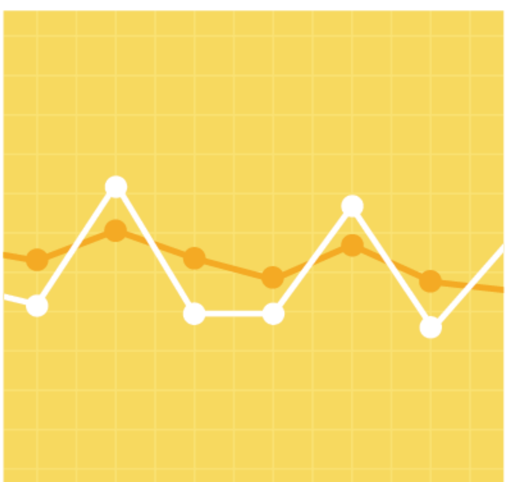
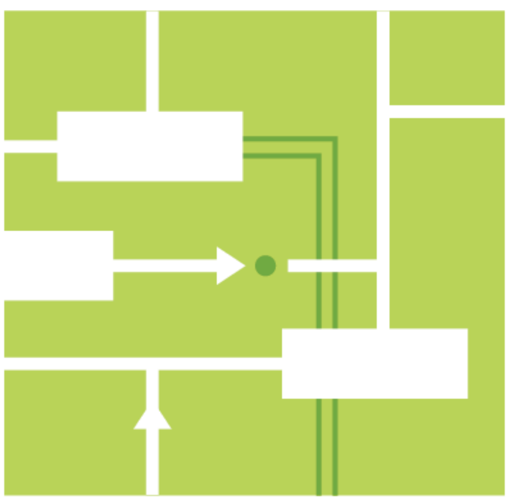
Summer 2023
Quarterly Markets Report

By ISO New England's Internal Market Monitor

OCTOBER 27, 2023





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.

Contents

Figures

Tables

Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Summer 2023 (June 1, 2023 through August 31, 2023).

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.59 billion, down 60% from $3.98 billion in Summer 2022. The decrease was driven by lower energy and capacity costs.

Energy costs totaled $1.23 billion; down 64% (by $2.19 billion) from Summer 2022 costs. Decreased energy costs were a result of lower natural gas prices. In Summer 2023, gas prices decreased by 71% compared to Summer 2022 reflecting lower national prices.

Capacity costs totaled $257 million, down 39% (by $166 million) from last summer. 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. During Summer 2022, 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 Summer 2022, the Mystic 8 and 9 generators sought to retire through the capacity market but were retained for reliability for their energy security value. 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 $33.6 million in Summer 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 $34.27 and $34.33 per megawatt hour (MWh), respectively. These were 60% lower than Summer 2022 prices on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $2.30/MMBtu in Summer 2023, 71% lower than the Summer 2022 price of $7.81/MMBtu. This decrease continued the trend of lower gas prices in Winter and Spring 2023, and reflected lower national prices and higher storage levels.[4]
- There were more nuclear generator outages in Summer 2023 than in Summer 2022 (up ~750MW). Additionally, net imports averaged 215 MW less compared to the previous summer. These factors offset, to some extent, the impact of lower natural gas prices on LMPs.

[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. 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.

[4] The decreases in natural gas prices were consistent with lower Henry Hub spot prices; working natural gas stocks were 13% higher than the five-year average during mid-July per the natural gas prices and storage discussions in EIA's Natural Gas Weekly Update.

- Energy market prices did not differ significantly among load zones.

System Event: Over the course of the quarter, smoke associated with Canadian wildfires caused either reductions or total outages of the Phase II interface in real-time, which is typically capable of importing 2,000 MW. While these fires reduced hourly imports by less than 20 MW on average for the quarter, on July 5 the wildfires caused the interface to go out-of-service during the peak load hour, and resulted in a capacity shortage event and real-time prices reaching $2,707/MWh.

FCM resources with a capacity supply obligation (CSO) were credited or charged the PfP rate of $3,500/MWh for any deviations from their CSO and the absolute value of credits/charges totaled $10.9 million. In addition, the July 5 event transferred over $3 million in PfP payments from under-performing capacity resources to supply assets and external transactions without a capacity obligation.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $6.8 million, down 63% or $11.8 million compared to Summer 2022. The year-over-year decrease was due to a decline in first contingency (also known as "economic") payments and was in line with lower energy prices. NCPC comprised 0.6% of total energy costs in Summer 2023, a slightly higher share than the previous summer (0.5%) but similar to other quarters over the reporting period.

Real-time Reserves: Real-time reserve payments totaled $3.7 million, a $9.7 million decrease from $13.4 million in Summer 2022. The decrease in spinning reserve payments was due to a lower frequency of non-zero reserve pricing intervals as well as lower reserve prices, consistent with lower energy prices and opportunity costs. Additionally, the average ten-minute spinning reserve requirement decreased by about 100 MW from the previous summer due to a smaller first contingency. Non-spinning reserve pricing continued to occur very infrequently, with the most notable pricing occurring on July 5, 2023, when ISO-NE experienced a capacity shortage event following a trip of the Phase II interface.

In Summer 2023, most payments (64%) were for ten-minute spinning reserve (TMSR), while smaller amounts went to resources providing non-spinning (or offline reserves); TMNSR ($0.7 million) or TMOR ($0.6 million). There was notable TMNSR and TMOR pricing on July 5, 2023, when ISO-NE experienced a capacity shortage event that resulted in penalty pricing for the non-spinning reserve products.

The frequency of non-zero spinning reserve prices decreased from 343 hours to 178 hours. This was partly due to lower spinning reserve requirements that resulted from a smaller first contingency in Summer 2023.[5] The average non-zero spinning reserve price also decreased relative to Summer 2022, from $19.98 to $13.30/MWh. The average TMNSR and TMOR prices in Summer 2023 were high ($270.38/MWh and $275.29/MWh, respectively) due to reserve constraint penalty factor (RCPF) pricing during the July 5 capacity scarcity conditions.

[5] See Section 3.5 for more information on this topic.

Regulation: Regulation market payments totaled $6.4 million, down 31% from $9.3 million in Summer 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 summer.

Financial Transmission Rights (FTRs): FTRs in June, July, and August 2023 were fully funded. Lower day-ahead prices contributed to lower day-ahead congestion revenue in Summer 2023. Day-ahead congestion revenue decreased by 7% compared to Summer 2022, totaling $3.9 million. Real-time congestion revenue in Summer 2023 ($0.5 million) remained modest and was in line with recent historical levels.

In terms of payments to and from FTR holders, positive target allocations totaled $4.4 million in Summer 2023, just slightly below the Summer 2022 value. Negative target allocations (-$0.7 million) increased by 97% from Summer 2022 (-$0.4 million).

At the end of August 2023, the congestion revenue fund had a year-to-date surplus of $4.5 million.

Energy Market Competitiveness: The residual supply index for the real-time energy market in Summer 2023 was 104, 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 34% of five-minute pricing intervals in Summer 2023, the same as the Summer 2022 value.

Mitigation continued to occur very infrequently. During Summer 2023, mitigation asset-hours represented just 0.04% of total-asset hours. Mitigation frequency decreased compared to Summer 2022 (0.08% of total asset-hours) due to a decline in reliability commitment mitigation.

Summer 2023 Forward Reserve Market Auction**:** In August 2023, ISO New England held the forward reserve auction for the Winter 2023-2024 delivery period (October 1, 2023 to May 31, 2024). System-wide supply offers in the Winter 2023-2024 auction exceeded the requirements for both TMNSR and TMOR.

The clearing prices for the Winter 2023-2024 auction were $3,350/MW-month for TMNSR and $671/MW-month for TMOR. Both prices decreased compared to the Summer 2023 auction, but increased compared to the Winter 2022-2023 auction. The TMOR price increased compared to the previous Winter auction due to a higher total thirty requirement and lower total thirty supply. The TMNSR price increased from Winter 2022-2023 auction pricing due to a higher requirement and higher offer prices.

The Residual Supply Index (RSI) for the system-level TMNSR and TMOR products in Winter 2023-2024 were 82 and 88, respectively. These values are below the structurally competitive level of 100. For TMNSR, all but two of the recent forward reserve auctions were structurally uncompetitive, while for TMOR, three of the six prior auctions were uncompetitive. We continue to be concerned that high forward reserve supply offers indicate an awareness that structurally-uncompetitive auctions provide an opportunity to submit uncompetitive supply offers. The increase in TMNSR clearing prices, in particular, has resulted primarily from increased supply offer pricing, without an obvious linkage to market conditions and risks. Our Spring 2023 report contained a recommendation that the ISO review and update the forward reserve supply offer cap to limit the potential exercise of market power and we are encouraged to see that such a review has commenced and is currently being discussed with stakeholders.[6,7]

[6] See Section 5 of the IMM's 2023 Spring report at: https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf#page=43&zoom=100,92,146

[7] See ISO-NE presentation to the NEPOOL Market Committee regarding the proposal to address market power concerns in the FRM, October 2023, at: https://www.iso-ne.com/static-assets/documents/100004/a08_mc_2023_10_11_12_proposed_revisions_update_frm_offer_cap_iso_presentation.pdf

Section 2
Overall Market Conditions

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

Table 2-1: High-Level Market Statistics

Market Statistics	Summer 2023	Spring 2023	Summer 2023 vs Spring 2023 (% Change)	Summer 2022	Summer 2023 vs Summer 2022 (% Change)
Real-Time Load (GWh)	31,799	25,798	23%	33,905	-6%
Peak Real-Time Load (MW)	22,982	16,206	42%	24,787	-7%
Average Day-Ahead Hub LMP ($/MWh)	$34.27	$29.62	16%	$86.13	-60%
Average Real-Time Hub LMP ($/MWh)	$34.33	$27.04	27%	$86.28	-60%
Average Natural Gas Price ($/MMBtu)	$2.30	$2.24	2%	$7.81	-71%
Average No. 6 Oil Price ($/MMBtu)	$14.91	$15.92	-6%	$23.53	-37%

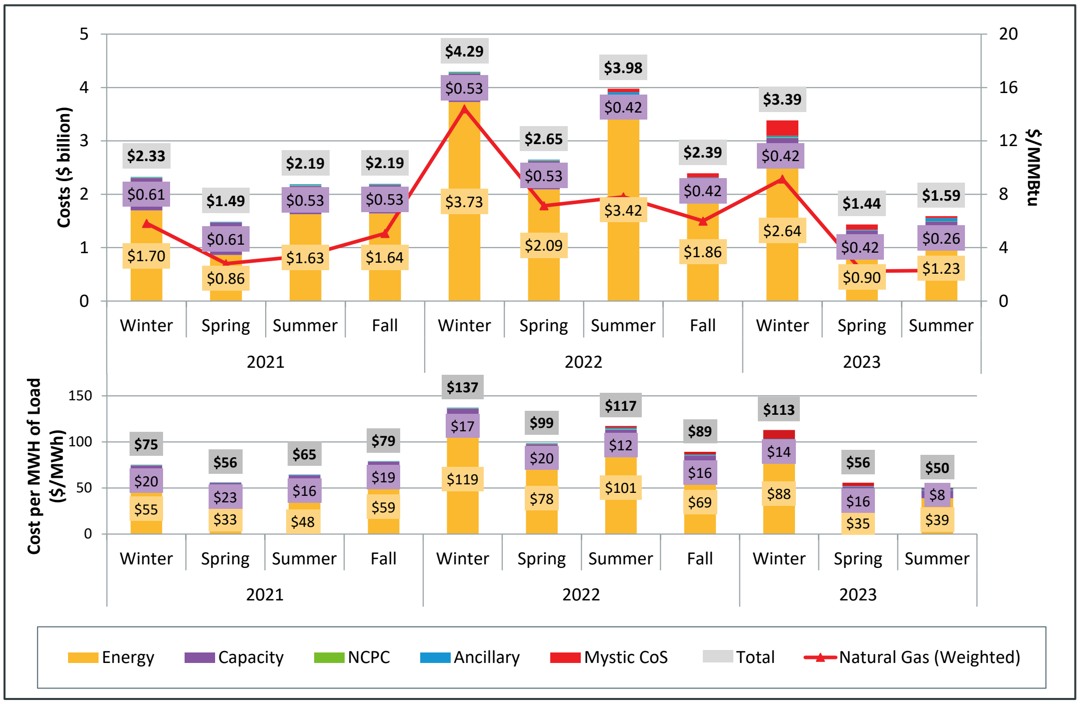
To summarize the table above:

- Day-ahead LMPs averaged $34.27/MWh in Summer 2023, down 60% from Summer 2022 ($86.13/MWh). Lower gas prices in Summer 2023 ($2.30/MMBtu) compared to Summer 2022 ($7.81/MMBtu) put downward pressure on LMPs.
- Energy prices did not decrease by as much as natural gas prices year-over-year (60% vs. 71%) because Summer 2023 saw less nuclear generation (down ≃750 MW on average per hour) and fewer net imports (down 215 MW on average per hour) compared to Summer 2022.
- Total load in Summer 2023 (31,799 GWh, or an average of 14,402 MW per hour) was 6% lower than in Summer 2022 (33,905 GWh, or an average of 15,355 MW per hour). The decrease was due to cooler temperatures, particularly in August.

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.[8] 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.[9] The bottom panel in Figure 2-1 depicts the wholesale cost per megawatt hour of real-time load.

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



In Summer 2023, the total estimated wholesale cost of electricity was $1.59 billion (or $50/MWh of load), a 60% decrease compared to $3.98 billion in Summer 2022 and an 11% increase compared to $1.44 billion in Spring 2023. The decrease from Summer 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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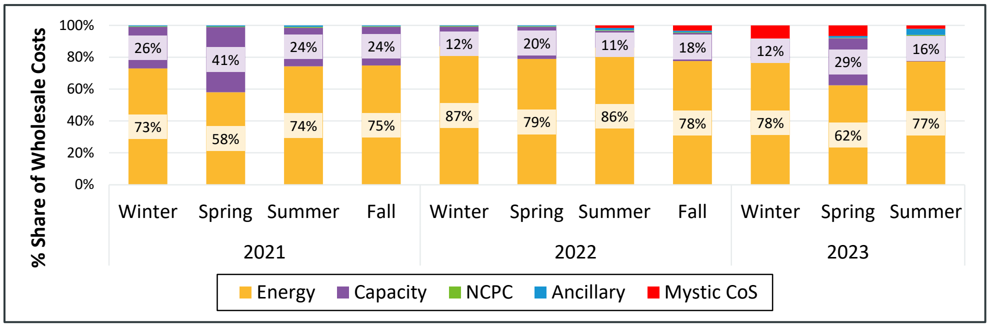
[8] In previous reports, we used system load obligations and average hub LMPs to approximate energy costs. Beginning with the Winter 2022 report, we updated the methodology to reflect energy costs based on location-specific load obligations and LMPs. These changes are reflected in all 11 seasons of data. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of quarterly wholesale costs.

[9] 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 77% of wholesale costs and totaled $1.23 billion ($39/MWh) in Summer 2023, 64% lower than Summer 2022 costs. Lower energy costs were driven by a 71% decrease in natural gas prices compared to the previous summer. This decrease continued the trend of lower gas prices in Winter and Spring 2023, and reflected lower national prices and increased storage. Natural gas prices continued to be a key driver of energy prices. Increased baseload outages and fewer net imports 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 Summer 2023, the FCA 14 clearing price resulted in capacity payments of $257 million ($8/MWh), representing 16% 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 $33.6 million in Summer 2023. Mystic 8 and 9 will receive supplemental payments until May 2024.

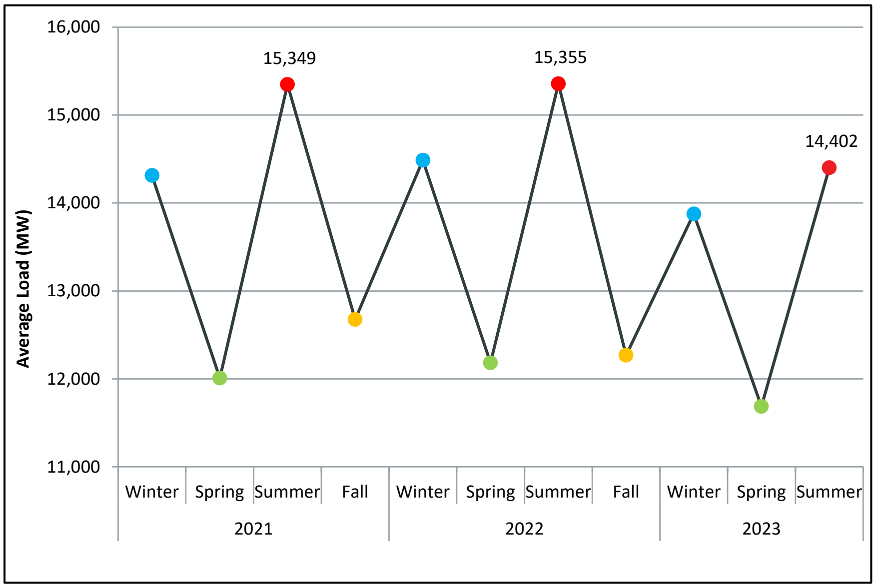
At $6.8 million ($0.21/MWh), Summer 2023 Net Commitment Period Compensation (NCPC) costs represented 0.6% of total energy costs, a similar share to other quarters over the reporting period. Summer 2023 NCPC costs were $11.8 million (or 63%) lower than in Summer 2022. The decrease was due to a decline in first contingency payments and was consistent with lower energy prices.

Ancillary service costs, which include payments for operating reserves and regulation, totaled $61.4 million ($1.93/MWh) in Summer 2023, representing 4% of total wholesale costs. Ancillary service costs increased by 14% compared to Summer 2022 costs. Though regulation and real-time reserve payments were lower, there was a large increase in forward reserve payments compared to Summer 2022 driven by higher Forward Reserve Auction clearing prices.

2.2 Load

Average hourly load by season is illustrated 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



In Summer 2023, hourly loads averaged 14,402 MW, which was 6% lower than both Summer 2022 and 2021 levels.[10] Average load fell year-over-year due to cooler weather especially during August 2023. Additionally, estimated behind-the-meter photovoltaic generation increased from 688 MW to 712 MW, on average, contributing to lower wholesale load during the month.

[10] 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).

Load and Temperature

The stacked graph in Figure 2-4 below compares average monthly load (left axis) to the monthly average Temperature-Humidity Index (right axis).[11]

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

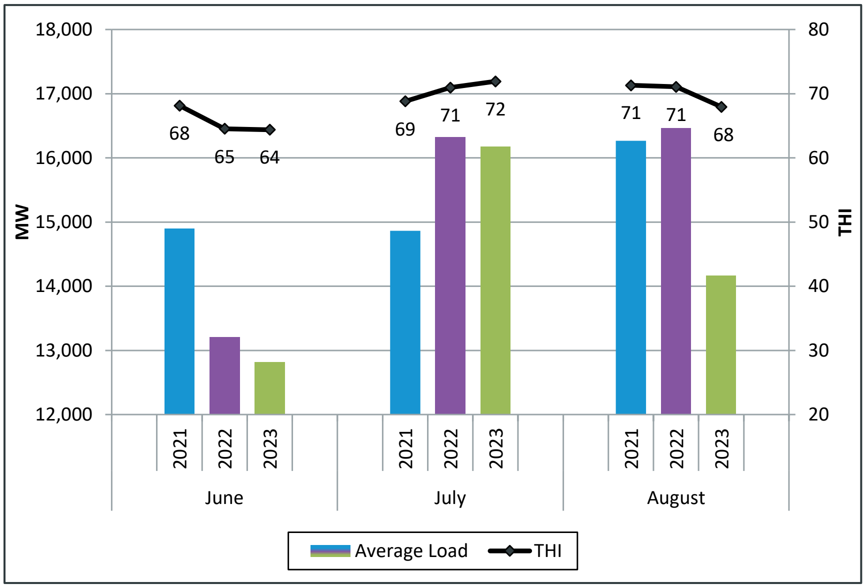


Figure 2-4 shows that average monthly load decreased in all three months compared to the prior year. In June 2023 and July 2023, average load decreased by 2% which was in line with the long-term trend of increased energy efficiency and behind-the-meter photovoltaic generation.[12] However, average loads in August 2023 (14,163 MW) fell by 2,302 MW compared to August 2022.[13] Lower loads were a result of cooler temperatures. In August 2023, temperatures averaged 70ºF, which was 5ºF cooler than in August 2022. The cooler weather led to an average temperature-humidity index (THI) of 68 and less air-conditioning demand.

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

[12] Average behind-the-meter photovoltaic generation decreased year-over-year by an estimated 15 MW in June 2023 (683 MW) and increased by 32 MW in July 2023 (769 MW).

[13] Behind-the-meter photovoltaic generation averaged 682 MW in August 2023, up from 628 MW in August 2022.

Peak Load and Load Duration Curves

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

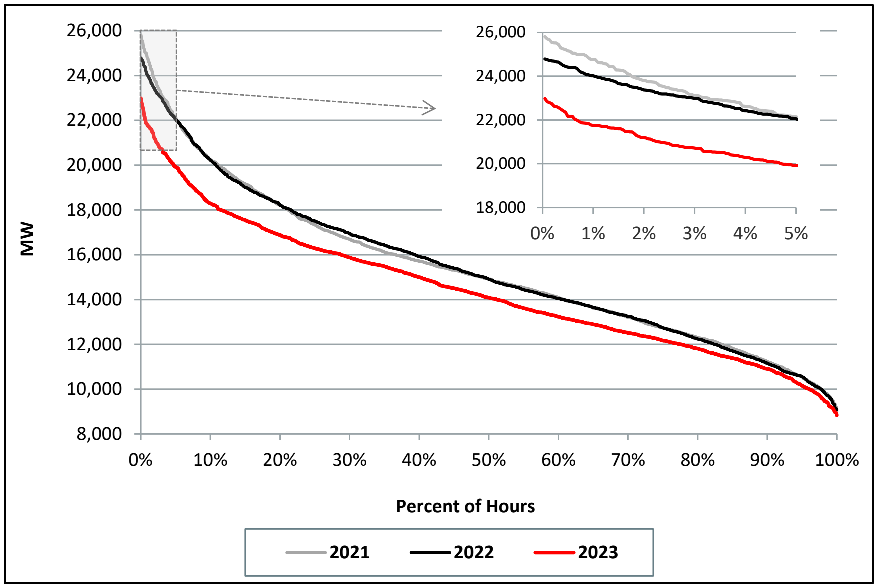


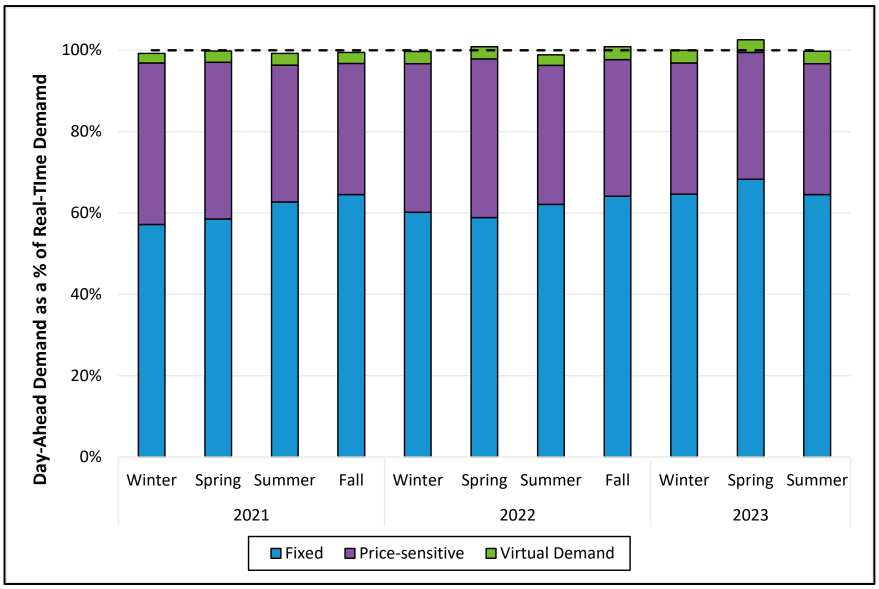
Figure 2-5 shows that loads in Summer 2023 were lower across all hours when compared to both Summer 2022 and 2021. In Summer 2023, peak loads (inset graph) were much lower than in the prior two summers. In the top 5% of all hours, load averaged 21,060 MW in Summer 2023, which was 2,179 MW lower than in Summer 2022 and 2,582 MW lower than in Summer 2021. The peak load during Summer 2023 (22,982 MW) was lower than the 65 highest load hours during Summer 2022 and was the lowest summer peak since 2000.[14] During the summer, temperatures never reached 89°F across New England compared to 54 hours above 89°F the prior summer.

[14] The current annual peak load occurred during September 2023 which falls outside the summer reporting period.

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.[15] 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 (blue), price-sensitive (purple) and virtual (green) demand.[16]

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



In Summer 2023, participants cleared an average of 100% of their real-time demand in the day-ahead market, which was up from 99% in Summer 2022. Participants cleared higher levels of fixed demand (65% vs. 62%) compared to Summer 2022. Virtual demand's contribution remained around 3% of total cleared demand. However, decreased levels of price-sensitive demand offset some of the increase in fixed demand. In Summer 2023, price-sensitive demand accounted for 32% of real-time demand compared to 34% in Summer 2022. Although price-sensitive demand bids are submitted with a MW quantity and corresponding price, the majority of these bids are priced well above the day-ahead LMP. Such transactions are, in practical terms, fixed demand bids. Therefore,

[15] 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.

[16] 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.

the shift from price-sensitive demand bids to fixed demand bids resulted in no significant market impacts.

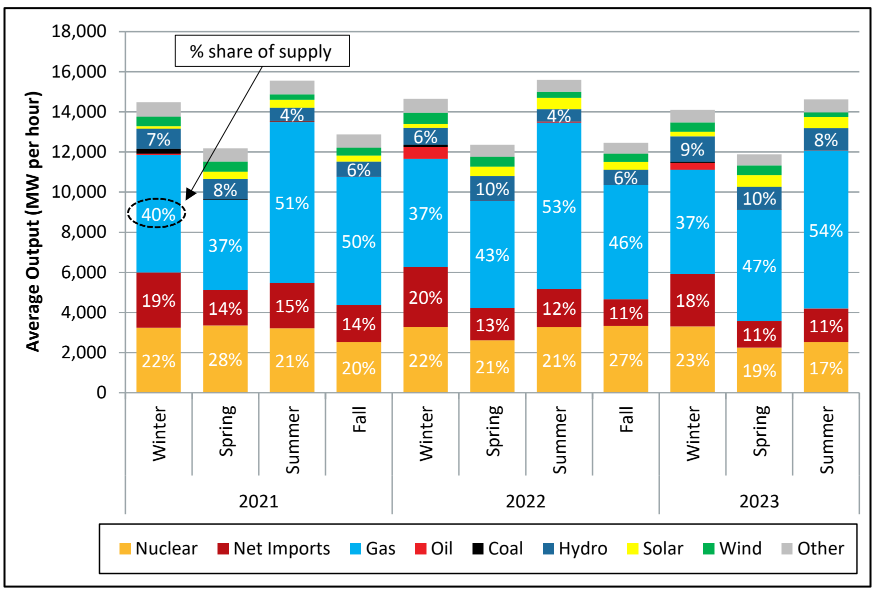
2.3 Supply

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 Summer 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.[17]

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



Average output in Summer 2023 (14,627 MW per hour) was 966 MW per hour less than in Summer 2022 (15,594 MW per hour) due to reduced demand. The largest season-over-season decrease occurred in nuclear generation, which fell by 749 MW per hour between Summer 2022 (3,275 MW per hour) and Summer 2023 (2,526 MW per hour). This decrease in nuclear generation largely occurred in June 2023 as a result of the extension of a planned refueling outage that had started in the spring, as well as a forced outage. Gas generation and net imports (imports netted for exports) also decreased modestly between Summer 2022 and Summer 2023. Despite their volumetric decreases, net imports and generation from the nuclear and gas-powered fleet represented over 82% of the total generation in Summer 2023. Meanwhile, hydro generation had the largest season-

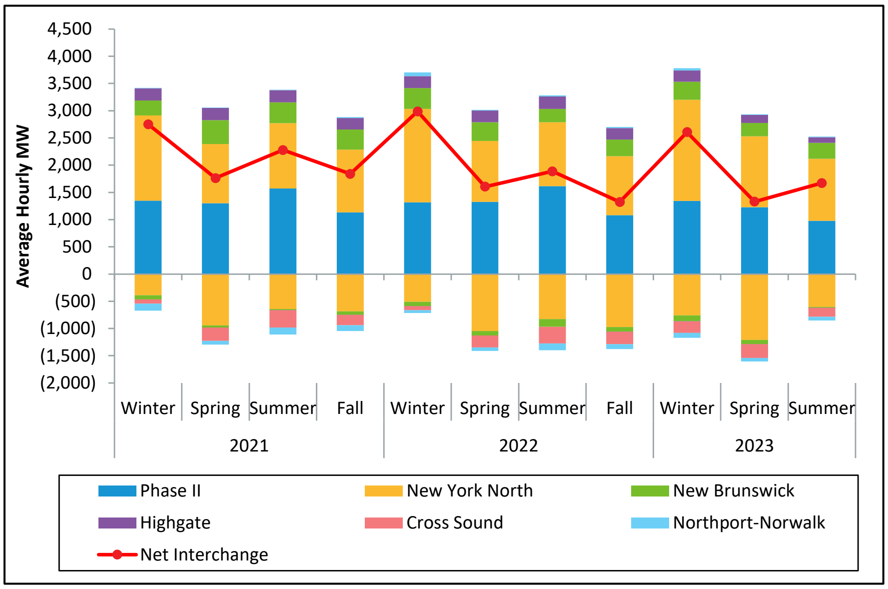
[17] Electricity generation equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, wood, and demand response. The "Hydro" category includes traditional hydro generation as well as pumped storage hydro generation.

over-season increase, rising from 599 MW per hour in Summer 2022 to 1,117 MW per hour in Summer 2023 as a result of increased rainfall in New England.

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 Summer 2023.[18] The average hourly import, export and net interchange power volumes by external interface for the last 11 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 1,672 MW per hour, up 26% from Spring 2023. Net interchange typically increases from spring to summer due to a combination of higher energy demand and LMPs, and a reduction in planned transmission outages between New England and the other control areas. However, compared to Summer 2022, hourly net interchange decreased by 11% year-over-year (by 215 MW) mainly due to fewer imports over the Phase II interface. Total net interchange in Summer 2023 represented 12% of load (NEL), which was equivalent to levels from Summer 2022 (12%).

Canadian Interfaces

In Summer 2023, net imports from the Canadian interfaces averaged 1,350 MW per hour, which accounted for 81% of total net imports into New England. However, net imports from Canadian interfaces fell by 599 MW compared to Summer 2022 due primarily to fewer net imports over the Phase II interface. In Summer 2023, net imports over the Phase II interface averaged 976 MW per hour, the lowest level of net imports over the prior 11 seasons and down from 1,614 MW in Summer 2022.

[18] 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.

Imports from Canada can vary based on the price in New England, and real-time LMPs decreased from an average of $86.28/MWh in Summer 2022 to $34.33/MWh in Summer 2023. This relationship is also be seen during the operating day as net interchange increases when load and LMPs increase. From hours ending (HE) 17 to 22, net imports at Phase II averaged 1,108 MW per hour compared to an average of 932 MW per hour during the rest of the operating day.

Additionally, real-time imports over Phase II were impacted by wildfires in Canada. On seven different occasions, smoke associated with the wildfires caused either reductions or total outages of the Phase II interface in real-time. These fires reduced hourly imports by less than 20 MW on average over the season. However, on July 5, 2023, wildfires caused the interface to go out-of-service during the peak load hour, and resulted in a capacity shortage event and real-time prices reaching $2,707/MWh.[19]

At the Highgate interface, net imports averaged 102 MW per hour, the lowest level of net imports over the reporting period. Net imports from New Brunswick averaged 272 MW per hour, rebounding from 110 MW in Summer 2022 when a nuclear generator outage led to lower-than-normal net imports into New England.

New York Interfaces

After being a net exporter to New York in Summer 2022, New England imported an average of 322 MW per hour across the three New York interfaces this summer. In Summer 2022, New York day-ahead prices at the New York North interface were $3.46/MWh higher than New England. The price spread fell to just $0.02/MWh in Summer 2023 (i.e., New York prices fell by more than New England prices). The improved price spread between the two control areas incentivized increased net imports into New England over the New York North interface. Net imports at the New York North interface averaged 540 MW per hour in Summer 2023, up from 343 MW per hour the prior summer. Another reason for the increase in net imports from New York was an outage at the Cross Sound Cable interface in August 2023. Average net exports at the Cross Sound Cable interface fell from 308 MW per hour in Summer 2022 to 166 MW per hour in Summer 2023. On August 5, 2023 the Cross Sound Cable interface went out-of-service through the rest of the summer. Prior to the outage, exports averaged 231 MW per hour.

[19] See Section 2.4 for more information on the July 5, 2023 capacity shortage event.

2.4 Market Performance on July 5, 2023

This section of the report looks specifically at how the New England electricity markets performed during the capacity scarcity conditions (CSC) that occurred on July 5, 2023.

2.4.1 Event Overview

On Wednesday, July 5, 2023, the ISO experienced 30 minutes of capacity scarcity conditions[20] due primarily to an unexpected reduction in net imports during the evening peak. At 18:15, the Phase II interconnection with Quebec tripped due to Canadian forest fires. As a result, net energy imports into New England from Phase II were around 1,000 MW lower compared to the day-ahead schedule during hour ending (HE) 19.[21] The ISO initiated emergency procedures in response to the tight conditions. System operators used manual actions including posturing, curtailing real-time only exports, and manually committing off-line fast-start units. An M/LCC2 Abnormal Conditions Alert[22] and OP-4[23] Actions 1 and 2 were in effect from 18:30-22:00. The capacity scarcity conditions were relatively short, lasting for six five-minute pricing intervals between 18:25-18:50.

2.4.2 Drivers of Tight System Conditions

Weather and Load

On July 5, warm weather led to increased air conditioning demand and high loads. During the day, temperatures averaged 77ºF and reached 86ºF during the shortage event. The warm temperatures led to a peak load of 21,698 MW, the ninth highest daily peak load of the summer. While temperatures were 3ºF warmer than forecasted at HE 19, humidity levels were lower than forecasted and weather effects had a minimal impact on load levels. During the shortage event, loads were about 250 MW higher than forecasted.

Unplanned Generator Outages

Overall, unplanned generator outages played a minimal role during the event. One larger generator that had not cleared in the day-ahead market self-scheduled in real-time for HE 18-24 on July 5, but was not able to come online due to a forced outage caused by mechanical issues. However, there were no forced outages for large (15+ MW) generators with day-ahead schedules during HE 19 on July 5.

Net Imports

Even prior to the Phase II trip during hour ending 19 on July 5, there was a considerable reduction in net imports in the real-time market relative to what had cleared in the day-ahead market. Deviations between day-ahead cleared and real-time scheduled net imports at the six interfaces are show below in Figure 2-9 below.

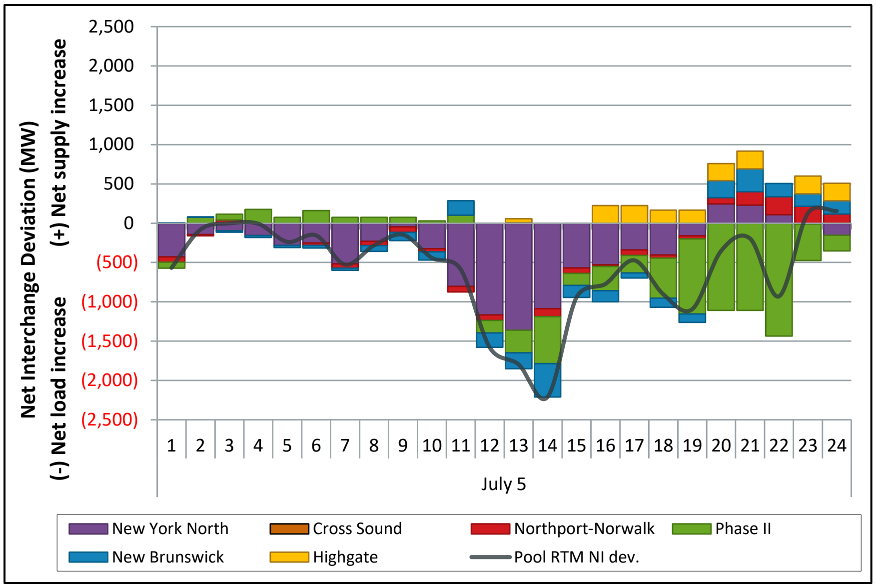
[20] See Market Rule 1, Section III.13.7.2.1.

[21] Nearly 1,300 MW of imports cleared in the day-ahead market over Phase II during HE 19, but after accounting for virtual demand bids, day-ahead net imports were 1,109 MW.

[22] For more information on M/LCC2, see https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/mast_satllte/mlcc2.pdf

[23] See ISO New England Operating Procedure No. 4 – Action During A Capacity Deficiency, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf

Figure 2-9: Day-Ahead vs. Real-Time Net Import Deviations by Interface[24]



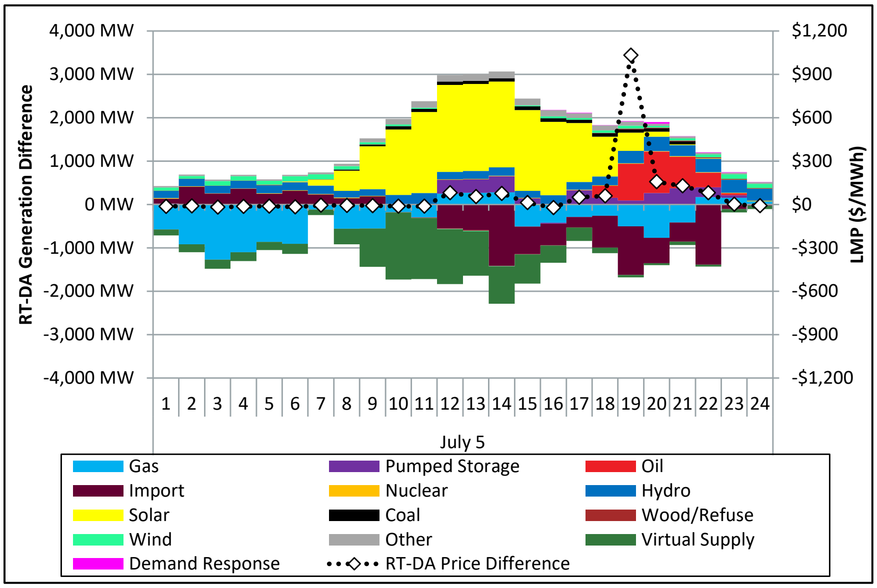
Due to higher-than-forecasted loads occurring in the New York control area, net imports were noticeably reduced over the New York North interface during the middle part of the day on July 5. These accounted for a majority of the system-level reductions at that time. Net import deviations were also negative over Phase II leading up to the shortage event that began during HE 19. One reason for this was because an AC cable that connects the Phase II tap to an internal substation tripped in HE 18. Consequently, real-time net imports at Phase II were 508 MW below their day-cleared volume. At 18:15, Phase II tripped, and net imports at the interface were reduced by 956 MW during HE 19. Phase II remained out-of-service for the next three hours of the operating day, leading to reductions of 1,218 MW compared to day-ahead cleared imports, on average. Following the shortage event, four of the six interfaces provided additional net imports into New England, helping alleviate issues related to the trip, until the Phase II interface was restored in HE 23.

[24] Additional net interchange at the Highgate interfaced resulted from virtual demand bids clearing in the day-ahead market with no exports at the interface in the real-time market.

Supply Mix Changes

The reduction in net imports and the trip of Phase II during the evening on July 5 resulted in changes to the real-time supply mix compared to the day-ahead mix. The differences in generation obligations and average LMPs at the Hub between the day-ahead and real-time markets are shown in Figure 2-10 below.

Figure 2-10: Differences between Hourly Real-Time and Day-Ahead Generation Obligations and LMPs



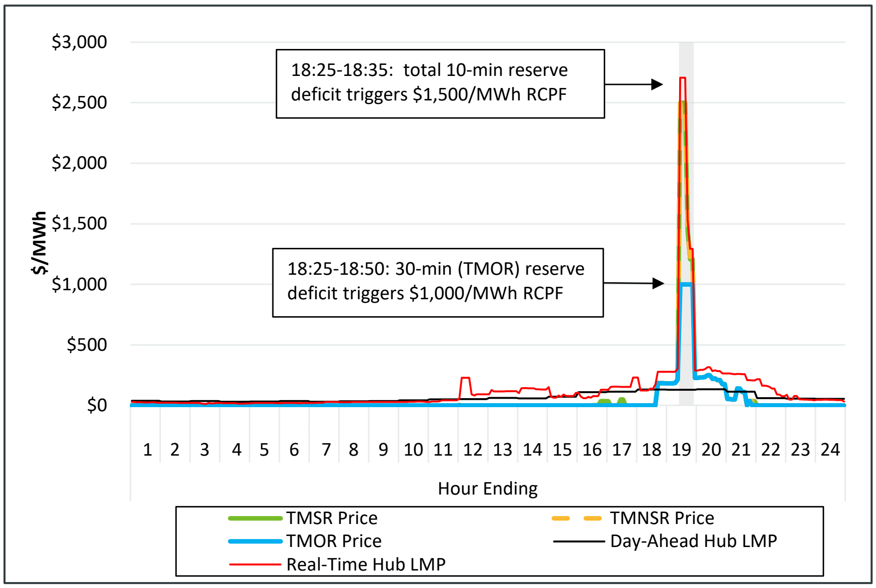
Additional real-time output from oil-fired generators started in hour ending 18 as numerous fast-start units were committed following the trip of an AC cable that connects the Phase II tap to an internal substation. Oil generation further increased in hour ending 19, following the trip of Phase II, which led to the commitment of additional fast-start units. Real-time deviations from oil reached their largest value in hour ending 19, when these units were producing close to 1,000 MW of additional energy in the real-time market.

2.4.3 Energy Prices, Reserve Prices, and Uplift

Energy and Reserve Prices

Energy and reserve prices from July 5 are shown in Figure 2-11 below. The timeframe of the capacity scarcity conditions is highlighted in gray.

Figure 2-11: Five-Minute Energy and Reserve Prices, System Level



Daily Hub prices averaged $64.23/MWh and $129.96/MWh in the day-ahead and real-time markets, respectively. Five-minute real-time prices were higher than the day-ahead prices leading into the evening peak (ranging between $277-303/MWh from 17:40-18:20), then jumped to $2,707/MWh at 18:25 when the capacity scarcity conditions began following the Phase II trip. This was the peak real-time Hub price of the event. Price separation between the load zones and the Hub (not shown in the graph) was minimal during the capacity scarcity conditions, ranging from -3% to 1% during hour ending 19.

The majority of the high energy prices during the capacity scarcity conditions were due to high reserve pricing that was incorporated into the LMP. During the event, there were deficits in both the system total thirty-minute reserve requirement and the ten-minute reserve requirement. Available total thirty-minute reserves were 250-281 MW below the corresponding requirement from 18:25-18:50, while available ten-minute reserves were 66 MW below the requirement from 18:25-18:35. These deficits triggered reserve constraint penalty factors of $1,000/MWh and $1,500/MWh, which are associated with the thirty-minute operating reserve (TMOR) and ten-minute reserve products, respectively. The TMOR penalty factor was in effect during the pricing intervals beginning 18:25 to 18:50, a total of six five-minute intervals. During three of these intervals (18:25-18:35), the ten-minute penalty factor was also activated. The ten-minute spinning reserve (TMSR) requirement did not bind at any time during the event. Yet, the TMSR price reached

$2,500/MWh because reserve prices are "cascaded" to ensure that higher quality reserve products are paid at least as much as lower quality reserve products.[25]

Uplift

Total real-time uplift amounted to $0.5 million on July 5. Manual commitments of fast-start generators and fast-start pricing drove the majority of these uplift payments. Rapid response opportunity cost credits driven by fast-start pricing mechanics totaled $0.2 million, or 39% of real-time uplift. Commitment out of merit payments to fast-start generators also reached $0.2 million. Dispatch opportunity cost payments, external uplift, and compensation to a postured pumped-storage generator made up the remainder of uplift payments.

2.4.4 Two-Settlement System Outcomes

This subsection of the report provides insight into under- and over-performers relative to forward positions. Coverage includes both the energy and the capacity markets.

Energy Charges and Payments

Total energy charges to load on July 5 amounted to an estimated $30.3 million. Of this, $28.7 million (95%) in charges were made in the day-ahead market, while net real-time charges accounted for the remaining $1.6 million (5%).[26] Gross payments for real-time deviations totaled $13.5 million, while gross charges totaled $14.0 million.[27] Real-time energy charges and payments by hour are shown in Figure 2-12 below.

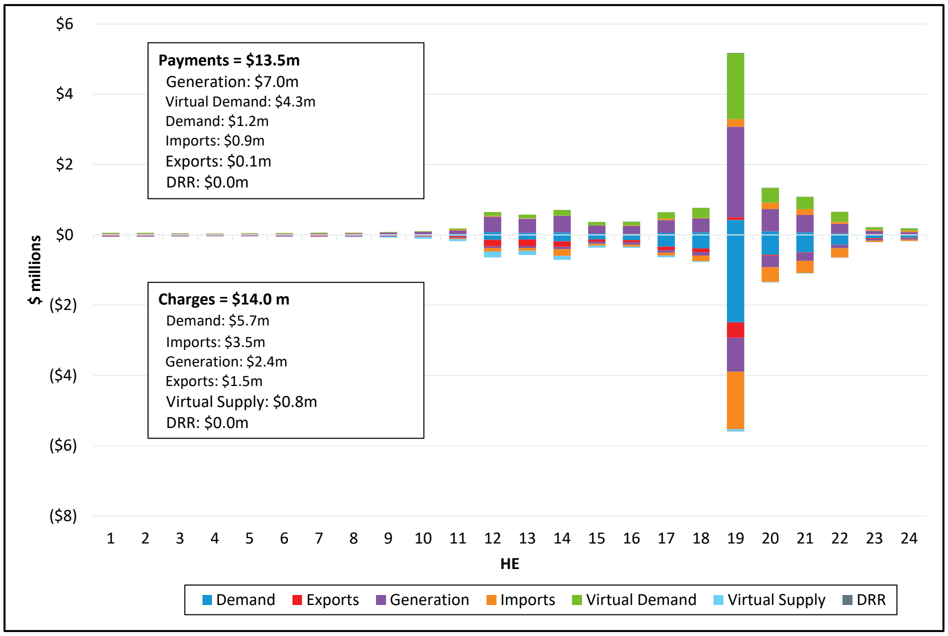
[25] To ensure that the incentives for providing the individual reserve products are correct, the market's reserve prices maintain an ordinal ranking. This ranking is consistent with the quality of the reserves provided as follows:

10-minute spin (TMSR) ≥ 10-minute non-spin (TMNSR) ≥ 30-minute (TMOR)

[26] Most costs are incurred in the day-ahead market, where most generation and load clear. Deviations against day-ahead positions are settled in the real-time market.

[27] These totals are the gross payments and charges that resulted from participant deviations from day-ahead obligations by activity type (load, generation, etc.) and location. In contrast, the $1.6 million represents net real-time charges that resulted from real-time load obligation deviations.

Figure 2-12: Real-Time Deviation Charges and Payments, July 5



Demand incurred the largest gross real-time charges ($5.7 million) on July 5 as some load-serving entities had to buy more energy in real-time than they had purchased in the day-ahead market.[28] Of this, $2.5 million in additional charges occurred during hour ending 19 when the scarcity event took place. There were also significant charges to imports ($3.5 million) on July 5. In aggregate, under-performing imports produced between 500 to 1,900 MW per hour less in real time compared to their day-ahead awards between hours ending 12 to 24. On the payments side, the majority of payments went to generators ($7.0 million) that produced more energy in real time than they had cleared in the day-ahead market. Significant payments were also made to virtual demand ($4.3 million), which essentially buys in the day-ahead market and sells back in the real-time market.

Forward Capacity Market (FCM) Pay-for-Performance

During the 30-minute period of capacity scarcity on July 5th, every FCM-participating resource, energy market asset, and external transaction was subject to Pay-for-Performance (PfP) credits or charges based on its performance compared to expectations. FCM-participating resources have their CSO MW multiplied by the associated capacity zone's balancing ratio to generate their expected obligation to provide energy or reserves during the scarcity condition.[29] Energy market assets and external transactions without a CSO receive PfP payments for any energy or reserves provided. All participating entities are credited or charged the PfP rate of $3,500/MWh for any

[28] Gross real-time charges to demand are calculated in three steps. First, each participant's positive demand deviations at each location (i.e., their real-time demand in excess of their day-ahead demand) is calculated. Second, that positive demand deviation is multiplied by the LMP at the same location to get the dollar amount charged to the participant. Third, the charges are summed across all participants and locations to arrive at gross real-time charges to demand. Similar steps are performed to compute the other charges and payments by activity type (generation, exports, etc.).

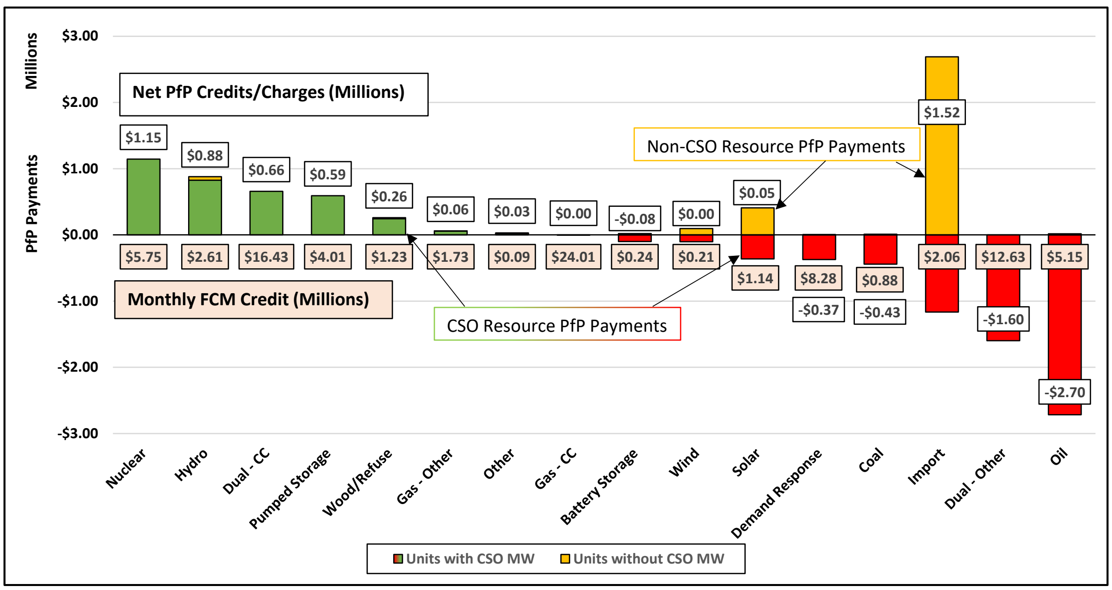
[29] For more information on the balancing ratio, see Section III.13.7.2.3 of the ISO-NE tariff.

deviations from their capacity supply obligation. The absolute value of credits/charges totaled $10.9 million.

The Pay-for-Performance settlement reduces a resource's base capacity revenue for under-performing resources, and increases revenue for over-performing resources. The transfer is among supply resources, meaning that load is not exposed to PfP risk. A resource's financial obligation is based on its CSO cleared in the Forward Capacity Auction, which can be adjusted in secondary auctions prior to the delivery month. Gross capacity payments for July 2023 totaled $86.8 million.

For the July 5th event, the balancing ratio averaged 79%, meaning FCM resources were expected to provide an average of 79% of their contracted capacity in the form of energy or reserves. Aggregated by fuel type and ranked, resource performance through PfP charges and credits alongside gross FCM credits is shown in Figure 2-13 below.[30]

Figure 2-13: Capacity Market Settlements by Fuel Type (July 2023)



Import resources were the best-performing resource type, with net PfP payments totaling $1.52 million. Following import resources, nuclear resources received the second highest net PfP payment; these generators operate as baseload resources at their full CSO MW during all hours and typically over-perform relative to their CSO. Import resources and nuclear resources were two of the best performing resource groups during the 2018 and 2022 PfP events as well.

Oil-fired resources were the worst performers, as relatively high fuel costs and physical technology constraints led to significant underperformance. Many large oil-fired generators in New England's fleet cannot start up fast enough to respond to sudden increases in real-time LMPs. Around $2.7 million of charges were collected from oil-fired resources during the July 5 PfP event.

[30] In this figure, "Dual" refers to dual-fuel (gas/oil) resources and "CC" refers to combined-cycle resources.

2.4.5 Operator Actions

System operators use manual actions to ensure reliability during tight conditions. Below, Table 2-2 lists available operator actions, and indicates whether each was used on July 5. We then give additional detail on each action that was used.

Table 2-2: Operator Interventions on July 5

Action	Occurred on 7/5
Cuts To External Transactions	Yes
Posturing	Yes
Manual Dispatch	Yes
Manual Fast-Start Commitments	Yes
Supplemental Commitments	No
Fast Start Reliability Flag	No
Reserve Bias Changes	No

Cuts to external transactions: The operators reduced real-time only exports in order to help ensure native load could be met.

Posturing: One pumped-storage generator was held off-line from 19:30-20:23 to ensure that the resource provided reserves.

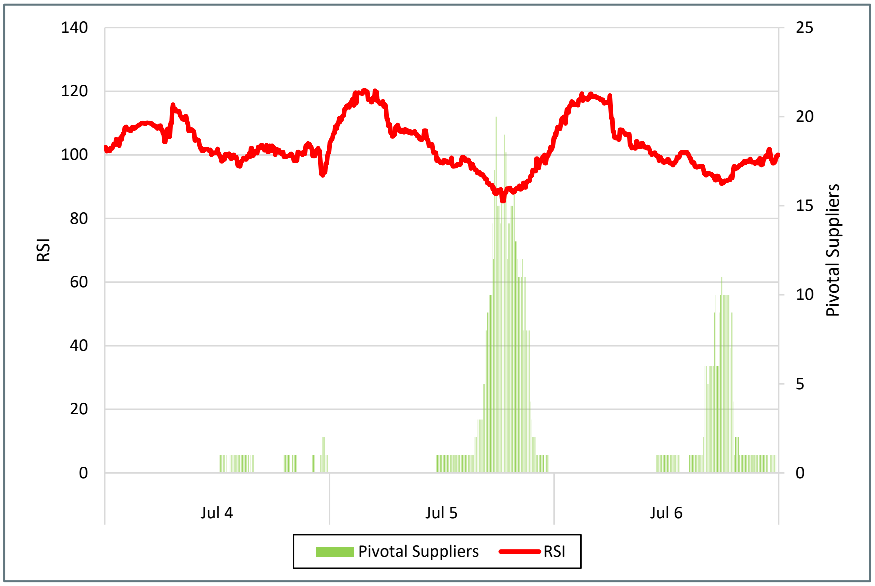
Manual dispatch: Around 17:30, the operators manually dispatched two on-line generators to increase available reserves. The operators can maintain available reserves from off-line fast-start units by dispatching long-lead-time generators up. System operators may also dispatch fast-start generators down, since fast-start generators have more flexibility to provide ten-minute reserves.

Manual Fast-Start Commitments: From 17:27-18:20, system operators manually committed 27 off-line fast-start resources in order to access 136 MW of additional off-line capacity. These resources had capacity available beyond their Claim 30 value, and bringing them on-line increased available reserves.

2.4.6 Market Power Assessment and Mitigation

With tight system conditions on July 5, we observed numerous participants ("pivotal suppliers") with potential market power. Pivotal suppliers occur when system demand (load) cannot be satisfied without the supply controlled by these suppliers. Figure 2-14 depicts the residual supply index (RSI) and number of pivotal suppliers on July 5.

Figure 2-14: Residual Supply Index



On July 5, the RSI reached its lowest value of 85.5 from 18:25-18:35, indicating that the system could only meet about 86% of load and the reserve requirement without the largest supplier.

The system event did not result in noteworthy energy market supply offer mitigation. With the exception of pivotal suppliers, the event also did not result in significant indicators of potential market power. Table 2-3 indicates the incidence of market power flags and mitigations.

Table 2-3: Market Power Flags and Mitigation

Type	DA Reliability	RT Reliability	MDE	DA CAE	RT CAE	Pivotal Suppliers
Market Power Flag - Asset Hours	0	4	2	0	0	641
Mitigations - Asset Hours	0	0	1	0	0	0

During the event, there were minimal reliability commitments and manual dispatches by the ISO. The reliability commitments were for two "special constraint resources" (SCR) providing support for a local distribution network. These SCR commitments frequently occur during the summer and did not necessarily occur as a result of the system event. Just two asset hours of manual generator dispatch (MDE) occurred on the day of the event, with one generator having its energy market supply offer mitigated for one hour.

As would be expected during the tight system conditions on July 5th, there were a significant number of generators associated with pivotal suppliers. Eighty-two generators were flagged as being associated with pivotal suppliers (resulting in 641 asset hours of pivotal supply dispatch). None of these generators were mitigated. The applicable mitigation for pivotal suppliers (general threshold mitigation) has relatively tolerant thresholds and none of the associated generators exceeded the conduct test and market impact test needed to trigger mitigation for pivotal suppliers.

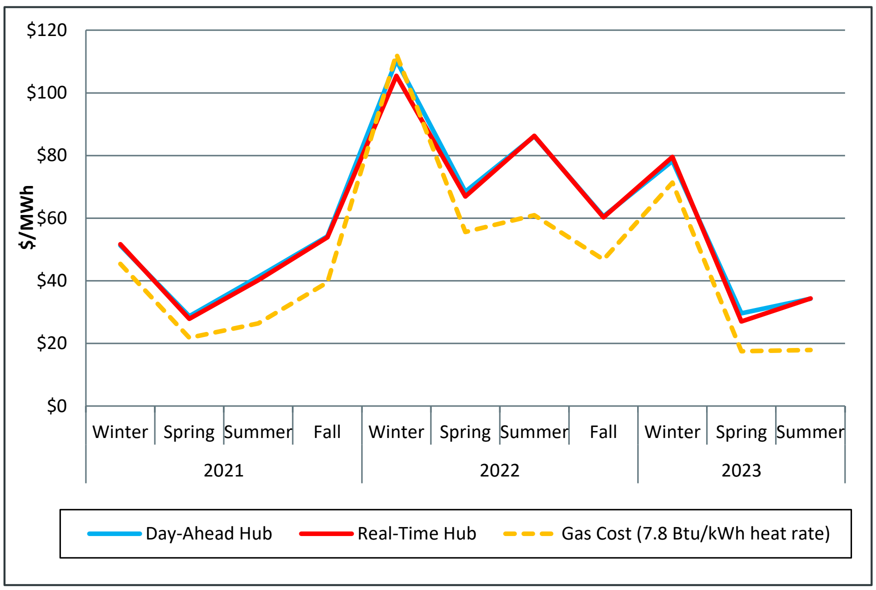
Section 3
Day-Ahead and Real-Time Markets

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.[31]

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 Summer 2023 were $34.33 and $34.27/MWh, respectively. Gas costs averaged $17.90/MWh in Summer 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 and load forecast error. There were also days with higher real-time prices due to generator and transmission line trips. The elevated real-time prices that occurred during the capacity scarcity conditions on July 5 are discussed in Section 2.4.

The spread between the average day-ahead electricity price and average estimated gas cost was $16/MWh in Summer 2023, lower than the $25/MWh spread in Summer 2022 but similar to the $15/MWh spread in Summer 2021. The higher spreads in Summer 2022 were primarily driven by the substantial increase in natural gas prices and the knock-on effect on energy prices.

[31] 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.

Average energy prices in Summer 2023 were lower than Summer 2022 prices by about $52/MWh (down 60%) in both the day-ahead and real-time markets. These decreases are consistent with lower natural gas prices in Summer 2023, which fell by 71% compared Summer 2022. Less baseload generation in Summer 2023 partially muted the impact of lower natural gas prices on LMPs. Both planned and forced outages resulted in less nuclear generation (down ~750 MW) in the supply mix compared to Summer 2022. Additionally, net imports decreased by 215 MW compared to Summer 2022. Prices did not differ significantly among the load zones in either market in Summer 2023, indicating that there was relatively little transmission congestion on the system at the zonal level.

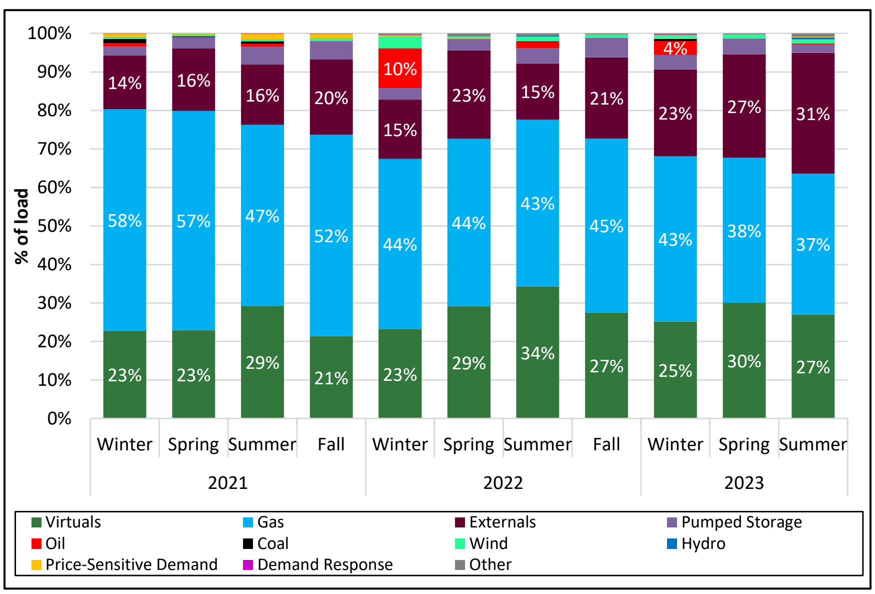
3.2 Marginal Resources and Transactions

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.

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

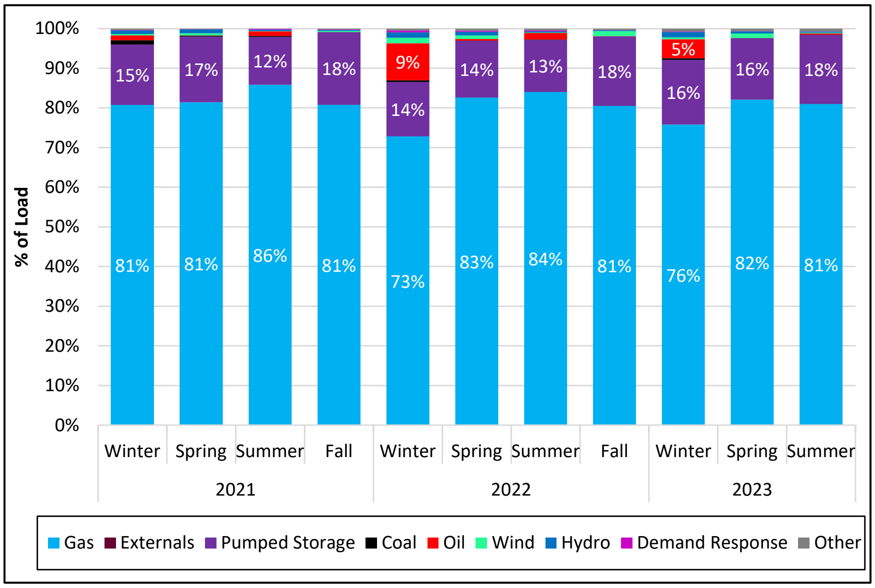


Gas-fired generators were the most common marginal resource type in the day-ahead market, setting price for 37% of total day-ahead load in Summer 2023. External transactions and virtual transactions were next, setting price for 31% and 27% of load, respectively. Other resource types were collectively marginal for about 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.[32]

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 Summer 2023 (81%). Pumped storage (generation and demand) was the marginal fuel for the second largest share of load in Summer 2023 (18%).

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 Spring 2023, wind generators were the marginal fuel type for less than 1% of real-time load.

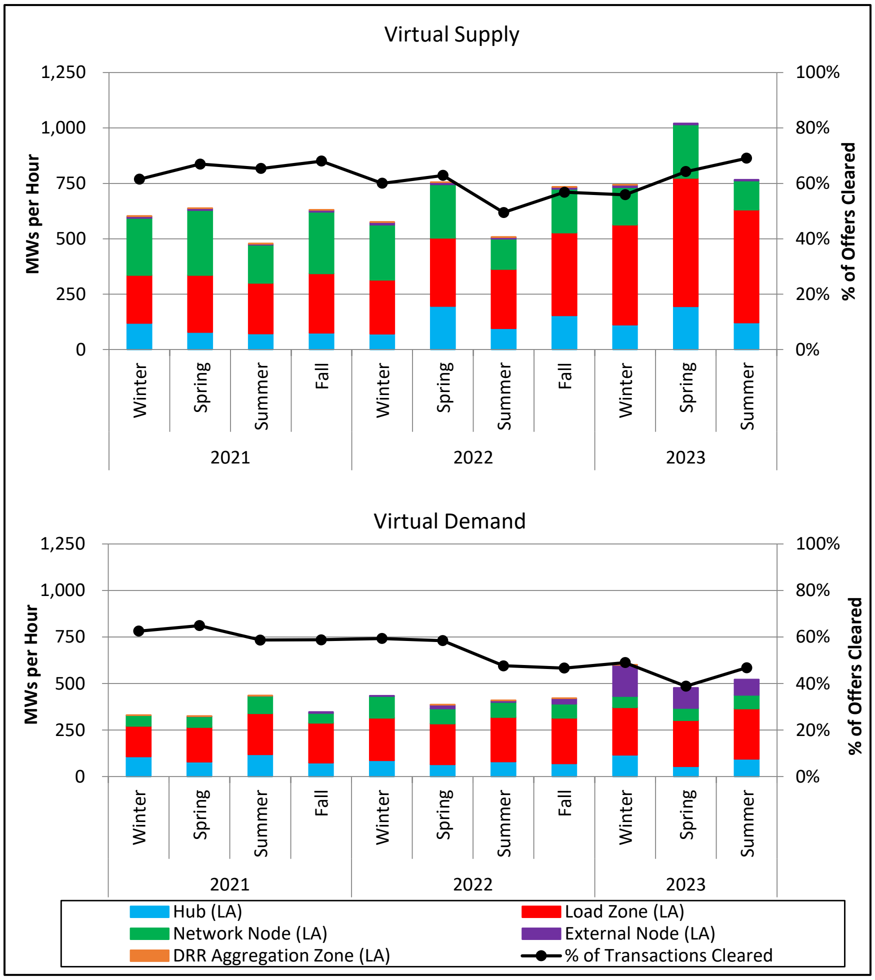
3.3 Virtual Transactions

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

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

Figure 3-4: Cleared Virtual Transactions by Location Type



Total cleared virtual supply averaged 767 MW per hour in Summer 2023, up 51% from Summer 2022 (507 MW per hour). Recently, virtual supply activity has been higher than virtual demand 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 Summer 2023, the installed capacity of solar SOGs was nearly 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.[33]

Cleared virtual demand averaged 522 MW per hour in Summer 2023, up 28% from Summer 2022 (409 MW per hour). Most of the year-over-year increase was driven by higher cleared volumes at the Highgate interface, which connects New England with the Hydro-Québec control area. Since Winter 2023, one participant has cleared substantial virtual supply offers at the Highgate interface

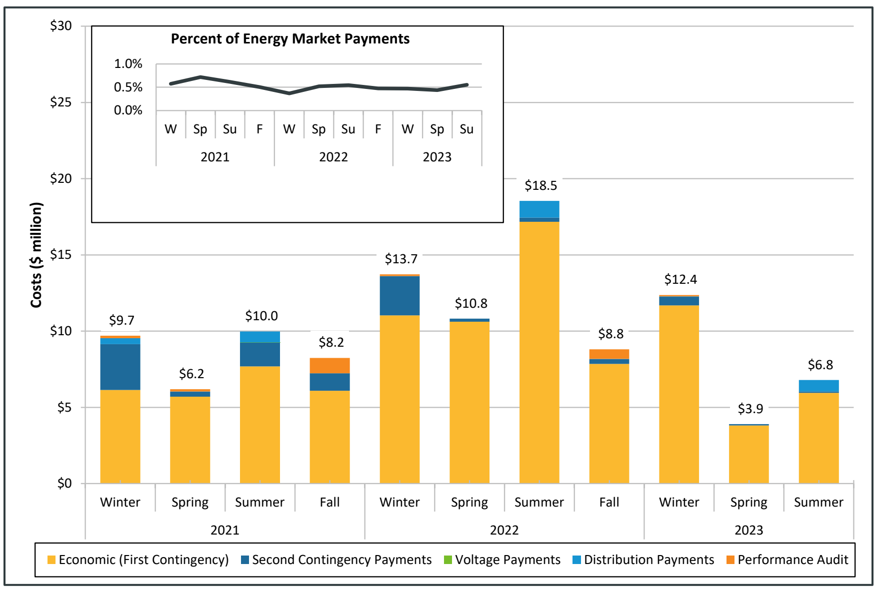
[33] In Summer 2023, wind generation averaged 102 MW in the day-ahead market, while real-time wind generation averaged 240 MW.

connecting New England to Hydro-Québec. These transactions allow imports to clear in excess of the total transfer capability (TTC) of the interface (225 MW). In Summer 2023, this participant cleared an average of about 50 MW per hour at Highgate. While this was lower than Winter 2023, participants collectively cleared less than 1 MW per hour during the prior eight seasons (Winter 2021 to Fall 2022).

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.[34] 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



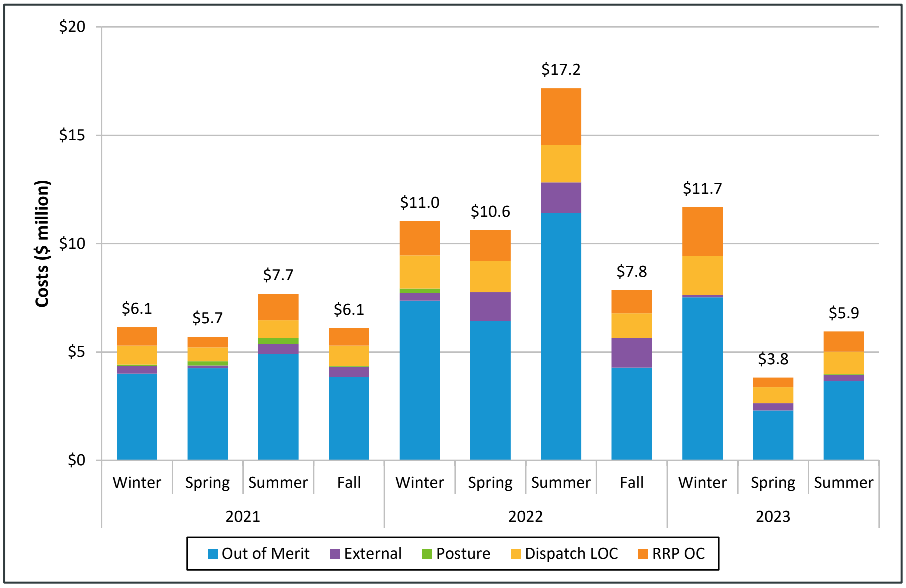
NCPC payments totaled $6.8 million in Summer 2023. Payments declined by 63% relative to Summer 2022, driven by lower fuel prices and resulting lower energy market payments. NCPC as a percentage of energy payments remained low at 0.6%. Economic first contingency payments totaled $5.9 million, or 88% of uplift. Distribution payments increased to $0.7 million, following a trend of local distribution payments in summer months. Second contingency payments comprised the remainder of uplift at $0.1 million.

Economic NCPC can be further categorized by reason, including out of merit payments for generator operating costs that are not fully covered through energy market revenue, external

[34] 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).

payments, posturing, and dispatch or rapid response opportunity cost payments. The following Figure 3-6 displays economic NCPC payments by reason.

Figure 3-6: Economic NCPC by Reason



Out of merit payments made up the largest share of economic NCPC at $3.6 million, or 61%. Out of merit payments were distributed among a variety of generators, with no single generator receiving more than 5% of this total for the Summer 2023 period. Dispatch and rapid response pricing opportunity cost payments comprised the second largest portion of economic NCPC, totaling $2.0 million. External transactions received the remaining $0.3 million of economic NCPC, with the majority of these payments made in real time to imports on Canadian interfaces that were scheduled using LMP forecasts.

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.[35] 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.[36]

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

Product	Zone	Summer 2023		Summer 2022		Summer 2021	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	**System**	$13.30	177.8	$19.98	343.1	$14.27	385.5
TMNSR	**System**	$270.38	5.4	$204.82	20.4	$120.74	23.5
TMOR	**Rest of System**	$275.29	3.5	$231.08	14.9	$154.98	7.0
	NEMA/Boston	$275.29	3.5	$231.08	14.9	$154.98	7.0
	CT	$275.29	3.5	$231.08	14.9	$154.98	7.0
	SWCT	$275.29	3.5	$231.08	14.9	$154.98	7.0

The system TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 178 hours (8% of total hours) during Summer 2023, which was 165 hours (48%) less than in Summer 2022 and 208 hours (54%) less than in Summer 2021. One of the reasons for the decrease in non-zero TMSR pricing was a smaller first contingency in Summer 2023 compared to the prior two summers.[37] In the New England power system, the first contingency is often the Phase II interface,

[35] 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.

[36] 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.

[37] The first contingency (or "first contingency loss") represents the capability (MW) that would be lost from the failure of a single element. It is a fundamental input into the calculation of the reserve requirements in New England. For more information about reserve requirements, see ISO-NE Operating Procedure 8: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

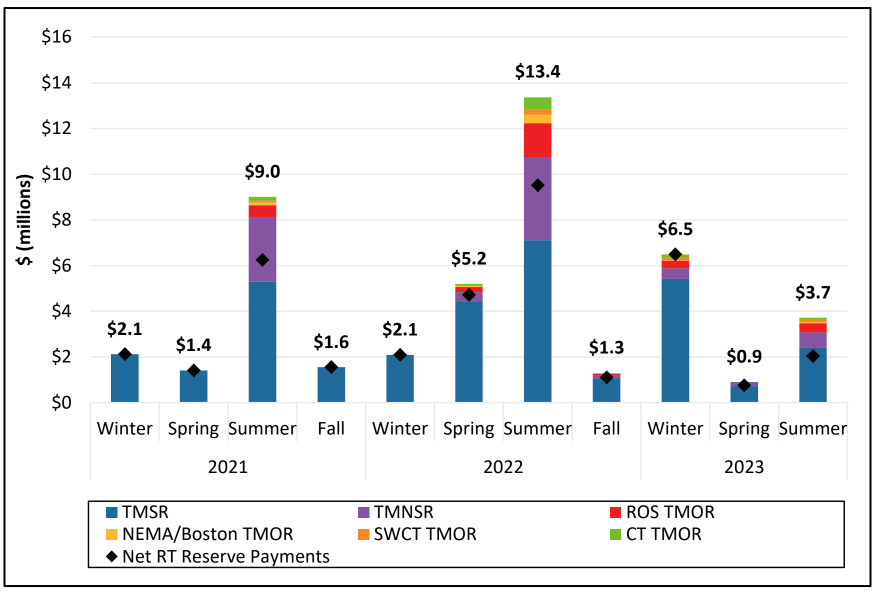
which connects to the Hydro-Québec (HQ) control area. In Summer 2023, HQ experienced extensive forest fires, which caused imports over this interface to be reduced at times. This contributed to reducing the average ten-minute spinning reserve requirement from 477 MW in Summer 2022 to 381 MW in Summer 2023. The average price during intervals with non-zero TMSR pricing in Summer 2023 ($13.30/MWh), Summer 2022 ($19.98/MWh) and Summer 2021 ($14.27/MWh) generally moved in line with energy prices, reflecting lower opportunity costs.

Meanwhile, non-zero TMNSR and TMOR prices continued to occur very infrequently in Summer 2023. One of the most notable periods of TMNSR and TMOR pricing was on July 5, 2023, when ISO-NE experienced a capacity shortage event following a trip of the Phase II interface.[38] This trip resulted in penalty pricing for several of the reserve requirements.[39]

Real-time Reserve Payments

Real-time reserve payments by product and by zone are illustrated in Figure 3-7 below.[40] 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).[41]

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



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[38] For more information about this shortage event, see Section 2.4.

[39] Specifically, there were six five-minute intervals with reserve constraint penalty factor (RCPF) pricing for the minimum total reserve requirement (RCPF = $1,000/MWh) and three five-minute intervals with RCPF pricing for the ten-minute reserve requirement (RCPF = $1,500/MWh). For more information about RCPFs, see Section III.2.7A (c) of Market Rule 1.

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

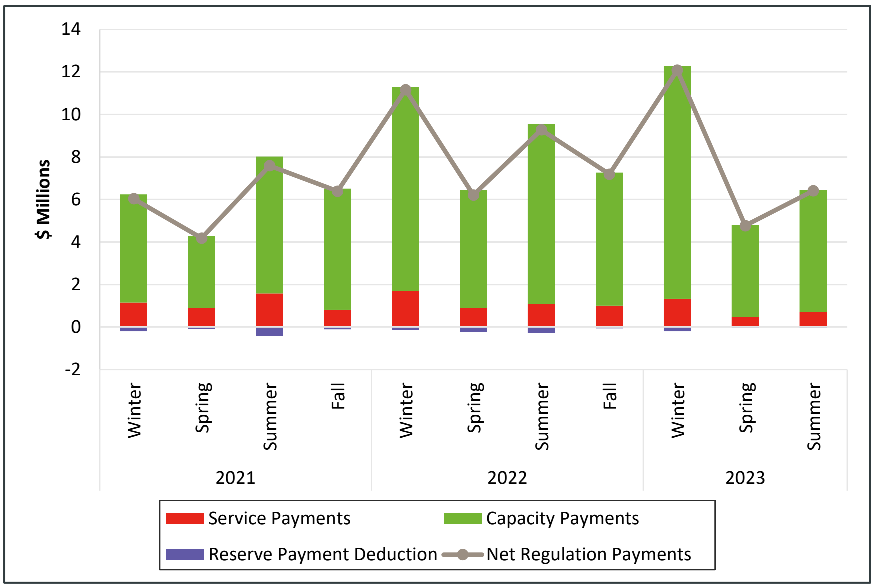
[41] The FRM is a forward market that procures operating reserve capability in advance of the actual delivery period. Real-time reserve payments to resources designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a resource is not paid twice for the same service. For more information about forward reserve obligation charges, see Section III.10.4 of Market Rule 1.

Gross reserve payments in Summer 2023 ($3.7 million) were down considerably from Summer 2022 ($13.4 million) and from Summer 2021 ($9.0 million). Most of the gross payments in Summer 2023 ($3.1 million) were made on July 5, during the scarcity event that happened on that day.[42] The vast majority of reserve payments in Summer 2023 went to resources providing TMSR ($2.4 million), while a relatively small amount went to resources providing TMNSR ($0.7 million) and TMOR ($0.6 million). Net real-time reserve payments in Summer 2023 ($2.0 million) were modestly reduced from their gross levels.

3.6 Regulation

Regulation is an essential reliability service provided by generators and other resources in the real-time energy market. Generators providing regulation allow the ISO to use a portion of their available capacity to match supply and demand (and to regulate frequency) over short-time intervals. Quarterly regulation payments are shown in Figure 3-8 below.

Figure 3-8: Regulation Payments



Total regulation market payments were $6.4 million during the reporting period, up approximately 34% from $4.8 million in Spring 2023 and down by 31% from $9.3 million in Summer 2022. The increase in payments compared to the Spring period resulted predominately from slightly higher regulation capacity prices (6% increase) and increased regulation requirements (28% increase) in Summer 2023. The increase in regulation requirements from Spring to Summer represents typical seasonal variation in those requirements. The decrease in regulation payments between Summer 2022 and Summer 2023 primarily reflected a decrease in capacity prices (23% decline); the reduced capacity prices resulted from reduced energy market opportunity costs (reflecting a significant decline in energy market LMPs) compared to the earlier period.

[42] See Section 2.4 for more information about the events on this day.

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.[43] 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[44] to the sum of each participant's total supply that is available within 30 minutes.[45] 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.

[43] 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.

[44] 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*] -$Demand$ - [$Reserve\ Requirement$]

[45] 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)

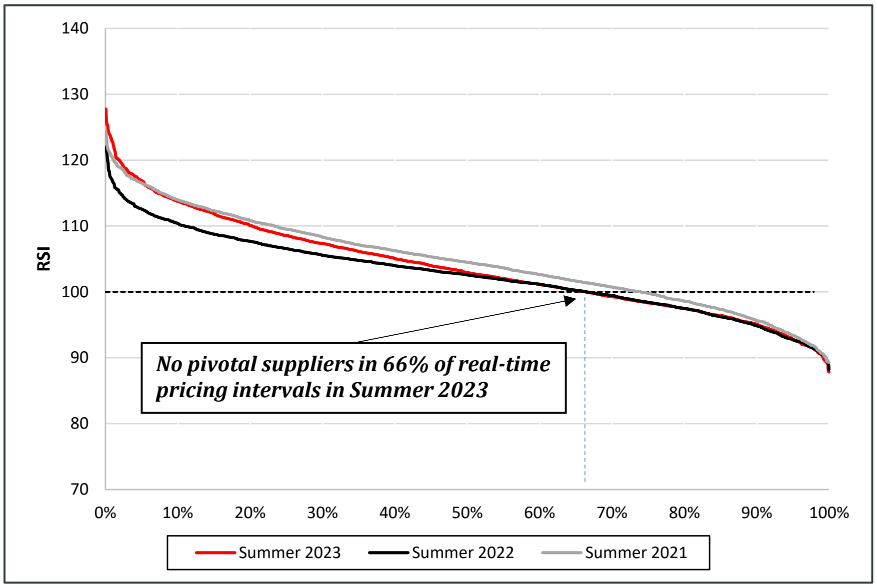
Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2021	107.9	8%
Spring 2021	106.6	14%
Summer 2021	104.7	27%
Fall 2021	105.0	24%
Winter 2022	106.5	12%
Spring 2022	106.7	19%
Summer 2022	102.6	34%
Fall 2022	104.0	28%
Winter 2023	105.2	20%
Spring 2023	107.7	22%
Summer 2023	103.8	34%

The RSI was above 100 in every quarter of the reporting period, indicating that, on average, the ISO could satisfy load and reserve requirements without the largest supplier. The percentage of intervals with pivotal suppliers was relatively low most in quarters, indicating that there were typically limited opportunities for any one supplier to exercise market power.

The frequency of pivotal suppliers in Summer 2023 was 34%, the same value as Summer 2022 but higher compared to Summer 2021 (27%). Summers 2023 and 2022 saw the highest pivotal supplier frequencies of the reporting period. The average Summer 2022 reserve margin (2,800 MW) was significantly lower than the Summer 2021 margin (3,070 MW), making it more likely that the largest supplier is needed. The average Summer 2023 reserve margin (3,020 MW) was higher than that of Summer 2022 but still 50 MW less than the Summer 2021 margin. Additionally, the average available supply from the largest participant (2,560 MW) increased by 60 MW compared to Summer 2022. These offsetting factors led to similar pivotal supplier frequencies over the two most recent summers.

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

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



In Summer 2023, the RSI was higher than that of Summer 2022 across about half of the ranked observations, and nearly identical across the remaining half. The lowest Summer 2023 value was 87.7 and occurred on July 21 during the evening peak hour (HE 18) when loads were relatively high. The second lowest value (87.8) occurred on July 5 during capacity scarcity conditions. The lowest value occurred on July 21 rather than July 5 because the largest supplier made up a greater portion of the total available supply on July 21.

4.2 Energy Market Supply Offer Mitigation

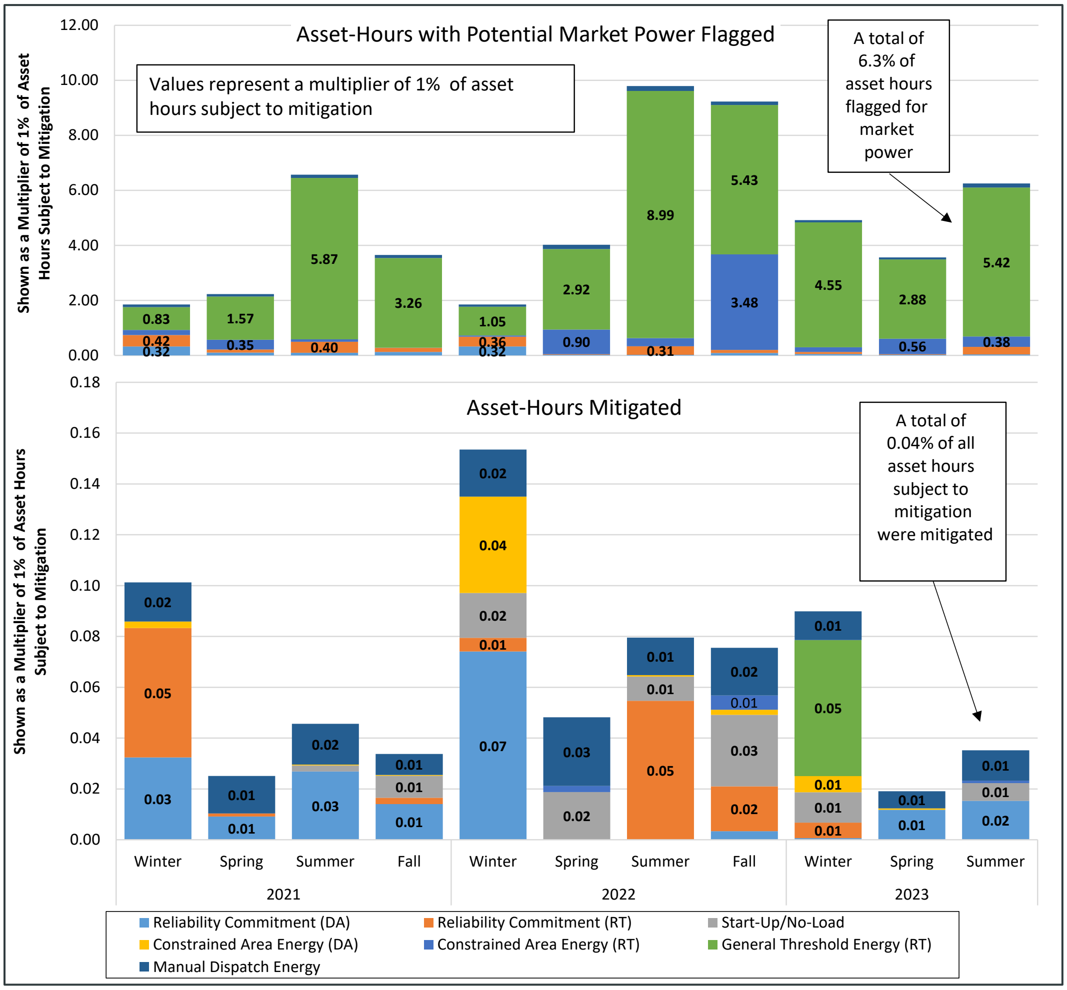
As in earlier periods, the mitigation of energy market supply offers occurred infrequently in Summer 2023.

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.[46] 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.

[46] 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).[47] The highest frequency of mitigation occurs for reliability commitments (46% 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 constrained area mitigation (green, dark blue, and yellow shading) have had the lowest mitigation frequency, with each accounting for 8% to 9% of mitigations over the review period.

The decrease in mitigations in Summer 2023, compared to the prior summer, resulted from a decline in reliability commitment mitigation. Comparing mitigations for Spring 2023 and Summer 2023, mitigations increased in Summer 2023 principally from increased reliability, start-up and no-

[47] 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.

load, and manual dispatch energy mitigations. Overall, there were just 115 asset hours of mitigation in Summer 2023, while 327 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).[48] 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, 44% and 35% 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: 51% of mitigations occurred in SEMA-RI and 17% occurred in Maine in the day-ahead market.[49] Overall, reliability mitigations decreased between Summer 2022 (178 asset hours) and Summer 2023 (50 asset hours); mitigations increased in Summer 2023 relative to Spring 2023, going from 40 asset hours to 50.

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).[50] 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 23 asset hours of start-up and no-load mitigation in Summer 2023, compared to 0 asset hours of mitigation in Spring 2023 and 31 asset hours of mitigation in Summer 2022.

Constrained area energy (CAE) mitigation:[51] 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 28 asset hours of CAE mitigation have occurred in the real-time energy market and only 168 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 Summer 2023, there were very few hours of structural test failures (1,233 asset hours) in the real-time market, and there were only three asset hours of constrained area energy mitigation. In the day-ahead market

[48] 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.

[49] 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.

[50] 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.

[51] 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.

for Summer 2023, there were no asset hours of mitigation. Mitigations in Summer 2023 increased modestly (3 asset hours) compared to Spring 2023 (2 asset hours of mitigation) and Summer 2022 (2 asset hours).

General threshold energy mitigation: This mitigation type also applies three tests prior to mitigation. This mitigation type typically has the lowest mitigation frequency of any mitigation type, because it also has the most tolerant conduct test and market impact thresholds of any mitigation type. 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 Summer 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 Summer 2023, there were 484 asset hours of manual dispatch and 39 asset hours of mitigation. These levels are slightly higher than Spring 2023 (254 asset hours of manual dispatch and 23 asset hours of mitigation). The Summer 2023 values declined relative to Summer 2022, which had 585 asset hours of manual dispatch and 48 asset hours of mitigation.

Section 5
Forward Markets

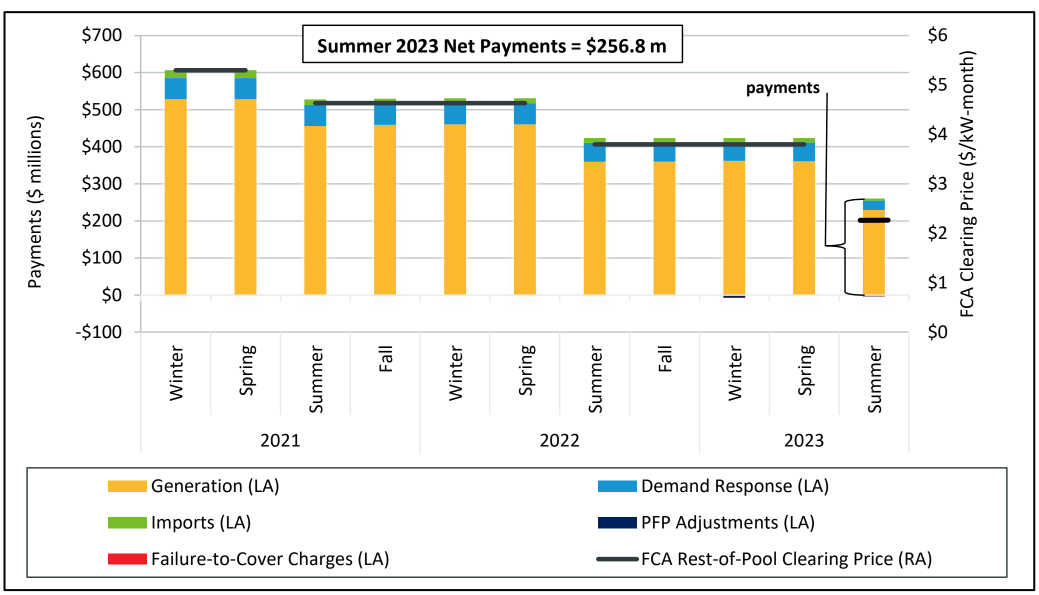
This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs), and in the Summer 2023 Forward Reserve Auction.

5.1 Forward Capacity Market

The capacity commitment period (CCP) associated with Summer 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.[52] 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 Summer 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



[52] 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 $524.8 million in cost-of-service payments.

In Summer 2023, capacity payments totaled $256.8 million. Total payments were down 39% from Summer 2022 ($423.1 million), driven by a 47% decrease in the clearing price from FCA 14 ($2.00/kW-month) to FCA 13 ($3.80/kW-month). A capacity scarcity event on July 5 transferred over $3 million in PfP payments away from under-performing FCM resources to assets and external transactions not associated with a capacity supply obligation (CSO).

Approximately $250 thousand in Failure-to-Cover (FTC) charges were administered in Summer 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 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 Summer 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	Highgate	New Brunswick	Northern New England	Southeastern New England
FCA 14 (2023 - 2024)	Primary	12-month	2.00	33,956					
	Monthly Reconfiguration	Aug-23	2.00	960					
	Monthly Bilateral	Aug-23	1.14	9					
	Monthly Reconfiguration	Sep-23	2.10	704					
	Monthly Bilateral	Sep-23	1.22	9					
	Monthly Reconfiguration	Oct-23	4.50	840					
	Monthly Bilateral	Oct-23	2.00	2					
FCA 15 (2024 - 2025)	Primary	12-month	2.61	33,270	2.48	2.48	2.48	2.48	3.98
	Annual Reconfiguration (2)	12-month	1.75	357, -1160					
FCA 16 (2025 - 2026)	Primary	12-month	2.59	32,810	2.53	2.53	2.53	2.53	2.64
	Annual Reconfiguration (1)	12-month	1.35	134, -591	1.34			1.34	

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

Two annual reconfiguration auctions (ARAs) took place in Summer 2023: the second annual reconfiguration auction for CCP 15 (2024-2025) and the first annual reconfiguration auction for CCP 16 (2025-2026). In ARA 2 of CCP 15, the auction cleared at $1.75/kW-month, below the primary auction clearing price of $2.61/kW-month for CCP 15. In total, 357 MW of supply cleared against 1,160 MW of cleared demand. The over-clearing of demand led to 803 MW of capacity leaving the system for CCP 15, driven by a 1,725 MW (5%) decrease in Net ICR from FCA 15 to ARA 2.[53] In ARA 1 of CCP 16, the auction cleared at $1.35/kW-month, below the primary auction clearing price of $2.59/kW-month. In total, 134 MW of supply cleared against 591 MW of cleared demand. The over-clearing of demand led to 456 MW of capacity leaving the system for CCP 15, driven by a 1,060 MW (3%) decrease in Net ICR from FCA 16 to ARA 1.

[53] The Net ICR is recalculated with the most up-to-date data for each annual reconfiguration auction leading up to the start of the capacity commitment period. All historical Net ICR values can be found here: https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx

Three monthly reconfiguration auctions (MRAs) took place in Summer 2023: the August 2023 auction in June, the September 2023 auction in July, and the October 2023 auction in August. All three MRAs cleared at or above the associated primary auction clearing price. In the October MRA, all supply offers cleared, resulting in a much higher clearing price due to insufficient supply. Cleared volumes remained relatively steady month-to-month, with the August 2023 auction clearing the largest volume at 960 MW.

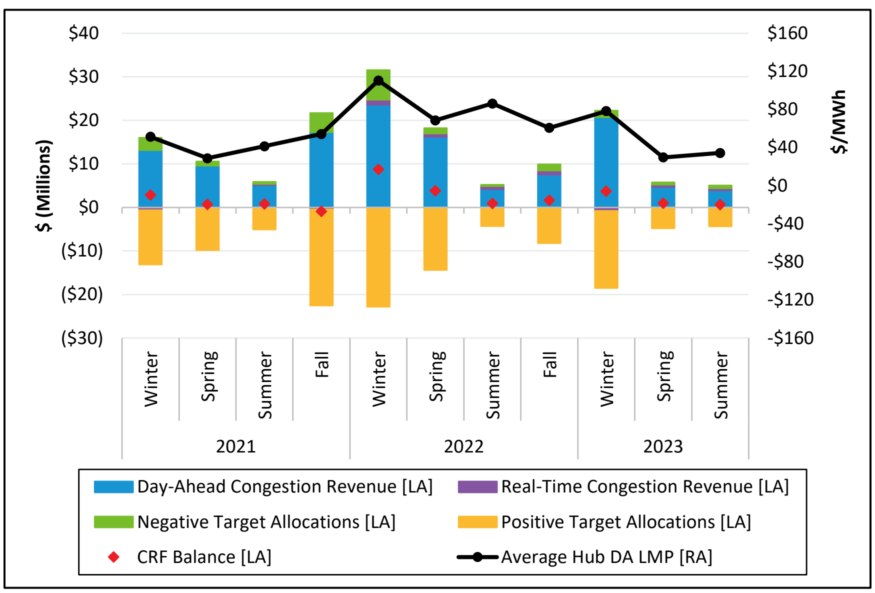
5.2 Financial Transmission Rights

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

1) the holders of FTRs with negative target allocations;
2) the revenue associated with transmission congestion in the day-ahead market;
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.[54] This figure also depicts the quarterly average day-ahead Hub LMP.[55]

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



[54] 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.

[55] The average annual day-ahead Hub LMP is measured on the right axis ("RA"), while all the other values are measured on the left axis ("LA").

Low day-ahead prices contributed to low day-ahead congestion revenue and target allocation values in Summer 2023.[56] Day-ahead congestion revenue amounted to $3.9 million in Summer 2023. This represents a decrease of 17% relative to Spring 2023 ($4.7 million) and a decrease of 7% relative to Summer 2022 ($4.1 million). Positive target allocations in Summer 2023 ($4.4 million) followed a similar pattern, decreasing by 9% relative to Spring 2023 ($4.8 million) and staying relatively unchanged from Summer 2022 ($4.3 million). Negative target allocations in Summer 2023 (-$0.7 million) increased by 23% from their Spring 2023 level (-$0.6 million) and by 97% from their Summer 2022 level (-$0.4 million). Meanwhile, real-time congestion revenue in Summer 2023 ($0.5 million) remained relatively modest and was generally in line with recent historical levels.

FTRs were fully funded in June 2023, July 2023, and August 2023.[57] At the end of August 2023, the congestion revenue fund had a surplus of $4.5 million.

5.3 Forward Reserve Market

In this section, we review the Winter 2023-2024 Forward Reserve Auction (FRA). Twice each year, ISO New England holds forward reserve auctions. The ISO uses forward reserve auctions to enter into forward obligations with participants to provide operating reserves in the real-time energy market. These forward obligations are intended to ensure the delivery of adequate operating reserves for both the ISO New England system-wide and local reserve zones. During August 2023, the ISO held the forward reserve auction for the Winter 2023-2024 delivery period (i.e., October 1, 2023 to May 31, 2024).[58]

5.3.1 Auction Reserve Requirements

Prior to each auction, the ISO establishes the amount of forward reserves, or requirements, for which it will enter into forward obligations. These requirements are set at levels intended to ensure adequate reserve availability in the real-time energy market, based on possible system and local reserve zone contingencies (i.e., unexpected events, such as the forced outage of a large generator or loss of a large transmission line).

The requirements for the Winter 2023-24 auction are illustrated in Figure 5-3 below. These requirements were specified for the ISO New England system and three local reserve zones.[59] The

[56] 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.

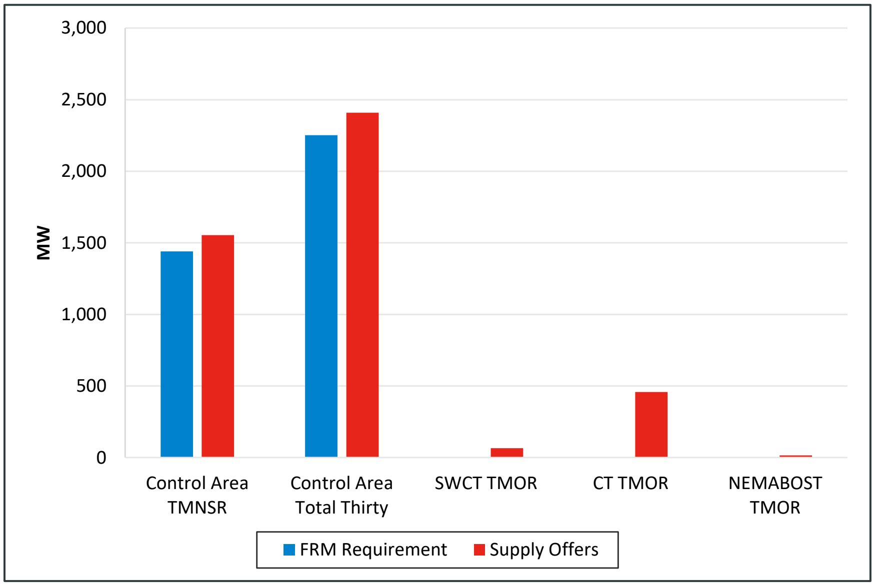
[57] FTRs are said to be "fully funded" when there is sufficient revenue is collected from the energy market and from FTR holders with negative target allocations to pay FTR holders with positive target allocations all the revenue to which they are entitled.

[58] The Forward Reserve Market has two delivery ("procurement") periods per year: Summer (June 1 to September 30) and Winter (October 1 to May 31).

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

figure also illustrates the total quantity of supply offers available to satisfy the reserve needs in the auction.[60]

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



Two reserve products had system (control area) requirements in the auction: ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR). The ISO bases the requirements for each product on possible system contingencies.[61] For TMNSR, the requirement was based on the expected single contingency of the Hydro Quebec Phase II Interconnection, and was estimated as a 1,441 MW TMNSR reserve need. The system-wide TMOR requirement was based on the expected single contingency of the Millstone, and was estimated as an 811 MW TMOR need. The total thirty-minute requirement (depicted in the figure) is the sum of the TMNSR and incremental TMOR requirements (i.e., 1,441 MW + 811 MW).[62] Offered reserve supply was adequate to satisfy requirements for both system-level products.

[60] Because TMOR supply offers within local reserve zones also provide TMOR to the system, the system-wide TMOR offers shown in the figure include the local reserve zone supply offers. Hence, the system-wide TMOR offers represent the total offers throughout the system. A similar adjustment has been made to the Connecticut TMOR supply offers; the SWCT zone is nested within the Connecticut zone, and SWCT offers can contribute to the Connecticut TMOR supply. Given this, SWCT TMOR supply offers are also included in the CT TMOR total. The system-level total thirty reserve data show all FRM supply offers in the auction, relative to the combined ten-minute non-spinning reserve (TMNSR) and TMOR system requirements. Finally, because TMNSR supply can contribute to TMOR supply, all TMOR totals in the graph show TMNSR in addition to TMOR supply.

[61] ISO New England Memorandum to Market Participants (Subject: Assumptions and Other Information for the Winter 2023-2024 Forward Reserve Auction), published July 21, 2023, indicates the system-wide and local reserve zone requirements. For the system-wide requirements, the final requirement may reflect ISO adjustments, such as biasing the requirement, increasing a requirement to reflect historical resource non-performance, and adjusting the TMOR requirement to reflect the replacement reserve requirement. See: https://www.iso-ne.com/static-assets/documents/2023/07/forward_reserve_auction_assumptions_winter_2023_2024.pdf

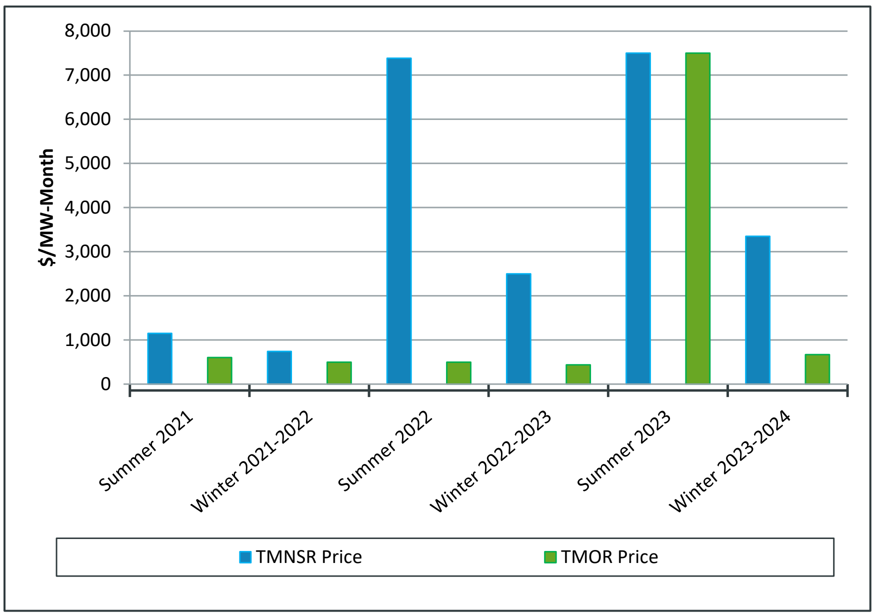
[62] The system TMOR requirement indicated in the ISO's auction assumptions represents an incremental requirement, in excess of the TMNSR requirement. The total thirty minute requirement for the auction is the sum of the TMNSR requirement and the system (incremental) TMOR requirement.

For the local reserve zones, only a TMOR requirement is specified. The ISO bases the local requirements on local second contingencies, adjusted for the availability of transmission capacity (which can also effectively supply reserves to the local area).[63] After adjustments, all local reserve zones – Connecticut, Southwest Connecticut and NEMA/Boston – were found to need no local reserve requirement, as "external reserve support" (i.e., available transmission capacity) exceeded the local second contingency requirements.

5.3.2 Auction Results

Forward reserve clearing prices for the system-wide TMNSR and TMOR products for the previous six auctions are shown in Figure 5-4 below.

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



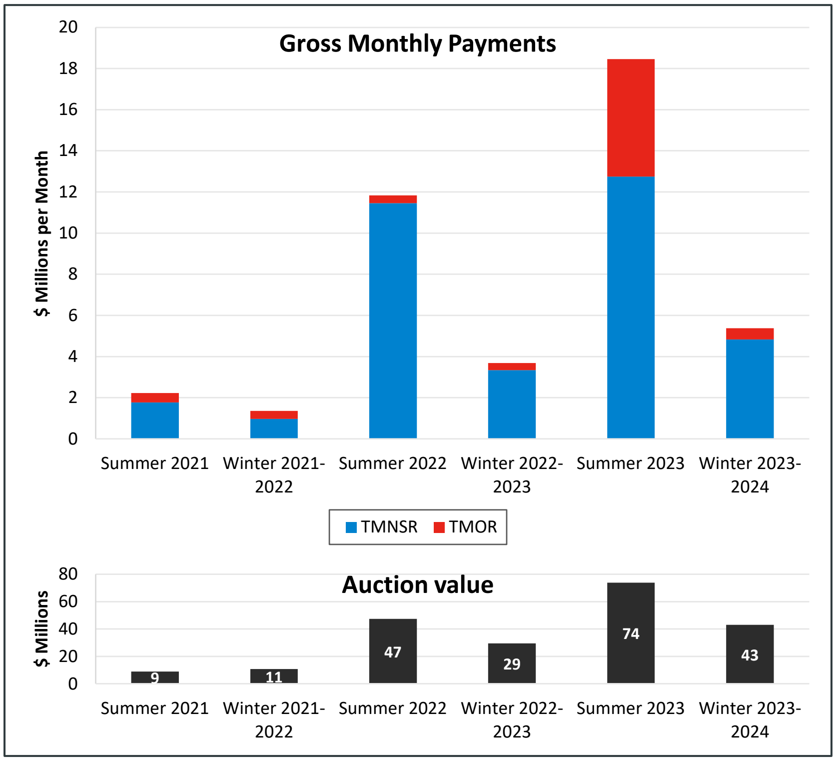
The clearing prices for the Winter 2023-2024 auction were $3,350/MW-month for TMNSR and $671/MW-month for TMOR. Both clearing prices were substantially lower than the prices for the Summer 2023 auction, which had TMNSR and TMOR prices of $7,499/MW-month. For TMNSR, the reduction in pricing resulted primarily from a decrease in offer pricing for TMNSR and a reduced TMNSR requirement (by 255 MW); for TMOR, a reduction in the total thirty requirement and an increase in total thirty supply, compared to the summer auction, resulted in a lower clearing price.

Compared to the Winter 2022-2023 auction pricing, TMNSR and TMOR pricing in the current auction increased by 34% and 53%, respectively. The Winter 2022-2023 auction had a TMNSR clearing price of $2,500/MW-month and a TMOR clearing price of $439/MW-month. The increase in Winter 2023-2024 TMNSR prices resulted from both a higher requirement (by 80 MW) and higher offer prices in that auction. The increase in TMOR prices in the Winter 2023-2024 auction resulted from an increase in the total thirty requirement and a decrease in total thirty supply, compared to the prior winter auction.

[63] See the ISO New England Manual for Forward Reserve and Real-Time Reserve for a more detailed indication of the determination of local reserve requirements (Manual M-36, Sections 2.2.3 – 2.2.5).

Figure 5-5 indicates the monthly gross payments (i.e., excluding penalties) available to participants with TMNSR and TMOR FRM obligations for the six most recent FRM delivery periods and the value of each auction.

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



While gross monthly payments for auctions preceding Summer 2022 ranged from $1.4 to $2.2 million per month, the elevated clearing prices for the Summer 2022 and 2023 auctions significantly increased FRM payments. The Summer 2022 auction had gross payments of approximately $11.8 million per month. Gross payments declined with the reduced TMNSR pricing for the Winter 2022-2023 auction, falling to $3.7 million per month; however, the Summer 2023 auction, with elevated TMNSR and TMOR pricing, resulted in gross payments of approximately $18.5 million per month. The decreased auction pricing for the Winter 2023-2024 auction also reduced gross monthly payments to $5.4 million per month.[64] The auction value presented in Figure 5-5 indicates the total payments (i.e., gross monthly payments multiplied by the number of months in delivery period) associated with each auction.

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

5.3.3 Auction Competitiveness

The Residual Supply Index (RSI) measures the FRM auction's structural competitiveness for the TMNSR and TMOR products.[65] Table 5-2 summaries the RSI values for each product and provides the clearing prices for each in recent auctions. It utilizes a heat map to indicate auctions that were structurally uncompetitive (i.e., red shading for RSI < 100, indicating the existence of one or more pivotal suppliers).

Table 5-2: FRM Auctions, RSI and Clearing Prices for TMNSR

Procurement Period	Offer RSI TMNSR	TMNSR Auction Clearing Price	Offer RSI Total Thirty	TMOR Auction Clearing Price
Summer 2021	92	$1,150	108	$600
Winter 2021-2022	110	$740	116	$499
Summer 2022	78	$7,386	90	$499
Winter 2022-2023	109	$2,500	112	$439
Summer 2023	81	$7,499	86	$7,499
Winter 2023-2024	82	$3,350	88	$671

For TMNSR, all but two of the recent forward reserve auctions have been structurally uncompetitive. Until the Summer 2022 auction, we observed relatively stable and low auction clearing prices. That result suggested a reduced risk of the potential exercise of market power, despite the lack of structural competitiveness. The Summer 2022 auction, however, resulted in a pricing outcome for TMNSR that was significantly higher than in the preceding auctions, and clearing prices have remained elevated in subsequent auctions.

For the TMOR (total thirty) forward reserve product, structurally-uncompetitive auctions have occurred during three of the prior six auctions. However, except for Summer 2023, the TMOR clearing prices have been relatively stable and low. In the Summer 2023 auction, TMOR supply was inadequate to meet the incremental TMOR requirement, and TMNSR supply had to be substituted to meet that requirement, resulting in both products obtaining the same clearing price.

We continue to be concerned that the relatively high forward reserve supply offers indicate an awareness that the structurally-uncompetitive auctions provide an opportunity to submit uncompetitive supply offers. The increase in TMNSR clearing prices, in particular, has resulted primarily from increased supply offer pricing, without an obvious linkage to market conditions and risks. Consequently, we are unable to conclude that the pricing outcomes in the recent auctions, including the Winter 2023-2024 auction, are consistent with what we would expect from a competitive process.

While the ISO expects to terminate the forward reserve market with the implementation of the Day-ahead Ancillary Services Initiative in March 2025, the exercise of market power in the remaining

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

auctions could result in a significant and inappropriate transfer of value from New England consumers to participants with FRM resources.

To limit the potential exercise of market power, our spring report contained a recommendation that the ISO review and update the forward reserve supply offer cap.[66] We are encouraged to see that such a review has commenced and is currently being discussed with stakeholders.[67,68]

[67] See Section 5 of the IMM's 2023 Spring report at: https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf#page=43&zoom=100,92,146

[68] See ISO-NE presentation to the NEPOOL Market Committee regarding the proposal to address market power concerns in the FRM, October 2023, at: https://www.iso-ne.com/static-assets/documents/100004/a08_mc_2023_10_11_12_proposed_revisions_update_frm_offer_cap_iso_presentation.pdf