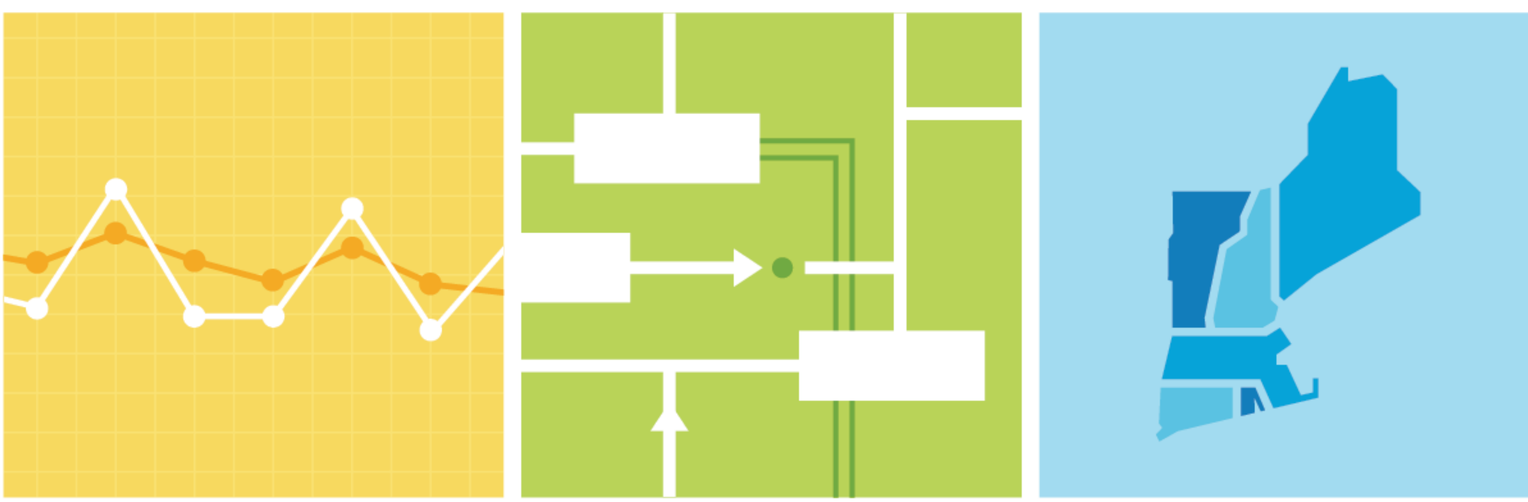
Spring 2024
Quarterly Markets Report

By ISO New England's Internal Market Monitor

JULY 22, 2024



Preface/Disclaimer

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

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

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

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

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

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

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

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Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Spring 2024 (March 1, 2024 through May 31, 2024).

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.10 billion, down 23% from $1.44 billion in Spring 2023. The decrease was driven by lower energy and capacity costs.

Energy costs totaled $0.76 billion; down 16% (or $0.14 billion) from Spring 2023 costs. Decreased energy costs were a result of lower natural gas prices. In Spring 2024, gas prices decreased by 29% compared to Spring 2023. Higher loads and an increase in emissions prices partially muted the impact of lower natural gas prices on LMPs.[3]

Capacity costs totaled $259 million, down 39% (by $164 million) from last spring. Beginning in Summer 2023, lower capacity clearing prices from the fourteenth Forward Capacity Auction (FCA 14) led to lower wholesale costs relative to the previous FCA. Last year, the capacity payment rate for all new and existing resources was $3.80/kW-month. This year, the payment rate for new and existing resources was lower, at $2.00/kW-month. The price decrease was driven by a lower Net Installed Capacity Requirement (down by 1,260 MW) and higher surplus capacity (up 375 MW) in FCA 14 compared to FCA 13.

In early 2019, the Mystic 8 and 9 generators sought to retire through the capacity market but were retained for reliability by the ISO. In June 2022, the generators began receiving supplemental payments to offset operating costs per their cost-of-service agreement (Mystic CoS) with the ISO.[4] These payments totaled $65 million in March and April 2024.[5] Mystic 8 and 9 received supplemental payments through the end of May 2024.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $25.66 and $24.64 per megawatt hour (MWh), respectively. Day-ahead and real-time prices were 9-13% lower than Spring 2023 prices, on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $1.60/MMBtu in Spring 2024, 29% lower than the Spring 2023 price of $2.24/MMBtu. This decrease continued the trend of lower gas prices since early 2023.
- Net imports averaged 780 MW less compared to the previous spring, and average loads were up by 180 MW. These factors somewhat offset the impact of lower natural gas prices on LMPs.

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[3] The average estimated cost of the Regional Greenhouse Gas Initiative (RGGI) program was $8.80/MWh in Spring 2024, up from $5.85 in Spring 2023.

[4] Under the Mystic CoS, Mystic 8 and 9 have an Annual Fixed Revenue Requirement (AFRR), which is the amount they need to operate for the commitment period. Revenues earned in the ISO-administered wholesale markets are not enough to cover the AFRR, and the supplemental payments fill the gap. Any additional revenues they receive are netted so revenues are capped at the AFRR.

[5] May cost-of-service payment data was not yet available at the time of this report.

- Average real-time Hub prices were just $1.02/MWh lower than average day-ahead prices, representing a tighter degree of price convergence than in Spring 2023 ($2.58/MWh) or Winter 2024 ($4.27/MWh). The improved price convergence in Spring 2024 reflected a decrease in load over-clearing in the day-ahead market relative to these prior seasons.
- Energy market prices did not differ significantly among load zones.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $4.6 million, up $0.7 million compared to Spring 2023. NCPC comprised 0.6% of total energy costs, a similar share to other quarters over the reporting period. All NCPC payments in Spring 2024 were first contingency (also known as "economic") payments. The absence of second contingency and voltage payments reflected the lack of reliability commitments during the season.

Real-time Reserves: Real-time reserve payments totaled $0.6 million, down slightly from $0.9 million in Spring 2023. Almost all payments (97%) were for ten-minute spinning reserve (TMSR). The low payments reflected high margins and the absence of major instances of stressed system conditions.

The frequency of non-zero spinning reserve prices in Spring 2024 (174 hours) was similar to that of Spring 2023 (149 hours) but substantially lower than in Spring 2022 (406 hours). The decline in the most recent two spring seasons was due to a reduction in the TMSR requirement, relative to the requirement in effect in Spring 2022.[6] The average non-zero spinning reserve price in Spring 2024 was $6.98/MWh, down from $9.16/MWh the previous spring. While the average ten-minute non-spinning reserve (TMNSR) price in Spring 2024 was $29.90/MWh, the occurrence of non-zero pricing was less than one hour. There was no thirty-minute operating reserve (TMOR) pricing in Spring 2024.

Regulation: Regulation market payments totaled $2.4 million, down 49% from $4.8 million in Spring 2023. This decrease primarily reflected lower capacity prices (down 58%). Capacity prices decreased due to 1) lower energy market opportunity costs, reflecting a decline in energy market LMPs compared to the earlier period, and 2) a decline in regulation offer prices as alternative technology regulation resources continue to make up a larger share of the regulation mix. Regulation service prices also decreased (down 66%) from Spring 2023.

Financial Transmission Rights (FTRs): FTRs were fully funded in March 2024 and April 2024, but were not in May 2024. In May, only 82% of positive target allocations were funded, primarily due to congestion in the day-ahead market at the Orrington-South ("ORR-SO") constraint in Maine. The limit for this interface was reduced at times in May, most notably at the end of the month because of generation and transmission outages.

Most congestion-related totals in Spring 2024 moved in line with the day-ahead energy price. Day-ahead congestion revenue decreased by 36% compared to Spring 2023, totaling $3.0 million. Positive target allocations totaled $3.4 million in Spring 2024, down 30% from Spring 2023.

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[6] This change reduced the percentage of the ten-minute reserve requirement that must be spinning from 31% to 25% on May 31, 2022. The operational decision to change this percentage stemmed from changes to the reserve designation rules for composite resources, which provide more accurate accounting of TMSR supplied by those resources. Composite resources those that are modeled as a single generator in the ISO's network model, but that exist in reality as multiple distinct units (such as a series of several hydroelectric dams).

Negative target allocations ($0.3 million) were 40% lower than their Spring 2023 level. Real-time congestion revenue in Spring 2023 ($0.1 million) remained modest.

Energy Market Competitiveness: The residual supply index for the Real-time energy market in Spring 2024 was 106, 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 29% of five-minute pricing intervals in Spring 2024, slightly up from the previous spring (22%). The year-over-year increase was due to lower total 30-minute reserve margins, which decreased by an average of 247 MW compared to Spring 2023 due to fast-start generator retirements and additional pumped-storage generator outages relative to Spring 2023.

Mitigation continued to occur very infrequently. During Spring 2024, mitigation asset hours represented just 0.02% of total asset hours, similar to the Spring 2023 mitigation frequency. Real-time manual dispatch energy (MDE) mitigation occurred the most frequently in Spring 2024 with 30 asset hours of mitigation. Notably, there were no reliability commitment mitigations because there were no reliability commitments during Spring 2024.

***Summer 2024 Forward Reserve Market Auction*:** In April 2024, ISO New England held the forward reserve auction for the Summer 2024 delivery period (i.e., June 1, 2024 to September 30, 2024). System-wide supply offers in the Summer 2024 auction exceeded the requirements for both TMNSR and TMOR. The system TMOR and TMNSR products both cleared at prices of $2,952/MW-month, a significant decrease from Summer 2023 clearing prices. The reduction was primarily due to lower offer prices and a reduced TMNSR requirement. The TMNSR requirement decreased from 1,696 MW in Summer 2023 to 1,374 MW in Summer 2024 due to reduced flows over the Phase II interface between Summer 2022 and Summer 2023.[7] Additionally, there was a modest increase in offered TMNSR supply between Summer 2023 and Summer 2024.

The Residual Supply Index (RSI) was above 100 for both the system-level TMNSR and TMOR products in Summer 2024, indicating that there was enough supply to meet the requirements without the largest participant. This was the first of the last three summer auctions that was structurally competitive for both requirements. The RSI for the TMNSR requirement was 107 in Summer 2024, up from 78 and 81 in Summers 2022 and 2023, respectively. While the level of offered supply for the TMNSR requirement increased in Summer 2024, the main driver behind the increased RSI was the lower TMNSR requirement. Because the total thirty-minute requirement for the auction is the sum of the TMNSR and TMOR requirements for the control area, the lower TMNSR requirement also reduced the total thirty-minute requirement in Summer 2024.

The IMM previously recommended that the ISO review and update the forward reserve supply offer cap, which is one of the only safeguards against the potential exercise of market power in this market. We were pleased to see that ISO acted on this recommendation with proposed rule changes and that these changes were approved by FERC.[8]

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[7] The control area FRM reserve requirements are based on historical data for the prior like delivery period (e.g., the TMNSR requirement for Summer 2024 was based off historical data from Summer 2023).

[8] See *Order Accepting Revisions to Update the Forward Reserve Market Offer Cap*, ER24-1245-000 (April 2024), available at https://www.iso-ne.com/static-assets/documents/100010/er24-1245-000.pdf

Section 2
Overall Market Conditions

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

Table 2-1: High-Level Market Statistics

Market Statistics	Spring 2024	Winter 2024	Spring 2024 vs Winter 2024 (% Change)	Spring 2023	Spring 2024 vs Spring 2023 (% Change)
Real-Time Load (GWh)	26,196	30,416	-14%	25,798	2%
Peak Real-Time Load (MW)	17,336	18,438	-6%	16,206	7%
Average Day-Ahead Hub LMP ($/MWh)	$25.66	$48.66	-47%	$29.62	-13%
Average Real-Time Hub LMP ($/MWh)	$24.64	$44.39	-44%	$27.04	-9%
Average Natural Gas Price ($/MMBtu)	$1.60	$4.87	-67%	$2.24	-29%
Average No. 6 Oil Price ($/MMBtu)	$15.74	$14.94	5%	$15.92	-1%

Key observations from the table above:

- Day-ahead LMPs averaged $25.66/MWh in Spring 2024, down 13% from Spring 2023 ($29.62/MWh). Lower gas prices in Spring 2024 ($1.60/MMBtu) compared to Spring 2023 ($2.24/MMBtu) put downward pressure on LMPs.
- The average premium paid in the day-ahead market during Spring 2024 was $1.02/MWh. This represents a tighter degree of price convergence than was observed in either Spring 2023 ($2.58/MWh) or Winter 2024 ($4.27/MWh), reflecting a decrease in load over-clearing in the day-ahead market relative to these prior seasons.[9]
- Load, natural gas prices, and LMPs decreased in Spring 2024 relative to Winter 2024, consistent with increased temperatures and the associated decrease in energy demand.[10]
- Total load in Spring 2024 was 2% higher than in Spring 2023.

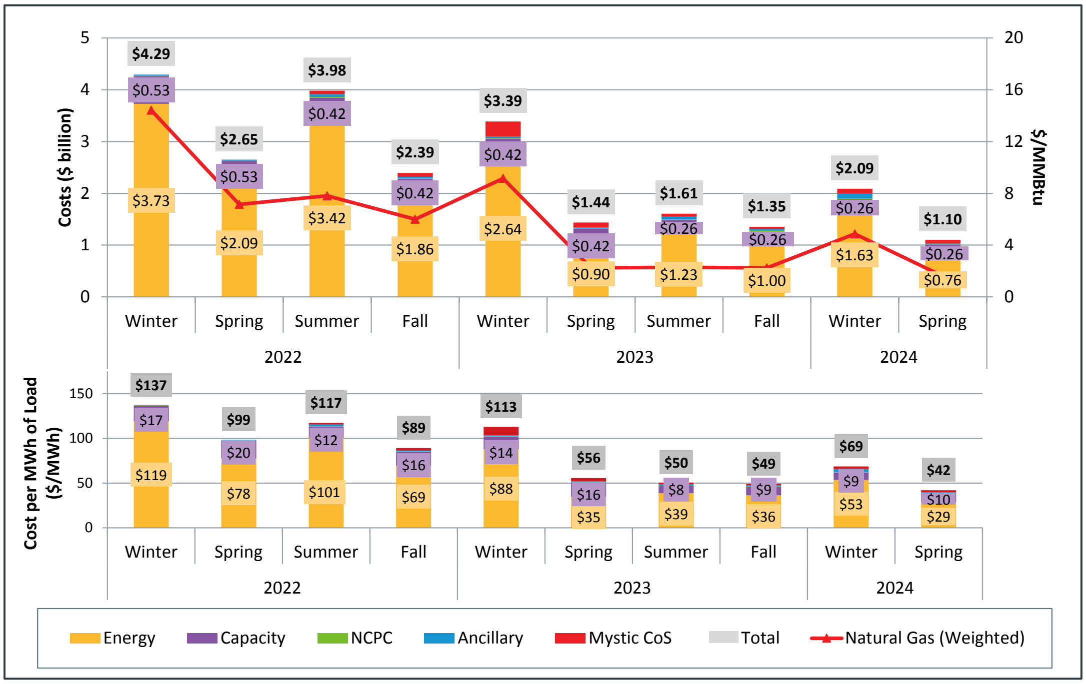
[9] See Section 2.2 for further discussion on load in the day-ahead market.

[10] These low New England natural gas prices align with low prices observed at Henry Hub, and are driven by strong natural gas production and more natural gas in storage. For more information on gas prices, see the EIA's *We expect Henry Hub natural gas spot price to average under $3.00/MMBtu in 2024 and 2025* (January 11, 2024), available at https://www.eia.gov/todayinenergy/detail.php?id=61223.

2.1 Wholesale Cost of Electricity

The estimated wholesale cost of electricity (in billions of dollars), categorized by cost component, is shown by season in the upper panel of Figure 2-1 below.[11] The upper panel also shows the average price of natural gas price (in $/MMBtu) as energy market payments in New England tend to be correlated with the price of natural gas in the region.[12] The bottom panel in Figure 2-1 depicts the wholesale cost per megawatt hour of real-time load.

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

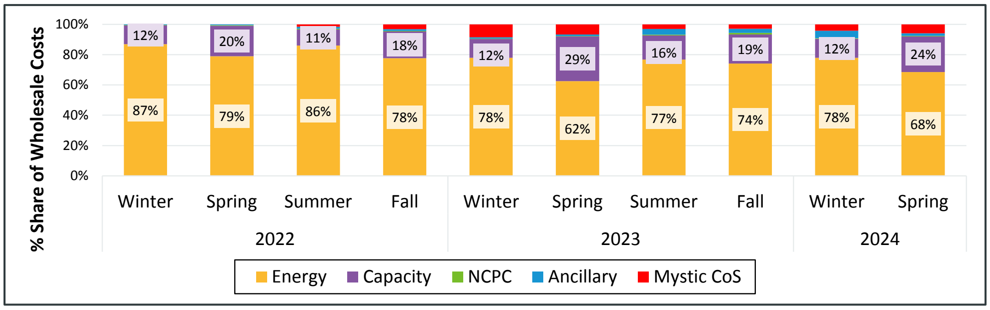


In Spring 2024, the total estimated wholesale cost of electricity was $1.10 billion (or $42/MWh of load), a 23% decrease compared to $1.44 billion in Spring 2023 and a 47% decrease compared to $2.09 billion in Winter 2024. The decrease from Spring 2023 was driven by a sharp decline in energy and capacity costs. The share of each wholesale cost component since Winter 2022 is shown in Figure 2-2 below.

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

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

Figure 2-2: Percentage Share of Wholesale Costs



Energy costs, which comprised 68% of the total wholesale cost, were $0.76 billion ($29/MWh) in Spring 2024, 16% lower than Spring 2023 costs, driven by a 29% decrease in natural gas prices. Natural gas prices continued to be a key driver of energy prices. Higher loads and a large decrease in net imports[13] (down 780 MW) partially muted the impact of lower natural gas prices on LMPs.

Capacity costs are determined by the clearing price in the primary Forward Capacity Auction (FCA). In Spring 2024, the FCA 14 clearing price resulted in capacity payments of $259 million ($10/MWh), representing 24% of total costs. The current capacity commitment period (CCP14, June 2023 – May 2024) cleared at $2.00/kW-month. This was 47% lower than the primary auction clearing price of $3.80/kW-month for the prior capacity commitment period.

Beginning in Summer 2022, the Mystic 8 and 9 generators began receiving supplemental payments per their cost-of-service agreement (Mystic CoS) with the ISO. These payments totaled $65.3 million in March and April 2024.[14] The agreement ended on May 31, 2024, when the generators retired.

At $4.6 million ($0.18/MWh), Spring 2024 Net Commitment Period Compensation (NCPC) costs represented 0.6% of total energy costs, a similar share to other quarters over the reporting period.

Ancillary service costs, which include payments for operating reserves and regulation, totaled $18.3 million ($0.70/MWh) in Spring 2024, representing 2% of total wholesale costs. Ancillary service costs increased by 11% compared to Spring 2023 costs due to higher forward reserve payments.

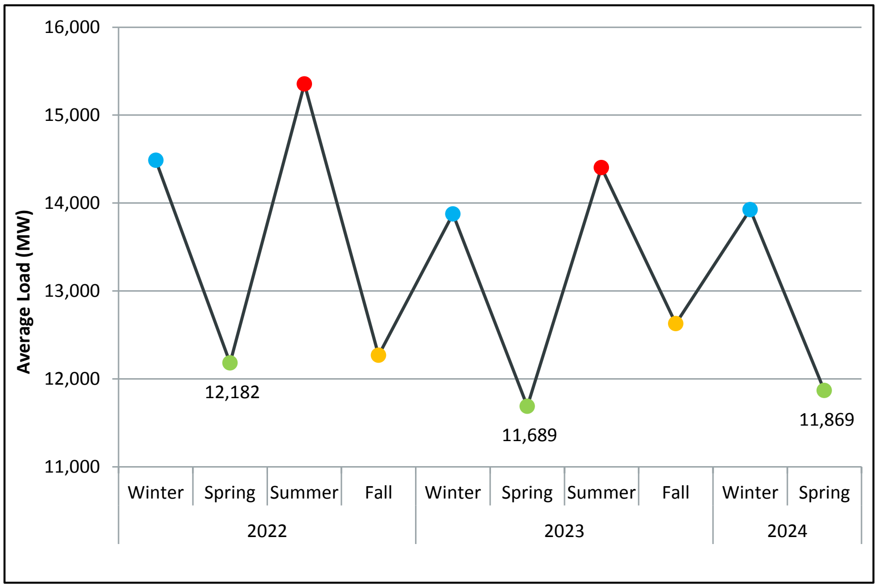
[13] See Section 2.3.2

[14] May 2024 cost-of-service payment data was not yet available at the time of this report.

2.2 Load

New England average loads typically fall in spring as heating demand falls and behind-the-meter (BTM) solar output increases.[15] Average hourly load by season is illustrated in Figure 2-3 below.

Figure 2-3: Average Hourly Load by Quarter



Spring 2024 hourly loads averaged 11,869 MW, up 2% from Spring 2023. As discussed below, this increase is largely attributable to weather differences between 2023 and 2024. Loads fell below historic average levels throughout 2023 into 2024 due to BTM solar and energy efficiency growth. Average hourly BTM solar generation increased to 739 MW in Spring 2024, up 15% from Spring 2023. While load remains low, load growth and increasing BTM solar generation are consistent with long-term load growth forecasts.[16]

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

[16] For the most recent load forecast estimates published by the ISO, see ISO System Planning's *2024 CELT Report* (May 17, 2024), available at https://www.iso-ne.com/system-planning/system-plans-studies/celt.

Load and Temperature

The stacked graph in Figure 2-4 below compares average monthly load (right axis) to the monthly total number of degree days (left axis) for the past three spring seasons.[17]

Figure 2-4: Monthly Average Load and Monthly Total Degree Days

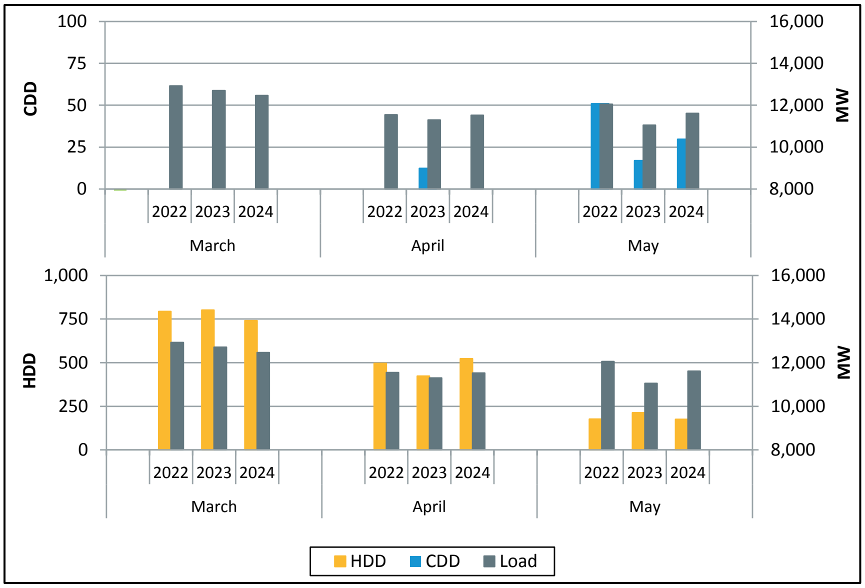


Figure 2-4 shows that much of the increase in average loads from Spring 2023 is attributable to higher May temperatures. March and April loads remained within 2% of 2023 loads, with differences being driven by weather patterns. May loads (11,608 MW) grew by 5% following hotter temperatures and increased cooling demand, with a monthly total of 30 CDDs, up 75% from 2023. With hotter temperatures leading into the summer, the ISO expects Summer 2024 load to surpass 2023, with an expected peak of 24,553 MW (up 7%).[18]

[17] Cooling degree day (CDD) measures how warm an average daily temperature is relative to 65°F and is an indicator of electricity demand for air conditioning. It is calculated as the number of degrees (°F) that each day's average temperature is above 65°F. For example, if a day's average temperature is 70°F, the CDD for that day is 5. Heating degree day (HDD) measures how cold an average daily temperature is relative to 65°F and is an indicator of electricity demand for heating. It is 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 HDD for that day is 5.

[18] For more information on the ISO's Summer 2024 expectations for the grid, see *ISO-NE outlines power grid preparedness for summer season* (June 3, 2024), available at https://isonewswire.com/2024/06/03/iso-ne-outlines-power-grid-preparedness-for-summer-season/.

Peak Load and Load Duration Curves

New England's system load over the past three spring seasons is shown as load duration curves in Figure 2-5 below with the inset graph showing the 5% of hours with the highest loads.[19]

Figure 2-5: Load Duration Curves

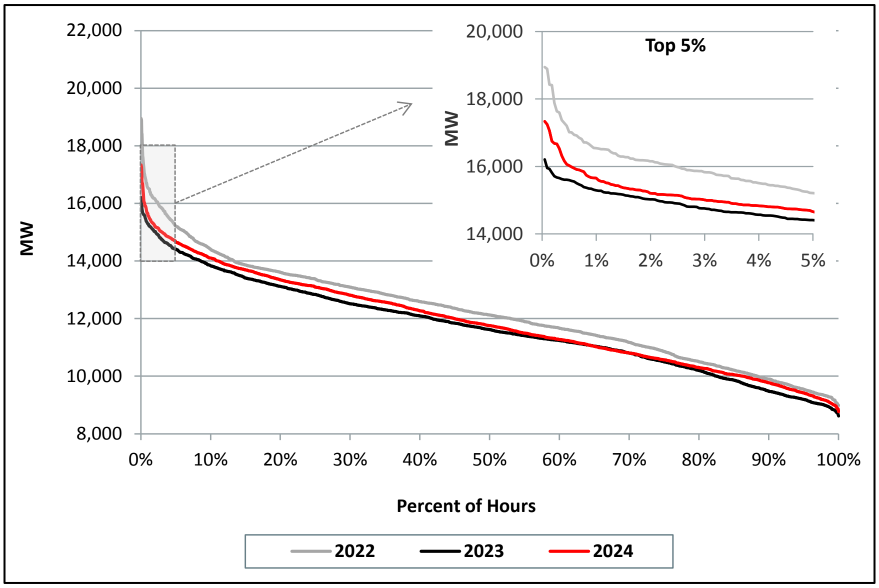


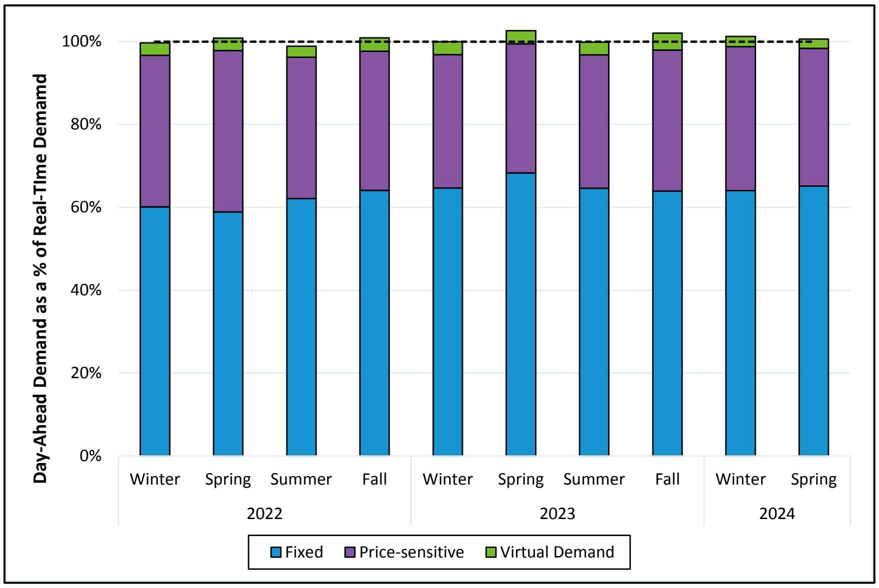
Figure 2-5 shows that loads in Spring 2024 were generally higher than in Spring 2023 and lower than in Spring 2022. Spring 2024 load peaked at 17,328 MW, up 7% from the Spring 2023 peak (16,202 MW). All hours in which Spring 2024 hourly load exceeded Spring 2023 peak load occurred in late May as temperatures increased.

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

Load Clearing in the Day-Ahead Market

The 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.[20] The day-ahead cleared demand as a percentage of real-time demand is shown in Figure 2-6 below.

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



On average, participants cleared 101% of their real-time load in the day-ahead market, down from 103% in Spring 2023. Participants cleared 65% of demand as fixed bids and 33% of demand as priced bids. Priced demand bids are typically priced well above expected LMPs, illustrating that demand is largely price-insensitive and that most priced bids are functionally similar to fixed bids. Virtual demand clearing fell to 2% of real-time load, down from 3% in 2023 as participants cleared less virtual demand at external nodes. The decline in total clearing is largely attributable to this decrease in virtual demand.[21]

[20] 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.

[21] See 3.3 for a discussion of virtual demand in Spring 2024.

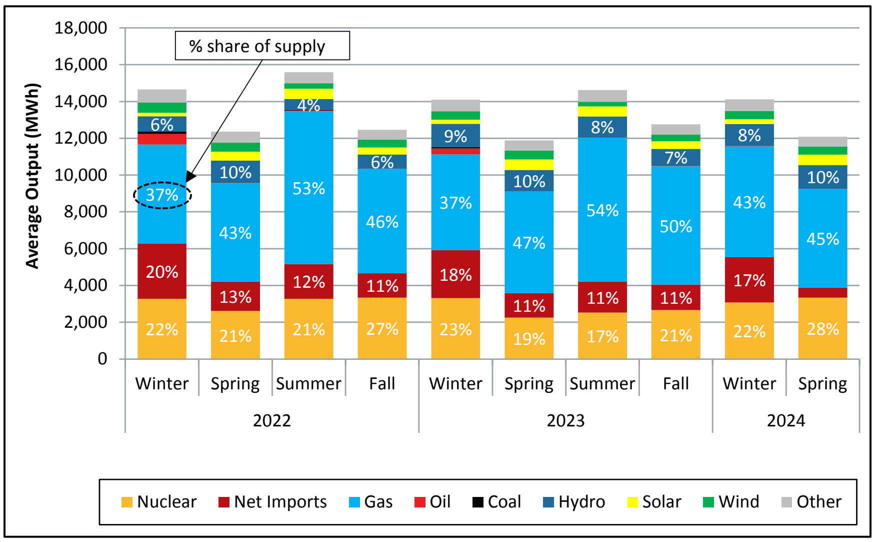
2.3 Supply

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

2.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The energy production by generator fuel type for Winter 2022 through Spring 2024 is 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 generation from that fuel type.[22]

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



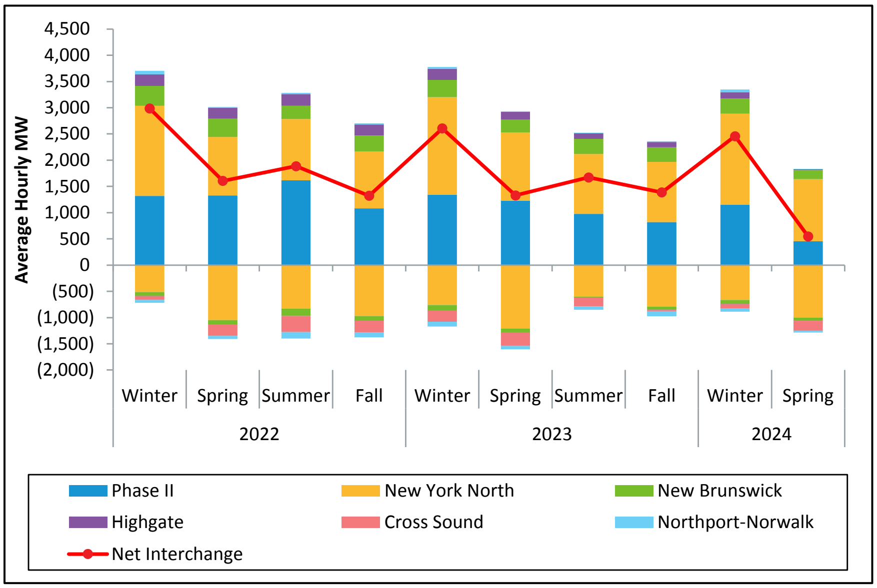
Average output in Spring 2024 (12,080 MWh) was 2% higher than in Spring 2023. One notable change from the prior spring season was a 60% (~780 MW) decrease in average net imports, which provided only 5% of the region's energy supply, on average. This was a result of reduced imports from Canada due to low hydro reservoir levels. In addition, nuclear generation provided a larger share of overall supply in Spring 2024 (28%) than in Spring 2023 (19%). Lower nuclear generation in Spring 2023 was driven by planned refueling outages; there were no notable nuclear generator outages this spring. The majority of New England's energy continued to be provided by nuclear generation, gas-fired generation, and net imports. Together, these categories accounted for 77% of total average production in Spring 2024.

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

2.3.2 Imports and Exports

On average, the net flow of energy into New England was 547 MW per hour from the neighboring control areas in Canada and New York, which was at least 59% lower than the prior nine quarters.[23] Total net interchange represented 5% of load (NEL), down from 11% in Spring 2023. The average hourly import, export, and net interchange power volumes by external interface for the last 10 seasons are shown in Figure 2-8 below.

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



Hourly net interchange decreased by 78% compared to Winter 2024. Net interchange increases during the winter when cold weather leads to a constrained natural gas system in New England. During the winter, natural gas-fired generators compete with heating demand for limited natural gas supply. This leads to upward pressure on natural gas and LMPs and incentivizes higher volumes of imports from neighboring regions. These conditions are infrequent during the spring, leading to less power delivered into New England from neighboring areas. Outages of transmission elements often increase during the spring, which further contributes to the lower volumes of net interchange compared to winter.

Compared to Spring 2023, hourly net interchange decreased by 63% year-over-year due to less imported energy across all three Canadian interfaces. At the Phase II and Highgate interfaces, which connect New England to the Hydro-Québec control area, average quarterly net interchange fell by 63% (or 769 MW) and 88% (or 130 MW), respectively. In Québec, normally abundant water resources and hydro generation provide excess electricity supply, which can be sold to neighboring control areas. However, in the past year, drier weather continued to contribute to lower reservoir

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

levels in Québec and less energy to export into New England.[24] Additionally, lower LMPs this spring reduced incentives to import power into New England. At the New Brunswick interface, net interchange averaged 109 MW per hour, a 58 MW decrease compared to Spring 2023. A nuclear generator in New Brunswick took an extended outage for the third consecutive spring, and net interchange remained below historical levels.

At the New York interfaces, New England typically imports power over the New York North interface and exports power over the two interfaces with Long Island, Cross Sound Cable and Northport-Norwalk. Collectively, New England was a net *exporter* to New York, averaging 35 MW of exports per hour, down from 211 MW in Spring 2023. At New York North, net *imports* averaged 182 MW per hour, up from 94 MW in Spring 2023. The increase in net imports was in line with the change in day-ahead LMPs at the interface. In Spring 2024, day-ahead LMPs at the proxy nodes for New York North were $0.84/MWh higher than in New England, compared to $1.14/MWh in Spring 2023. At Cross Sound Cable, net *exports* fell from 256 MW per hour to 188 MW per hour. Net exports decreased because the interface took a planned outage during Spring 2024. At Northport-Norwalk, net *exports* decreased by 20 MW per hour in Spring 2024 (29 MW per hour vs. 49 MW per hour).

[24] For more information on Québec reduction in exports, see Hydro-Québec's *Quarterly Bulletin, First Quarter 2024*, available at https://www.hydroquebec.com/data/documents-donnees/pdf/quarterly-bulletin-2024-1.pdf.

Section 3
Day-Ahead and Real-Time Markets

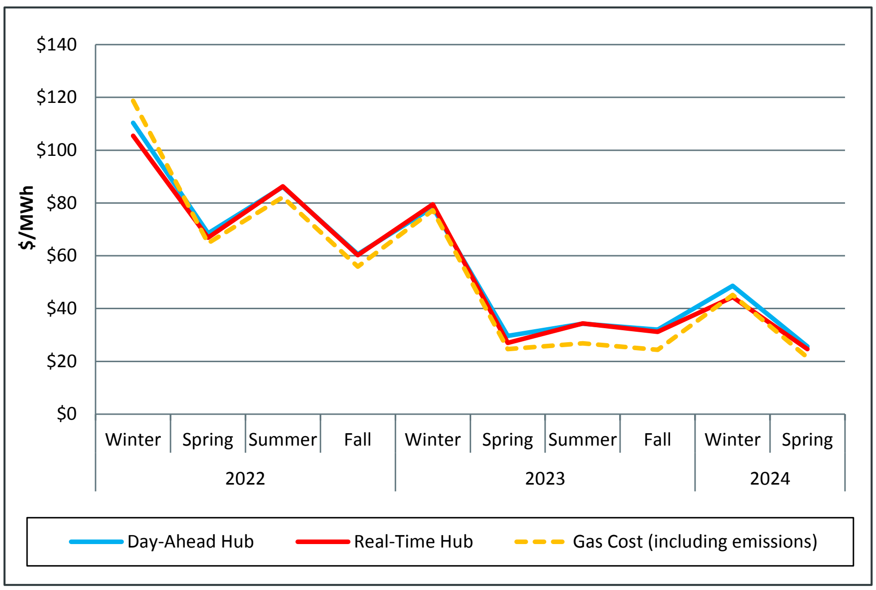
This section explores the trends and driving factors influencing market outcomes for energy, operating reserves, and regulation products.

3.1 Energy Prices

The average real-time Hub price for Spring 2024 was $24.64/MWh, slightly below the average day-ahead price of $25.66/MWh. Compared to Spring 2023, average real-time and day-ahead Hub prices decreased by 9% and 13%, respectively, driven by a 29% decrease in average natural gas prices.

Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas, are shown in Figure 3-1 below. The natural gas cost is based on the seasonal average natural gas price and a generator heat rate of 7,800 Btu/kWh and includes estimated emissions costs.[25]

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



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

Gas costs averaged $21.47/MWh in Spring 2024. Average electricity prices were about $4/MWh higher than average estimated Spring 2024 gas costs in the day-ahead market, a similar spread compared to that of Spring 2023 ($5/MWh). In Spring 2024, lower average net imports (down 780 MW) and higher average loads (up 180 MW) partially muted the impact of lower natural gas prices

[25] The average heat rate of combined cycle gas turbines in New England is estimated to be 7,800 Btu/kWh. In previous reports, the Gas Costs in this figure did not include estimated emissions costs.

on LMPs. However, there was a large increase in nuclear generation (up 1,086 MW) due to fewer planned outages in Spring 2024, which balanced out the effect of lower net imports and led to similar spreads.

Prices did not differ significantly among the load zones in either market in Spring 2024, indicating that there was relatively little transmission congestion on the system at the zonal level.

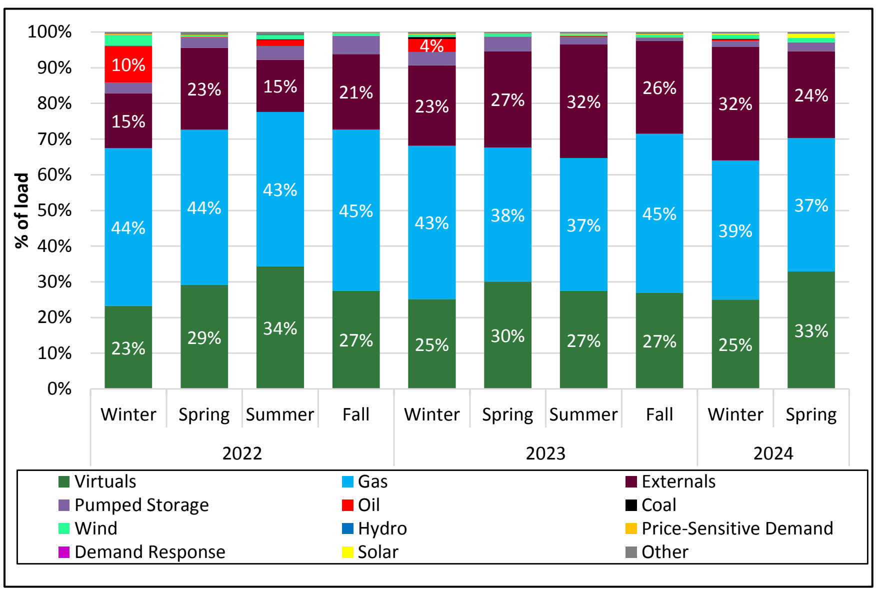
3.2 Marginal Resources and Transactions

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

Day-ahead Energy Market

The percentage of load for which each transaction type set price in the day-ahead market since Winter 2022 is illustrated in Figure 3-2 below.[26,27]

Figure 3-2: Day-Ahead Marginal Units by Transaction and Fuel Type



Gas-fired generators were the most common marginal resource type in the day-ahead market, setting price for 37% of total day-ahead load in Spring 2024. Virtual transactions and external transactions were next, setting price for 33% and 24% of load, respectively. Other resource types were collectively marginal for around 5% of load. Of note from this group, solar accounted for approximately 1%. Beginning in December 2023, solar resources with a capacity supply obligation

[26] "Other" category contains wood, biomass, black liquor, fuel cells, landfill gas, nuclear, propane, refuse, solar, and battery storage.

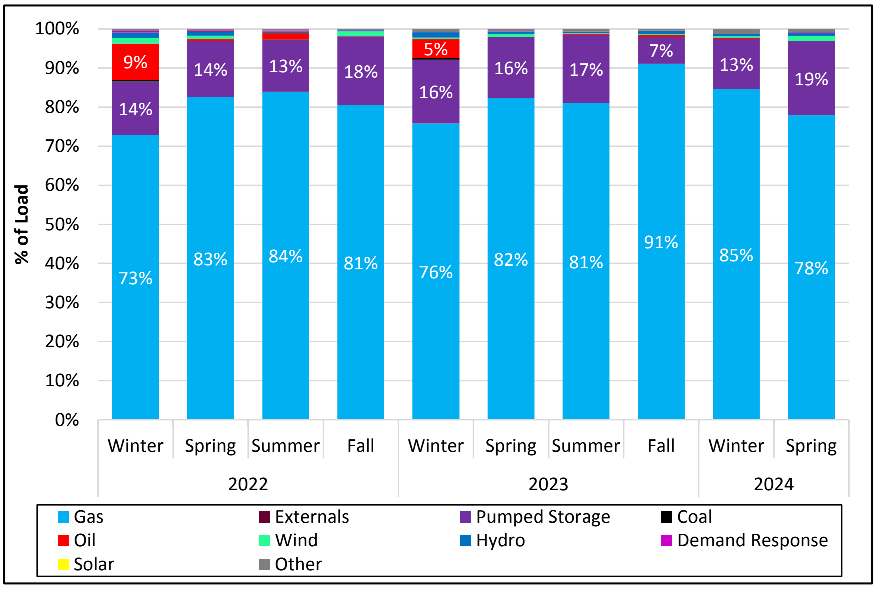
[27] Please note that some values presented in this figure changed slightly from prior reports as a result of a code change to address a data issue.

("CSO") were required to begin participating in the day-ahead market as a part of the Do Not Exceed Dispatch ("DNE") project.[28]

Real-time Energy Market

The percentage of load for which each fuel type set price in the real-time market since Winter 2022 is shown in Figure 3-3 below.

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



Similar to the day-ahead market, natural gas-fired generators set price for highest percentage of load in the real-time market in Spring 2024 (78%). Pumped-storage facilities (generation and demand) set price for 19% of load in Spring 2024. Both of these levels were comparable to the prior two spring seasons. All other resource types accounted for around 3% of load, with solar generation representing a little over 0.1%.

3.3 Virtual Transactions

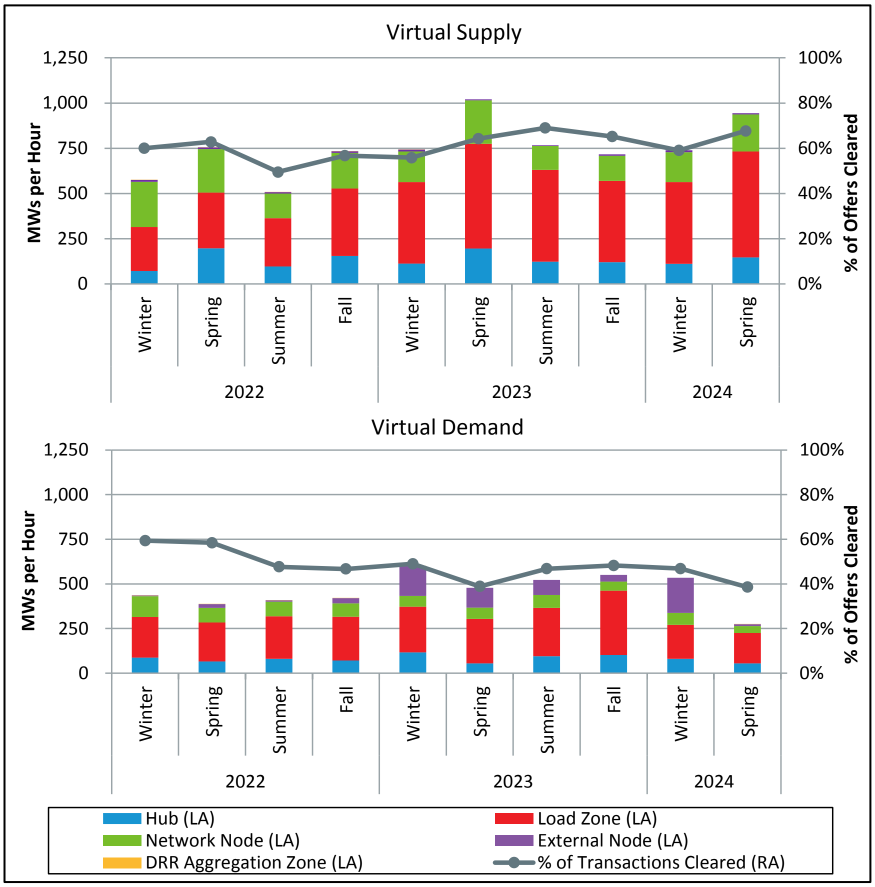
In the day-ahead energy market, participants submit virtual demand bids and virtual supply offers to profit from differences between day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence and help the day-ahead dispatch model better reflect real-time conditions.

The average volume of cleared virtual supply (top graph) and virtual demand (bottom graph) are shown on the left axis in Figure 3-4 below. Cleared transactions are categorized based on the location type where they cleared: Hub, load zone, network node, external node, and Demand

[28] For more information about the incorporation of solar generation into the DNE rules, see the ISO's filing to FERC Revisions to ISO New England Transmission, Markets and Services Tariff to Incorporate Solar Resources into DNE Dispatch Rules, Docket No. ER23- -000 (November 30, 2022), available at https://www.iso-ne.com/static-assets/documents/2022/11/extend_dne_to_solar_resources.pdf.

Response Resource (DRR) aggregation zone. The line graph (right axis) shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

Figure 3-4: Cleared Virtual Transactions by Location Type



Total cleared virtual supply averaged 944 MW per hour in Spring 2024, down 8% from Spring 2023 (1,021 MW per hour). Two notable factors behind the levels of cleared virtual supply are: 1) the growing amount of solar settlement-only generation (SOG) and 2) the day-ahead bidding behavior of wind generation.[29] By the end of Spring 2024, the installed capacity of solar SOGs was over 2,200 MW. Since SOGs cannot participate in the day-ahead market, participants often clear virtual supply on days when solar generation is expected to be high and impactful on real-time prices. Participants also frequently use virtual supply to try to capture differences between day-ahead and real-time prices in export-constrained areas, particularly areas with wind generators. Typically, these generators offer high-priced energy in the day-ahead market, but produce energy at low, or even negative, prices in the real-time market.[30]

[29] Beginning in December 2023, the Do-Not-Exceed (DNE) Dispatch Project expanded to include intermittent solar generators, allowing them to set price in the real-time market. Like wind generators, utility-scale solar generation offers high prices in the day-ahead market, but typically offers low prices in the real-time market. This bidding behavior allows for virtual supply traders to profit from the difference between the higher day-ahead LMPs and lower real-time LMPs.

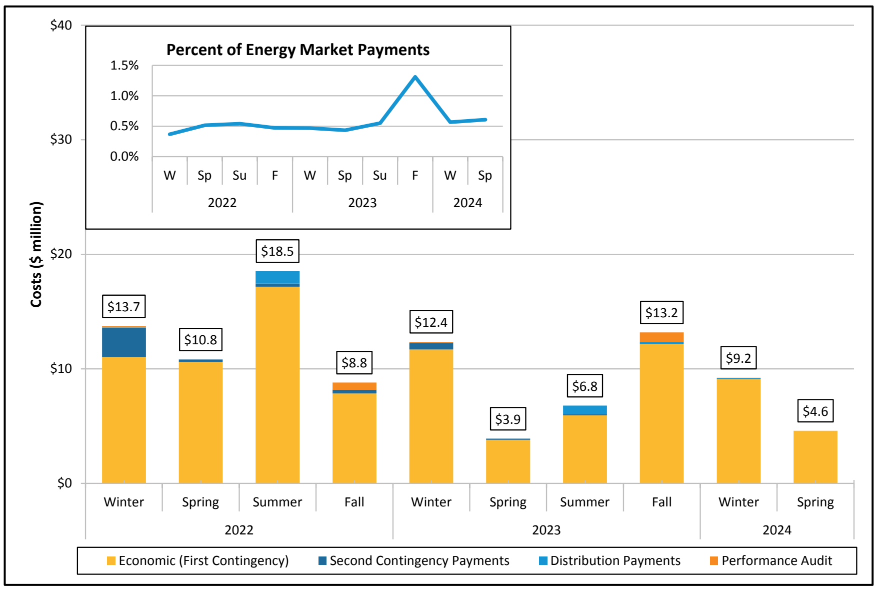
[30] In Spring 2024, wind generation averaged 185 MW per hour in the day-ahead market, while real-time wind generation averaged 433 MW hour.

Cleared virtual demand averaged 274 MW per hour in Spring 2024, down 43% from Spring 2023 (477 MW per hour). In Spring 2024, participants cleared an average of 10 MW per hour at external nodes, which was down from 110 MW per hour in Spring 2023. Most of the decrease occurred at the Highgate interface, which connects New England to the Hydro-Québec control area. At Highgate, average cleared virtual demand dropped from 85 MW per hour in Spring 2023 to less than 1 MW per hour in Spring 2024.

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.[31] Figure 3-5 below shows quarterly NCPC by category and season for 2022-2024. The inset chart shows NCPC as a percentage of energy market payments.

Figure 3-5: NCPC by Category

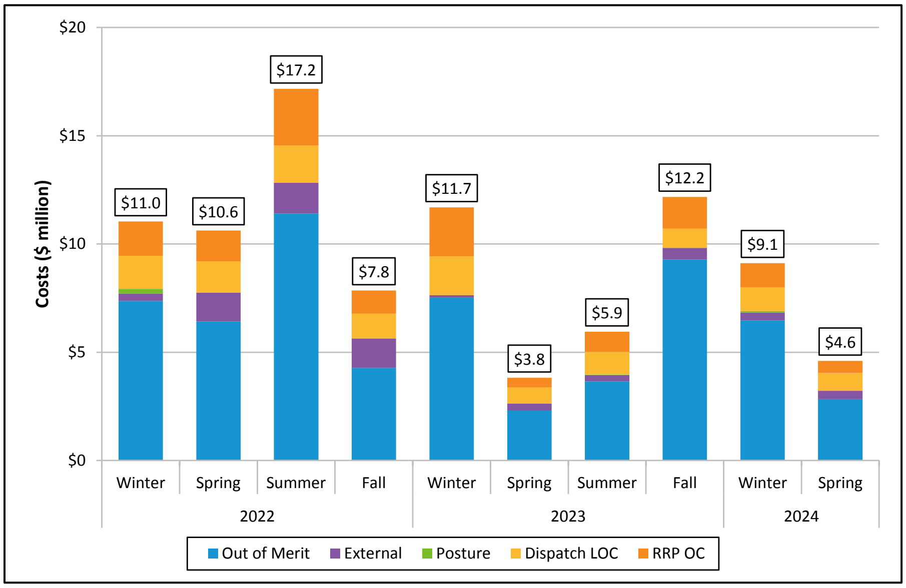


Spring 2024 NCPC payments totaled $4.6 million, up $0.7 million from Spring 2023. The increase in NCPC relative to 2023 is attributable to an increase in economic first contingency payments, which comprised all uplift payments throughout Spring 2024. As discussed below, Spring 2024 economic uplift was primarily driven by payments to real-time fast-start generators, particularly flexible pumped-storage units. The absence of second contingency and distribution or voltage payments illustrate that no uneconomic reliability commitments occurred during the season. While NCPC payments fell 50% from Winter 2024, uplift stayed constant as a share of energy market payments (0.6%).

[31] 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).

Economic uplift includes payments made to resources providing first-contingency protection as well as resources that incur opportunity costs by operating at an ISO-instructed dispatch point below their economic dispatch point (EDP). Figure 3-6 below shows economic payments by sub-category.

Figure 3-6: Economic NCPC by Reason



Out of merit payments to generators that did not fully recover their commitment costs in the energy market comprised the largest share (62%) of Spring 2024 NCPC. Day-ahead generators require out of merit payments when their incremental energy costs are close to LMPs and they do not earn sufficient revenue to cover their commitment costs. In real-time, fast-start resources might similarly fail to recover their commitment costs when their costs up to their economic minimum limit (EcoMin) are not fully covered by LMPs.[32] Real-time fast-start NCPC was the primary driver of out of merit uplift in Spring 2024, with significant payments to pumped-storage and other fast-start units in periods where LMPs fell while the units remained online. External NCPC payments totaled $0.4 million, driven by forecast error at external nodes in real-time and transfers among market participants for congestion-relieving transactions in the day-ahead market. Dispatch and rapid-response pricing opportunity cost payments together totaled $1.4 million or 30% of total economic uplift, similar to Spring 2023. There were no posturing actions or resulting uplift throughout the quarter.

[32] Fast-start pricing mechanics reduce NCPC payments to fast-start generators through including their commitment costs alongside their incremental energy costs in the supply stack and allowing fast-start units to set price more frequently by relaxing their EcoMin to 0 in the pricing run. While fast-start generators still receive out of merit NCPC, total uplift is reduced as a result of fast-start pricing mechanics. For a detailed analysis on the effects of fast-start pricing, see the IMM's *2023 Annual Markets Report* (May 24, 2024), available at https://www.iso-ne.com/static-assets/documents/100011/2023-annual-markets-report.pdf.

3.5 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.[33] Resources providing reserves during these periods receive real-time reserve payments.

Real-time Reserve Pricing

The frequency of system-level non-zero reserve pricing for each product, along with the average price during these intervals, for the past three winter seasons is provided in Table 3-1 below.[34]

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

Product	Spring 2024		Spring 2023		Spring 2022	
	Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	$6.98	173.5	$9.16	148.8	$16.98	405.8
TMNSR	$29.90	0.3	$84.76	1.8	$290.32	3.0
TMOR	$0.00	0	$0.00	0	$193.40	1.9

The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 174 hours during Spring 2024. This is 25 more hours than in Spring 2023 and 232 fewer hours than in Spring 2022. The decline in the most recent two spring seasons is attributable to a reduction in the TMSR requirement, relative to the requirement in effect in Spring 2022.[35]

TMNSR prices were non-zero in only 0.3 hours during Spring 2024, and there were no instances of non-zero TMOR pricing during this period. These pricing outcomes reflect the ample supply of total 10-minute and 30-minute reserves that were available to the system during this season.

[33] 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.

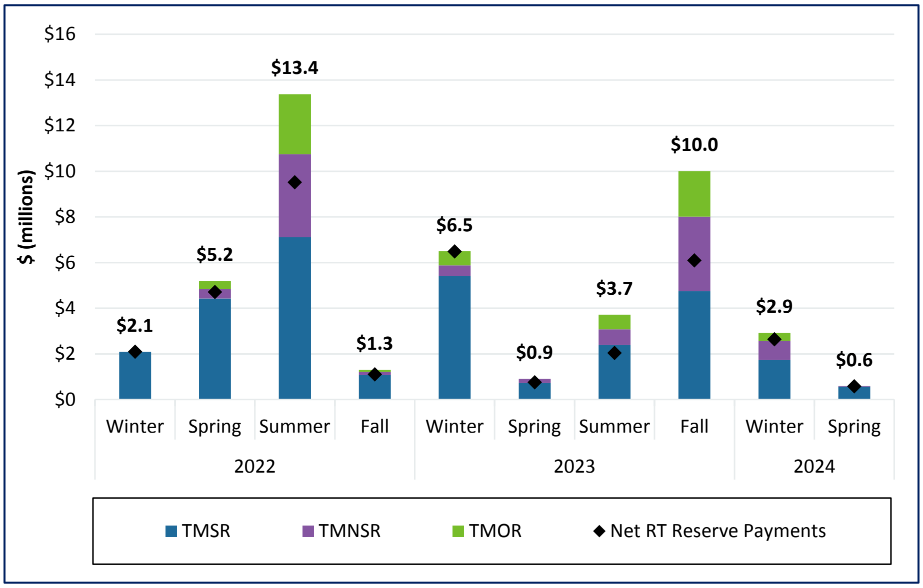
[34] The zonal thirty-minute reserve requirements did not bind in any of these spring seasons. As a result, real-time reserve prices in reserve zones were equal to those at the system level.

[35] This change reduced the percentage of the ten-minute reserve requirement that must be spinning from 31% to 25% on May 31, 2022. The operational decision to change this percentage stemmed from changes to the reserve designation rules for composite resources, which provide more accurate accounting of TMSR supplied by those resources. Composite resources are those that are modeled as a single generator in the ISO's network model, but that exist in reality as multiple distinct units (such as a series of several hydroelectric dams).

Real-time Reserve Payments

Real-time reserve payments by product are illustrated in Figure 3-7 below.[36] The height of the bars indicate gross reserve payments, while the black diamonds show net payments (i.e., payments after reductions have been made to Forward Reserve Resources providing real-time reserves).[37]

Figure 3-7: Real-Time Reserve Payments by Product and Zone



Gross reserve payments in Spring 2024 were $0.6 million, of which the majority (97%) went to resources providing TMSR. These payments were down slightly from Spring 2023 ($0.9 million), and down significantly from Spring 2022 ($5.2 million) when the TMSR requirement was set at a higher level. Net real-time reserve payments in Spring 2024 were effectively equal to gross payments. This is a direct result of the infrequency of TMNSR and TMOR pricing (the two products that are procured in the Forward Reserve Market).

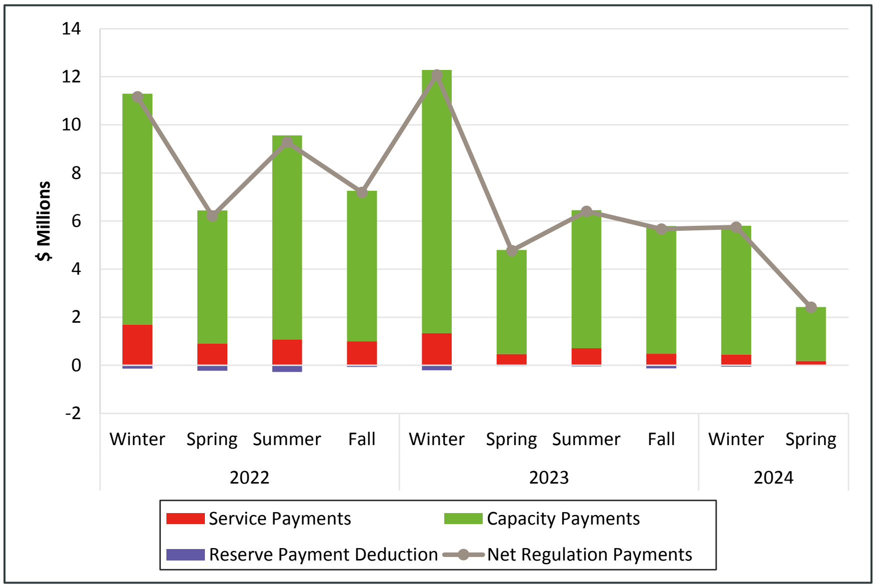
[36] The current reserve zones are: Northeastern Massachusetts/Boston (NEMA/Boston), Connecticut (CT), Southwest Connecticut (SWCT), and Rest of System (ROS).

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

3.6 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 3-8 below.

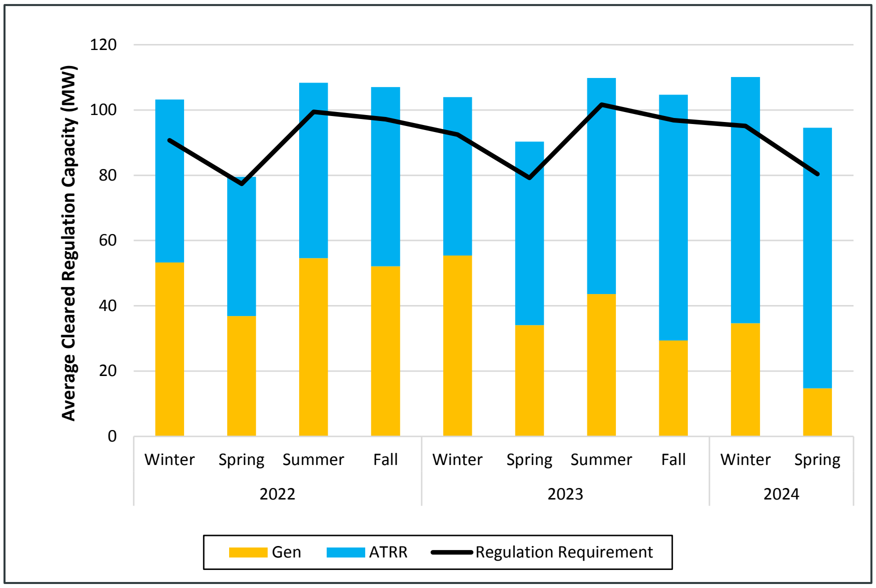
Figure 3-8: Regulation Payments



Total regulation market payments were $2.4 million during Spring 2024, down 49% from $4.8 million in Spring 2023. The decrease in payments compared to Spring 2023 resulted primarily from lower capacity prices (down 58%). Capacity prices decreased due to 1) lower energy market opportunity costs, reflecting a decline in energy market LMPs compared to the earlier period, and 2) a decline in regulation offer prices as alternative technology regulation resources continue to make up a larger share of the regulation mix. Regulation service prices also decreased (down 66%) from Spring 2023.

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 3-9 below.

Figure 3-9: Average Cleared Regulation MW by Resource Type



The resource mix of cleared regulation capacity has changed over the reporting period. In Winter 2022, ATRRs (blue shading) cleared an average of 50 MW of regulation capacity, making up 48% of total cleared regulation. In Spring 2024, ATRRs provided 80 MW or 84% of regulation. This change follows continuing increases in the installed capacity of battery resources in the region. The ATRR percentage share was particularly notable this quarter due to the smaller average regulation requirement in spring. Regulation capacity available from ATRRs increased to 215 MW on average in Spring 2024, up from 168 MW in Spring 2023. The change in resource mix also suggests that battery resources are lower-cost regulation resources, as ATRRs have increasingly displaced traditional generators in merit order for regulation market commitment.

Section 4
Energy Market Competitiveness

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

4.1 Pivotal Supplier and Residual Supply Indices

This analysis examines opportunities for participants to exercise market power in real time using two metrics: the pivotal supplier test (PST) and the residual supply index (RSI).[38]

When a participant's available supply exceeds the supply margin[39], they are considered pivotal.[40] 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 2022	106.5	12%
Spring 2022	106.7	19%
Summer 2022	102.6	34%
Fall 2022	104.0	28%
Winter 2023	105.2	20%
Spring 2023	107.7	22%
Summer 2023	103.8	34%
Fall 2023	98.9	60%
Winter 2024	101.7	45%
Spring 2024	105.5	29%

[38] 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.

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

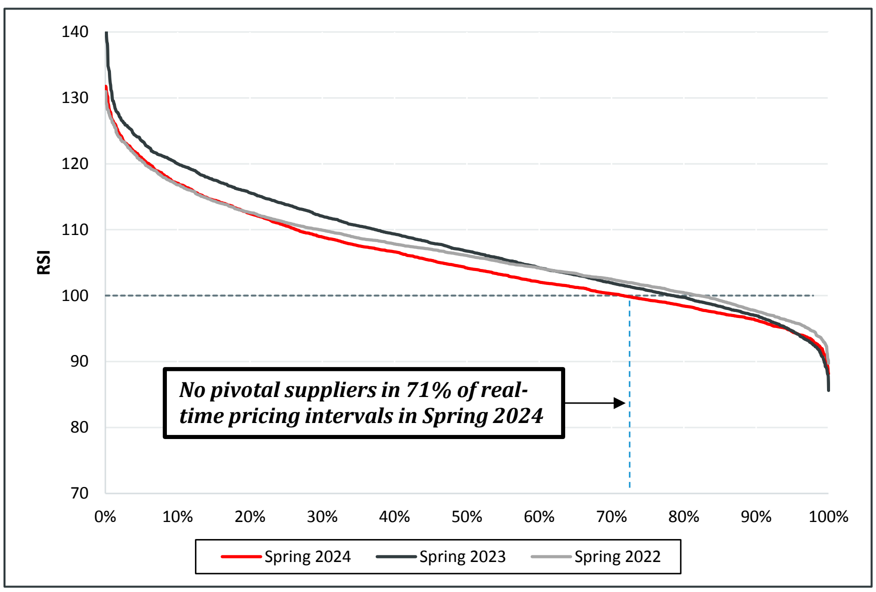
[40] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

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

There was at least one pivotal supplier in 29% of real-time pricing intervals in Spring 2024, which was higher than that of the previous two springs (22% and 19%), but lower than that of Fall 2023 and Winter 2024 (60% and 45%). The year-over-year increase was due to lower total 30-minute reserve margins, which decreased by an average of 247 MW compared to Spring 2023. When reserve margins are lower, it is more likely that the largest supplier is needed to meet load and the reserve requirement. The lower reserve margins primarily resulted from fast-start generator retirements and additional pumped-storage generator outages relative to Spring 2023. The increase in pivotal suppliers this spring relative to Spring 2022 was due to an increase in supply from the largest participant (up 740 MW) due to fewer generator outages for that participant.

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

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



In Spring 2024, the RSI was lower than in the previous two springs across most ranked observations due to the lower reserve margins compared to Spring 2023 and the increase in supply from a large participant relative to Spring 2022 discussed above.

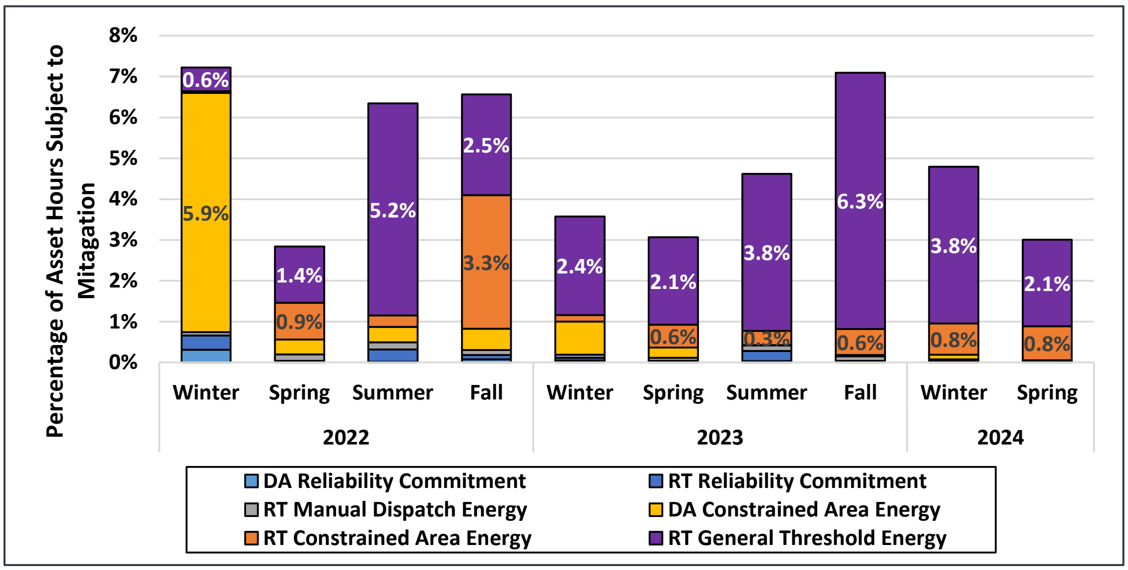
4.2 Energy Market Supply Offer Mitigation

The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power. As in earlier periods, the mitigation of energy market supply offers occurred infrequently in Spring 2024.

Energy Market Mitigation Frequency

A structural test failure serves as the first indicator of potential market power in our energy markets. The percentage of commitment asset hours with a structural test failure from Winter 2022 to Spring 2024 is shown below in Figure 4-2.[41]

Figure 4-2: Energy Market Mitigation Structural Test Failures



In Spring 2024, the total asset hours subject to mitigation reached 437,000 asset hours, in which approximately 13,000 asset hours (3%) failed structural tests.[42] The structural test for general threshold energy mitigation fails the most often and is triggered when a committed generator is owned by a pivotal supplier. Overall, asset hours of structural test failures represent a very small fraction of potential asset hours subject to mitigation and, consequently, lead to an even smaller fraction of asset hours mitigated.

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

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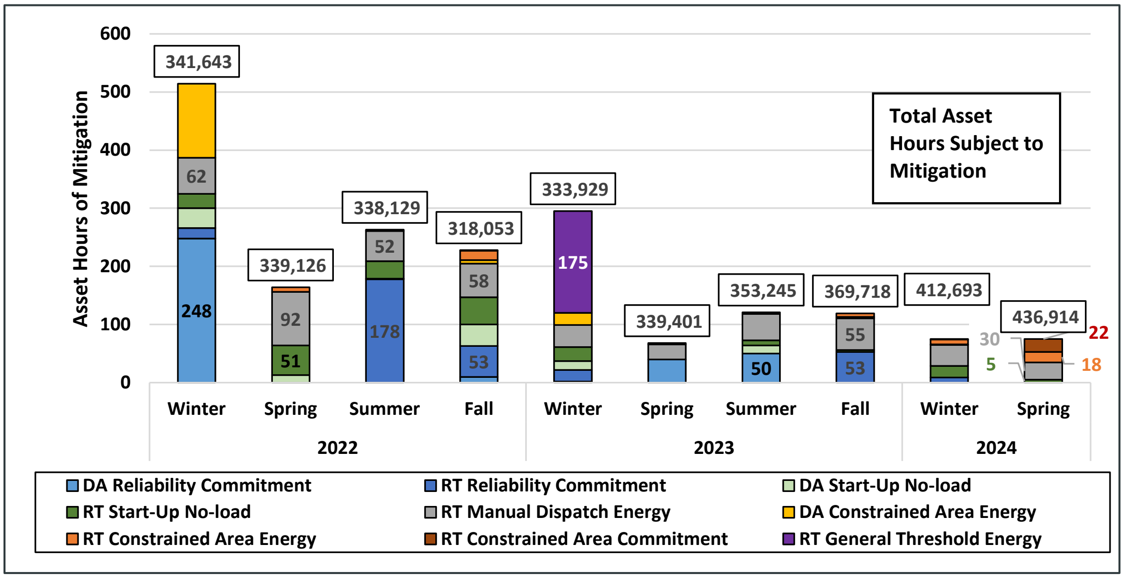
41 A structural test failure depends on the type of mitigation analyzed. For the definitions of the structural test applied in general threshold and constrained area mitigation, see *Section III Market Rule 1 Appendix A Market Monitoring, Reporting and Market Power Mitigation*, Section III.A.5.2, available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

42 The asset hours subject to mitigation are estimated as a committed generator with an economic dispatchable range at or above its economic minimum (eco min). Each such on-line generator during a clock hour represents one asset hour of generation potentially subject to energy market mitigation.

Figure 4-3: Energy Market Mitigation Asset Hours



There was a total of 75 mitigation asset hours in Spring 2024, which was similar to the Spring 2023 value of 68 asset hours. Real-time manual dispatch energy (MDE) mitigation occurred the most frequently in Spring 2024 with 30 asset hours of mitigation. The conduct test threshold for MDE mitigation is relatively tight, only allowing offers of resources being manually dispatched by the ISO to be 10% higher than reference levels.[43]

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs, and are generally due to routine transmission line outages, outages facilitating upgrade projects, or localized distribution system support.[44] There were no reliability commitments in Spring 2024, a decrease from 40 asset hours in Spring 2023. The absence of reliability commitments this spring reflected mild system conditions and fewer impactful transmission outages.

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.[45] SUNL mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate – particularly natural gas. In Spring 2024, only one participant was associated with the five asset hours of SUNL commitment mitigation.

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

[44] 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.

[45] 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).

Constrained area (CAE/CACM) mitigation: The frequency of transmission-constrained area mitigation follows the incidence of transmission congestion and import-constrained areas within New England. In Spring 2024, structural test failures totaled 3,656 asset hours spread across several load zones. With relatively tolerant conduct and market impact test thresholds, the frequency of constrained area mitigation is low relative to the frequency of structural test failures. Over the reporting period, mitigation has occurred for only 161 asset hours in the day-ahead energy market and only 83 asset hours in the real-time energy market. In Spring 2024, there were 22 asset hours of constrained area mitigation, all occurring on May 7 as a result of transmission constraints associated with planned line outages.

General threshold energy (GTE) mitigation: Despite having the highest frequency of structural test failures, general threshold energy mitigation occurs the least frequently of all mitigation types. Across the reporting period, an average of roughly 10,900 asset hours of pivotal supplier energy were subject to mitigation each quarter; mitigation has occurred for only 175 asset hours, all in Winter 2023. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators, with five participants accounting for 86% of the structural test failures over the reporting period.

Manual dispatch energy (MDE) mitigation: The ISO will utilize manual dispatch points for flexible resources to address short-term issues on the transmission grid. As a result, gas- or dual fuel-fired generators receive manual dispatches most often, accounting for 88% of the 216 asset hours of manual dispatch in Spring 2024. Due to a relatively tight conduct test, manual dispatch energy mitigation occurs more often than any other mitigation type, totaling 30 asset hours in Spring 2024.

Section 5
Forward Markets

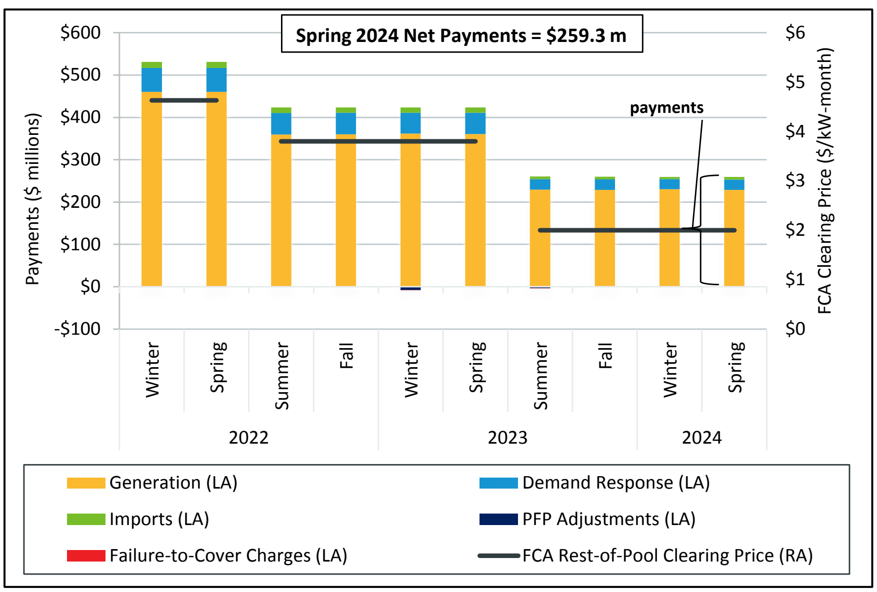
This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs), and in the Summer 2023 Forward Reserve Auction.

5.1 Forward Capacity Market

The capacity commitment period (CCP) associated with Spring 2024 started on June 1, 2023 and will end on May 31, 2024. The corresponding Forward Capacity Auction (FCA 14) resulted in a lower clearing price than the previous auction and obtained sufficient resources needed to meet forecasted demand. The auction procured 33,956 megawatts (MW) of capacity, which exceeded the 32,490 MW Net Installed Capacity Requirement (Net ICR). Mystic 8 and 9 (~1,400 MW total) remained in FCA 14 due to a cost-of-service agreement with the ISO for winter fuel security.[46]

Total FCM payments, as well as the clearing prices for Winter 2022 through Spring 2024, are shown in Figure 5-1 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, light blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The dark blue bar represents Pay-for-Performance adjustments, while the red bar represents Failure-to-Cover charges.

Figure 5-1: Capacity Market Payments



[46] Between June 2022 and May 2024, Mystic 8 and 9 received supplemental payments per their cost-of-service agreement with the ISO. The two Mystic generators received a total of $755 million in cost-of-service payments through March 2024, with charges for April-May 2024 yet to be settled. Following the expiration of the cost-of-service agreement, both Mystic units retired on June 1, 2024.

In Spring 2024, capacity payments totaled $259.2 million. Total payments were down 39% from Spring 2023 ($423.3 million), driven by a 47% decrease in the clearing price from FCA 13 ($3.80/kW-month) to FCA 14 ($2.00/kW-month). The $2.00/kW-month clearing price was applied to all capacity zones and interfaces within New England. The results of FCA 14 led to an estimated annual cost of $0.9 billion in capacity payments, $0.7 billion lower than capacity payments incurred in FCA 13. Failure-to-Cover (FTC) charges totaled approximately $159 thousand in Spring 2024.[47]

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

Table 5-1: Primary and Secondary Market Outcomes

					Capacity Zone/Interface Prices ($/kW-mo)		
FCA # (Commitment Period)	**Auction Type**	**Period**	**Systemwide Price ($/kW-mo)***	**Cleared MW****	**Maine**	**Northern New England**	**Southeastern New England**
FCA 14 (2023 - 2024)	Primary	12-month	2.00	33,956			
	Monthly Reconfiguration	May-24	0.80	729			
	Monthly Bilateral	May-24	1.52	110			
FCA 15 (2024-2025)	Primary	12-month	2.61	34,621	2.48	2.48	3.98
	Annual Reconfiguration (3)	12-month	2.00	221, -512			2.01
	Monthly Reconfiguration	Jun-24	1.00	358			5.00
	Monthly Bilateral	Jun-24	2.29	47			
	Monthly Reconfiguration	Jul-24	2.48	415			8.00
	Monthly Bilateral	Jul-24	3.91	91			

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

The third annual reconfiguration auction (ARA 3) for CCP 2024-2025 occurred in Spring 2024. The auction cleared at $2.00/kW-month, below the corresponding FCA 15 clearing price of $2.61/kW-month. The Net ICR for ARA 3 was reduced to 31,380 MW, down from 33,270 MW in the forward capacity auction.[48] Following the reduction in Net ICR, 221 MW of supply cleared the auction while 512 MW of demand bids shed their capacity supply obligations. Clearing prices separated within the import-constrained Southeastern New England (SENE) capacity zone, rising slightly to $2.01/kW-month.

Three monthly reconfiguration auctions (MRAs) took place in Spring 2024. The May 2024 auction was the final MRA corresponding to the 2023-2024 CCP, and cleared at $0.80/kW-month, 60% below the FCA 14 clearing price. The June 2024 and July 2024 auctions both correspond to the

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[47] FTC charges are negative adjustments to FCM credits applied when resources have not demonstrated the ability to cover their CSO. Pay for performance (PFP) adjustments occur when capacity market payments are transferred to assets or imports that do not have CSOs during a PFP event.

[48] The Net ICR is recalculated with the most up-to-date data for each annual reconfiguration auction leading up to the start of the capacity commitment period. All historical Net ICR values can be found in the *ISO New England Forward Capacity Market - Summary of ICR and Related Values* spreadsheet, available at https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx

2024-2025 capacity commitment period. The June 2024 MRA cleared 358 MW of supply offers and demand bids at $1.00/kW-month in the rest-of-pool capacity zone. The July 2024 MRA cleared 415 MW at $2.48/kW-month, slightly below the FCA 15 clearing price. In both MRAs, significant price separation occurred in the Southeast New England (SENE) capacity zone, at $5.00/kW-month in June and $8.00/kW-month in July. This price separation was primarily driven by limited supply offers and strong demand-side participation, with demand bids reflecting a high willingness to pay for buying back capacity in the SENE capacity zone.

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.

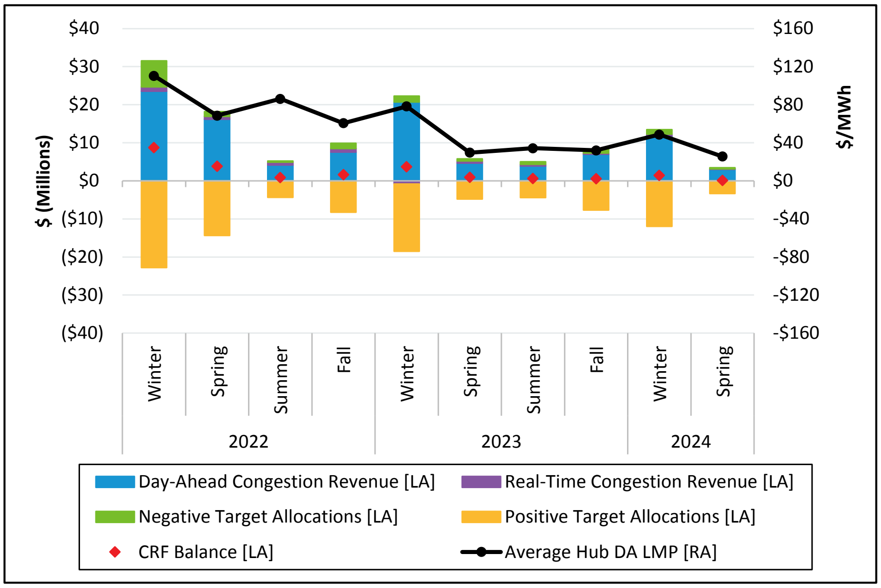
Figure 5-2 below shows, by quarter, the amount of congestion revenue from the day-ahead and real-time energy markets, the amount of positive and negative target allocations, and the congestion revenue fund (CRF) balance.[49,50] This figure also depicts the quarterly average day-ahead Hub LMP.[51]

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

[50] 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.

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

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



Most congestion-related totals in Spring 2024 moved in line with the day-ahead energy price. Day-ahead congestion revenue amounted to $3.0 million in Spring 2024. This represents a 74% decrease relative to Winter 2024 ($11.8 million) and a 36% decrease relative to Spring 2023 ($4.7 million). Positive target allocations in Spring 2024 ($3.4 million) followed a similar pattern, decreasing by 72% relative to Winter 2024 ($12.0 million) and decreasing by 30% relative to Spring 2023 ($4.8 million). Negative target allocations in Spring 2024 ($0.3 million) decreased by 70% from their Winter 2024 level ($1.1 million) and decreased by 40% from their Spring 2023 level ($0.6 million). Meanwhile, real-time congestion revenue in Spring 2024 ($0.1 million) remained relatively modest.

FTRs were fully funded in March 2024 and April 2024, but were not in May 2024.[52,53]
In May 2024 only 81.7% of positive target allocations were funded ($1.4 million of the $1.7 million due). Much of the underfunding in May 2024 was the result of congestion in the day-ahead market at the Orrington-South ("ORR-SO") constraint in Maine. The limit for this interface was reduced at times in May, most notably at the end of the month, as a result of generation and transmission outages.

However, any excess congestion revenue collected during the year is allocated to unpaid positive target allocations at the end of the year, to the extent possible. At the end of May 2024, the congestion revenue fund had a surplus of $1.6 million for the year.

[52] FTRs are said to be "fully funded" when sufficient revenue is collected from the energy market and from FTR holders with negative target allocations to pay FTR holders with positive target allocations all the revenue to which they are entitled.

[53] For more information about the monthly FTR settlement, see the *2024 FTR Monthly Summary*, available at https://www.iso-ne.com/static-assets/documents/100008/2024-monthly-summary.pdf.

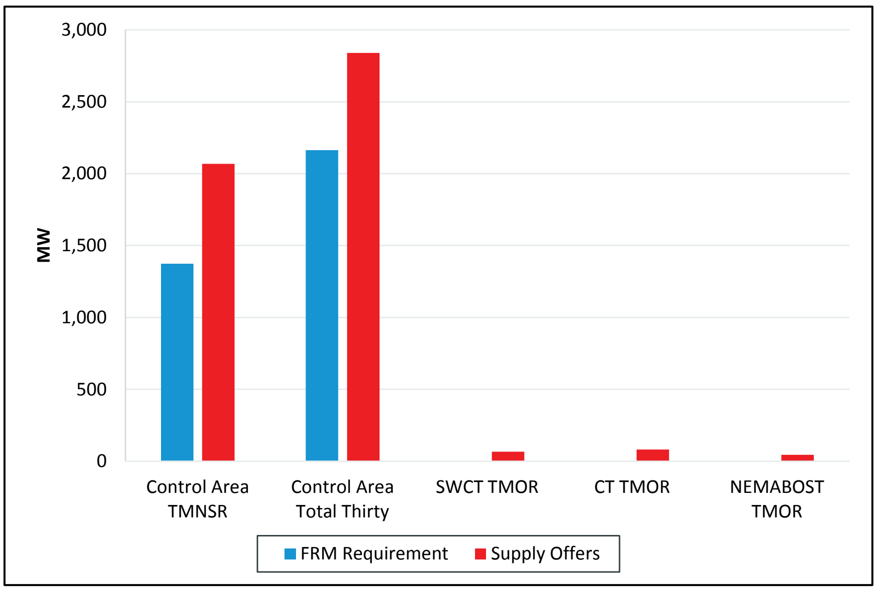
5.3 Forward Reserve Market

During April 2024, the ISO held the forward reserve auction for the Summer 2024 delivery period (i.e., June 1, 2024 to September 30, 2024). The Summer 2024 auction is the last Forward Reserve Market auction for the summer delivery period that the ISO will conduct as the market will sunset with the implementation of the Day-Ahead Ancillary Services Initiative ("DASI") in March 2025.[54] In this section, we review the results of the Summer 2024 auction.

5.3.1 Auction Reserve Requirements and Offered Supply

Offered supply was adequate to satisfy the reserve requirements for the Summer 2024 auction. This can be seen in Figure 5-3 below, which shows the ISO New England control area and local reserve zones requirements as well as the total quantity of supply offers in the auction available to satisfy these reserve needs.[55, 56,57]

Figure 5-3: Forward Reserve Requirements and Supply Offer Quantities



[54] More information about DASI can be found on the ISO's *Day-Ahead Ancillary Services Initiative (DASI)* page, available at https://www.iso-ne.com/participate/support/participant-readiness-outlook/day-ahead-ancillary-services-initiative.

[55] The local reserve zones are Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston (NEMABOST).

[56] The total thirty-minute requirement referred to here is the sum of the ten-minute non-spinning reserve ("TMNSR") and thirty-minute operating reserve ("TMOR") requirements for the control area. This is indicated in the ISO New England Memorandum to Market Participants *Assumptions and Other Information for the Summer 2024 Forward Reserve Auction*, (March 18, 2024), available at https://www.iso-ne.com/static-assets/documents/100009/forward_reserve_auction_assumptions_summer_2024.pdf.

[57] Because TMOR supply offers within local reserve zones also provide TMOR to the system, the control area TMOR offers shown in the figure include the local reserve zone supply offers. Hence, the control area TMOR offers represent the total offers throughout the system. A similar adjustment has been made to the Connecticut TMOR supply offers; the SWCT zone is nested within the Connecticut zone, and SWCT offers can contribute to the Connecticut TMOR supply. Given this, SWCT TMOR supply offers are also included in the CT TMOR total. Finally, because TMNSR supply can contribute to TMOR supply, all TMOR totals in the graph show TMNSR in addition to TMOR supply.

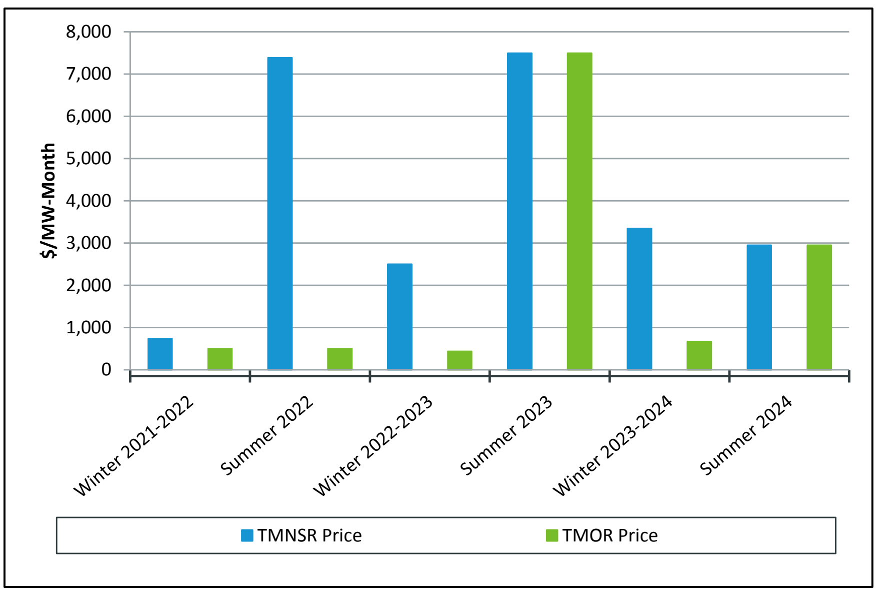
The Summer 2024 auction had sufficient offered supply to meet both TMNSR and total thirty-minute reserve requirements for the control area. The ISO bases these requirements on possible system contingencies.[58] The TMNSR requirement was based on the expected single contingency of the Hydro-Québec Phase II Interconnection ("Phase II"). This requirement was 1,374 MW for the Summer 2024 auction. Total offered supply that could meet the TMNSR requirement amounted to approximately 2,069 MW. The control area TMOR requirement was based on the expected single contingency of the Seabrook nuclear generator. This requirement was 790 MW for the Summer 2024 auction. Consequently, the total thirty-minute requirement was 2,164 MW (1,374 MW + 790 MW). The total offered supply that could meet the total thirty-minute requirement amounted to approximately 2,840 MW.

All local reserve zones, which only have a TMOR requirement, were found to have no reserve need.[59]

5.3.2 Auction Results

Clearing prices for the TMNSR and TMOR products in the Summer 2024 auction were substantially lower than the prices for the prior summer auction. This can be seen in Figure 5-4 below, which shows forward reserve clearing prices for the TMNSR and TMOR products for the previous six auctions.

Figure 5-4: FRM Clearing Prices for TMNSR and TMOR



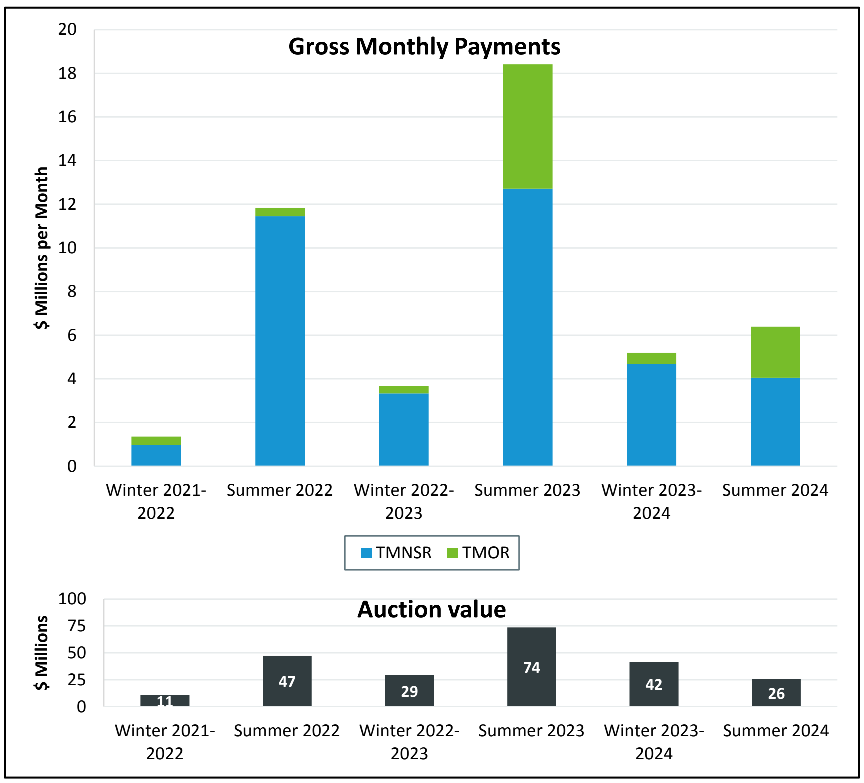
[58] The final requirement may reflect ISO adjustments, such as biasing the requirement, increasing a requirement to reflect historical resource non-performance, and adjusting the TMOR requirement to reflect the replacement reserve requirement. For more information about system forward reserve requirements, see *Section III Market Rule 1 Standard Market Design*, Section III.9.2.1, available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

[59] For a more detailed indication of the determination of local reserve requirements, see the *ISO New England Manual for Forward Reserve and Real-Time Reserve Manual M-36*, Sections 2.2.3 – 2.2.5, (Effective Date: December 3, 2019), available at https://www.iso-ne.com/static-assets/documents/2020/02/manual_36_forward_reserve_and_realtime_reserve_rev23_20191203.pdf.

The clearing prices for the Summer 2024 auction were $2,952/MW-month for both TMNSR and TMOR. Both clearing prices were substantially lower than the prices for the Summer 2023 auction, which had TMNSR and TMOR prices of $7,499/MW-month. The reduction in pricing resulted primarily from a decrease in offer pricing and a reduced TMNSR requirement. The TMNSR requirement for the control area decreased from 1,696 MW in Summer 2023 to 1,374 MW in Summer 2024. For both these auctions, this requirement was based on the flows over Phase II, and the lower requirement is generally reflective of reduced flows over this interface between Summer 2022 and Summer 2023.[60] There was also a modest increase in offered TMNSR supply between Summer 2023 and Summer 2024.

The decline in forward reserve clearing prices in the Summer 2024 auction should lead to markedly lower gross monthly payments to participants. Figure 5-5 indicates the gross monthly payments (i.e., excluding penalties) available to participants with TMNSR and TMOR FRM obligations for the six most recent FRM delivery periods. The figure also depicts the auction value associated with each auction.[61]

Figure 5-5: Gross Monthly FRM Payments and Auction Value



Gross monthly payments for the Summer 2024 auction are estimated to be $6.4 million, representing a substantial decrease from the Summer 2022 and 2023 auctions.[62] The Summer 2022

[60] The control area FRM reserve requirements are based on historical data for the prior like delivery period (e.g., the TMNSR requirement for Summer 2024 was based off historical data from Summer 2023).

[61] The auction value here represents the gross monthly payments multiplied by the number of months in delivery period.

[62] The gross payments are a function of both the clearing prices and the quantities cleared for each FRM product (i.e., TMNSR and TMOR) in each auction.

auction, with elevated TMNSR prices, had gross payments of approximately $11.8 million per month, while the Summer 2023 auction, with elevated TMNSR and TMOR prices, had gross payments of approximately $18.4 million per month.

5.3.3 Auction Competitiveness

The Residual Supply Index ("RSI"), which is a measure of supply-side structural competitiveness, showed an improvement in the level of competitiveness amongst suppliers for both the TMNSR and total thirty-minute requirements.[63] Table 5-2 summarizes the RSI values for each requirement in recent auctions. It utilizes a heat map to indicate auctions that were structurally uncompetitive (i.e., red shading for RSI < 100, indicating the existence of one or more pivotal suppliers).

Table 5-2: RSI for the TMNSR and Total Thirty-Minute Requirements

Procurement Period	Offer RSI TMNSR	Offer RSI Total Thirty
Winter 2021-2022	110	116
Summer 2022	78	90
Winter 2022-2023	109	112
Summer 2023	81	86
Winter 2023-2024	82	89
Summer 2024	107	103

The Summer 2024 auction represents the first auction for a summer delivery period in the last three that was structurally competitive for both the TMNSR and total thirty-minute requirements. After RSI values of 78 and 81 for Summer 2022 and Summer 2023, respectively, the RSI for the TMNSR requirement increased to 107 in Summer 2024. While the level of offered supply that could meet the TMNSR requirement increased in Summer 2024 (to 2,069 MW from 1,810 MW in Summer 2022 and 1,903 MW in Summer 2023), a larger factor for the increased RSI was the reduction in the TMNSR requirement (to 1,374 MW from 1,564 MW in Summer 2022 and 1,696 MW in Summer 2023).

The smaller TMNSR requirement was also a factor in the improved RSI for the total thirty-minute requirement in Summer 2024. As noted above, the total thirty-minute requirement for the auction is the sum of the TMNSR and TMOR requirements for the control area. Consequently, the lower TMNSR requirement also reduced the total thirty-minute requirement in Summer 2024 (to 2,164 MW from 2,356 MW in Summer 2022 and 2,522 MW in Summer 2023). Meanwhile, the level of offered supply that could meet the total thirty-minute requirement rose in Summer 2024 (to 2,840 MW from 2,735 MW in Summer 2022 and 2,695 MW in Summer 2023).

[63] The RSI values indicate the supply that is available to meet the specific reserve requirement when the supply of the largest supplier is not available. The RSI is stated as a percent of the requirement: for example in Summer 2023, supply – after excluding the largest supplier – could meet only 81% of the TMNSR requirement. When the RSI is less than 100, it suggests that the largest supplier, and potentially other suppliers with strategic information, may be able to exercise market power in the auction. Note also that RSI values for the local reserve zones are not presented since these auctions have not had a local reserve requirement.

Given the low levels of structural competitiveness for the prior summer auctions, the IMM recommended that the ISO review and update the forward reserve supply offer cap, which is one of the only safeguards against the potential exercise of market power in this market.[64] We were pleased to see that ISO acted on this recommendation with proposed rule changes and that these changes were approved by FERC.[65]

[65] See *Order Accepting Revisions to Update the Forward Reserve Market Offer Cap*, ER24-1245-000 (April 2024), available at https://www.iso-ne.com/static-assets/documents/100010/er24-1245-000.pdf.