Spring 2026
Quarterly Markets Report

ISO New England Internal Market Monitor

AUGUST 24, 2026

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.

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[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 2026 (March 1, 2026 through May 31, 2026).

Wholesale Costs: In Spring 2026, the total estimated wholesale market cost of electricity was $1.75 billion, up 6% from $1.64 billion in Spring 2025. Energy costs comprised 84% of wholesale costs and totaled $1.46 billion, a 16% increase from Spring 2025. Lower natural gas prices (down 18% from Spring 2025) were offset by higher emissions costs (up 65% for a typical natural gas generator in the region).[3] Energy market costs also include the cost of the Forecast Energy Requirement (FER) payments made to day-ahead cleared physical generation. These costs totaled $56 million, down from $74 million in Spring 2025.

Capacity costs totaled $266 million, representing 15% of total wholesale market costs. The current capacity commitment period (CCP 16, June 2025 – May 2026) cleared at $2.59/kw-month, which was nearly the same as the prior year ($2.61/kw-month in CCP 15, June 2024 – May 2025). Despite the comparable clearing price, total costs were 26% lower in Spring 2026 than in Spring 2025, due to lower cleared capacity and less price separation in import-constrained zones.

Energy Prices: The day-ahead Hub LMP averaged $46.36/MWh and the FER price averaged $2.05/MWh, leading to an all-in payment of $48.41/MWh for day-ahead physical generation. The real-time Hub price averaged $47.54/MWh.

- With average natural gas prices down 18% from Spring 2025, higher emissions costs and baseload outages were the primary drivers of higher energy prices. Average Regional Greenhouse Gas Initiative (RGGI) CO_2 allowance prices rose 65% from $20.50/ short ton of CO_2 in Spring 2025 to $33.91 in Spring 2026, while average MA EGEL prices rose 265% from $6.80 to $24.82/ short ton of CO_2.
- The New England Clean Energy Connect (NECEC) transmission line from Quebec took both planned and forced outages this spring while two nuclear generators took planned refueling outages. These baseload outages led to more less-efficient generators setting the marginal price for the system.
- In the day-ahead and real-time markets, average prices in Maine were 8% and 10% lower than the Hub price, respectively. This price separation has occurred since the NECEC interface began commercial operation in January 2026.

[3] This number includes costs from the Regional Greenhouse Gas Initiative only. Costs from the Massachusetts Electricity Generator Emissions Limits program are discussed in Section 3.1.

- Hourly loads were up 2% compared to Spring 2025. This increase was primarily driven by warmer weather, including a period of unseasonably high temperatures from May 17 to May 20.[4]

Supply mix: Higher imports in Spring 2026 offset lower nuclear and gas generation. Average net imports more than doubled from 798 MW per hour in Spring 2025 to 1,625 MW per hour in Spring 2026, driven by flows over the new NECEC line. Net imports accounted for 13% of the region's energy supply compared to 7% in Spring 2025. The share of supply from nuclear generation decreased slightly due to refueling outages; however, nuclear and gas-fired generation continued to provide the majority (62%) of New England's energy in Spring 2026.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $9.4 million in Spring 2026, up 42% from Spring 2025 and representing 0.6% of energy costs. The two highest load days (May 19 and 20) accounted for more than $1 million (13%) of total NCPC payments, mostly due to real-time out of merit commitment uplift.

Day-Ahead Ancillary Services: Total net ancillary services payments were down slightly from Spring 2025 ($13.1 million) to Spring 2026 ($8.8 million). DA A/S payments represented just 0.6% of energy and ancillary services payments, the lowest level since the start of the market. One reason for this was that net DA A/S payments were negative for the month of May 2026 (-$5.8 million) as realized closeouts frequently exceeded DA A/S clearing prices.

Real-time Reserves: Overall, there was ample supply of total-ten and thirty-minute reserve capability available on the system in Spring 2026. There were fewer hours of non-zero ten-minute spinning reserve pricing compared to prior springs, but the average price per MWh was higher. As a result, net reserve payments ($1.0 million) were similar to prior springs.

Regulation: Total regulation market payments were $2.1 million during Spring 2026, up 20% from $1.8 million in Spring 2025. The higher payments primarily reflected a nearly $0.5 million increase in capacity payments, partially offset by a $0.16 million decrease in service payments.

Energy Market Competitiveness: The residual supply index for the real-time energy market in Spring 2026 was 108, 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 2026, which was the same as Spring 2025.

Of about 68,000 eligible asset hours that failed structural tests, there were only 178 asset hours of mitigation in Spring 2026 (0.26% of asset hours mitigated). This was up from 65 asset hours of mitigation in Spring 2025. Real-time constrained area energy and commitment mitigation occurred most frequently (about 100 asset hours) in Spring 2026, driven by two constraints binding more frequently due to power flows from the NECEC interface.

[4] https://www.iso-ne.com/static-assets/documents/100036/system-and-market-ops-report-june-2026.pdf

Financial Transmission Rights (FTRs): Since becoming operational in Winter 2026, the NECEC line has increased system congestion costs. Congestion revenue totaled $21.3 million in Spring 2026. This reflects a modest 4% increase from Spring 2025, when transmission outages related to the construction of the NECEC drove high congestion costs. However, Spring 2026 congestion costs were up more than five-fold from Spring 2024, when there was no NECEC-related congestion. Beyond the NECEC, higher day-ahead LMPs and planned outages contributed to an increase in congestion revenue relative to Spring 2025. The CRF was fully funded in each month of Spring 2026.

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 2026	Winter 2026	Spring 2026 vs Winter 2026 (% Change)	Spring 2025	Spring 2026 vs Spring 2025 (% Change)
Real-Time Load (GWh)	26,536	33,233	-20%	26,010	2%
Peak Real-Time Load (MW)	19,496	20,216	-4%	17,346	12%
Average Day-Ahead Hub LMP ($/MWh)	$46.36	$147.99	-69%	$41.19	13%
Average Forecast Energy Requirement Price ($/MWh)	$2.05	$17.50	-88%	$2.66	-23%
Average Real-Time Hub LMP ($/MWh)	$47.54	$137.66	-65%	$39.25	21%
Average Natural Gas Price ($/MMBtu)	$2.79	$17.79	-84%	$3.40	-18%
Average No. 6 Oil Price ($/MMBtu)	$23.95	$15.13	58%	$13.77	74%

Key observations from the table above:

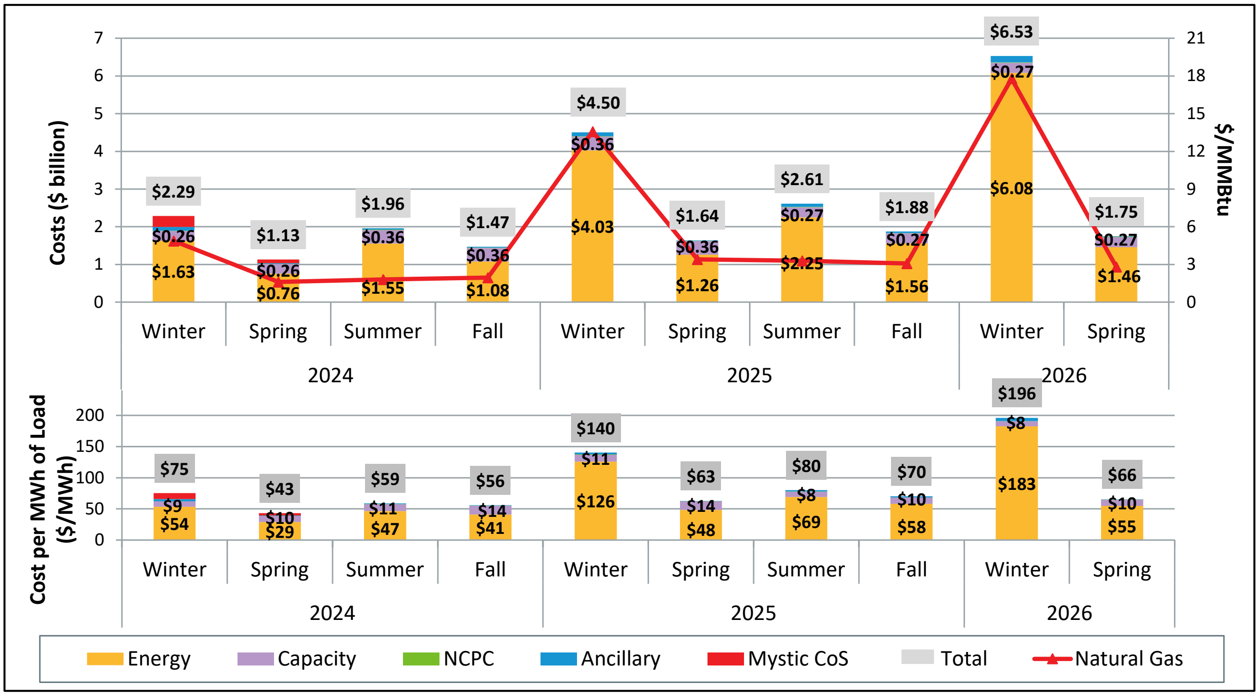
- Day-ahead LMPs averaged $46.36/MWh in Spring 2026, up 13% from Spring 2025. Higher carbon prices put upward pressure on LMPs. The Forecast Energy Requirement Price averaged $2.05/MWh, leading to an all-in day-ahead price of $48.41/MWh for day-ahead cleared physical generation.
- Regional Greenhouse Gas Initiative (RGGI) prices averaged $34/short ton, up from $20.50/short ton in Spring 2025. MA EGEL carbon allowance prices rose from $9.30/metric ton in the March 2025 auction to $30.00/metric ton in the March 2026 auction.[5] These elevated prices reflect tightening emissions caps for both programs coinciding with higher emissions in New England during Winter 2025/2026 due to extreme cold conditions.
- Load increased by 2% compared to Spring 2025 due to warmer weather during May 2026.

[5] See the report from the MA EGEL March 2026 auction: https://www.mass.gov/doc/market-monitor-report-auction-2026-2/download

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. 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.[6] The bottom panel in Figure 2-1 depicts the wholesale cost per megawatt hour of real-time load.

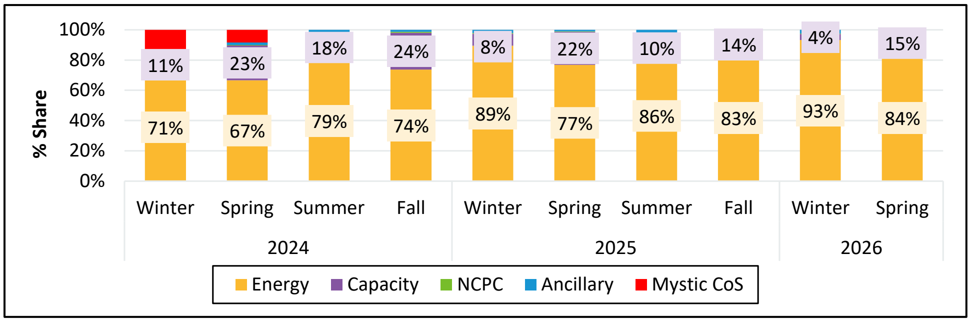
Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Season



In Spring 2026, the total estimated wholesale cost of electricity was $1.75 billion (or $66/MWh of load), a 6% increase compared to $1.64 billion in Spring 2025 and a 73% decrease compared to $6.53 billion in Winter 2026. The increase from Spring 2025 was driven by increased energy costs. The share of each wholesale cost component since Winter 2024 is shown in Figure 2-2 below.

[6] 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 84% of the total wholesale cost, were $1.46 billion ($55/MWh) in Spring 2026, 16% higher than Spring 2025 costs, due to higher carbon costs. In Spring 2026 Regional Greenhouse Gas Initiative (RGGI) prices averaged $33.91/short ton, up from $20.50/short ton in Spring 2025. Massachusetts Electric Generator Emissions Limits (MA EGEL) carbon allowance prices rose from $9.30/metric ton in the March 2025 auction to $30.00/metric ton in the March 2026 auction. Additionally, the energy costs include the cost of the Forecast Energy Requirement (FER) payments made to day-ahead cleared physical generation. FER payments totaled $56 million in Spring 2026, down from $74 million in Spring 2025.

Capacity costs are determined by the clearing price in the primary Forward Capacity Auction (FCA). In Spring 2026, the FCA 16 clearing price resulted in capacity payments of $266 million ($10/MWh), representing 15% of total costs. The current capacity commitment period (CCP 16, June 2025 – May 2026) cleared at $2.59/kw-month, which was similar to the prior year (CCP 15, June 2024 – May 2025). Costs were lower in Spring 2026 due to a decrease in cleared capacity in FCA 16 and less price separation in the import-constrained Southeast New England capacity zone. Section 5.1 discusses recent trends in the Forward Capacity Market in more detail.

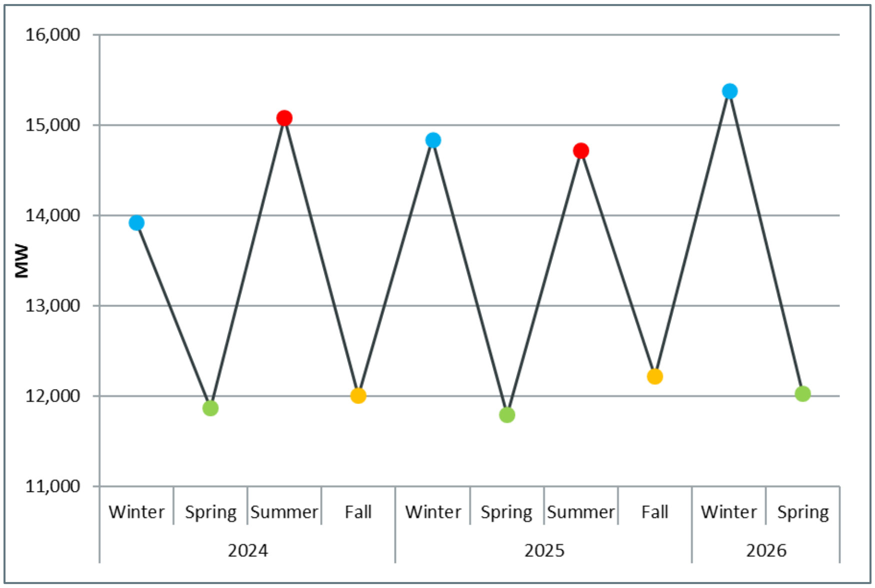
At $9.4 million ($0.35/MWh), Spring 2026 Net Commitment Period Compensation (NCPC) costs accounted for 0.6% of energy costs. Economic payments comprised 98% of total NCPC costs. Section 3.4 provides additional detail on NCPC payments.

Ancillary service costs, which include payments for day-ahead reserves, real-time operating reserves, and regulation, totaled $11.9 million ($0.45/MWh) in Spring 2026, representing 0.7% of total wholesale costs. Reserve payments associated with the Day-Ahead Ancillary Services (DA A/S) market accounted for roughly 75% of total ancillary service costs.

2.2 Load

New England loads typically decline in the spring as heating demand decreases and behind-the-meter (BTM) solar output increases following the winter season.[7] Average hourly load by season is shown in Figure 2-3 below.

Figure 2-3: Average Hourly Load by Quarter



Spring 2026 hourly loads averaged 12,063 MW, increasing 2% from 11,785 MW in Spring 2025. The increase was primarily driven by warmer weather, including a period of particularly elevated temperatures on May 19 and May 20. Despite this increase, overall load patterns remained consistent with typical spring conditions, as declining heating demand and higher behind-the-meter (BTM) solar output continued to moderate system load levels. These higher levels of solar generation increase the reduction in metered load during spring months, particularly during midday hours, highlighting the role of BTM solar as a key factor in seasonal load outcomes.

Relative to the prior year, BTM output also increased from 674 MW in Spring 2025 to 724 MW in Spring 2026 (up 50 MW, or approximately 7%), driven by continued additions of distributed solar resources in New England.

[7] 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.[8]

Figure 2-4: Load Duration Curves

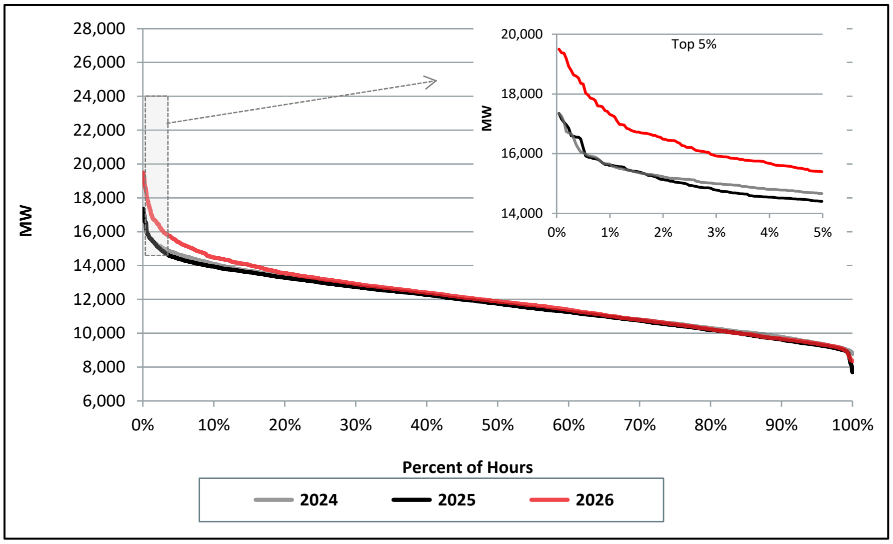


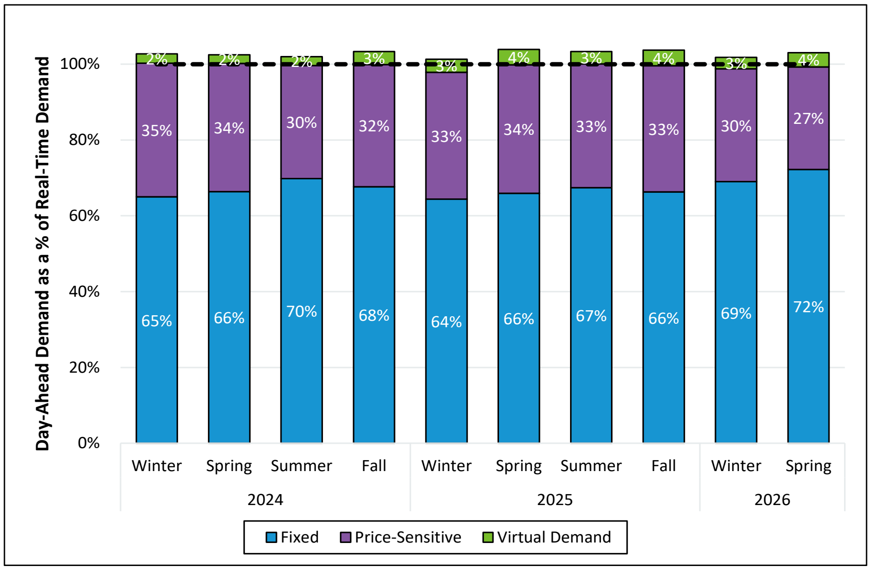
Figure 2-4 shows that loads in Spring 2026 were generally higher than in the prior two years. Load reached a peak of 19,496 MW on May 20 during a heat wave, resulting in the highest spring peak load since 2017. The lowest hourly load in Spring 2026 exceeded the Spring 2025 minimum of 7,665 MW. This indicates that, although favorable solar conditions continued to suppress midday demand, minimum load conditions were higher than in the prior year.

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

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



In Spring 2026, participants cleared 103% of real-time load in the day-ahead market, slightly lower than the 104% cleared in Spring 2025, but consistent with recent levels of over-clearing. This reflects a continuation of clearing behavior above real-time load observed in prior springs.

Participants cleared 72% of demand as fixed bids and 27% as priced bids, compared with 66% fixed and 34% priced in Spring 2025. Priced demand declined to approximately 3,188 MW on average. As in prior periods, priced demand bids were typically submitted at levels above expected LMPs, making them likely to clear.

Virtual demand clearing (DECs) accounted for approximately 4% of cleared demand, similar to Spring 2025.[9] Overall, day-ahead cleared demand totaled 12,120 MW compared to real-time load of 11,801 MW.

[9] See 0 for more information on virtual demand.

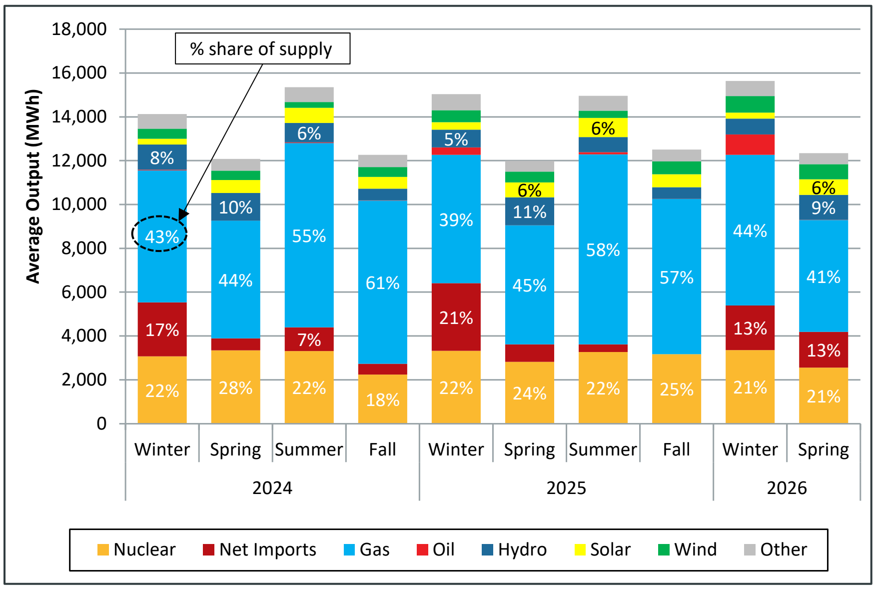
2.3 Supply

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 2024 through Spring 2026 is illustrated in Figure 2-6 below. Each bar's height represents the average electricity generation from that fuel type, while the percentages represent share of total generation.[10]

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



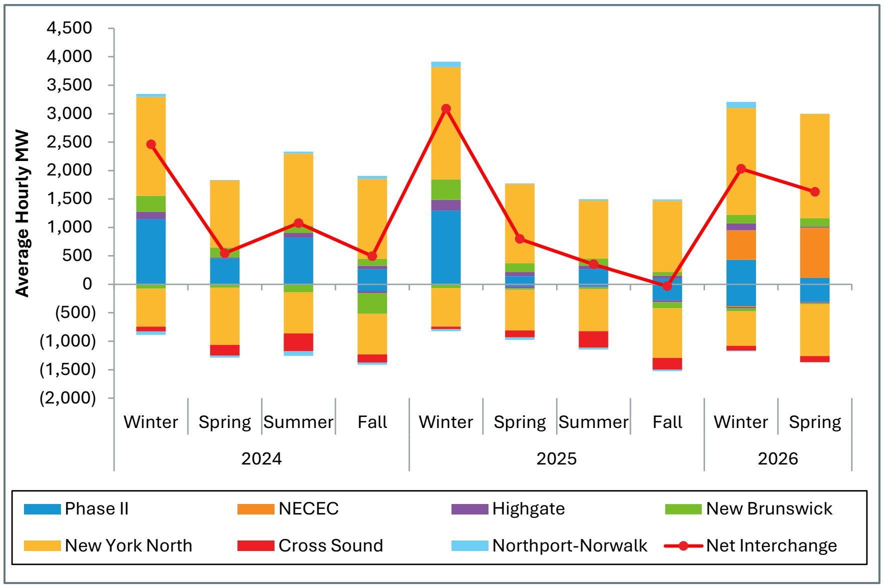
In Spring 2026, higher imports offset lower nuclear and gas generation. Net imports supplied 13% of the region's energy. Lower nuclear output was driven by planned refueling outages. Average net imports more than doubled compared with Spring 2025 due to flows over the new NECEC line, discussed in more detail in the following section. Nuclear and gas-fired generation continued to provide the majority of New England's energy, accounting together for 62% of total average production in Spring 2026.

2.3.2 Imports and Exports

In Spring 2026, New England was a net importer of power from the neighboring control areas in Canada and New York, with imports on the new NECEC line driving a significant increase in the net interchange from Spring 2025. 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.

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

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



On average, the net flow of energy into New England was 1,625 MW per hour from Canada and New York combined. This represented an increase of 104% from a net interchange of 798 MW per hour in Spring 2025.

Canadian interfaces

Spring 2026 was the first full quarter in which the new NECEC transmission line from Quebec to New England was operational, driving the highest net interchange across all Canadian interfaces (819 MW per hour) since Winter 2025. NECEC flows averaged 885 MW per hour, up from 511 MW per hour in Winter 2026, when the line was operational for only half of the quarter. Since NECEC entered service, New England has typically imported about 1,100 MW per hour over the interface when the line is in service; however, both planned and unplanned outages during Spring 2026 reduced the quarterly average below that level.

Net imports over the NECEC interface were partially offset by net exports (194 MW per hour) over the Phase II interface. While New England has typically been a net importer over Phase II, Spring 2026 marks the second quarter in the past year when it has been a net exporter (net exports averaged 172 MW per hour in Fall 2025). As noted in previous reports, drier weather over the past few years has reduced the excess energy available in Quebec and limited exports from Canada into New England. Recent Hydro-Québec reports highlight efforts to manage imports and exports in a way that preserves water resources and energy reserves while maximizing revenue.[11] During Spring 2026 New England was a net exporter over Phase II in 35% of hours, compared to 4% of hours in Spring 2025 and 0% of hours in Spring 2024.

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[11] For more information on the reduction in exports, see Hydro-Québec's *Quarterly Bulletin, First Quarter 2026*, available at https://www.hydroquebec.com/data/documents-donnees/pdf/quarterly-bulletin-2026-1.pdf and the 2025 Annual Report, available at https://www.hydroquebec.com/data/documents-donnees/pdf/hq-rapport-annuel-2025-anglais.pdf.

Highgate, the other interface connecting New England to Quebec, was out of service for nearly two months in Spring 2026. As a result, New England imported an average of only 1 MW per hour over that interface, down from 39 MW per hour in Spring 2025.New England imported the same amount (127 MW per hour) from New Brunswick as in Spring 2025, despite a planned outage at a large nuclear generator in New Brunswick that started in mid-April 2026.

New York Interfaces

With average net imports of 806 MW per hour, New York remained an important source of supply for New England in Spring 2026. Net interchange increased by 284 MW per hour relative to Spring 2025, driven primarily by a 35% (239 MW) increase in net imports at the New York North interface. The increase occurred despite slightly higher average prices in New York. In Spring 2026, the average day-ahead price on the New York side of the interface was $0.40 higher than the day-ahead price (including the FER price) on the New England side. When prices are higher in New York, participants may still be willing to import into New England at a loss and collect additional revenues through Power Purchase Agreements or by selling Renewable Energy Certificates.

New England exports energy to Long Island, an area that is often import-constrained compared to the rest of the New York control area. In Spring 2026, New England exported an average of 110 MW to Long Island over the Cross Sound Cable, down 9% from Spring 2025. The other interface with Long Island, Northport-Norwalk, was out of service for all but one week of the quarter. As a result, New England imported 3 MW per hour over the entire quarter, compared to average net exports of 31 MW per hour in Spring 2025.

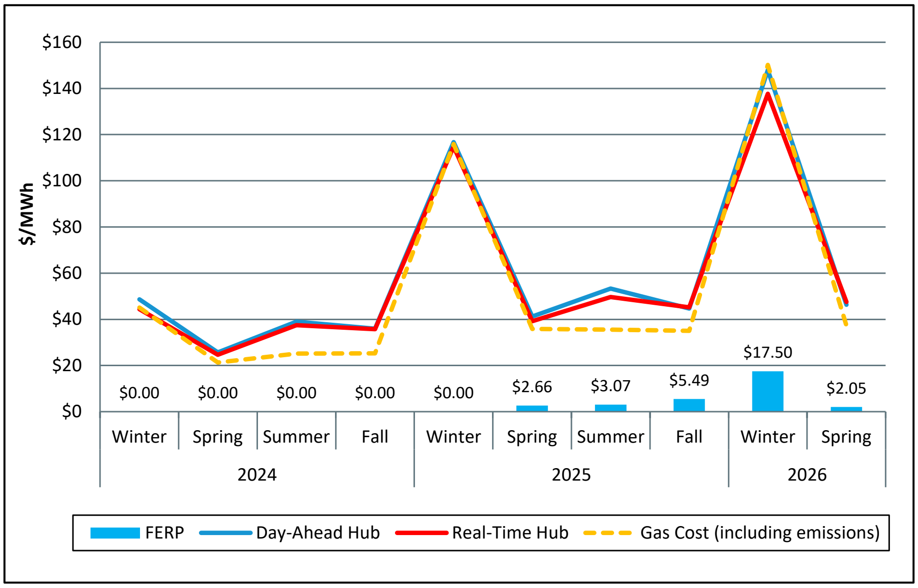
Section 3
Day-Ahead and Real-Time Markets

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 LMPs, along with the estimated fuel and emissions costs of generating electricity using natural gas in New England.[12] The figure also shows the Forecasted Energy Requirement Price (FERP), which is a payment to day-ahead cleared physical generation and charged to real-time 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 LMPs averaged $46.36/MWh and $47.54/MWh respectively in Spring 2026, up 13% and 21% compared to Spring 2025. The FER price averaged $2.05/MWh leading to an

[12] 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.

all-in cost of $48.41/MWh for day-ahead cleared physical generation. Higher LMPs resulted from increased carbon costs (discussed below) and baseload outages taken during Spring 2026. The New England Clean Energy Connect (NECEC) experienced both planned and forced outages this spring, coinciding with scheduled refueling outages at two nuclear generating units. These baseload outages result in a higher frequency of less-efficient generators setting the marginal price for the system.

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 10% lower than the Hub price, respectively. This price separation has occurred since the NECEC interface began commercial operation in January 2026.

In Spring 2026, carbon allowance prices continued to increase under both the Regional Greenhouse Gas Initiative (RGGI) and Massachusetts Electric Generator Emissions Limits (MA EGEL) programs. In the March 2026 auction, RGGI allowances cleared at $24.99/short ton.[13] Spot prices from the secondary market surged in late April and early May, reaching an all-time high of approximately $55/short ton. As a result, Spring 2026 RGGI prices averaged $33.91/short ton, up from $20.50/short ton in Spring 2025. MA EGEL carbon allowance prices rose from $9.30/metric ton in the March 2025 auction to $30.00/metric ton in the March 2026 auction.[14] These elevated prices reflect tightening emissions caps for both programs coinciding with higher emissions in New England during Winter 2025/2026 due to extreme cold conditions.[15] In addition, the spike in RGGI spot prices likely reflected market expectations surrounding Virginia's planned reentry into RGGI on July 1, 2026.

During seasons when natural gas prices are low, emissions costs make up a substantial share of natural gas generators' production costs, as shown in Figure 3-2.[16]

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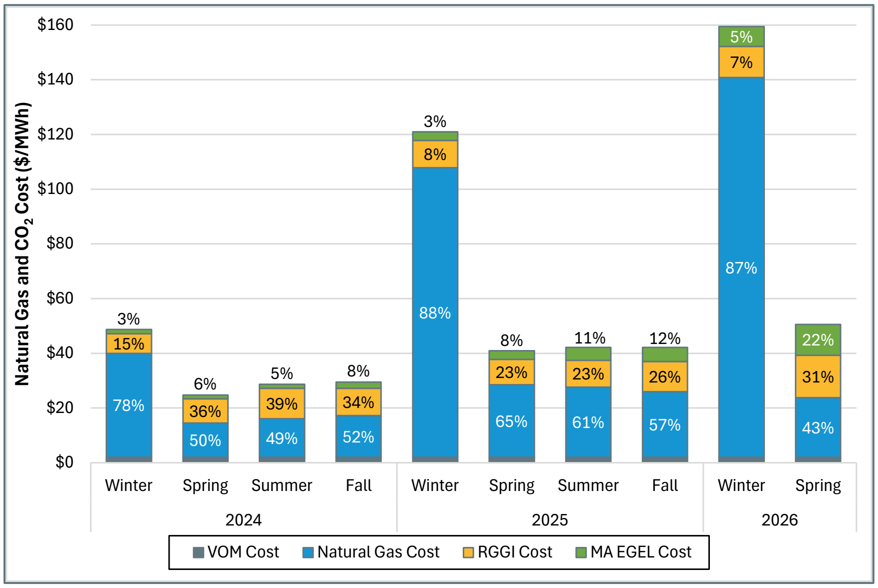
[13] RGGI auction results are documented here: https://www.rggi.org/auctions/auction-results

[14] See the report from the MA EGEL March 2026 auction: https://www.mass.gov/doc/market-monitor-report-auction-2026-2/download

[15] See the ISO's estimates of CO_2 emissions through April 2026 here: https://isonewswire.com/2026/06/02/monthly-wholesale-electricity-prices-and-demand-in-new-england-april-2026/

[16] Fuel, CO_2 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. CO_2 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.

Figure 3-2: Estimated Average Costs of Generation and Emissions



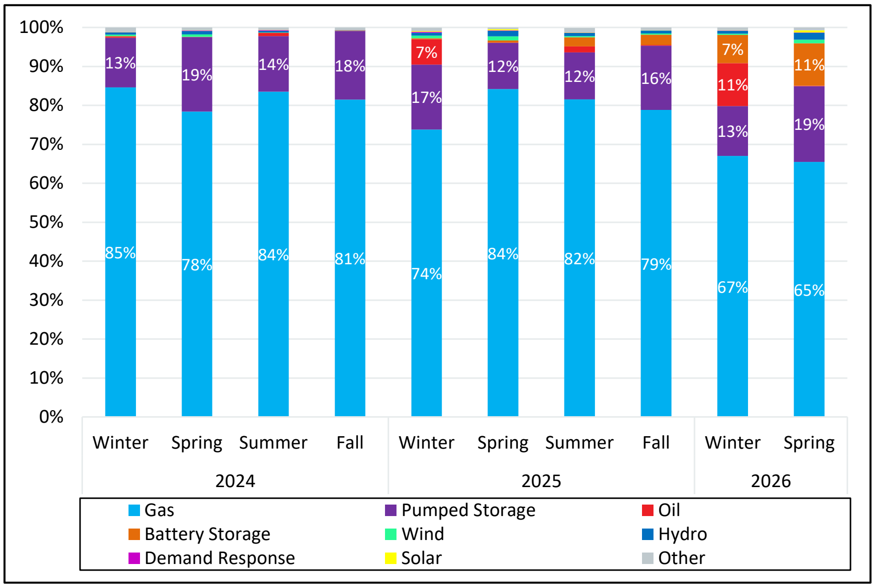
In Spring 2026, RGGI compliance costs added $15.47/MWh to the production cost of an average natural gas combined-cycle unit, up from $9.35/MWh in Spring 2025. MA EGEL compliance costs increased from $3.10/MWh in the prior spring to $11.33/MWh. In total, emissions costs from the RGGI and MA EGEL programs accounted for 53% of production costs for natural gas generators in Massachusetts, up from 30% in Spring 2025. The data suggest that covered generators are fully incorporating these increased costs into their energy market offers.

3.2 Marginal Resources and Transactions

This section reports marginal resources by transaction and fuel type on a load-weighted basis. When more than one resource is marginal, the system generally is constrained, and the marginal resources frequently do not contribute equally to setting prices for load across the system. The methodology used in this section accounts for these differences by weighting each marginal resource's contribution 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 2024 is shown in Figure 3-3 below.

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



Natural gas generators were the most frequent marginal unit in Spring 2026, as they set price for 65% of real-time load. Gas decreased as a share of the marginal unit mix relative to the prior Spring seasons. This was due, in part, to a modest decrease in gas generation throughout the season as the NECEC drove an offsetting increase in imports.[17] In addition, energy storage resources were marginal more frequently than in prior spring seasons, displacing gas as price-setting energy over daily peaks. Pumped storage set price for a similar share of load as in prior seasons (19%); the increase in marginal energy storage resources was driven by an increase in battery generation, which set price for 11% of real-time load.[18] The increasing marginality of energy storage resources carries important implications for price formation; energy storage resources offer based on their expected opportunity costs of charging or discharging, and reduce prices when they clear in place of costlier generation in peak hours.

[17] See 2.3.1 for more information on generation by fuel type, and 2.3.2 for more information on the NECEC.

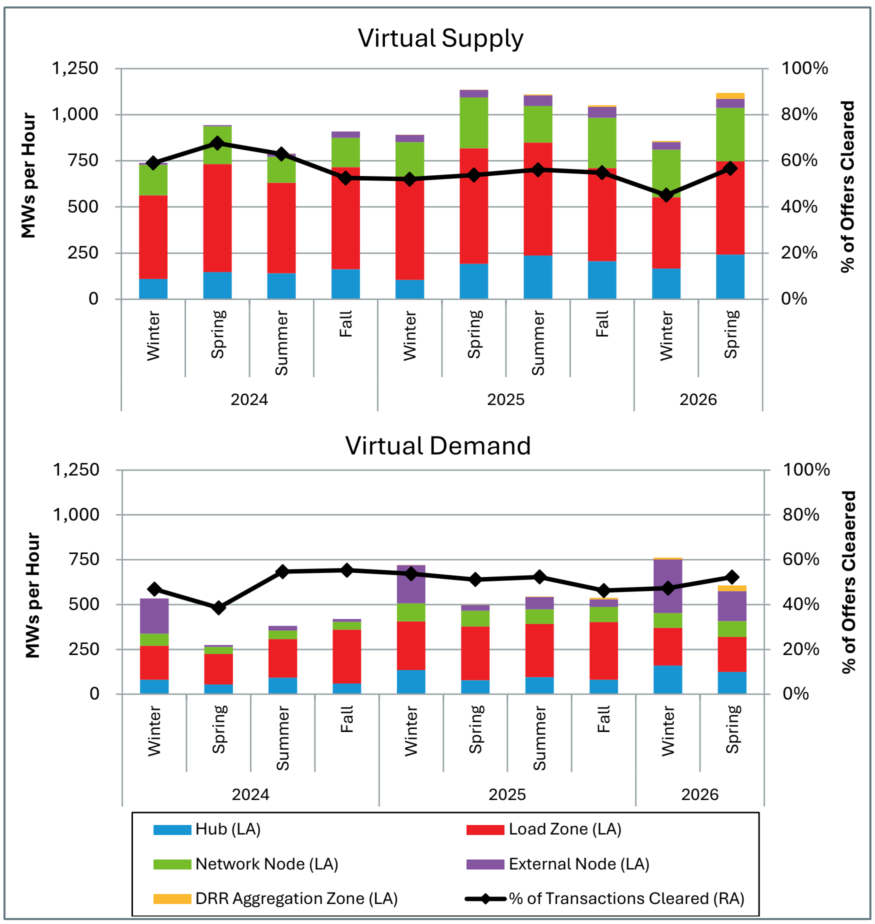
[18] Note that the energy storage resources can set price when they consume energy through their demand bids. The marginal unit estimates in this figure combine the shares of load for which energy storage was marginal through either generation or demand.

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 to better reflect real-time conditions.

The average volume of cleared virtual supply (top graph) and virtual demand (bottom graph) by quarter are shown on the left axis in Figure 3-4 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 on the right axis of each chart shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

Figure 3-4: Cleared Virtual Transactions by Location Type



Cleared virtual supply averaged 1,118 MW per hour in Spring 2026, down 2% from Spring 2025 (1,136 MW per hour). The percentage of offers cleared increased from Winter 2026 but was on par with other recent seasons. In recent years, virtual supply has consistently increased alongside the growth in solar participation, filling in for settlement-only generation (SOG) which does not participate in the day-ahead market but generates in the real-time. However, this marks the second consecutive quarter in which virtual supply volumes decreased from the prior year, despite a 4%

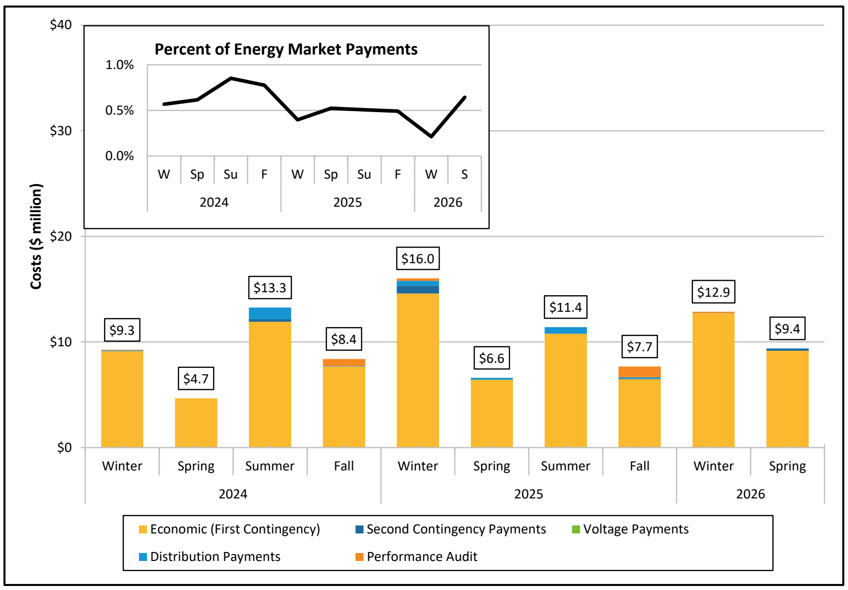
year-over-year increase in SOG solar installed capacity. The decrease in cleared virtual supply could be a response to a slightly higher average RT LMP over the quarter ($1.18 higher than the average DA LMP).

Cleared virtual demand averaged 607 MW per hour, up 22% from 498 MW per hour in Spring 2025. Cleared virtual demand bids decreased at the load zones (-105 MW/hour) but increased at the Hub (47 MW/hour), external interfaces (136 MW/hour) and DRR aggregation zones (32 MW/hour).

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. Figure 3-5 below shows quarterly NCPC by category and season for 2024-2026. The inset chart shows NCPC as a percentage of energy market payments.

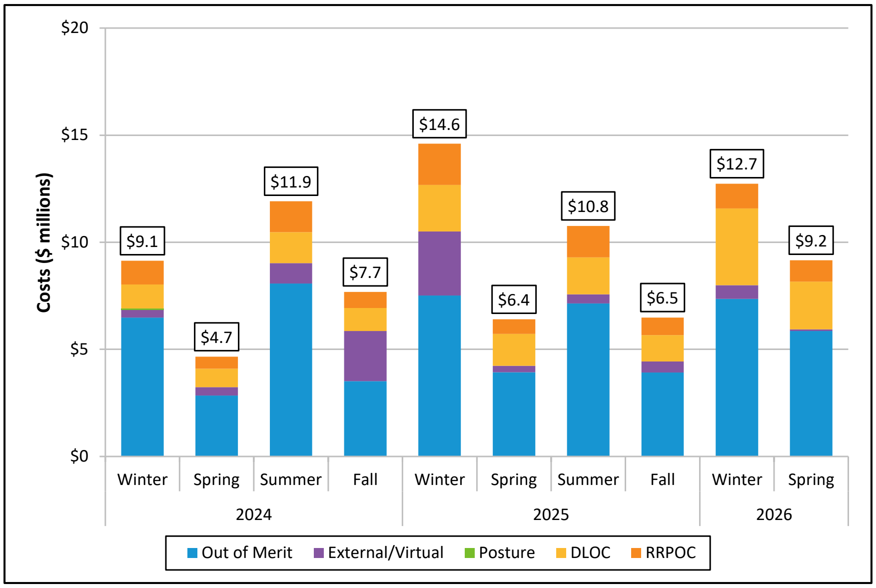
Figure 3-5: NCPC by Category



NCPC payments totaled $9.4 million in Spring 2026, up 42% from Spring 2025 and representing 0.6% of energy costs. Almost all uplift payments were economic (98%), with the remaining payments covering second-contingency and distribution commitments.

The increase in total NCPC relative to Spring 2025 is attributable to higher economic uplift payments. Economic payments can be subcategorized, including payments for out of merit commitments, external or virtual transactions, posturing, and dispatch lost opportunity costs (DLOC) or rapid-response pricing opportunity costs (RRPOC). Figure 3-5 below shows economic payments by subcategory.

Figure 3-6: Economic NCPC by Reason



Two subcategories drove the increase in economic NCPC relative to prior spring quarters. First, out of merit NCPC totaled $5.9 million, up almost 50% from Spring 2025. Fast-start or other supplemental real-time commitments often require real-time out of merit uplift when operators manually commit units to meet system reliability needs. Such interventions typically are relatively rare in shoulder seasons due to relaxed system conditions; however, Spring 2026 featured a few notably hot days with high loads. The two highest-load days (May 19 and May 20) accounted for more than $1 million in total NCPC (13%), mostly due to real-time out of merit commitment uplift.

Second, DLOC uplift totaled $2.2 million, a 50% increase from Spring 2025. DLOC credits compensate generators when they receive dispatch instructions that are below their profit-maximizing output. This primarily occurs because dispatch instructions are sent 10 to 15 minutes in advance to give resources time to ramp up or down; when resources ramp down early, DLOC credits compensate their opportunity costs of following dispatch instructions. Because DLOC credits are based on opportunity costs, they rise with LMPs, and the higher Spring 2026 LMPs partly explain the higher DLOC credits throughout the season. Additionally, many battery storage generators have become operational since Spring 2025; battery storage units can ramp almost immediately and therefore receive relatively large DLOC credits when they receive advance dispatch instructions. Batteries received $421k in DLOC credits (19% of total DLOC) in Spring 2026.

3.5 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 summarizes outcomes related to this market for the period between March 1, 2025, and May 31, 2026.[19]

3.5.1 Flexible Response Services

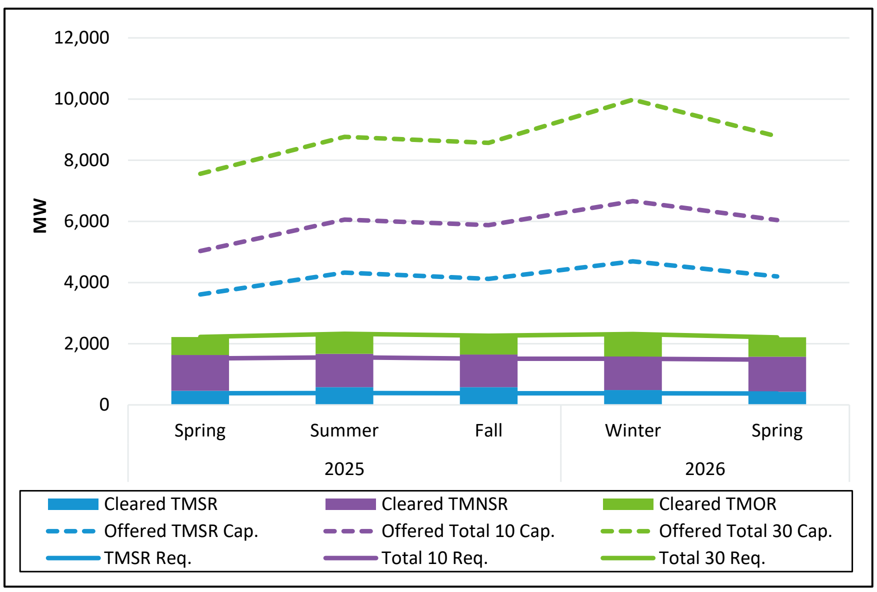
One set of ancillary service capabilities procured via the DA A/S market ensure that the ISO has sufficient fast-starting and fast-ramping capability to quickly respond to a large supply loss. These capabilities, commonly called operating reserve capabilities, are referred to as Flexible Response Services (FRS) under this market design. Requirements for FRS capabilities have analogs to those that exist in the real-time market, including the ten-minute spinning reserve, total ten-minute reserve, and total 30-minute reserve requirements.[20]

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)

In general, offered FRS capability has been many times larger than FRS requirements. This can be seen in Figure 3-7, which shows the average hourly FRS requirements, offered capability, and the cleared awards, by quarter.[21]

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



[19] The DA A/S market went live for the operating day of March 1, 2025.

[20] For more information about these requirements, see *Section III Market Rule 1: Standard Market Design*, Section III.1.8.3, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

[21] Offered capabilities reflect participant-submitted DA A/S offer quantities limited by physical resource characteristics (e.g., ramp rate, ecomax).

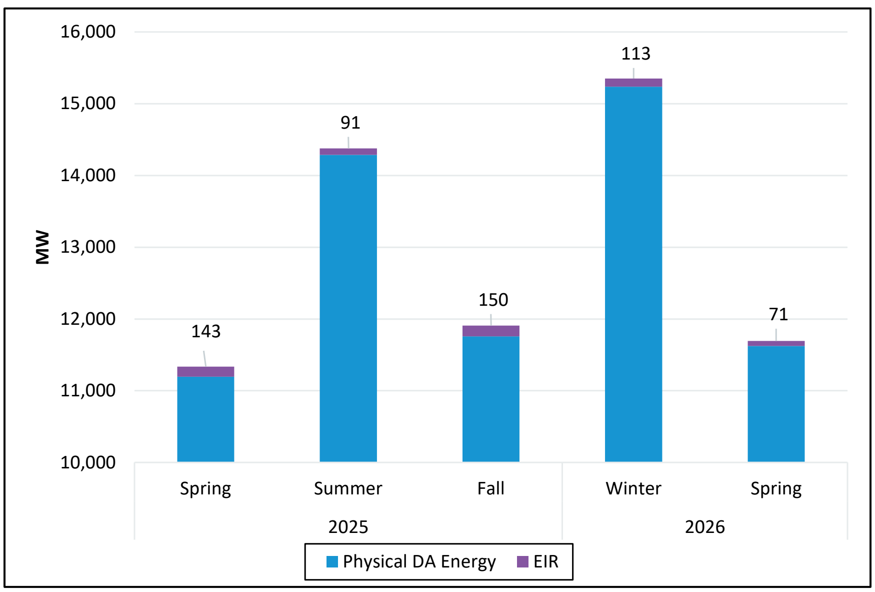
While the FRS requirements – which are based on the projected first and second contingencies – did not change much quarter over quarter, the offered capability that could meet those requirements decreased moderately relative to the winter.[22] This decreased participation is partly reflective of resources undertaking maintenance during the spring season when load tends to be lower. Notably, average offered capability increased between 15%-20% relative to the prior spring, which was the first season of the new market design.

3.5.2 Energy Imbalance Reserves

The other ancillary service procured in the DA A/S market is reserve capability that can be used to help meet the load forecast. Physical supply resources within New England that have 60-minute reserve capability can now be compensated for this capability by clearing offers on a new ancillary service product called Energy Imbalance Reserve (EIR). The market clearing engine procures this product via the Forecast Energy Requirement (FER) constraint, which can be satisfied by a mix of day-ahead energy awards cleared on physical resources and EIR awards. Both groups (i.e., physical supply resources with day-ahead energy awards and EIR awards) are paid the FER Price (FERP) as both contribute 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 3-8, which shows the average hourly cleared FER supply by quarter.

Figure 3-8: Cleared Awards to Satisfy the Forecast Energy Requirement



[22] The non-performance factor used to determine the Ten-Minute (Total 10) Reserve Requirement was reduced from 120% to 115% effective 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.

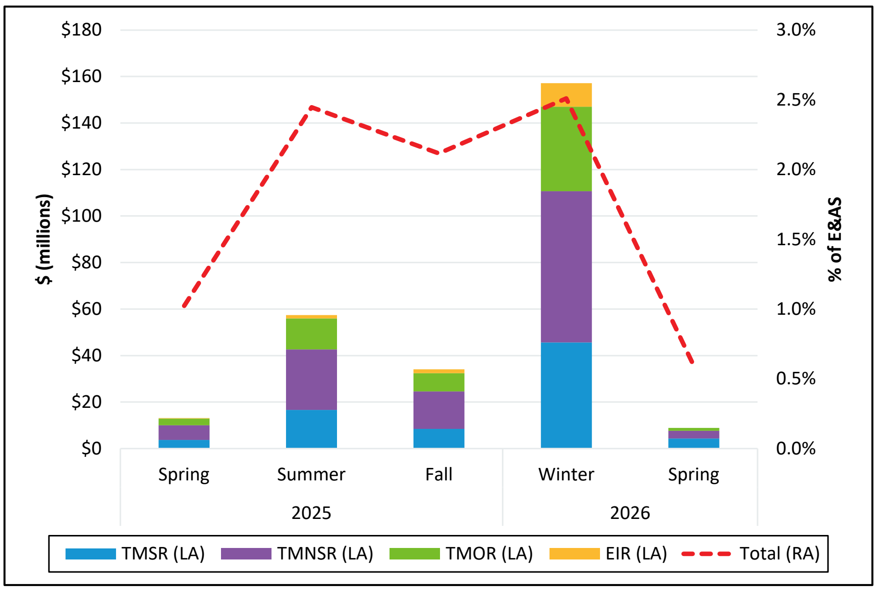
The average hourly volume of EIR that cleared decreased in Spring 2026 (71 MW) relative to Winter 2026 (113 MWh). For the quarter, EIR represented less than one percent of the capability used to satisfy the FER demand, with cleared day-ahead energy accounting for over 99%.

3.5.3 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.

To date, the DA A/S products have represented a small percentage of overall energy and ancillary services (E&AS) payments.[23] This can be seen in Figure 3-9, which shows, by season, the *net* payment for each DA A/S product (as colored bars) as well as the total net payment for all DA A/S products expressed as a percentage of E&AS payments (as a line).[24]

Figure 3-9: DA A/S Settlements ($ millions)



Total net ancillary services payments dropped significantly between Winter 2026 ($157.1 million) and Spring 2026 ($8.8 million) but were at a similar level to the prior spring ($13.1 million). When expressed as a percentage of E&AS payments, DA A/S payments represented their lowest level (0.6%) since the start of the market. One reason for this was that net DA A/S payments were negative for the month of May 2025 (-$5.8 million) as realized closeouts frequently exceeded DA A/S clearing prices. There is no guarantee under the DA A/S market design that net DA A/S

[23] Total energy and ancillary services costs include day-ahead and real-time energy, reserve, regulation, and NCPC payments.

[24] The net payments for each DA A/S product are measured in millions of dollars on the left axis (LA) while the total net payment for all DA A/S products is measured as a percentage of E&AS payments on the right axis (RA)

payments will be positive over a monthly horizon, and many resources may have offset their DA A/S settlement with production of energy in the real-time market.

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 and the average price during these intervals are shown by product for the past three spring seasons in Table 2-1 below.

Table 3-1: Hours and Level of Non-Zero Reserve Pricing

Product	Spring 2026		Spring 2025		Spring 2024	
	Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	$15.64	78.9	$6.87	175.3	$6.98	173.5
TMNSR	$86.93	3.0	$54.49	1.2	$29.90	0.3
TMOR	$73.16	1.9	$168.77	0.3	$0.00	0

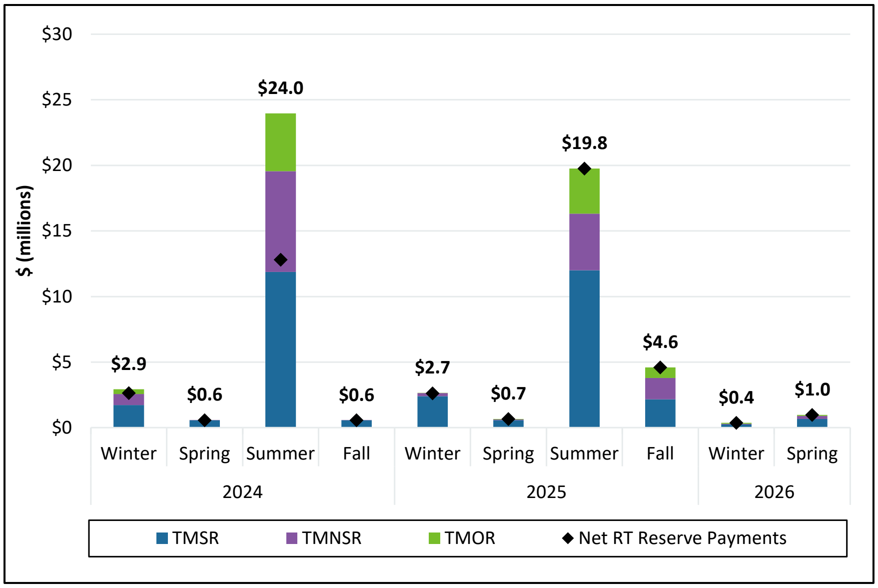
The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in about 79 hours during Spring 2026. This spring season had a lower frequency of TMSR pricing than the prior two seasons, indicating a lower need to re-dispatch resources in order to create TMSR. These re-dispatches primarily occurred around the evening peak, when the spinning capability of the generation fleet is converted into energy production in order to meet the higher loads. Non-zero TMNSR and TMOR prices continued to occur infrequently, indicating that, generally, there was ample supply of total-ten and thirty-minute reserve capability available on the system in Spring 2026.

[25] For more information about these requirements, see *ISO New England Operating Procedure No. 8 Operating Reserve and Regulation*, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

Real-time Reserve Payments

Real-time reserve payments by product are illustrated in Figure 3-10 below. The height of the bars indicates gross reserve payments, while the black diamonds show net payments.[26]

Figure 3-10: Real-Time Reserve Payments by Product



Net reserve payments in Spring 2026 ($1.0 million) were similar to those in the prior two springs. Notable seasonal reserve payments illustrated in this figure include Summer 2024, Summer 2025, and Fall 2025. All three of these seasons had at least one period when a Capacity Scarcity Condition (CSC) existed; these are periods when the system is tight on total ten-minute or total thirty-minute reserves and reserve clearing prices are set by Reserve Constraint Penalty Factors (RCPFs).[27]

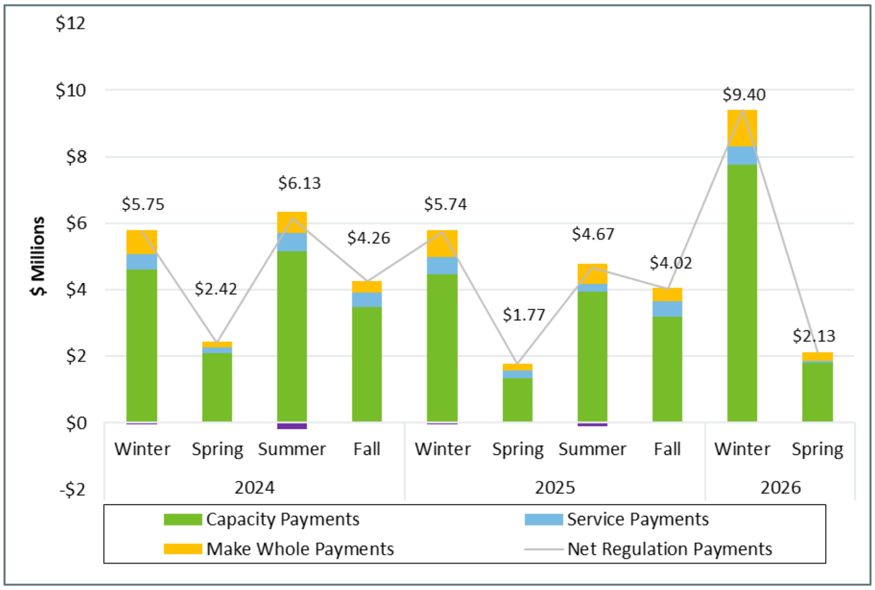
[26] Net payments reflect reductions to Forward Reserve Market (FRM) resources providing real-time reserves. The FRM was a forward market that procured operating reserve capability in advance of the actual delivery period. This market sunset with the implementation of Day-Ahead Ancillary Services (DA A/S) market on March 1, 2025. Under the FRM design, real-time reserve payments to generators designated to satisfy forward reserve obligations were reduced by a forward reserve obligation charge so that a generator was not paid twice for the same service.

[27] For more information about Capacity Scarcity Conditions, see *Section III Market Rule 1: Standard Market Design*, Section III.13.7.2.1, available at: https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.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 3-11 below.

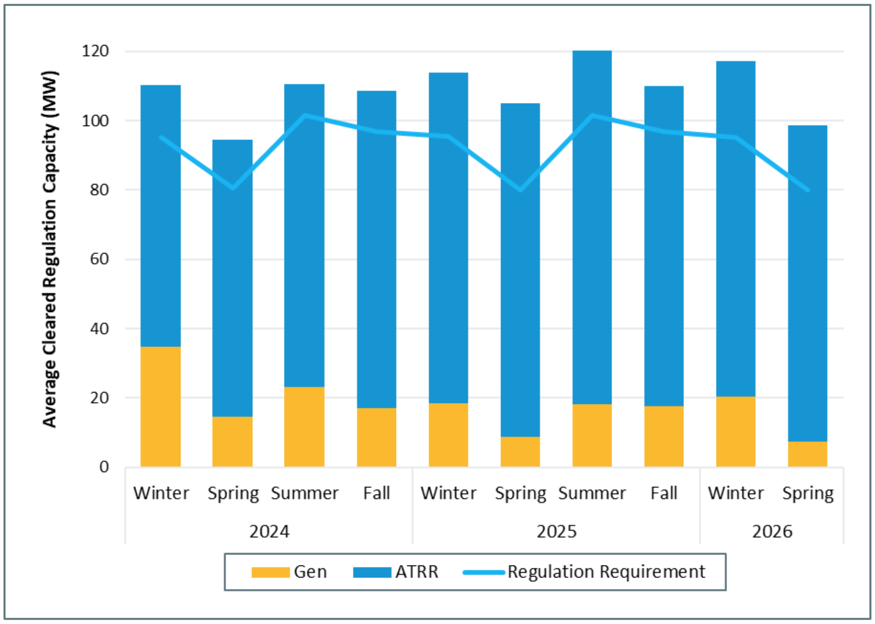
Figure 3-11: Regulation Payments



Total regulation market payments were $2.1 million during Spring 2026, up 20% from $1.8 million in Spring 2025. The increase primarily reflected higher capacity payments, which increased from $1.3 million to $1.8 million (35%). This increase was partially offset by lower service payments, which declined from $0.22 million in Spring 2025 to $0.06 million in Spring 2026. Make-whole payments increased from $0.21 million to $0.26 million.

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 3-12 below.

Figure 3-12: Average Cleared Regulation MW by Resource Type



The resource mix of cleared regulation capacity has changed significantly over the past several years as battery resources have increased their participation in the regulation market. By Spring 2024[28], ATRRs (blue shading) accounted for 84% of cleared regulation capacity, compared to substantially lower shares in earlier periods. Since then, the resource mix has remained relatively stable. In Spring 2026, ATRRs cleared an average of 91 MW of regulation capacity, representing 92% of total cleared regulation, consistent with Spring 2025. Traditional generators provided the remaining 8% of cleared regulation capacity. The sustained dominance of ATRRs suggests that battery resources remain lower-cost providers of regulation service and continue to clear ahead of traditional generators in the regulation merit order.

[28] More information about average cleared regulation MW by resource type before 2024 can be found in the 2024 Spring Quarterly Markets Report 2024-spring-quarterly-markets-report.pdf

Section 4
Energy Market Competitiveness

One of ISO New England's three critical goals is the administration of competitive wholesale energy markets. Competitive markets help ensure that consumers pay fair prices while providing generators with incentives to make short- and long-term investments that maintain system reliability. This section first evaluates energy market competitiveness by quarter using two system-level structural market power metrics. It then presents statistics on instances of system and local market power identified by the automated mitigation system, as well as the amount of mitigation applied when a supply offer was replaced with 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 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%
Summer 2025	104.4	31%
Fall 2025	103.0	39%
Winter 2026	107.6	13%
Spring 2026	108.0	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.

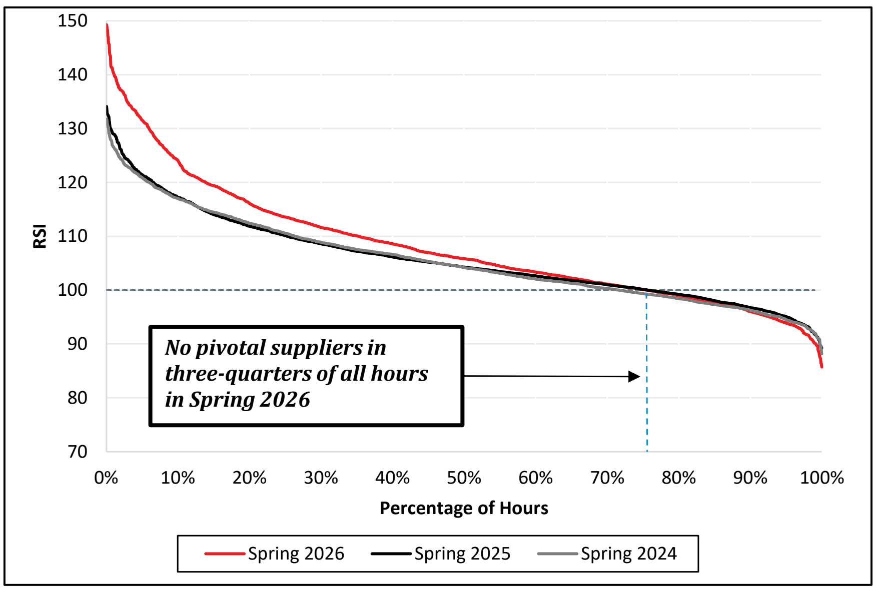
[30] The real-time supply margin measures the amount of available supply on the system after load and the reserve requirement are satisfied. It accounts for ramp constraints and is equal to the Total30 reserve margin: Gen_{Energy} + $Gen_{Reserves}$ + $[Net\ Interchange]$ -$Demand$ - $[Reserve\ Requirement]$

[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 every quarter of the reporting period, indicating that, on average, the ISO could satisfy load and reserve requirements without the largest supplier. The RSI of 108.0 was the highest RSI since Spring 2020. The RSI has increased due to higher reserve margins. The two factors that played a role in higher reserve margins are: 1) lower reserve requirements (resulting from a lower first contingency value) and 2) an increase in battery storage capacity. There was at least one pivotal supplier in 25% of real-time pricing intervals in Spring 2026 which was equivalent to the previous spring.

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 2026, the RSI was above most observations during the last two springs. However, the RSI was similar to prior springs when the RSI was below 100. This indicates that the market is more competitive than prior springs during times with surplus capacity than during periods with tighter system conditions.

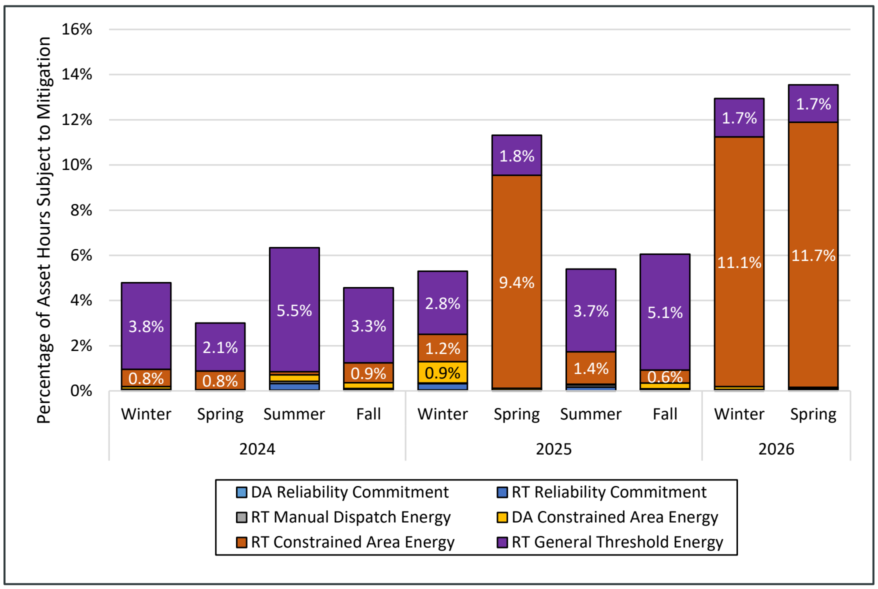
4.2 Energy Market Supply Offer Mitigation

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 2026.

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 2024 to Spring 2026 is shown below in Figure 4-2.[33]

Figure 4-2: Energy Market Mitigation Structural Test Failures



In Spring 2026, about 500,000 total asset hours were subject to mitigation, in which approximately 68,000 asset hours (13.6%) failed structural tests.[34] Like last spring and this winter, the structural test for real-time constrained area energy mitigation failed the most frequently this spring. This spring, the real-time constrained area energy mitigation structural test failures were driven by generators on the import-constrained side of two large constraints (the Maine-New Hampshire and

[32] Day-Ahead Ancillary Services mitigations can be found in Section **Error! Reference source not found.**.

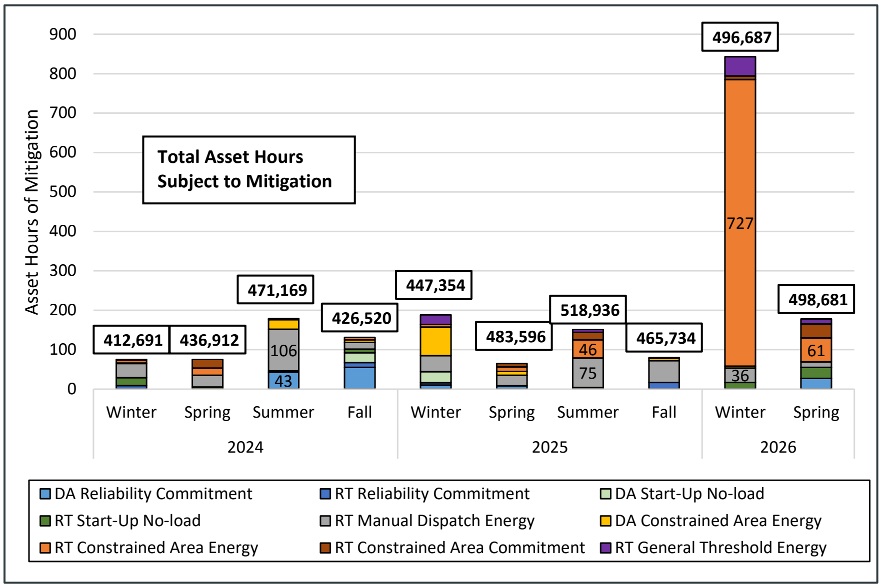
[33] A structural test failure depends on the type of mitigation analyzed. For the definitions of the structural test applied in general threshold and constrained area mitigation, see *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.5.2, available 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 by adding economically committed generators or self-scheduled generator with an economic dispatchable range at or above 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.

Northern New England Scobie 345 kV – Scobie + 394 constraints), discussed more in Section 5.2. These constraints binding more often than in previous seasons due to the NECEC line, discussed more in Section 2.3.2.

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



Overall, there was a low number of mitigation asset hours in Spring 2026 (178), which was higher than in Spring 2025 (65) and lower than Winter 2026 (843). Real-time constrained area energy and commitment mitigation occurred most frequently (about 100 combined asset hours).[35]

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 2026, structural test failures totaled nearly 59,000 asset hours spread across several load zones. As discussed above, the market power flags associated with these mitigations were driven by two constraints binding more frequently due to power flows from the NECEC interface. The conduct and impact tests for real-time constrained area energy were also not as likely to be violated in Spring 2026 as in Winter 2026 due to the relatively low gas and energy prices in the spring. The conduct test fails if any offer block price exceeds the reference level by an amount greater than 50% or $25/MWh, whichever is lower. When overall prices are high, $25/MWh represents a smaller percentage markup over reference and may be more likely to be violated if participants have not communicated accurate fuel prices or heat rates to the IMM.

[35] More information on Energy Market Mitigation types and thresholds can be found in *An Overview of New England's Wholesale Electricity Markets (2025 Update)* (May 23, 2025), Section 11.2.1, available at https://www.iso-ne.com/static-assets/documents/100023/imm-markets-primer.pdf.

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 27 asset hours of reliability commitment mitigations in Spring 2026, an increase from 8 asset hours in Spring 2025.

Start-up and no-load (SUNL) commitment mitigation: This mitigation type addresses offered commitment costs that significantly exceed reference levels, which could otherwise result in very high uplift.[37] 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 Spring 2026, there were 28 asset hours of SUNL mitigations.

General threshold energy (GTE) mitigation: In Spring 2026, there were 13 asset hours of general threshold energy mitigation. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators, with five participants accounting for 86% 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 61% of the 126 asset hours of manual dispatch in Spring 2026. Due to a relatively tight conduct test, manual dispatch energy mitigation typically occurs more often than most other mitigation types, although there were only 14 asset hours of manual dispatch energy mitigation in Spring 2026.

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[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).

Section 5
Forward Markets

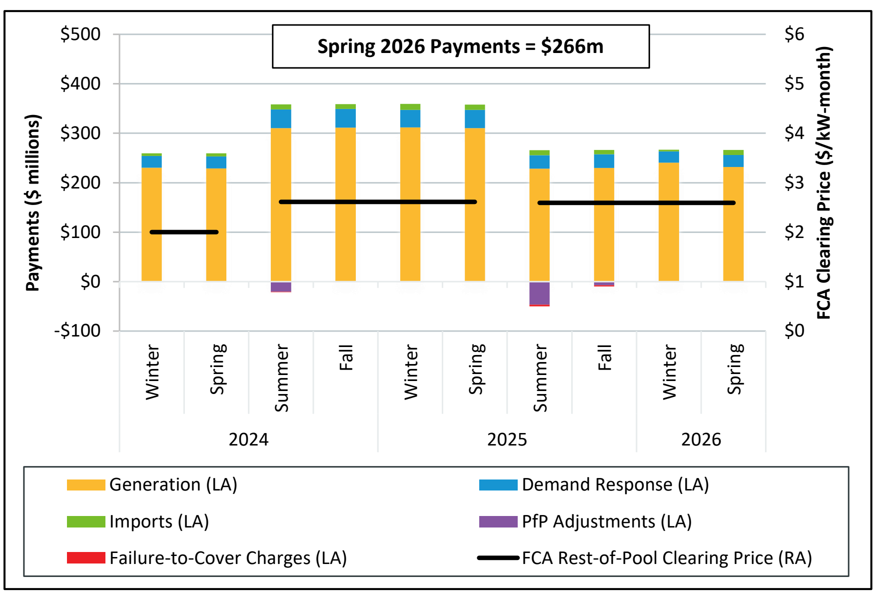
This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs).

5.1 Forward Capacity Market

The Capacity Commitment Period (CCP) associated with Spring 2026 started on June 1, 2025, and ended on May 31, 2026. The corresponding Forward Capacity Auction (FCA 16) cleared at \$2.59/kW-month for the Rest-of-Pool capacity zone, with prices relatively unchanged from FCA 15 (\$2.61/kW-month). The auction cleared with 32,810 MW of Capacity Supply Obligation (CSO), representing a surplus of more than 1,000 MW over the Net Installed Capacity Requirement (Net ICR; 31,645 MW). FCA 16 cleared with modest price separation; the import-constrained Southeast New England capacity zone cleared at \$2.64/kW-month, while the export-constrained Northern New England and Maine capacity zones cleared at \$2.53/kW-month. Although new generating capacity additions totaled less than 600 MW for FCA 16, solar and battery resources comprised the largest shares of new capacity.

Total FCM payments, as well as the clearing prices for Winter 2024 through Spring 2026, 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.

Figure 5-1: Capacity Market Payments



Capacity payments totaled \$266.4 million in Spring 2026, down 26% from Spring 2025. Capacity payments declined despite similar clearing prices between FCA 15 and FCA 16 due to two factors;

first, there was less cleared capacity in FCA 16 (32,810 MW) than in FCA 15 (34,621 MW). Second, price separation in import-constrained zones was more modest in FCA 16 than FCA 15. There were no PfP events throughout Spring 2026, and failure-to-cover charges were minimal.

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 2026 alongside results of the relevant primary FCA are detailed in Table 5-1 below.[38]

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**	**New Brunswick Interface**	**Northern New England**	**Southeastern New England**
FCA 16 (2025-2026)	**Primary**	**12-month**	**32,810**	**2.59**	**2.53**	**2.53**	**2.53**	**2.64**
	MRA	May-26	547	1.38	1.38	1.38	1.38	1.38
	MBA	May-26	7	2.16				
FCA 17 (2026-2027)	**Primary**	**12-month**	**31,370**	**2.59**	**2.59**	**2.55**	**2.59**	
	ARA 3	12-month	97, -496	4.50	4.50	4.50	4.50	
	MRA	Jun-26	697	4.50	4.50	4.50	4.50	
	MBA	Jun-26	77	0.14				
	MRA	Jul-26	666	4.50	4.50	4.50	4.50	
	MBA	Jul-26	5	1.96				

** For primary auctions, this represents cleared system CSO. For annual reconfiguration auctions, this represents incremental cleared supply and demand. Note that capacity can enter or exit the market in ARAs; incremental cleared supply (positive) and demand (negative) are shown separately. For monthly reconfiguration and bilateral auctions, this represents the amount of exchanged CSO.*

*** Bilateral prices are volume-weighted averages.*

[38] Clearing prices for Southeastern New England (SENE) are not included for CCP 17 since SENE was not modeled in FCA 17.

The third annual reconfiguration auction (ARA 3) for CCP 17 occurred in Spring 2026. The secondary auction cleared at $4.50/kW-month in all capacity zones, marking a 74% increase in rest-of-pool prices compared to the primary auction. The elevated prices in CCP 17 ARA 3 follow a trend of relatively high ARA prices in recent auctions, including CCP 17 ARA 2 and CCP 18 ARA 1, which both cleared near $5/kW-month. Prices increased in ARA 3 due to relatively high demand and tight supply. Load forecasts did not contribute to high demand, as the Net ICR fell from the primary auction.[39] Rather, resources submitted over 3,000 MW of demand bids to shed CSO, and 496 MW of demand bids ultimately cleared the auction. By contrast, total supply offers were less than 400 MW, with only 97 MW of cleared incremental supply. Relatively large CSO terminations have contributed to tighter supply in reconfiguration auctions, and over 500 MW of CSO was terminated between FCA 17 and the third ARA.[40]

The final Monthly Reconfiguration Auction (MRA) for May of CCP 16 cleared at $1.38/kW-month. The first two MRAs of CCP 17, June and July 2026, both cleared at $4.50/kW-month. These MRAs cleared at higher prices than FCA 17 due to relatively high demand to shed CSO coupled with large supply bids priced around $4.50/kW-month that set price in each auction.

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.

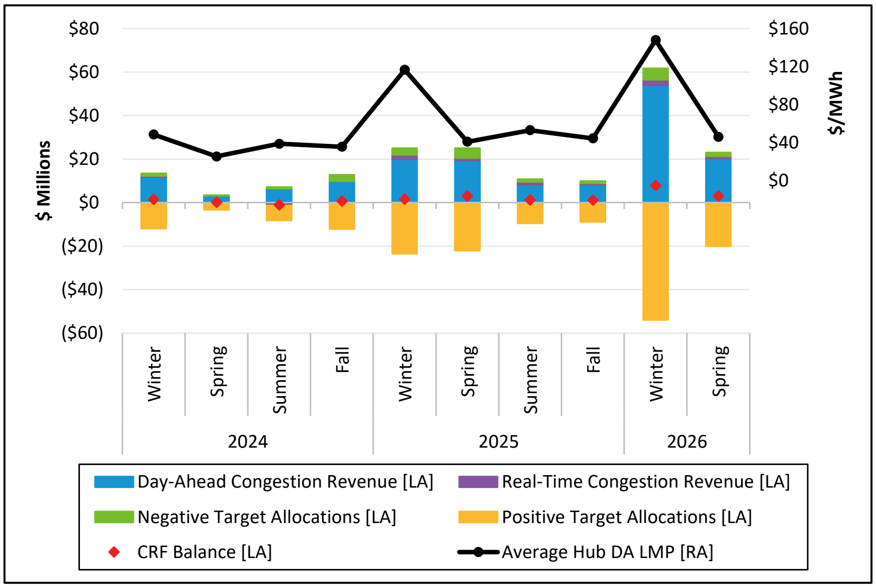
Figure 5-2 below shows, by quarter, the amount of congestion revenue from the day-ahead and real-time energy markets, the amount of positive and negative target allocations, and the

[39] The Net ICR for CCP 17 ARA 3 was 30,050 MW, down from 30,305 MW in the primary auction

[40] For more information on CSO terminations, see tariff section III.13.3.4A. Additionally, see the ISO's public data on monthly CSO adjustments, available at https://www.iso-ne.com/static-assets/documents/markets/othrmkts_data/fcm/doc/cso_monthly_changes_lz.xlsx.

congestion revenue fund (CRF) balance.[41,42] This figure also depicts the quarterly average day-ahead Hub LMP.[43]

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



Congestion revenue totaled $21.3 million in Spring 2026, marking a modest increase from Spring 2025 (4%) but a more than five-fold increase from Spring 2024. The New England Clean Energy Connect (NECEC) transmission line has driven increased system congestion costs since becoming operational in Winter 2026. Even before its completion, transmission outages related to the construction of the NECEC drove high congestion costs in Spring 2025; therefore, Spring 2024 provides a better comparison for pre-NECEC spring congestion outcomes.[44]

The NECEC injects energy into Maine, which is connected to the rest of the system via limited transmission. Sets of transmission elements are referred to as interfaces, and the collective power that flows over these interfaces is monitored by the ISO for system reliability purposes. The **Maine-New Hampshire (MENH)** interface now binds more frequently than it did before the NECEC

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[41] 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).

[42] 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.

[43] 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.

[44] *Spring 2025 Quarterly Markets Report* (July 16, 2025), 43, https://www.iso-ne.com/static-assets/documents/100025/2025-spring-quarterly-markets-report.pdf.

became operational, affecting 148 hours of the day-ahead market in Spring 2026. The nearby **Northern New England Scobie 345 kV – Scobie + 394 (NS_ST)** constraint has also been affected, limiting power flows in 44 hours of the day-ahead market in Spring 2026. Together, the two constraints accounted for an estimated 30% of all positive target allocations throughout the season. The New England States Committee on Electricity (NESCOE) directed the ISO to issue a Request for Proposals (RFP) for long-term transmission planning, with one objective to increase the transfer capability of the Maine-New Hampshire interface.[45] This RFP targets an in-service date of 2035.

Beyond the NECEC, higher day-ahead LMPs and planned outages related to standard shoulder-season transmission work contributed to an increase in congestion revenue relative to Spring 2025. The CRF was fully funded in each month of Spring 2026.

[45] *ISO-NE releases summary of proposals submitted under longer-term transmission planning effort* (November 21, 2025), https://isonewswire.com/2025/11/21/iso-ne-releases-summary-of-proposals-submitted-under-longer-term-transmission-planning-effort/.