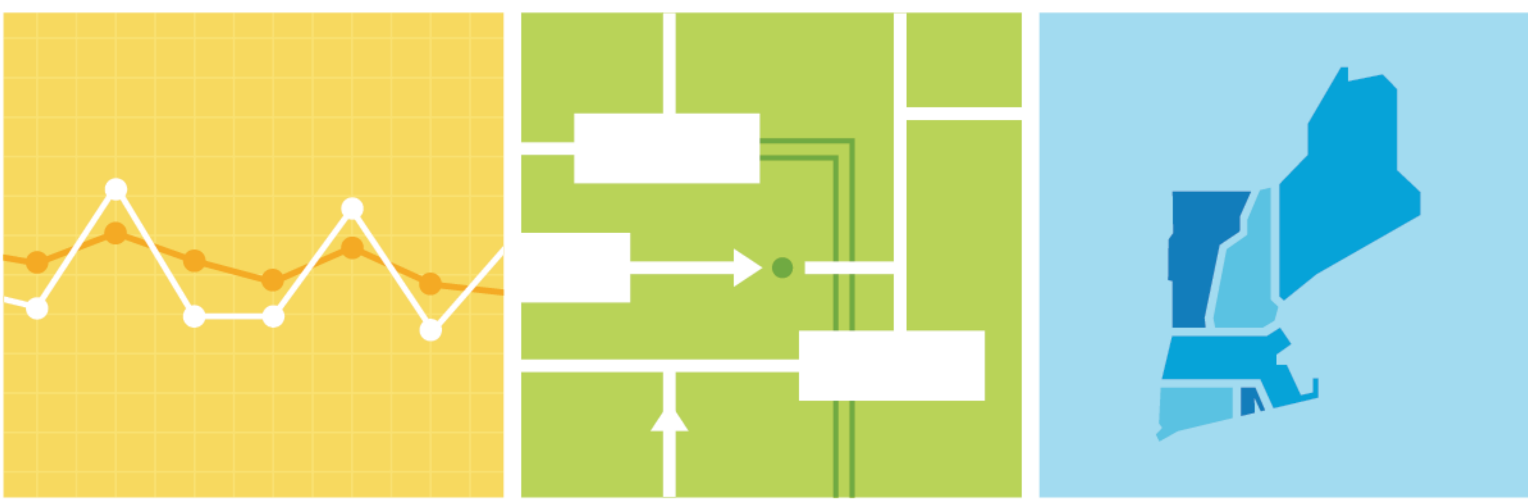
Fall 2024
Quarterly Markets Report

By ISO New England's Internal Market Monitor

FEBRUARY 5, 2025



Preface/Disclaimer

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

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

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

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

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

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

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

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Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Fall 2024 (September 1, 2024 through November 30, 2024).

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.47 billion, up 8% from $1.35 billion in Fall 2023. The increase was driven by higher energy and capacity costs.

Energy costs totaled $1.08 billion; up 8% (by $0.08 billion) from Fall 2023 costs. Though average natural gas prices decreased (down 13%), energy costs increased due to increased CO_2 emissions costs and less supply from net imports and nuclear generators.

Capacity costs totaled $359 million, up 38% (by $99 million) from last fall. Beginning in Summer 2024, higher capacity clearing prices from the fifteenth Forward Capacity Auction (FCA 15) led to higher wholesale costs relative to the previous FCA. During Fall 2023, the capacity payment rate for all new and existing resources was $2.00/kW-month. This year, the payment rate for new and existing resources increased to $2.61/kW-month due to a higher Net Installed Capacity Requirement (up by 780 MW) and a decrease in surplus capacity due to the retirement of the Mystic combined cycle generators.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $35.91 and $35.72 per megawatt hour (MWh), respectively. These were 12-14% higher than Fall 2023 prices on average.

- LMPs typically move in the same direction as natural gas prices. However, in Fall 2024, several factors contributed to higher LMPs despite a decline in gas prices:
    - There was less low-cost 'base load' energy supply due to additional planned and forced nuclear generator outages and fewer net imports compared to Fall 2023. Nuclear generation and net imports decreased by about 420 MW and 890 MW, on average.
    - The average cost of RGGI CO_2 allowances increased by about 50% from Fall 2023, increasing the average RGGI cost for a standard natural gas-fired generator from $6.56/MWh to $10.02/MWh.
- Gas prices averaged $1.95/MMBtu in Fall 2024, 13% lower than the Fall 2023 price of $2.24/MMBtu.
- Energy market prices did not differ significantly among most load zones. Prices in the Connecticut load zone saw the largest difference from the Hub on average, at 4% and 3% lower than the Hub price in the day-ahead and real-time markets, respectively.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $8.4 million, down 37% or $4.8 million compared to Fall 2023, and comprised less than 1% of total energy payments. The year-over-year decrease was due to fewer economic first contingency payments to fast-start resources, which were high in Fall 2023 due to generator outages. First contingency payments totaled $7.7 million and comprised the majority of NCPC. Within this category, External and Virtual uplift increased significantly (totaling $2.3 million) from last fall, and was driven by export congestion on the New Brunswick interface. Uplift payments for performance audits are common during shoulder seasons, and audit NCPC totaled $0.7 million in Fall 2024.

Real-time Reserves: Real-time reserve payments totaled $0.6 million, a substantial decrease from $10.0 million in Fall 2023. Fall 2024 saw reserve pricing with far less frequency and at much lower magnitude than the past two fall seasons. The TMSR constraint bound in fewer than 200 hours, with an average clearing price of $6.39/MWh. The total ten-minute reserve requirement bound for less than one hour, resulting in low TMNSR clearing prices during that short period, and the total reserve requirement did not bind at all. The system generally had an ample supply of reserves to satisfy requirements throughout Fall 2024. This stands in contrast to prior fall seasons, which had a tighter supply of reserves and more frequent and higher reserve prices.

Regulation: Regulation market payments totaled $4.3 million, down 25% from $5.7 million in Fall 2023. The decrease in payments resulted primarily from lower capacity prices (down 35%). Capacity prices decreased due to a decline in regulation offer prices, as lower cost alternative technology regulation resources increase their share of the regulation mix.

Financial Transmission Rights (FTRs): FTRs were fully funded in October and November 2024, but they were not in September 2024. In September, only 78% of positive target allocations were funded. However, at the end of November 2024, the congestion revenue fund had a surplus of $2.8 million for the year.

Real-time congestion revenue in Fall 2024 (-$0.2 million) remained relatively modest. Day-ahead congestion revenue amounted to $9.9 million, up 42% on Fall 2023. In terms of payments to and from FTR holders, positive target allocations totaled $12.0 million in Fall 2024, up 56% from Fall 2023. Negative target allocations (-$3.0 million) increased significantly from their Fall 2023 level (-$0.9 million).

Energy Market Competitiveness: The residual supply index for the real-time energy market in Fall 2024 was 105, 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 31% of five-minute pricing intervals in Fall 2024, about half of the Fall 2023 value. The decline in pivotal supplier frequencies was due to higher reserve margins that resulted from greater pumped-storage generator availability this fall.

Mitigation continued to occur very infrequently. During Fall 2024, mitigation asset-hours represented just 0.03% of total asset-hours, which was similar to the previous fall. Most mitigations (55 asset-hours) in Fall 2024 were reliability commitment mitigations that occurred in the day-ahead market for generators committed for local second contingency protection.

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	Fall 2024	Summer 2024	Fall 2024 vs Summer 2024 (% Change)	Fall 2023	Fall 2024 vs Fall 2023 (% Change)
Real-Time Load (GWh)	26,143	33,319	-22%	27,580	-5%
Peak Real-Time Load (MW)	16,934	24,888	-32%	24,054	-30%
Average Day-Ahead Hub LMP ($/MWh)	$35.91	$39.03	-8%	$32.03	12%
Average Real-Time Hub LMP ($/MWh)	$35.72	$37.45	-5%	$31.23	14%
Average Natural Gas Price ($/MMBtu)	$1.95	$1.80	8%	$2.24	-13%
Average No. 6 Oil Price ($/MMBtu)	$13.91	$14.54	-4%	$15.81	-12%
RGGI Carbon Price ($/Short Ton CO_2)	$21.97	$24.44	-10%	$14.38	53%

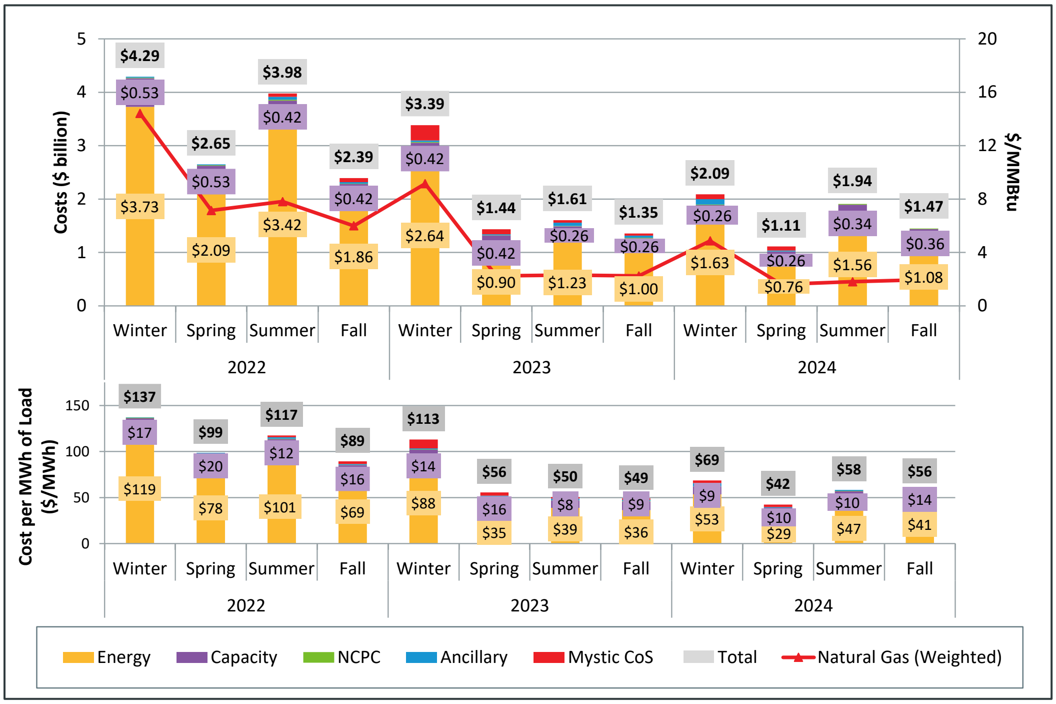
Key observations from the table above:

- Day-ahead and Real-time LMPs increased in Fall 2024 relative to Fall 2023, despite lower natural gas prices (down 13%) and lower real-time loads (down 5%).
    - One reason for the higher energy prices was reduced supply from low-cost, base load energy supply, such as nuclear generation, net imports, and hydro.
        - As a result, natural gas-fired generators were called upon to operate in more expensive and less efficient portions of their dispatchable ranges. These generators, as well as other higher-priced forms of supply, consequently set price at higher levels with greater frequency in Fall 2024.
        - See Sections 2.3.1 and 2.3.2 for further discussion.
    - Another contributor of higher energy prices was the increased costs of CO_2 emissions, which rose by over 50% in Fall 2024 relative to Fall 2023.
        - See Section 3.1 for more detail.
- Real-time loads were lower in Fall 2024 than in the prior fall season, in part due to increased irradiance which drove higher output from behind-the-meter solar generation.
    - See Sections 2.2 and 2.3.1 further discussion.

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. It also shows the average 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.[3] The bottom panel in Figure 2-1 depicts the quarterly wholesale cost per megawatt hour of real-time load for Winter 2022 through Fall 2024.

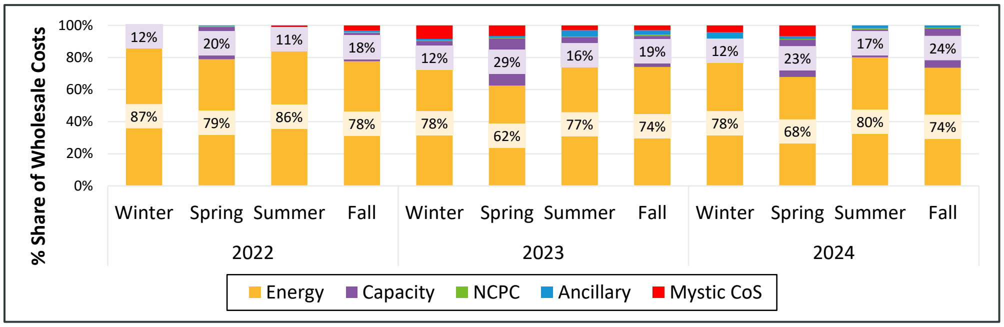
Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Season



In Fall 2024, the total estimated wholesale cost of electricity was $1.47 billion (or $56/MWh of load), an 8% increase compared to $1.35 billion in Fall 2023 and a 25% decrease compared to $1.94 billion in Summer 2024. The increase from Fall 2023 resulted from higher energy and capacity costs. The share of each wholesale cost component since Winter 2022 is shown in Figure 2-2 below.

[3] 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 Z6-200L. 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 10 on D+2.

Figure 2-2: Percentage Share of Wholesale Costs



Energy costs comprised 74% of wholesale costs and totaled $1.08 billion ($41/MWh) in Fall 2024, 8% higher than Fall 2023 costs. Though average natural gas prices decreased (down 13%), energy costs increased due to lower base load generation and increased CO_2 emissions costs.

Capacity costs are determined by the clearing price in the primary forward capacity auction (FCA). In Fall 2024, the FCA 15 clearing price resulted in capacity payments of $359 million ($14/MWh), representing 24% of total costs. The current capacity commitment period (CCP15, June 2024 – May 2025) cleared at $2.61/kw-month for Rest-of-Pool. This was 30% higher than the primary auction clearing price of $2.00/kW-month for the prior capacity commitment period. Section 5.1 discusses recent trends in the Forward Capacity Market in more detail.

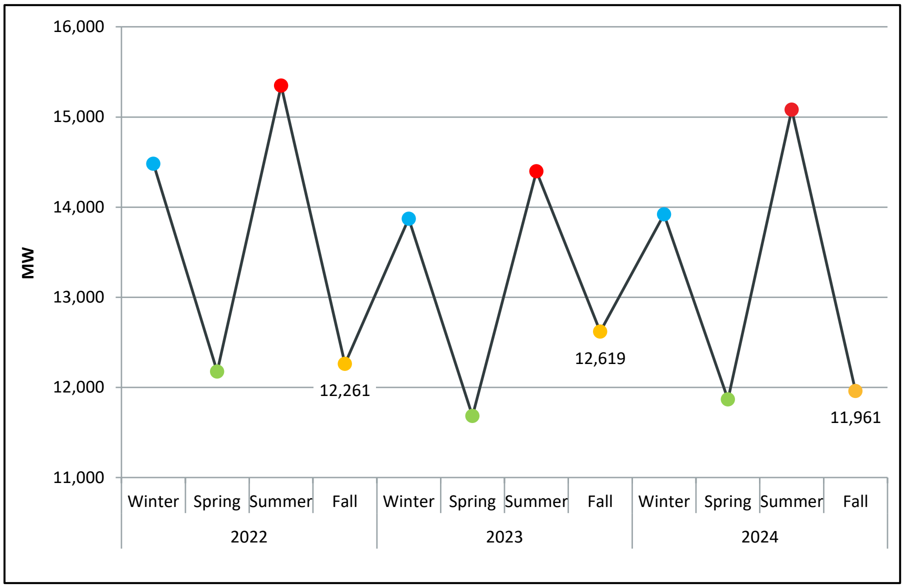
At $8.4 million ($0.32/MWh), Fall 2024 Net Commitment Period Compensation (NCPC) costs decreased by 36% compared to Fall 2023 due to a $4.5 million decrease in economic payments. In Fall 2023, multiple planned pumped-storage generator outages led to the frequent commitment of relatively expensive fast-start generation. NCPC costs represented 0.8% of total energy payments in Fall 2024.

Ancillary service costs, which include payments for operating reserves and regulation, totaled $19.8 million ($0.76/MWh) in Fall 2024, representing 1% of total wholesale costs. Ancillary service costs decreased by 47% compared to Fall 2023 costs due to lower real-time and forward reserve payments.

2.2 Load

This section reports quarterly load and demand conditions and contextualizes Fall 2024 loads relative to historic conditions.[4] Average hourly loads by quarter are shown in Figure 2-3 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer and the yellow dots represent fall.

Figure 2-3: Average Hourly Load by Quarter



Hourly loads averaged 12,000 MW in Fall 2024, marking, at least, a 24-year low for fall loads. As discussed below, fall loads fell significantly from Fall 2023 due to relatively mild weather patterns. Behind-the-meter (BTM) solar output grew 28% from 438 MW to 561 MW in Fall 2024, following both higher average irradiance and installed capacity growth (up 9% from Fall 2023).[5]

Load and Temperature

Low Fall 2024 loads followed relatively mild weather conditions. The stacked graph in Figure 2-4 below compares average monthly load to the monthly total number of degree days. The top panel compares average monthly load to monthly total cooling degree days (CDDs), while the bottom panel compares average monthly load to monthly total heating degree days (HDDs).[6]

[4] 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).

[5] Irradiance is a measurement of sunlight exposure in watts per square meter. Irradiance is directly correlated with solar generation.

[6] Cooling degree days (CDDs) measure how warm average daily temperature is relative to 65°F and are an indicator of electricity demand for cooling. CDDs are calculated as the number of degrees (°F) that the average of a given day's high and low temperatures are above 65°F. Heating degree days (HDD) measure how cold the average of a day's high and low temperatures are 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 has a high temperature of 80°F and a low temperature of 60°F, the average of the high and low temperature is 70°F and the day has 5 CDDs.

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

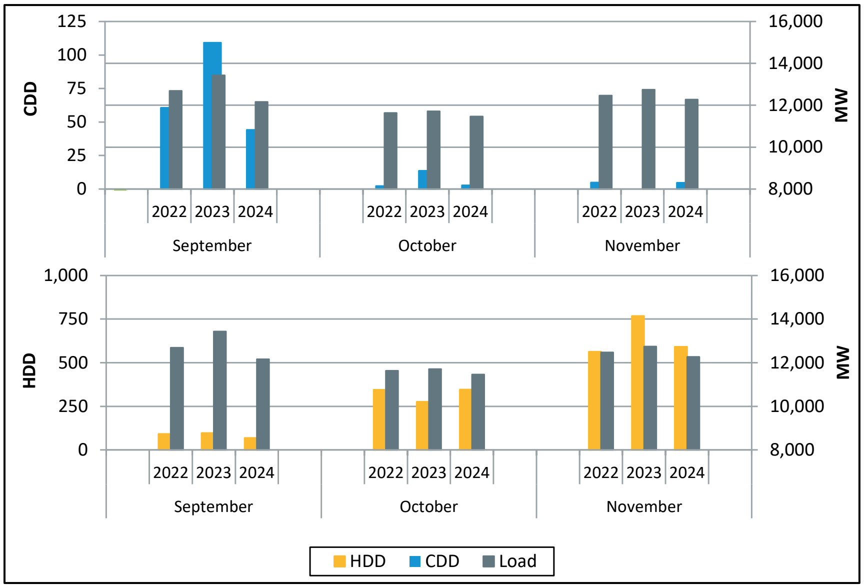


Figure 2-4 shows that average monthly Fall 2024 loads fell in all months prior to the last two years. September 2024 cooling degree days fell significantly from September 2023 due to abnormal heatwave conditions last year. Weather conditions were largely comparable or milder than Fall 2022, with lower loads due to relatively high BTM solar load reductions (561 MW) throughout the season.

Peak Load and Load Duration Curves

New England's system load over the past three fall 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.[7]

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

Figure 2-5: Fall Load Duration Curves

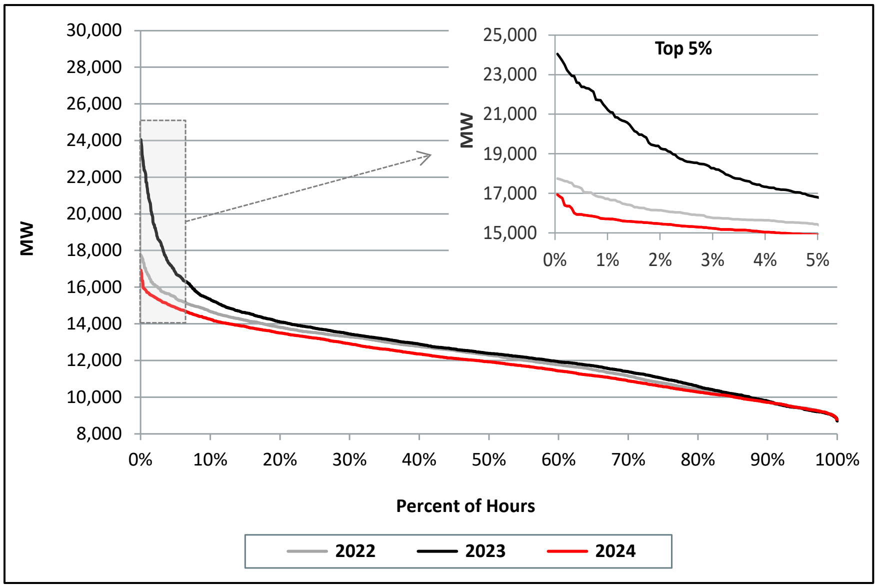


Figure 2-5 shows that Fall 2024 loads were notably lower than in the prior fall, even in peak hours. Peak loads fell significantly below Fall 2023 peak loads as abnormal heatwave conditions did not occur again in 2024. Peak load for Fall 2024 reached 16,930 MW, marking the only instance on record that fall peak loads did not exceed 17,000 MW.[8]

Load Clearing in the Day-Ahead Market

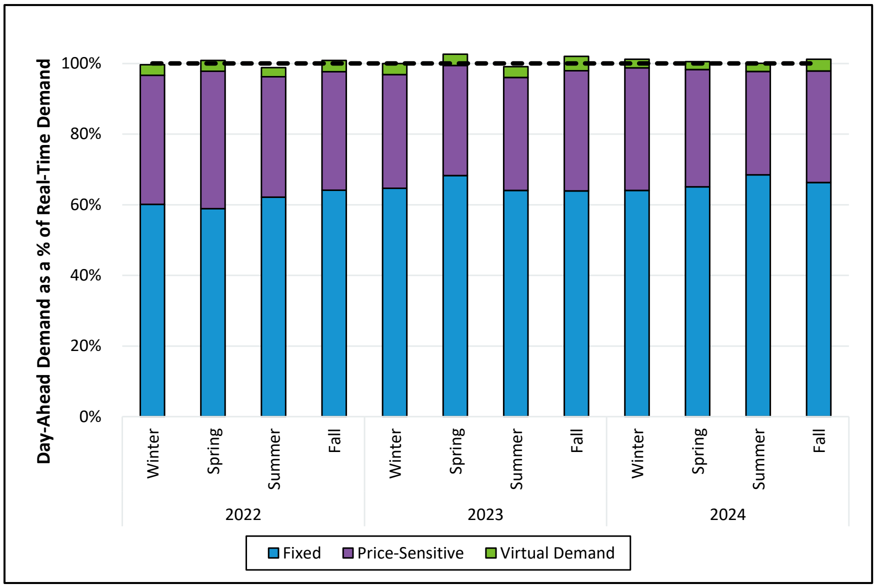
The amount of demand that clears in the day-ahead market is important because, along with the ISO's Reserve Adequacy Analysis, it influences generator commitment decisions for the operating day.[9] Low demand clearing in the day-ahead market may warrant supplemental generation commitments to meet real-time demand. Commitments that occur after the day-ahead market process can lead to higher real-time prices compared to day-ahead prices, assuming all else equal. The day-ahead cleared demand as a percentage of real-time demand is shown Figure 2-6 below. Day-ahead demand is broken down by bid type: fixed, price-sensitive, and virtual demand.[10]

[8] Our records for load levels begin in the year 2000.

[9] 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.

[10] Day-ahead cleared demand is calculated as fixed demand + price-sensitive demand + virtual demand, excluding both asset-related demand and any load at external interfaces. Real-time metered load is calculated as the sum of real-time metered load at internal locations, minus load related to asset-related demand. This is different from the ISO Express report, which defines day-ahead cleared demand as fixed demand + price-sensitive demand + virtual demand - virtual supply + asset-related demand and real-time load as generation – asset-related demand + price-responsive demand + net imports – losses. We have found that comparing the modified definition of day-ahead cleared demand and real-time metered load can provide better insight into day-ahead and real-time price differences.

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



Participants cleared 101% of real-time demand in the day-ahead market in Fall 2024, down from 102% in Fall 2023. Fixed demand bids comprised 66% of real-time load, while price-sensitive demand bids comprised 32%. Both of these shares are relatively static compared to prior quarters. Participants continued to price the majority of price-sensitive demand bids well above expected day-ahead LMPs. Therefore, price-sensitive demand bids continue to have relatively minimal market impacts. Virtual demand accounted for 3% of real-time load. While virtual demand accounted for most of the over-clearing relative to real-time load, virtual demand declined in Fall 2024 from Fall 2023 as discussed in Section 3.3.

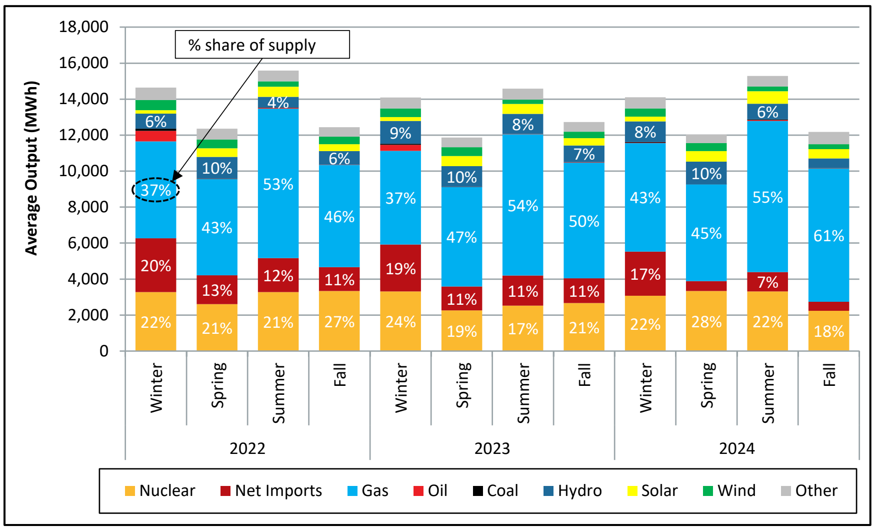
2.3 Supply

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 share of energy production by generator fuel type for Winter 2022 through Fall 2024 is illustrated in Figure 2-7 below. Each bar's height represents average electricity generation, while the percentages represent the share of generation from each fuel type.[11]

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



Natural gas-fired generation continued to provide the largest share of energy in Fall 2024, supplying 61% of the region's energy on average. This is the highest share for natural gas-fired generation in the study period; the increased reliance on gas results from a reduction in the share of energy provided by nuclear generation and net imports. The reduction in nuclear energy supply resulted from both planned and unplanned outages of nuclear generators throughout this season. Net imports supplied only 4% of the region's energy on average in Fall 2024, the lowest share for net imports over the study period. This outcome is discussed further in Section 2.3.2. Energy supply from hydro resources decreased by approximately 40% relative to the prior fall season, as a result of extended drought conditions in the region.

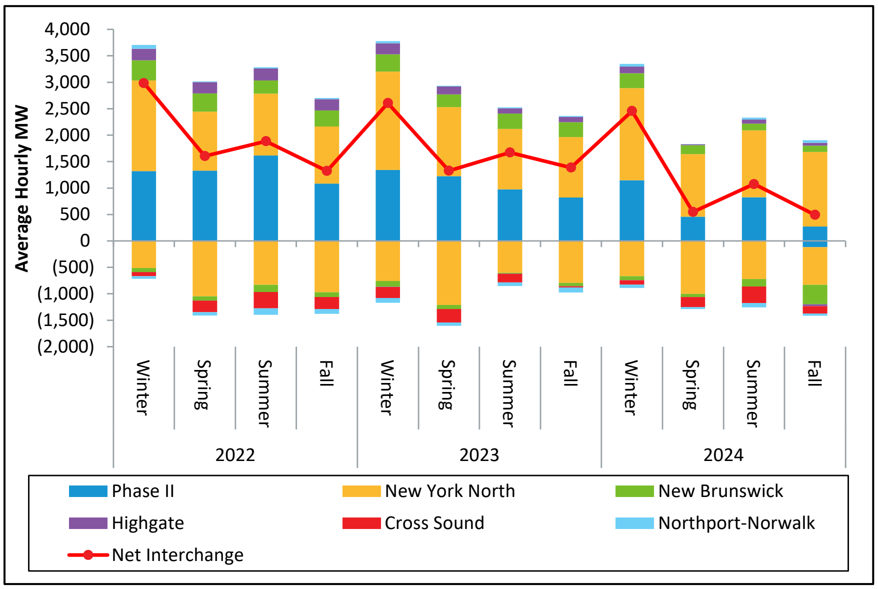
While not self-evident in the figure, energy supply from solar generators increased relative to past fall seasons. During Fall 2024, solar generators provided 512 MWh on average, up 25% from Fall 2023 and 33% from Fall 2022, and exceeded the share of energy supply from net imports. This increase was driven by the addition of new solar resources on the system, as well as increased irradiance on average relative to prior fall seasons.

[11] Electricity generation in Section 2.3.1 equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, and wood.

2.3.2 Imports and Exports

Net interchange from the neighboring control areas in Canada and New York fell to the lowest levels in over a decade. The main drivers of lower net interchange were 1) continued dry weather in Québec and 2) a nuclear generator outage in New Brunswick. These factors led to New England becoming a net exporter of energy to Canada in Fall 2024. On average, the net flow of energy into New England was 494 MW per hour as imports from New York increased. Total net interchange represented just 4% of load (NEL), down from 11% in Fall 2023. The average hourly import, export and net interchange power volumes by external interface for the last 12 seasons are shown in Figure 2-8 below.

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



Canadian Interfaces

New England exported 75 MW per hour over the three Canadian interfaces during Fall 2024. Historically, New England has been a net importer of energy from all Canadian interfaces with net interchange averaging 1,440 MW per hour from Winter 2022 to Summer 2024.

At the Phase II and Highgate interfaces, which connect New England to Québec, average quarterly net interchange fell from Fall 2023 levels by 81% (or 667 MW) and 78% (or 74 MW), respectively. In Québec, normally abundant water resources and hydro generation provide excess electricity supply, which can be sold to neighboring control areas. However, drier weather over the last year reduced the excess energy available in Québec and limited exports into New England.[12] At Phase II, net interchange averaged just 153 MW per hour. Notably, from November 16 to November 26 New England exported an average of 695 MW per hour to Québec.

In Fall 2024, New England exported an average of 249 MW per hour to New Brunswick. Beginning in Spring 2024, a nuclear generator in New Brunswick started an extended outage that continued

[12] For more information on the reduction in exports, see Hydro-Québec's *Quarterly Bulletin, Third Quarter 2024*, available at https://www.hydroquebec.com/data/documents-donnees/pdf/quarterly-bulletin-2024-3.pdf.

until December.[13] This outage limited the generation capacity within New Brunswick and resulted in increased exports out of New England over the New Brunswick interface.

New York Interfaces

At the New York interfaces, higher energy prices in New England led to average net interchange increasing by 316 MW per hour relative to Fall 2023. At the New York North and the Northport-Norwalk interfaces, imports increased in line with increased price spreads between New England and New York. Average day-ahead prices at New York North were $2.91/MWh higher in New England compared to New York, up from $0.06/MWh in Fall 2023. This led to net interchange at New York North averaging 697 MW per hour, which was the highest non-winter volume of imports over the reporting period. At Northport-Norwalk, New England imported an average of 11 MW per hour after exporting over the interface in the prior 10 seasons.

New England exports energy over the Cross Sound Cable to Long Island, an area that is often import-constrained compared to the rest of the New York control area. In Fall 2024, New England exported an average of 139 MW, up from 22 MW in Fall 2023. During Fall 2023, transmission work forced the Cross Sound Cable to go out of service for over two months, limiting the total exports last fall.[14]

[13] For more information on the outage of the New Brunswick nuclear generator, see *Update to extended outage schedule at Point Lepreau Nuclear Generating Station* (Aug 15, 2024), available at: https://www.nbpower.com/en/about-us/news-media-centre/news/2024/update-to-extended-outage-schedule-at-point-lepreau-nuclear-generating-station/.

[14] The Cross Sound Cable interface was on an outage for about 12 days during Fall 2024.

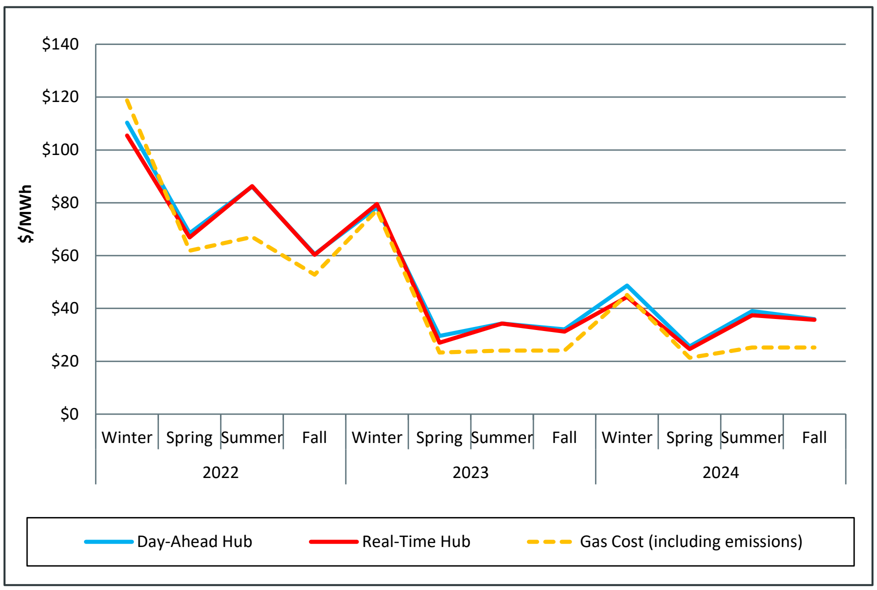
Section 3
Day-Ahead and Real-Time Markets

This section covers trends in, and drivers of, market outcomes for energy, operating reserves, and regulation products.

3.1 Energy Prices

In New England, seasonal movements of energy prices are generally consistent with changes in natural gas generation costs. These trends can be seen in Figure 3-1 which shows the average day-ahead and real-time energy prices, along with the estimated cost of generating electricity using natural gas in New England.[15]

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



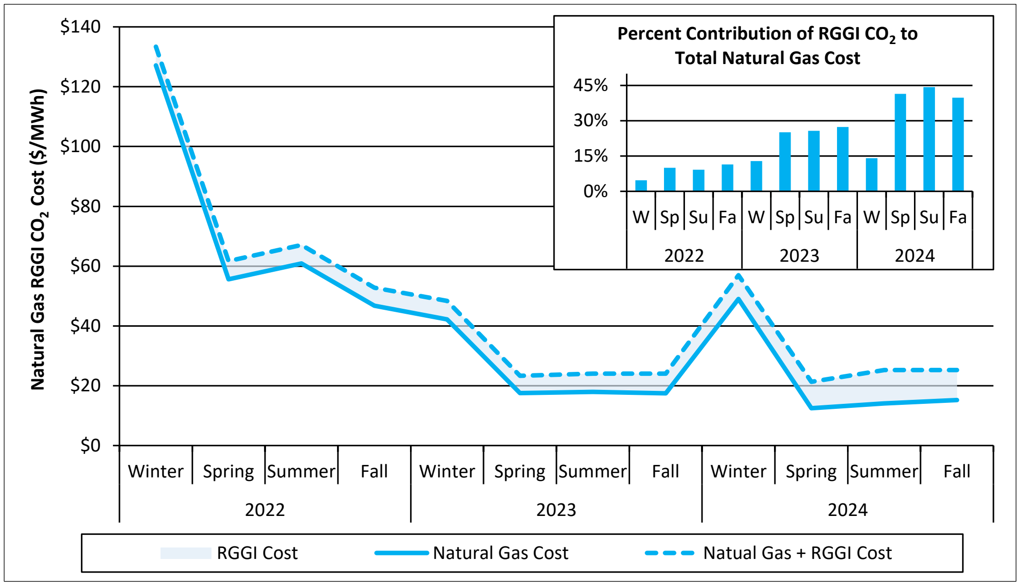
The average real-time and day-ahead Hub prices for Fall 2024 were $35.72 and $35.91/MWh, respectively. Gas costs averaged $25.25/MWh in Fall 2024.

Average energy prices in Fall 2024 were higher than Fall 2023 prices by about $4 and $5/MWh (up 12-14%) in the day-ahead and real-time markets, respectively. These increases occurred despite lower natural gas prices in Fall 2024, which were down 13% from Fall 2023 prices. LMPs typically move in the same direction as natural gas prices. However, in Fall 2024, Regional Greenhouse Gas

[15] The natural gas cost is based on the average natural gas price each season 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.

Initiative (RGGI)[16] costs increased notably for fossil fuel generators, contributing to a larger impact on wholesale electricity prices in New England.

Figure 3-2: Average Seasonal Fuel, RGGI CO_2 Cost, and Percent Contribution of RGGI CO_2 to Total Production Costs for a Proxy Natural Gas Combined Cycle Generator



From Fall 2023 to Fall 2024, RGGI prices rose substantially from \$14.38 to \$21.97/short ton of CO_2, increasing natural gas generator costs from \$6.56 to \$10.02/MWh. This increase was primarily driven by the depletion of Cost Containment Reserve (CCR) allowances in March 2024.[17] Increasing emission prices more than offset lower gas prices, resulting in slightly higher gas generator costs in Fall 2024 relative to 2023. Overall, the contribution of CO_2 prices to total energy costs increased from about 27% to 40%.

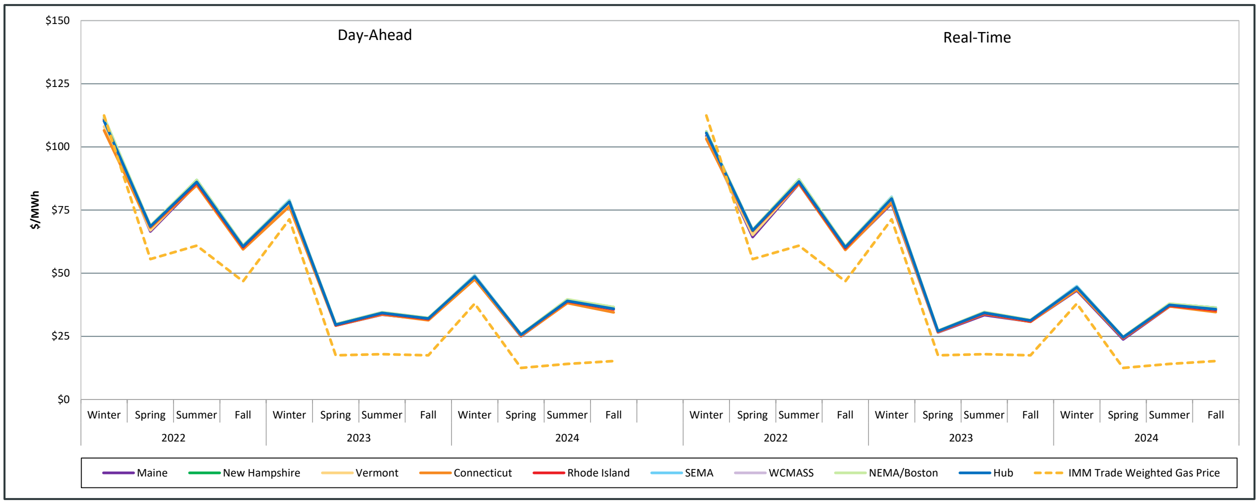
The spread between the average day-ahead electricity price and average estimated gas and CO_2 emissions cost was \$10.66/MWh in Fall 2024, higher than the \$7.98/MWh spread in Fall 2023. The higher spread in Fall 2024 compared to the previous fall was driven by supply mix changes that resulted in relatively more expensive generation setting price. First, net imports decreased by about 890 MW. Second, the average energy supplied by nuclear generation decreased by about 420 MW compared to the previous fall due to additional planned and unplanned outages.

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

[17] The CCR sells additional allowances held in reserve if prices rise above an established price.

The seasonal average day-ahead and real-time energy prices for each of the eight New England load zones and for the Hub are shown below in Figure 3-3.[18] Transmission congestion is the largest driver of locational differences in energy prices.

Figure 3-3: Simple Average Day-Ahead and Real-Time Prices by Location and Gas Generation Costs



Prices in the Connecticut load zone saw the largest difference from the Hub on average, at 4% and 3% lower than the Hub price in the day-ahead and real-time markets, respectively. Connecticut has been export-constrained more frequently in recent years, due to the addition of new highly efficient and less expensive gas-fired generators in the load zone coupled with limitations of the transmission system in exporting that power to the rest of the system. Additionally, in Fall 2024 there were multiple days in late November when congestion resulting from planned transmission outages led to lower prices in Connecticut.

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 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.

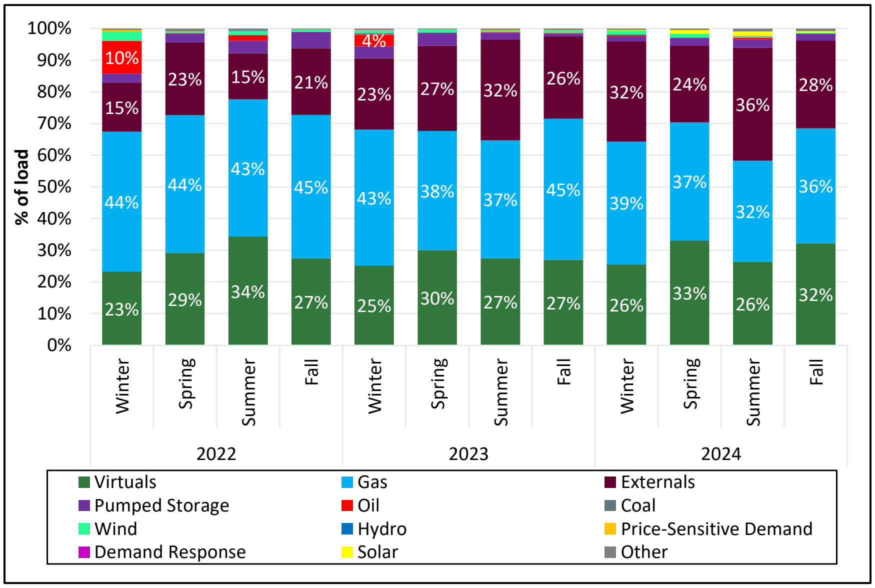
Day-Ahead Energy Market

The percentage of load for which each transaction type set price in the day-ahead market since Winter 2022 is illustrated in Figure 3-4 below.[19]

[18] A load zone is an aggregation of pricing nodes within a specific area. There are currently eight load zones in the New England region, which correspond to the reliability regions.

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

Figure 3-4: Day-Ahead Marginal Units by Transaction and Fuel Type



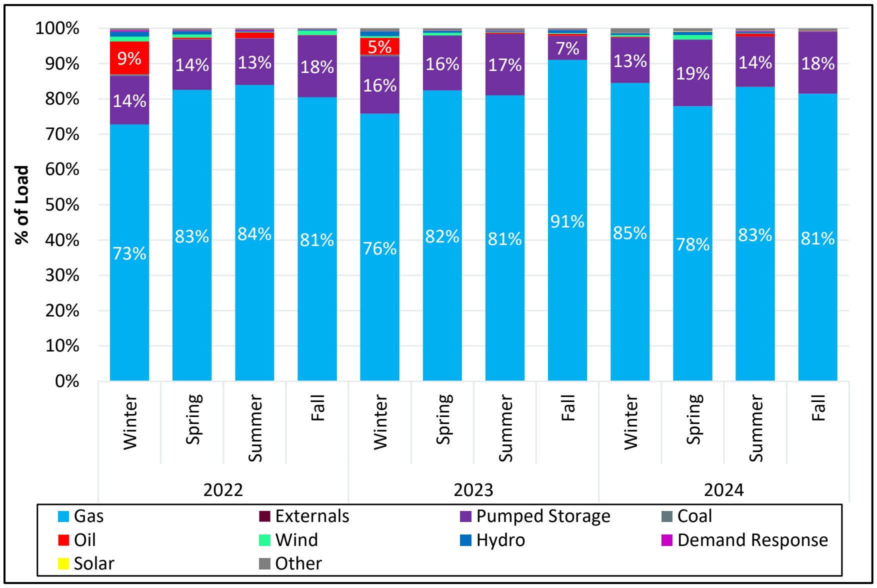
Gas-fired generators were the most common marginal resource type in the day-ahead market in Fall 2024, setting price for 36% of day-ahead load. This was a moderate reduction from the prior fall, when natural gas set price for 45% of day-ahead load. The changing supply conditions in Fall 2024 relative to Fall 2023 resulted in low heat-rate gas units becoming inframarginal more frequently in the day-ahead market and consequently setting price for a smaller percentage of load.[20] The decline in gas marginality was offset by an increase by virtual transactions (from 27% of load in Fall 2023 to 32% in Fall 2024). Meanwhile, external transactions set price for comparable percentages between Fall 2023 and Fall 2024 (26% and 28%, respectively). Other resource types were collectively marginal for less than 4% of day-ahead load.

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 3-5 below.

[20] See Section 2.3.1 for more information about the supply mix.

Figure 3-5: Real-Time Marginal Units by Fuel Type



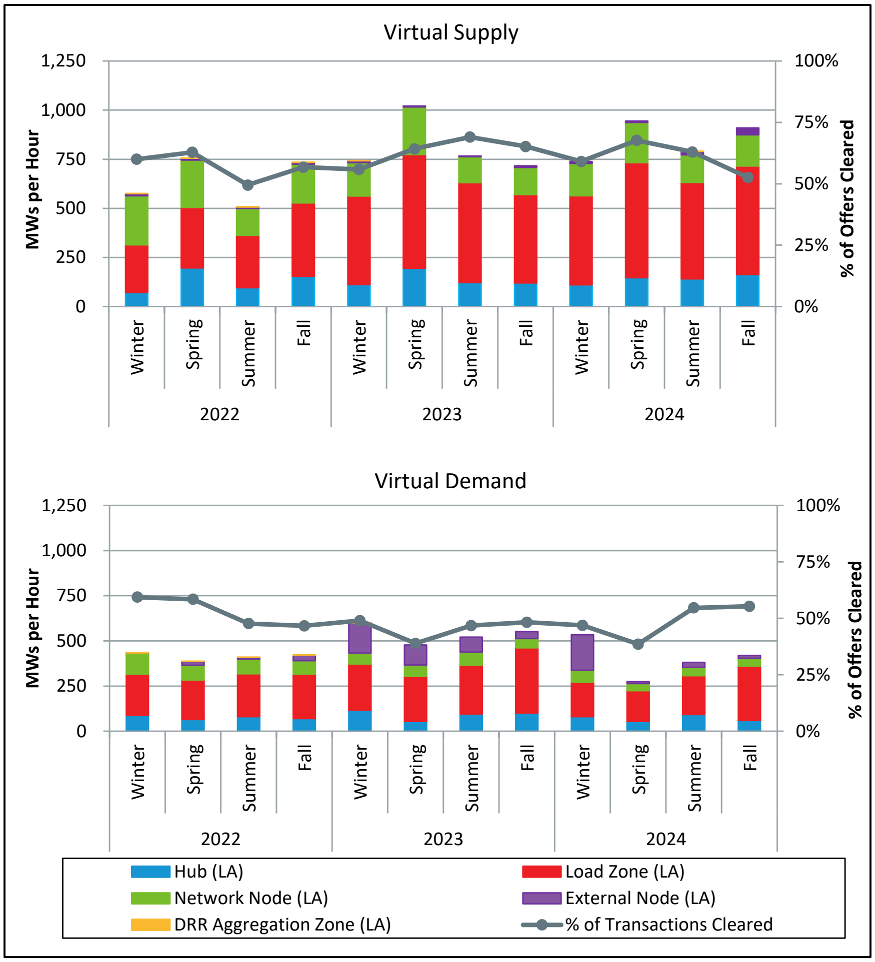
Natural gas-fired generators set price for the highest percentage of load in the real-time market in Fall 2024 (81%). Pumped storage (generation and demand) set price for 18% of load in Fall 2024. Both of these levels were in-line with the values observed over the last several years. All other resource types accounted for less than 1% 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 volumes of cleared virtual supply (top graph) and virtual demand (bottom graph) are shown on the left axis in Figure 3-6 below. Cleared transactions are categorized based on the location type where they cleared: Hub, load zone, network node, external node, and Demand Response Resource (DRR) aggregation zone. The line graph (right axis) shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

Figure 3-6: Cleared Virtual Transactions by Location Type



As seen in the top figure, virtual supply volumes continue to increase due to:

1) the growing amount of solar settlement-only generation (SOG) and
2) the day-ahead bidding behavior of wind and solar generation.

Cleared virtual supply averaged 909 MW per hour in Fall 2024, up 27% from Fall 2023 (717 MW per hour). By the end of Fall 2024, the installed capacity of solar SOGs was over 2,300 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.

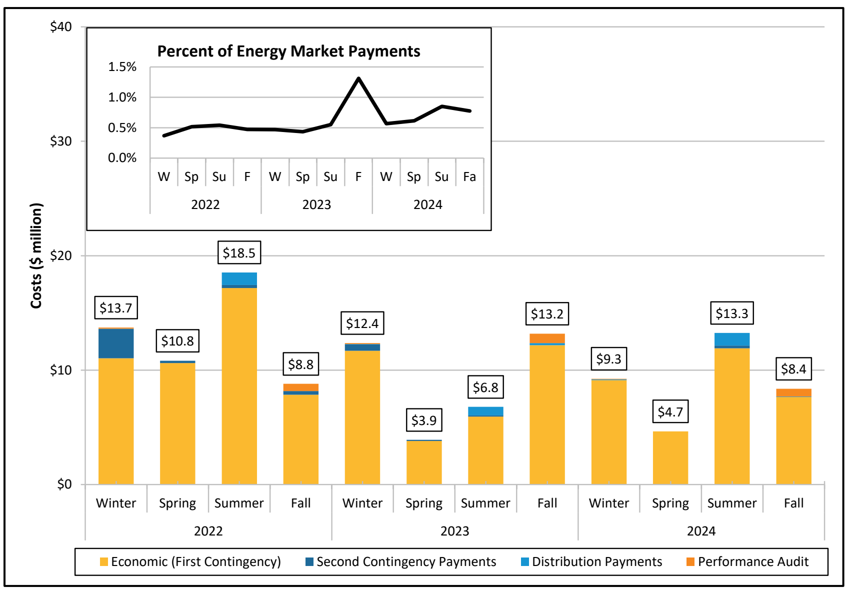
Participants also frequently use virtual supply to try to capture differences between day-ahead and real-time prices in export-constrained areas, particularly areas with wind and solar generation. Beginning in December 2023, the Do-Not-Exceed (DNE) Dispatch Project expanded to include utility-scale (> 5 MW installed capacity) solar generation. Typically, these wind and solar generators offer high-priced energy in the day-ahead market, but produce energy at low, or even negative, prices in the real-time market.[21]

Cleared virtual demand averaged 420 MW per hour in Fall 2024, down 24% from Fall 2023 (551 MW per hour). In Fall 2024, cleared virtual demand fell at every location type year-over-year.[22]

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.[23] Figure 3-7 below shows total NCPC by category and quarter for 2022-2024. The inset graph shows quarterly NCPC payments as a percent of total energy market payments.

Figure 3-7: NCPC by Category



NCPC payments totaled $8.4 million in Fall 2024, comprising less than 1% of energy market payments. First contingency payments made up the majority of NCPC payments throughout the season, totaling $7.7 million. Uplift payments for performance audits are common in the fall shoulder season, and audit NCPC totaled $0.7 million.

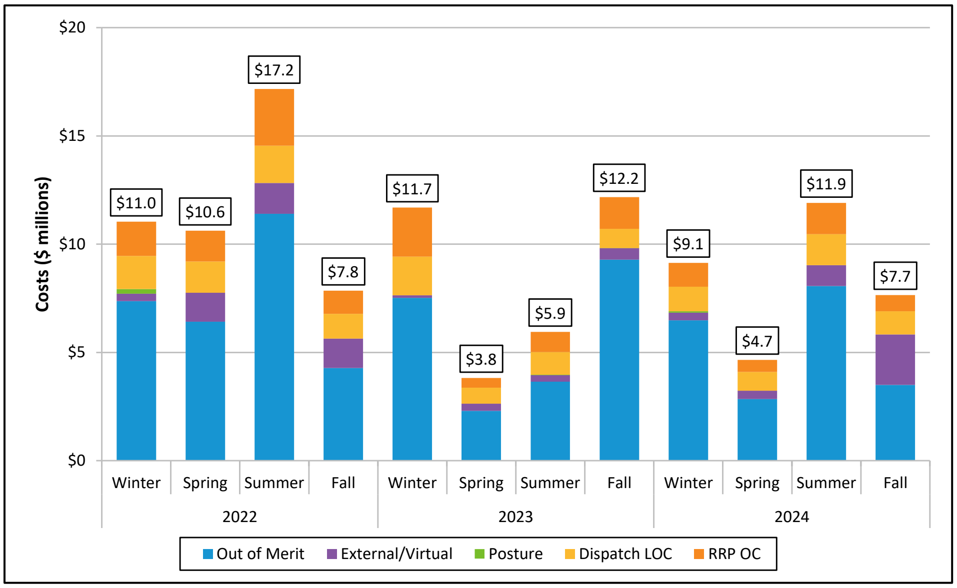
[21] In Fall 2024, wind generation averaged 157 MW per hour in the day-ahead market, while real-time wind generation averaged 273 MW hour.

[22] Participants did not submit or subsequently clear any virtual demand at DRR aggregation zones in Fall 2024 and Fall 2023.

[23] 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 payments accounted for above 90% of all NCPC payments in Fall 2024. Figure 3-8 displays economic NCPC payments by reason.

Figure 3-8: Economic NCPC by Reason



Out of merit payments continued to comprise the largest share of economic payments in Fall 2024, totaling $3.5 million. Out of merit payments declined substantially from Fall 2023, when generator outages led to the frequent commitment of relatively expensive fast-start generation that did not always fully recover operating costs through energy prices. While these conditions did not occur again in Fall 2024, uplift payments to fast-start generators continued to drive the majority of out of merit payments. Dispatch and rapid-response pricing opportunity cost payments together totaled $1.8 million, down from $2.4 million in Fall 2023. There were no posturing actions or resulting uplift in Fall 2024.

External and Virtual uplift increased notably in Fall 2024, totaling $2.3 million. Most of these payments (88%) occurred in the day-ahead market. Day-ahead external and virtual uplift is driven by congestion at external interfaces. When an external interface clears at its total transfer capability (TTC) in the day-ahead market, external or virtual transactions that provide counterflow are cleared in price order. This increases economic efficiency at the external interface, and the counterflow transactions are made whole to their offered costs through NCPC payments.[24] These payments are charged only to external transactions in the congested direction; therefore, load is not exposed to these day-ahead NCPC charges. Such transactions occurred relatively frequently in Fall 2024 because of export congestion on the New Brunswick interface.

[24] For more information and an example of day-ahead external NCPC allocations, see the ISO*'s FAQ article for NCPC*, available at https://www.iso-ne.com/participate/support/faq/ncpc-rmr.

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

Real-time Reserve Pricing

The frequency of system-level non-zero reserve pricing for each product, along with the average price during these intervals, for the past three summer seasons is provided in Table 3-1 below.[26]

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

Product	Fall 2024		Fall 2023		Fall 2022	
	Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	$6.39	196.1	$24.91	214.0	$9.58	205.7
TMNSR	$15.06	0.3	$128.97	29.4	$158.74	0.9
TMOR	$0.00	0.0	$145.17	18.3	$239.63	0.4

Fall 2024 saw reserve pricing with far less frequency and at much lower magnitude than the past two fall seasons. The TMSR constraint bound in fewer than 200 hours, with an average clearing price of $6.39/MWh. The total ten-minute reserve requirement bound for less than one hour, resulting in low TMNSR clearing prices during that short period, and the total reserve requirement (which is tied to TMOR pricing) did not bind at all.

The key takeaway here is that system conditions were not tight, and the system generally had an ample supply of reserves to satisfy these key reliability requirements throughout Fall 2024. This stands in contrast to prior fall seasons, which had a tighter supply of reserves and more frequent and higher reserve prices.[27]

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

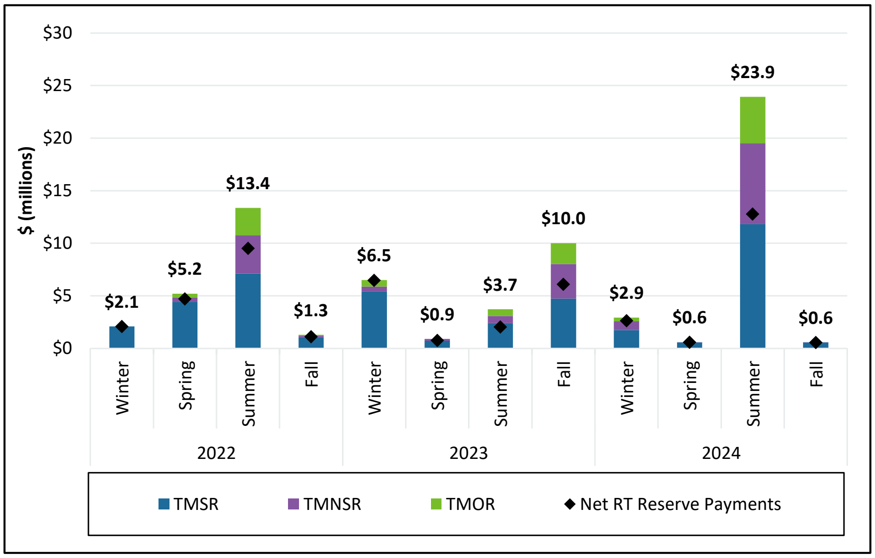
[26] In addition to the system-level prices shown here, the zonal thirty-minute reserve requirement in NEMA/Boston bound for two five-minute intervals during the Fall 2023 season. As a result, non-zero reserve prices were $28.22/MWh for all reserve products provided in NEMA/Boston during those intervals, while the system-level reserve prices were $0/MWh.

[27] For more detail on reserve pricing outcomes in those seasons, see our *Fall 2023 Quarterly Markets Report* (January 29, 2024), and our *Fall 2022 Quarterly Markets Report* (January 31, 2023), available at https://www.iso-ne.com/static-assets/documents/100007/2023-fall-quarterly-markets-report.pdf and https://www.iso-ne.com/static-assets/documents/2023/01/2022-fall-quarterly-markets-report.pdf respectively.

Real-time Reserve Payments

Real-time reserve payments by product are illustrated in Figure 3-9 below.[28] 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).[29]

Figure 3-9: Real-Time Reserve Payments by Product and Zone



The low frequency and magnitude of reserve pricing led to low real-time reserve payments in Fall 2024. Total payments for the season were roughly $600k, with the vast majority of that sum paid to resources providing TMSR.

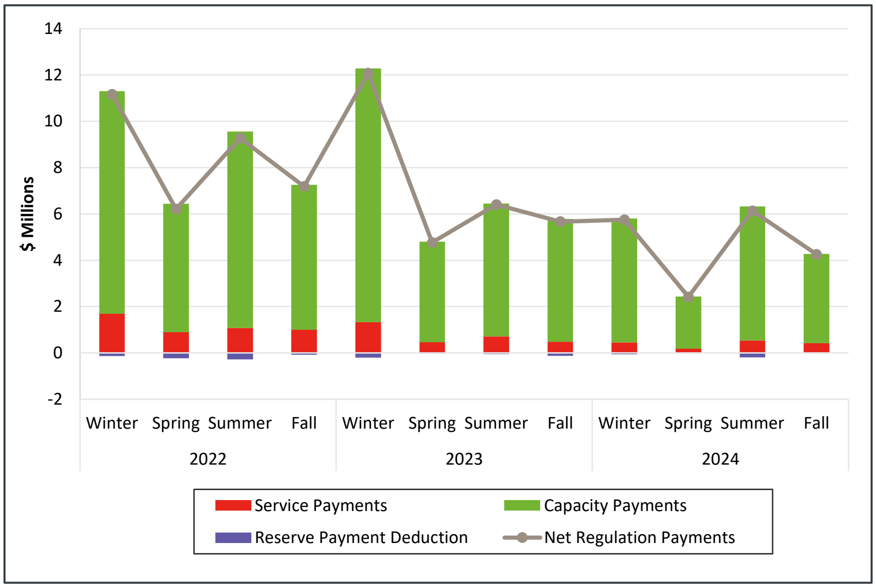
[28] The current reserve zones are: Northeastern Massachusetts/Boston (NEMA/Boston), Connecticut (CT), Southwest Connecticut (SWCT), and Rest of System (ROS).

[29] 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 real-time. 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 3-10 below.

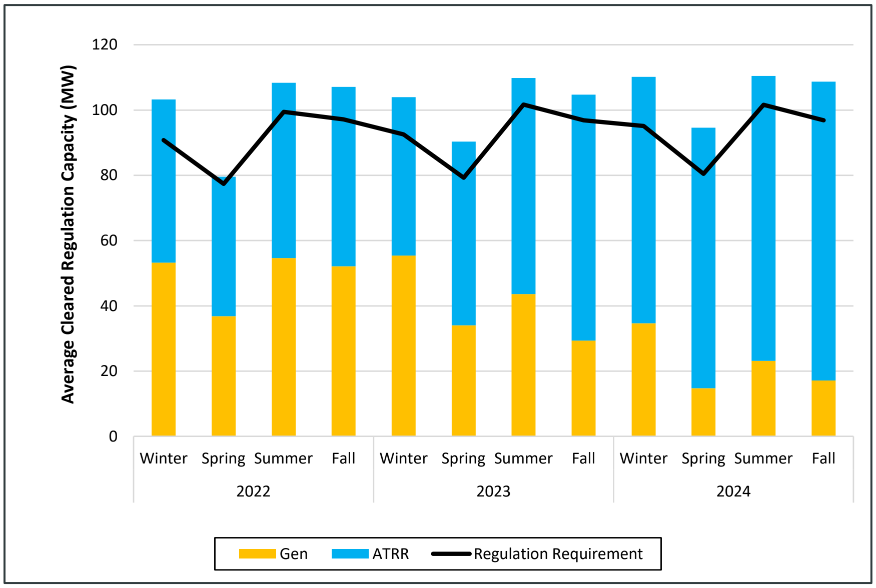
Figure 3-10: Regulation Payments



Total regulation market payments were $4.3 million during Fall 2024, down 25% from $5.7 million in Fall 2023. The decrease in payments resulted primarily from lower capacity prices (down 35%). Capacity prices decreased due to a decline in regulation offer prices, as lower cost alternative technology regulation resources continue to make up a larger share of the regulation mix.

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 3-11 below.

Figure 3-11: 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 bars) cleared an average of 50 MW of regulation capacity, making up 48% of total cleared regulation. In Fall 2024, ATRRs provided 92 MW or 84% of regulation. This change follows continuing increases in the installed capacity of battery resources in the region. Regulation capacity available from ATRRs increased to 237 MW on average in Fall 2024, up from 110 MW in Winter 2022. 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. Section 4.1 evaluates energy market competitiveness at the quarterly level. First, this section presents two metrics on system-wide structural market power. Next, the section provides statistics on system and local market power flagged by the automated mitigation system. We also discuss the amount of actual mitigation applied for instances where supply offers were replaced by the IMM's reference levels.

4.1 Pivotal Supplier and Residual Supply Indices

This analysis examines opportunities for participants to exercise market power in the real-time energy market using two metrics: 1) the pivotal supplier test (PST) and 2) the residual supply index (RSI). Both of these metrics identify instances when the largest supplier has market power.[30] The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier would be needed to meet demand, and could exercise market power if permitted. Further, if the RSI is less than 100, there is one or more pivotal suppliers.

Pivotal suppliers are identified at the five-minute level by comparing the real-time supply margin[31] to the sum of each participant's total supply that is available within 30 minutes.[32] When a participant's available supply exceeds the supply margin, they are pivotal.

The average RSI and the percentage of five-minute intervals with pivotal suppliers are presented in Table 4-1 below.

[30] 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.

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

[32] 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.

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

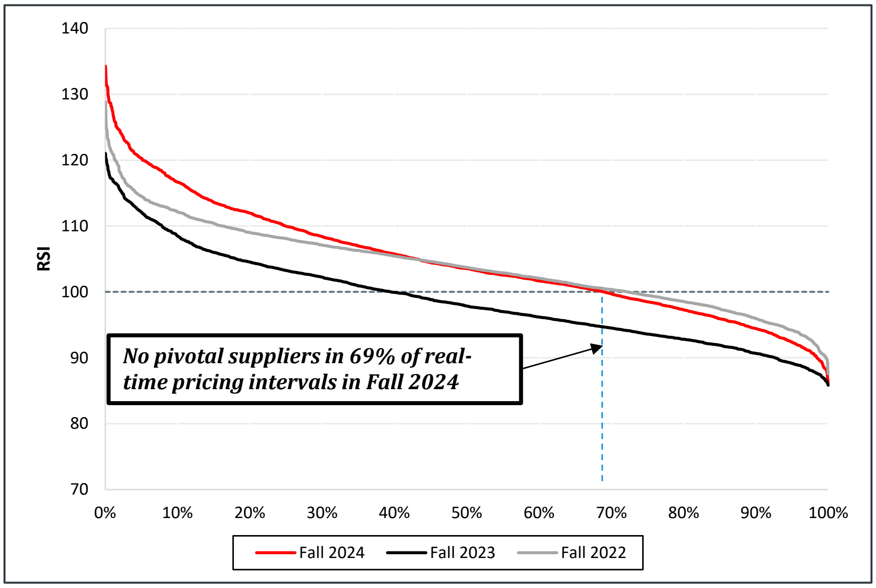
Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2022	106.5	12%
Spring 2022	106.7	19%
Summer 2022	102.6	34%
Fall 2022	104.0	28%
Winter 2023	105.2	20%
Spring 2023	107.7	22%
Summer 2023	103.8	34%
Fall 2023	98.9	60%
Winter 2024	101.7	45%
Spring 2024	105.5	29%
Summer 2024	104.0	34%
Fall 2024	104.7	31%

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 31% of real-time pricing intervals in Fall 2024, which was much lower than the Fall 2023 frequency due to higher reserve margins that resulted from increased availability of pumped-storage generators.

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 Fall 2024, the RSI was higher than that of Fall 2023 across all ranked observations, reflecting the higher reserve margins.

4.2 Energy Market Supply Offer Mitigation

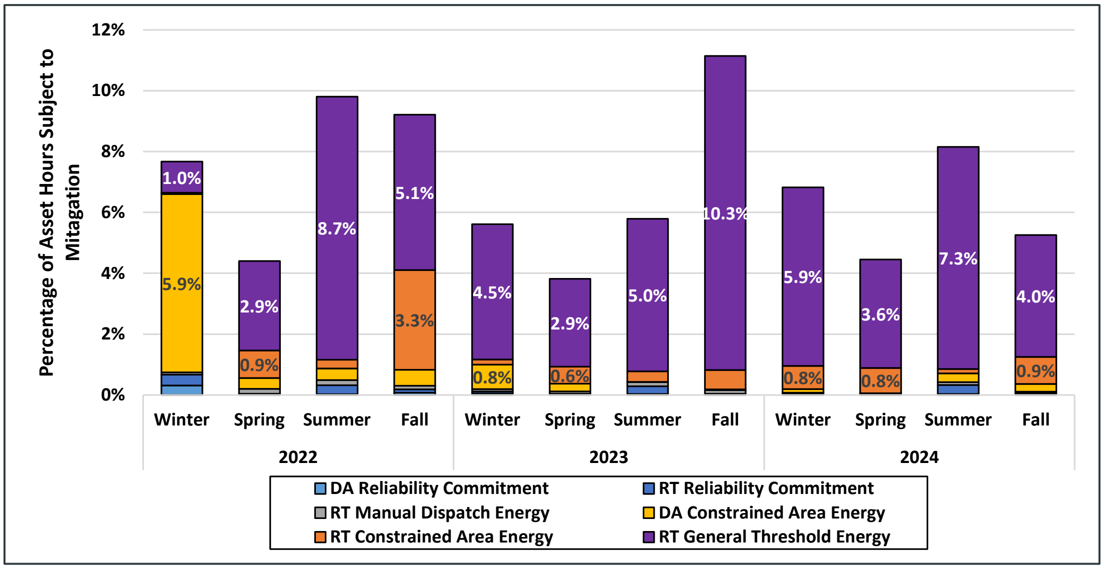
The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power. As in earlier periods, the mitigation of energy market supply offers occurred infrequently in Fall 2024.

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 Fall 2024 is shown below in Figure 4-2.[33]

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

Figure 4-2: Energy Market Mitigation Structural Test Failures

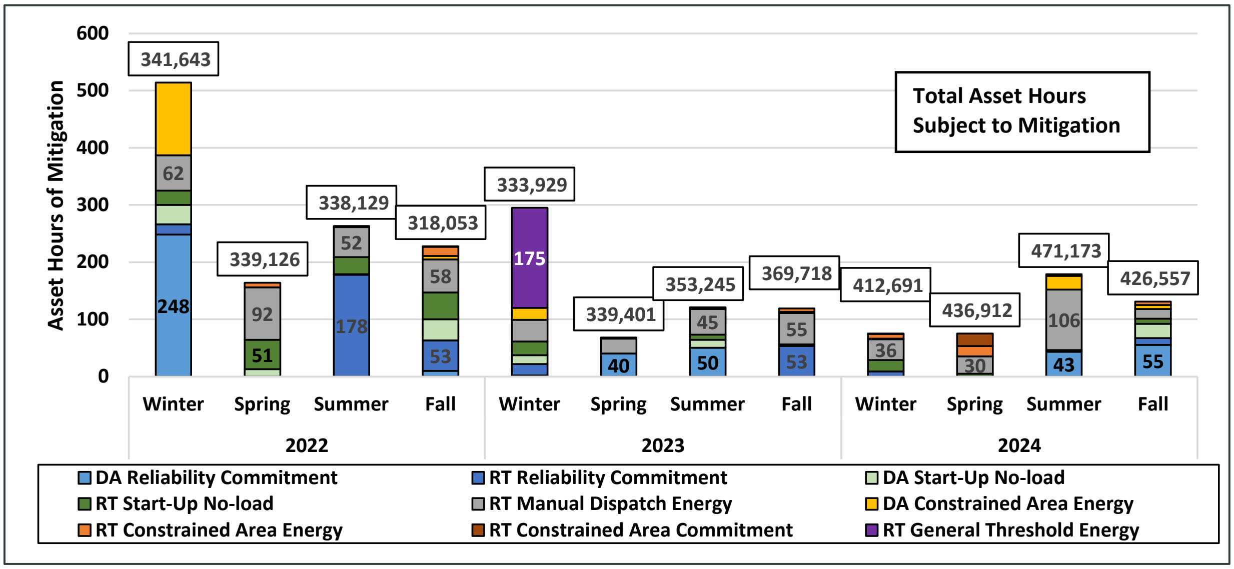


In Fall 2024, the total asset hours subject to mitigation reached about 427,000 asset hours, in which 22,428 asset hours (5.3%) failed structural tests.[34] The frequency of structural test failures was lower than in Fall 2023, which saw a higher frequency of general threshold energy test failures. This type of structural test failure occurs when a committed generator is owned by a pivotal supplier, and there was a higher incidence of pivotal suppliers in Fall 2023 due to lower reserve margins caused by prolonged pumped-storage generator outages. 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).

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

Figure 4-3: Energy Market Mitigation Asset Hours



There were 131 mitigation asset hours in Fall 2024, a similar total to that of Fall 2023.

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.[35] Day-ahead reliability commitment mitigation was the most frequent mitigation type of Fall 2024 at 55 asset hours, and occurred in the Southeast Massachusetts load zone across multiple days for generators that were committed for local second contingency protection. There were also 12 asset hours of real-time reliability commitment mitigations, which occurred for generators that were committed to perform audits.

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.[36] SUNL mitigations occur infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate – particularly natural gas. In Fall 2024, just one participant was associated with 34 asset hours of SUNL commitment mitigation.

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 Fall 2024, structural test failures totaled 4,844 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. In Fall 2024, there were 13 asset hours of constrained area mitigation, many of which occurred in the day-ahead

[35] 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.

[36] 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).

market on November 4 when load and generation patterns resulted in a binding constraint on the North-East New England Import Interface.

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 19,200 asset hours of pivotal supplier energy offers were subject to GTE 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 four participants accounting for 84% of the structural test failures in Fall 2024.

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 84% of the 159 asset hours of manual dispatch in Fall 2024. Due to a relatively tight conduct test, manual dispatch energy mitigation typically occurs more frequently than other mitigation types. However, there were only 17 asset hours of MDE mitigation in Fall 2024. This was consistent with the decline in manual dispatches in Fall 2024, which decreased by 259 asset hours compared to the previous fall.

Section 5
Forward Markets

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

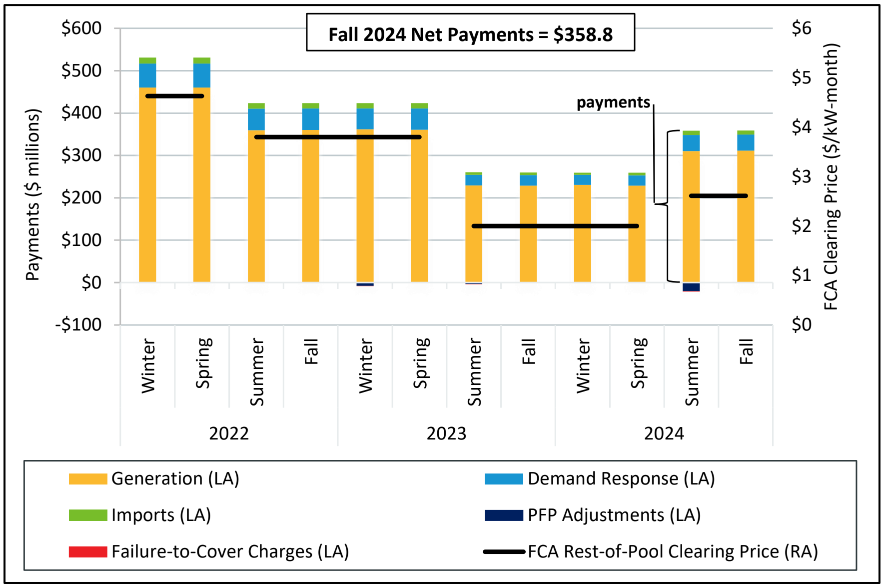
5.1 Forward Capacity Market

The Capacity Commitment Period (CCP) associated with Fall 2024 started on June 1, 2024, and will end on May 31, 2025. The corresponding Forward Capacity Auction (FCA 15) cleared at $2.61/kW-month, 30% higher than FCA 14. The auction cleared with 34,621 MW of Capacity Supply Obligation (CSO), surpassing the net installed capacity requirement (Net ICR) of 33,270 MW. Price separation between zones occurred in FCA 15, with a lower price ($2.48/kW-month) in the export-constrained Northern New England (NNE) and nested Maine capacity zones and a higher price ($3.98/kW-month) in the import-constrained Southeast New England (SENE) capacity zone. Battery storage resources comprised the largest share of new cleared generating capacity. The cost-of-service agreement that retained Mystic 8 and 9 during FCA 13-FCA 14 ended and the generators retired effective June 1, 2024. The results of FCA 15 led to a projected total annual cost of $1.32 billion in capacity payments, 39% higher than capacity payments incurred in FCA 14.[37]

Total FCM payments, as well as the clearing prices for Winter 2022 through Fall 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 (PfP) adjustments, while the red bar represents Failure-to-Cover charges.

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

Figure 5-1: Capacity Market Payments



In Fall 2024, net capacity payments totaled $358.8 million, up 38% from Fall 2023. The increase in capacity payments is largely attributable to the higher clearing prices in effect for CCP 15. There were no PfP events or related transfers throughout Fall 2024.

Following the primary auction, 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 Fall 2024 alongside the 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 15 (2024-2025)	Primary	12-month	2.61	34,621	2.48	2.48	3.98
	Monthly Reconfiguration	Nov-24	1.30	728			
	Monthly Bilateral	Nov-24	1.37	1			
	Monthly Reconfiguration	Dec-24	2.15	1,301			
	Monthly Bilateral	Dec-24	0.06	25			
	Monthly Reconfiguration	Jan-25	2.75	1,208			
	Monthly Bilateral	Jan-25	2.06	58			

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

Three monthly reconfiguration auctions (MRAs) took place in Fall 2024: the November 2024 auction in September, the December 2024 auction in October, and the January 2025 auction in November. The November and December reconfiguration auctions cleared below the FCA clearing price, while the January 2025 cleared slightly higher at $2.75/kW-month. No price separation occurred in any of the reconfiguration auctions. The quantity cleared in each auction increased relative to prior months, consistent with observed increases in cleared volumes in winter months of prior years. As colder winter weather approaches, increased activity in reconfiguration auctions may be due to perceived elevated risk of a PfP event.

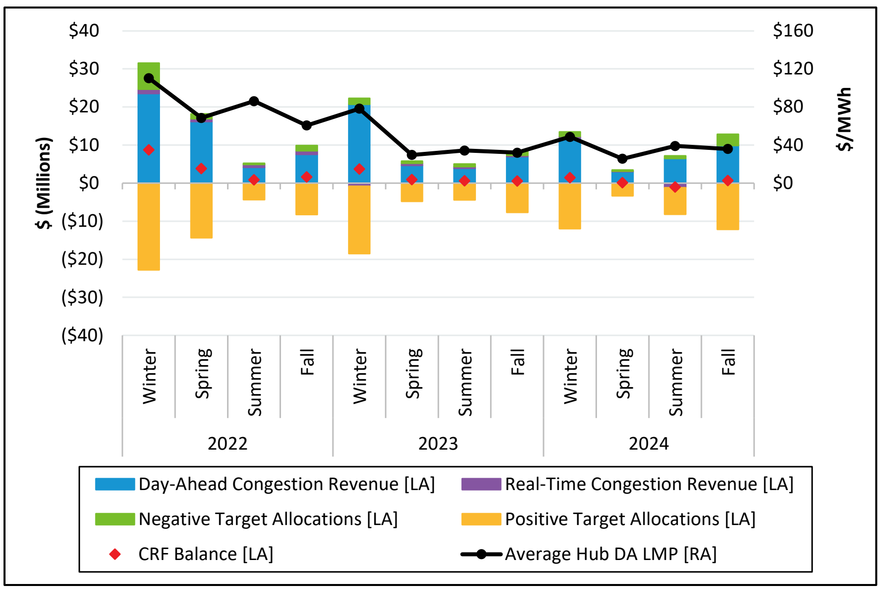
5.2 Financial Transmission Rights

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;
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.[38, 39] This figure also depicts the quarterly average day-ahead Hub LMP.[40]

Figure 5-2: Congestion Revenue, Target Allocations, and Day-Ahead LMP by Quarter



[38] 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).

[39] 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.

[40] 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").

Day-ahead congestion revenue amounted to $9.9 million in Fall 2024. This represents an increase of 53% relative to Summer 2024 ($6.4 million) and an increase of 42% relative to Fall 2023 ($7.0 million). Positive target allocations in Fall 2024 ($12.0 million) followed a similar pattern, increasing by 71% relative to Summer 2024 ($7.0 million) and increasing by 56% relative to Fall 2023 ($7.7 million). One transmission constraint associated with the increased positive target allocations in Fall 2024 was the New England West-East (NE_WE) interface. This interface constraint bound periodically in the day-ahead market in the second half of November 2024 partly as a result of the changing power flows over the Phase II external interface.[41] Negative target allocations in Fall 2024 (-$3.0 million) increased significantly from their Summer 2024 (-$0.7 million) and Fall 2023 (-$0.9 million) levels. Meanwhile, real-time congestion revenue in Fall 2024 (-$0.2 million) was relatively modest.

FTRs were fully funded in October and November 2024, but they were not in September 2024.[42,43] In September 2024 only 77.5% of positive target allocations were funded ($1.6 million of the $2.0 million due). 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 November 2024, the congestion revenue fund had a surplus of $2.8 million for the year.

[41] See Section 2.3.2 for more information about external transactions.

[42] 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.

[43] 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.