Summer 2026 Quarterly Markets Report

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ISO New England Internal Market Monitor

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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 Summer 2026 (June 1, 2026 through August 31, 2026). Overall, the energy market performed competitively with prices consistent with changes in input costs, resource mix and load levels.

Wholesale Costs: In Summer 2026, the total estimated wholesale market cost of electricity was $2.52 billion, down 4% from $2.61 billion in Summer 2025. Energy costs comprised 89% of wholesale costs and totaled $2.23 billion, a 1% decrease from Summer 2025. Lower natural gas prices (down 22% from Summer 2025) were offset by higher emissions costs (up 89% 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 $47 million, down from $122 million in Summer 2025 due to higher day-ahead net interchange, particularly over the New England Clean Energy Connect (NECEC) interface.

Capacity costs totaled $232 million, representing 9% of total wholesale market costs. The current capacity commitment period (CCP 17, June 2026 – May 2027) cleared at $2.59/kw-month, which was the same as the prior year (CCP 16, June 2025 – May 2026). Despite the comparable clearing price, total costs were 13% lower in Summer 2026 than in Summer 2025, due to less cleared supply and the absence of price separation in import-constrained areas.

Energy Prices: The day-ahead Hub LMP averaged $56.69/MWh and the FER price averaged $1.14/MWh, leading to an all-in cost of $57.83/MWh for day-ahead physical generation (up 3% from Summer 2025). The real-time Hub price averaged $53.36/MWh (up 7%).

- Average natural gas prices were down 22% from Summer 2025, decreasing from $3.29/MMBtu to $2.56/MMBtu in Summer 2026. The decrease was consistent with broader market conditions, including record US natural gas production and ample inventories, which helped limit upward pressure on prices despite strong summer demand.
- With gas prices down, higher emissions costs were the primary driver of higher energy prices. Average Regional Greenhouse Gas Initiative (RGGI) CO_2 allowance prices rose 89% from $21.65/ short ton of CO_2 in Summer 2025 to $40.99 in Summer 2026, while average MA EGEL prices rose 133% from $10.22/ short ton of CO_2 to $23.76. Elevated carbon prices reflect tightening emissions caps for both programs, coinciding with higher emissions in New England during an exceptionally cold Winter 2025/2026. Higher RGGI spot prices may also reflect market expectations associated with Virginia's reentry into RGGI on July 1, 2026, which will increase future demand for allowances.
- During the July 1–3, 2026 heat wave, the daily average day-ahead LMP premium ranged from $28/MWh to $173/MWh. The day-ahead LMP reached $935/MWh (July 2, 2026) for one hour, the second-highest hourly level since the introduction of Standard Market Design in 2003.

[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.

- In the day-ahead and real-time markets, average prices in Maine were 11% and 12% lower than the Hub price, respectively. The incidence of lower pricing in Maine has increased since the New England Clean Energy Connect (NECEC) interface began commercial operation in January 2026. Lower prices in Maine were a partial driver of lower load-weighted day-ahead energy prices, and therefore lower overall energy costs, compared to Summer 2025.
- Hourly loads were up 1% compared to Summer 2025. The increase was primarily driven by warmer weather in August, as well as a period of elevated temperatures in early July.

Supply mix: Net imports increased while gas-fired generation declined in Summer 2026, continuing a trend since the beginning of the year. The increase in net imports is largely attributable to imports from the NECEC line. While gas generation fell from Summer 2025, it still comprised the largest individual share of the supply mix and averaged over 7,000 MW per hour, or 51% of total supply. Notably, wind generation increased from 300 MW on average in Summer 2025 to 500 MW in Summer 2026, driven by new offshore wind capacity. Oil generators did not produce in most hours of Summer 2026, but were called on during some of the hottest days of the season; peaking at over 2,300 MW on July 2.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $9.2 million in Summer 2026, down 19% from Summer 2025 and representing 0.4% of energy costs. The decrease was primarily driven by lower out-of-merit NCPC, which occurs when resources are committed or dispatched for reliability reasons rather than economic reasons. The highest daily NCPC payments occurred on July 2, accounting for 9% of total NCPC payments and coinciding with high LMPs. Day-Ahead Economic NCPC decreased during Summer 2026, driven primarily by increased availability of low-cost supply, including NECEC imports and offshore wind generation.

Day-Ahead Ancillary Services: Total net day-ahead ancillary services (DA A/S) payments decreased from Summer 2025 ($57.4 million) to Summer 2026 ($39.2 million). Lower net DA A/S payments moved in line with lower expected closeout charges ($9.36/MWh to $6.77/MWh), which form a fundamental part of DA A/S offer formulation.[4] Overall, net DA A/S payments accounted for 1.7% of total energy and ancillary services (E&AS) payments in Summer 2026, consistent with their share of E&AS payments since the start of the market in March 2025.

On August 1, 2026, ISO-NE implemented an enhancement to the Gaussian Mixture Model (GMM) that is used to calculate two key DA A/S market values: (1) the strike price[5] and (2) the expected closeout charge.[6] The enhancement incorporates Massachusetts Hub day-ahead energy futures from the Intercontinental Exchange (ICE) as an additional source of information about expected

[4] For more information about the Expected Closeout, see section 3.1.3 of the IMM's *An Assessment of the Day-Ahead Ancillary Services Market*, available here: https://www.iso-ne.com/static-assets/documents/100036/imm_assessment_of_da_ancillary_services_market.pdf

[5] The strike price is equal to the expected real-time LMP plus a $10/MWh adder.

[6] A full discussion of the model update was provided by ISO-NE in a July 22, 2026, memo, which is available here: https://www.iso-ne.com/static-assets/documents/100037/incorporating_electricity_futures_into_daas_forecasts_memo.pdf

next-day peak and off-peak LMPs. Initial results indicate that incorporating the futures market information from ICE improved the model's ability to estimate real-time prices.

Real-time Reserves: Overall, there was ample supply of total-ten and thirty-minute reserve capability available on the system in Summer 2026. The number of hours of non-zero pricing, the average price per MWh, and total net reserve payments were down for all three reserve products compared to the prior two summers. One factor in this decline was the absence of a Capacity Scarcity Condition (CSC), making Summer 2026 the first summer since 2022 without one.

Regulation: Total regulation market payments were $3.5 million during Summer 2026, down 26% from $4.7 million in Summer 2025. Lower capacity prices were the largest driver of this reduction, reflecting a decline in offer prices as lower-cost Alternative Technology Regulation Resources (primarily battery energy storage systems) continue to make up a larger share of the regulation mix. This reduction reflected a decrease in all categories of regulation payments compared to the prior summer.

Energy Market Competitiveness: The average residual supply index for the real-time energy market in Summer 2026 was 104.9, indicating that the ISO could meet the region's load and reserve requirement without energy and reserves from the largest supplier. However, the RSI fell below 100 in 30% of intervals and below 90 in some intervals, indicating significant reliance on large suppliers during those periods. Similarly, there was at least one pivotal supplier present in the real-time market for 30% of five-minute pricing intervals in Summer 2026, similar to 31% in Summer 2025. Overall, energy market outcomes remain consistent with a competitive market.

There were 671 asset-hours of mitigation in Summer 2026, continuing an upward trend since Winter 2026. Real-time constrained area energy and commitment mitigation occurred most frequently, driven by the Maine-New Hampshire interface binding more frequently due to power flows from the NECEC interface. Despite the increase, mitigation remained relatively rare: while 19% of real-time economic asset-hours failed structural tests, less than 0.2% ultimately failed the conduct and/or impact tests required for mitigation.

Financial Transmission Rights (FTRs): Congestion revenue totaled $22.8 million in Summer 2026, more than twice the total in Summer 2025. This increase was driven largely by the NECEC transmission line, which has caused increased congestion over the Maine-New Hampshire interface. That interface accounted for over half of all positive target allocations in Summer 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	Summer 2026	Spring 2026	Summer 2026 vs Spring 2026 (% Change)	Summer 2025	Summer 2026 vs Summer 2025 (% Change)
Real-Time Load (GWh)	32,743	26,572	23%	32,488	1%
Peak Real-Time Load (MW)	25,832	19,489	33%	26,592	-3%
Average Day-Ahead Hub LMP ($/MWh)	$56.69	$46.36	22%	$53.31	6%
Average Forecast Energy Requirement Price ($/MWh)	$1.14	$2.05	-44%	$3.07	-63%
Average Real-Time Hub LMP ($/MWh)	$53.36	$47.54	12%	$49.65	7%
Average Natural Gas Price ($/MMBtu)	$2.56	$2.79	-9%	$3.29	-22%
Average No. 6 Oil Price ($/MMBtu)	$23.53	$23.95	-2%	$15.18	55%

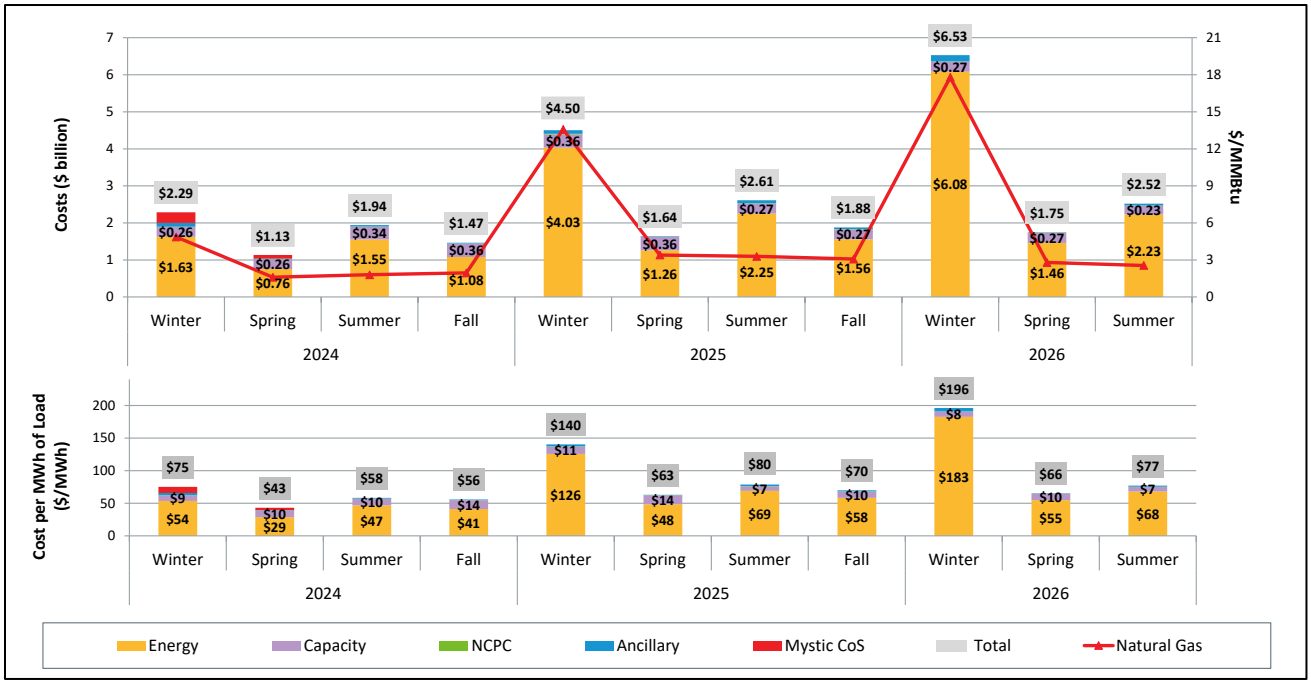
Key observations from the table above:

- Day-ahead LMPs averaged $56.69/MWh in Summer 2026, up 6% from Summer 2025. Higher carbon prices put upward pressure on LMPs. The Forecast Energy Requirement Price averaged $1.14/MWh, leading to an all-in day-ahead price of $57.83/MWh for day-ahead cleared physical generation.
- Summer 2026 RGGI spot prices from the secondary market remained at historically elevated levels; prices averaged $40.99/short ton, nearly double the Summer 2025 average of $21.65/short ton. The clearing price from the June 2026 auction under the Massachusetts Electric Generator Emissions Limits (MA EGEL) program was $20.07/metric ton, down from $30/metric ton in the March 2026 auction but higher than the June 2025 clearing price of $12/metric ton.
- Average load increased by 1% compared to Summer 2025 while peak load decreased by 3%.

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.[7] 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

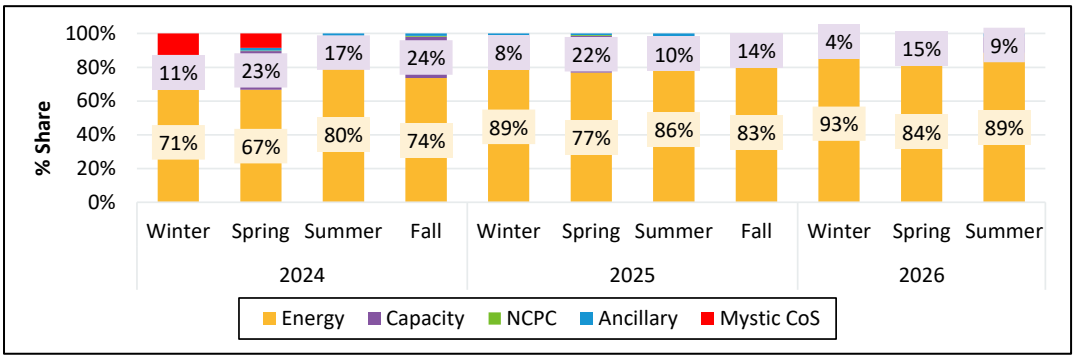


In Summer 2026, the total estimated wholesale cost of electricity was $2.52 billion (or $77/MWh of load), a 4% decrease compared to $2.61 billion in Summer 2025. Costs decreased across all four categories, as discussed below.

The share of each wholesale cost component since Winter 2024 is shown in Figure 2-2 below.

[7] 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 decreased by 1% to $2.23 billion (or $68/MWh) in Summer 2026. Natural gas prices fell 22%, from $3.29/MMBtu to $2.56/MMBtu. The decrease was consistent with broader market conditions, including record US natural gas production and ample inventories. However, higher carbon allowance prices offset lower natural gas costs, resulting in higher overall production costs for natural gas-fired generators. Average Regional Greenhouse Gas Initiative (RGGI) prices rose from $21.65/short ton in Summer 2025 to $40.99/short ton in Summer 2026, while Massachusetts Electric Generator Emissions Limits (MA EGEL) auction prices increased from $12.00/metric ton in June 2025 to $20.07/metric ton in June 2026. Energy prices consequently increased, yet load-weighted day-ahead energy prices declined, partly because of lower prices in Maine. Additionally, the decrease in the Forecast Energy Requirement (FER) price reduced FER payments from $122 million to $47 million year over year, more than offsetting a $54 million increase in day-ahead and real-time energy payments.

Capacity costs are determined by the clearing price in the primary Forward Capacity Auction (FCA). In Summer 2026, the FCA 16 clearing price resulted in capacity payments of $232 million ($7/MWh), representing 9% of total costs. The current capacity commitment period (CCP 17, June 2026 – May 2027) cleared at $2.59/kw-month, which was the same as the prior year (CCP 16, June 2025 – May 2026). Costs were lower in Summer 2026 due to less cleared supply (following a smaller net installed capacity requirement, or NICR) and the absence of price separation in import-constrained areas. Section 5.1 discusses recent trends in the Forward Capacity Market in more detail.

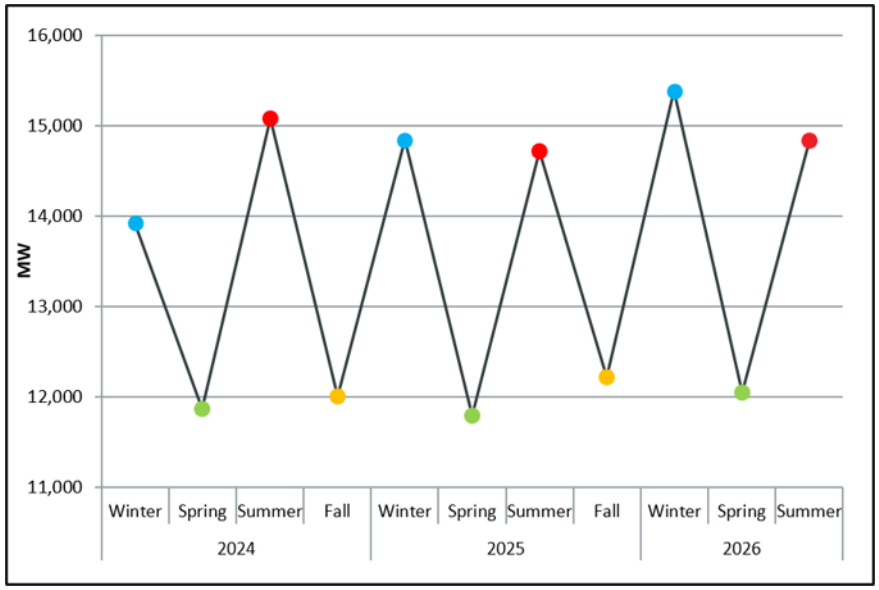
At $9.2 million ($0.28/MWh), Summer 2026 Net Commitment Period Compensation (NCPC) costs accounted for 0.4% of energy costs. Payments to resources committed in economic merit order ("economic payments") comprised nearly all of total NCPC costs. Section 3.4 provides additional detail on NCPC payments.

Ancillary service costs, which include payments for day-ahead ancillary services, real-time operating reserves, and regulation, totaled $46 million ($1.41/MWh) in Summer 2026, representing 2% of total wholesale costs. Reserve payments associated with the Day-Ahead Ancillary Services (DA A/S) market accounted for 85% of total ancillary service costs.

2.2 Load

New England loads typically increase in the summer due to higher cooling demand, while increased behind-the-meter (BTM) solar output helps offset peak-hour load demand.[8] Average hourly load by quarter is shown in Figure 2-3 below.

Figure 2-3: Average Hourly Load by Quarter



Summer 2026 hourly loads averaged 14,829 MW, increasing by 115 MW or 1% compared to Summer 2025. The increase was primarily driven by warmer weather in August, as well as a period of elevated temperatures in early July. On July 2 and July 3, temperatures averaged 85°F and 86°F, respectively, compared to the Summer 2026 average temperature of 71°F. This contributed to elevated hourly loads averaging 20,725 MW and 20,448 MW on July 2 and 3, respectively, approximately 40% higher than average Summer 2026 hourly loads.

Wildfire smoke conditions, particularly on July 15, affected load forecasting during the summer. Widespread smoke throughout the region reduced temperatures, solar irradiance, and BTM solar output relative to forecast levels. Average temperature forecast errors reached up to 10°F and solar generation forecast errors exceeded 50%, contributing to elevated load forecast errors.[9] Despite these conditions, overall load patterns remained consistent with typical summer conditions, with increased cooling demand balanced by high BTM solar output, reducing net system load.

[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).

[9] See the August 2026 System and Market Operations Report for additional discussion of the impacts of wildfire smoke on forecast accuracy, available at https://www.iso-ne.com/static-assets/documents/100038/system-and-market-ops-report-aug-2026.pdf.

The high levels of solar generation offset metered load during high load summer 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 increased from an estimated 872 MW in Summer 2025 to 906 MW in Summer 2026 (up 34 MW, or approximately 4%), driven by continued additions of distributed solar resources in New England.

Load and Temperature

The stacked graph in Figure 2-4 below compares average monthly load (left axis) to the monthly average Temperature-Humidity Index (right axis).[10]

Figure 2-4: Monthly Average Load and Monthly Temperature-Humidity Index

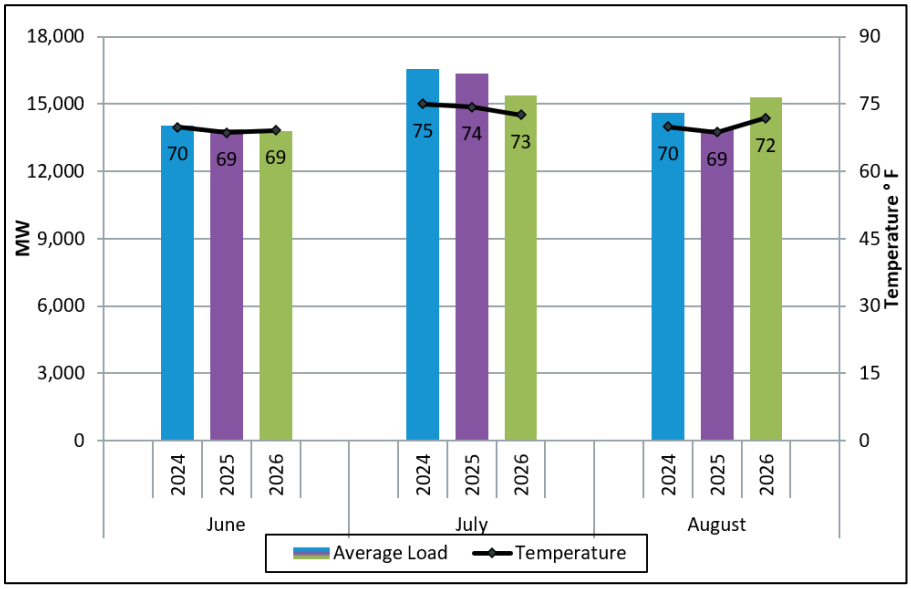


Figure 2-4 shows that average load decreased in June and July but increased in August compared to the prior year. Average load increased by 10% in August 2026 compared to August 2025, driven by a significant increase in temperatures as reflected in a higher temperature-humidity index. Hot weather led to 601 cooling degree days (CDDs) in Summer 2026, nearly unchanged from Summer 2025 (down 1 CDD overall). June and July CDDs declined 8% and 22%, respectively, while August

[10] The Temperature-Humidity Index combines temperature and dew point (humidity) into one metric that is a useful indicator of electricity demand in summer months when the impact of humidity on load is highest. The THI is calculated as 0.5 x [Dry-Bulb Temperature (^{0}F)]+ 0.3 x [Dew Point (^{0}F)] + 15.

CDDs increased 53% year over year.[11] June and July loads decreased 1% and 6% from the prior year, respectively.

Peak Load and Load Duration Curves

New England's system load over the past three summer seasons is shown as load duration curves in Figure 2-5 below with the inset graph showing the 5% of hours with the highest loads.[12]

Figure 2-5: Load Duration Curves

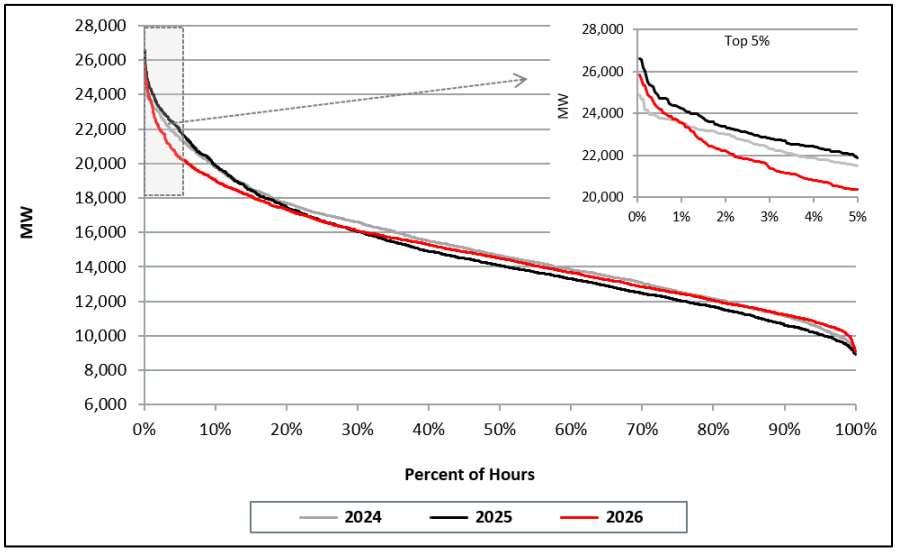


Figure 2-5 shows that loads during high-load hours in Summer 2026 were lower than those in the prior year, while loads during the remaining hours were generally higher. Summer 2025 experienced historically high peak loads, recording 25,934 MW, the highest summer peak in the past five years, while the average load during the top 5% of hours was 22,853 MW, more than 1,200 MW higher than in Summer 2026. These high-load conditions coincided with more persistent heat conditions. During the top 5% of load hours in Summer 2025, the average THI was 78°F, 9°F higher than the 69°F average in Summer 2026. By contrast, Summer 2026 experienced fewer hours of extreme heat and humidity, although load reached a peak of 25,832 MW on July 2 during a heat wave, the highest peak load since June 2025. Consistent with the high temperatures discussed previously, July 2 and July 3 dominated the upper end of the Summer 2026 load duration curve, accounting for 58% of the top 24 highest hourly loads.

[11] Cooling degree days (CDD) measure how warm an average daily temperature or temperature-humidity index is relative to 65°F, and is an indicator of electricity demand for air conditioning. It is calculated as the number of degrees (°F) that the average of a day's high and low temperatures are above 65°F. For example, if a day's high temperature is 80°F and low temperature is 60°F, the average of the high and low temperatures is 70°F, and the CDD for that day is 5. These CDDs are based on THI and are reported in the Net Energy and Peak Load Report, available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load.

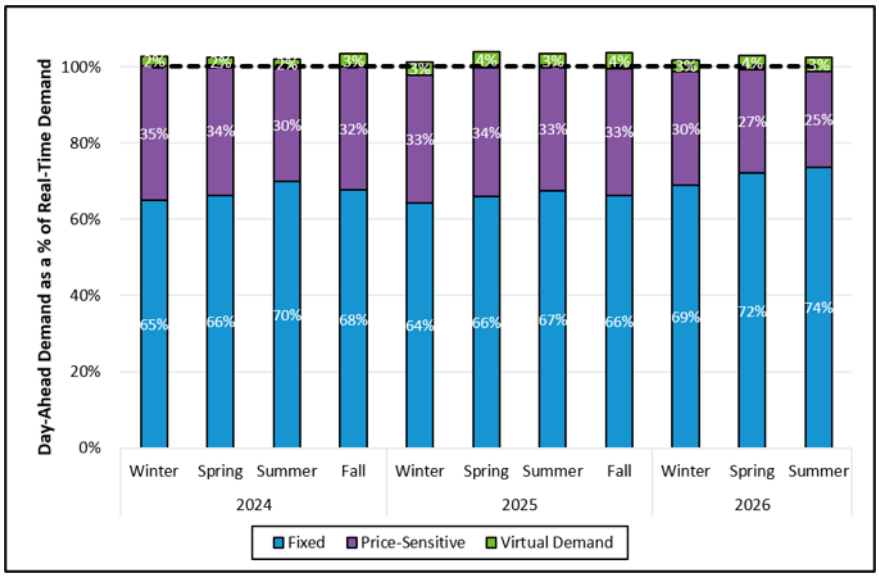
[12] A load duration curve depicts the relationship between load levels and the frequency in which loads occur at that level or higher.

The lowest hourly load in Summer 2026 (9,061 MW) exceeded the Summer 2025 minimum of 8,912 MW but not the Summer 2024 minimum of 9,095 MW. This indicates that, although favorable solar conditions continued to suppress midday demand, minimum load conditions were higher than in Summer 2025 but remained within the range observed in recent years.

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 2-6 below.

Figure 2-6: Day-Ahead Cleared Demand as Percent of Real-Time Demand, by Quarter



In Summer 2026, participants cleared 102% of real-time demand in the day-ahead market, 1% lower than the 103% cleared in Summer 2025, but consistent with recent levels of over-clearing. This reflects a continuation of clearing behavior above real-time load observed in prior summers.

Participants cleared 74% of demand as fixed bids and 25% as priced bids, compared with 67% fixed and 33% priced in Summer 2025. Priced demand declined to approximately 3,644 MW on average in Summer 2026, down 23% from 4,720 MW in Summer 2025. As in prior periods, priced demand bids were typically submitted at levels above expected LMPs, making them likely to clear.[13]

Virtual demand clearing (DECs) accounted for approximately 3% of cleared demand, similar to Summer 2025.[14] Overall, day-ahead cleared demand totaled 14,844 MW compared to real-time load of 14,502 MW.

[13] Following the $900/MW DA LMPs observed in January 2026, some participants increased bid prices, reflecting a continued willingness to clear in most hours.

[14] See Section 3.3 on Virtual Transactions for more information on virtual demand.

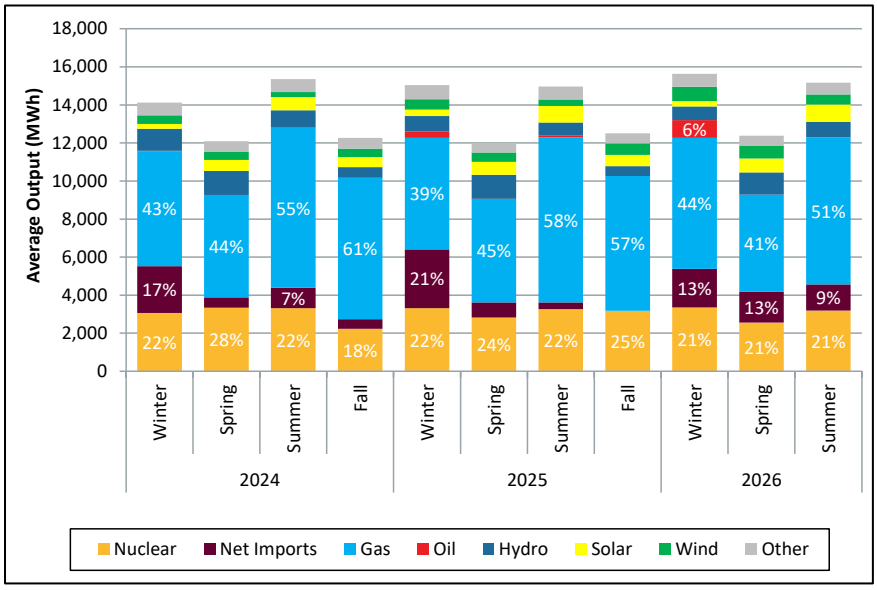
2.3 Supply

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 Summer 2026 is illustrated in Figure 2-7 below. Each bar's height represents the average electricity generation from that fuel type, while the percentages represent share of total generation.[15]

Figure 2-7: Share of Electricity Generation by Fuel Type



Net Imports increased while gas-fired generation declined in Summer 2026, continuing a trend since the beginning of the year. The increase in net imports is largely attributable to imports from the NECEC. While gas generation fell from Summer 2025, it still comprised the largest individual share of the supply mix and averaged over 7,000 MW per hour. Notably, wind generation increased from 300 MW on average in Summer 2025 to 500 MW in Summer 2026, driven by new offshore wind capacity. Total wind generation reached over 1,700 MW in some hours. Oil generators did not produce in most hours of Summer 2026, but were called on during some of the hottest days of the season; for example, oil generation peaked at over 2,300 MW on July 2.

While battery storage is a small part of the overall supply mix on average (30 MW) since battery storage units spend long periods of the day without discharging, they have provided significant

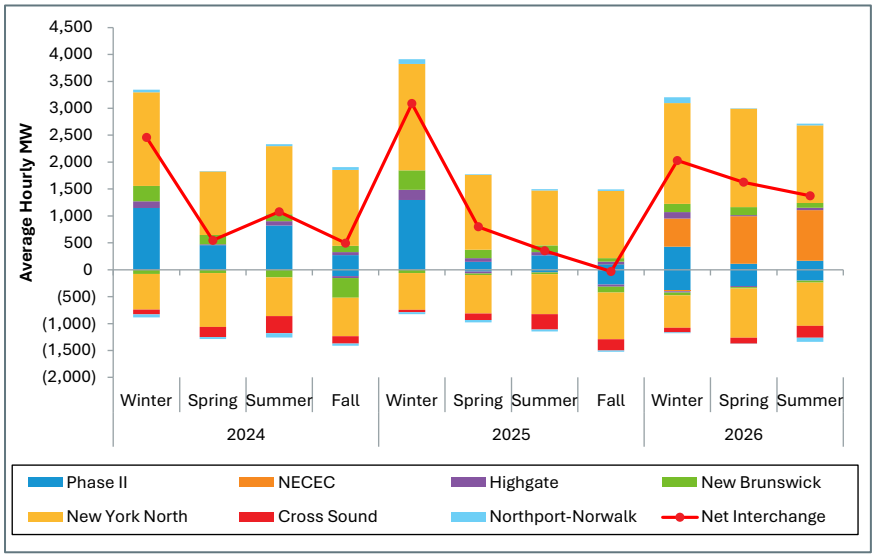
[15] Electricity generation equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, wood, and demand response.

energy during daily peak periods.[16] Peak daily battery storage supply injections were frequently more than 200 MW.

2.3.2 Imports and Exports

In Summer 2026, the average net flow of energy into New England from Canada and New York was 1,373 MW, nearly four times the average net interchange in Summer 2025. Higher imports over the NECEC transmission line and the New York North interface were the main drivers of this increase. The average hourly import, export, and net interchange power volumes by external interface for the last 11 seasons are shown in Figure 2-8 below.

Figure 2-8: Average Hourly Real-Time Imports, Exports, and Net Interchange



Canadian interfaces

Net interchange across all Canadian interfaces increased for the third consecutive quarter, reaching the highest level (1,003 MW) since Winter 2025. Flows over the new NECEC transmission line from Quebec to New England accounted for the majority of net imports, averaging 943 MW. Since the NECEC entered service, New England has typically imported about 1,100 MW over the interface when the line is in service. However, an unplanned outage in late August reduced the quarterly average below that level.

Net imports over the NECEC interface were slightly offset by net exports (31 MW) over the Phase II interface. While New England has historically been a net importer over Phase II, Summer 2026 marks the third quarter in the past year when it has been a net exporter. As noted in previous reports, persistently drier conditions in Quebec have reduced surplus hydroelectric generation

[16] The 30 MW average for battery storage generation is calculated with gross supply and consequently does not include periods where batteries charged and added to system load.

available for export to 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.[17] Despite this trend, imports from Quebec remained high in Summer 2026 when loads increased on hot days. During hours when loads exceeded 20,000 MW, total net imports from Quebec averaged 2,158 MW, including 967 MW over Phase II, 1,115 MW over NECEC, and 75 MW over Highgate (the other interface connecting New England to Quebec). This was an increase from 1,677 average net imports from Quebec during high load hours in Summer 2025.

Over the full summer, New England imported an average of 37 MW over Highgate, down slightly from 49 MW in Summer 2025. Imports from New Brunswick were down 44% year-over-year (54 MW compared to 96 MW in Summer 2025). External transactions over the New Brunswick interface tend to be linked to the output of a large nuclear generator in New Brunswick. While that generator was out-of-service for periods of both Summer 2025 and 2026, the planned 2026 outage lasted for most of the summer, resulting in lower net imports relative to Summer 2025.

New York Interfaces

Net imports over all New York interfaces averaged 370 MW, up significantly from Summer 2025 when New England exported 21 MW to New York, on average. Net imports over the New York North interface increased 132% from 274 MW in Summer 2025 to 636 MW in Summer 2026. In Summer 2026, the average day-ahead price on the New York side of the interface was $0.31 higher than the day-ahead price (including the FER price) on the New England side, compared to $0.95 higher in Summer 2025. Despite higher average day-ahead prices in New York, market participants may continue importing into New England when additional revenues from Power Purchase Agreements, Renewable Energy Certificates, or other contractual arrangements offset the apparent pricing disadvantage.

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 Summer 2026, New England exported an average of 221 MW to Long Island over the Cross Sound Cable interface, down 23% from Summer 2025. New England also exported 44 MW over the Northport-Norwalk interface, up from just 8 MW in Summer 2025.

[17] For more information on the reduction in exports, see Hydro-Québec's *Quarterly Bulletin, Second Quarter 2026*, available at https://www.hydroquebec.com/data/documents-donnees/pdf/quarterly-bulletin-2026-2.pdf and the 2025 Annual Report, available at https://www.hydroquebec.com/data/documents-donnees/pdf/hq-rapport-annuel-2025-anglais.pdf.

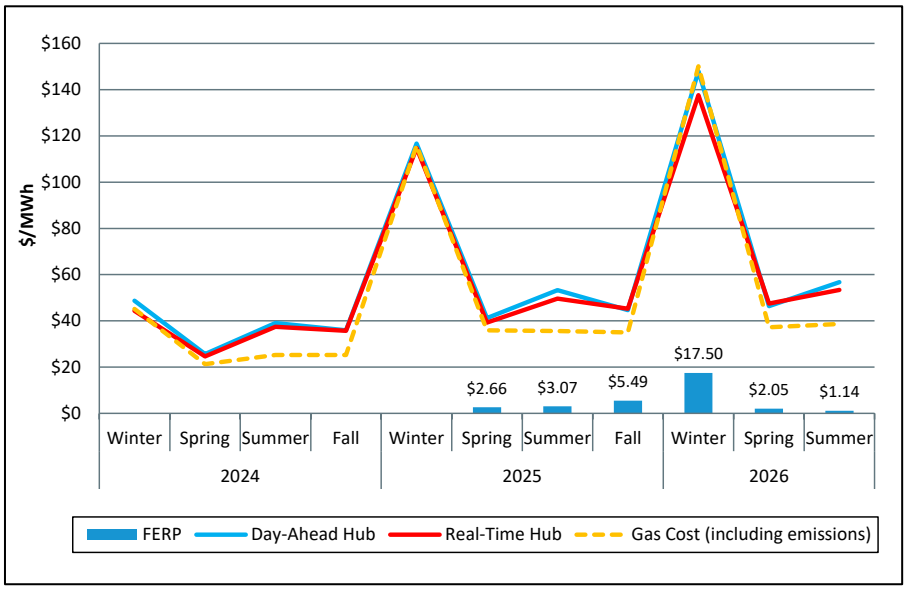
Section 3
Day-Ahead and Real-Time Markets

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.[18] 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 $56.69/MWh and $53.36/MWh respectively in Summer 2026, up 6% and 7% compared to Summer 2025. The FER price averaged $1.14/MWh

[18] 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 associated with the Regional Greenhouse Gas Initiative.

leading to an all-in cost (LMP + FERP) of $57.83/MWh for day-ahead cleared physical generation. Higher energy prices resulted from increased carbon costs (discussed below) that outweighed lower natural gas prices. Higher day-ahead net interchange, particularly from the NECEC, led to the decreased average FER price.

Day-ahead LMP premiums were higher during periods of tight system conditions. In the day-ahead ancillary services market, reserves are co-optimized with energy market awards. When efficient generators are selected to satisfy reserve requirements rather than provide energy, higher-cost generators may set the energy price. This effect is more pronounced under stressed conditions, when the energy supply curve is steeper. During the July 1–3, 2026 heat wave, the daily average day-ahead LMP premium ranged from $28/MWh to $173/MWh.[19] The day-ahead LMP reached a high of $935/MWh for one hour (July 2, 2026), the second-highest hourly level since the introduction of Standard Market Design in 2003.

In Summer 2026, average day-ahead and real-time LMPs in the Maine load zone were 11% and 12% lower than Hub prices, respectively. Historically, wind generation has contributed to lower LMPs in Maine when transmission constraints limit flows to the rest of New England. Increased imports over the NECEC interface have increased supply in Maine, contributing to more frequent transmission congestion and even lower prices relative to the Hub.

In Summer 2026, carbon allowance prices continued to increase under the Regional Greenhouse Gas Initiative (RGGI). In the June 2026 auction, RGGI allowances cleared at $35.00/short ton, the highest auction clearing price to date.[20] Summer 2026 RGGI spot prices from the secondary market averaged $40.99/short ton, nearly double the Summer 2025 average of $21.65/short ton. Although spot prices stabilized relative to the volatility observed during Spring 2026, they remained at historically elevated levels.

The clearing price from the June 2026 auction under the Massachusetts Electric Generator Emissions Limits (MA EGEL) program was $20.07/metric ton, down from $30/metric ton in the March 2026 auction but higher than the June 2025 clearing price of $12/metric ton.[21]

Overall, these elevated carbon prices reflect tightening emissions caps for both programs, coinciding with higher emissions in New England during Winter 2025/2026 due to extreme cold conditions.[22] The increase in RGGI spot prices may also reflect market expectations associated with Virginia's reentry into RGGI on July 1, 2026, which will increase future demand for allowances.

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[19] The FERP is not included when discussing the day-ahead LMP premium.

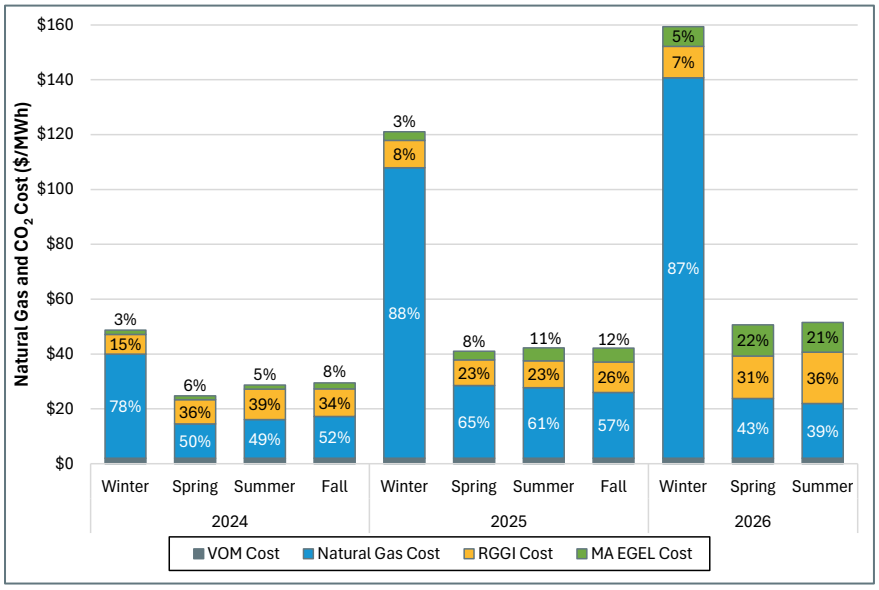
[20] RGGI auction results are documented here: https://www.rggi.org/auctions/auction-results

[21] See the report from the MA EGEL June 2026 auction: https://www.mass.gov/doc/market-monitor-report-auction-2026-3/download

[22] 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/

With emissions costs high and natural gas prices relatively low during Summer 2026, emissions costs made up a substantial share of natural gas generators' production costs, as shown in Figure 3-2.[23]

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



We estimate that in Summer 2026, RGGI compliance costs added $18.70/MWh to the production cost of an average natural gas combined-cycle unit, up from $9.88/MWh in Summer 2025. MA EGEL compliance costs increased from $4.66/MWh in the prior summer to $10.84/MWh. In total, emissions costs from the RGGI and MA EGEL programs accounted for 57% of production costs for natural gas generators in Massachusetts, up from 34% in Summer 2025.

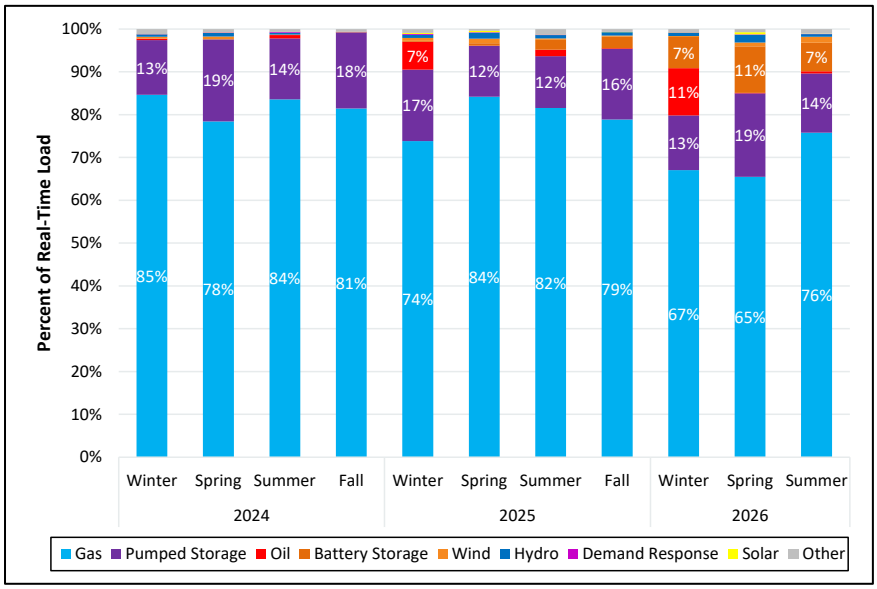
3.2 Marginal Resources and Transactions

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.

[23] 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 3-3: Real-Time Marginal Units by Fuel Type



Natural gas generators were the most frequent marginal unit in Summer 2026, as they set price for 76% of real-time load. Pumped storage (14%) and battery storage (7%) continued to set price for significant amounts of real-time load. In particular, battery storage has increased in the marginal unit mix throughout 2026 relative to prior years as more units became operational relative to prior years. Battery storage units are typically marginal during daily peak periods as they respond to state incentive programs (which typically cover daily peak load hours) and energy market signals.[24]

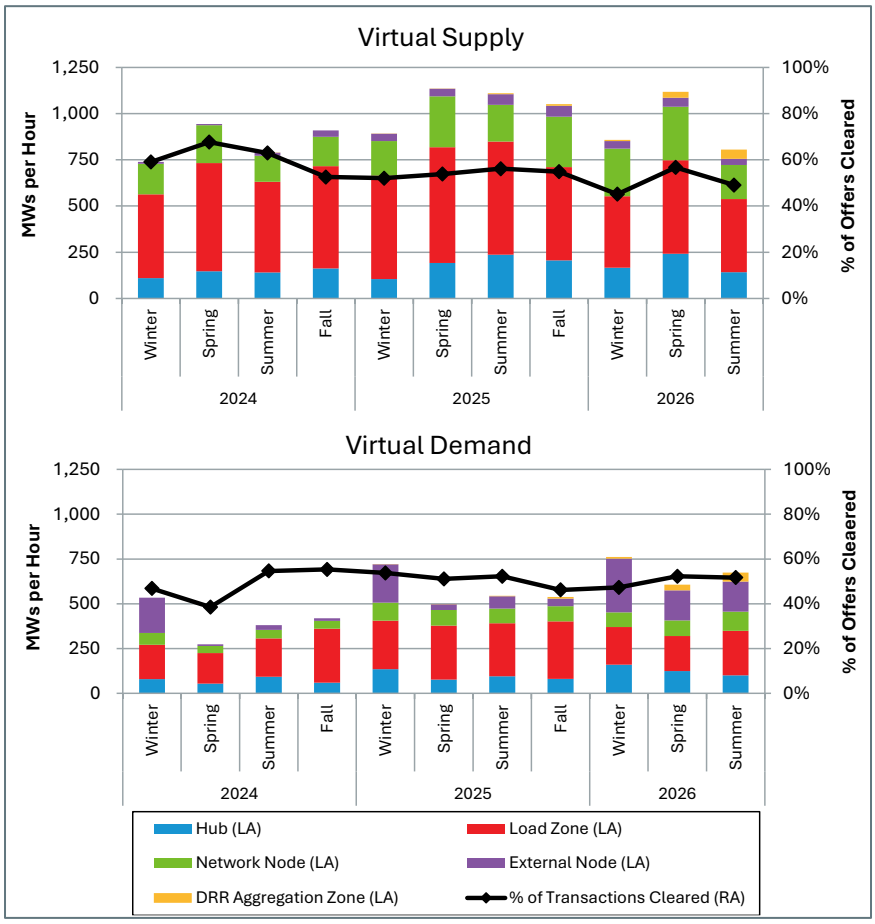
3.3 Virtual Transactions

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.

[24] For example, battery storage generators receive credits through the Massachusetts Clean Peak Program. For program information, see https://www.mass.gov/info-details/clean-peak-energy-standard-program-details.

Figure 3-4: Cleared Virtual Transactions by Location Type



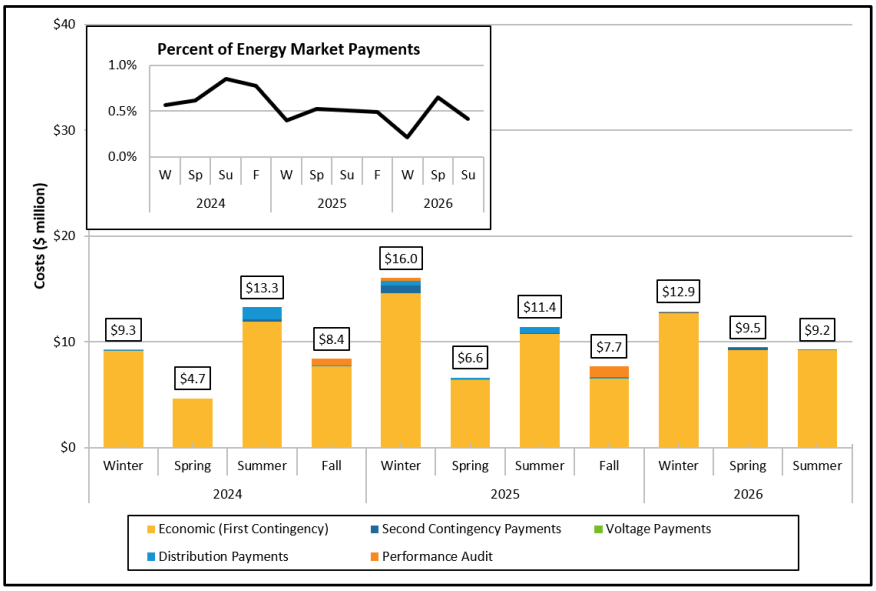
Cleared virtual supply averaged 805 MW per hour in Summer 2026, down 27% from Summer 2025 (1,110 MW per hour). Both the quantity of submitted virtual supply offers and the percentage of offers that cleared decreased relative to prior summer seasons, a trend observed across multiple participants. In recent years, virtual supply volumes increased alongside the growing solar participation, filling in for settlement-only generation (SOG) which does not participate in the day-ahead market but produces energy in real time. However, Summer 2026 marks the third consecutive quarter in which virtual supply volumes decreased from the prior year, despite a 4% year-over-year increase in SOG solar installed capacity. Average day-ahead/real-time price spreads remained positive and generally similar to those observed in Summer 2025, suggesting that the decline in cleared virtual supply was not driven by a reduction in spread opportunities. Instead, the decline likely reflects changes in participant bidding behavior, risk tolerance, or expectations regarding the likelihood of realizing those spread opportunities.

Cleared virtual demand averaged 674 MW per hour, up 24% from 544 MW per hour in Summer 2025. Cleared virtual demand bids decreased at the load zones (-49 MW/hour) but increased at network nodes (26 MW/hour), external interfaces (99 MW/hour) and DRR aggregation zones (48 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.

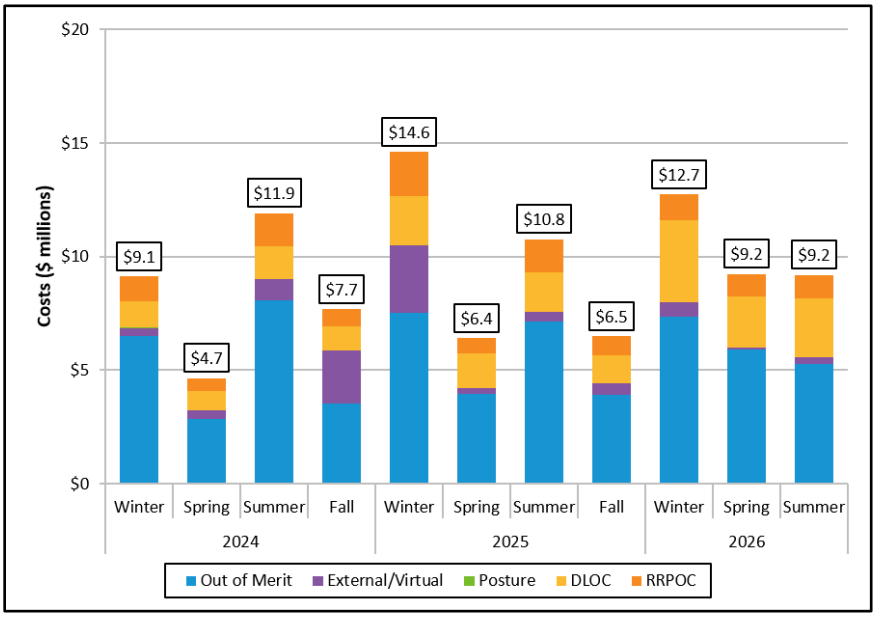
Figure 3-5: NCPC by Category



NCPC payments totaled $9.2 million in Summer 2026, down 19% from Summer 2025 and representing 0.4% of energy costs. Economic payments accounted for nearly all NCPC, with only a small remainder associated with second-contingency and distribution commitments.

Economic payments subcategories include: 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 3-6 below shows economic payments by subcategory.

Figure 3-6: Economic NCPC by Reason



Economic NCPC totaled $9.2 million in Summer 2026, a 15% decrease from $10.8 million in Summer 2025. The decrease was primarily driven by lower out-of-merit NCPC, partially offset by higher DLOC payments. Of the $9.2 million in economic NCPC, approximately $8.5 million occurred in the Real-Time Market and $0.8 million in the Day-Ahead Market. The highest daily NCPC payments occurred during warmer temperatures on July 2, accounting for 9% of total NCPC payments and coinciding with high LMPs. Day-Ahead Economic NCPC decreased during Summer 2026, driven primarily by increased availability of low-cost supply, including NECEC imports and offshore wind generation.

Out of merit NCPC totaled approximately $5.3 million, a 26% decrease from $7.1 million in Summer 2025. Out-of-merit NCPC generally results when resources operate outside of normal economics due to operator commitments needed to maintain system reliability. Although out-of-merit payments remained the largest component of economic NCPC in Summer 2026, payments were lower than in each of the prior two summers.

By contrast, DLOC payments totaled $2.6 million, a 51% increase from Summer 2025 and an 81% increase from Summer 2024. DLOC credits compensate generators for opportunity costs associated with following dispatch instructions below their profit-maximizing output. Because dispatch instructions are issued in advance to provide resources time to ramp, generators may incur opportunity costs when they reduce output before market conditions would otherwise make doing so economic. The increase in DLOC payments partially offset the decrease in out-of-merit NCPC and continued the upward trend in DLOC payments over the past three summers.

RRPOC totaled $1.0 million, a 30% decrease from $1.5 million in Summer 2025. Together, DLOC and RRPOC accounted for 40% of economic NCPC in Summer 2026, unchanged from Summer 2025 but up from 24% in Summer 2024. External and virtual NCPC remained relatively small, totaling approximately $0.3 million combined, while there were no posturing payments.

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 August 31, 2026.[25]

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.[26]

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)

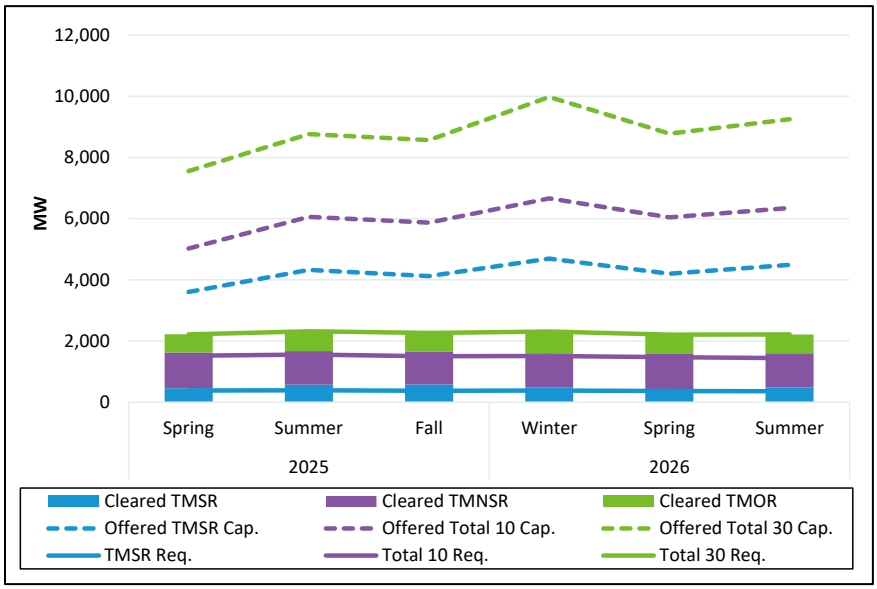
In general, offered FRS capability has been many times larger than FRS requirements. This can be seen in Figure 3-7, which shows the average hourly FRS requirements, offered capability, and the cleared awards, by quarter.[27]

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

[26] 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.

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

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



The amount of offered capability available to satisfy the FRS requirements increased moderately relative to the spring. This increase in participation, at least in part, reflects resources returning from planned maintenance outages during the spring season. Offered capability was also higher relative to the prior summer (between 4%-6% on average), with combined cycles accounting for a significant share of the year-over-year increase.

Meanwhile FRS requirements, which are based on projected first and second contingencies, remained relatively stable from the spring to the summer. However, it is worth noting that 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.[28] Additionally, the ISO plans to further reduce this non-performance factor (from 115% to 110%) effective for the operating day of November 1, 2026.[29]

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 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.,

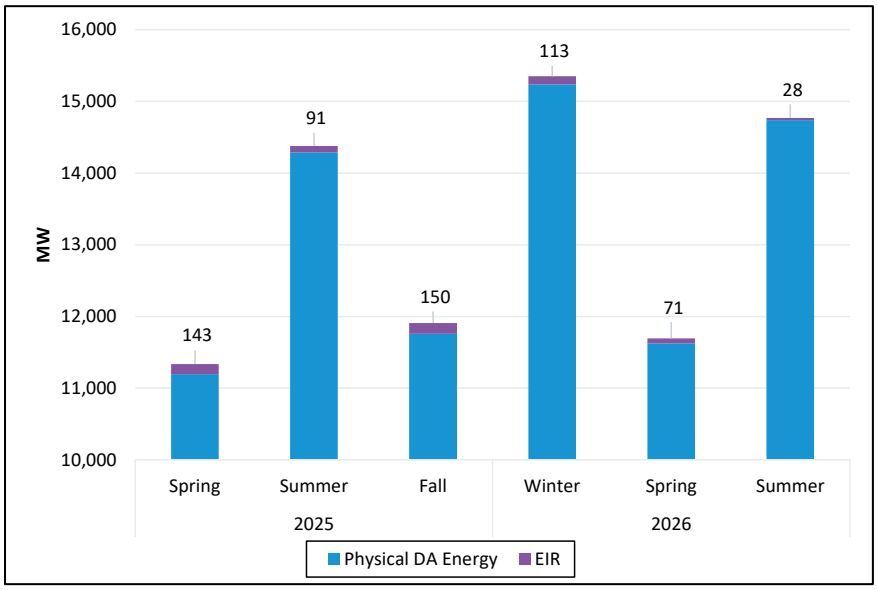
[28] For more information about this change, see: https://www.iso-ne.com/staticassets/documents/100034/a05_reserve_nonperformance_factor_updates.pdf.

[29] For more information about this upcoming change, see: https://www.iso-ne.com/static-assets/documents/100040/a10_reserve_nonperformance_factor_updates.pdf

physical supply resources 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 the figure below, which shows the average hourly cleared FER supply by quarter.

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



The average hourly volume of EIR that cleared in Summer 2026 (28 MW) was lower than in Summer 2025 (91 MW). A key factor contributing to the decline was an increase in day-ahead cleared imports, which are treated as physical energy supply and therefore satisfy the FER constraint. While the most significant increase in imports occurred over the recently commercialized New England Clean Energy Connect (NECEC) transmission line, imports across the New York North (NYN) interface also rose. Overall, EIR accounted for less than one percent of the capability used to satisfy FER demand during the quarter, while cleared day-ahead energy accounted for over 99%.

3.5.3 Settlements

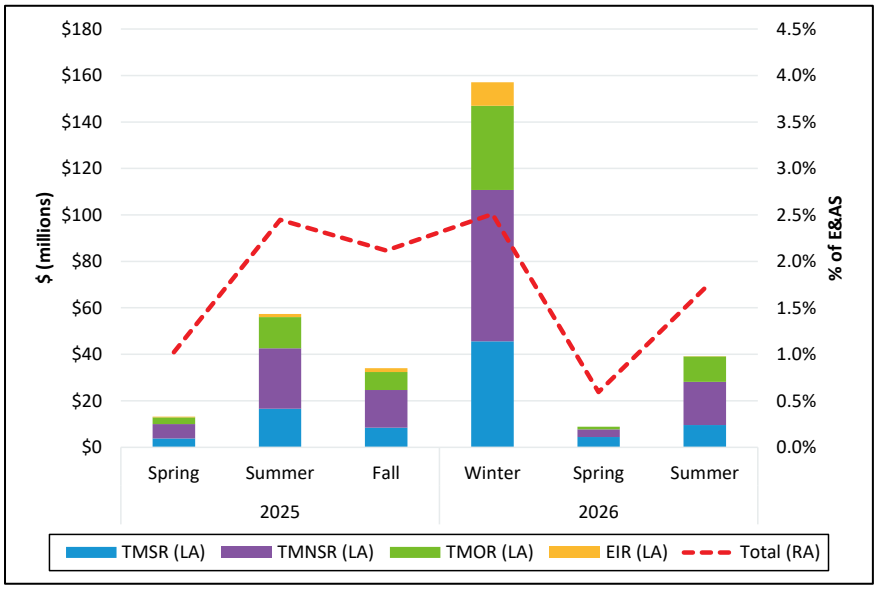
The four DA A/S products are paid an initial credit at the applicable DA A/S clearing price and incur a closeout charge whenever the real-time Hub LMP exceeds the strike price. For the purposes of calculating the settlement value of the DA A/S market, we sum the initial credit and the closeout charge 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.[30] This can be seen in the figure below, which shows, by season, the *net*

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

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).[31]

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



Total net DA A/S payments increased between Spring 2026 ($8.8 million) and Summer 2026 ($39.2 million) though they remained below the level observed in the prior summer ($57.4 million). Notable payments occurred on July 1- 3 and July 14-15, when forecast high temperatures led to elevated load forecasts and tight anticipated system conditions; net DA A/S payments over these five days accounted for nearly half the net DA A/S payments in Summer 2026. Overall, net DA A/S payments accounted for 1.7% of total E&AS payments in Summer 2026, consistent with their share of E&AS payments since the start of the market in March 2025.

3.5.4 GMM Performance

On August 1, 2026, ISO-NE implemented an enhancement to the Gaussian Mixture Model (GMM) that is used to calculate two key DA A/S market values: (1) the strike price[32] and (2) the expected closeout charge.[33] The enhancement incorporates Massachusetts Hub day-ahead energy futures from the Intercontinental Exchange (ICE) as an additional source of information about expected next-day peak and off-peak LMPs. These futures prices are used to update the model's probability

[31] 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)

[32] The strike price is equal to the expected real-time LMP plus a $10/MWh adder.

[33] A full discussion of the model update was provided by ISO-NE in a July 22, 2026, memo, which is available here: https://www.iso-ne.com/static-assets/documents/100037/incorporating_electricity_futures_into_daas_forecasts_memo.pdf

distributions through a Bayesian approach[34]. The magnitude of the adjustments to the distributions vary by hour and season based on historical relationships between ICE prices and realized day-ahead LMPs.

Initial results indicate that incorporating the futures market information from ICE improved the model's ability to estimate real-time prices. The average real-time LMP bias, measured as the *actual* real-time LMP minus the *expected* real-time LMP, declined to $2.36/MWh in August 2026, compared to $9.33/MWh during June and July 2026 and $5.07/MWh in August 2025.

However, the impact of the enhancement on the model's ability to estimate expected closeout charges was more mixed. Whereas the previous GMM (i.e., the version prior to the incorporation of the ICE futures) tended to underestimate the upper tail of the real-time LMP distribution and therefore underestimate expected closeout charges,[35] the current GMM (i.e., the version that incorporates the ICE futures) may have overcorrected for this tendency. This is because, while the enhancement increased the *expected* closeout charges by giving the GMM substantially wider distributions, it reduced *actual* closeout charges as a result of having a more accurate estimate of the real-time price (as discussed above). This can be seen in Table 3-1, which shows the average actual and expected closeout charges prior to and after the GMM enhancement.

Table 3-1: Actual and Expected Closeout Charges before and after the GMM Enhancement

	June/July 2026 *(Pre-enhancement)*	August 2026 *(Post-enhancement)*
Average Actual Closeout ($/MWh)	$7.44	$4.55
Average Expected Closeout ($/MWh)	$4.18	$6.40
Average Bias[36] ($/MWh)	$3.27	-$1.85

In June and July 2026 (prior to the enhancement), actual closeout charges exceeded expected closeout charges by an average of $3.27/MWh, representing a continuation of the GMM's tendency to underestimate actual closeouts charges. Following the August 2026 update, the expected closeout charges *exceeded* the actual closeout charges by $1.85/MWh on average, representing a notable departure from the historical tendency. Because the updated methodology has only been in operation for one month, additional data will be required to fully evaluate its performance. The IMM will continue to monitor the effectiveness of the updated approach.

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-

[34] Bayesian updating is a statistical method for revising a forecast as new information becomes available. The GMM provides the initial, or *prior*, estimate of the pricing probability distributions. The observed futures prices are then incorporated to produce an updated, or *posterior*, distribution. This posterior distribution reflects both the historical patterns captured by the prior and the market expectations implied by observed futures prices.

[35] For a more thorough discussion on this topic, please see Section 8 of the IMM's Assessment of the Day-Ahead Ancillary Services Market, which is available here: https://www.iso-ne.com/static-assets/documents/100036/imm_assessment_of_da_ancillary_services_market.pdf

[36] The average bias represents the actual closeout charge less the expected closeout charge.

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.[37] 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 summer seasons in the table below.

Table 3-2: Hours and Level of Non-Zero Reserve Pricing

Product	Summer 2026		Summer 2025		Summer 2024	
	Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	$25.49	73.1	$69.96	111.3	$48.57	215.5
TMNSR	$132.27	10.0	$211.89	34.3	$180.67	51.3
TMOR	$137.77	8.6	$256.30	26.1	$212.35	31.1

Summer 2026 had fewer hours with positive real-time reserve prices across all reserve products than either of the prior two summers, indicating that reserve capability was generally ample throughout the season. This decline is partly attributable to the commercialization of several large battery storage facilities in recent years. These resources have increased the level of ten-minute spinning reserve designations in the real-time market, placing downward pressure on prices for all real-time reserve products because these designations can be used to satisfy not only the ten-minute spinning reserve requirement but also the total-10 and total-30 minute reserve requirements.

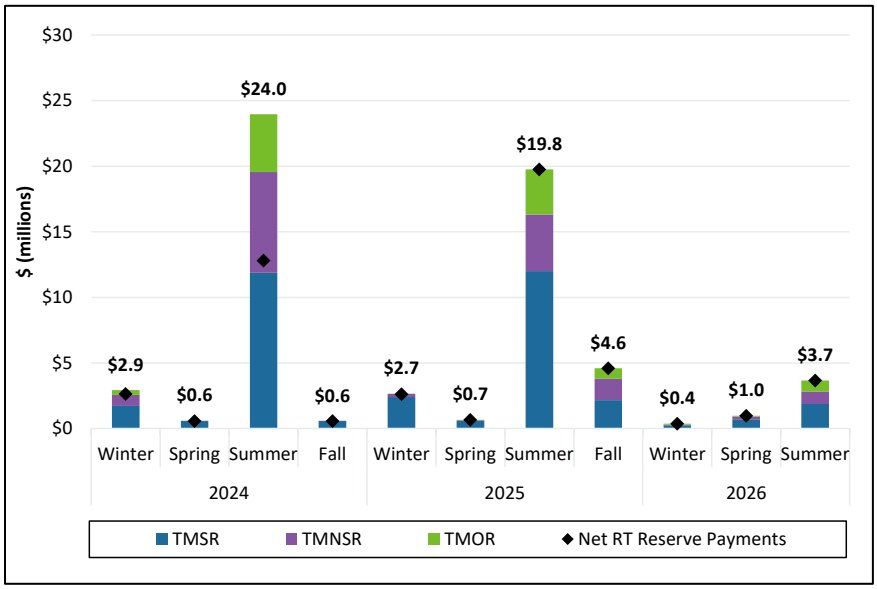
Real-time Reserve Payments

Real-time reserve payments by product are illustrated in the figure below. The height of the bars indicates gross reserve payments, while the black diamonds show net payments.[38]

[37] For more information about real-time reserve 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.

[38] 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.

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



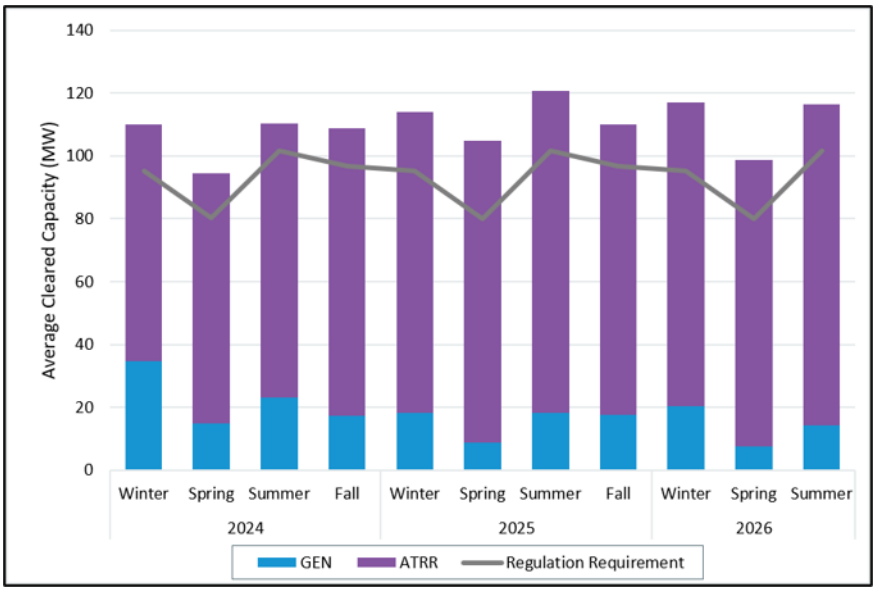
Net reserve payments in Summer 2026 ($3.7 million) were considerably lower than in the previous two summers. One factor in this decline was the absence of a Capacity Scarcity Condition (CSC), making Summer 2026 the first summer since 2022 without one. CSCs occur when the system is tight or deficient in total ten-minute or total thirty-minute reserves, causing reserve clearing prices to be set by Reserve Constraint Penalty Factors (RCPFs). Despite the absence of a CSC, several days experienced tight real-time system conditions during Summer 2026, including June 12, July 2, July 3, and July 8. Real-time reserve payments exceeded $0.5 million on each of these days.

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.

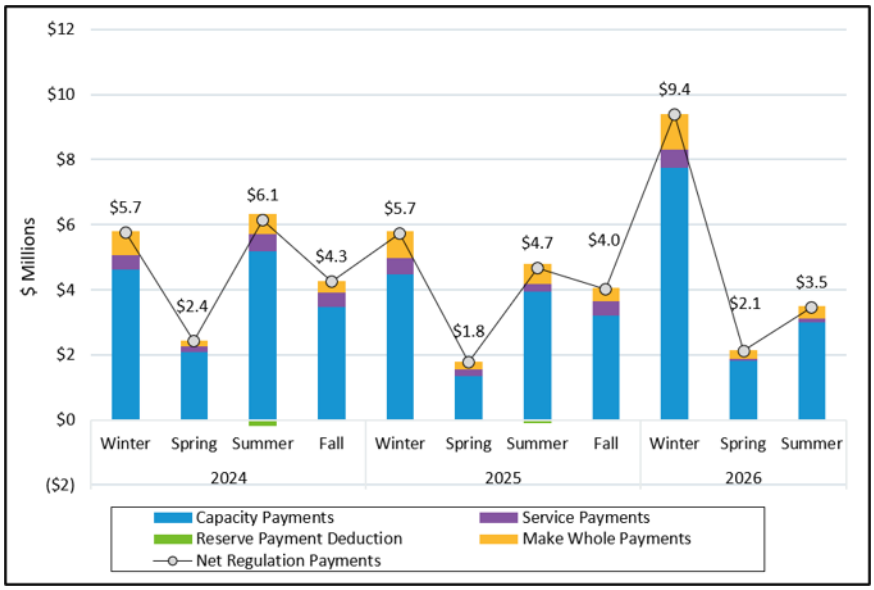
Two different types of resources can provide regulation: traditional generators and alternative technology regulation resources (ATRRs). Almost all ATRRs in the New England market are battery resources that can opt to participate solely as regulation resources or may choose to provide a broader combination of energy market and ancillary services: consumption (battery charging), generation (battery discharging), and regulation. The regulation resource mix is shown in Figure 3-11 below.

Figure 3-11: 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. Summer typically has higher average cleared regulation capacity. Total cleared regulation decreased slightly from 121 MW in Summer 2025 to 117 MW in Summer 2026. This decrease was concentrated among traditional generators, whose average cleared quantity decreased from 18 MW to 14 MW, while ATRR participation remained relatively stable at approximately 102 MW. As a result, the ATRR share of cleared regulation increased from 85% in Summer 2025 to about 88% in Summer 2026. The higher ATRR share primarily reflects the decrease in traditional generator participation rather than an increase in average cleared regulation from ATRRs, continuing the broader shift in the resource mix toward ATRRs. Quarterly regulation payments are shown in Figure 3-12 below. The bars show the breakdown of total regulation payments into capacity, service, make-whole, and reserve payment deductions, illustrating both the overall level and composition of regulation market payments.

Figure 3-12: Regulation Payments



Total regulation market payments were $3.5 million during Summer 2026, down 26% compared with Summer 2025. The decrease primarily reflected lower capacity payments, which decreased 24%, from $3.9 million to $3.0 million, while remaining the largest component of regulation payments across all seasons. Service payments decreased 54% and represented a slightly smaller share of total payments than in Summer 2025. Regulation make-whole payments[39] decreased 38% but remained consistent with prior seasons and years at approximately 11% of total payments. Reserve payment deductions decreased 73% and remained a small component of total payments.

[39] ISO New England, *Market Rule 1*, § III.14.8(b)(iii). Regulation make-whole payments address eligible compensation shortfalls within the Regulation Market and are distinct from NCPC. See ISO-NE Market Rule 1, Section III.14: Regulation Market.

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. While the presence of market power exists, energy market outcomes remain consistent with a competitive market.

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).[40]

When a participant's available supply exceeds the supply margin[41], they are considered pivotal.[42] 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%

[40] 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.

[41] 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*]

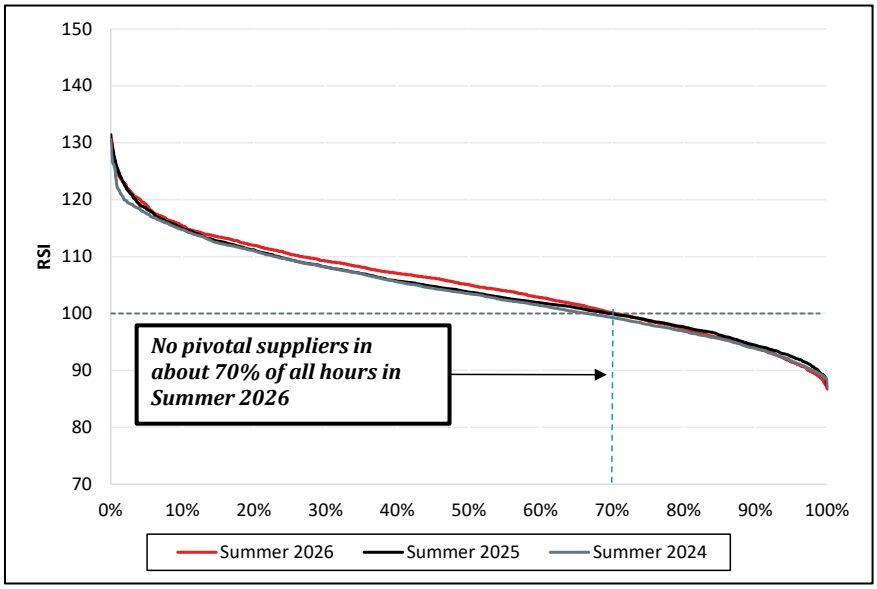
[42] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Spring 2026	108.0	25%
Summer 2026	104.9	30%

The quarterly average RSI exceeded 100 throughout the reporting period, indicating that, on average, the ISO could meet load and reserve requirements without the largest supplier. In Summer 2026, the RSI averaged 104.9, slightly above Summer 2025 (104.4) and Summer 2024 (104.0). Growth in battery storage capacity, which exceeded 1,100 MW by the end of the summer, contributed to this increase. Battery storage provides flexible supply that can be dispatched to meet energy or operating reserve requirements during peak demand and stressed system conditions. Its growing contribution to operating reserves has also increased reserve margins.

Duration curves that rank the average hourly RSI over each summer 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 Summer 2026, the RSI was slightly in line with the two prior summers. The lowest Summer 2026 RSI value was 85.1 and occurred during the evening (HE 21) of June 3.

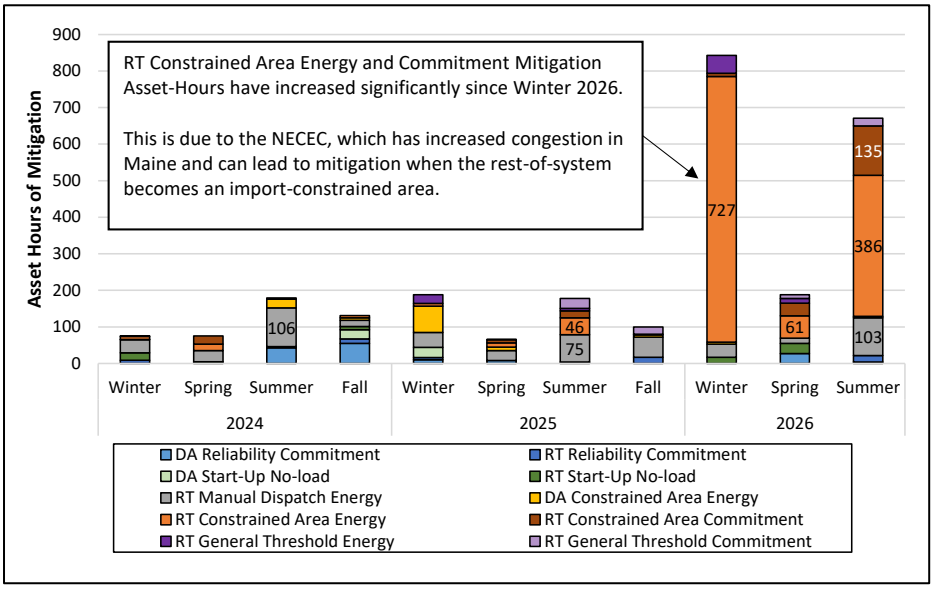
4.2 Energy Market Supply Offer Mitigation

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 relatively infrequently in Summer 2026, with increases driven by more frequent system congestion and resulting constrained area mitigations.

Energy Market Mitigation Frequency[43]

Asset hours of mitigation by type are shown in Figure 4-2 below.

Figure 4-2: Energy Market Mitigation Asset Hours



Summer 2026 saw 671 asset-hours of mitigation, continuing a trend of more frequent mitigation since Winter 2026. Despite the increase, mitigation remained infrequent: while 19% of real-time economic asset-hours failed structural tests (pivotal supplier or constrained area), less than 0.2% of real-time economic asset-hours were ultimately mitigated after conduct and/or impact tests.[44]

The largest share of both structural test failures and mitigations were attributable to real-time constrained area tests. Real-time Constrained Area Energy (CAE) and Constrained Area Commitment (CACM) mitigations occurred in 386 and 135 asset-hours, respectively. Constrained area structural test failures have increased since the NECEC came online in Winter 2026. As discussed in 5.2, the NECEC has led to transmission congestion in Maine as low-cost energy from the NECEC and renewable generators flows southwest to the rest-of-system across limited

[43] Note that Day-Ahead Ancillary Services mitigations are not included in this section.

[44] We use real-time economic asset-hours to estimate the amount of asset-hours that are subject to mitigation. This includes all generation with an economic offer over a dispatchable range, even if that generation is self-scheduled up to Eco Min.

interfaces. For the purposes of real-time constrained area mitigation, this creates an import-constrained zone in the rest-of-system.[45] When this occurs, generators outside of Maine can fail constrained area tests and are subject to constrained area conduct and impact test thresholds, which are relatively sensitive compared to the thresholds for general threshold energy or commitment mitigation.

The primary interface that causes import constrained areas outside of Maine is the Maine-New Hampshire (MENH) interface.[46] This interface bound in 7.4% of real-time intervals in Summer 2026, and 62% of all intervals with real-time constrained area structural test failures were at least partially attributable to MENH. Mitigation followed only in cases where conduct and impact tests also subsequently failed; even in the minority of intervals where assets failed constrained-area structural tests due to congestion in Maine, assets only failed conduct and impact tests less than 2% of the time.

Beyond real-time constrained area mitigations, other mitigation types were generally in-line with previous summers. Manual Dispatch Energy mitigations occurred in 103 asset-hours; these generally occur on tight days when slow-ramping units are manually dispatched to increase the amount of reserves available to the system, or when manual dispatches occur for other short-term system needs. Real-time reliability commitment mitigations occurred in 18 asset-hours, and real-time general threshold commitment mitigations occurred in 21 asset-hours. The remaining mitigation asset-hours occurred in the day-ahead market, with 4 asset-hours of reliability commitment mitigations and 4 asset-hours of constrained area energy mitigations.

[45] See the ISO-NE Tariff section III.A.5.2.2., which states that a real-time resource is considered to be in a constrained area if "the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint."

[46] While the MENH interface is the most common source of congestion from Maine to the rest of the system, other interfaces or transmission elements can also result in similar congestion patterns. Most notably, the Northern New England Scobie (NS_ST) interface is similarly impacted by the NECEC and limits energy flowing out of Maine.

Section 5
Forward Markets

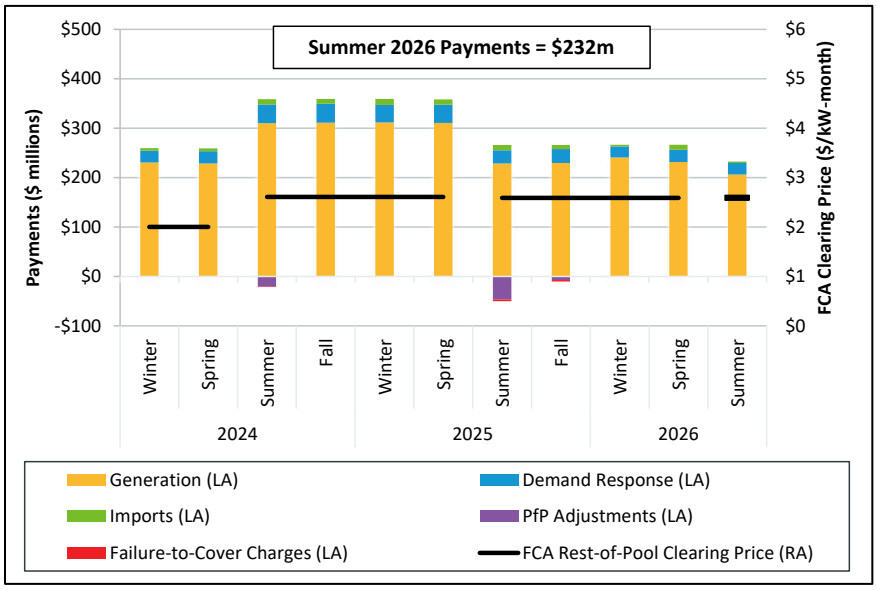
This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs).

5.1 Forward Capacity Market

The Capacity Commitment Period (CCP) associated with Summer 2026 started on June 1, 2026 and will end on May 31, 2027. The corresponding Forward Capacity Auction (FCA 17) cleared at $2.59/kW-month for the Rest-of-Pool capacity zone, an unchanged price from FCA 16. The auction cleared 31,370 MW of Capacity Supply Obligation (CSO), a 1,065 MW surplus above the Net Installed Capacity Requirement (Net ICR; 30,305 MW). Price separation in FCA 17 was minor; there were no capacity zones with clearing prices higher than the rest-of-pool, and lower clearing prices occurred only on the New Brunswick interface ($2.55/kW-month). There were few generating capacity retirements in FCA 17, and battery storage, wind, and solar made up most of the 600 MW of new generating capacity.

Total FCM payments, as well as the clearing prices for Winter 2024 through Summer 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, blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The purple bar represents Pay-for-Performance adjustments, while the red bar represents Failure-to-Cover charges.

Figure 5-1: Capacity Market Payments



Capacity payments totaled $232 million in Summer 2026, down 13% from Summer 2025. Payments declined in FCA 17 despite similar clearing prices to FCA 16, due to less cleared CSO

(following a smaller NICR) and the absence of price separation in import-constrained areas. There were no PfP payments in Summer 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 Summer 2026 alongside results of the relevant primary FCA are detailed in Table 5-1 below.[47]

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**
FCA 17 (2026-2027)	**Primary**	**12-month**	**31,370**	**2.59**	**2.59**	**2.55**	**2.59**
	MRA	Aug-26	445	6.62	6.62	6.62	6.62
	MBA	Aug-26	4	1.74			
	MRA	Sep-26	374	4.00	4.00	4.00	4.00
	MBA	Sep-26	3	1.83			
	MRA	Oct-26	390	1.25	1.25	1.25	1.25
	MBA	Oct-26	2	1.11			
FCA 18 (2027-2028)	**Primary**	**12-month**	**31,556**	**3.58**	**3.58**	**3.58**	**3.58**
	ARA 2	12-month	481, -626	3.94	3.94	3.94	3.94

** 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.*

During Summer 2026, monthly reconfiguration auctions (MRAs) were held for August, September, and October 2026. Less than 500 MW cleared in each MRA, reflecting modest participation. Prices fell from $6.62/kW-month in August to $1.25/kW-month in October. The variability in clearing prices reflects seasonal differences; hotter months such as August generally have higher risk for

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

longer-duration capacity scarcity conditions and resulting PfP charges, which MRA participants may reflect in high-priced demand bids and supply offers.

The second Annual Reconfiguration Auction (ARA) for CCP 18 cleared at $3.94/kW-month, an 11% price increase from the primary auction. The second ARA featured a 29,855 MW Net ICR, down 695 MW from the primary auction. Roughly 150 MW left the capacity market on a net basis through cleared demand bids (626 MW) exceeding newly cleared supply (481 MW).

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.

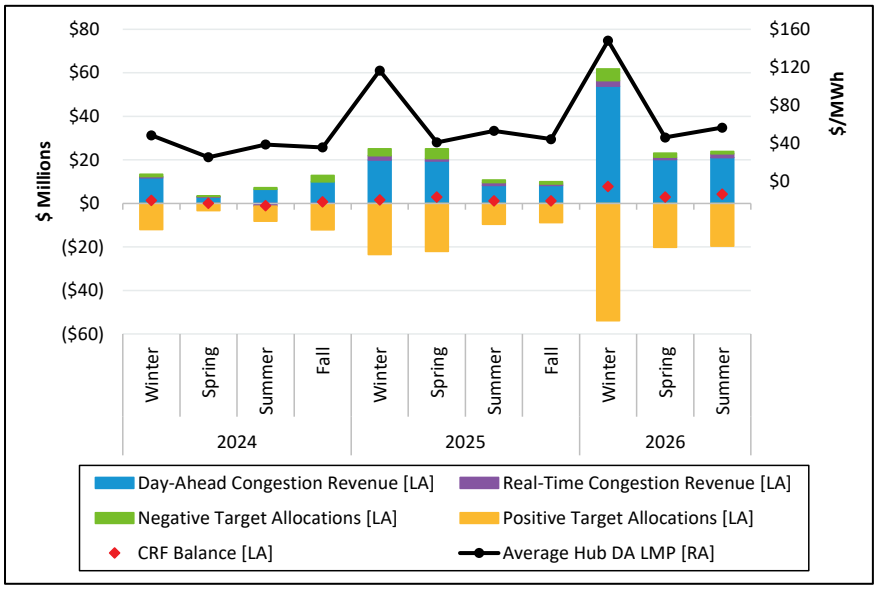
The figure below shows, by quarter, the amount of congestion revenue from the day-ahead and real-time energy markets, the amount of positive and negative target allocations, and the congestion revenue fund (CRF) balance.[48,49] This figure also depicts the quarterly average day-ahead Hub LMP.[50]

[48] The CRF balances depicted in this figure 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).

[49] This figure 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.

[50] 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

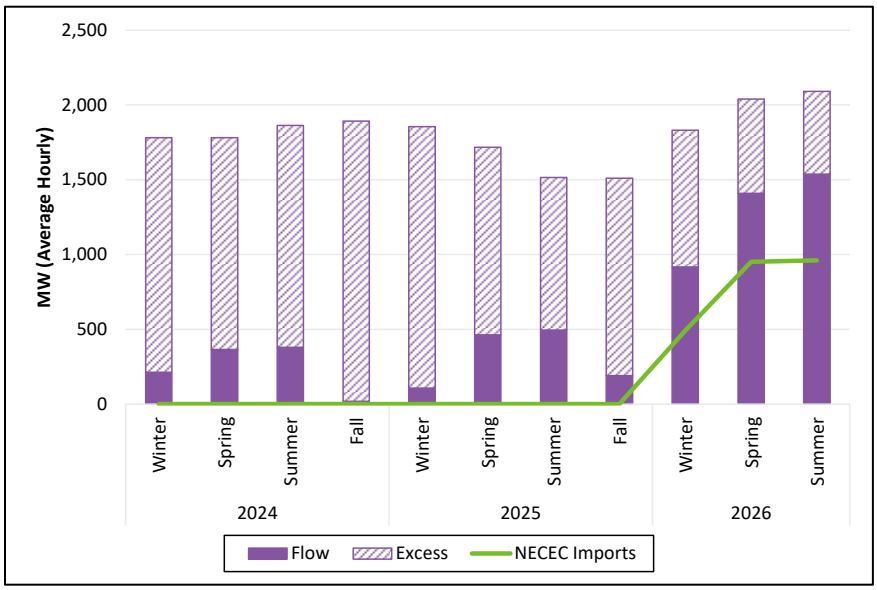


Congestion revenue totaled $22.8 million in Summer 2026, marking a modest increase from Spring 2026 (7%) but a more than two-fold increase from Summer 2025. One reason for large year-over-year increase in congestion revenue is related to the New England Clean Energy Connect (NECEC) transmission line. Since the NECEC became operational in Winter 2026, utilization of the Maine-New Hampshire (MENH) interface, which manages power flows between Maine and the rest of New England, has increased significantly, leading to more frequent congestion and larger FTR-related settlement outcomes.[51] For example, the MENH interface bound in only one hour in the day-ahead market in Summer 2025 but in over 200 hours in Summer 2026. This increased congestion led the MENH interface to account for over half of all positive target allocations in Summer 2026.

The relationship between day-ahead cleared imports over the NECEC transmission line and the flow of power over the MENH interface in the day-ahead market is shown in Figure 5-3 below. The green line depicts average quarterly day-ahead cleared NECEC imports, while the stacked purple bars show the average quarterly power flow over the MENH interface (solid) and the average excess capability of the interface (hatched). The total height of each bar represents the average capability (or "limit") of the interface in the day-ahead market.

[51] 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.

Figure 5-3: Average Day-Ahead Market Values for the MENH Interface and Cleared NECEC Imports by Quarter



Prior to Winter 2026, the average day-ahead flows over the MENH interface ranged between 0-500 MW per hour, depending on the quarter. At these levels, the interface had substantial unused transfer capability, with average excess interface capability ranging between 1,000 MW to almost 2,000 MW per hour. Beginning in Winter 2026, however, average flows increased markedly as imports began clearing over the NECEC transmission line. By Summer 2026, average flows exceeded 1,500 MW per hour, while average day-ahead imports over the NECEC approached nearly 1,000 MW per hour. Although the MENH interface capability has increased relative to prior seasons due, at least in part, to upgrades associated with the NECEC project, higher flow levels have caused the interface to bind more frequently.