Fall 2023
Quarterly Markets Report

By ISO New England's Internal Market Monitor

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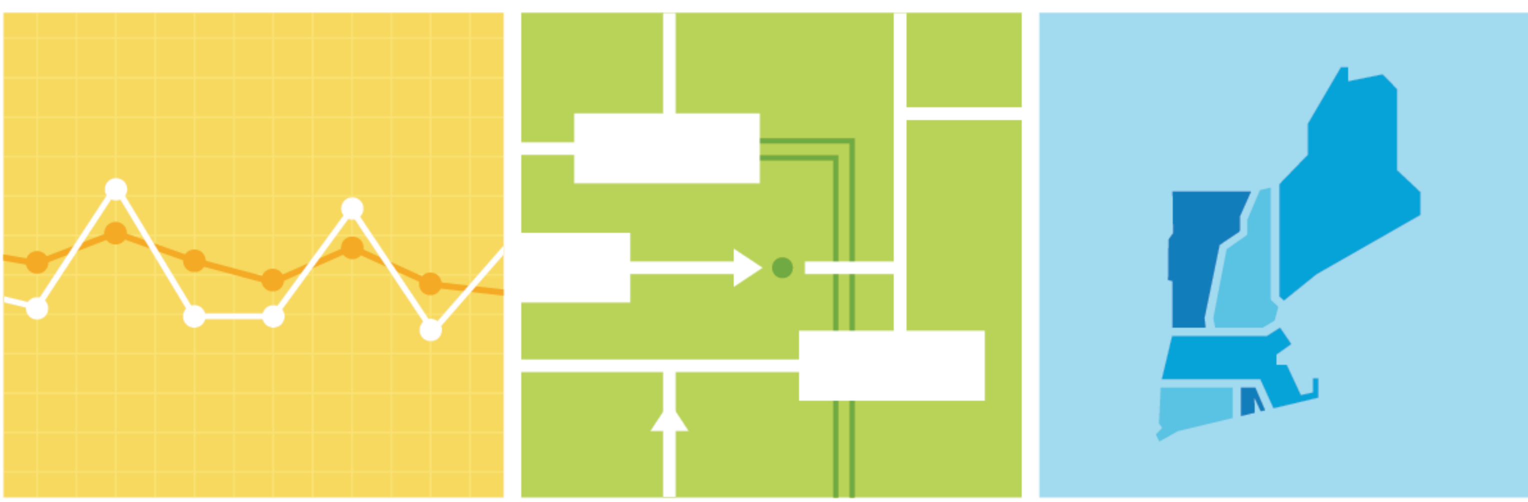

Preface/Disclaimer

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

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

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

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

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

[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 2023 (September 1, 2023 through November 30, 2023).

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.35 billion, down 43% from $2.39 billion in Fall 2022. The decrease was driven by lower energy and capacity costs.

Energy costs totaled $1.00 billion; down 46% (by $0.85 billion) from Fall 2022 costs. Decreased energy costs were a result of lower natural gas prices. In Fall 2023, gas prices decreased by 63% compared to Fall 2022 reflecting lower national prices.

Capacity costs totaled $259 million, down 39% (by $164 million) from last fall. 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.[3] These payments totaled $39.8 million in Fall 2023. Mystic 8 and 9 will receive supplemental payments until May 2024.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $32.03 and $31.23 per megawatt hour (MWh), respectively. These were 47-48% lower than Fall 2022 prices on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $2.24/MMBtu in Fall 2023, 63% lower than the Fall 2022 price of $6.00/MMBtu. This decrease continued the trend of lower gas prices throughout 2023, and reflected lower national prices and higher storage levels.
- An increase in generator outages in Fall 2023 compared to the previous fall partially muted the impact of lower natural gas prices on LMPs. Nuclear generation was down by 677 MW on average per hour primarily due to a planned refueling outage. Additionally, the average system Total-30 reserve margin decreased by 628 MW in Fall 2023 compared to the previous fall due to a 730 MW increase in pumped-storage generator outages. These outages increased instances of tight system conditions and resulted in more expensive generator commitments.
- Energy market prices did not differ significantly among load zones.

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[3] 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. Capacity Supply Obligation (CSO) payments 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.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $13.2 million, up 50% or $4.4 million compared to Fall 2022. NCPC comprised 1.3% of total energy costs in Fall 2023, the highest level in the reporting period. NCPC payments increased due to multiple factors: First, available fast-start pumped-storage generation decreased in Fall 2023 due to multiple long-term planned outages. Fossil fuel-fired units filled the need for fast-start generation, and required more uplift than pumped-storage generators due to higher operating costs. Second, many peaking generators received significant NCPC payments in early September during heat wave conditions and during M/LCC 2 events on October 4 and 23.

Real-time Reserves: Real-time reserve payments totaled $10.0 million, a substantial increase from $1.3 million in Fall 2022. Nearly half of the gross real-time reserve payments in Fall 2023 went to resources providing TMSR ($4.7 million), while resources providing TMNSR received $3.3 million, and resources providing TMOR received $2.0 million. The system experienced more frequent non-zero TMNSR and TMOR pricing in Fall 2023 than in either of the prior two falls due to lower reserve margins caused by the planned outages of several pumped-storage generators. These units are capable of providing substantial amounts of reserves, and their absence led to decreases of 498 MW and 628 MW in the average margins for the system ten-minute and Total-30 reserve requirements, respectively. Additionally, the higher incidence of non-zero TMNSR and TMOR reserve prices contributed to higher TMSR clearing prices in Fall 2023 ($24.91/MWh) compared to the prior two falls ($9.58/MWh and $7.35/MWh).

Regulation: Regulation market payments totaled $5.7 million, down 21% from $7.2 million in Fall 2022. This decrease primarily reflected lower regulation capacity prices. Reduced capacity prices resulted from lower energy market opportunity costs (i.e., lower energy prices) compared to the previous fall.

Financial Transmission Rights (FTRs): FTRs were fully funded in September and November 2023, but not in October 2023. In October, only 79.6% of positive target allocations were funded ($2.3 million of the $2.9 million). However, at the end of November 2023, the congestion revenue fund had a surplus of $5.7 million for the year.

Real-time congestion revenue in Fall 2023 ($0.3 million) remained relatively modest and was generally in line with recent historical levels. Day-ahead congestion revenue amounted to $7.0 million in Fall 2023, down 8% on Fall 2022 ($7.5 million). In terms of payments to and from FTR holders, positive target allocations totaled $7.7 million in Fall 2023, down 7% from Fall 2022 ($8.2 million). Negative target allocations (-$0.9 million) decreased by 36% from their Fall 2022 level (-$1.4 million).

Energy Market Competitiveness: The residual supply index for the real-time energy market in Fall 2023 was 98.9, indicating that the ISO could *not* satisfy load and reserve requirements without the largest supplier, on average. Additionally, the percentage of intervals with pivotal suppliers was the highest in Fall 2023 at 60%, indicating that there were more opportunities for suppliers to exercise market power than in other quarters. The low RSI and high pivotal supplier frequency in Fall 2023 resulted from lower reserve margins, which decreased due to planned generator outages.

Mitigation continued to occur very infrequently. During Fall 2023, mitigation asset-hours represented just 0.07% of total asset-hours. This was a similar share to that of Fall 2022 (0.08%) despite the increase in pivotal supplier asset-hours. Most mitigations (167 asset-hours) in Fall 2023 were reliability commitment mitigations that occurred in the real-time market. Additionally, there were 54 asset-hours of real-time manual dispatch energy mitigation in Fall 2023, a similar level to other quarters in the reporting period. These two mitigation types are typically the most common due to relatively tight conduct test thresholds.

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 2023	Summer 2023	Fall 2023 vs Summer 2023 (% Change)	Fall 2022	Fall 2023 vs Fall 2022 (% Change)
Real-Time Load (GWh)	27,581	31,802	-13%	26,793	3%
Peak Real-Time Load (MW)	24,026	23,006	4%	17,752	35%
Average Day-Ahead Hub LMP ($/MWh)	$32.03	$34.27	-7%	$60.58	-47%
Average Real-Time Hub LMP ($/MWh)	$31.23	$34.33	-9%	$60.28	-48%
Average Natural Gas Price ($/MMBtu)	$2.24	$2.30	-2%	$6.00	-63%
Average No. 6 Oil Price ($/MMBtu)	$15.81	$14.91	6%	$19.33	-18%

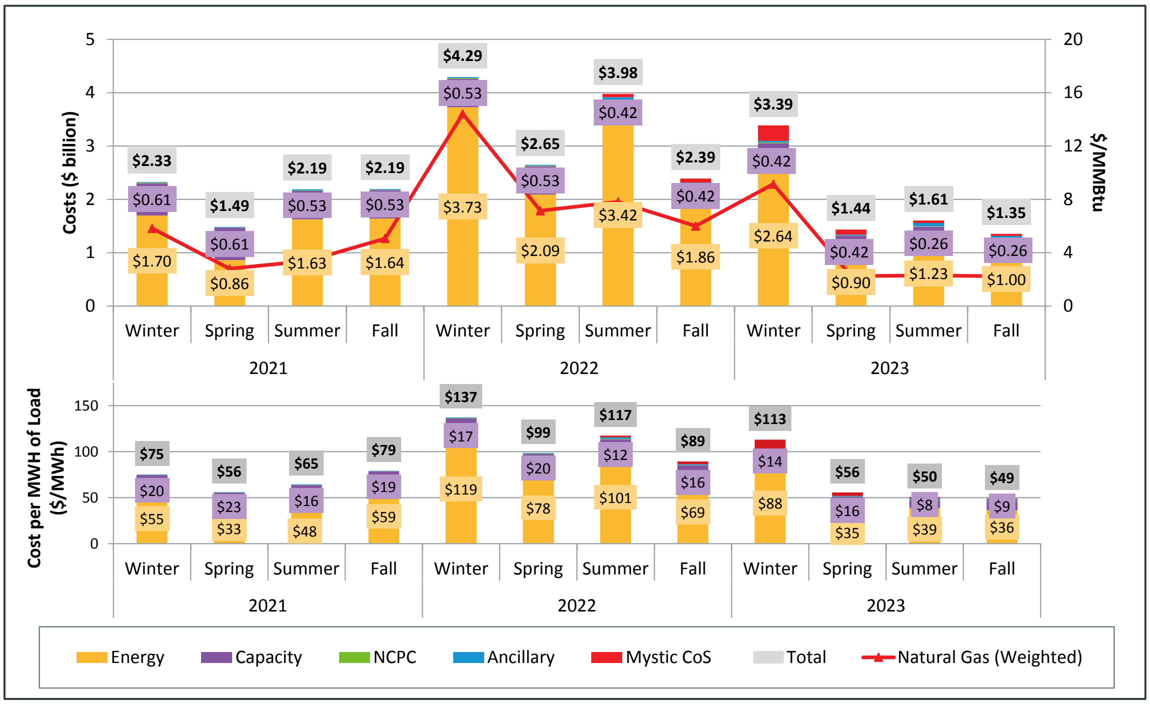
To summarize the table above:

- Day-ahead LMPs averaged $32.03/MWh in Fall 2023, down 47% from Fall 2022 ($60.58/MWh). Lower gas prices in Fall 2023 ($2.24/MMBtu) compared to Fall 2022 ($6.00/MMBtu) put downward pressure on LMPs.
- Energy prices did not decrease by as much as natural gas prices year-over-year (about 48% vs. 63%) because Fall 2023 saw a 1,200 MW increase in generator outages, on average, compared to Fall 2022.
    - Nuclear generation was down by 677 MW, on average, per hour primarily due to a planned refueling outage.
    - About 1,140 MW of pumped-storage generator capacity was out of service in Fall 2023, on average. This 730 MW year-over-year increase occurred due to multiple long-term planned outages. Though average pumped-storage generation output only decreased by 36 MW, these units typically provide large volumes of reserves.
    - The average margin for the system Total-30 reserve requirement was 2,099 MW in Fall 2023, the lowest value of the reporting period. The margin decreased by 628 MW compared to the previous fall, primarily due to the increase in pumped-storage generator outages. These outages led to tight system conditions and more expensive generator commitments.
- Total load in Fall 2023 (27,581 GWh, or an average of 12,629 MW per hour) was 3% higher than in Fall 2022 (26,793 GWh, or an average of 12,268 MW per hour). The increase was due to warmer temperatures in early September.

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.[4] 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.[5] 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 Fall 2023, the total estimated wholesale cost of electricity was $1.35 billion (or $49/MWh of load), a 43% decrease compared to $2.39 billion in Fall 2022 and a 17% decrease compared to $1.61 billion in Summer 2023. The decrease from Fall 2022 resulted from lower energy and capacity costs. The share of each wholesale cost component since Winter 2021 is shown in Figure 2-2 below.

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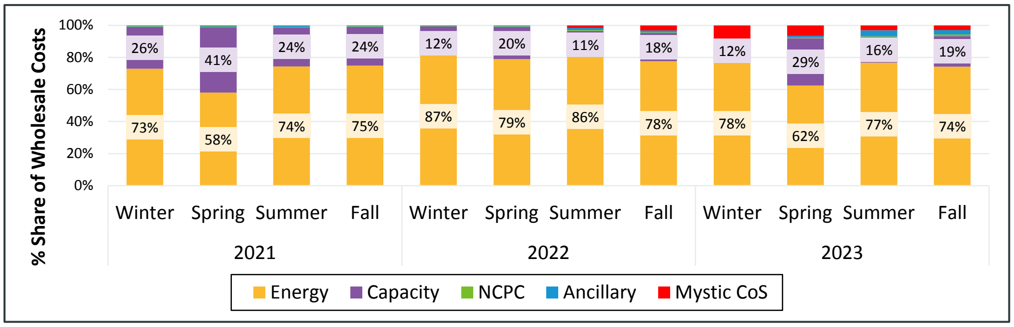
[4] In previous reports, we used system load obligations and average hub LMPs to approximate energy costs. Beginning with the Winter 2022 report, we updated the methodology to reflect energy costs based on location-specific load obligations and LMPs. These changes are reflected in all 11 seasons of data.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

[5] 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 $1.00 billion ($36/MWh) in Fall 2023, 46% lower than Fall 2022 costs. Lower energy costs were driven by a 63% decrease in natural gas prices compared to the previous fall. This decrease continued the trend of lower gas prices throughout 2023, and reflected lower national prices and higher storage levels.[6] However, increased generator outages and the resulting lower reserve margins 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 Fall 2023, the FCA 14 clearing price resulted in capacity payments of $259 million ($9/MWh), representing 19% 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. Section 5.1 discusses recent trends in the Forward Capacity Market in more detail.

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 $39.8 million in Fall 2023. Mystic 8 and 9 will receive supplemental payments until May 2024.

At $13.2 million ($0.48/MWh), Fall 2023 Net Commitment Period Compensation (NCPC) costs increased by 51% compared to Fall 2022 due to a $4.3 million increase in economic payments. Additionally, NCPC represented 1.3% of total energy costs in Fall 2023, the highest share of the reporting period. NCPC payments increased primarily due to two factors: First, available fast-start pumped-storage generation decreased in Fall 2023 due to multiple long-term planned outages. Fossil fuel-fired units filled the need for fast-start generation, and required more uplift than pumped-storage generators due to higher operating costs. Second, many peaking generators received significant NCPC payments in early September during heat wave conditions, and during M/LCC 2 events on October 4 and 23.

Ancillary service costs, which include payments for operating reserves and regulation, totaled $37.3 million ($1.35/MWh) in Fall 2023, representing 3% of total wholesale costs. Ancillary service costs increased by 37% compared to Fall 2022 costs due to higher real-time and forward reserve payments.

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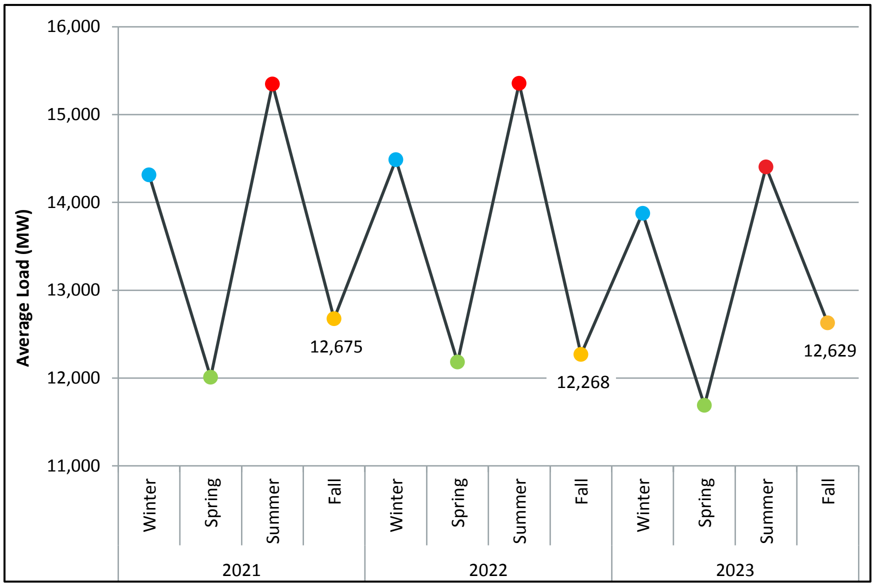
[6] The decreases in natural gas prices were consistent with lower Henry Hub spot prices. Additionally, working natural gas in storage in the Lower 48 United States was at its highest level since 2020, as discussed in the December 7 EIA report.

2.2 Load

This section reports quarterly load and demand conditions.[7] 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 12,629 MW in Fall 2023. Load increased 3% from Fall 2022, marking the only quarter in which average loads increased in 2023 relative to 2022. As discussed below, increased loads in Fall 2023 are attributable to weather conditions, particularly in early September. While average loads increased, average hourly load reductions attributable to behind-the-meter photovoltaic generation also increased to 440 MW, up 17% from Fall 2022.[8]

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

[8] Estimated installed behind-the-meter photovoltaic capacity rose to 4,089 MW in Fall 2023, up 18% from Fall 2022.

Load and Temperature

Monthly weather patterns significantly affected loads in Fall 2023. 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).[9]

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

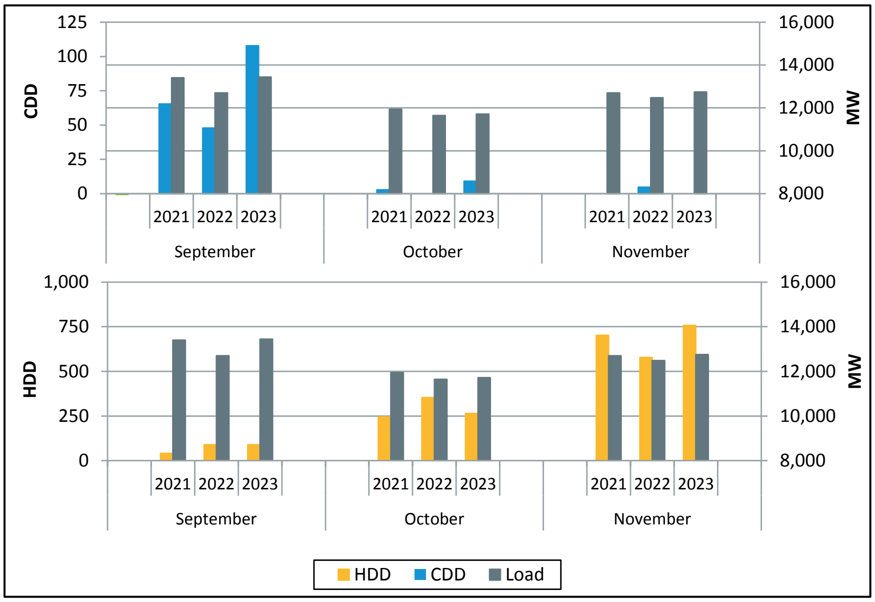


Figure 2-4 shows that average monthly Fall 2023 loads were highest in September, driven by a significant increase in CDDs during hot weather. While September temperatures averaged 65°F, hourly temperatures from September 3 to September 9 averaged 76°F and peaked at 90°F across New England during heat wave conditions, leading to high air conditioning demand. This heat wave drove September average loads to 13,447 MW, up from 12,700 MW in September 2022. October average loads (11,645 MW) were comparable to 2022, while November average loads (12,750 MW) increased 2% from 2022, following colder temperatures and an increase in HDDs.[10]

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

[10] Changes in CDDs have a greater impact on load than changes in HDDs. Electricity demand responds more to changes in air conditioning demand than heating demand in New England.

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. 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

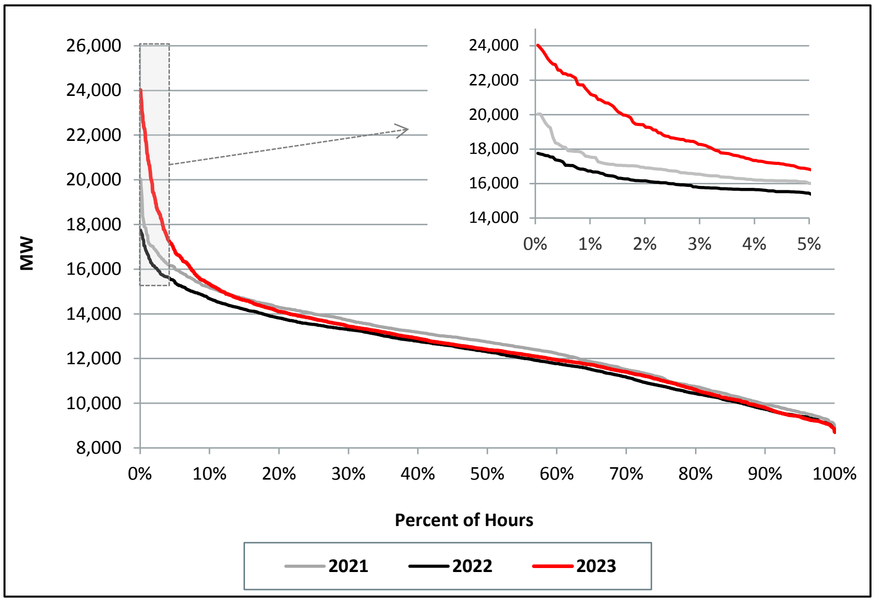


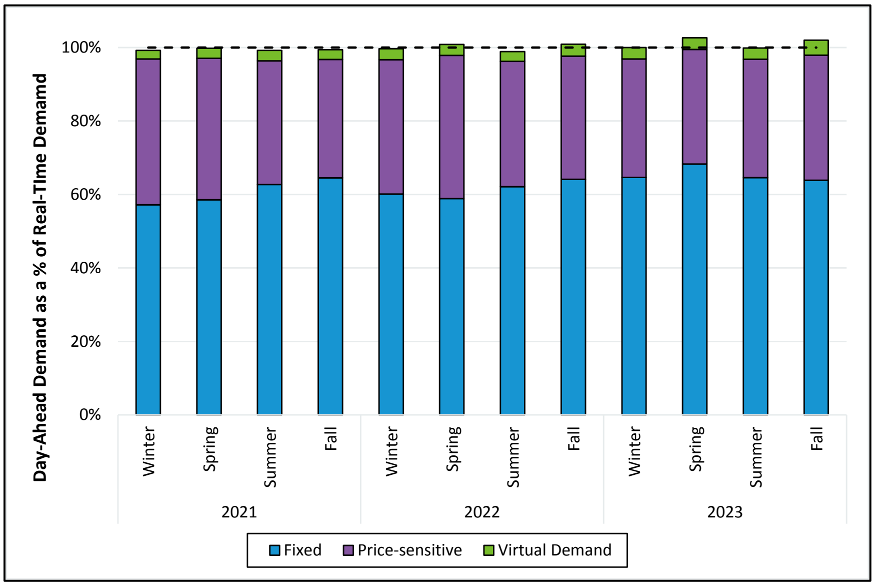
Figure 2-5 shows that Fall 2023 loads were generally higher than Fall 2022 loads. Notably, loads within the top 5% of hours in Fall 2023 greatly exceeded prior year fall loads. The top 4% of Fall 2023 loads all occurred within early September during heatwave conditions. In this period, the system reached annual peak load at 24,016 MW, exceeding prior annual peak load in July.[11] In these extreme conditions, Fall 2023 loads in the top 5% of hours averaged 19,260 MW, up from 16,158 MW in 2022 and 16,954 MW in 2021. Outside this extreme range, Fall 2023 loads were relatively comparable to prior years. The bottom 95% of Fall 2023 loads averaged 12,280 MW, only 2% above Fall 2022 (12,063 MW) and below Fall 2021 (12,450 MW).

[11] September 2023 annual peak load marks the only time that New England annual peak load did not occur during summer months in over 20 years. Summer 2023 New England peak temperatures did not exceed 89°F, while temperatures during the September heat wave reached 90°F. The resulting September peak loads exceeded the relatively mild Summer 2023 loads.

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.[12] 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.[13]

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



In Fall 2023, participants cleared an average of 102% of their real-time demand in the day-ahead market, up from 101% in Fall 2022. Fixed demand bidding remained static at 64% of real-time demand. Cleared price-sensitive bids averaged 34% of real-time demand, similarly unchanged from Fall 2022. Priced demand bids continued to have limited market impacts.[14] Cleared virtual demand marginally increased from 3% of real-time demand in Fall 2022 to 4% in Fall 2023, driven by increased virtual demand clearing at load zones.

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[12] 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.

[13] Day-ahead cleared demand is calculated as fixed demand + price-sensitive demand + virtual demand. Real-time metered load is calculated as generation + settlement-only generation – asset-related demand + price-responsive demand + net imports – losses. 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. Real-time load is calculated 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.

[14] Although price-sensitive demand bids are submitted with a MW quantity and a corresponding price representing a maximum willingness to pay, the majority of price-sensitive demand bids are priced well above day-ahead LMPs. These bids are effectively fixed demand under observed market conditions, and only differ from fixed demand bids in hypothetical extreme pricing scenarios.

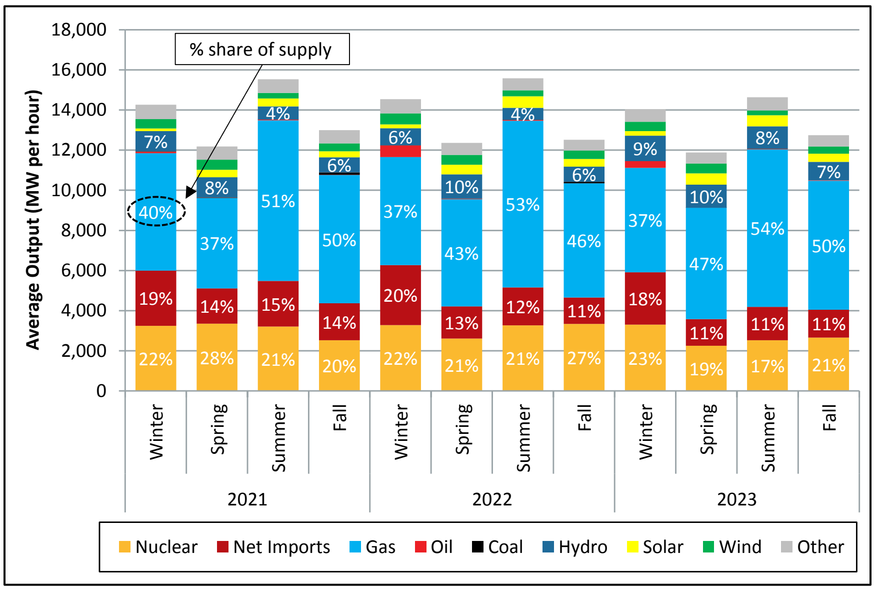
2.3 Supply

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

2.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The shares of energy production by generator fuel type for Winter 2021 through Fall 2023 are illustrated in Figure 2-7 below. Each bar's height represents the average electricity generation from that fuel type (in MW per hour), while the percentages represent the share of generation from that fuel type.[15]

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



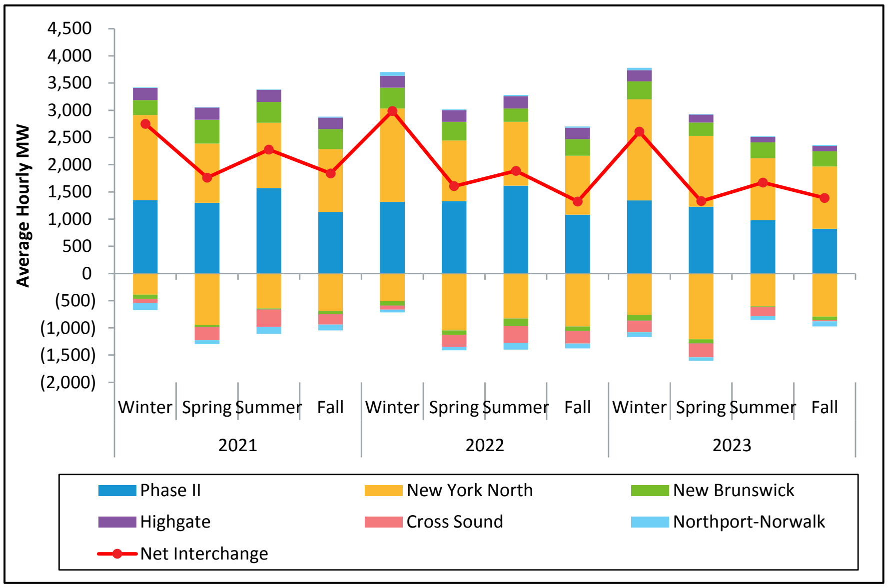
Average output in Fall 2023 (12,759 MW per hour) was 303 MW per hour more than in Fall 2022 (12,455 MW per hour) due to increased demand. The largest season-over-season increase occurred in gas generation, which rose by 733 MW per hour between Fall 2022 (5,690 MW per hour) and Fall 2023 (6,424 MW per hour). This increase more than offset the decrease in nuclear generation (677 MW per hour) that occurred as a result of predominately planned outages, with one nuclear generator out of service for close to half the period on a planned refueling outage. Collectively, net imports and generation from the nuclear and gas-powered fleet represented 82% of the total generation in Fall 2023, closely matching their contribution from Fall 2022 (83%).

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

2.3.2 Imports and Exports

New England continued to be a net importer of power from its neighboring control areas of Canada and New York in Fall 2023.[16] The average hourly import, export and net interchange power volumes by external interface for the last 12 seasons are shown Figure 2-8 below.

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



On average, the net flow of energy into New England was 1,387 MW per hour in Fall 2023, down 17% from Summer 2023. Net interchange typically decreases from summer to fall due to a combination of lower energy demand and LMPs, and increased planned transmission outages between New England and the other control areas. Compared to Fall 2022, hourly net interchange increased by 5% year-over-year (by 64 MW) mainly due to fewer exports to New York. Total net interchange in Fall 2023 represented 11% of load (NEL), which was equivalent to levels from Fall 2022 (11%).

New York Interfaces

After being a net exporter to New York in Fall 2022, New England imported an average of 253 MW per hour across the three New York interfaces this fall. In Fall 2022, New York day-ahead prices at the New York North interface were $4.22/MWh higher than New England prices. The price spread fell to just $0.05/MWh in Fall 2023 (i.e., New York prices fell by more than New England prices). The lower price spread between the two control areas is consistent with increased net imports into New England over the New York North interface. Net imports at the New York North interface averaged 354 MW per hour in Fall 2023, up from 109 MW per hour the prior fall. Additionally, the Cross Sound Cable interface was out-of-service for over two months during the fall due to

[16] 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.

transmission work. Consequently, average net exports at the Cross Sound Cable interface fell from 228 MW per hour in Fall 2022 to 22 MW per hour in Fall 2023.

Canadian Interfaces

In Fall 2023, net imports from the Canadian interfaces averaged 1,134 MW per hour, the lowest level of imports from Canada over the prior 12 seasons. The majority of the reduction in Canadian imports occurred at the Phase II interface that connects New England with Québec. In Québec, abundant water resources and hydro generation provide excess electricity supply, which can be sold to neighboring control areas. However, in the past year, sparse snow cover, a low spring run-off and less summer precipitation contributed to lower reservoir levels in Québec and fewer opportunities to export power into New England.[17] At Phase II, net imports averaged 821 MW per hour, which was 24% lower than in Fall 2022.

Highgate, the other interface that connects New England to Québec, also saw a decrease in net imports. In Fall 2023, net imports averaged 94 MW per hour at Highgate, which was down from 214 MW per hour in Fall 2022. The reduction was due to lower cleared real-time transactions from a participant across the interface.

[17] For more information on Québec reduction in exports, see Hydro-Québec Quarterly Bulletin, Third Quarter 2023

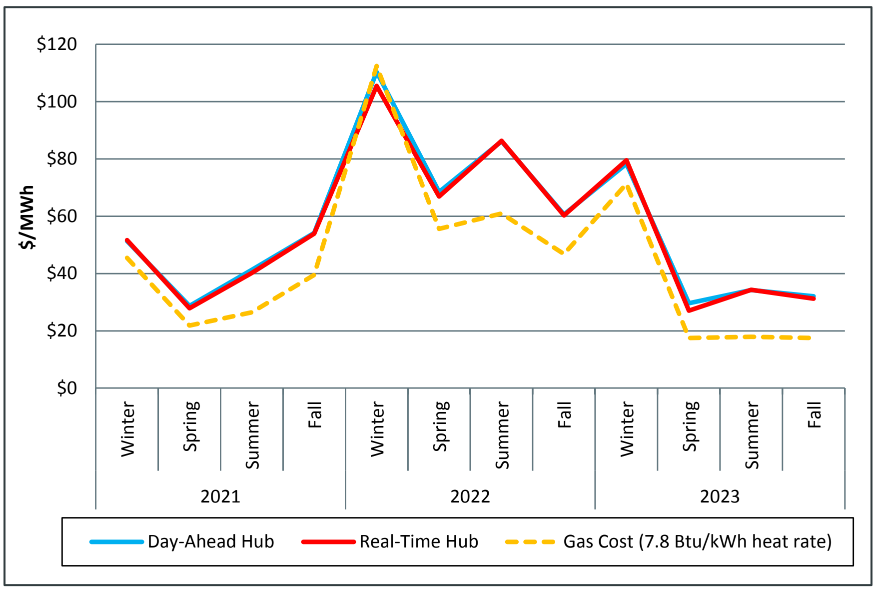
Section 3
Day-Ahead and Real-Time Markets

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.[18]

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 2023 were $31.23 and $32.03/MWh, respectively. Gas costs averaged $17.48/MWh in Fall 2023. Though quarterly average real-time and day-ahead prices were similar, there were certain days where real-time prices were substantially lower than day-ahead prices due to factors like additional renewable or fixed-price generation in real-time. Generally, if there is more price-taking generation in real-time compared to the day-ahead schedule, it displaces more expensive generation and leads to lower prices. There were also days with higher real-time prices due to tight system conditions. For example, there were M/LCC 2 events on October 4 and 23 due to unplanned generator and transmission outages.

The spread between the average day-ahead electricity price and average estimated gas cost was $14.55/MWh in Fall 2023, slightly higher than the $13.80/MWh spread in Fall 2022 but similar to the $14.67/MWh spread in Fall 2021. The higher spread in Fall 2023 compared to the previous fall resulted from a 1,200 MW increase in generator outages, on average. The additional outages led to

[18] 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.

tighter system conditions and more expensive generator commitments, resulting in higher energy prices relative to the average estimated gas cost.

Average energy prices in Fall 2023 were lower than Fall 2022 prices by about $29/MWh (down 47-48%) in both the day-ahead and real-time markets. These decreases are consistent with lower natural gas prices in Fall 2023, which fell by 63% compared Fall 2022. The increase in generator outages in Fall 2023 compared to the previous fall partially muted the impact of lower natural gas prices on LMPs. Nuclear generation was down by 677 MW on average per hour due to a planned refueling outage. Additionally, the system Total-30 reserve margin decreased by 628 MW in Fall 2023 compared to the previous fall, primarily due to a 730 MW increase in pumped-storage generator outages. These outages increased the likelihood of tight system conditions and resulted in more expensive generator commitments.

Prices did not differ significantly among the load zones in either market in Fall 2023, indicating that there was relatively little transmission congestion on the system at the zonal level.

3.2 Marginal Resources and Transactions

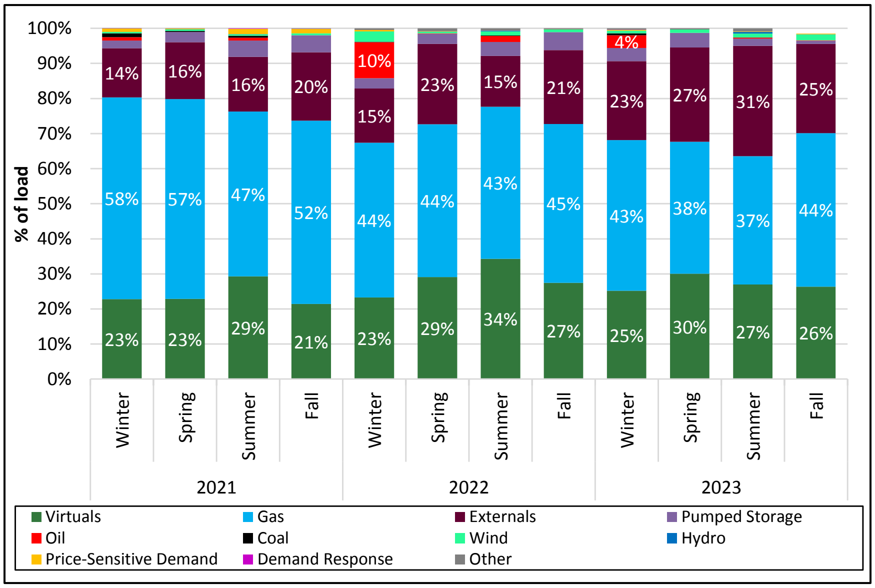
This section reports marginal units by transaction and fuel type on a load-weighted basis. When more than one resource is marginal, the system is typically constrained and marginal resources likely do not contribute equally to setting price for load across the system. The methodology employed in this 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 2021 is illustrated in Figure 3-2 below.[19]

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

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

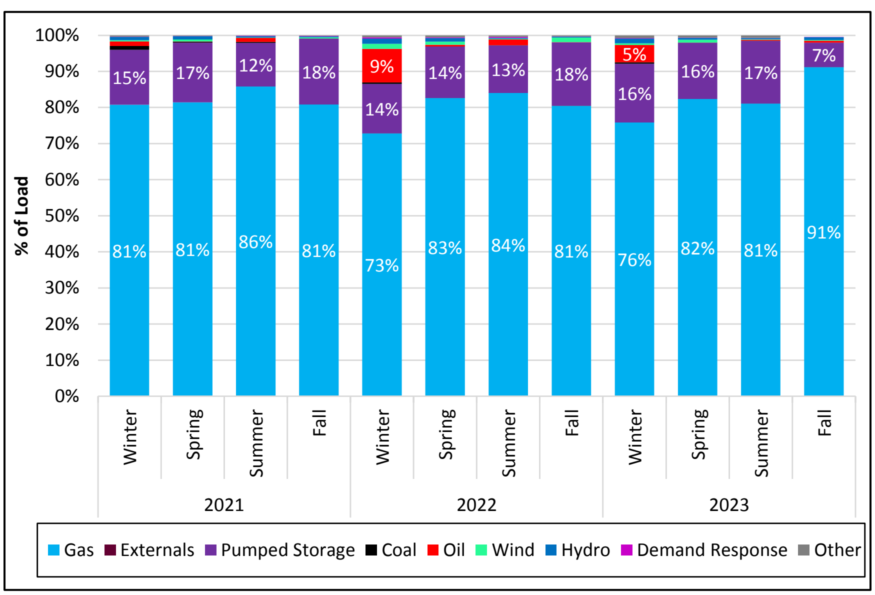


Gas-fired generators were the most common marginal resource type in the day-ahead market, setting price for 44% of total day-ahead load in Fall 2023. Virtual transactions and external transactions were next, setting price for 26% and 25% of load, respectively. Other resource types were collectively marginal for less than 5% of load.

Real-Time Energy Market

The percentage of load for which each fuel type set price in the real-time market since Winter 2021 is shown in Figure 3-3 below.

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



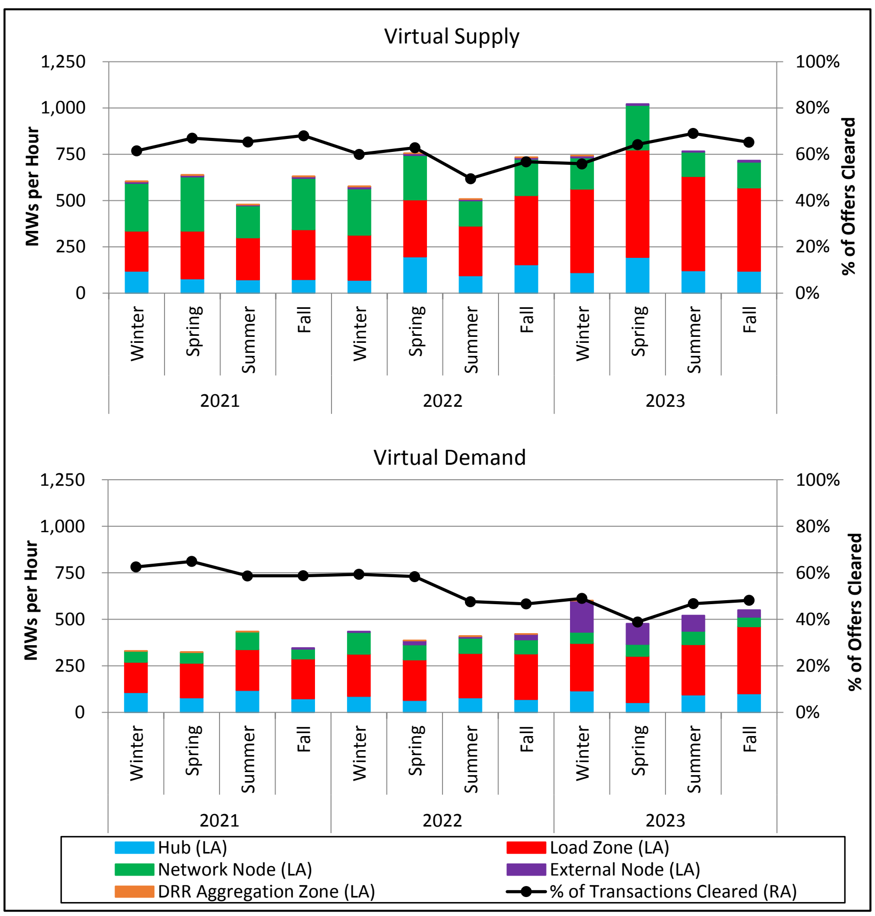
Similar to the day-ahead market, natural gas-fired generators set price for the highest percentage of load in the real-time market in Fall 2023 (91%). Pumped storage (generation and demand) was the marginal fuel with the second largest share of load in Fall 2023 (7%). This represents the smallest share of load associated with pumped-storage facilities over the entire reporting period. The primary drivers for this reduction were planned outages for several of these units that spanned almost the entire season. While wind generators are frequently marginal in real time, the load within the constrained areas where they set price tends to be quite small. In Fall 2023, wind generators were the marginal fuel type 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 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 3-4 below. Cleared transactions are categorized based on the location type where they cleared: Hub, load zone, network node, external node, and Demand Response Resource (DRR) aggregation zone. The line graph (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 717 MW per hour in Fall 2023, down 2% from Fall 2022 (733 MW per hour). Generally, virtual supply activity is greater than virtual demand activity for two reasons: 1) the growing amount of solar settlement-only generation (SOG) and 2) the day-ahead bidding behavior of wind generation. By the end of Fall 2023, the installed capacity of solar SOGs was over 2,100 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 generation. Typically, wind generators offer high-priced energy in the day-ahead market, but produce energy at low, or even negative, prices in the real-time market.[20]

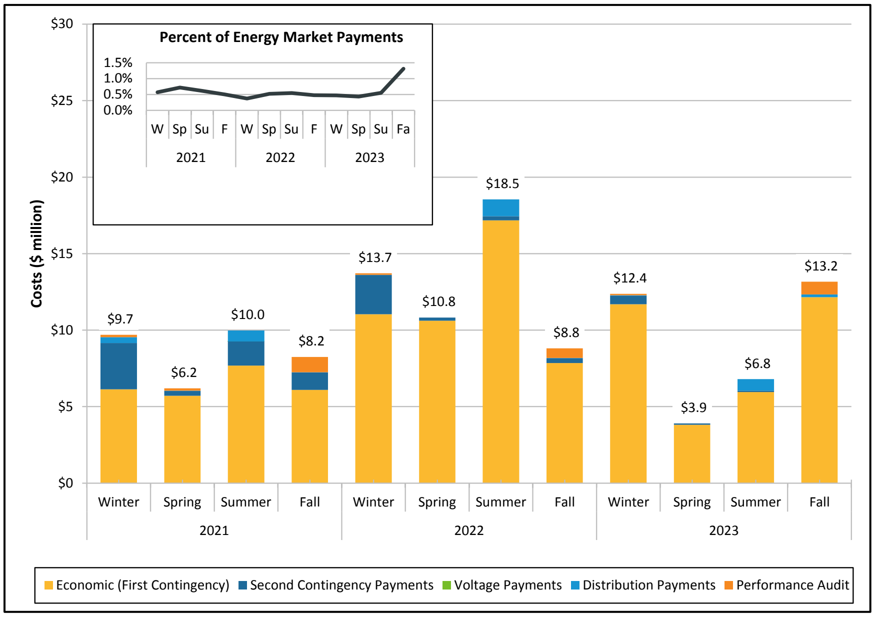
Cleared virtual demand averaged 551 MW per hour in Fall 2023, up 31% from Fall 2022 (421 MW per hour). The year-over-year increase was mostly due to higher volumes of cleared virtual demand at load zones, which increased by 116 MW per hour. One participant accounted for a majority of the increase at load zones (86 MW per hour).

[20] In Fall 2023, wind generation averaged 155 MW per hour in the day-ahead market, while real-time wind generation averaged 359 MW hour.

3.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) credits are make-whole payments to generators, external transactions, or virtual participants that incur uncompensated costs when following ISO dispatch instructions. NCPC categories include first- and second-contingency protection, voltage support, distribution system protection, and generator performance auditing.[21] Figure 3-5 below shows total NCPC by category and quarter for 2021-2023. The inset graph shows quarterly NCPC payments as a percent of total energy market payments.

Figure 3-5: NCPC by Category

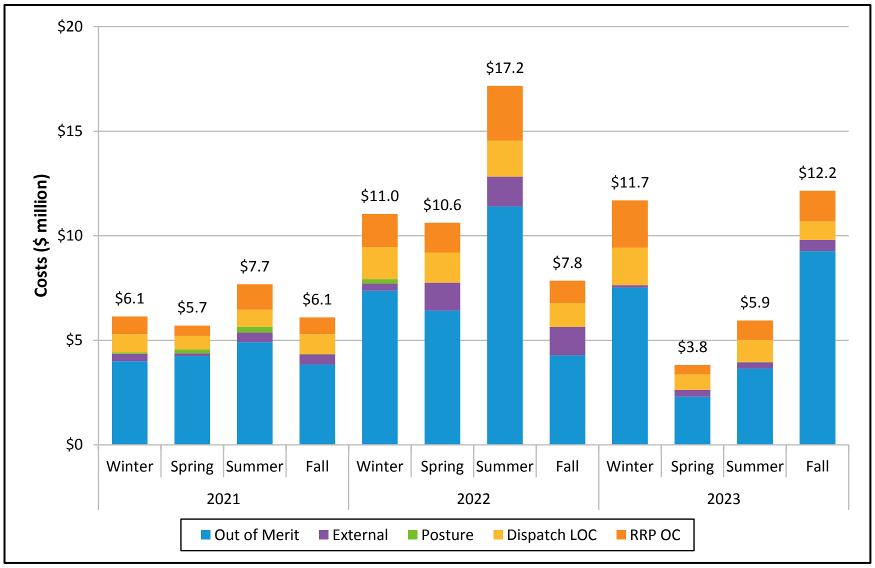


NCPC payments totaled $13.2 million in Fall 2023, the highest quarterly level in the year. Payments increased by 50% relative to Fall 2022 and increased by 94% relative to Summer 2023. NCPC rose to 1.3% of energy market payments, the highest level in the reporting period. The increase in NCPC payments was driven by elevated economic first contingency payments, which totaled $12.2 million. Audit NCPC totaled $0.8 million in Fall 2023 as a result of ISO-initiated generator audits prior to the winter months. Distribution payments reached $0.2 million, and there were no second contingency or voltage payments throughout the quarter.

Economic payments account for 92% of all NCPC payments throughout Fall 2023. Economic NCPC can be categorized by reason, including out of merit payments for generator operating costs that are not fully covered through energy market revenue, external payments, posturing, and dispatch or rapid response opportunity cost payments. The following Figure 3-6 displays economic NCPC payments by reason.

[21] 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).

Figure 3-6: Economic NCPC by Reason



The increase in economic NCPC in Fall 2023 was primarily driven by out of merit payments, which totaled $9.3 million, or 76% of economic payments. Out of merit payments more than doubled from Fall 2022 ($4.3 million) and Summer 2023 ($3.6 million). Despite the increase in out of merit payments, no single generator received more than 5% of the total out of merit payments in the quarter. Dispatch and rapid-response pricing opportunity cost payments totaled $2.4 million, and external uplift totaled $0.5 million.

The increase in Fall 2023 NCPC payments can be attributed to the need to commit and dispatch more expensive fast-start generation. The amount of fast-start capable pumped-storage generation available at the system level fell in Fall 2023 relative to prior quarters due to significant outages. During tight system conditions, including M/LCC 2 events on October 4 and October 23, fossil fuel units filling the need for fast-start generation received significant uplift due to higher operating costs than typical fast-start pumped-storage generation. While fast-start pricing mechanics typically increase LMPs to compensate fast-start unit commitment costs, fossil fuel units were often unable to recover their full operation costs during periods where they did not set price. Uplift during these periods drove the increase in total NCPC payments as a percentage of energy market payments in Fall 2023.

3.5 Real-Time Operating Reserves

This section provides details about real-time operating reserve pricing and payments.

Real-time Reserve Pricing

Real-time reserve pricing (that is non-zero) occurs when a resource incurs an opportunity cost as a result of providing reserves instead of energy. This happens when the reserve capability of the system only just meets a reserve requirement, and resources that would otherwise be profitable providing energy need to be compensated when instead providing reserves.[22] Consequently, periods with reserve pricing can be indicative of tighter system conditions. The frequency of non-zero reserve pricing by product and zone, along with the average price during these intervals for the past three years, is provided in Table 3-1 below.[23]

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

Product	Zone	Fall 2023		Fall 2022		Fall 2021	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	**System**	$24.91	214.0	$9.58	205.7	$7.35	350.5
TMNSR	**System**	$128.97	29.4	$158.74	0.9	$0.00	0.0
TMOR	**Rest of System**	$145.17	18.3	$239.63	0.4	$0.00	0.0
	NEMA/Boston	$144.11	18.4	$239.63	0.4	$0.00	0.0
	CT	$145.17	18.3	$239.63	0.4	$0.00	0.0
	SWCT	$145.17	18.3	$239.63	0.4	$0.00	0.0

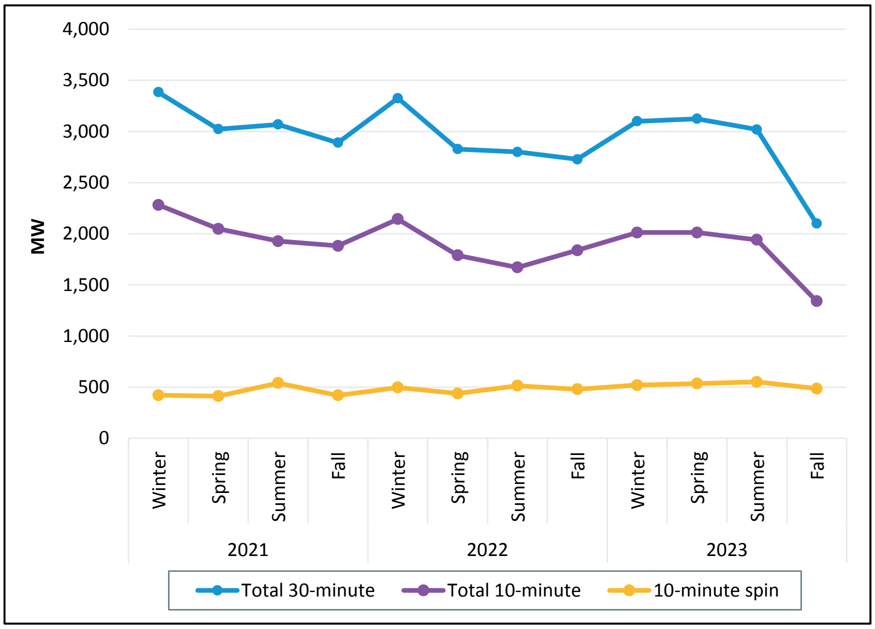
The system experienced much higher counts of non-zero TMNSR and TMOR prices in Fall 2023 than in either of the prior two falls as the reserve capability of the New England fleet was reduced due in part to the planned outages of several pumped-storage hydro units. Collectively, these units are capable of providing substantial amounts of 10-minute non-spinning reserves (when offline) and 10-minute spinning reserves (when online and pumping); their absence led to notable decreases in the reserve margins during the fall, Figure 3-7. Specifically, the average margin for the ten-minute reserve requirement fell by 498 MW (from 1,838 MW in Fall 2022 to 1,340 MW in Fall 2023), and the average margin for the total reserve requirement fell by 628 MW (from 2,727 MW in Fall 2022 to 2,099 MW in Fall 2023). Lower margins mean that the system has less unloaded capacity to rely upon when a contingency, such as the loss of a generator, occurs, and, all else equal, would result in more intervals in which a reserve requirement is binding and there is non-zero

[22] 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.2.7A of Market Rule 1.

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

reserve pricing. Additionally, the higher incidence of non-zero TMNSR and TMOR reserve prices contributed to higher TMSR clearing prices in Fall 2023 compared to the prior two falls.[24]

Figure 3-7: Average Reserve Margins by Quarter



Real-time Reserve Payments

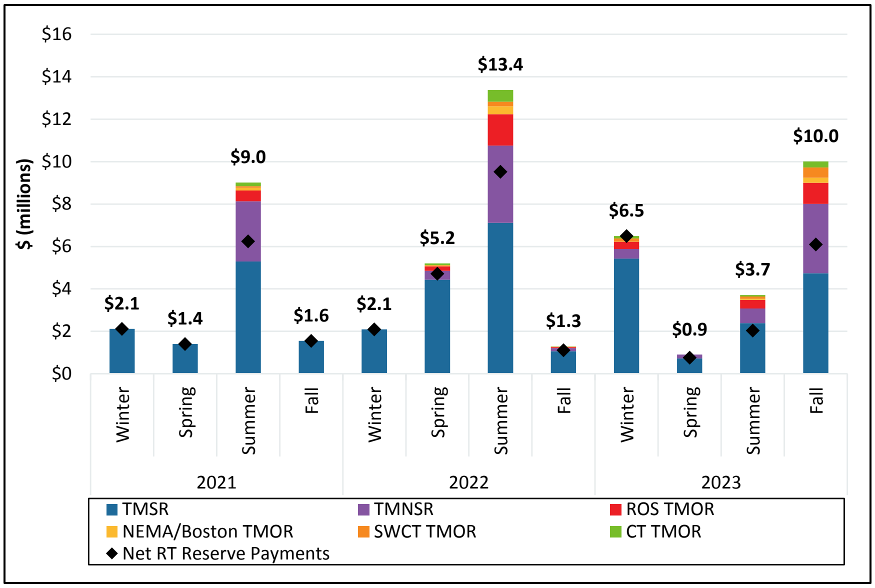
Real-time reserve payments by product and by zone are illustrated in Figure 3-8 below.[25] The height of the bars indicate gross reserve payments, while the black diamonds show net payments (i.e., payments after reductions have been made to Forward Reserve Market (FRM) resources providing real-time reserves).[26]

[24] Real-time operating reserve prices cascade up from TMOR to TMNSR to TMSR. See Section III.2.7A(d).

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

[26] 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.10.4 of Market Rule 1.

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

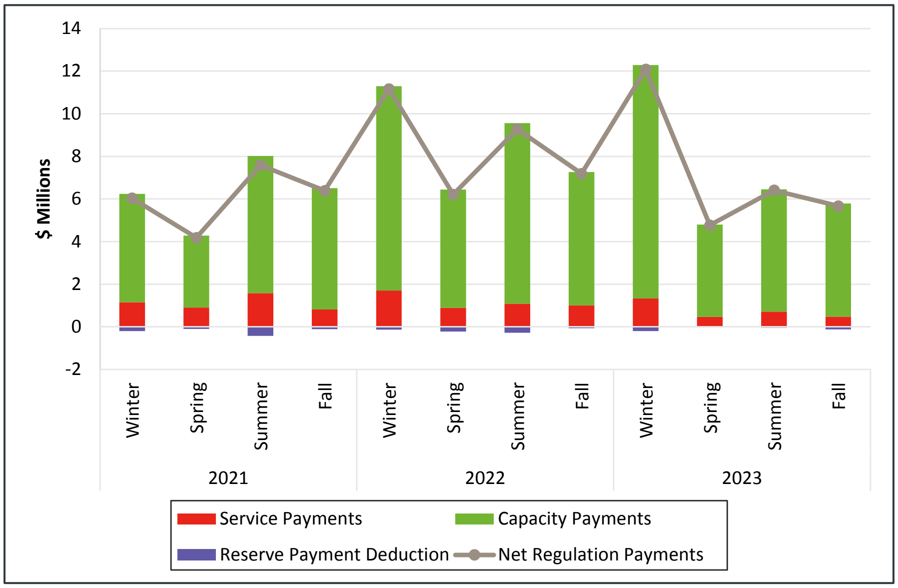


The tighter reserve conditions in Fall 2023 resulted in gross payments ($10.0 million) that considerably exceeded their value from Fall 2022 ($1.3 million) and from Fall 2021 ($1.6 million). Nearly half of the gross real-time reserve payments in Fall 2023 went to resources providing TMSR ($4.7 million), while resources providing TMNSR received $3.3 million, and resources providing TMOR received $2.0 million. However, as some of the resources that provided reserves in real time were FRM resources, there were considerable forward reserve obligation charges ($3.9 million). Consequently, net real-time reserve payment in Fall 2023 amounted to $6.1 million.

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 3-9 below.

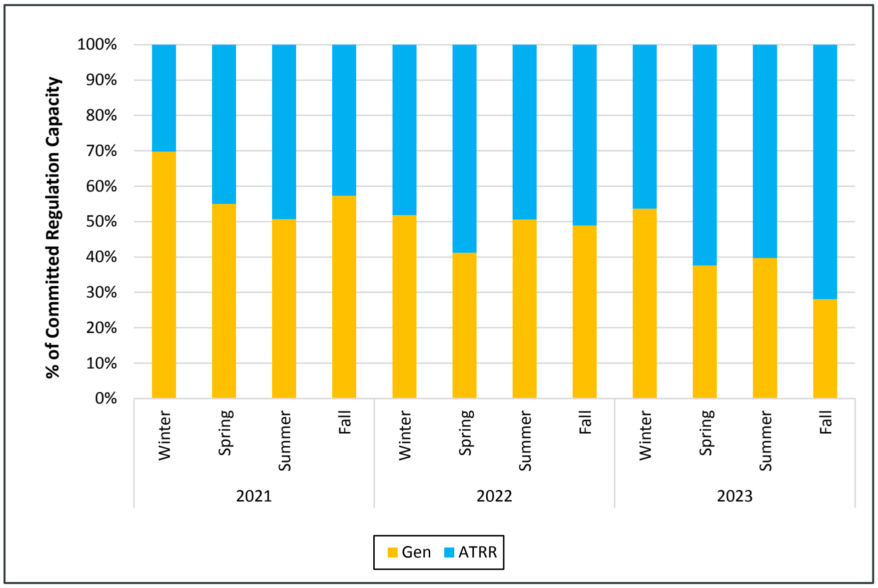
Figure 3-9: Regulation Payments



Total regulation market payments were $5.7 million during the reporting period, down 21% from $7.2 million in Fall 2022 and down by 12% from $6.4 million in Summer 2023. The decrease in payments compared to Fall 2022 resulted primarily from lower capacity prices (down 7%). Capacity prices decreased due to lower energy market opportunity costs (reflecting a decline in energy market LMPs) compared to the earlier period. Regulation service prices also decreased (down 53%) from Fall 2022. The lower regulation payments in Fall 2023 compared to Summer 2023 also reflected lower capacity prices (down 4%).

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 function solely as regulation resources, or may operate as a combination of energy market services: consumption (battery charging), generation (battery discharging), and regulation. The regulation resource mix is shown in Figure 3-10 below.

Figure 3-10: Regulation Resource Mix



The resource mix of committed regulation capacity has changed over the reporting period. In Fall 2021 and 2022, ATRRs (blue shading) provided 43% and 51% of committed regulation capacity, respectively. In Fall 2023, ATRRs provided 72%. This change follows continuing increases in the installed capacity of battery resources in the ISO's energy markets. Regulation capacity available from ATRRs increased to 210 MW on average in Fall 2023, up from 138 MW in Fall 2022 and 101 MW in Fall 2021. The change in resource mix also suggests that battery resources are lower-cost regulation resources, as ATRRs have increasingly displaced traditional generators in the 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.[27] 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[28] to the sum of each participant's total supply that is available within 30 minutes.[29] When a participant's available supply exceeds the supply margin, they are pivotal. The number of five-minute intervals with at least one pivotal supplier are divided by the total number of five-minute intervals in each quarter to obtain the percentage of intervals with pivotal suppliers.

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

[27] 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.

[28] 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 Total-30 reserve margin: Gen_{Energy} + $Gen_{Reserves}$ + [*Net Interchange*] -*Demand* - [$Reserve\ Requirement$]

[29] 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)

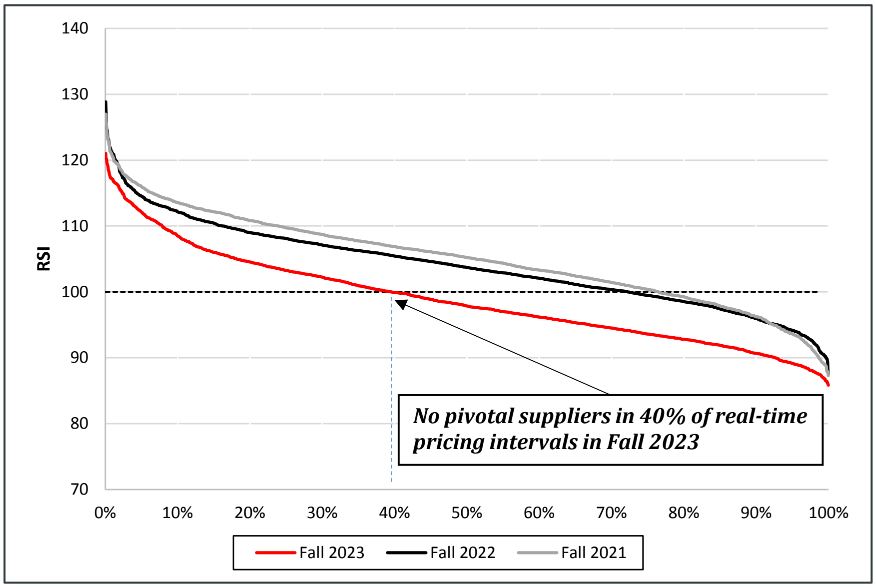
Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2021	107.9	8%
Spring 2021	106.6	14%
Summer 2021	104.7	27%
Fall 2021	105.0	24%
Winter 2022	106.5	12%
Spring 2022	106.7	19%
Summer 2022	102.6	34%
Fall 2022	104.0	28%
Winter 2023	105.2	20%
Spring 2023	107.7	22%
Summer 2023	103.8	34%
Fall 2023	98.9	60%

The RSI was above 100 in every quarter of the reporting period *except* for Fall 2023. The Fall 2023 value of 98.9 indicates that the ISO could not satisfy load and reserve requirements without the largest supplier on average. Additionally, the percentage of intervals with pivotal suppliers was the highest in Fall 2023 at 60%, indicating that there were more opportunities for suppliers to exercise market power than in other quarters. Despite increased opportunities to exercise market power, mitigation frequency was about the same in Fall 2023 as in Fall 2022. This suggests that participants didn't increase their attempts to raise prices above competitive levels even though they had more opportunities to do so. Section 4.2 discusses mitigation in more detail.

The low RSI and high pivotal supplier frequency in Fall 2023 resulted from lower reserve margins. The average Fall 2023 reserve margin (2,099 MW) was 628 MW lower than the Fall 2022 margin, and the lowest value of the reporting period. Total available reserves were 741 MW less compared to Fall 2022 on average, primarily due to 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. A 113 MW decrease in the average reserve requirement partially offset some of the lower reserve totals.

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 2023, the RSI was lower than that of Fall 2022 and 2021 across all ranked observations. The lowest RSI values took place over several different days of the quarter because reserve margins were low throughout the majority of the fall period.

4.2 Energy Market Supply Offer Mitigation

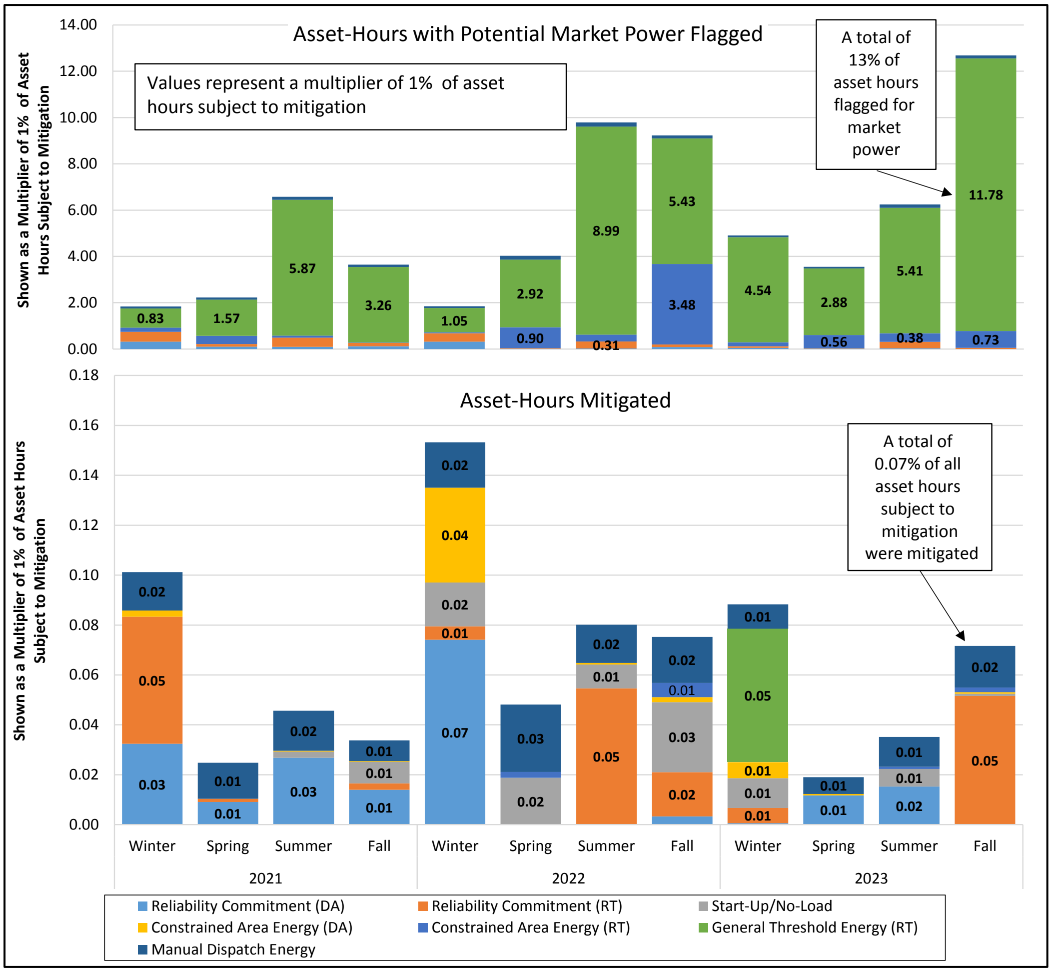
As in earlier periods, mitigation of energy market supply offers occurred infrequently in Fall 2023.

Energy Market Mitigation Frequency

This section summarizes three types of mitigation data: structural test failures, generator commitment or dispatch hours, and mitigation occurrences. An indication of mitigation frequency relative to opportunities to mitigate generators is illustrated in Figure 4-2 below.[30] It compares asset hours of structural test failures for dispatch and commitment (depending on mitigation type) to asset hours of mitigations. To provide additional context, the values in the figure have been scaled relative to one percent of total asset hours subject to potential mitigation.

[30] For example, a generator (asset) committed for reliability for a 12-hour period would represent 12 asset hours of commitment. If that asset were mitigated upon commitment, then 12 asset hours of mitigation would occur. For constrained areas, if 10 assets were located in an import-constrained area for two hours, then 20 asset hours of structural test failures would have occurred. If a pivotal supplier has seven assets and is pivotal for a single hour, then seven hours of structural test failures would have occurred for that supplier; however, more than one supplier may be pivotal during the same period (especially during tighter system conditions), leading to larger numbers of structural test failures than for other mitigation types. Manual dispatch energy commitment data indicate asset hours of manual dispatch (i.e., the asset hours when these generators are subject to commitment). Finally, Start-up/No-load (SUNL) commitment hours are not shown because mitigation hours equal commitment hours.

Figure 4-2: Energy Market Mitigation



In general, the data in Figure 4-2 indicate that mitigation occurs very infrequently relative to the initial triggers for potential mitigation: ISO commitment and operation of a generator and energy market mitigation thresholds (i.e., structural test failures, commitment or dispatch).[31] The highest frequency of mitigation occurs for reliability commitments (49% of all mitigations, light blue or orange shading in the figure); this results from a relatively tight conduct test threshold, with any participant supply offer more than 10% above the IMM reference offer value being mitigated. General threshold (pivotal supplier) mitigation and start-up/no-load mitigation (green and gray shading) have had the lowest mitigation frequency, with each accounting for 8% to 10% of mitigations over the review period.

Comparing mitigations for Summer 2023 and Fall 2023, mitigations increased in Fall 2023 principally from increased reliability commitment mitigations in the real-time market. Overall,

[31] Because the general threshold commitment and constrained area commitment conduct tests resulted in so few mitigations during the review period that they would not display on the figure, those mitigation types have been omitted from the figure. The structural test failures associated with each mitigation type are the same as for the respective general threshold energy and constrained area energy structural test failures.

there were just 232 asset hours of mitigation in Fall 2023, while 324 thousand asset hours were potentially subject to mitigation.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs (such as local second contingency protection).[32] These commitments frequently reflect the reliability needs associated with transmission line outages and upgrades, as well as very localized distribution system support. Over the review period, Southeastern Massachusetts and Rhode Island (SEMA-RI) and Maine had the highest frequency of reliability commitment asset hours, at 59% and 33% respectively in the day-ahead energy market. This is consistent with transmission upgrades that occurred in SEMA-RI over the past several years, and with the frequency of localized transmission issues within Maine. Reliability commitment mitigations also occurred frequently in SEMA-RI and Maine: 85% of mitigations occurred in SEMA-RI and 15% occurred in Maine in the day-ahead market.[33] There were no reliability mitigations in Fall 2023, down from 10 asset hours in Fall 2022 and 50 hours in Summer 2023.

Start-up and no-load commitment mitigation: This mitigation type, like reliability commitments, occurs based on a generator's commitment and does not rely on a structural test failure. It uses a very high conduct test threshold (200% applied to the start-up, no-load, and offer segment financial parameters) to guard against the potential commitment of generators that are not covered by other mitigation types and that appear to have grossly over-stated their commitment costs (relative to reference values).[34] Grossly over-stated commitment costs are likely to lead to unnecessary uplift payments. These mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate. There were three asset hours of start-up and no-load mitigation in Fall 2023, compared to 23 asset hours of mitigation in Summer 2023 and 84 asset hours of mitigation in Fall 2022.

Constrained area energy (CAE) mitigation:[35] This mitigation type applies three tests prior to mitigation: structural, conduct and market impact. With relatively tolerant conduct and market impact test thresholds, the frequency of mitigation is low relative to the frequency of structural test failures. The frequency of mitigation given a structural test failure (i.e., generator located in an import-constrained area) in the real-time energy market has been approximately 0% (of structural test failure asset hours) over the review period, as only 34 asset hours of CAE mitigation have occurred in the real-time energy market and only 170 asset hours of mitigation have occurred in the day-ahead energy market. The frequency of structural test failures follows the incidence of transmission congestion and import-constrained areas within New England. In Fall 2023, there were few hours of structural test failures (2,352 asset hours) in the real-time market, and there

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[32] 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. Market Rule 1, Appendix A, Section III.A.5.5.6.1.

[33] Reliability commitments are typically made in the day-ahead energy market and carry over to the real-time energy market. Hence, day-ahead reliability commitments account for the majority of the reliability commitment asset hours in the real-time energy market. Special-constraint resource (SCR) commitments are an exception to day-ahead reliability commitments, as those mainly occur in the real-time energy market.

[34] 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 reference values for those same parameters.

[35] Day-ahead energy market structural test failures are not being reported at this time. This results from questions about some of the source data for these failures. We expect to report on these structural test failures in future reporting.

were only six asset hours of constrained area energy mitigation. In the day-ahead market for Fall 2023, there were only two asset hours of mitigation.

General threshold energy mitigation: This mitigation type also applies three tests prior to mitigation. General threshold energy mitigation typically has the lowest frequency of any mitigation type, because it also has the most tolerant conduct test and market impact thresholds. This occurs in spite of this mitigation type having the highest frequency of structural test failures (i.e., pivotal supplier asset hours) for any mitigation type. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators. Two participants accounted for 70% of the structural test failures and five participants accounted for 85% of structural test failures over the review period. No general threshold energy mitigations occurred during Fall 2023. During the review period, general threshold energy mitigation has occurred only during Winter 2023.

Manual dispatch energy mitigation: Manual dispatch energy mitigation occurs when a generator is manually dispatched by the ISO. Behind reliability commitment mitigation, this mitigation type occurs with the second highest frequency of any mitigation type (accounting for 23% of mitigations over the review period). Like reliability commitment mitigation, manual dispatch energy mitigation has a relatively tight conduct test threshold (10%). Manual dispatch is relatively infrequent in the real-time energy market, with just a few hundred asset hours occurring each quarter. Combined-cycle generators have the highest frequency of manual dispatch; this is consistent with manual dispatch frequently occurring in the context of (1) regulation service provided to the real-time energy market and (2) the need for relatively flexible generators to be positioned away from the market software-determined dispatch to address short-term issues on the transmission grid. In Fall 2023, there were 418 asset hours of manual dispatch and 54 asset hours of mitigation. These levels are comparable with Summer 2023 (484 asset hours of manual dispatch and 39 asset hours of mitigation) and Fall 2022 (384 asset hours of manual dispatch and 55 asset hours of mitigation).

Section 5
Forward Markets

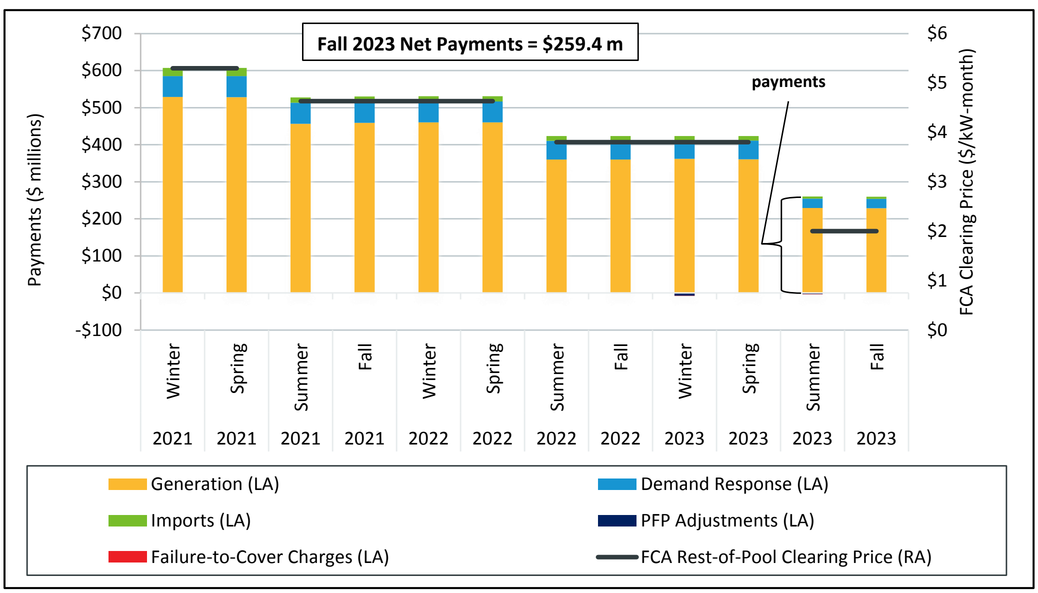
This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs), and in the Summer 2023 Forward Reserve Auction.

5.1 Forward Capacity Market

The capacity commitment period (CCP) associated with Fall 2023 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.[36] The auction cleared at a price of $2.00/kW-month, 47% lower than the previous year's $3.80/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.

Total FCM payments, as well as the clearing prices for Winter 2021 through Fall 2023, 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.

Figure 5-1: Capacity Market Payments



[36] From June 2022 to May 2024, Mystic 8 and 9 will receive supplemental payments per their cost-of-service agreement with the ISO. Since June 2022, the two Mystic units received a total of $542.7 million in cost-of-service payments.

In Fall 2023, capacity payments totaled $259.4 million. Total payments were down 39% from Fall 2022 ($423.3 million), driven by a 47% decrease in the clearing price from FCA 14 ($2.00/kW-month) to FCA 13 ($3.80/kW-month).

Approximately $276 thousand in Failure-to-Cover (FTC) charges were administered in Fall 2023. The FTC charge is a negative adjustment to the FCM credit which is applied when a resource has not demonstrated the ability to cover its Capacity Supply Obligation (CSO).

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 2023 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 14 (2023 - 2024)	Primary	12-month	2.00	33,956			
	Monthly Reconfiguration	Nov-23	3.00	863			
	Monthly Bilateral	Nov-23	4.00	8			
	Monthly Reconfiguration	Dec-23	3.50	982			
	Monthly Bilateral	Dec-23	1.22	6			
	Monthly Reconfiguration	Jan-24	3.94	1,074			
	Monthly Bilateral	Jan-24	2.00	6			

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

Three monthly reconfiguration auctions (MRAs) took place in Fall 2023: the November 2023 auction in September, the December 2023 auction in October, and the January 2024 auction in November. All three MRAs cleared at or above the associated primary auction clearing price with the January 2024 auction clearing at the highest price of $3.94/kW-month. Cleared volumes remained relatively steady month-to-month, with the January 2024 auction clearing the largest volume at 1,074 MW. As colder winter weather approaches, increased activity in reconfiguration auctions may be due to perceived elevated risk of a PfP event. The lack of prices in Maine, Northern New England, and Southeastern New England indicate no price separation in those capacity zones.

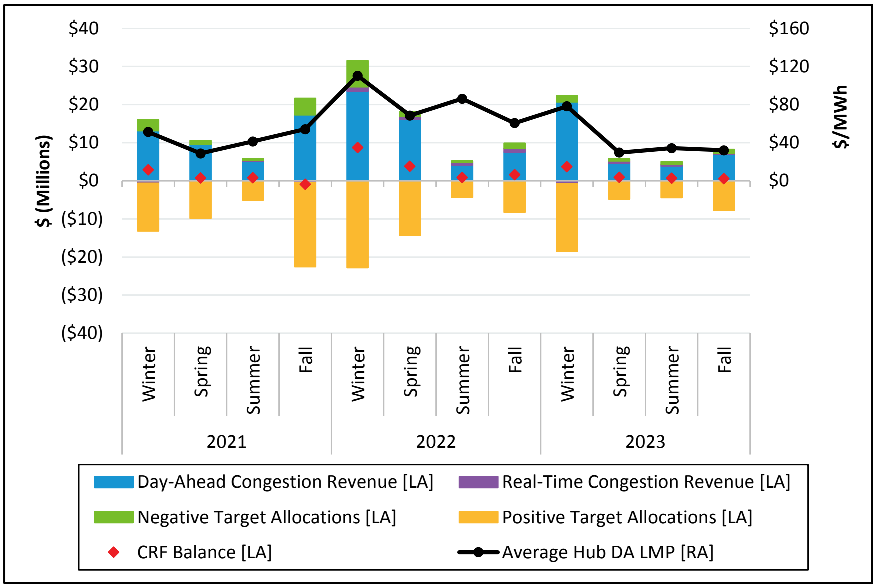
5.2 Financial Transmission Rights

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.[37, 38] This figure also depicts the quarterly average day-ahead Hub LMP.[39]

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



Binding transmission constraints in the southwestern part of Connecticut were one of the largest contributors to increased congestion totals in Fall 2023 relative to Summer 2023.[40] Day-ahead congestion revenue amounted to $7.0 million in Fall 2023. This represents an increase of 80% relative to Summer 2023 ($3.9 million) and a decrease of 8% relative to Fall 2022 ($7.5 million). Positive target allocations in Fall 2023 ($7.7 million) followed a similar pattern, increasing by 74% relative to Summer 2023 ($4.4 million) and decreasing by 7% relative to Fall 2022 ($8.2 million). Negative target allocations in Fall 2023 (-$0.9 million) increased by 30% from their Summer 2023 level (-$0.7 million) and decreased by 36% from their Fall 2022 level (-$1.4 million). Meanwhile,

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37 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). This figure depicts positive target allocations as negative values, as these allocations represent outflows from the CRF. Meanwhile, negative target allocations are depicted as positive values, as these allocations represent inflows to the CRF.

38 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").

39 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.

40 The most notable transmission congestion was associated with the following constraints: BUNKR_HL_1029-2_A_LN and S_NAUGTK_1580_A_LN.

real-time congestion revenue in Fall 2023 ($0.3 million) remained relatively modest and was generally in line with recent historical levels.

FTRs were fully funded in September 2023 and November 2023, but they were not in October 2023.[41] In October 2023 only 79.6% of positive target allocations were funded ($2.3 million of the $2.9 million due).[42] 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 2023, the congestion revenue fund had a surplus of $5.7 million for the year.

[41] 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.

[42] For more information about the monthly FTR settlement, see https://www.iso-ne.com/static-assets/documents/2023/02/2023_ftr_monthly_summary.pdf.