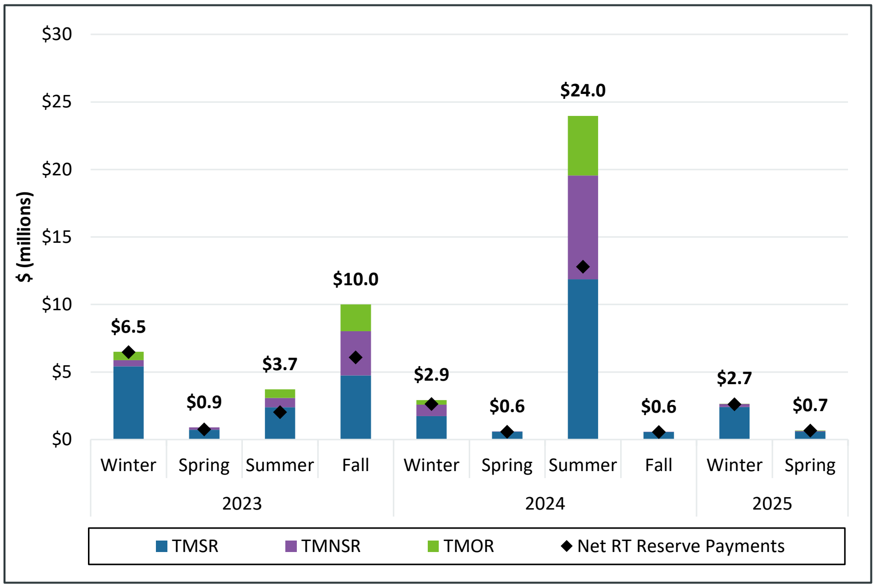
[25] Real-time operating reserve requirements are utilized to maintain system reliability. There are several real-time operating reserve requirements: (1) the ten-minute reserve requirement; (2) the ten-minute spinning reserve requirement; (3) the minimum total reserve requirement; (4) the total reserve requirement; and (5) the zonal reserve requirements. For more information about these requirements, see *Section III Market Rule 1: Standard Market Design*, Section III.2.7A, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

[26] The zonal thirty-minute reserve requirements did not bind in any of these spring seasons. As a result, real-time reserve prices in reserve zones were equal to those at the system level.

Real-time Reserve Payments

Real-time reserve payments by product are illustrated in Figure 3-12 below.[27] The height of the bars indicate gross reserve payments, while the black diamonds show net payments (i.e., payments after reductions have been made to Forward Reserve Resources providing real-time reserves).[28] With the sunsetting of the Forward Reserve Market in March 2025, future gross and net payments will be equivalent, beginning Spring 2025. Both are shown in this report for comparison with past quarters.

Figure 3-12: Real-Time Reserve Payments by Product and Zone



Gross reserve payments in Spring 2025 were $0.7 million, of which the majority (87%) went to resources providing TMSR. Reserve payments were similar to Spring 2024. Less than $0.1 million in combined payments were made for TMOR and TMNSR.

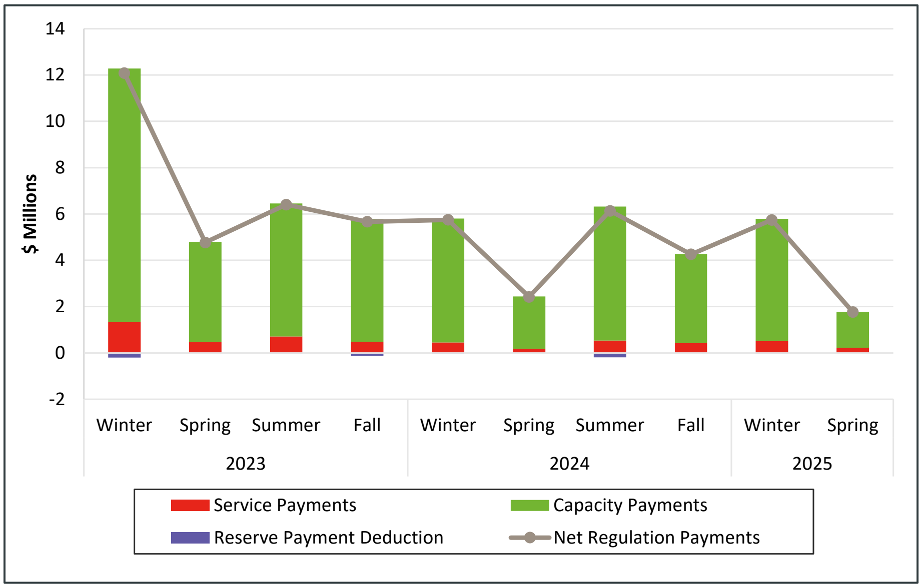
[27] The current reserve zones are: Northeastern Massachusetts/Boston (NEMA/Boston), Connecticut (CT), Southwest Connecticut (SWCT), and Rest of System (ROS).

[28] The FRM was a forward market that procured operating reserve capability in advance of the actual delivery period. Real-time reserve payments to resources designated to satisfy forward reserve obligations were reduced by a forward reserve obligation charge so that a resource was not paid twice for the same service. For more information about forward reserve obligation charges, see *Section III Market Rule 1 Standard Market Design*, Section III.10.4, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

3.7 Regulation

Regulation is an essential reliability service provided by generators and other resources in the real-time energy market. Generators providing regulation allow the ISO to use a portion of their available capacity to match supply and demand (and to regulate frequency) over short time intervals. Quarterly regulation payments are shown in Figure 3-13 below.

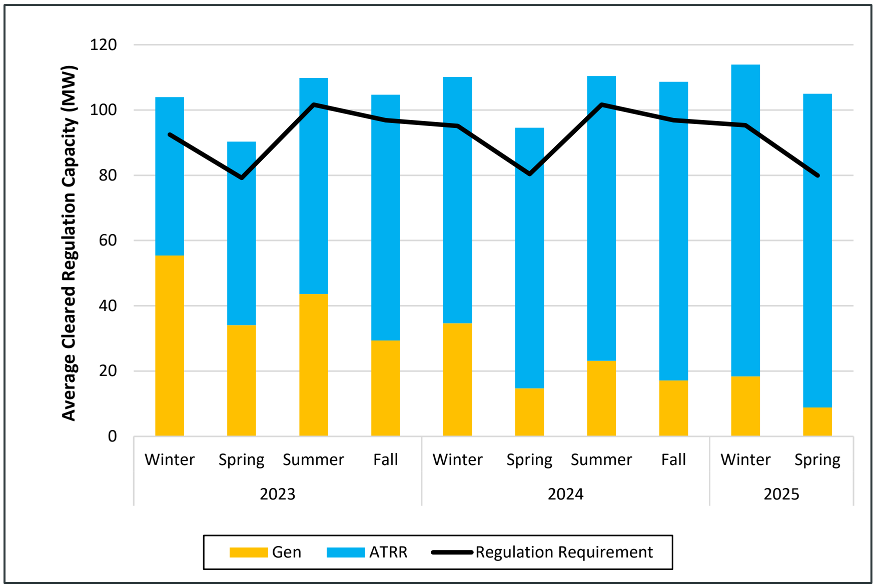
Figure 3-13: Regulation Payments



Total regulation market payments were $1.8 million during Spring 2025, down 27% from $2.4 million in Spring 2024. The decrease in payments compared to Spring 2024 resulted primarily from lower capacity prices (down 46%). Regulation service prices increased from $0.03/mile in Spring 2024 to $0.05/mile in Spring 2025.

Two different types of resources can provide regulation: traditional generators and alternative technology regulation resources (ATRRs). Almost all ATRRs in the New England market are battery resources that can opt to participate solely as regulation resources, or may choose to provide a broader combination of energy market services: consumption (battery charging), generation (battery discharging), and regulation. The regulation resource mix is shown in Figure 3-14 below.

Figure 3-14: Average Cleared Regulation MW by Resource Type



The resource mix of cleared regulation capacity has changed over the reporting period. In Winter 2023, ATRRs (blue shading) cleared an average of 49 MW of regulation capacity, making up 47% of total cleared regulation. In Spring 2025, ATRRs provided 96 MW or 92% of regulation. This change follows continuing increases in the installed capacity of battery resources in the region. Regulation capacity available from ATRRs increased to 395 MW on average in Spring 2025, up from 215 MW in Spring 2024. The change in resource mix also suggests that battery resources are lower-cost regulation resources, as ATRRs have increasingly displaced traditional generators in merit order for regulation market commitment.

Section 4
Energy Market Competitiveness

One of ISO New England's three critical goals is to administer competitive wholesale energy markets. Competitive markets help ensure that consumers pay fair prices and incentivize generators to make short- and long-run investments that preserve system reliability. We first evaluate energy market competitiveness by quarter using two structural market power metrics at the system level. We then provide statistics on system and local market power flagged by the automated mitigation system, and on the amount of actual mitigation applied, whereby a supply offer was replaced by the IMM reference level.

4.1 Pivotal Supplier and Residual Supply Indices

This analysis examines opportunities for participants to exercise market power in real time using two metrics: the pivotal supplier test (PST) and the residual supply index (RSI).[29]

When a participant's available supply exceeds the supply margin[30], they are considered pivotal.[31] We calculate the percentage of five-minute pricing intervals with at least one pivotal supplier by quarter. The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. The average RSI and the percentage of five-minute intervals with pivotal suppliers are presented in Table 4-1 below.

Table 4-1: Residual Supply Index and Intervals with Pivotal Suppliers (Real-Time)

Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2023	105.2	20%
Spring 2023	107.7	22%
Summer 2023	103.8	34%
Fall 2023	98.9	60%
Winter 2024	101.7	45%
Spring 2024	105.5	29%
Summer 2024	104.0	34%
Fall 2024	104.7	31%
Winter 2025	101.3	47%
Spring 2025	105.7	25%

[29] Many resources in New England are owned by companies that are subsidiaries of larger firms. Consequently, tests for market power are conducted at the parent company level.

[30] The real-time supply margin measures the amount of available supply on the system after load and the reserve requirement are satisfied. It accounts for ramp constraints and is equal to the Total30 reserve margin: Gen_{Energy} + $Gen_{Reserves}$ + [*Net Interchange*] -$Demand$ - [$Reserve\ Requirement$]

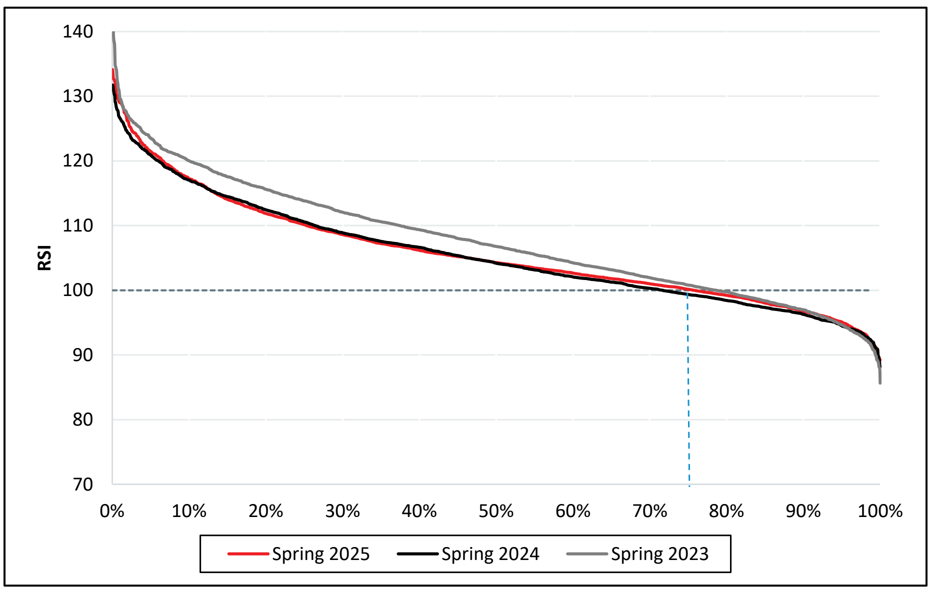
[31] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

The RSI was above 100 in most quarters of the reporting period, indicating that, on average, the ISO could satisfy load and reserve requirements without the largest supplier. The Fall 2023 RSI was below 100 due to lower reserve margins that resulted from several long-term pumped-storage generator outages. Pumped-storage units typically provide large volumes of reserves, as they can come online at their full capacity quickly.

There was at least one pivotal supplier in 25% of real-time pricing intervals in Spring 2025 which was lower than that of the previous spring (29%). The year-over-year decrease was due to slightly lower loads (120 MW decrease) and higher net interchange (253 MW increase) which led to lower reserve requirements. When both load and reserve requirements are lower, it is less likely that the largest supplier is needed to meet load and the reserve requirement.

Duration curves that rank the average hourly RSI over each spring quarter in descending order are illustrated in Figure 4-1 below. The figure shows the percent of hours when the RSI was above or below 100 for each quarter. An RSI below 100 indicates the presence of at least one pivotal supplier.

Figure 4-1: System-Wide Residual Supply Index Duration Curves



In Spring 2025, the RSI was similar to nearly all observations during Spring 2024 and typically below observations in Spring 2023. Net interchange has been low the last two springs, which has contributed to the lower values since Spring 2023.

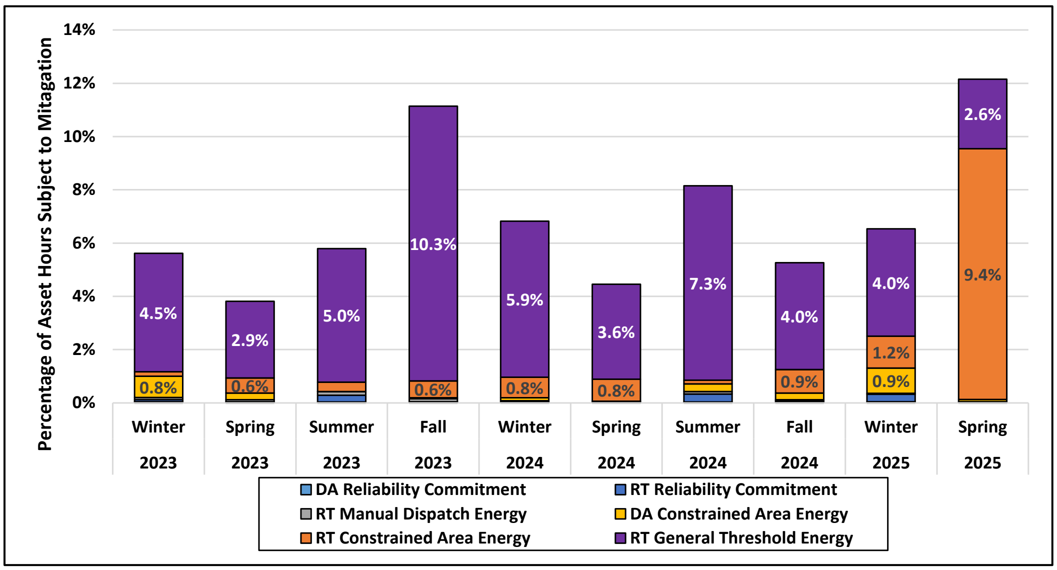
4.2 Energy Market Supply Offer Mitigation

The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power. As in earlier periods, the mitigation of energy market supply offers occurred infrequently in Spring 2025.

Energy Market Mitigation Frequency[32]

A structural test failure serves as the first indicator of potential market power in our energy markets. The percentage of commitment asset hours with a structural test failure from Winter 2023 to Spring 2025 is shown below in Figure 4-2.[33]

Figure 4-2: Energy Market Mitigation Structural Test Failures



In Spring 2025, the total asset hours subject to mitigation reached 484,000 asset hours, in which approximately 59,000 asset hours (12.2%) failed structural tests.[34] The structural test for real-time constrained area energy mitigation failed the most frequently this spring; it is triggered when an asset has market power behind a transmission constraint. 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.

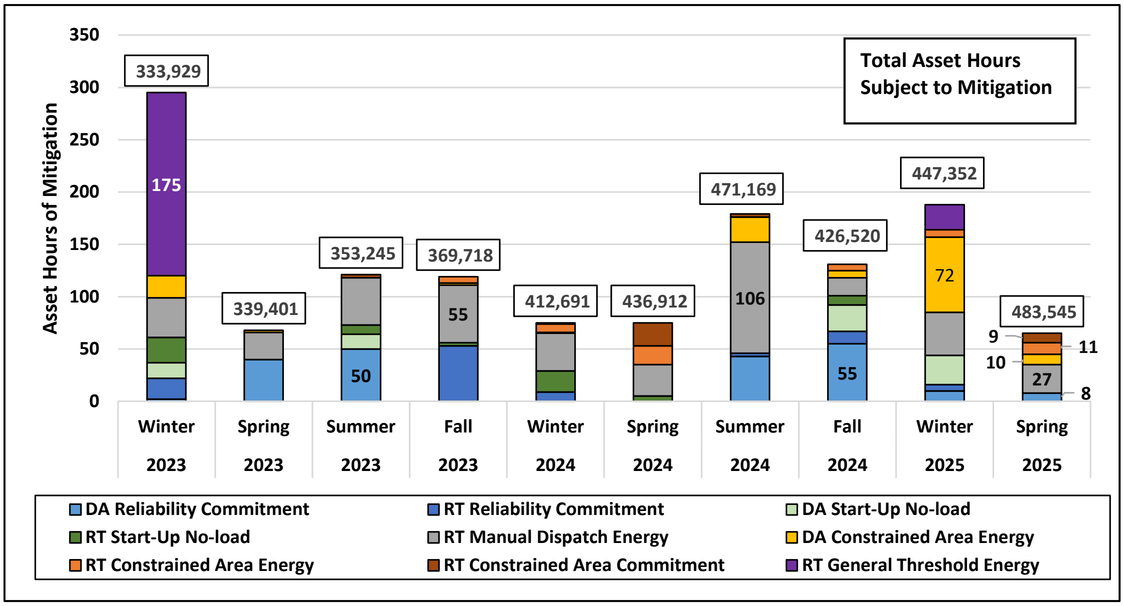
[32] Day-Ahead Ancillary Services mitigations can be found in Section 3.5.

[33] A structural test failure depends on the type of mitigation analyzed. For the definitions of the structural test applied in general threshold and constrained area mitigation, see *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.5.2, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf. For the conditions to pursue manual dispatch energy and reliability commitment mitigation see the same aforementioned source, Sections III.A.5.5.3 and III.A.5.5.6.1, respectively.

[34] 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.

Asset hours of mitigation by type are shown in Figure 4-3 along with the total amount of asset hours subject to mitigation (white boxes).

Figure 4-3: Energy Market Mitigation Asset Hours



There was a total of 65 mitigation asset hours in Spring 2025, which was similar to the Spring 2024 value of 75 asset hours. Real-time manual dispatch energy (MDE) mitigation occurred the most frequently in Spring 2025 with 27 asset hours of mitigation. The conduct test threshold for MDE mitigation is relatively tight, only allowing offers of resources being manually dispatched by the ISO to be 10% higher than reference levels.[35]

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.[36] There were eight reliability commitments in Spring 2025, an increase from 0 asset hours in Spring 2024. The increase in reliability commitments this spring reflected more impactful transmission outages than the prior spring.

Start-up and no-load (SUNL) commitment mitigation: This mitigation type addresses grossly over-stated commitment costs (relative to reference values), which could otherwise result in very high uplift.[37] SUNL mitigations occur very infrequently and may reflect a participant's failure to update

[35] More information on Energy Market Mitigation types and thresholds can be found in *An Overview of New England's Wholesale Electricity Markets: A Market Primer (June 5, 2023)*, Section 11.2.1, available at https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf.

[36] 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. For more on applicability, see *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.5.5.6.1, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

[37] 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).

energy market supply offers as fuel prices fluctuate – particularly natural gas. In Spring 2025, there were no SUNL mitigations.

Constrained area (CAE/CACM) mitigation: The frequency of transmission-constrained area mitigation follows the incidence of transmission congestion and import-constrained areas within New England. In Spring 2025, structural test failures totaled nearly 46,000 asset hours spread across several load zones. With relatively tolerant conduct and market impact test thresholds, the frequency of constrained area mitigation is low relative to the frequency of structural test failures. Despite the high totals of structural test failures, mitigation occurred in only 30 asset hours in Spring 2025, ten fewer than in Spring 2024.

General threshold energy (GTE) mitigation: Despite having the highest frequency of structural test failures in nine of the last ten quarters, general threshold energy mitigation occurs the least frequently of all mitigation types. Across the reporting period, an average of roughly 20,000 asset hours of pivotal supplier energy were subject to mitigation each quarter; mitigation has occurred for only 199 asset hours, all in Winter 2023 and Winter 2025. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators, with five participants accounting for 92% of the structural test failures over the reporting period.

Manual dispatch energy (MDE) mitigation: The ISO will utilize manual dispatch points for flexible resources to address short-term issues on the transmission grid. As a result, gas- or dual fuel-fired generators receive manual dispatches most often, accounting for 72% of the 93 asset hours of manual dispatch in Spring 2025. Due to a relatively tight conduct test, manual dispatch energy mitigation occurs more often than most other mitigation type, totaling 27 asset hours in Spring 2025.

Section 5
Forward Markets

This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs), and in the Summer 2023 Forward Reserve Auction.

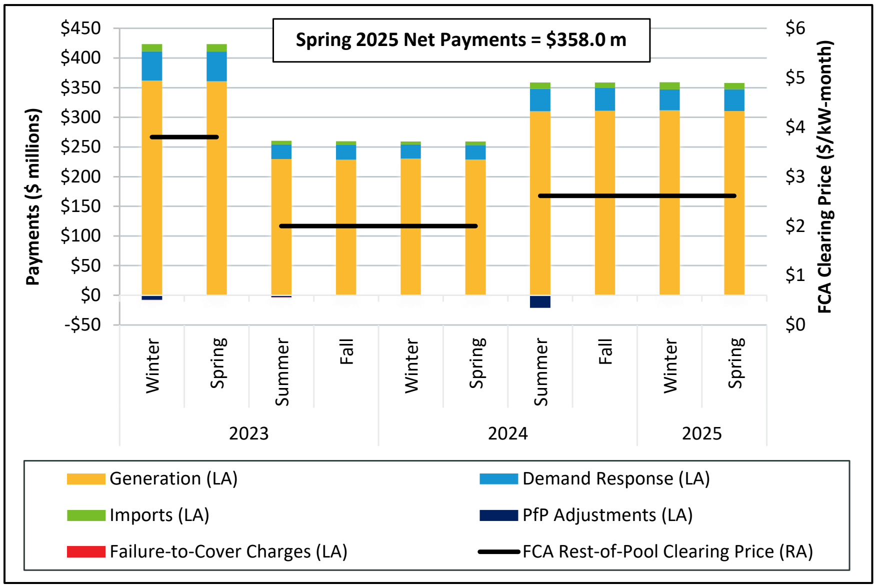
5.1 Forward Capacity Market

The Capacity Commitment Period (CCP) associated with Spring 2025 started on June 1, 2024, and ended on May 31, 2025. The corresponding Forward Capacity Auction (FCA 15) cleared at $2.61/kW-month, 30% higher than FCA 14. The auction cleared with 34,621 MW of Capacity Supply Obligation (CSO), surpassing the net installed capacity requirement (Net ICR) of 33,270 MW. Price separation between zones occurred in FCA 15, with a lower price ($2.48/kW-month) in the export-constrained Northern New England (NNE) and nested Maine capacity zones and a higher price ($3.98/kW-month) in the import-constrained Southeast New England (SENE) capacity zone. Battery storage resources comprised the largest share of new cleared generating capacity. The cost-of-service agreement that retained Mystic 8 and 9 during FCA 13-FCA 14 ended and the generators retired effective June 1, 2024. The results of FCA 15 led to a projected total annual cost of $1.32 billion in capacity payments, 39% higher than capacity payments incurred in FCA 14.[38]

Total FCM payments, as well as the clearing prices for Winter 2023 through Spring 2025, are shown in Figure 5-1 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, light blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The dark blue bar represents Pay-for-Performance adjustments, while the red bar represents Failure-to-Cover charges.

[38] For more information on FCA 15, see our *Winter 2021 Quarterly Markets Report* (April 28, 2021), available at https://www.iso-ne.com/static-assets/documents/2021/04/2021-winter-quarterly-markets-report.pdf.

Figure 5-1: Capacity Market Payments



Capacity payments totaled $358.0 million in Spring 2025. The increase in payments from Spring 2024 is attributable to higher capacity clearing prices in FCA 15. Failure-to-cover charges were minimal, and no PfP events or payments occurred in Spring 2025.

Secondary auctions allow participants the opportunity to acquire or shed capacity supply obligations after the primary auction. A summary of prices and volumes associated with reconfiguration auction and bilateral trading activity during Spring 2024 alongside results of the relevant primary FCA are detailed in Table 5-1 below.

Table 5-1: Primary and Secondary Market Outcomes

				Capacity Zone/Interface Prices ($/kW-mo)			
FCA # (Commitment Period)	Auction Type	Period	Cleared MW*	Rest-of-Pool**	Maine	Northern New England	Southeastern New England
FCA 15 (2024-2025)	Primary	12-month	34,621	2.61	2.48	2.48	3.98
	Monthly Reconfiguration	May-25	690	2.75			
	Monthly Bilateral	May-25	69	4.39			
FCA 16 (2025-2026)	Primary	12-month	32,810	2.59	2.53	2.53	2.64
	Annual Reconfiguration (3)	12-month	184, -782	3.06			
	Monthly Reconfiguration	Jun-25	386	4.69			
	Monthly Bilateral	Jun-25	20	2.55			
	Monthly Reconfiguration	Jul-25	473	5.50			
	Monthly Bilateral	Jul-25	20	2.55			

**represents cleared supply/demand*

***bilateral prices represent volume weighted average prices*

The third annual reconfiguration auction (ARA 3) for CCP 2025-2026 occurred in Spring 2025. The auction cleared at $3.06/kw-month, up from the $2.59/kw-month price for the rest-of-pool capacity zone in FCA 16. The Net ICR for ARA 3 was 30,300 MW, down from 31,645 MW in FCA 16. Following the decrease in Net ICR, 782 MW of capacity exited the market while only 184 MW acquired capacity supply obligations, driving a slight decrease in system capacity.

Three monthly reconfiguration auctions (MRAs) occurred in Spring 2025. The May 2025 MRA marked the final month of CCP 15 and cleared at $2.75/kw-month, similar to FCA 15 prices. The June 2025 MRA cleared 386 MW at $4.69/kw-month, higher than prices in FCA 16. The July 2025 MRA similarly cleared 473 MW at $5.50/kw-month.

5.2 Financial Transmission Rights

This section of the report discusses Financial Transmission Rights ("FTRs"), which are financial instruments that settle based on the transmission congestion that occurs in the day-ahead energy market. The credits associated with holding an FTR are referred to as positive target allocations, and the revenue used to pay them comes from three sources:

1) the holders of FTRs with negative target allocations,
2) the revenue associated with transmission congestion in the day-ahead market, and
3) the revenue associated with transmission congestion in the real-time market.

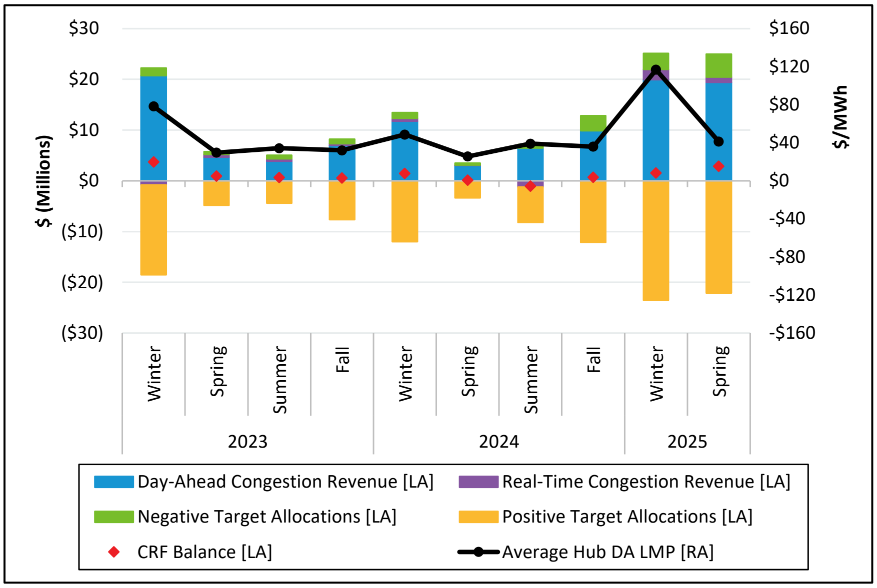
Figure 5-2 below shows, by quarter, the amount of congestion revenue from the day-ahead and real-time energy markets, the amount of positive and negative target allocations, and the congestion revenue fund (CRF) balance.[39,40] This figure also depicts the quarterly average day-ahead Hub LMP.[41]

[39] The CRF balances depicted in Figure 5-2 are simply the sum of the month-end balances for the three months that comprise the quarter. The month-end balances are calculated as $\sum(DA\ Congestion\ Revenue + RT\ Congestion\ Revenue + |Negative\ Target\ Allocations|) - Positive\ Target\ Allocations$ and do not include any adjustments (e.g., surplus interest, FTR capping).

[40] Figure 5-2 depicts positive target allocations as negative values, as these allocations represent outflows from the CRF. Meanwhile, negative target allocations are depicted as positive values, as these allocations represent inflows to the CRF.

[41] All else equal, congestion revenue and target allocations tend to be higher when energy prices are higher. To see this, we can consider an example of an export-constrained area where the marginal resource is setting the area's LMP at $0/MWh. If the marginal resource outside the export-constrained area is setting that area's price at $35/MWh, then the marginal value of the binding constraint (which is used to determine congestion revenue and target allocations) would be -$35/MWh. If the marginal resource outside of the export-constrained area were setting the price at $70/MWh (instead of $35/MWh), the marginal value of the binding constraint, the congestion revenue and the target allocation values would increase in a corresponding fashion.

Figure 5-2: Congestion Revenue and Target Allocations by Quarter



Spring 2025 featured the highest congestion-related totals relative to the day-ahead LMP over the reporting period. Day-ahead congestion revenue totaled $19.4 million in Spring 2025, and real-time congestion revenue totaled $1.0 million. FTRs as a whole were highly profitable in Spring 2025, with $22.1 million in positive target allocations and $4.5 million in negative target allocations.

Congestion and price separation in Spring 2025 were largely driven by transmission outages and corresponding export congestion in Maine. These outages were related to maintenance and upgrades to accommodate future construction of the New England Clean Energy Connect (NECEC) line.[42] Coopers Mills-South (COMI-S) and Orrington-South (ORR-SO) were among the most constrained interfaces, and FTR paths sourced behind these interfaces with sinks at or near the hub were highly profitable. Outage work began in April and ended in late May, and both congestion revenue and FTR target allocations fell to average levels following the outage completion.

While there were high positive target allocations in Spring 2025, the CRF was fully funded in each month. The CRF was funded due to both congestion revenue collection and negative target allocations for counterflow paths along the binding constraints.[43]

[42] The NECEC line is a new 320 kV, HVDC interconnection between Hydro-Québec and New England. The line will connect to the New England grid in Maine and will feature up to 1,200 MW of import-only capacity. The line is scheduled to be commercial in Q4 2025. For more information, see *New England Clean Energy Connect (NECEC) Tariff Conforming Changes*, presented by Josh Lenzen at the June NEPOOL Markets Committee meeting, available at https://www.iso-ne.com/static-assets/documents/100024/a05b_mc_2025_06-10-11_necec_tariff_conforming_changes.pdf.

[43] See the *2025 FTR Monthly Summary*, available at https://www.iso-ne.com/static-assets/documents/100020/2025_monthly_summary.pdf.