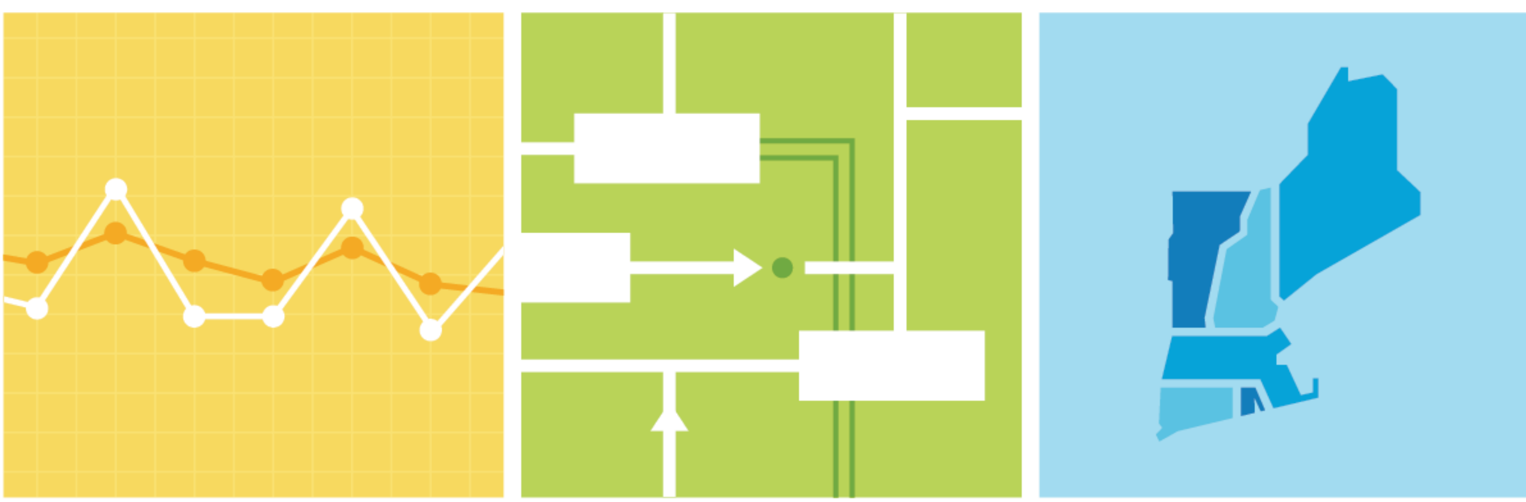
Winter 2026
Quarterly Markets Report

By ISO New England's Internal Market Monitor

JULY 9, 2026

ISO-NE PUBLIC



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Preface

The Internal Market Monitor ("IMM") of ISO New England Inc. (the "ISO") publishes a Quarterly Markets Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. The report addresses the development, operation, and performance of the wholesale electricity markets and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of Market Rule 1, Appendix A, Section III.A.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation*:

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

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

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

[1] Capitalized terms not defined herein have the meanings ascribed to them in the *ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3* (the "Tariff"), Section I, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_1/sect_i.pdf.

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

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Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Winter 2026 (December 1, 2025 through February 28, 2026).[3]

Winter Assessment: New England experienced prolonged periods of below-normal temperatures in Winter 2026, including a 19-day cold snap between January 23 and February 10, the longest since Winter 2015.[4] These conditions led to elevated demand, high natural gas prices, LNG sendout, and oil inventory burn. In total, winter wholesale market costs reached $6.5 billion, up 45% from Winter 2025 and higher than in any other year since 2014. Despite the high costs, the power system operated reliably and efficiently. There were no reserve deficiencies leading to pay-for-performance events, no posturing, low NCPC, and wholesale market outcomes that were generally consistent with key fundamentals (natural gas, oil, demand) and market incentives. Below are highlights of the supply mix, fuel markets, and other outcomes.

- Winter 2026 saw the highest LMPs of all winter seasons since 2014. Day-ahead and real-time energy price convergence was particularly poor from January 25 to 29, with day-ahead LMPs exceeding real-time LMPs in most hours.
- Average hourly demand was 15,381 MW, and the peak load was 20,221 MW, the highest winter peak load since January 2019.
- New England gas pipelines were significantly constrained throughout Winter 2026, and the region was reliant on LNG sendout to provide liquidity during gas-scarce, high-priced periods. LNG sendout reached approximately 45.9 million MMBtu in Winter 2026, roughly double the 22.4 million MMBtu of sendout in Winter 2025.
- Oil was utilized more than in any season since at least Winter 2015. Oil generation averaged roughly 4,000 MW on an hourly basis from January 24 through February 9, a period during which natural gas prices exceeded No. 2 oil prices and many dual-fuel generators switched to oil.
- New England started the winter with lower-than-normal oil inventories, which were depleted to under 50% of the lows from the prior two winters. However, replenishment was higher than in previous winters. Additionally, many oil generators appeared to respond to opportunity costs associated with burning stored oil by switching to gas or increasing energy market offers. This resulted in an efficient allocation of fuel across the system.
- The new 1,200 MW New England Clean Energy Connect (NECEC) transmission line from Quebec achieved commercial operation in mid-January, but total net imports were down from the prior winter. New England was a net exporter to other regions for several hours during the height of the cold snap in late January.
- Gas procurement challenges led to natural gas generation reference levels that were significantly higher than index prices, and the IMM allowed supply offers to exceed the $1,000/MWh soft cap during nine days.

Wholesale Costs: The total estimated wholesale market cost of electricity was $6.53 billion, up 45% from $4.50 billion in Winter 2025. Energy costs, which include the Forecast Energy Requirement (FER) credits associated with the Day-Ahead Ancillary Services (DA A/S) market, comprised 93% of

[3] In Quarterly Markets Reports, outcomes are reviewed by season as follows: Winter (December through February), Spring (March through May), Summer (June through August) and Fall (September through November).

[4] The 19-day cold snap included Winter Storm Fern between January 23 and January 27.

wholesale costs and totaled $6.08 billion, a 51% increase from Winter 2025. Higher natural gas prices were the main driver of elevated energy costs. Emissions costs were also up year-over-year. In addition, the DA A/S market resulted in an estimated $574 million in additional costs.

Capacity costs totaled $266 million, representing 4% 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 capacity costs were 26% lower in Winter 2026 than in Winter 2025, due to lower cleared capacity and less upward price separation in the import-constrained Southeast New England capacity zone.

Energy Prices: The day-ahead Hub LMP averaged $147.99/MWh and the FER price (FERP) averaged $17.50/MWh, leading to an all-in payment of $165.49/MWh for day-ahead physical generation. The real-time Hub price averaged $137.66/MWh.

- Average natural gas prices averaged $17.79/MMBtu, up 31% compared to the prior winter. The increase was due to colder weather and the highest gas demand in over 10 years.
- Carbon allowance prices also increased, with Regional Greenhouse Gas Initiative (RGGI) CO_2 allowance prices up 14% and Massachusetts Electricity Generator Emission Limits (MA EGEL) prices up 133% from Winter 2025. These prices added approximately $11-$17/MWh in costs for a typical combined cycle and $24-$38/MWh for a No. 2 oil-fired generator, depending on location.

Supply mix: There were notable differences in the supply mix in Winter 2026 compared to Winter 2025. Higher average loads and reduced net imports compared to previous winters led to increased reliance on natural gas and oil. While imports increased compared to spring, summer, and fall of 2025, net imports provided 13% of total supply, down from 21% in Winter 2025. Natural gas rose from 39% of supply in Winter 2025 to 44% of supply in Winter 2026, while oil increased from 2% to 6% of supply.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $13.0 million, representing 0.2% of total wholesale energy costs, down from $16.0 million in Winter 2025. Nearly all NCPC payments (99%) were economic payments to generators committed to meet systemwide load and reserve requirements. Within these economic payments, dispatch lost opportunity cost (DLOC) credits totaled $3.6 million in Winter 2026, a 65% increase from the prior winter. This increase was primarily driven by higher real-time LMPs, which raised generators' opportunity cost payments, as well as higher compensation to battery storage resources for quickly ramping output ahead of market price movements.

Day-Ahead Ancillary Services[5]: Net DA A/S payments, which account for credits and closeout charges, increased substantially between Fall 2025 ($34.1 million) and Winter 2026 ($157.1 million). However, this increase was largely in line with higher energy costs: net DA A/S payments rose slightly from 2.1% to 2.5% of total E&AS costs.

Real-time Reserves: Overall, there was ample supply of total-ten and thirty-minute reserve capability available on the system in Winter 2026. There were fewer hours of reserve pricing for all

[5] On March 1, 2025, ISO New England launched a new suite of day-ahead ancillary services (DA A/S) designed to procure operating reserves and ensure sufficient supply to meet the ISO's load forecast through market mechanisms. The new products include day-ahead ten-minute spinning reserve (DA TMSR), day-ahead ten-minute non-spinning reserve (DA TMNSR), day-ahead thirty-minute reserves (DA TMOR), and Energy Imbalance Reserve (EIR).

three reserve products compared to prior winters. As a result, real-time reserve payments were lower, totaling $0.4 million in Winter 2026 compared to $2.9 and $2.7 million in Winter 2024 and 2025, respectively.

Regulation**:** Total regulation market payments were $9.38 million, up significantly from $5.74 million in Winter 2025. Higher regulation capacity prices in Winter 2026 put upward pressure on regulation capacity payments, while capacity offer prices remained relatively low as lower-cost alternative technology regulation resources continue to expand their presence in the regulation mix.

Energy Market Competitiveness: The residual supply index for the real-time energy market in Winter 2026 was 107.6, 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 only 13% of five-minute pricing intervals, despite higher loads and lower net interchange. This represents the lowest level of pivotal suppliers in the past two years, 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.

The mitigation of energy market supply offers occurred much more frequently in Winter 2026 compared with previous seasons, driven primarily by a large import-constrained area on the west side of the Maine-New Hampshire constraint. The Maine-New Hampshire constraint was binding more frequently than in previous seasons due to increased supply in Maine associated with the NECEC line. In total, mitigation asset hours increased from 188 hours in Winter 2025 to 843 hours in Winter 2026. Real-time constrained area energy mitigation was by far the most frequent mitigation type in Winter 2026, totaling 727 asset hours.

Financial Transmission Rights (FTRs): Congestion revenue totaled $56 million in Winter 2026, more than doubling from Winter 2025. Congestion revenue is correlated with high day-ahead LMPs; in addition, the NECEC line drove significant system congestion from Maine to the rest-of-system after it became operational in mid-January. Beyond the new flows driven by the NECEC, typical winter-related congestion patterns arose throughout Winter 2026, with frequent congestion at the New York-New England interface. Overall, FTRs were fully funded in each month of the season.

Section 1
Assessment of Winter 2026 Market Issues

This section evaluates how the New England wholesale electricity markets performed during Winter 2026 under sustained cold-weather conditions. It examines how weather-driven demand, fuel supply constraints (particularly natural gas and oil), and market design features shaped market outcomes. The section also focuses on how participant responses to price signals and operational incentives—such as fuel switching, imports, and energy market opportunity costs—affected fuel allocation, system reliability, and overall market efficiency.

1.1 Winter 2026 Summary

In Winter 2026, wholesale electricity costs totaled $6.53 billion ($196/MWh), increasing 45% from Winter 2025 and more than doubling relative to Fall 2025, driven by the highest seasonal energy market costs since the start of Standard Market Design. Natural gas prices remained the primary driver of electricity prices, rising 31% year-over-year. Correspondingly, peak demand days, day-ahead energy prices (including FERP), and real-time LMPs reached their highest levels since at least Winter 2014.

These outcomes were shaped by extended periods of cold weather, most notably a 19-day cold snap from January 23 to February 10 that included Winter Storm Fern. This was the second-longest streak of consecutive cold days since 2010, exceeded only by a 28-day period during the 2015 polar vortex. While long relative to recent winters, similar or longer cold spells have occurred historically, with approximately 25% of winters between 1950 and 2009 experiencing longer streaks.

Market outcomes were driven heavily by the 19-day cold snap, which accounted for nearly 45% of total energy, ancillary, and uplift costs. During this period, system gas prices reached up to $122/MMBtu and fuel-price adjustments reached up to $400/MMBtu. These conditions led to greater reliance on oil generation than in any winter since at least 2015. Despite elevated costs and tight market conditions, the system operated reliably and efficiently, with no posturing, minimal uplift, and no capacity scarcity events.

New England gas prices are particularly sensitive to cold weather, as increased residential heating demand reduces the availability of natural gas for electricity generation. These pipeline constraints contributed to the highest regional natural gas prices since Winter 2014.

At times, pipeline utilization approached full capacity, driven primarily by residential demand. LNG sendout—more than double Winter 2025 levels—helped alleviate constraints by supplying gas that would otherwise have been unavailable. Despite this, gas procurement challenges led to natural gas generation reference levels that were significantly higher than index prices, and the IMM allowed supply offers to exceed the $1,000/MWh soft cap on nine days.

During the cold snap, gas and oil prices inverted, and oil generation exceeded gas generation on several days. Although starting oil inventories were lower than in prior winters and some units approached depletion, replenishment was substantially higher. As oil inventories declined, participants faced increasing energy market opportunity costs and responded by incorporating these into oil offers or switching to gas where dual-fuel capability was available. These responses preserved oil inventories, maintained reserves, and supported an efficient allocation of gas and oil.

Winter 2026 was the first with the Day-Ahead Ancillary Services (DA A/S) market, which introduced day-ahead procurement and pricing of operating reserves and resulted in approximately $574 million in additional costs.[6] These new incentives may have contributed to higher availability of combustion turbines, the primary providers of DA A/S services.

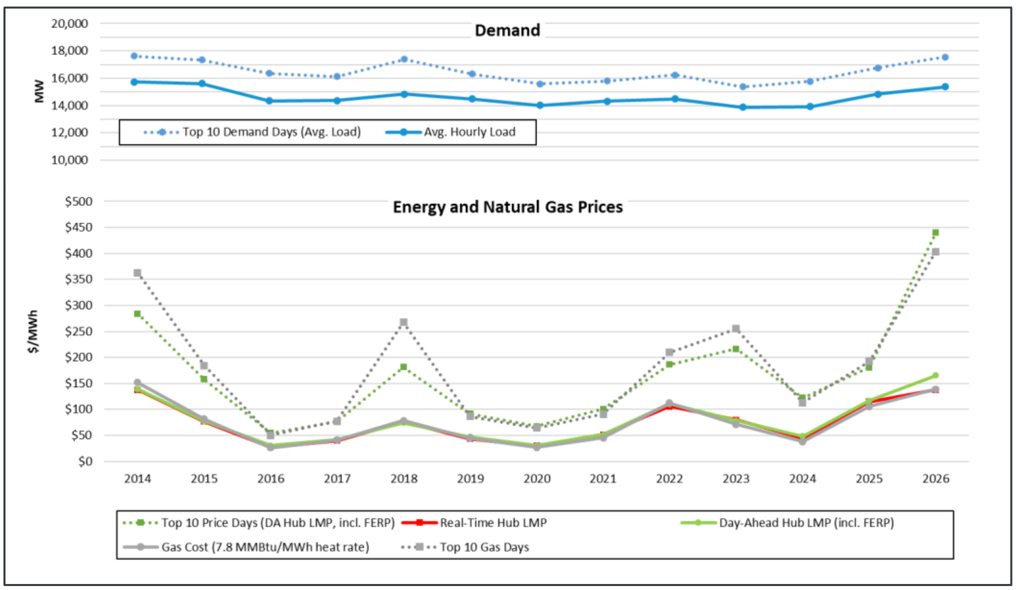
Finally, the New England Clean Energy Connect (NECEC) transmission line entered service on January 16, 2026, increasing import capability from Canada during the latter portion of the winter. This new interface altered power flows and price separation patterns in Maine and represents a meaningful structural change to the regional supply mix. Despite the additional import capability, net imports declined relative to the prior winter, and New England was a net exporter to neighboring regions for several hours during the cold snap in late January.

1.2 Winter Weather and System Conditions

1.2.1 Summary of Market Outcomes

Figure 1-1 shows average LMPs, natural gas costs, and peak demand, since 2014.[7]

Figure 1-1: Winter LMPs, Natural Gas Costs, and Loads



Average load in Winter 2026 reached 15,381 MW, with a winter peak load of 20,221 MW on January 25, 2026. This peak was the highest since Winter 2019. Load in the top ten demand days (17,559 MW) was also the highest over the period shown in the figure, surpassing levels seen during the notable cold conditions in Winter 2018.

Average day-ahead energy prices (incl. FERP) and real-time LMPs in Winter 2026 ($165/MWh and $138/MWh) were the highest over the period. Day-ahead prices exceeded the previous peak observed in Winter 2014, while real-time prices were in line with Winter 2014 levels but above all other recent winters. The average real-time LMP on the top ten high-priced days in Winter 2026 ($300/MWh) was also the highest on record, reflecting more frequent and sustained high-price

[6] For more information about this analysis, please see Section 3.5.4.

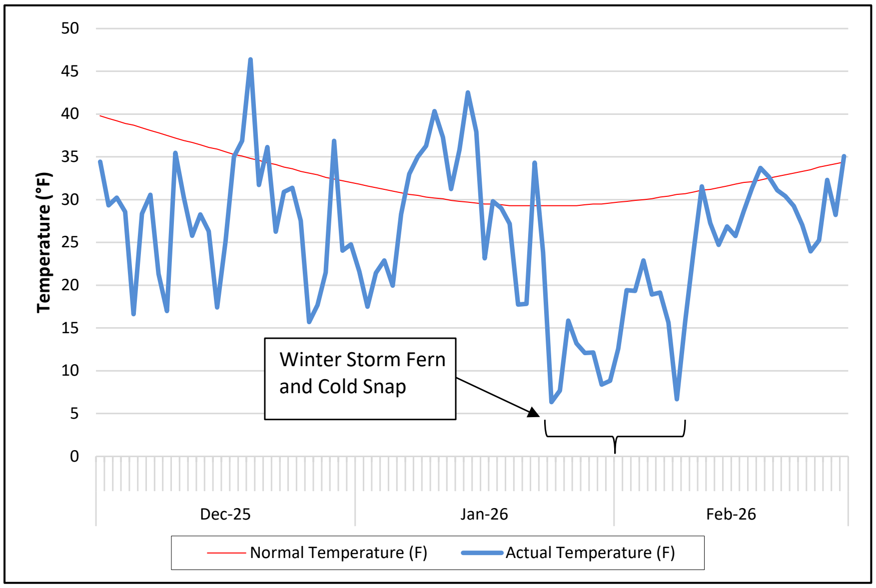
[7] The IMM uses a heat rate of 7.8 MMBtu/MWh to represent standard-efficiency gas generators.

conditions. Consistent with fuel market outcomes, top ten gas day prices reached $52/MMBtu—well above prior winters—and drove top ten gas-related cost outcomes to $404/MWh, the highest in the series. Relative to all other winters in the historical record, Winter 2026 was characterized by elevated demand and sustained upward pressure on electricity prices stemming from fuel market conditions.

1.2.2 Weather

Winter 2026 was characterized by multiple periods of below-normal temperatures from December through February, including a prolonged 19-day cold snap from January 23 to February 10 that included Winter Storm Fern (January 23–27). Figure 1-2 below shows the daily average temperature compared to historic normal temperatures for New England.[8]

Figure 1-2: New England Daily Temperatures Compared to Historic Normal Temperatures



The daily average temperature in New England was approximately 6.8°F below the 1991–2020 normal. The lowest daily average temperature (6.3°F) occurred on January 24, marking the coldest day of the cold snap. This temperature pattern is consistent with a prolonged period of below-normal temperatures, with multiple extended cold intervals driving daily averages lower than seasonal norms.

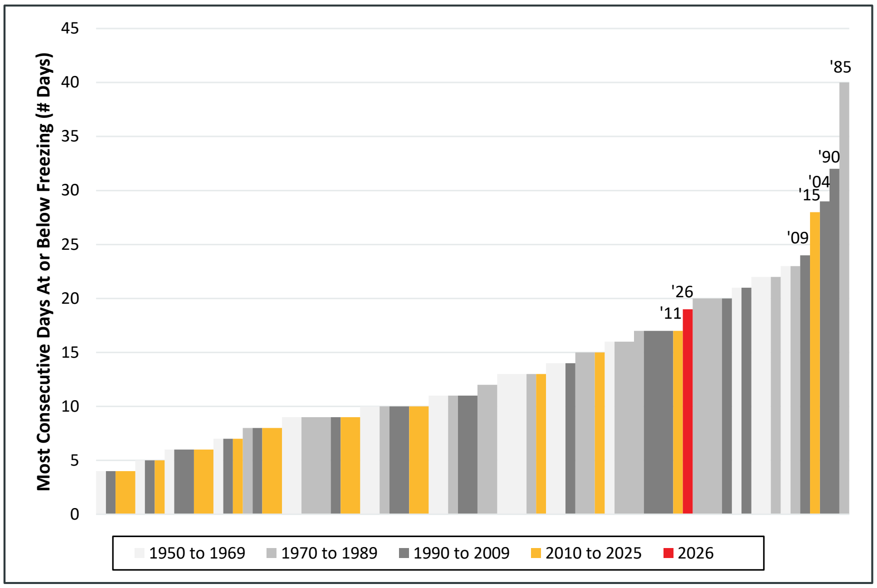
Consistent with these conditions, January 2026 recorded the highest heating degree days (HDD) since 2015, reaching 1,274, and an average load of 15,626 MW per hour. Cold conditions persisted

[8]Daily temperatures are based on observed maximum and minimum values measured at Boston Logan International Airport and archived by NOAA's National Centers for Environmental Information. Normal temperatures represent the 1991–2020 30-year average for each calendar day and serve as NOAA's standard climatological reference period; Boston Logan is commonly used as a representative benchmark for temperature conditions in New England. National Oceanic and Atmospheric Administration (NOAA), National Centers for Environmental Information (NCEI). Global Historical Climatology Network – Daily (GHCN-Daily) dataset, accessed via NCEI Data Access. Daily maximum and minimum temperatures for Boston Logan International Airport (GHCN ID: USW00014739) covering December 1, 2025 through February 28, 2026. Data available at https://www.ncei.noaa.gov/access/search/data-search/daily-summaries.

into February, although less severe than in January, with a total HDD of 1,135. This was approximately 7% higher than February 2025, reinforcing the role of colder temperatures in driving higher demand this winter.

In total, Winter 2026 included 19 consecutive days with average temperatures below freezing, indicating a sustained cold interval. Figure 1-3 below shows the length of the longest streak of sub-freezing days in Boston, by winter, between 1950 and 2026.

Figure 1-3: Length of Longest Streak of Sub-Freezing Days in Boston by Winter, 1950-2026



The figure shows that the 19-day streak of sub-freezing days the region observed during the cold snap was the second longest maximum streak of consecutive days below freezing since 2010, exceeded only by a 28-day streak in 2015. Although the cold snap was long compared to recent history, sixteen winters (almost a quarter) since 1950 have experienced longer streaks. This illustrates that despite being harsh compared to the mild conditions in recent years, this winter may not be an outlier in terms of historic weather severity.

1.2.3 Demand

Load outcomes during Winter 2026 averaged 15,381 MW per hour, with a seasonal peak of 20,221 MW, exceeding the ISO's winter forecast. The peak occurred on January 25 during Winter Storm Fern and reflects the system's growing exposure to winter-driven demand conditions. Compared to the prior winter, peak demand increased by 614 MW (3%) from 19,607 MW observed on January 22, 2025.[9] Consistent with prior severe winters, peak demand was driven by periods of extreme cold; however, in comparison to recent winters, this season was distinguished by both the magnitude and persistence of elevated load conditions. This pattern reflects the increasing

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[9] ISO New England, "Winter 2024/2025 Recap," April 11, 2025; ISO New England, "Winter Outlook," November 17, 2025 https://isonewswire.com/2025/04/11/winter-2024-2025-recap-regions-grid-remains-reliable-though-cold-weather-drives-up-wholesale-electricity-prices/

sensitivity of demand to cold weather, contributing to an ongoing shift toward a winter-peaking system.

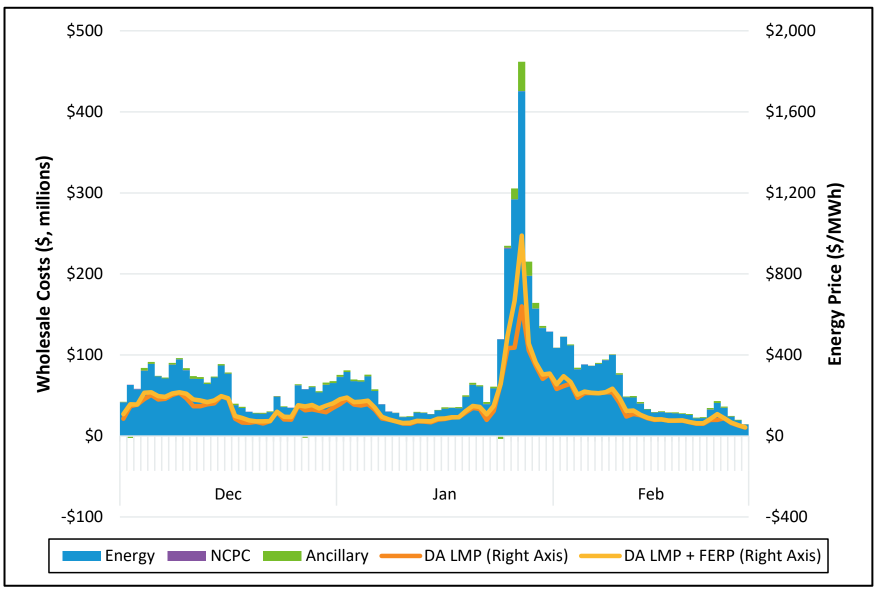
The cold snap from January 23 through February 10 was associated with persistently high demand, with average hourly load increasing to approximately 17,000 MW over this period. In contrast to prior winters where peak conditions were concentrated in shorter intervals, this event was characterized by sustained high load levels over multiple consecutive days. This extended duration increased operational stress on the system, as elevated demand levels were maintained for a prolonged period rather than driven by a single peak hour.

Market outcomes during the early portion of the cold snap further reflect these conditions. During this period, load undercleared in the day-ahead market relative to the ISO's load forecast. This resulted in elevated FER pricing, as the FER constraint ensured that day-ahead market outcomes were aligned with the load forecast despite load underclearing. For more information about load clearing in the day-ahead market, review Section 3.2.

1.3 Market Prices

In Winter 2026, energy, ancillary and uplift costs totaled nearly $6.3 billion. Figure 1-4 below shows daily wholesale costs for the season. The orange line depicts the daily average day-ahead Hub LMP, while the yellow line depicts the sum of the daily average day-ahead Hub LMP and the daily average FER price.

Figure 1-4: Daily Wholesale Costs

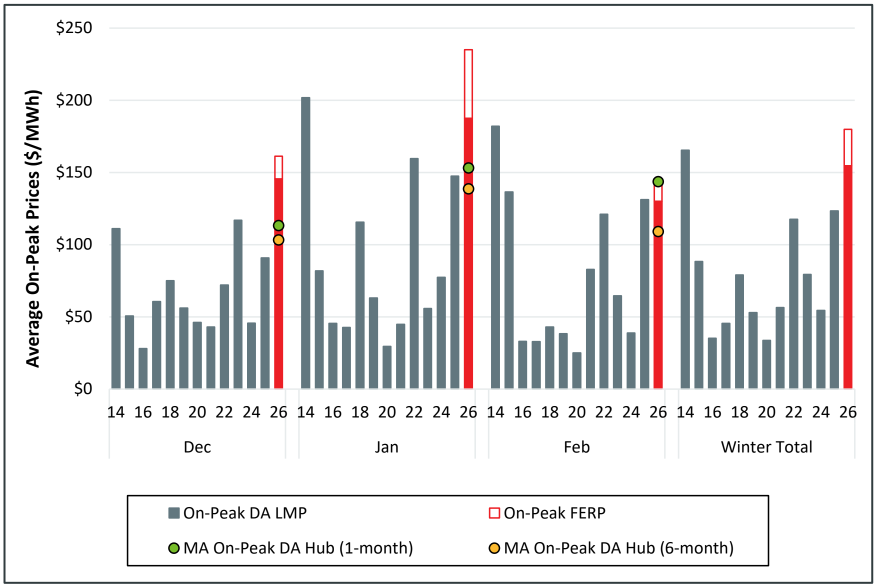


Nearly 45% of all daily energy, NCPC, and ancillary costs occurred over the 19-day cold snap between January 23 and February 10, 2026. Drivers of the wholesale costs are discussed below.

1.3.1 Energy Market Prices

Winter 2026 saw the highest day-ahead on-peak LMPs since Winter 2014. Figure 1-5 shows monthly average energy prices during on-peak hours for the prior 13 winters. The figure also includes average monthly forward prices for the ISO-NE day-ahead on-peak Hub LMP for 1 month and 6 months prior to the monthly delivery period.[10]

Figure 1-5: Historical Day-Ahead On-Peak Energy Prices



In Winter 2026, day-ahead on-peak LMPs averaged $155/MWh, which was 6% lower than average day-ahead on-peak LMPs in Winter 2014 ($165/MWh). However, the Forecast Energy Requirement (FER) constraint can put downward pressure on the day-ahead LMP, and the LMP can understate the total day-ahead price paid to physical generation (LMP + FERP).[11] When including the average FERP ($25/MWh), day-ahead on-peak prices ($180/MWh) were over $14/MWh higher on average compared to day-ahead LMPs in Winter 2014. The monthly On-Peak Energy Price (DA LMP plus FERP) in December and January exceeded all winters between 2014 and 2025. February prices were lower than in 2014, but higher than in all other winters in the period.

ISO-NE Mass Hub Day-Ahead On-peak forward prices traded well below realized prices in December 2025 and January 2026, highlighting that prices exceeded expectations six months ahead, and up to one month ahead in December and January. By contrast, for February 2026, average forward prices exceeded settled prices for trades placed once the winter began, reflecting market expectations shaped by earlier winter price outcomes.

Energy Price Convergence

During Winter Storm Fern (January 23-27) and in the two days that followed, day-ahead and real-time LMP convergence was notably poor compared to the entire cold snap period. Figure 1-6 shows day-ahead and real-time price convergence for the seven-day period. This period includes January 27, 2026, which saw the highest day-ahead energy prices since the start of Standard Market Design.

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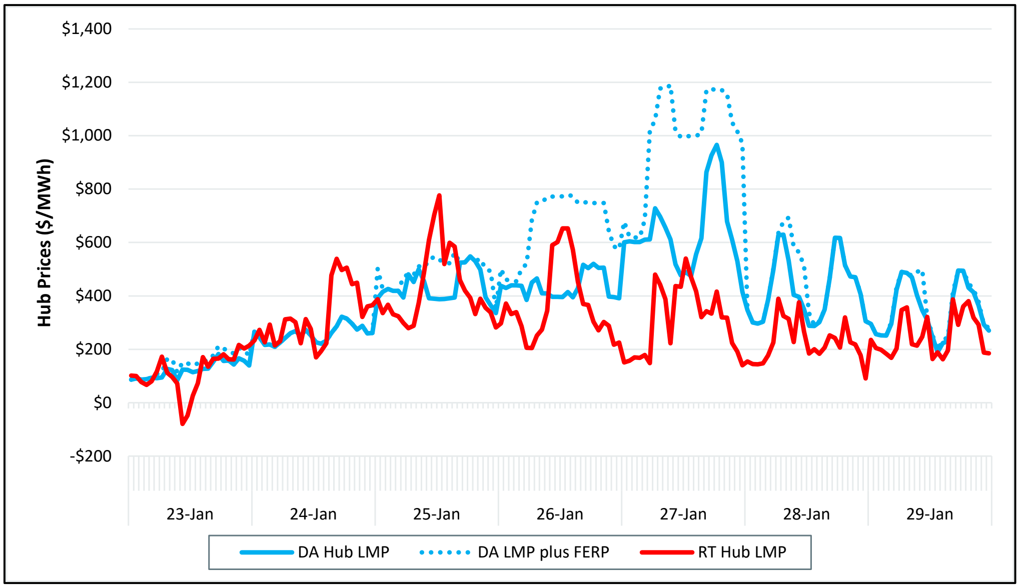
[10] Forward prices are sourced from ICE.

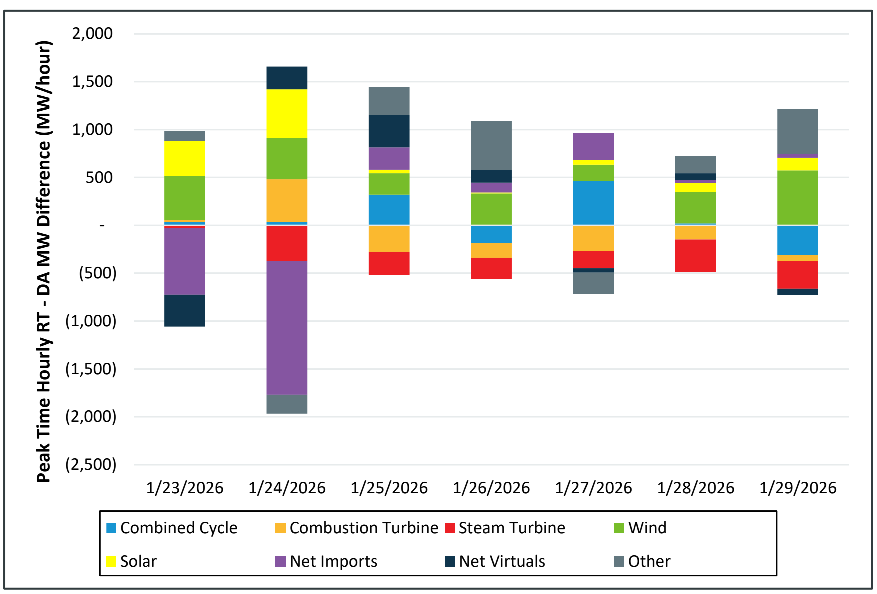
[11] For more information on the FER constraint's impact on day-ahead LMPs, see the IMM's *An Assessment of the Day-Ahead Ancillary Services Market* found at https://www.iso-ne.com/static-assets/documents/100036/imm_assessment_of_da_ancillary_services_market.pdf

Figure 1-6: Day-Ahead and Real-Time Hub Prices during Winter Storm Fern



In an efficient market, day-ahead (forward) prices should generally reflect expected real-time (spot) prices. From January 23-25, day-ahead and real-time LMP deviations were largely due to load forecast error. However, from January 26-29, real-time prices were significantly lower than day-ahead prices in most hours. Figure 1-7 below shows day-ahead and real-time supply differences during peak hours (hours ending 8 through 23) over the same period.[12]

Figure 1-7: Peak-Time Hourly Real-Time Minus Day-Ahead Generation Difference during Winter Storm Fern



[12] To better highlight technologies of interest, more technologies than typical are included in the "Other" category. The category includes hydro, nuclear, pumped storage, battery storage, wood/refuse, and demand response.

The primary driver of large day-ahead and real-time LMP deviations was net interchange differences. At the NECEC interface, no import transactions cleared in the day-ahead market until January 28, 2026. By contrast, imports began flowing in the real-time market during most hours starting on the evening of January 26, 2026. The additional real-time net interchange displaced more expensive generation particularly combustion turbines and steam turbines.

Another contributing factor was the relationship between virtual supply and intermittent generation. Under normal conditions, virtual supply transactions typically take the place of intermittent generators that offer their energy at high prices in the day-ahead market. This helps converge prices. However, during extreme weather events, virtual supply appears more reluctant to take on day-ahead positions, while virtual demand increases as physical generators seek to hedge the risk of generator trips during real time.

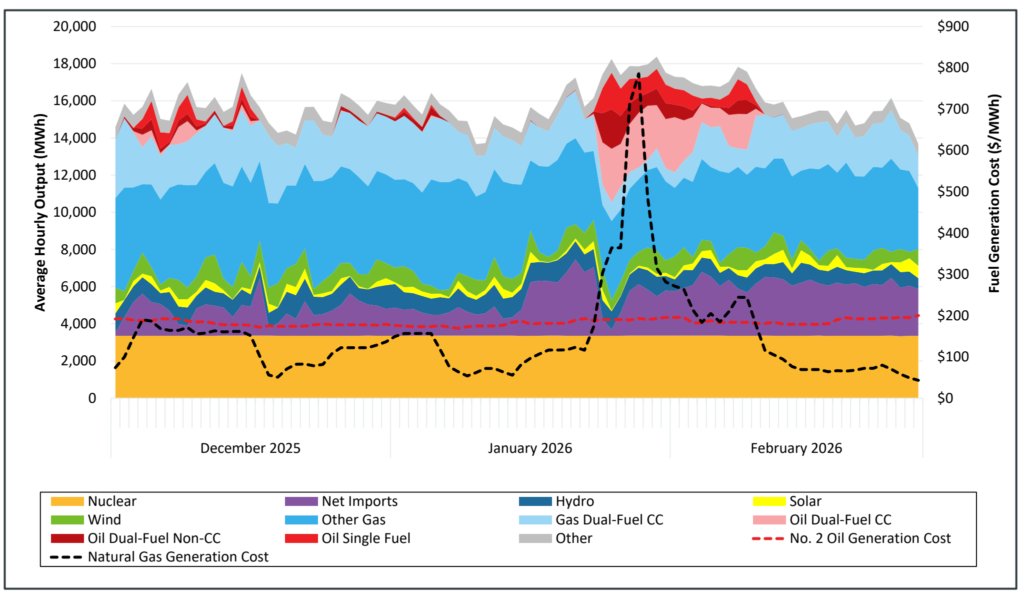
Further, the co-optimization of day-ahead energy and reserves also contributed to higher day-ahead prices. In the DA A/S market, the day-ahead market produces a more robust and flexible operating plan for real time than with the previous market construct. The cost of procuring this additional flexibility may have resulted in a day-ahead premium. In real time, improved operating conditions (including the realization of imports and intermittent production) allowed lower-cost supply to displace the higher-cost generation that was committed in the day-ahead market, resulting in lower real-time prices and wider day-ahead to real-time price spreads.

1.4 Generation and Import Availability and Performance

1.4.1 Supply Mix

During Winter 2026, oil was utilized more than in any season since at least Winter 2015. Periods of elevated oil burn coincided with high gas prices and residential gas demand that constrained the gas system. Figure 1-8 shows the daily supply mix during Winter 2026.

Figure 1-8: Real-Time Generation Obligation by Fuel Type and Gas/Oil Price



The daily supply mix highlights an increase in oil generation during the 19-day cold snap between January 23 and February 9. Oil generation averaged roughly 4,000 MW on an hourly basis from

January 24 through February 9, the period when gas prices exceeded oil prices. During that time, dual-fuel combined cycle units provided an average of 2,100 MW of oil and 1,200 MW of gas on an hourly basis. The switch to oil was consistent with economics; it coincided with high gas prices driven by limited pipeline capacity due to residential gas demand.

Gas pipeline constraints drove high gas prices and oil inventory levels drove energy market opportunity costs. As oil storage was depleted, dual-fuel units utilized energy market opportunity costs by either switching to gas (including a substantial amount of LNG) despite the high gas costs or increasing oil offers. This resulted in an efficient allocation of fuel across the fleet of generators during the cold snap. The control room did not posture any generators during the winter and there were no capacity scarcity conditions. Despite the efficient allocation of fuel and performance of the system, oil inventories were depleted and costs were high due to the constrained nature of the system. LNG and oil replenishments were crucial for energy security during the winter, and are discussed below.

Steam turbines played an important role in maintaining fuel security by providing over 1,200 MW per hour of oil-fueled generation during the 19-day cold snap. Although these units are slow-to-start and cannot respond to unexpected system events, they provide important reliability benefits in the form of stored fuel generation during extended cold-weather events.

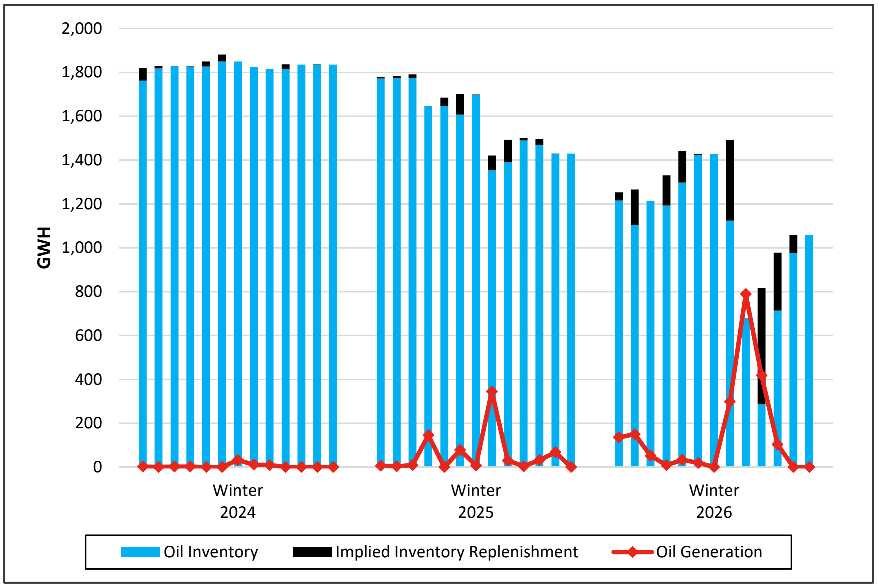
Also of note is the reduction in net imports during the beginning of the cold snap, which occurred due to winter capacity deficiencies in Quebec. This is discussed more in Section 2.3.2, below.

1.4.2 Stored Fuel Availability

During Winter 2026, oil burn was higher than in every winter since the ISO began tracking oil burn in Winter 2016, and oil inventories were depleted to a higher extent than in previous winter seasons. Figure 1-9 below shows weekly fuel inventories and estimated replenishments that occurred throughout the winter.[13]

[13] Oil Inventory data are collected by the ISO in weekly surveys. The IMM estimates daily inventories by subtracting oil generation from reported inventories between report dates. While oil inventory replenishments are not directly reported, we estimate implied inventory replenishments in cases when the oil inventory reported in a new survey exceeds the amount of oil inventory suggested by the previous survey less oil used for generation. These reports are typically released at a weekly level during the winter; therefore, it is not possible to attribute inventory replenishments to particular days, and this graph is shown at the weekly level. Notably, the ISO collected *daily* oil inventory reports from January 27 to February 2. Roughly 350 GWh of daily oil inventory replenishment occurred during this period.

Figure 1-9: Winter Fuel Oil Inventories



Oil inventories in New England were lower at the beginning of the winter than in previous years. About half of the lower starting inventory was driven by a large generator retirement and lower inventory at a large station. The other half of the lower starting inventory was due to lower inventories among eight different stations. Over the cold snap, between January 23 and February 10, the oil fleet provided necessary energy security, as gas pipelines were reaching capacity due to residential heating load. Inventories were depleted to under 50% of the lows from the prior two winters. In the February 2 fuel survey, oil generators reported a fleet-wide inventory of 700 GWh.[14]

Despite the inventory depletion, there was about 1,800 GWh of estimated oil replenishment this winter to offset the higher usage, compared with 400 GWh last winter. Most notably, there was over 370 GWh of replenishment between January 25 and February 2, and nearly 800 GWh of replenishment in the following two weeks. Many oil units, including dual-fuel generators, appeared to respond to opportunity costs associated with burning stored oil, by switching to gas or foregoing generation through increased energy market offers. These energy market opportunity costs (EMOCs) are modeled by the IMM and are discussed more in the following section.

1.4.3 Energy Market Opportunity Costs

Energy market reference levels include an energy market opportunity cost (EMOC) adder for resources that maintain oil inventory.[15] During cold weather events, the inclusion of opportunity costs in energy offers (and reference levels) enables the market to preserve limited fuel for hours when it is most valuable to the system.

[14] For perspective, the highest daily oil generation we estimated during the cold snap was 168 GWh on January 25. Daily surveys stopped on February 2, so we do not have accurate data indicating if inventories dropped below 700 GWh due to the large number of replenishments offsetting oil generation between February 2 and the next survey on February 10.

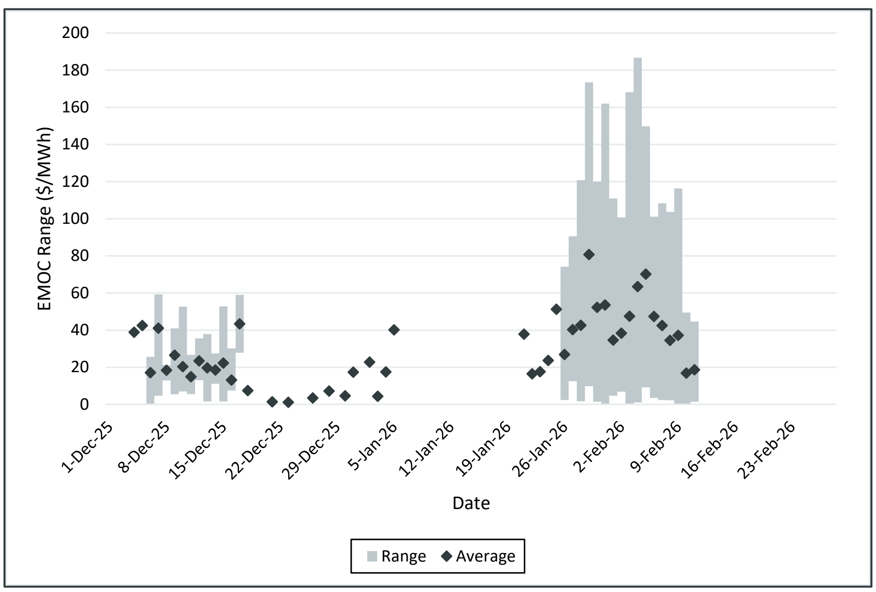
[15] This enhancement to reference levels, implemented in 2018, was motivated by concerns that, during sustained cold weather events, generators were unable to incorporate opportunity costs associated with the depletion of their limited fuel stock into their energy supply offers due to the risk of market power mitigation. Such an event arose during Winter 2018 - which resulted in ISO operators posturing oil-fired generators to conserve oil inventories.

Every day, the IMM calculates generator-specific EMOC adders with a mixed-integer programming model. For a given forecast of LMPs and fuel prices, the model seeks to maximize an oil-fired generator's net revenue by optimizing fuel use over a seven-day horizon, subject to constraints on fuel inventory and asset operational characteristics.

While the calculation of EMOCs is complicated and dependent on a number of variables (gas and oil price forecasts, fuel inventory levels, and generator characteristics), it is possible to develop a general sense of when EMOCs are likely to occur. Primarily, we should expect to see EMOCs for a generator when relative oil and gas prices are forecasted to be close enough that an oil-fired generator would be in merit long enough to deplete their oil inventory. This type of scenario would typically occur during an extended period of very cold weather when demand for natural gas is highest.

This winter, EMOCs were produced on 53 different days and for 88 different assets, up from 28 days and 10 assets last winter. Figure 1-10 below shows a summary of real-time energy market opportunity costs by day during the winter. Although day-ahead EMOCs were generally higher than real-time EMOCs (day-ahead EMOCs reached up to $460 during the winter), we focus on real-time EMOCs below.[16]

Figure 1-10: Real-Time Daily EMOC Summary



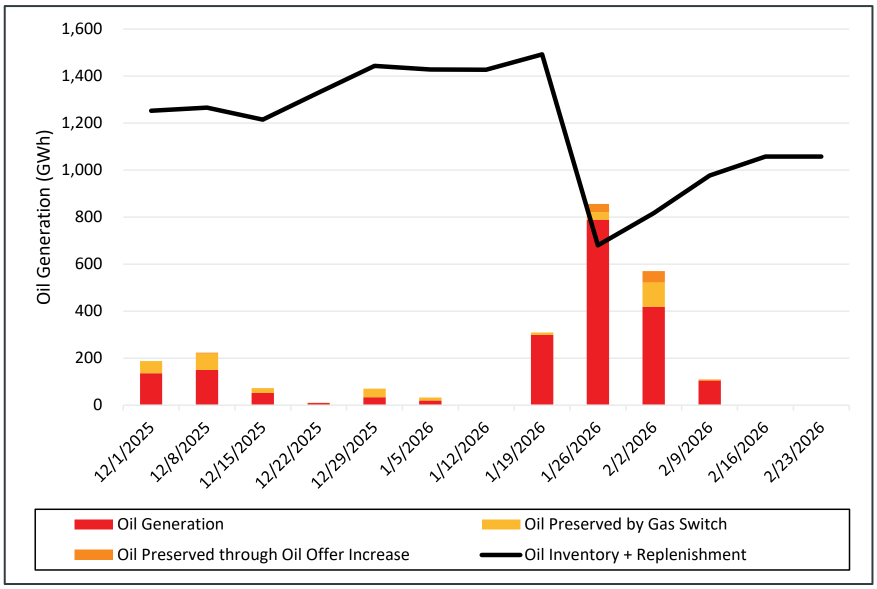
During the winter, real-time EMOCs reached over $180/MWh during the 19-day cold snap. At this time, energy prices were high and oil inventories were depleted, putting upward pressure on the opportunity cost of burning oil. As oil inventories were replenished and temperatures eased, EMOCs declined until the end of the cold snap.

[16] We focused on real-time EMOCs because 80% of the impact of EMOCs on oil consumption was due to dual-fuel combined cycles switching from oil to gas. While these dynamics can impact the day-ahead schedule depending on if gas offers clear, we expect dual-fuel generators to run on the most economic fuel in real-time. Another 13% of EMOC impacts were on fast-start units.

This winter, we observed impacts on oil consumption driven by energy market opportunity costs. Figure 1-11 below shows estimates of EMOCs on fuel burn. Impacts are separated into two categories:

- **Oil preserved by gas switching:** This indicates that we estimated that oil would have been burned if the participant had offered on oil without an EMOC. In these cases, the inclusion of the EMOC made oil the more expensive fuel and the participant chose to offer on gas instead.
- **Oil preserved through oil offer increase:** In these cases, we estimated that oil would have been burned if the participant offered on oil without an EMOC, but by including the EMOC in their oil offer they were pushed out of merit, preserving their oil for generation in a future period.

Figure 1-11: Estimated EMOC Impacts on Oil Inventory



Throughout the winter, we estimate that participants responded to energy market opportunity costs by preserving 433 total GWh of oil generation during the winter. More than half of the deferred oil generation occurred around the 19-day cold snap. The retention of stored fuel enhances energy security for the region by preserving limited fuel for hours when it is most valuable to the system.

1.5 Natural Gas Market Conditions

1.5.1 System Gas Prices

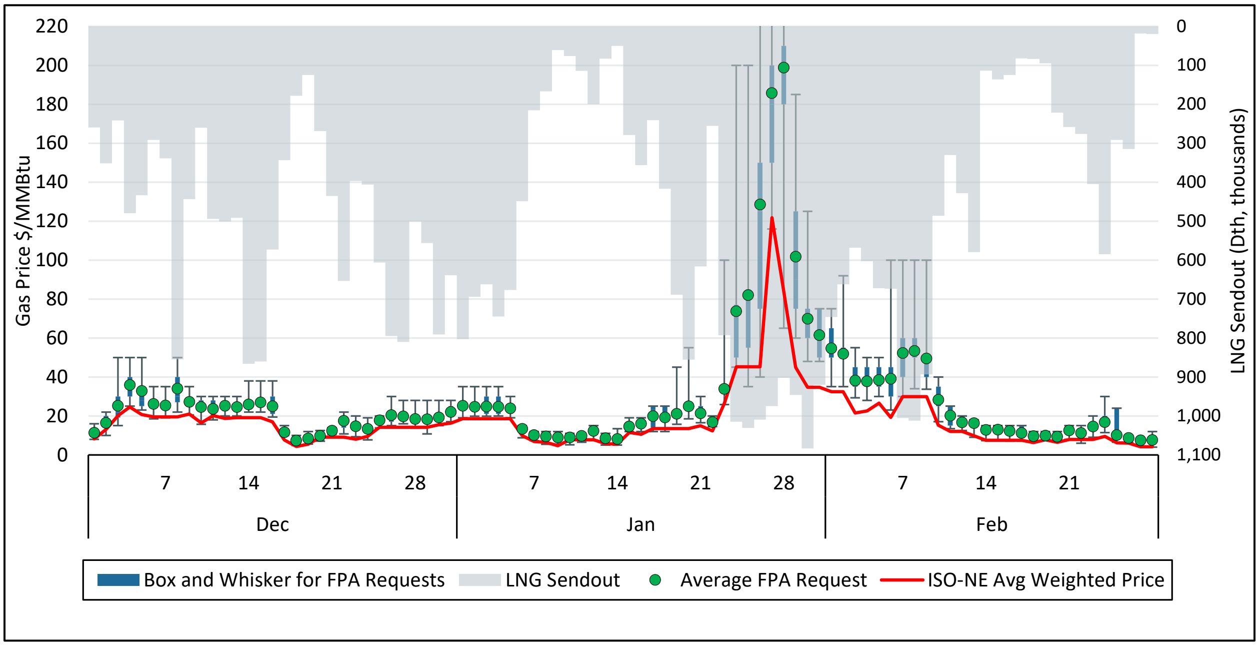
In New England, limited gas pipeline infrastructure, coupled with the absence of local natural gas deposits, can lead to procurement challenges for operators of natural gas-fired generators.[17] During the January 2026 cold snap, natural gas prices in New England increased significantly under

[17] Pipelines in New England include Portland Natural Gas, Tennessee Gas, Algonquin, Iroquois, and Maritimes and Northeast. Additionally, there are three operational LNG import facilities that inject gas into New England: Excelerate, Saint John (formally Canaport), and Everett (Distrigas).

constrained conditions, reaching a record high of approximately $122/MMBtu on January 27, during Winter Storm Fern and the broader cold weather event.

Figure 1-12 below shows that many generators rely on short-term purchases, including next-day and same-day procurement.[18] As natural gas prices increase, purchases of LNG can increase supply and provide counterflow to alleviate pipeline constraints. Therefore, on days when gas pipelines are constrained, some Fuel-Price Adjustments (FPAs) may be based on LNG prices; these adjustments will be reflected in energy offers.

Figure 1-12: FPA Requests and Average Gas-Weighted Prices



Increased LNG sendout to New England (gray bars) coincided with periods of elevated index prices and higher FPA activity, with the most pronounced alignment occurring during Winter Storm Fern (January 23-26), and to a lesser extent during the rest of the cold snap. During this period, the gas system experienced high demand, along with reduced trading liquidity and increased procurement uncertainty, reflected in the sharp increase in FPA requests (box-and-whisker ranges) and average request levels, with FPA requests up to $400/MMBtu during Winter Storm Fern. This event occurred within the broader context of elevated winter activity, as total FPAs reached 5,596 in Winter 2026, with 92% (5,169) originating in the day-ahead market, indicating that most procurement decisions were made ahead of real-time conditions.

1.5.2 Pipeline Constraints

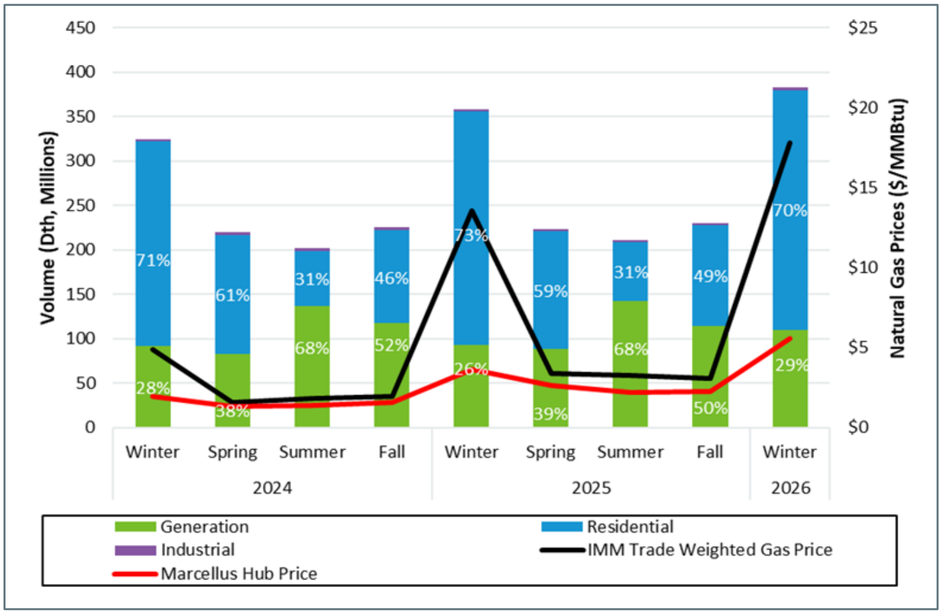
Natural Gas Usage

As temperatures fall in the winter months, residential heating demand increases and natural gas-fired generators must compete for limited pipeline capacity. The volume of gas demand by sector,

[18] See the ISO's Natural Gas Infrastructure Constraints information page, available at https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints.

alongside the average quarterly New England and Marcellus Hub natural gas prices, are shown in Figure 1-13 below.

Figure 1-13: Natural Gas Demand by Sector



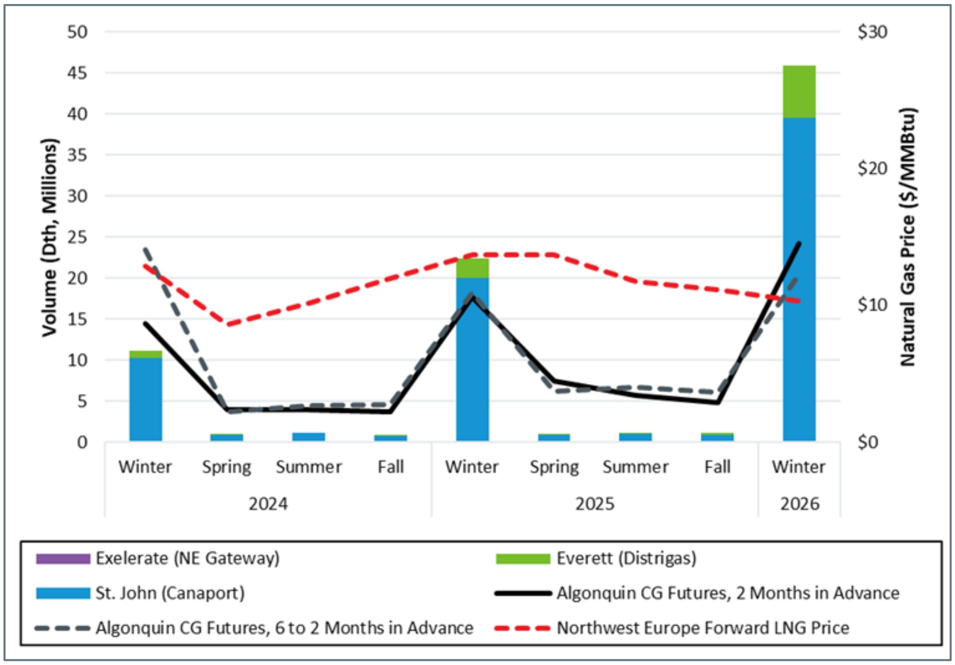
Total gas pipeline demand increased to approximately 383 million MMBtu in Winter 2026, continuing the upward trend observed in prior years and reaching the highest level in more than a decade. The increase reflected strong residential heating demand as well as sustained electric generation demand, which increased to approximately 110 million MMBtu, up from 93 million MMBtu in Winter 2025. Basin prices also increased sharply on January 27–28, reaching historically high levels, with Henry Hub peaking at approximately $30/MMBtu and Marcellus at $54/MMBtu. These levels represent some of the highest observed prices at these locations, indicating that transportation constraints, rather than basin supply costs alone, were a primary driver of regional price formation. Both Algonquin and basin prices increased to levels that were among the highest observed in recent winters, providing context for the magnitude of the observed price increases.

As in the prior winter, pipeline constraints extended beyond New England and contributed to regional price differences across the Northeast. During Winter Storm Fern on January 27, Algonquin prices reached approximately $122/MMBtu, while basin and nearby market prices were also elevated, including prices as high as $143/MMBtu observed in New York. The 19-day cold snap highlights the magnitude and persistence of these increases in both basin and delivered prices. Despite these elevated prices, LNG supplies, including imports into New England, helped moderate price impacts and support system reliability by supplementing constrained pipeline capacity and limiting exposure to more extreme price increases.

LNG Supply

Liquefied natural gas (LNG) provides another source of natural gas delivery into New England pipelines and can be helpful in providing counterflow when pipelines are constrained from west to east, increasing the supply of natural gas available to gas-fired generators. The volume of injections (sendout) into the interstate pipelines from the St. John (formerly Canaport), Everett (Distrigas), and Excelerate LNG facilities for the past three years is illustrated in Figure 1-14 below. The lines (right axis) show New England gas prices, the forward prices for LNG contracts for Northwest Europe LNG, and average Algonquin Citygates (ALG) futures prices two months before delivery.[19]

Figure 1-14: LNG Sendout by Facility



Forward prices averaged around $12/MMBtu before the winter and climbed to nearly $15/MMBtu as the season approached. The high futures prices immediately preceding the season reflected the expectation that Winter 2026 would be the most severe winter since 2014, and actual outcomes surpassed these expectations.

LNG sendout increased significantly, reaching approximately 45.9 million MMBtu in Winter 2026 compared to 22.4 million MMBtu in Winter 2025 (a 105% increase), driven primarily by higher volumes from Everett and St. John. This increase indicates LNG played a key role in supplementing supply and moderating price spikes. However, the persistence of elevated gas prices in New England shows LNG only partially reduced the New England price premium but did not fully offset regional constraints.

New England gas pipelines were significantly constrained throughout Winter 2026, and the region was reliant on LNG sendout to provide liquidity during gas-scarce, high-priced periods. Figure 1-15 below shows gas demand for heating and generation during Winter 2026.[20] Two lines are included

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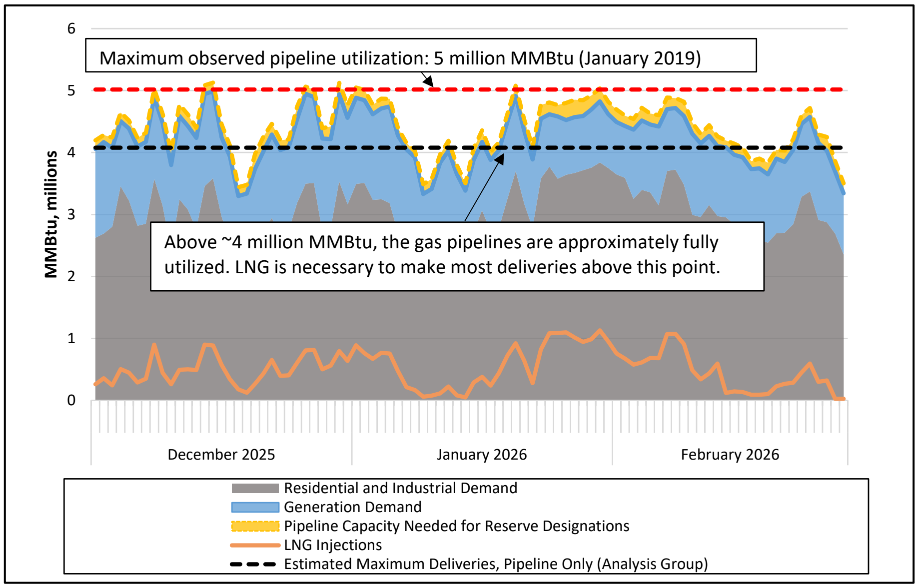
[19] Future LNG prices are two-month forward prices provided by the Argus Media Group. Algonquin Citygates future prices are provided by the Intercontinental Exchange for the corresponding forward time period. Average prices by delivery month are calculated for trading days two months in advance of delivery, then aggregated to the season level through taking averages of monthly values within the season weighted by number of days.

[20] The data supporting this figure was sourced from Wood Mackenzie. We define pipeline utilization as the sum of gas deliveries into New England. Deliveries are measured at delivery or receipt points for citygates, end users (collectively generation and industrial demand), and power plants (generation demand). The data is at the gas day rather than calendar day level.

for reference; first, a line at 4 million MMBtu/day representing the estimated maximum amount of gas that can be delivered by pipeline into New England without reliance on LNG sendout.[21] Second, a line at 5 million Dth/day is included to represent the highest historically observed gas pipeline utilization.[22] Finally, the estimated additional gas that would be necessary to convert operating reserve designations into energy for gas generators is shown in yellow.[23]

Figure 1-15: Pipeline Utilization and Energy Reserve Reliance Relative to Constraints



The New England gas system was reliant on LNG to make pipeline deliveries on roughly 58 days during Winter 2026. Total gas usage (including LNG injections) neared but did not exceed historic levels. Gas-fired generation averaged just under 7,000 MW per hour over the season; by comparison, the total seasonal LNG sendout was equivalent to 2,700 MW per hour of standard heat rate gas generation (39% of total gas generation).[24] On the most limited days during Winter Storm Fern, gas generation averaged just 4,900 MW. This amount is relatively similar to the estimated

[21] The estimated amount of pipeline-only deliveries is based on research from the Analysis Group for the gas constraint component of the CAR-SA project. See Analysis of Winter Supplies from Gas-Fired Generators*,* presented by Todd Schatzki at the November 2025 Markets Committee meeting, available at https://www.iso-ne.com/static-assets/documents/100029/a03.2.b_mc_rc_2025_11_12_13_car-sa_gas_availability_study_ag.pdf. Analysis Group estimated a pipeline supply capacity range (excluding LNG injections) of 3,603-3,928 MMcf/d (slide 11). Taking the upper end of this range (3,928 MMcf/d) and applying a conversion rate of 1,038 MMBtu per MMcf (EIA) yields a pipeline supply capacity of roughly 4 million MMBtu/d without LNG injections. Note that this estimation assumes no deliverability issues, such as upstream supply constraints or compressor outages.

[22] The maximum historic pipeline usage recorded in our data occurred on January 21, 2019. Total gas pipeline deliveries (implicitly including LNG injections) reached just over 5 million MMBtu/d.

[23] Incremental pipeline capacity needed to support reserve designations is estimated using generation (MW) and heat rate (MMBtu/MWh) data. The calculation includes the estimated gas needed to turn all operating reserves (MW) from gas-fired generators into energy, and the estimated gas for online dual-fuel generators according to their incremental fuel mix. Gas units with offline reserve designations are included: for each continuous period during which an offline gas unit provides reserves, the calculation includes the estimated gas needed to operate the generator once at its EcoMin limit for its minimum run time. Offline reserve designations to dual-fuel units are not included under the assumption that such units could start on oil if needed.

[24] We assume a standard heat rate of 7.8 MMBtu/MWh to represent the New England gas generation fleet.

amount of gas (pipeline and LNG) available for New England generators on the coldest winter days under the CAR-SA gas constraint design (~4,500 MW).[25]

Gas generation approached historic total pipeline usage, and if all reserve designations for gas units had been converted to energy, the gas system would have exceeded the historic reference capacity on eight days by up to 111,000 MMBtu (equivalent to 600 MW per hour of standard-efficiency generation). Generators are required to notify the ISO if they cannot perform according to their offered parameters, including EcoMax limits that may be counted towards reserves.[26] We estimate that additional LNG daily injection capacity would have been available to generators on each of these days.[27]

1.5.3 Generator Availability and Outages

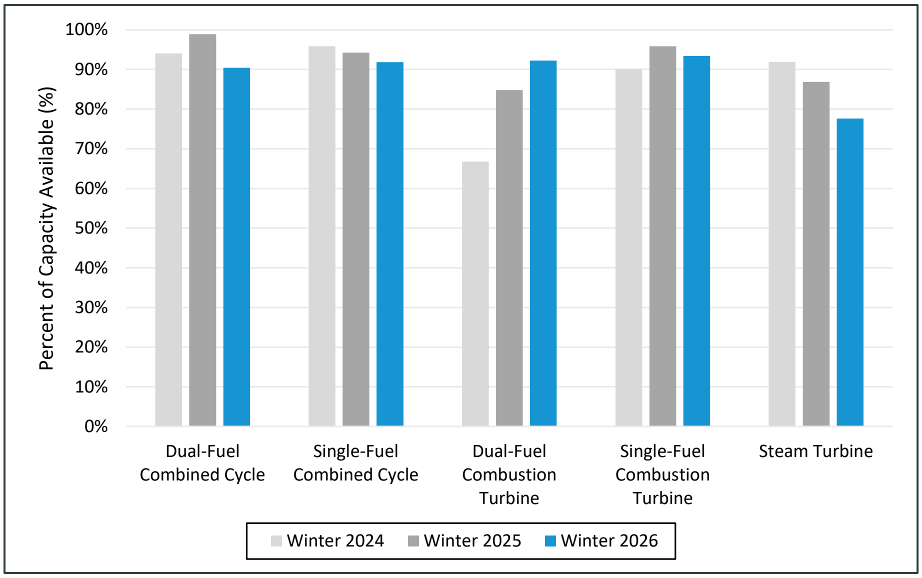
Generators in Winter 2026 were available at a similar rate to the two previous winters, with some notable exceptions. Figure 1-16 below shows the percentage of capacity available by technology type in Winter 2026 compared to the previous two winter seasons.

[25] See *Analysis of Winter Supplies from Gas-Fired Generators,* presented by Todd Schatzki (Analysis Group) at the December 2025 Markets Committee, available at https://www.iso-ne.com/static-assets/documents/100030/a04.1.b_mc_rc_2025_12_09-10_gas_availability_study_follow_up.pdf. On slide 8, Analysis Group estimates that 4,516 MW of hourly gas generation is available on cold winter days (HDD ≥ 45). Note that this is only an average taken from the distribution output from Analysis Group's gas availability model.

[26] See *ISO-NE Operating Procedure No. 14*, Section II.F.1.a, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

[27] Only the St. John and Everett facilities are included in our estimate of maximum possible daily LNG injections. The Excelerate station is excluded.

Figure 1-16: Capacity Available by Technology Type



More than 90% of combined cycle unit capacity was available in Winter 2026. About 1% of single-fuel combined cycle capacity was out of service due to fuel-related issues, compared with 0% last winter. Dual-fuel combined cycles were impacted less by fuel related issues, reflecting their flexibility in adapting to fuel conditions; only 0.2% of dual-fuel combined cycle capacity was out of service due to fuel-related reasons.

Steam turbines were available at a lower rate than in the previous two winters, however, the outages were driven by units at a single station. Other steam units were available in a similar capacity to previous winters.

Dual-fuel combustion turbines were available more often than in previous winters. The increase in availability may have been impacted by additional DA A/S incentives that increase the opportunity cost of placing units out of service.

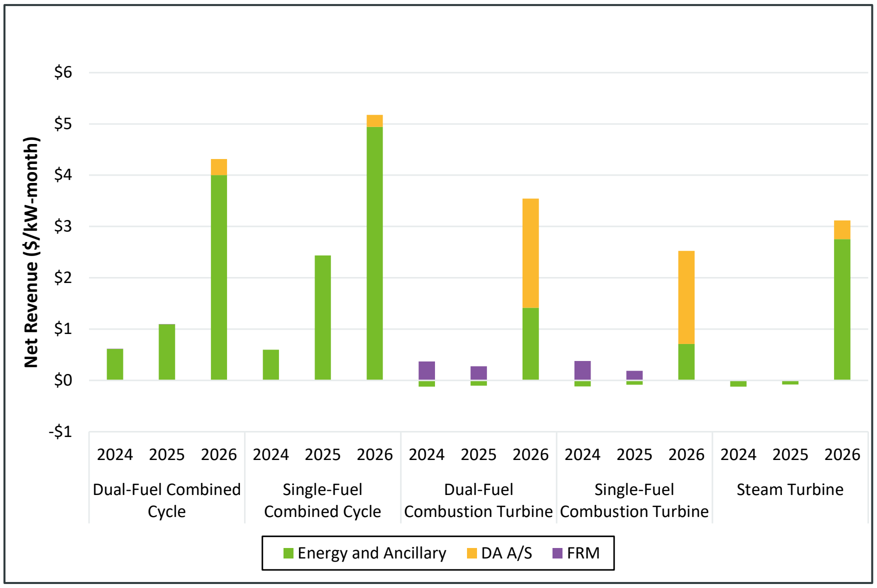
Winter 2026 Profitability by Technology Type

Figure 1-17 below shows the net revenues of combined cycle, combustion turbine, and steam turbine generators for the past three winters. Revenues are presented in annual dollars per kW-month. In other words, the total winter revenues are divided by the kW capacity of the generators in each category over 12 months. Revenues are broken into three categories:

- Energy and ancillary services (including energy revenues and cost, FER payments, regulation, real-time reserves, and NCPC),
- forward reserves, and
- DA A/S net credits from the sale of FRS and EIR products.

Forward reserves are included to compare revenues with the DA A/S market, which superseded the Forward Reserve Market following Winter 2025.

Figure 1-17: Winter Profitability by Technology Type



Each of the technology types shown earned much higher revenues from the day-ahead and real-time energy markets in Winter 2026 than in the previous two winters. Combustion and steam turbines made between $2.50/kW-month and $3.60/kW-month in 2026, after making under $0.30/kW-month the past two years.

Dual-fuel combustion turbines made incremental energy and ancillary services revenue compared with single-fuel combustion turbines, although it is difficult to assign causality to dual-fuel capability due to the relative efficiency of the dual-fuel combustion turbine generators (New England's dual-fuel combustion turbine fleet is almost 20% more efficient than the single-fuel combustion turbines). We did not observe a similar premium for combined cycle units, potentially due to the relative efficiency of the single-fuel combined cycles (about 5% more efficient than the dual-fuel combined cycle units in New England). However, it is likely that units with dual-fuel capability did receive incremental revenues as evidenced by their fuel-switching in response to relative fuel prices over the winter. Additionally, because New England pipelines were approaching the maximum observed flows from previous years, dual-fuel capacity switching to oil likely prevented gas-related outages. Confounding factors like unit efficiencies, gas contracts, and locational gas and energy constraints are likely driving the observed results.[28]

DA A/S was a significant source of revenue for the combustion turbines in New England this winter and may have impacted generator availability, discussed in the previous section.

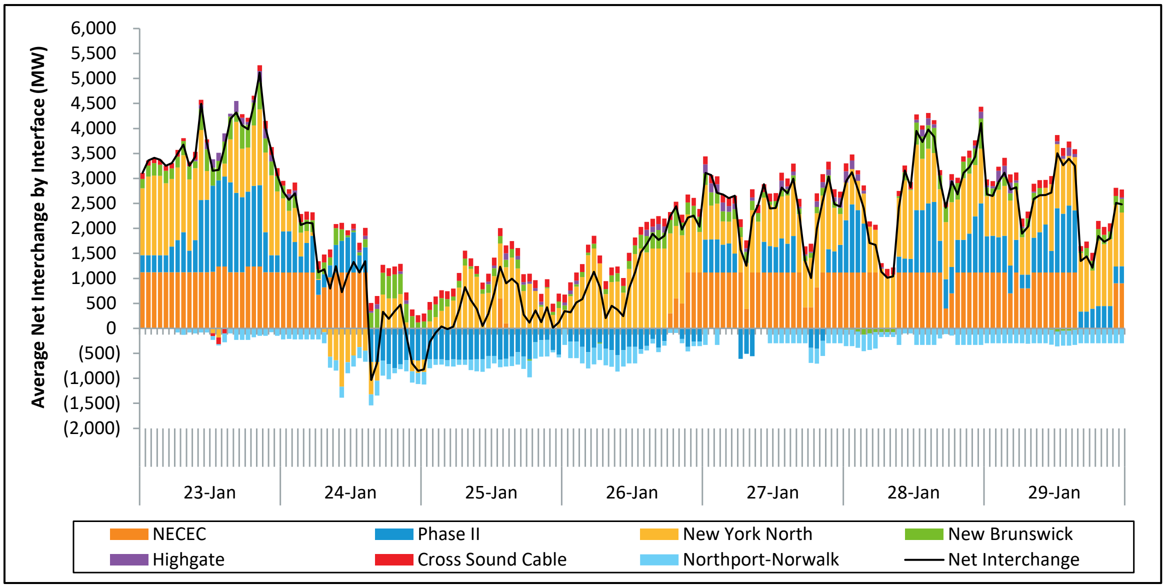
1.5.4 Import Availability and Outages

Net interchange typically plays an important role in meeting energy demand in New England during periods with high loads as high energy prices can incentivize increased levels of imports into New England. However, interchange performance was mixed during Winter Storm Fern as widespread

[28] While evaluating whether units with dual-fuel capability received incremental revenues, we compared a subset of the dual-fuel fleet with a subset of the single-fuel fleet with similar heat rates to determine if heat-rate normalized revenues increased. Although we identified an increase in energy payments, energy costs also increased, indicating that differences in fuel costs could be driving the higher *net* revenues for single fuel combined cycle units.

extreme weather conditions led to stressed conditions across neighboring regions. Figure 1-18 shows net interchange (black line) between New England and neighboring regions by each of the seven interfaces (columns).

Figure 1-18: Average Net Interchange during Winter Storm Fern



From the evening of January 23 to the afternoon of January 24, New England's net interchange shifted. The region went from importing over 5,100 MW of power to exporting more than 1,000 MW.

This change was driven by extreme cold weather in Canada leading to increased electricity demand in Quebec. Imports over the New England Clean Energy Connect (NECEC) stopped (1,120 MW to 0 MW) in HE 16, while flows over the Phase II interface flipped from 502 MW of net imports to 672 MW of net exports. New England continued to export energy to Quebec for more than two days. With less electricity coming from Quebec, the region relied heavily on imports from New York and increased native generation to meet demand. By the early morning of January 25, New England shifted back to being a net importer of electricity and remained in that position for the rest of the winter.

Section 2
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes for Winter 2026 and preceding seasons. 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	Winter 2026	Fall 2025	Winter 2026 vs Fall 2025 (% Change)	Winter 2025	Winter 2026 vs Winter 2025 (% Change)
Real-Time Load (GWh)	33,230	26,674	25%	32,063	4%
Peak Real-Time Load (MW)	20,221	17,219	17%	19,607	3%
Average Day-Ahead Hub LMP ($/MWh)	$147.99	$44.64	231%	$116.73	27%
Average Forecast Energy Requirement Price ($/MWh)	$17.50	$5.49	219%	-	-
Average Real-Time Hub LMP ($/MWh)	$137.66	$45.22	204%	$114.80	20%
Average Natural Gas Price ($/MMBtu)	$17.79	$3.07	479%	$13.58	31%
Average No. 6 Oil Price ($/MMBtu)	$15.13	$14.95	1%	$14.69	3%
Average RGGI Carbon Price ($/Short Ton CO_2)	$25.00	$24.24	3%	$21.91	14%

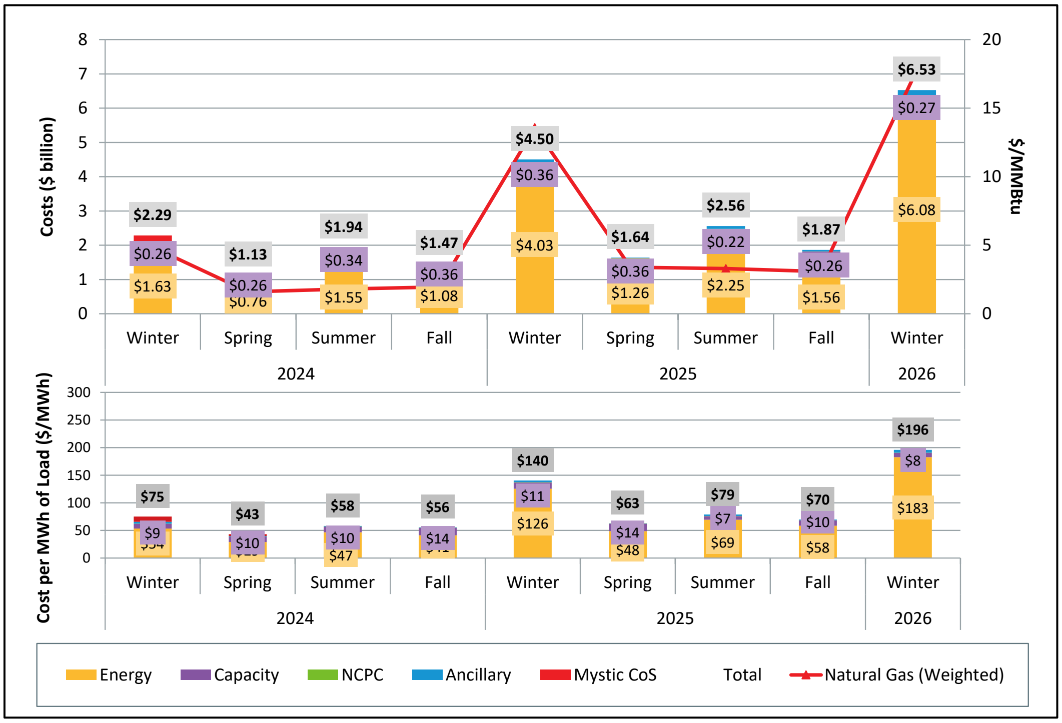
Key observations from the table above:

- Average real-time load increased by 4% in Winter 2026 relative to Winter 2025, driven by colder weather throughout the season. Section 2.2 below discusses load in more detail.
- Average natural gas prices increased in Winter 2026 compared to Winter 2025 (up 31%), due to the cold snap during Winter Storm Fern. Section 1 above discusses the gas market in more detail.
- Higher natural gas prices were the primary driver of increased day-ahead and real-time LMPs. Winter 2026 saw average day-ahead LMPs of $147.99/MWh, 27% higher than in Winter 2025 ($116.73/MWh). The Forecast Energy Requirement price averaged $17.50/MWh leading to all-in day-ahead price of $165.49/MWh for physical generation. The upward pressure of higher natural gas and emissions prices on LMPs was partially offset by oil generation displacing expensive gas generation on the coldest days.

2.1 Wholesale Cost of Electricity

The estimated wholesale electricity cost (in billions of dollars) for each season by market and the average natural gas price (in $/MMBtu) are shown in Figure 2-1 below. The bottom graph shows the wholesale cost per megawatt hour of real-time load served.[29,30]

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

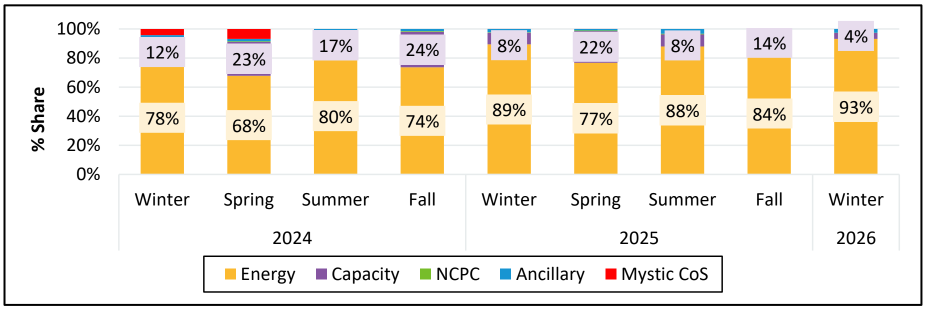


In Winter 2026, the total estimated wholesale cost of electricity was $6.53 billion (or $196/MWh), an increase of 45% compared to $4.50 billion in Winter 2025, and an increase of 250% over the previous quarter (Fall 2025) due to the highest seasonal energy market costs since the start of Standard Market Design. Natural gas prices continued to be a key driver of energy prices with average prices increasing by 31% compared to Winter 2025. The share of each wholesale cost component is shown in Figure 2-2 below.

[29] In previous reports, we used system load obligations and average hub LMPs to approximate energy costs. Beginning with the Winter 2022 report, we updated the methodology to reflect energy costs based on location-specific load obligations and LMPs. These changes are reflected in all 11 seasons of data.

[30] 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 and Tennessee gas pipeline Z6-200L. 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 11 on D+2.

Figure 2-2: Percentage Share of Wholesale Cost



Energy costs were $6.08 billion ($183/MWh) in Winter 2026, up 51% on Winter 2025 costs, driven by a substantial increase in natural gas prices which averaged $17.79/MMBtu. Energy costs made up 93% of the total wholesale costs.

Capacity costs are determined by the clearing price in the primary forward capacity auction (FCA). In Winter 2026, the FCA 16 clearing price resulted in capacity payments of $266 million ($8/MWh), representing 4% of total costs. The current capacity commitment period (CCP16, June 2025 – May 2026) cleared at $2.59/kw-month for Rest-of-Pool. This was similar to the primary auction clearing price of $2.61/kW-month for the prior capacity commitment period. Section 5 discusses recent trends in the Forward Capacity Market in more detail.

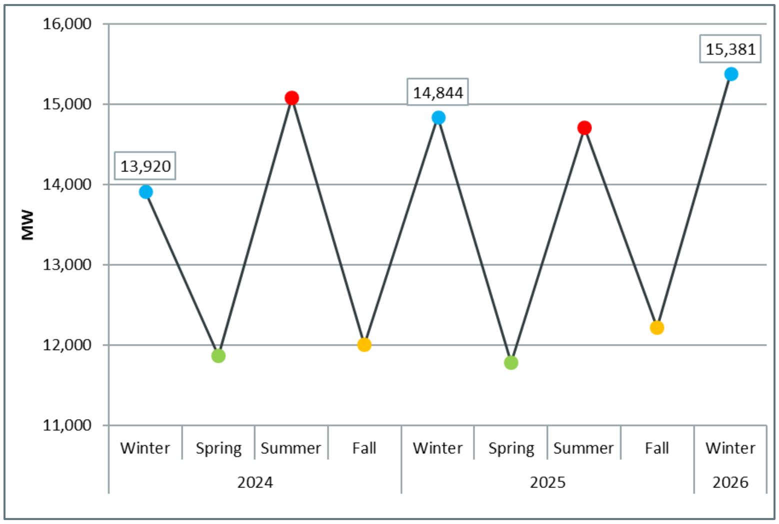
At $13.0 million ($0.50/MWh), Winter 2026 Net Commitment Period Compensation (NCPC) costs represented 0.2% of total energy costs which was a much lower share than prior quarters in the reporting horizon. Section 3.4 contains further details on NCPC costs.

Ancillary services, which include day-ahead and real-time operating reserves, and regulation totaled $167 million ($5/MWh) in Winter 2026 and were 3% of total costs. Ancillary service costs were 67% higher than costs in Winter 2025 ($100 million) which includes Forward Reserve Market costs. Day-ahead reserves accounted for 94% of all ancillary service costs. Section 3.5 discusses day-ahead ancillary services in more detail.

2.2 Load

New England winter loads are primarily driven by heating demand. Average seasonal loads through Winter 2026 are shown in Figure 2-3 below.

Figure 2-3: Average Hourly Load

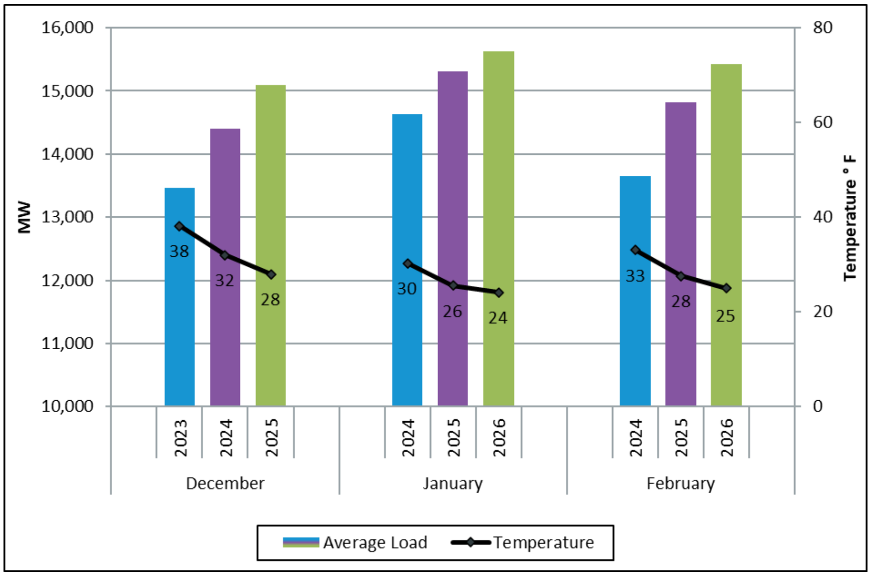


Average hourly load increased to approximately 15,382 MW in Winter 2026 and peak load reached 20,221 MW, the highest winter peak load since January 2019, reflecting colder temperatures and stronger heating demand. Behind-the-meter solar continued to reduce daytime net load, with estimated average BTM solar output increasing to 229 MW in Winter 2026 from 200 MW in Winter 2025, consistent with growth in estimated installed BTM capacity. By contrast, total observed solar generation averaged 279 MW during Winter 2026, lower than the 339 MW observed in Winter 2025. This outcome reflects winter operating conditions, including reduced daylight hours and weather-related impacts such as cloud cover and snowfall, which limited realized solar output despite continued capacity growth.

Load and Temperature

The stacked graph in Figure 2-4 below compares average monthly load (right axis) with temperatures in degrees Fahrenheit (left axis).

Figure 2-4: Monthly Average Load and Temperature



Weather in Winter 2026 was colder than Winter 2025 across all months, continuing a trend of colder conditions relative to recent winters. Average temperatures declined to approximately 26°F, down from 28°F in Winter 2025, reinforcing stronger heating demand.

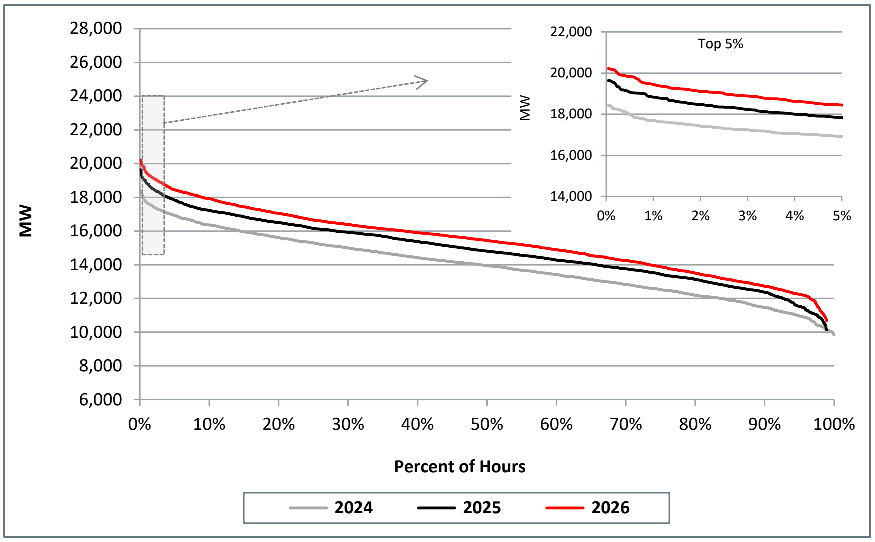
Notably, January 2026 was the coldest month in HDD since 2015, with loads averaging 15,626 MW - exceeding January 2025 averages. Cold conditions persisted through February, which again experienced elevated heating degree days (HDDs) and average loads approaching 15,500 MW, higher than February 2025 levels.[31]

Peak Load and Load Duration Curves

New England's system load over the past three winter 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.

[31] Heating degree days (HDD) measure how cold an average daily temperature is relative to 65°F and are an indicator of electricity demand for heating. HDDs are calculated as the number of degrees (°F) that each day's average temperature is below 65°F. For example, if a day's average temperature is 60°F, the day has 5 HDDs.

Figure 2-5: Load Duration Curve



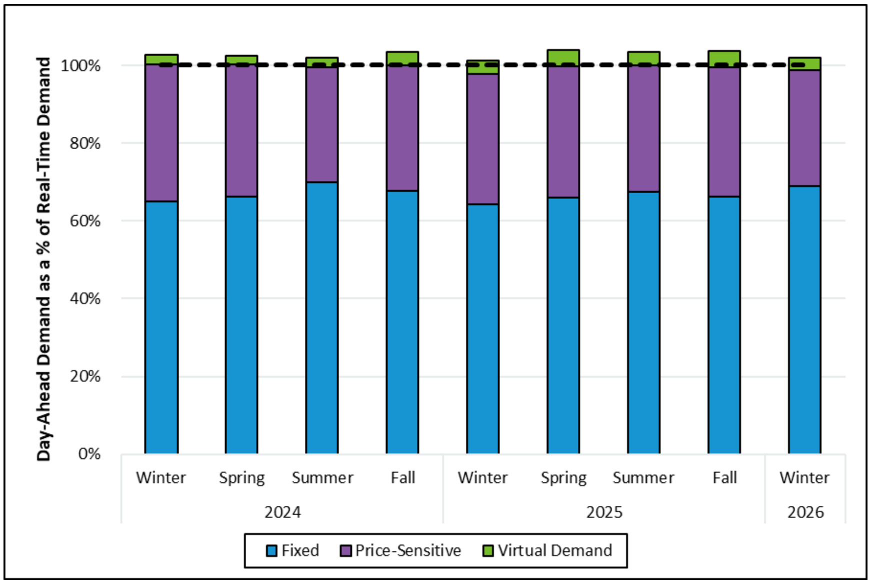
Winter 2026 peak load reached approximately 20,221 MW on January 25 during Storm Fern, exceeding the Winter 2025 peak of 19,607 MW. The seasonal peak occurred during a period of very cold temperatures, which were lower than those observed during the prior winter. As in Winter 2025, cold weather was the primary driver of peak demand, with the highest load hours occurring during sustained cold snaps.

Load Clearing in the Day-Ahead Market

The amount of demand that clears in the day-ahead market is important because, along with the ISO's Reserve Adequacy Analysis, it influences generator commitment decisions for the operating day.[32] The day-ahead cleared demand as a percentage of real-time demand is shown in Figure 2-6 below.

[32] The Reserve Adequacy Analysis (RAA) is conducted after the day-ahead market is finalized and is designed to ensure sufficient capacity is available to meet ISO-NE real-time demand, reserve requirements, and regulation requirements. The objective is to minimize the cost of bringing additional capacity into the real-time market.

Figure 2-6: Day-Ahead Cleared Demand as a Percent of Real-Time Demand



Participants cleared 102% of load in the day-ahead market on average in Winter 2026, up from 101% in Winter 2025 but slightly below 103% in Winter 2024. Fixed demand bids continued to represent most of the cleared demand, while priced bids accounted for a smaller share. Participants this winter did not submit bids above expected market prices in many instances, particularly during Winter Storm Fern, when Day-Ahead LMPs were sufficiently high that a significant amount of priced bids did not clear. During the cold snap (January 23 to February 10), fixed bids comprised approximately 70% of cleared demand, while priced bids declined to approximately 28% of cleared demand. Although participants bid priced demand consistent with tight market conditions, these bids did not clear on the coldest days of the season as they were priced below the extremely high day-ahead LMPs.

These outcomes reflect the composition of cleared demand, as fixed bids cleared consistently while priced bids were more sensitive to higher day-ahead prices and contributed to underclearing during higher-demand hours. These dynamics were more evident during the early portion of the cold snap, when higher day-ahead clearing prices limited the clearing of priced demand bids. Virtual demand accounted for a small share of cleared day-ahead bids as discussed in Section 3.3.

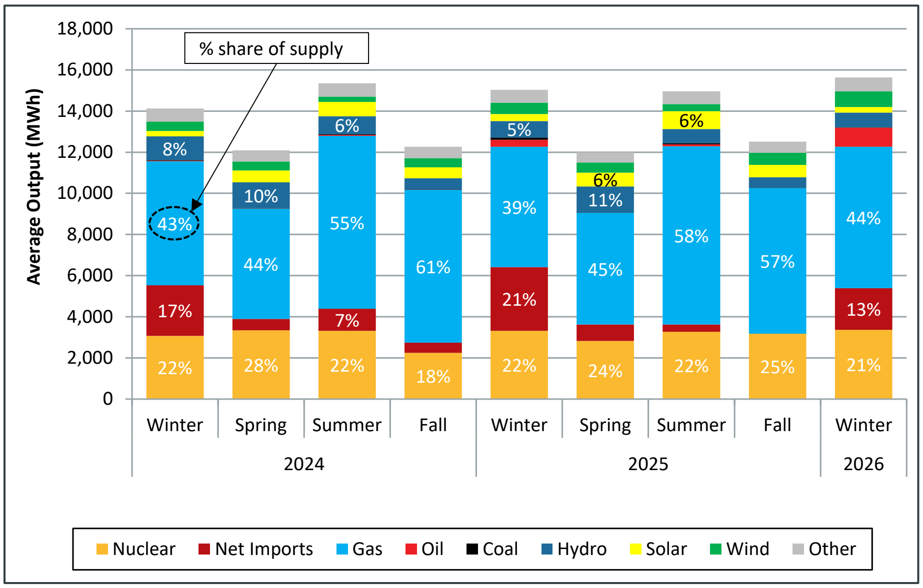
2.3 Supply

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 shares of energy production by generator fuel type for Winter 2024 through Winter 2026 are illustrated in Figure 2-7 below. Each bar's height represents the average electricity generation from that fuel type, while the percentages represent the share of average generation from that fuel type.[33]

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



Average output in Winter 2026 (15,632 MWh) was higher than prior winters. This increase was driven by higher average loads, as discussed in Section 2.2. In keeping with prior winter seasons, the three largest contributors to New England's energy supply were natural gas generators, nuclear generators, and imports from neighboring control areas. Collectively, these three forms of supply provided 79% of the region's energy, on average. Notably, the share of energy supply from net imports increased significantly from the low levels observed in the spring, summer, and fall seasons of 2025. See Section 2.3.2 for further details.

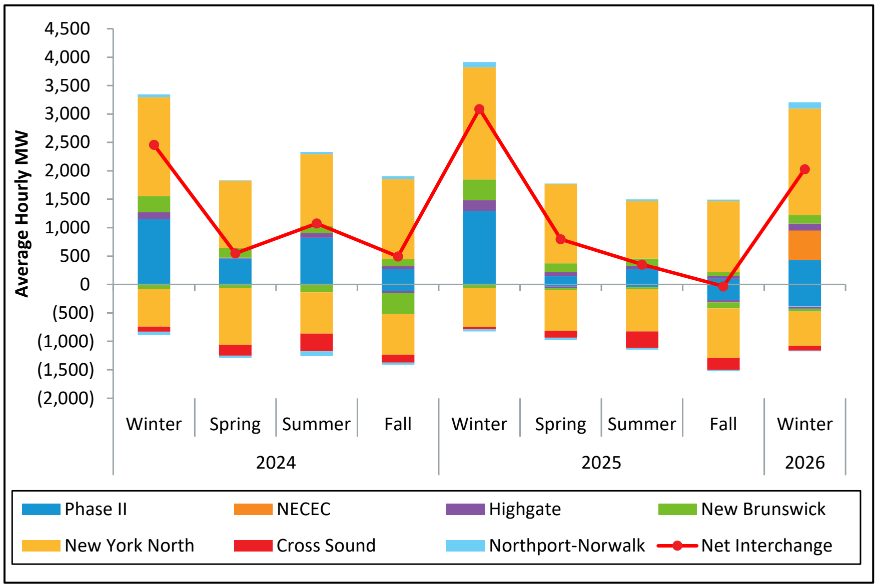
Oil-fired generation supplied 6% of energy in Winter 2026, the largest share for this fuel type since at least Winter 2015. This increase in production from oil-fired generation resulted from colder temperatures periodically driving natural gas prices above oil prices, causing oil-fired generators to be in-merit.

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

2.3.2 Imports and Exports

New England was a net importer of power from its neighboring control areas of Canada and New York in Winter 2026.[34] The average hourly import (positive), export (negative) and net interchange power volumes by external interface for the last nine seasons are shown in Figure 2-8 below. The figure includes the New England Clean Energy Connect (NECEC) interface which began non-commercial testing in November 2025 and commercial operation in January 2026.

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



On average, the net flow of energy into New England was 2,029 MW per hour in Winter 2026, which was down 34% (or 3,088 MW) from Winter 2025. Total net interchange in Winter 2026 represented 13% of load (NEL), which was lower than in Winter 2025 (21%). While net interchange decreased, average net interchange remained higher than all non-winter seasons over the reporting period. In the winter, colder temperatures and greater heating demand lead to increased natural gas demand in the region, putting upward pressure on natural gas prices and LMPs. These elevated prices incentivize higher volumes of imports from neighboring regions.

Canadian Interfaces

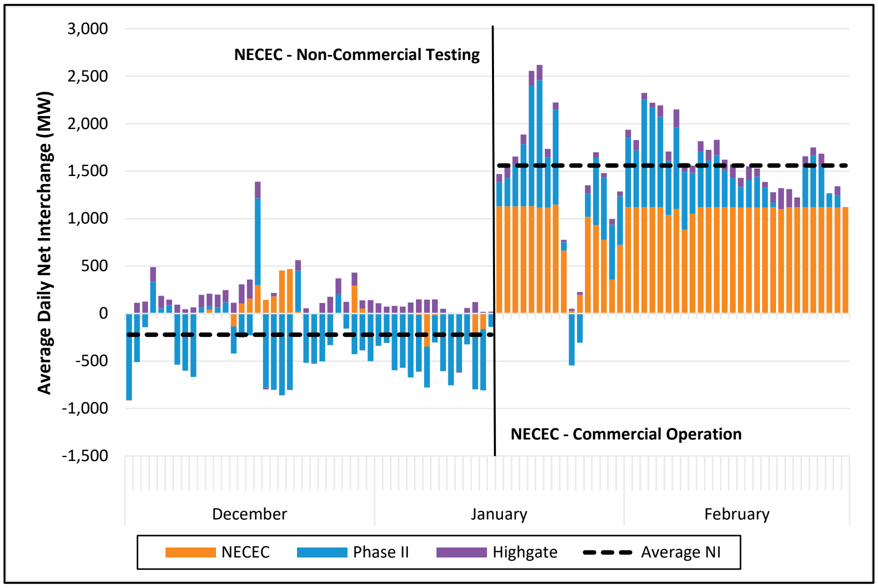
Despite the NECEC beginning commercial operations on January 16, 2026, net imports from Canada decreased by 58% compared to Winter 2025. On average, New England imported 750 MW per hour, which was well below historical levels for the winter. Historically, abundant water resources and hydro generation in Quebec provide excess electricity supply, which can be sold into New England, but dry conditions in Canada have limited imports to New England over the last several

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

years and led to historically low reservoir levels in Quebec.[35] Net interchange between New England and Quebec increased substantially after the NECEC began commercial operation.

Figure 2-9 shows daily average net interchange for the three interfaces connecting New England and Quebec. The figure includes average net interchange before and after the NECEC began commercial operation (dashed lines).

Figure 2-9: Daily Average Interchange with Quebec by Interface



Prior to January 16, 2026, New England exported an average of 223 MW per hour, with most transactions occurring at the Phase II interface. While New England has historically been a net importer over Phase II—maintaining elevated net imports during winter even amid ongoing drought conditions in Quebec—this pattern changed prior to the NECEC's commercial operation date. In the 46 days leading up to NECEC's commercial operation, New England exported an average of 346 MW per hour over Phase II and was a net exporter on 36 of those days over this interface.

The initial flows at the NECEC interface reflect non-commercial testing prior to commercial operation. At Highgate, most transactions are wheeled through Quebec from Ontario as participants aim to capture price spreads between IESO and ISO-NE. Highgate flows remained stable before and after January 16, 2026.

After the NECEC began commercial operation, imports from Quebec averaged 1,560 MW per hour which was higher than average levels in both Winter 2025 (1,483 MW per hour) and Winter 2024 (1,271 MW per hour). Net imports over the NECEC averaged 1,015 MW per hour after commercial operation. Additionally, New England returned to importing energy over Phase II during the second half of the winter with net imports averaging 449 MW per hour. New England was a net importer from Quebec on all but two days following the NECEC's commercial operation (January 25-26).

[35] For more information on Quebec's reduction in exports and reservoir levels, see Hydro-Québec's *Quarterly Bulletin, First Quarter 2026*, available at https://www.hydroquebec.com/data/documents-donnees/pdf/quarterly-bulletin-2026-1.pdf

These days occurred during Winter Storm Fern as cold weather led to extremely high demand in Quebec.[36]

New York Interfaces

Average net interchange with New York remained stable, decreasing by just 25 MW per hour (or 2%) year over year (1,305 MW vs. 1,280 MW). At the New York North interface, net imports averaged 1,267 MW per hour, just 28 MW lower than Winter 2025. New England typically exports energy to Long Island, but higher gas prices and LMPs can lead to New England importing energy in the winter. New England imported an average of 12 MW per hour from the Long Island interfaces, which was relatively unchanged from Winter 2025. At the Cross Sound Cable interface, New England net exports increased from 45 MW per hour to 84 MW per hour, while at Northport-Norwalk, net imports increased from 54 MW per hour to 96 MW per hour.

[36] For more information on flows with Canada during Winter Storm Fern, see the EIA's *New transmission line connecting Hydro-Quebec to ISO-NE begins commercial operations,* available at https://www.eia.gov/todayinenergy/detail.php?id=67105

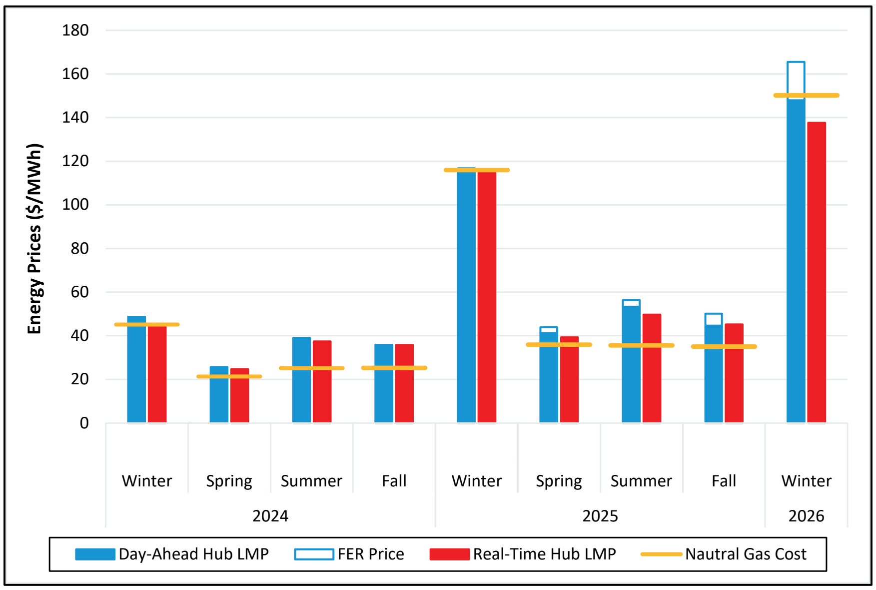
Section 3
Day-Ahead and Real-Time Markets

This section covers trends in, and drivers of, spot market outcomes, including the energy markets, and markets for ancillary services products: operating reserves and regulation.

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 cost of generating electricity using natural gas in New England.[37] The Forecast Energy Requirement Price (FERP) is included above the day-ahead LMP beginning in Spring 2025.

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 (columns) are generally consistent with changes in natural gas generation costs (lines). 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.

In Winter 2026, the day-ahead Hub LMP averaged $147.99/MWh and the FERP averaged $17.50/MWh, leading to an all-in payment of $165.49/MWh for day-ahead physical generation. The real-time Hub price averaged $137.66/MWh. The increase in energy prices coincided with higher estimated costs (incl. emissions) for a natural gas generator; we estimate these costs averaged $150.17/MWh in Winter 2026, representing an increase of approximately $34/MWh compared to the previous winter. Natural gas costs increased due to 1) colder weather, especially during Winter

[37] 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.

Storm Fern, and 2) higher emissions costs. Regional Greenhouse Gas Initiative (RGGI)[38] prices averaged \$25.00/short ton of CO_2, up 14% from Winter 2025. RGGI costs accounted for nearly 8% of a standard natural gas-fired generator's production costs. Massachusetts Electricity Generator Emissions Limit (MA EGEL) costs averaged \$15.88/short ton, up 133% from Winter 2025. In total, these carbon allowance prices added approximately \$11-\$17/MWh in costs for a typical combined cycle and \$24-\$38/MWh for a No. 2 oil-fired generator, depending on location.

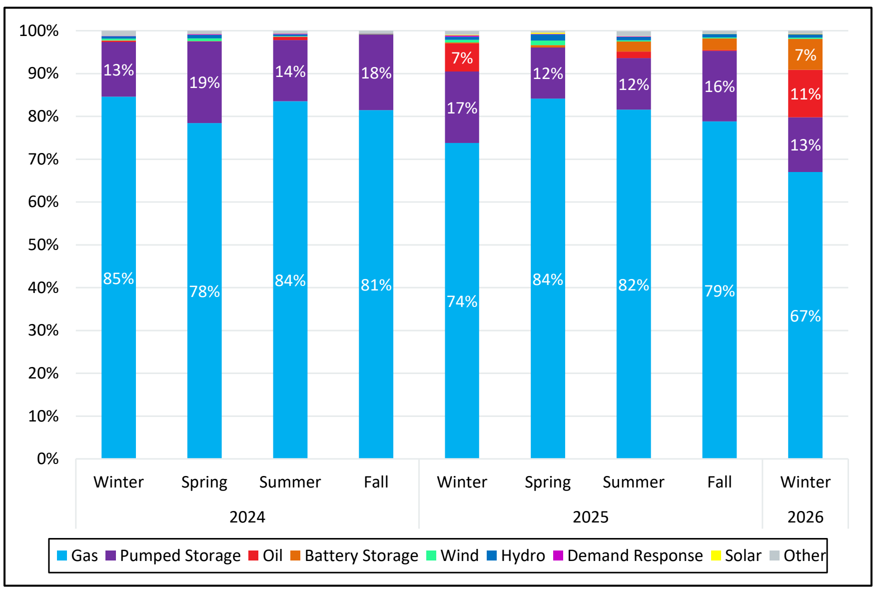
3.2 Marginal Resources and Transactions

This section reports marginal units by transaction and fuel type on a load-weighted basis. When more than one resource is marginal, the system is typically constrained, and the marginal resources likely do not contribute equally to setting price for load across the system. The methodology employed in this section accounts for these differences, weighting the contribution of each marginal resource based on the amount of load in each constrained area.

Real-time Energy Market

The percentage of load for which each fuel type set price in the real-time market since Winter 2024 is shown in Figure 3-2 below.

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



While natural gas-fired generation remained the most frequent marginal unit in Winter 2026, oil-fired generation set the real-time price for 11% of load. The relatively high share of marginal oil units reflects the extended periods when gas-fired generation was uneconomic relative to oil-fired generation because of the relative fuel prices.

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

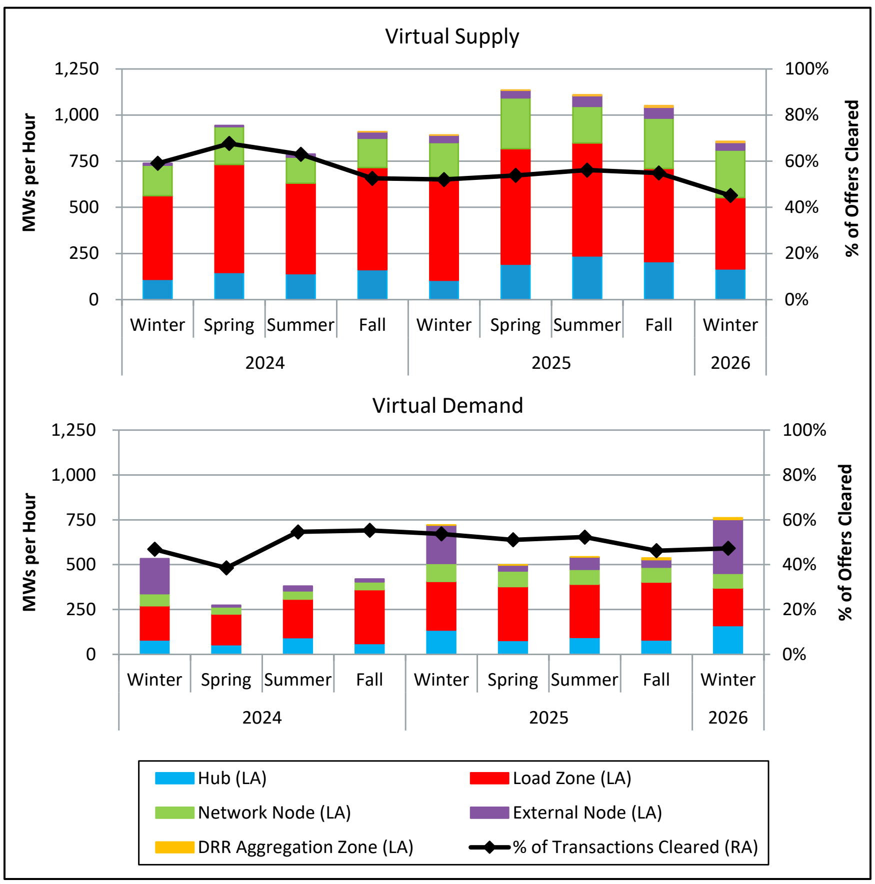
Energy storage facilities, both pumped and battery, frequently set real-time prices. Notably, battery storage facilities set price for 7% of real-time load, marking the highest recorded share. As large batteries have proliferated on the system, batteries and pumped storage combined set price for 20% of real-time load.

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) for each quarter of the past three years are shown on the left axis (LA) in Figure 3-3 below. Cleared transactions are categorized based on the location type where they cleared: Hub, load zone, network node, external node, and Demand Response Resource (DRR) aggregation zone. The line graph on the right axis (RA) of each chart shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

Figure 3-3: Cleared Virtual Transactions by Location Type



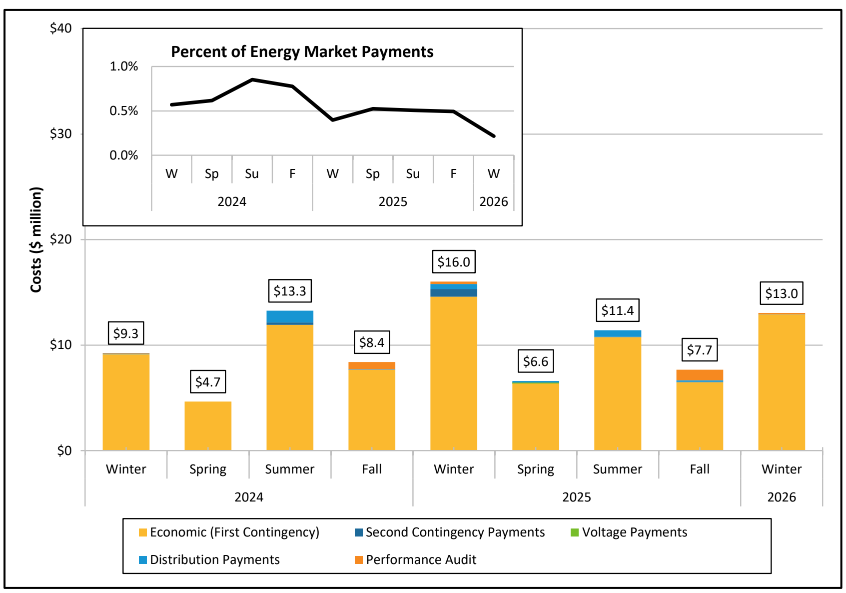
As seen in the top figure, virtual supply volumes decreased slightly year-over-year, while the percentage of offers cleared decreased to the lowest level in the past two years. Cleared virtual supply averaged 858 MW per hour in Winter 2026, down 4% from Winter 2025 (892 MW per hour). This was a notable departure from 2025, when we observed higher year-over-year volumes of cleared virtual supply in each quarter. At the same time, the percentage of offers that cleared fell from 54% in Winter 2025 to 47% in Winter 2026. Several participants increased the quantity of their offers while clearing similar amounts to the prior winter.

Cleared virtual demand averaged 762 MW per hour, the highest volume of cleared virtual demand over the prior nine quarters. Throughout the last three winters, higher volumes of virtual demand have cleared at the Highgate interface, which interconnects New England to Quebec. Importers at Highgate frequently offer high-priced virtual demand in conjunction with a low- or fixed-priced import transaction. The virtual demand transaction provides the importer with both a financial hedge and can help them clear the full volume of their imports. In addition, cleared virtual demand at the New York North interface increased from 24 MW per hour in Winter 2025 to 100 MW per hour in Winter 2026.

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.[39] Figure 3-4 below shows total NCPC by category and season for 2024-2026. The inset graph shows quarterly NCPC payments as a percent of total energy market payments.

Figure 3-4: NCPC Payments by Category ($ millions)



NCPC payments totaled $13.0 million in Winter 2026, comprising only 0.2% of energy costs. The low share of NCPC relative to energy costs illustrates that generators recovered the majority of

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

their operating costs through the high energy market prices observed throughout the season.[40] The vast majority of NCPC payments (99%) were economic payments to generators committed to meet systemwide load and reserve requirements.

As a component of economic payments, dispatch lost opportunity cost (DLOC) credits totaled $3.6 million in Winter 2026, a 65% increase from the prior winter. Two factors drove the increase in DLOC credits. First, real-time LMPs were higher in Winter 2026, leading to higher opportunity cost payments for regular dispatch deviations. Second, battery storage resources have increased as a share of the system over the past year. Such resources respond to dispatch instructions quickly. Dispatch instructions are sent slightly in advance to account for the ramping times of slower resources. The advance dispatch for fast-ramping resources results in relatively large DLOC credits to compensate resources for quickly changing their output ahead of market prices.

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 provides details on the performance of this market between March 1, 2025, and February 28, 2026.[41]

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.

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

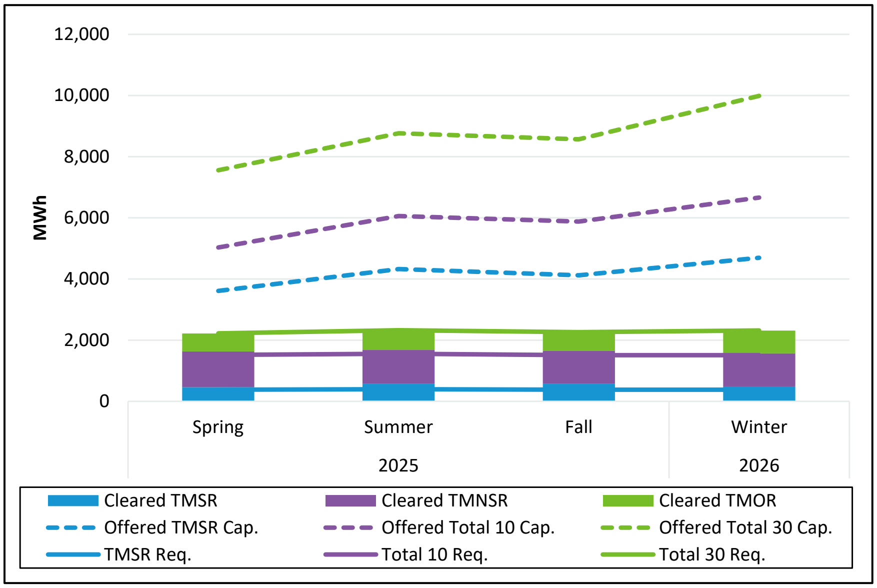
Figure 3-5, which shows the average hourly FRS requirements, offered capability, and the cleared awards, by quarter.[42]

[40] As part of our one-year assessment of DA A/S outcomes, we estimated the impacts of DA A/S on NCPC payments. While NCPC payments were quite low throughout Winter 2026, there was limited evidence that the decline in payments was a direct result of DA A/S. For more information, see the one-year Day-Ahead Ancillary Services assessment, available at https://www.iso-ne.com/static-assets/documents/100036/imm_assessment_of_da_ancillary_services_market.pdf.

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

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

Figure 3-5: FRS Requirements, Offered Capability, and Cleared Awards



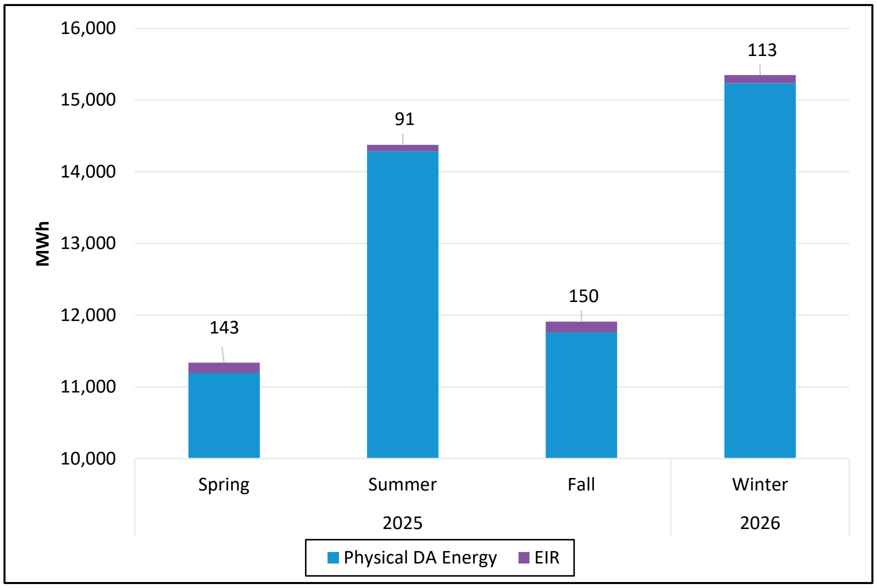
While the FRS requirements – which are based on the projected first and second contingencies – did not change much quarter over quarter, the offered capability that could meet those requirements rose moderately relative to the fall. This increased participation is partly reflective of resources returning to full capability after undertaking winter readiness maintenance in the fall.

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 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 3-6, which shows the shows the average hourly cleared FER supply by quarter.

Figure 3-6: Cleared Awards to Satisfy the Forecast Energy Requirement



The average hourly volume of EIR cleared decreased in Winter 2026 (113 MWh) relative to Fall 2025 (150 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%. The relatively low reliance on EIR to meet expected demand may indicate that the generation fleet was operating near full availability in order to profit from the high winter energy prices.

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.

The DA A/S products have represented a small percentage of overall energy and ancillary services (E&AS) costs.[43] This can be seen in Table 3-1, which shows the *net* settlements for the DA A/S products by quarter.

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

Table 3-1: DA A/S Settlements ($millions)

DA A/S	Spring 2025	Summer 2025	Fall 2025	Winter 2026	Total
DA TMSR (net)	$3.7	$16.6	$8.5	$45.6	$74.4
DA TMNSR (net)	$6.3	$26.1	$16.1	$65.1	$113.6
DA TMOR (net)	$2.9	$13.3	$7.8	$36.3	$60.3
EIR (net)	$0.2	$1.4	$1.7	$10.1	$13.4
Total (net)	**$13.1**	**$57.4**	**$34.1**	**$157.1**	**$261.7**
Total E&AS Costs	$1,284	$2,345	$1,607	$6,261	$11,500
% Total E&AS Cost	1%	2%	2%	3%	2%

Total net ancillary services payments rose significantly between Fall 2025 ($34.1 million) and Winter 2026 ($157.1 million). This increase was in line with the change in total E&AS costs observed between the two periods. As a result, DA A/S costs represented between 2% and 3% of E&AS costs in both quarters.

3.5.4 Incremental Cost of DA A/S

The following analysis estimates the incremental economic cost of DA A/S on market costs relative to the day-ahead market (DAM) design that was in place prior to March 1, 2025. These costs are different than the settlement costs that were presented in the prior section, which measure the credits and charges created by the DA A/S design, including DA A/S credits and closeout charges, and FER credits and charges. Although these items determine who pays and who receives money, they do not, by themselves, measure the incremental cost of the new market design because the same market design change also affects other settlement-related factors (e.g., day-ahead LMPs).

For this reason, we also present a simulation-based estimate of incremental economic cost. Importantly, the simulations do not measure all offsetting or interactive effects, including the retirement of the Forward Reserve Market (FRM), potential reductions in NCPC, future effects on capacity-market offer behavior and Net CONE, or changes in investment and retirement incentives. Consequently, the simulation-based results can be best understood as measures of the incremental day-ahead and deviation-settlement effects of introducing the FER and FRS requirements, not as a full cost-benefit analysis of the initiative

To perform these simulations, we used an in-house market simulation tool that both replicates the logic of the day-ahead market (DAM) that exists in production today and also provides the flexibility to modify constraints and other key inputs.[44] In order to estimate the impact of DA A/S on market costs, the following scenarios were simulated:

1) **No DA A/S**: a scenario in which all DA A/S constraints (FER, FRS) are 'turned off.' This scenario is intended to reflect the pre-March 2025 day-ahead market.[45]

[44]Importantly, while the IMS benchmarks very well against the GE market clearing engine (MCE) that is used in production at ISO-NE, the simulation results should be viewed as indicative rather than exact. The market simulator captures the main co-optimized commitment, scheduling, constraint, and pricing logic that has been benchmarked to production-market outcomes, but it does not reproduce every production-engine feature.

[45] The IMM did *not* adjust energy offers in this scenario in any way (e.g., there was no adjustment to reflect the way participants with FRM obligations were required to offer in the real-time market under that market design).

2) **DA A/S:** a scenario in which all DA A/S constraints are 'turned on.' This scenario is intended to reflect the current day-ahead market.

The following table provides a high-level comparison of these two scenarios for Winter 2026.[46]

Table 3-2: Estimated Change in Market Costs

Category	No DA A/S ($M)	DA A/S ($M)	Delta ($M)	Delta (%)
DA Energy	**$5,595**	**$6,020**	**$425**	**7.6%**
LMP	$5,595	$5,379	-$216	-3.9%
FER Price	$0	$641	$641	
DA A/S	**$0**	**$153**	**$153**	
Credits	$0	$251	$251	
Closeouts	$0	-$98	-$98	
Total Charges/Credits	**$5,595**	**$6,174**	**$578**	**10.3%**
Cost of Incremental RT Energy	$81	$76	-$5	-6.0%
Total Cost/Revenue Change	**$5,676**	**$6,249**	**$574**	**10.1%**

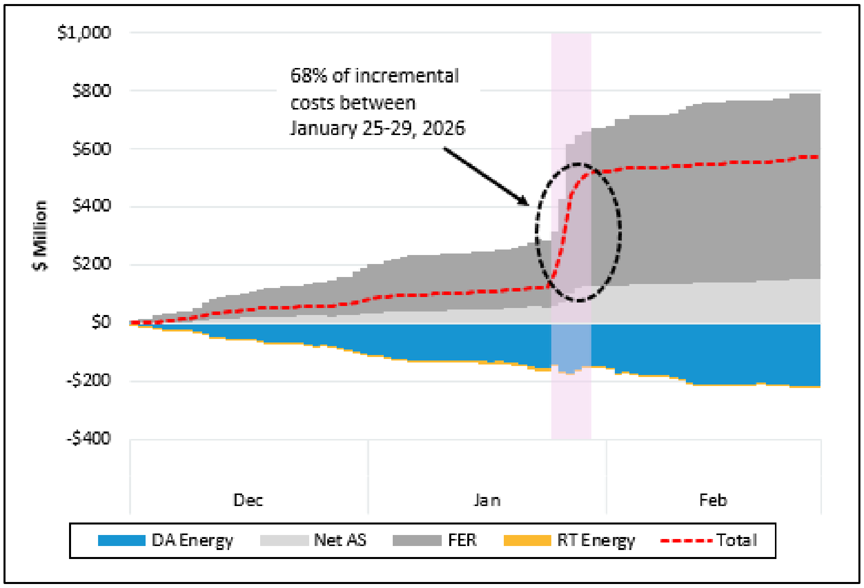
We estimate that DA A/S resulted in an increase of $574 million (10.1%) in total day-ahead and deviation-settlement costs relative to the prior energy-only design. The majority of the incremental cost increases are in the form of higher day-ahead energy market payments, where we estimate an increase of $425 million relative to the 'No DA A/S' scenario. While energy payments via the day-ahead LMP decreased by $216 million relative to the 'No DA A/S' scenario, this is more than offset by a $641 million FER credit. Net payments to the new DA A/S awards ($153 million) represent all of the remaining estimated cost increase. The simulations indicate very little change in incremental real-time energy purchases between the two scenarios.[47]

A key observation is that a limited number of high-cost days accounted for a disproportionately large share of the incremental DA A/S-related costs incurred during Winter 2026. This observation is evident in Figure 3-7, which presents the cumulative incremental change in market costs by cost component.

[46] Due to simulation-related constraints, December 5, 2025, and January 3, 2026, are not reflected in any of the simulation results.

[47] We calculate the cost of incremental real-time energy as (real-time load obligation – day-ahead load obligation) * real-time LMP, mimicking the deviation settlement logic. These costs can differ because one scenario may clear more energy supply in the day-ahead market relative to another and therefore need to procure less energy supply in real-time market. Importantly, we assume no changes in the real-time LMP between the two scenarios, which is a conservative assumption in hours where DA A/S improved the day-ahead operating plan and reduced the likelihood of moving up a steep real-time supply curve.

Figure 3-7: Cumulative Incremental Change in Market Costs



We estimate the five-day period between January 25, 2026, to January 29, 2026, accounted for over two-thirds of incremental DA A/S-related costs during Winter 2026 ($389 million of $574 million). Notably, one day alone, January 27, 2026, accounted for 31% of the incremental DA A/S costs incurred over the winter. In nearly 60% of hours (71 of 120) over this five-day period, the day-ahead market did not procure the full replacement reserve (180 MW) and in 54 of these hours it procured zero replacement reserve.[48]

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.[49] 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 winter seasons in Table 3-3 below.[50]

[48] For more information about these requirements, see *Section III Market Rule 1: Standard Market Design*, Section III.2.7A, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

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

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

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

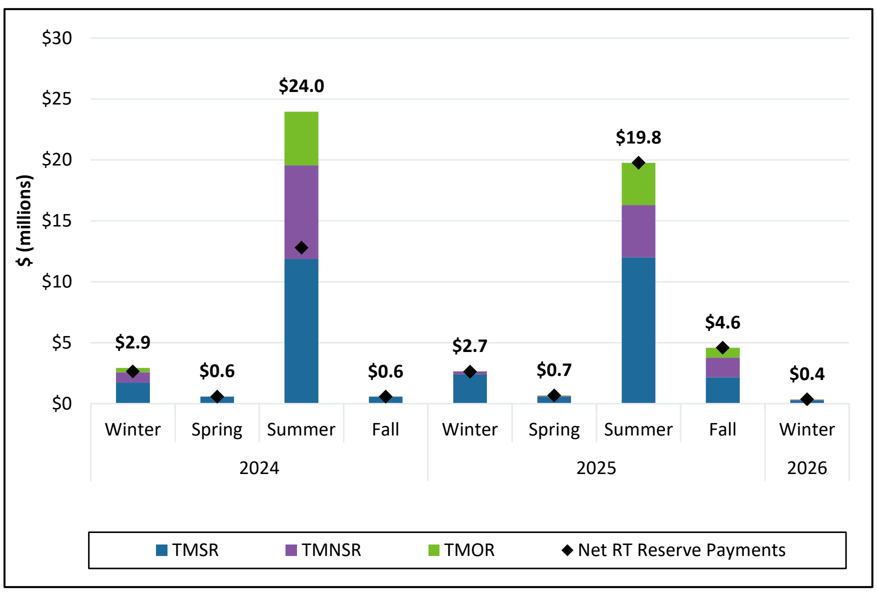
Product	Winter 2026		Winter 2025		Winter 2024	
	Avg. Price $/MWh	*Hours of pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	$13.24	29.3	$18.34	222.9	$18.14	140.0
TMNSR	$77.66	1.1	$40.79	2.6	$72.43	11.1
TMOR	$77.66	1.1	$20.22	1.3	$78.29	5.8

The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 29 hours during Winter 2026. This winter 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 occur during the morning and evening ramps. Non-zero TMNSR and TMOR prices also occurred less frequently, indicating that, generally, there was ample supply of total-ten and thirty-minute reserve capability available on the system in Winter 2026.

Real-time Reserve Payments

Real-time reserve payments by product are illustrated in Figure 3-8 below. The height of the bars indicates gross reserve payments, while the black diamonds show net payments.[51]

Figure 3-8: Real-Time Reserve Payments by Product



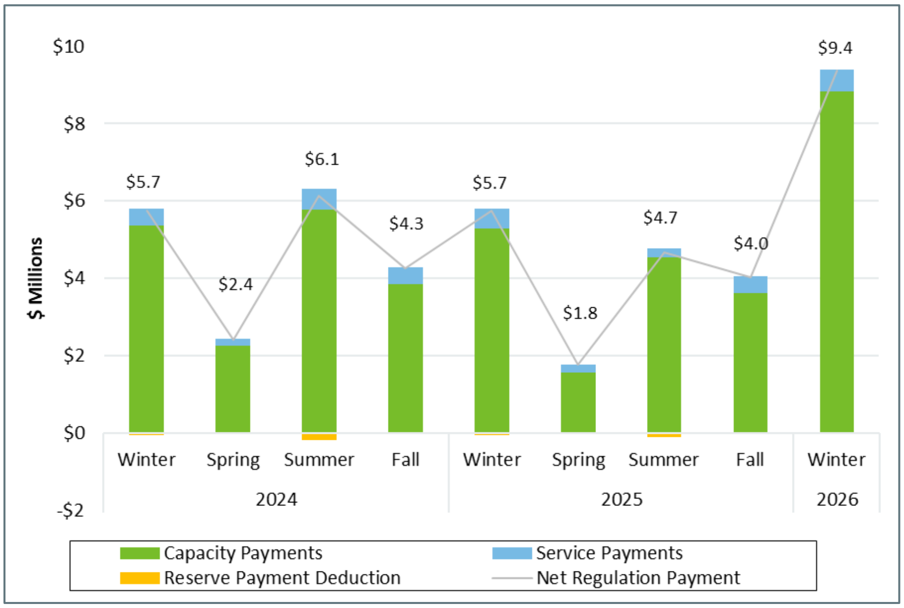
Net reserve payments in Winter 2026 ($0.4 million) were lower than those in the prior two winters. Other notable seasonal reserve payments illustrated in this figure include Summer 2024, Summer 2025, and Fall 2025, which all had at least one period of capacity scarcity conditions.

[51] 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.

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 3-9 below.

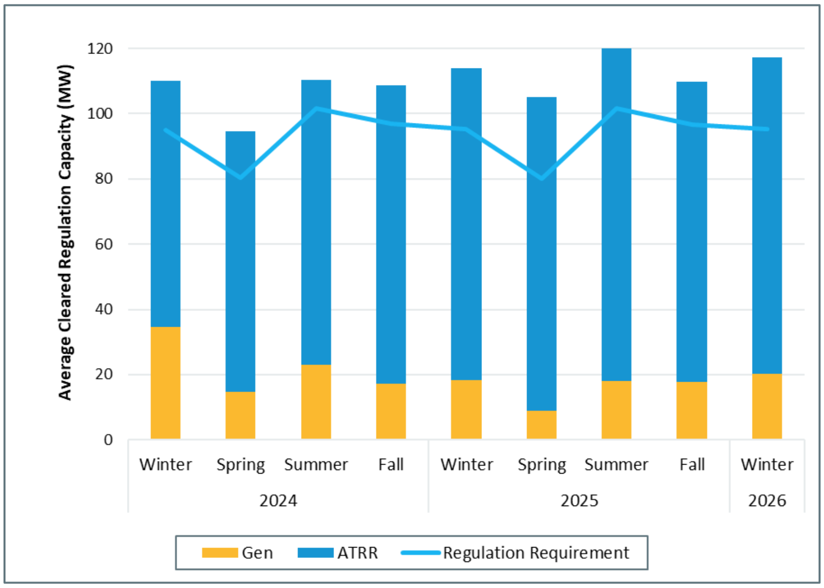
Figure 3-9: Regulation Payments



Total regulation market payments were $9.4 million during Winter 2026, up significantly from $5.7 million in Winter 2025. Higher regulation capacity prices in Winter 2026 resulted in higher regulation capacity payments, while capacity offer prices remained relatively low.

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 3-10 below.

Figure 3-10: Average Cleared Regulation MW by Resource Type



The resource mix of cleared regulation capacity in Winter 2026 remains dominated by ATRRs, continuing the shift observed in prior periods. ATRRs (blue shading) cleared an average of approximately 97 MW, accounting for about 83% of total cleared regulation in Winter 2025. Regulation requirements remained stable at 95 MW, while the average available regulation capacity increased to 850 MW, up from 246 MW in Winter 2025.

This evolution in the resource mix reflects the advantages of battery resources in providing regulation services. ATRRs are well-suited to regulation due to their ability to respond quickly and accurately to control signals, allowing them to offer lower-cost and more precise regulation compared to conventional generators. As a result, ATRRs have displaced traditional generation in the merit order for regulation market commitment, contributing to their growing share of cleared regulation capacity.

Section 4
Energy Market Competitiveness

One of ISO New England's three critical goals is to administer competitive wholesale energy markets. Competitive markets help ensure that consumers pay fair prices and incentivize generators to make short- and long-run investments that preserve system reliability. In section 4.1, we evaluate energy market competitiveness by quarter using two structural market power metrics at the system level. In section 4.2, we provide statistics on system and local market power flagged by the automated mitigation system, and on the amount of actual mitigation applied, whereby a supply offer was replaced by the IMM reference level.

4.1 Pivotal Supplier and Residual Supply Indices

This analysis examines opportunities for participants to exercise market power in real time using two metrics: the pivotal supplier test (PST) and the residual supply index (RSI).[52]

When a participant's available supply exceeds the supply margin,[53] they are considered pivotal.[54] 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%

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.

[52] 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.

[53] 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* - [$Reserve\ Requirement$]

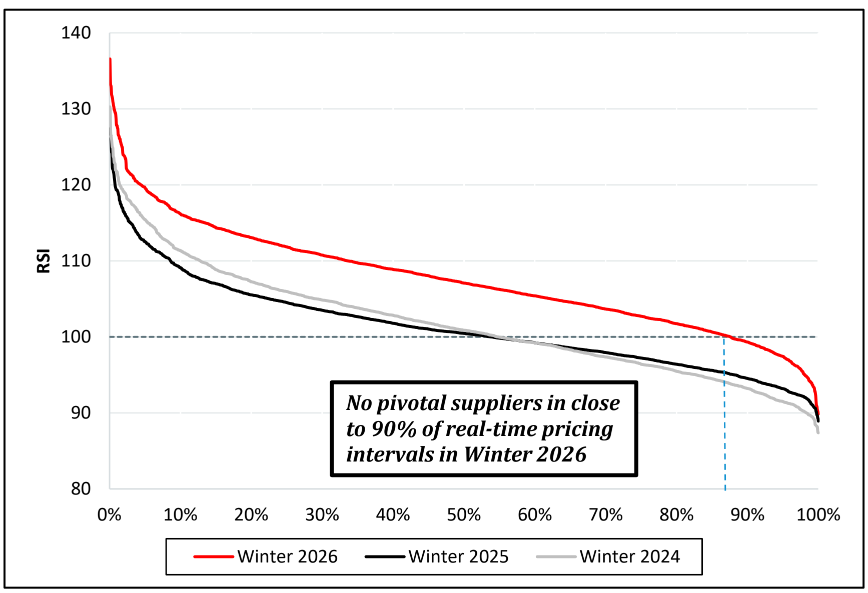
[54] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

There was at least one pivotal supplier in only 13% of real-time pricing intervals in Winter 2026, despite higher loads and lower net interchange. This represents the lowest level of pivotal suppliers over the reporting period. Instances with a pivotal supplier decreased 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.

Historically, the Phase II interface has been ISO-NE's first contingency as import levels were often higher than the output of any nuclear generators. This winter saw a large decrease in net interchange from Quebec, especially at the Phase II interface. In Winter 2025, Phase II was the first contingency in 70% of hours compared to just 4% of hours this winter. The lower first contingency value led to lower reserve requirements and higher reserve margins in Winter 2026. Additionally, battery storage capacity has been increasing with several larger batteries becoming commercial over the last nine months. Battery storage's flexibility allows them to provide large amounts of real-time operating reserves, further increasing reserve margins.

Duration curves that rank the average hourly RSI over each winter 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 Winter 2026, the RSI was much higher than in Winter 2024 and Winter 2025. Both Winter 2024 and 2025 saw lower average reserve margins compared to Winter 2026, as discussed above.

4.2 Energy Market Supply Offer Mitigation

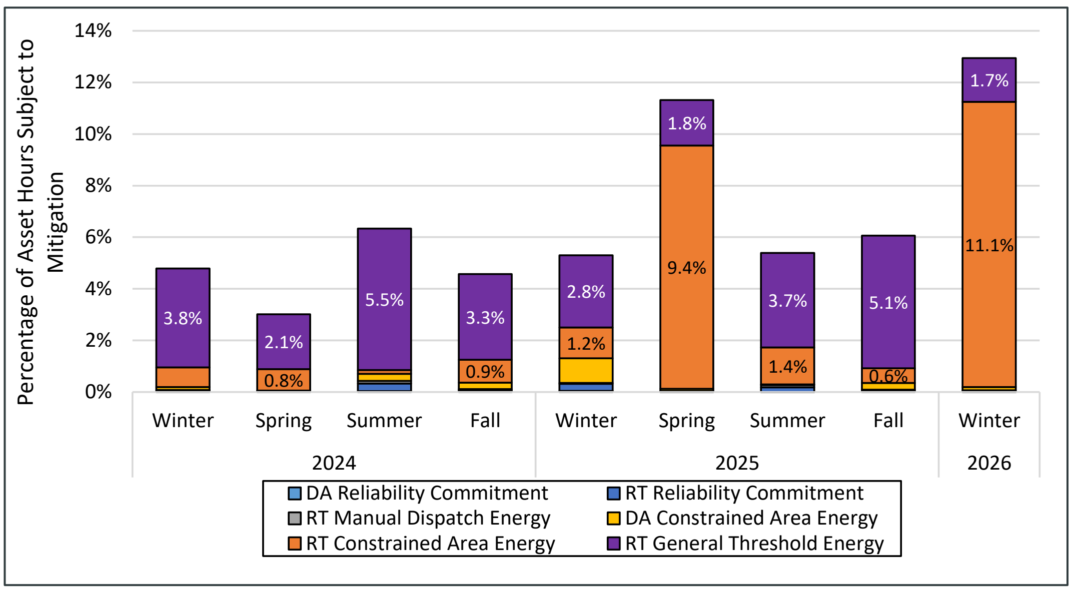
The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review can result in energy market supply offer mitigation. Mitigation of supply offers minimizes opportunities for participants to exercise market power.

The mitigation of energy market supply offers occurred much more frequently in Winter 2026 compared with previous seasons, driven primarily by a large import-constrained area on the west side of the Maine-New Hampshire constraint. The Maine-New Hampshire constraint was binding more frequently than in previous seasons due to increased supply in Maine associated with the NECEC line.

Energy Market Mitigation Frequency

A structural test failure serves as the first indicator of potential market power in the energy markets. The percentage of commitment asset hours with a structural test failure from Winter 2024 to Winter 2026 is shown below in Figure 4-2.[55]

Figure 4-2: Energy Market Mitigation Structural Test Failures



In Winter 2026, approximately 497,000 asset hours were subject to mitigation, of which 64,000 (13%) failed structural tests.[56] The structural test for general threshold energy mitigation has historically failed the most often and is triggered anytime a committed generator is owned by a pivotal supplier. However, in Winter 2026 the real-time constrained area energy test failed most,

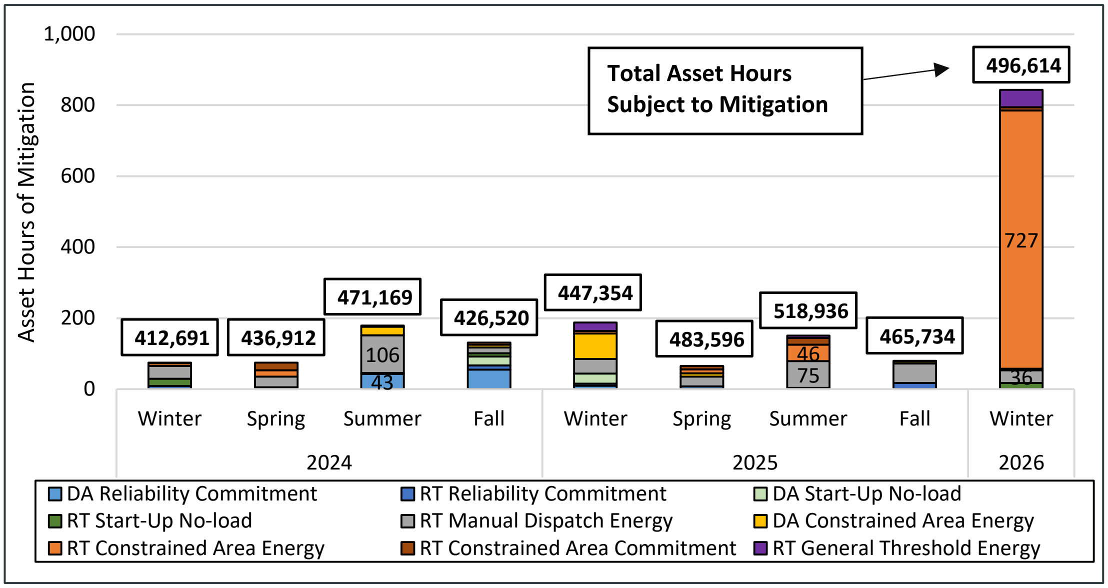
[55] A structural test failure depends on the type of mitigation analyzed. For the definitions of the structural test applied in general threshold and constrained area mitigation, see *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.5.2, available 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.

[56] 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.

driven by generators on the import-constrained side of the Maine-New Hampshire constraint, discussed more in Section 5.2. The Maine-New Hampshire constraint was binding more often than in previous seasons due to the NECEC line, discussed more in 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



Total mitigation asset hours increased from 188 hours in Winter 2025 to 843 hours in Winter 2026.[57]

Constrained area (CAE/CACM) mitigation: The frequency of transmission-constrained areas follows the incidence of transmission congestion and import-constrained areas within New England. Real-time constrained area energy mitigation was by far the most frequent mitigation type in Winter 2026, totaling 727 asset hours. As discussed above, the market power flags associated with these mitigations were driven by the Maine-New Hampshire constraint binding more frequently due to power flows from the NECEC interface. The conduct and impact tests for real-time constrained area energy were also more likely to be violated in Winter 2026 due to high gas and energy prices. 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.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs, and are generally due to routine transmission line outages, outages facilitating

[57] 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.

upgrade projects, or localized distribution system support.[58] In Winter 2026, there were no reliability commitment mitigations.

Start-up and no-load (SUNL) commitment mitigation: This mitigation type addresses grossly over-stated commitment costs (relative to reference values), which could otherwise result in very high uplift.[59] 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 Winter 2026, only two participants were associated with the 17 asset hours of SUNL commitment mitigation.

General threshold energy (GTE) mitigation: General threshold energy mitigation typically occurs infrequently. There were 49 asset hours of general threshold energy mitigation in Winter 2026, and all occurred on one day for a single supplier. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators, with four participants accounting for three quarters of the structural test failures in Winter 2026.

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 70% of the 274 asset hours of manual dispatch in Winter 2026. Due to a relatively tight conduct test, manual dispatch energy mitigation generally occurs more often than most other mitigation types relative to structural test failures, reaching a total of 36 asset hours in Winter 2026.

[58] 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.

[59] 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

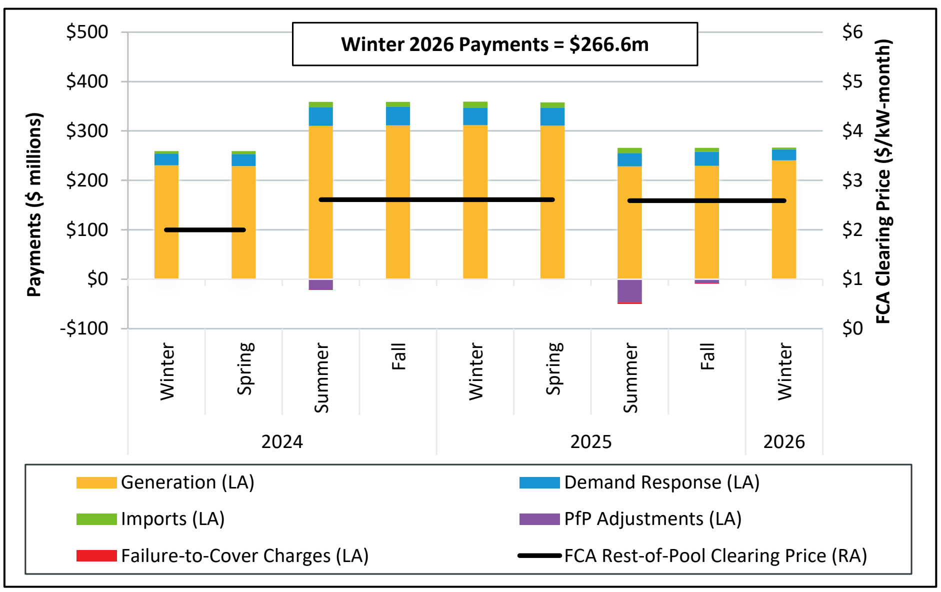
This section covers activity in the Forward Capacity Market (FCM), and in Financial Transmissions Rights (FTRs).

5.1 Forward Capacity Market

The Capacity Commitment Period (CCP) associated with Winter 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 price cleared at $2.64/kW-month, while the export-constrained Northern New England and Maine capacity zones cleared at $2.53/kW-month. While 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 Winter 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 (PfP) adjustments, while the red bar represents Failure-to-Cover charges.

Figure 5-1: Capacity Market Payments



Capacity payments totaled $266.6 million in Winter 2026, a 26% decrease from Winter 2025. Despite relatively severe operating conditions during Winter Storm Fern and the extended cold snap, there were no PfP events throughout the season. Failure-to-Cover charges were minimal.

Secondary auctions allow participants the opportunity to acquire or shed capacity after the initial auction. A summary of prices and volumes associated with the reconfiguration auction and bilateral trading activity during Winter 2026 alongside the results of the relevant primary FCA are detailed in Table 5-1 below.

Table 5-1: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

				Capacity Zone/Interface Prices ($/kW-mo)			
FCA # (Commitment Period)	Auction Type	Period	Cleared MW*	Rest-of-Pool**	Maine	Northern New England	Southeastern New England
FCA 16 (2025-2026)	**Primary**	**12-month**	**32,810**	**2.59**	**2.53**	**2.53**	**2.64**
	Monthly Reconfiguration	Feb-26	988	5.97	5.97	5.97	5.97
	Monthly Bilateral	Feb-26	126	0.13			
	Monthly Reconfiguration	Mar-26	623	2.50	2.50	2.50	2.50
	Monthly Bilateral	Mar-26	6	2.63			
	Monthly Reconfiguration	Apr-26	439	1.30	1.30	1.30	1.30
	Monthly Bilateral	Apr-26	6	2.63			

Three monthly reconfiguration auctions (MRAs) took place in Winter 2026: the February 2026 auction in December, the March 2026 auction in January, and the April 2026 auction in February. Clearing prices in the February 2026 MRA ($5.97/kW-mo), which was the last operating month of Winter 2026, were elevated above the primary auction clearing price, similar to the December 2025 and January 2026 prices ($4.50/kW-mo and $5.50/kW-mo, respectively). Outside the relatively risky winter season, the March and April 2026 auctions cleared below the primary auction clearing price with somewhat modest participation.

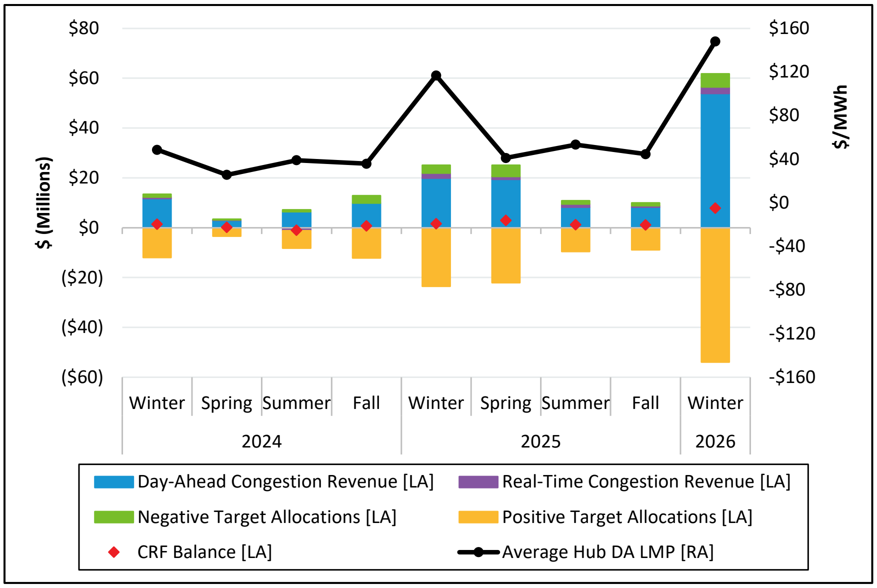
5.2 Financial Transmission Rights

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

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

Figure 5-2 below shows, by quarter, the amount of congestion revenue from the day-ahead and real-time energy markets, the amount of positive and negative target allocations, and the congestion revenue fund (CRF) balance.[60,61] This figure also depicts the quarterly average day-ahead Hub LMP.[62]

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



Congestion revenue totaled $56 million in Winter 2026, more than doubling from Winter 2025. Congestion revenue is correlated with high day-ahead Hub LMPs as hub prices rise above the relatively low LMPs in constrained areas. In addition, the New England Clean Energy Connect (NECEC) line drove significant system congestion after it became operational in mid-January.[63] The NECEC sinks energy into Maine, joining the mostly-renewable power that flows from Maine to the rest-of-system. This resulted in relatively frequent binding of two interfaces:

1) **Maine-New Hampshire (MENH):** This interface limits the flows from Maine into New Hampshire. This interface rarely bound before the NECEC became operational. Over Winter 2026, the constraint bound in 103 hours in the day-ahead market.
2) **Northern New England Scobie 345kV – Scobie + 394 (NS_ST):** This interface limits flows through the Scobie bus along the north-south interface boundary. While this interface bound less often than MENH, it similarly greatly increased in frequency, binding in 38 hours over the season.

Beyond the new flows driven by the NECEC, typical winter-related congestion patterns arose throughout Winter 2026. The **Berlin 1771 line** can be limited by the local 115-kV transmission system, resulting in occasional import congestion into Connecticut and Western Massachusetts

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[60] The CRF balances depicted 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).

[61] 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.

[62] The average quarterly day-ahead Hub LMP is measured on the right axis (“RA”), while all the other values are measured on the left axis (“LA”).

[63] See Section 2.3.2 for more information on the NECEC line.

throughout the season. The **New York-New England (NYNE)** interface often binds in the winter; when New England faces higher gas costs than New York, it is generally economic for New York to export as much energy as possible into New England, resulting in congestion. Notably, these conditions did not hold during Winter Storm Fern, when New York fuel prices were similar to or higher than New England.[64] Despite both novel and typical congestion patterns, FTRs were fully funded in each month of the season.

[64] See Section 1 for more information on Winter Storm Fern.

Section 6
Appendix: Overview of FPA Process

Fuel Price Adjustments (FPAs) provide a means for participants to reflect their expected fuel cost in their reference levels in the event that it differs significantly from the corresponding fuel index. As outlined in Section III.A.3.4(ii) of the Tariff, the submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its supply offer. When a participant submits an FPA, the IMM calculates the reference level for that resource using the cost-based methodology, which uses documented cost information provided by the participant to estimate incremental energy offers.[65] To provide additional insight into how FPAs impact reference levels, the Incremental Energy formula of the cost-based reference level methodology is shown below:[66]

$$\begin{aligned} &\mathit{Incremental\ Energy} \\ &\qquad = (\mathit{incremental\ heat\ rate} * \mathit{fuel\ costs}) + (\mathit{emissions\ rate} \\ &\qquad * \mathit{emissions\ allowance\ price}) + \mathit{variable\ operating\ and\ maintenance\ costs} \\ &\qquad + \mathit{opportunity\ costs} \end{aligned}$$

Without an FPA, the IMM estimates the fuel costs in the preceding equation using automated index-based cost data received from third party vendors. Because the indices are based on historical transactions (in the case of natural gas, the weighted average price of the preceding day's next-day trading strip), they may not reflect current market prices. If the reference level is set too low, a resource runs the risk of inappropriate mitigation and failure to recover its operating costs. By overriding the fuel costs in the previous equation, FPAs provide a way to update fuel costs and reference levels in real time.

While FPAs can be submitted for market days up to seven days in the future, they are most commonly submitted in association with offers into the day-ahead (DA) and real-time (RT) energy markets.[67] FPA requests for the DA market must be submitted by the close of day-ahead market window (10:00 AM Eastern Time), while FPA requests for the RT energy market can be submitted up to 30 minutes before the start of the operating hour in which they would take effect.

While the automated processing of FPAs increases the participant's ability to reflect their costs through supply offers rather than after-the-fact uplift payments, it comes with an obligation of verification. To lessen this concern and the ability of a participant to exercise market power, the IMM has two tools: an ability to set a limit on requested FPA prices, and cost verification through *ex-post* documentation.

The IMM uses a proprietary model to estimate a reasonable upper bound for natural gas prices ("FPA Limit"). More specifically, the model uses a variety of forecasting techniques to create probabilistic estimates of pipeline-specific natural gas prices paid by generators for next day and

[65] See *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.7.5, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

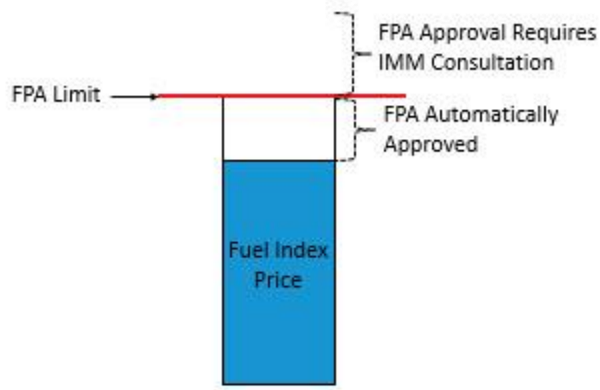
[66] Similar formulae are also used to estimate no-load and start-up costs, but are not shown here to preserve space.

[67] The software suspends the processing of FPA requests for market days greater than one day out until the beginning of the day before the requested market day.

same day delivery of natural gas. The model uses data on regional natural gas transactions from the Intercontinental Exchange (ICE), actual and forecasted weather, and load.

Once submitted, the system either approves the FPA at the requested price or caps it at the FPA Limit (see Figure below). As outlined in III.A.3 of the Tariff, if a participant's fuel cost expectation exceeds the FPA Limit, they may consult with the IMM to provide additional documentation for the increased cost. The IMM will draw on its visibility into all FPA requests as well as ICE bids, offers, and transactions to either: 1) manually approve the participant-specific FPA request; 2) raise the FPA limit to more accurately reflect market conditions; or 3) keep the FPA request capped.

FPA Processing Overview



In addition to this *ex-ante* measure, the IMM requires that within five business days of the FPA submittal, the participant must provide supporting documentation in the form of an invoice or purchase confirmation, a quote from a named supplier, or a price from a publicly available trading platform or reporting agency. Should the participant fail to provide this documentation, it can lose the right to use the FPA mechanism (per Section III.A.3.4 of the Tariff).