Summer 2022
Quarterly Markets Report

By ISO New England's Internal Market Monitor

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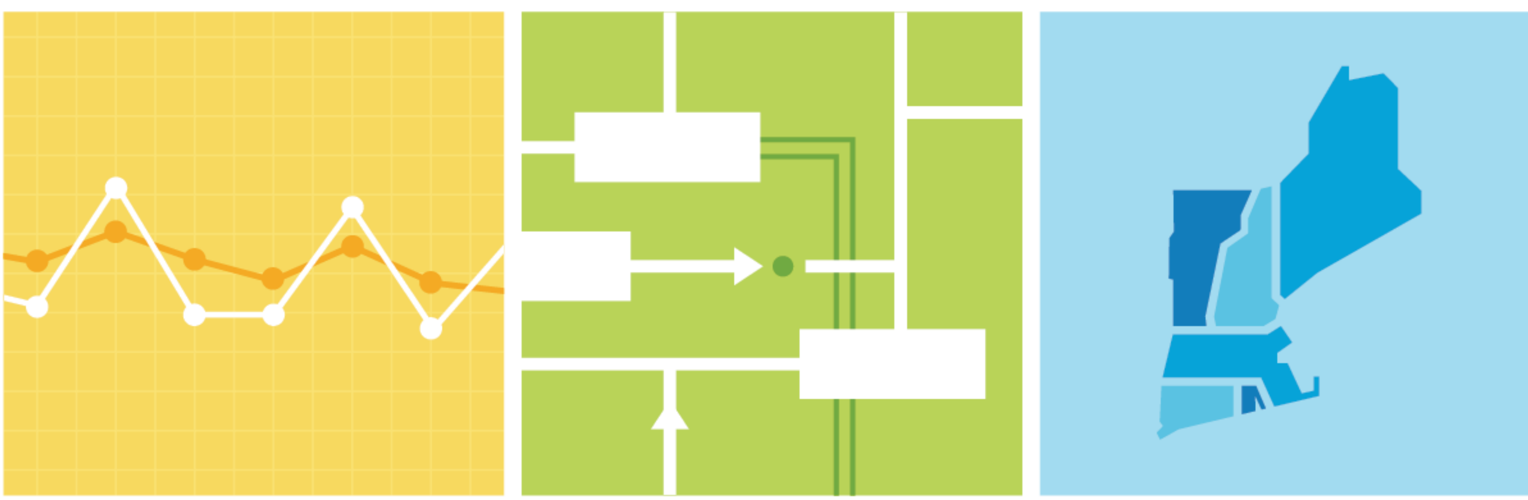

Preface

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

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

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

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

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

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

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

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Section 1
Executive Summary

Wholesale Costs: The total estimated wholesale market cost of electricity was $3.92 billion, up 79% from $2.19 billion in Summer 2021. The increase was driven by higher energy costs.

Energy costs totaled $3.42 billion; up 110% (or $1.79 billion) from Summer 2021 costs. Increased energy costs were a result of higher natural gas prices. In Summer 2022, gas prices increased by 131% compared to Summer 2021.

Capacity costs totaled $423 million, down 20% (by $107 million) from last summer. Beginning in Summer 2022, lower capacity clearing prices from the thirteenth Forward Capacity Auction (FCA 13) contributed to lower wholesale costs relative to the previous summer. Last year, the capacity payment rate for all new and existing resources was $4.63/kW-month. This year, the payment rate for new and existing resources was lower, at $3.80/kW-month.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $86.13 and $86.28 per megawatt hour (MWh), respectively. Day-ahead and real-time prices were 109-115% higher than Summer 2021 prices, on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $7.81/MMBtu in Summer 2022, more than double the Summer 2021 price of $3.39/MMBtu.
- Energy market prices did not differ significantly among load zones.
- The markets performed well during two notable summer heat waves. While there were instances of high LMPs and reserve prices, these were consistent with marginal resource dispatch costs.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $18.6 million, an increase of 86% or $8.6 million compared to Summer 2021. NCPC remained relatively low and comprised just 0.5% of total energy payments in Summer 2022. This was a slight decrease from Summer 2021 (0.6%).

The majority of NCPC (93%) was for first contingency protection, also known as "economic" NCPC. Summer 2022 economic NCPC payments increased by 124% or $9.5 million compared to Summer 2021 payments, consistent with the increase in energy payments. Most economic payments (74%) occurred in the real-time market. Commitment and dispatch payments continue to make up the majority of economic uplift, and increased from $5.0 million to $12.7 million between Summer 2021 and Summer 2022 due to the increase in natural gas and oil prices.

Real-time Reserves: Real-time reserve payments totaled $13.4 million, a $4.4 million increase from $9.0 million in Summer 2021. The increase was driven by larger ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR) payments, which increased by $797 thousand and $1.8 million, respectively. Most non-spinning reserve payments occurred on days when system conditions were tight due to hot weather and high loads. Additionally, ten-minute spinning reserve (TMSR) payments increased by $1.8 million compared to Summer 2021.

The frequency of non-zero spinning reserve prices decreased from 386 hours to 343 hours. However, the average non-zero spinning reserve price increased relative to Summer 2021, from $14.27 to $19.98/MWh. TMNSR and TMOR prices also increased. These increases were consistent with higher natural gas and real-time energy prices in Summer 2022.

Regulation: Regulation market payments totaled $9.3 million, up 22% from $7.6 million in Summer 2021. This increase reflected higher energy market opportunity costs for generators providing regulation. Average real-time Hub LMPs were significantly higher in Summer 2022 compared to the previous summer, leading to a $2 million increase in regulation capacity payments.

Financial Transmission Rights (FTRs): FTRs were fully funded in June, July, and August 2022. Positive target allocations totaled $4.3 million in Summer 2022, down 14% from Summer 2021 ($5.1 million). Day-ahead congestion revenue also decreased in Summer 2022, totaling $4.1 million compared to $5.1 million in Summer 2021. Negative target allocations ($0.4 million) were 32% lower than their Summer 2021 level ($0.5 million). Real-time congestion revenue was $0.4 million in Summer 2022, up from Summer 2021 ($0.2 million). At the end of August, the 2022 congestion revenue fund surplus was $7.8 million, meaning more than sufficient revenue was generated to pay FTR holders.

Winter 2022/23 Forward Reserve Market Auction: In August 2022, the ISO held the forward reserve auction for the Winter 2022-2023 delivery period (October 1, 2022 to May 31, 2023). System-wide supply offers in the Winter 2022-2023 auction exceeded the requirements for both ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR), and there were no pivotal suppliers.

The net clearing prices for offline system thirty- and ten-minute reserves were $439 and $2,500 per megawatt-month (MW-month), respectively. The clearing prices declined in the Winter 2022-2023 auction compared to the Summer 2022 auction (TMNSR: $7,386/MW-month; TMOR: $499/MW-month) due to significantly reduced offer prices for both products and a decrease in the TMNSR requirement. Compared to the Winter 2021-2022 auction (TMNSR: $740/MW-month; TMOR: $499/MW-month), TMNSR cleared at a higher price and TMOR cleared at a lower price. These fluctuations were driven by changes in offer behavior.

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 2022	Spring 2022	Summer 2022 vs Spring 2022 (% Change)	Summer 2021	Summer 2022 vs Summer 2021 (% Change)
Real-Time Load (GWh)	33,907	26,886	26%	33,890	0%
Peak Real-Time Load (MW)	24,774	18,948	31%	25,807	-4%
Average Day-Ahead Hub LMP ($/MWh)	$86.13	$68.49	26%	$41.29	109%
Average Real-Time Hub LMP ($/MWh)	$86.28	$66.91	29%	$40.22	115%
Average Natural Gas Price ($/MMBtu)	$7.81	$7.14	9%	$3.39	131%
Average No. 6 Oil Price ($/MMBtu)	$23.53	$24.35	-3%	$13.03	81%

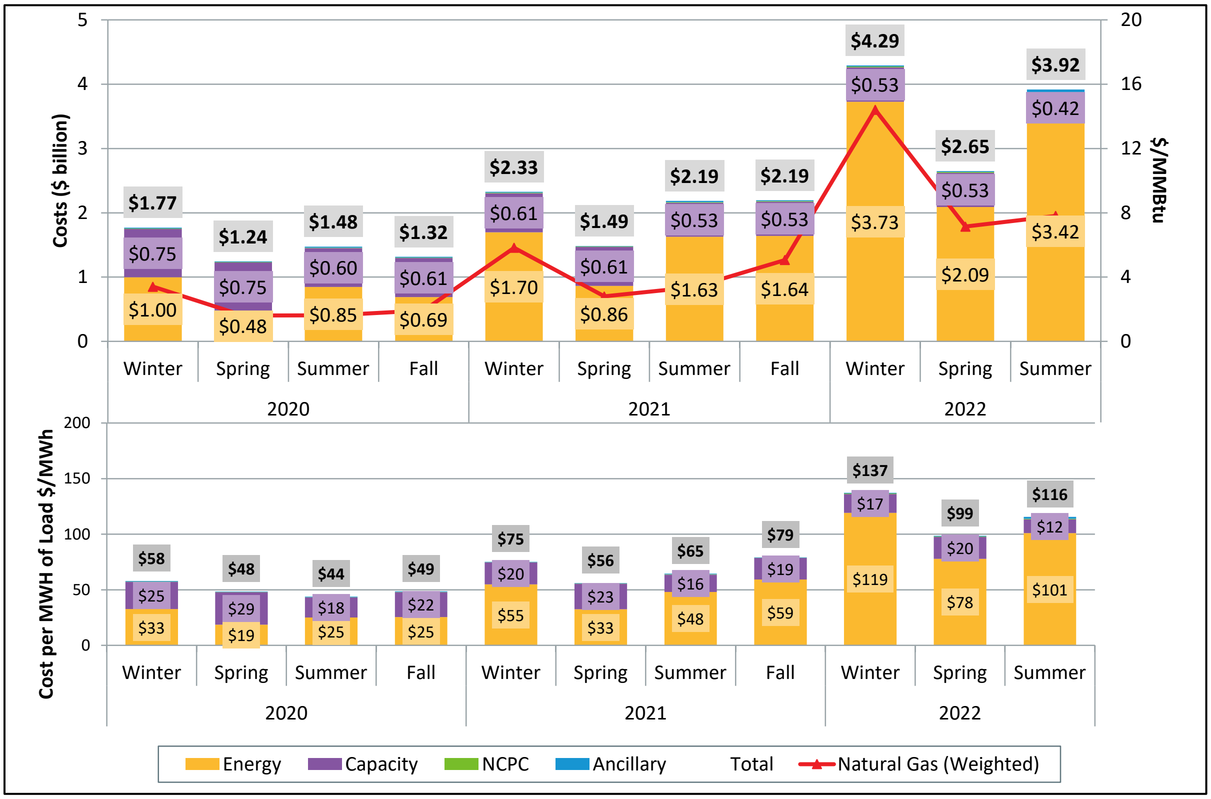
To summarize the table above:

- Average day-ahead LMPs in Summer 2022 were $86.13/MWh, 109% higher than in Summer 2021. Higher gas prices in Summer 2022 ($7.81/MMBtu) compared to Summer 2021 ($3.39/MMBtu) put upward pressure on LMPs.
- Natural gas prices averaged $7.81/MMBtu, a $4.42/MMBtu (or 131%) increase compared to Summer 2021. Since New England has no native natural gas production, natural gas prices at supply basins directly influence New England natural gas prices. Summer 2022 natural gas prices from Marcellus shale, the primary source of New England's natural gas, averaged $6.68/MMBtu, a $3.74/MMBtu increase compared to Summer 2021 ($2.94/MMBtu) and a $0.98/MMBtu increase compared to Spring 2022 ($5.70/MMBtu). Increased demand for natural gas outpaced supply increases, leading to the higher prices.

2.1 Wholesale Cost of Electricity

The estimated wholesale electricity cost (in billions of dollars) for each season by market, along with average natural gas prices (in $/MMBtu) is shown in Figure 2-1 below. The bottom graph shows the wholesale cost per megawatt hour of real-time load served.[3,4]

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



In Summer 2022, the total estimated wholesale cost of electricity was $3.92 billion (or $116/MWh of load), a 79% increase compared to $2.19 billion in Summer 2021, and a 48% increase over the previous quarter (Spring 2022). Energy costs were $3.42 billion ($101/MWh) in Summer 2022, which accounted for 87% of total costs. The share of each wholesale cost component is shown in Figure 2-2 below.

Natural gas prices continued to be a primary driver of energy prices, and led to substantially higher energy costs this summer (87%) compared to Summer 2021 (74%) as a share of total costs. Summer 2022 natural gas prices averaged $7.81/MMBtu, an increase of $4.42/MMBtu or

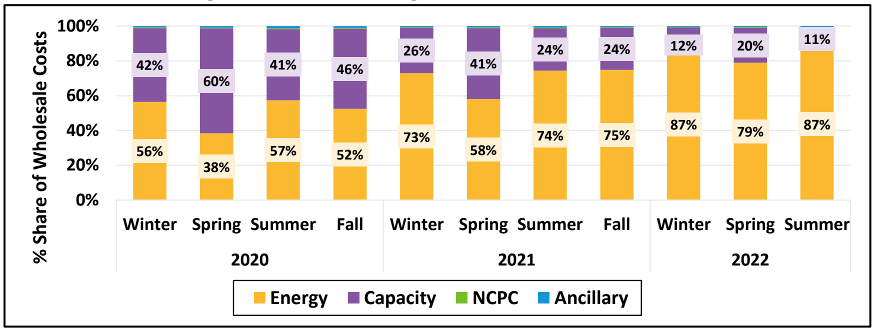
[3] The total cost of electric energy is approximated as the product of the day-ahead load obligation for the region and the average day-ahead locational marginal price (LMP) plus the product of the real-time load deviation for the region and the average real-time LMP. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of quarterly wholesale costs.

[4] Unless otherwise stated, the natural gas prices shown in this report are based on the weighted average of the Intercontinental Exchange next-day index values for the following trading hubs: Algonquin Citygates, Algonquin Non-G, Portland and Tennessee gas pipeline Z6-200L. Next-day implies trading today (D) for delivery during tomorrow's gas day (D+1). The gas day runs from hour ending 11 on D+1 through hour ending 11 on D+2.

131% compared to Summer 2021 prices. Resulting energy costs were 110% higher in Summer 2022 than Summer 2021.

Capacity costs are driven by clearing prices in the primary capacity auctions (in this reporting period, FCA 13), and totaled $423 million ($12/MWh), representing 11% of total costs. The current capacity commitment period (CCP13, June 2022 – May 2023) cleared at $3.80/kw-month. This was 18% lower than $4.63/kW-month the prior auction. Section 5.1 discusses recent trends in the Forward Capacity Market in more detail.

Figure 2-2: Percentage Share of Wholesale Cost



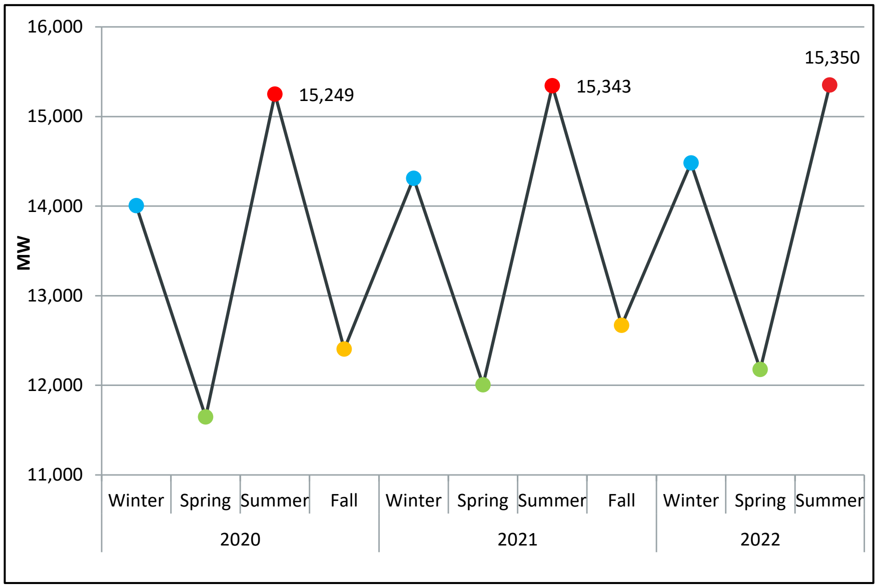
At $18.6 million ($0.55/MWh), Summer 2022 Net Commitment Period Compensation (NCPC) costs represented 0.5% of total energy costs, a similar share compared to other quarters in the reporting horizon. Economic commitment and dispatch payments increased by 156% from $5.0 million to $12.7 million between Summer 2021 and Summer 2022, driven by an increase in fuel prices.

Ancillary service costs, which include payments for operating reserves and regulation, totaled $53.8 million ($1.59/MWh) in Summer 2022, representing 1.3% of total wholesale costs. Ancillary service costs increased by 168% compared to Summer 2021. The increase was driven by higher forward (Section 5.3) and real-time (Section 3.6) reserve prices compared to Summer 2021.

2.2 Load

In Summer 2022, average loads were nearly identical to Summer 2021 (15,350 MW vs. 15,343 MW), as average temperatures and humidity were similar year over year.[5] 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

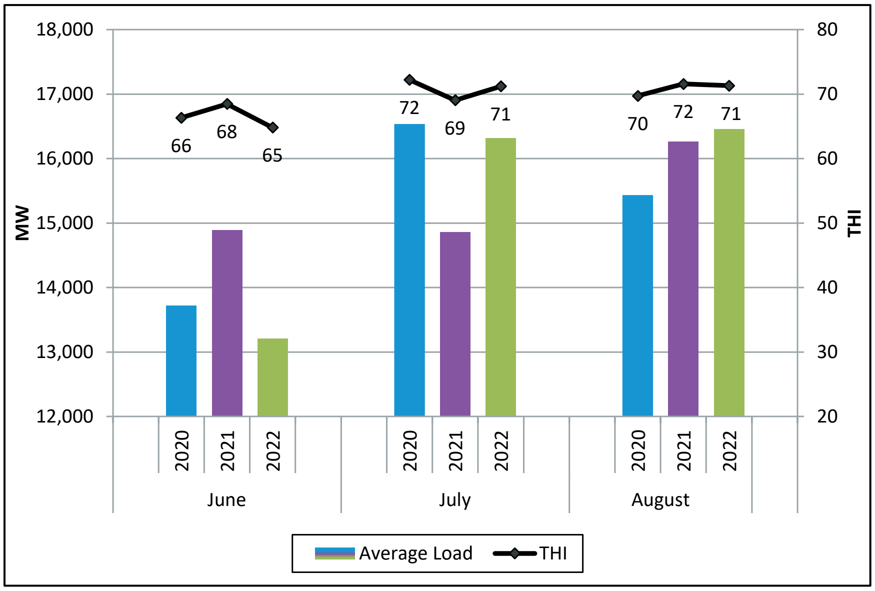


In Summer 2022, loads averaged 15,350 MW, a 0.1% increase from Summer 2021 (15,343 MW) and a 0.7% increase compared to Summer 2020 (15,249 MW). The comparable loads between summers are due to small changes in temperatures (73°F vs. 72°F) and the Temperature-Humidity Index (THI) (69 vs. 70) over the same period.[6] The monthly breakdown of the THI and load over the past three summers is shown in Figure 2-4 below. The bars illustrate monthly average load (left axis) and the lines illustrate the monthly average THI (right axis).

[5] 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).

[6] 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 (°F)]+ 0.3 x [Dew Point (°F)] + 15.

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

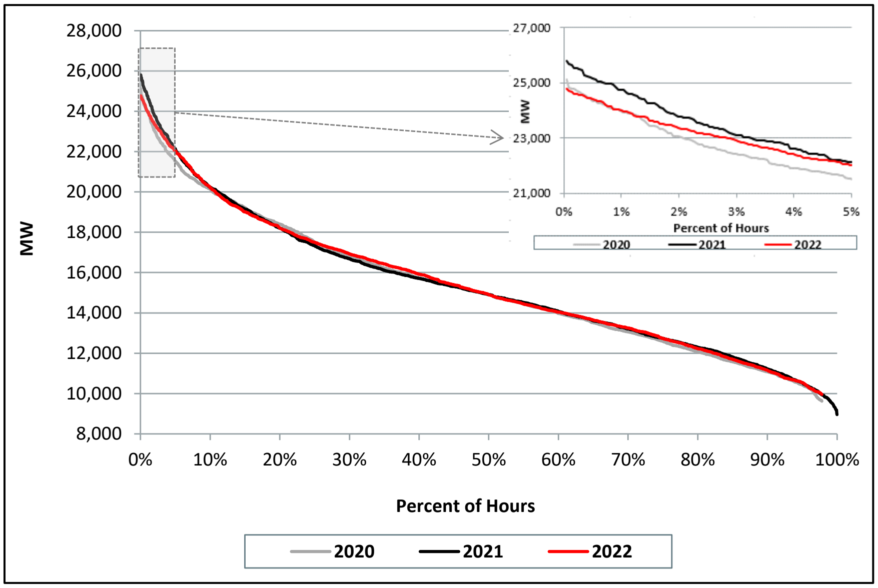


At a monthly level, changes in the THI explain most of the year-over-year changes in average load. For example, June 2022 loads and THI were lower than in June 2021, whereas July 2022 loads and THI were higher than in July 2021. The primary driver behind higher July loads and THI in 2022 was a heat wave from July 19 to 24. The market outcomes from those days are discussed in Section 3.2.

Peak Load and Load Duration Curves

New England's system load over the past three summers 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. Summer 2022 is shown in red, while Summer 2021 is shown in dark gray and Summer 2020 is shown in light gray.

Figure 2-5: Load Duration Curve



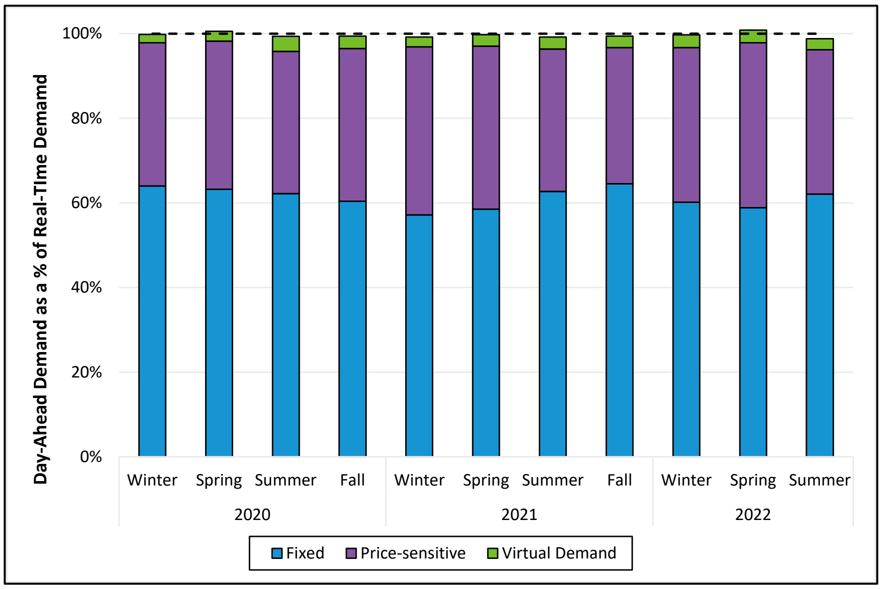
The duration curves illustrate the comparable load levels between the two most recent summers; Summer 2022 loads were higher than Summer 2021 loads in 48% of hours. The peak load in Summer 2022 (24,774 MW) was lower than in 2021 (25,799 MW) and in 2020 (25,121 MW). In Summer 2022, loads were higher than 18,000 MW in 21.5% of all hours, compared to 21.2% and 22.6% in Summer 2021 and 2020, respectively. In Summer 2022, the top 5% of all hours averaged 23,206 MW, which was 428 MW lower than in Summer 2021 (23,634 MW) and 301 MW higher than in Summer 2020 (22,906 MW).

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 the generator commitment decision for the operating day.[7] Low demand clearing in the day-ahead market, may warrant supplemental generation commitment to meet real-time demand. This can lead to higher real-time prices compared to day-ahead prices when additional commitments are needed subsequent to the day-ahead process.

The day-ahead cleared demand as a percentage of real-time demand is shown in Figure 2-6 below. Day-ahead demand is broken down by bid type: fixed (blue), price-sensitive (purple) and virtual (green) demand.[8]

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



Day-ahead cleared demand as a percentage of real-time demand was slightly lower in Summer 2022 (98.8%) than in Summer 2021 (99.2%) and Summer 2020 (99.4%), on average. Each component of demand was within an expected range for summer; fixed demand (62.1%), cleared virtual demand (2.6%), and price-sensitive demand (34.1%) were within 1% difference from the past two summers.

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

[8] Day-ahead cleared demand is calculated as fixed demand + price-sensitive demand + virtual demand, while 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. The IMM has 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.

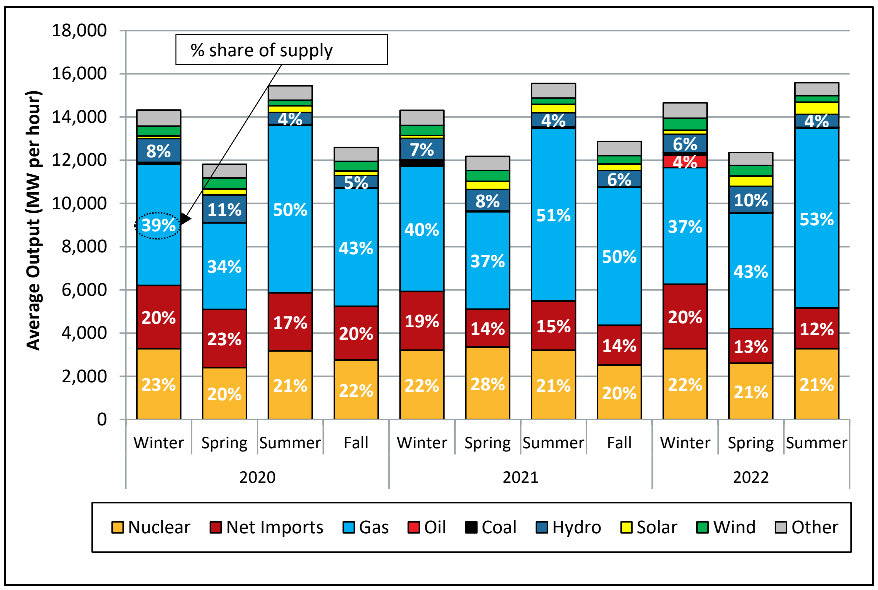
2.3 Supply

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

2.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The share of energy production by generator fuel type for Winter 2020 through Summer 2022 is illustrated in Figure 2-7 below. Each bar's height represents average electricity generation, while the percentages represent the percent share of generation from each fuel type.[9]

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



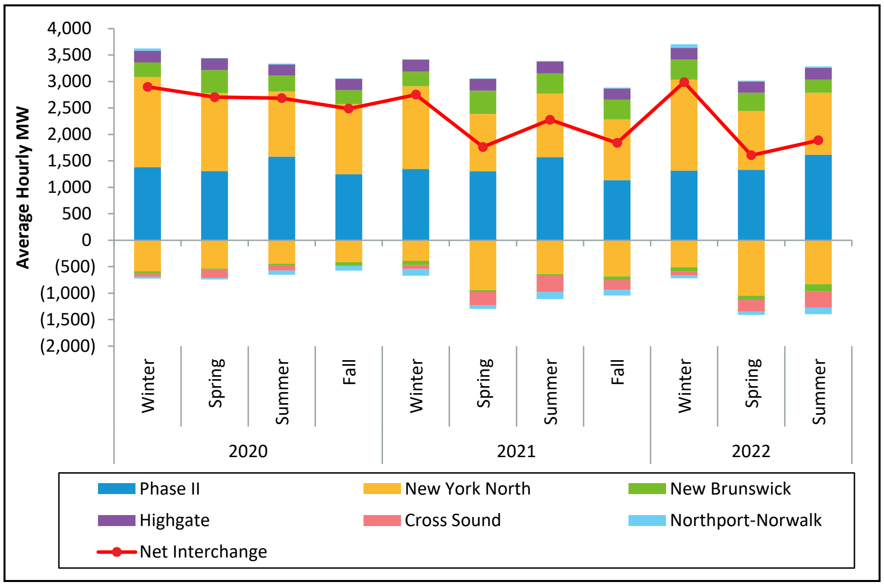
The majority of New England's energy comes from nuclear generation, gas-fired generation, and net imports (imports netted for exports). Together, these categories accounted for 86% of total energy production in Summer 2022. Although gas prices were higher compared to previous summers, natural gas-fired generator production increased 4% compared to Summer 2021, and 56% compared to Spring 2022. The increase in natural gas generation offset the 17% decline in average net imports in Summer 2022 (1,887 MW per hour) from Summer 2021 (2,278 MW per hour). As described in Section 2.3.2, the reduction in net imports occurred over the New Brunswick and New York North interfaces.

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

2.3.2 Imports and Exports

New England continued to be a net importer of power from its neighboring control areas of Canada and New York in Summer 2022.[10] On average, the net flow of energy into New England was 1,887 MW per hour. The total net imports represented 12% of load (NEL), which was lower than the prior nine seasons. The average hourly import, export, and net interchange power volumes by external interface for the last 11 quarters are shown in Figure 2-8 below.

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



Hourly net interchange averaged 1,887 MW, up 18% (or 282 MW) from Spring 2022 (1,605 MW) and down 17% (or 391 MW) from Summer 2021 (2,278 MW). 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. Compared to Summer 2021, net interchange fell due to decreased flows over both the New Brunswick Interface and the New York North Interface. Flows across the New Brunswick Interface fell year-over-year after a New Brunswick nuclear power plant's spring outage unexpectedly extended through most of the summer.[11] At New York North, the average forecasted price spread decreased (i.e., New York Prices increased by more than New England prices) leading to the drop in the average net interchange over the interface. Overall, the 17% (or 391 MW) decrease in net interchange contributed to the increased LMPs in New England.

[10] 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.

[11] The nuclear power plant accounts for 46% of New Brunswick's native generation. For more information on the outage, see this link

Phase II Interface

The Phase II interface continues to account for the largest share of net interchange (86%) into New England. Phase II's share of total net interchange has risen over the last 11 seasons as total net interchange at other interfaces has trended down, especially at the New York interfaces. Additionally, net interchange at Phase II averaged 1,614 MW, the highest net interchange over the reporting period. Average net interchange at Phase II represented a 45 MW (or 3%) increase compared to Summer 2021 (1,570 MW), and a 287 MW (or 22%) increase compared to Spring 2022 (1,327 MW).

New York North Interface

The reduction in net interchange over New York North, along with New Brunswick, was a major contributor to the overall decrease in net interchange compared to Summer 2022. At the New York North interface, hourly average net interchange decreased by 218 MW (or 39%) compared to Summer 2021 (343 MW vs. 561 MW). The main driver behind this difference was the change in the forecasted price spread at the New York North interface, which led to a 30 MW decrease in imports and a 188 MW (or 29%) increase in exports over the New York North interface, on average. New England forecasted prices were $4.53/MWh lower than New York forecasted prices in Summer 2022 compared to just $3.29/MWh in Summer 2021, on average. The increase in forecasted price spreads occurred as congestion costs increased in the New York zones bordering New England, especially in New York's Capital Zone. Between Summer 2021 and Summer 2022, the congestion component of the real-time LBMP increased from $5.55/MWh to $23.16/MWh in New York's Capital Zone.[12]

New Brunswick Interface

On average, net interchange at the New Brunswick interface was 249 MW (or 69 %) lower in Summer 2022 than in Summer 2021 (110 MW vs. 359 MW). A nuclear power plant in New Brunswick went on a refueling outage during April 2022 and was expected to return before the start of Summer 2022. However, the outage took longer than expected and the unit remained out of service until the end of July 2022. This unit represents nearly half of the total generation in New Brunswick, and its extended outage was the major contributor to the reduced net interchange. Once the generator fully returned from its refueling outage, net interchange with New Brunswick averaged 375 MW, which was comparable with average net interchange in Summer 2021 (359 MW).

[12] LBMP is the New York ISO's Locational Based Marginal Price.

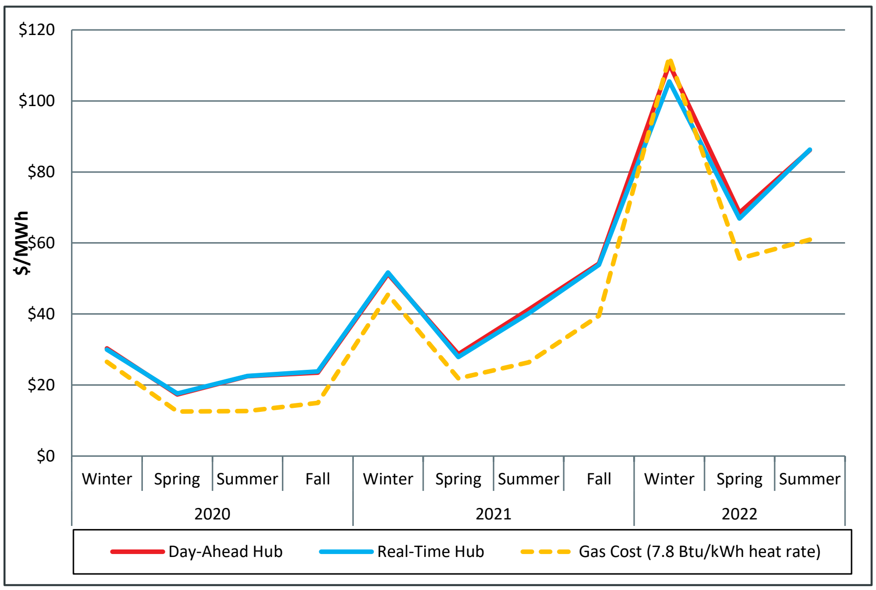
Day-Ahead and Real-Time Markets

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

3.1 Energy Prices

The average real-time Hub price for Summer 2022 was $86.28/MWh, similar to the average day-ahead price of $86.13/MWh. Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas in New England, are shown in Figure 3-1. The natural gas cost is based on the average natural gas price each season and a generator heat rate of 7,800 Btu/kWh.[13]

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



As Figure 3-1 illustrates, the seasonal movements of energy prices (solid lines) are generally consistent with changes in natural gas generation costs (dashed line). The spread between the estimated cost of a typical natural gas-fired generator and electricity prices tends to be highest during the summer months. During the summer, less efficient generators or generators burning more expensive fuels are required to meet the region's higher demand. Gas costs averaged $61/MWh in Summer 2022.

Average day-ahead electricity prices were $25.22/MWh above average estimated gas costs in Summer 2022, which was higher than the $14.87/MWh spread in Summer 2021. The higher spreads were primarily driven by the substantial increase in natural gas prices and the knock-

[13] The average heat rate of combined cycle gas turbines in New England is estimated to be 7,800 Btu/kWh.

on effect on energy prices.[14] Additionally, average net imports were about 390 MW lower in Summer 2022 compared to Summer 2021, resulting in the dispatch of less efficient, higher-cost gas generation.

In Summer 2022, average day-ahead and real-time prices were much higher than in Summer 2021, by about $45 and $46/MWh, respectively. This is consistent with the large change in natural gas prices, which increased by 131%. Average hourly loads in Summer 2022 were similar to that of Summer 2021.

The seasonal average day-ahead and real-time energy prices for each of the eight New England load zones and for the Hub are shown below in Figure 3-2.

Figure 3-2: Simple Average Day-Ahead and Real-Time Prices by Location and Gas Generation Costs

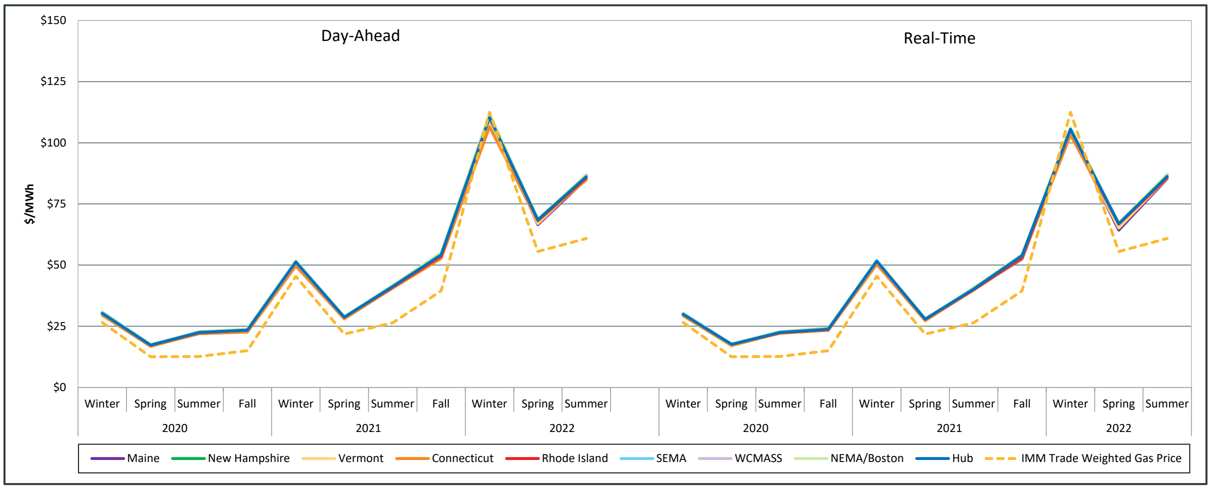


Figure 3-2 illustrates that prices did not differ significantly among the load zones in either market in Summer 2022, indicating that there was relatively little transmission congestion on the system at the zonal level.[15]

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[14] For example, assume the implied heat rate was 11,000 MMBtu/MWh in both Summers 2021 and 2022. Given the natural gas prices, LMPs would average $37.29/MWh ($3.39/MMBtu x 11,000 Btu/kWh) in Summer 2021 and $85.90/MWh ($7.81/MMBtu x 11,000 Btu/kWh) in Summer 2022. Since we estimate a heat rate of 7,800 Btu/kWh for standard efficiency gas-fired generators, the estimated cost of natural gas-fired generation would be $26.44/MWh ($3.39/MMBtu x 7,800 Btu/kWh) in Summer 2021 and $60.92/MWh ($7.81/MMBtu x 7,800 Btu/kWh) in Summer 2022. This means the spark spreads (or LMP minus estimated cost of generation) would average $10.85/MWh ($37.29/MWh minus $26.44/MWh) in Summer 2021 and $24.99/MWh ($85.91/MWh minus $60.92/MWh) in Summer 2022. In this example, the increase in natural gas prices caused the increase in spark spreads.

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

3.2 Real-Time LMPs During System Events In Summer 2022

This section discusses two notable heat wave events that occurred during Summer 2022. First, we detail the key event causes and outcomes during both heat waves in the bullet points below. We then provide a more in-depth discussion of energy market performance during the events.

Overall, we found that the market performed well during these events. LMPs were consistent with marginal resource dispatch costs and reserve and NCPC payments were in line with our expectations. Though the events resulted in the highest loads of the summer, there were no capacity scarcity (shortage event) conditions.

July 19-24 Heat Wave

- Over this six-day period, temperatures averaged 82°F, with a high of at least 90°F on each day.
- Peak loads were above 22,500 MW on all days of the event. Load peaked at 24,608 MW during hour-ending (HE) 18 on July 20.
- Overall, weather and load forecasts were accurate. Hourly temperature forecast errors ranged from just 0°-3°F. The hourly load forecast was within 500 MW of actual load during 87% of event hours.
- On July 19, the ISO declared an M/LCC 2[16] event due to anticipated capacity deficiencies during the impending heat wave. M/LCC2 remained in effect until Sunday, July 24 at 10pm.
- Unplanned transmission outages were minimal and did not significantly affect the system during the heat wave.
- The most unplanned generator outages of the July 19-24 period occurred on July 20. On this day, nine generators deviated significantly from their day-ahead schedules due to unexpected outages or reductions. Outages peaked in the evening during HE 17-21, when those nine generators produced a combined 1,700-2,075 MW less than their day-ahead scheduled amounts. All of these outages occurred due to mechanical issues, with the exception of one fuel-related outage. In that case, a generator had difficulty procuring natural gas due to reduced availability caused by pipeline maintenance and high demand.
- Day-ahead LMPs peaked at $362.74/MWh on July 22, while hourly real-time Hub LMPs peaked at $764.88/MWh on July 20. TMOR pricing occurred on July 19, 20, 23, and 24, and TMNSR pricing occurred on July 20, 22, 23, and 24.
- NCPC payments during the event totaled $6.0 million.

August 4-9 Heat Wave

- Temperatures averaged 82°F, with daily highs ranging from 89°F to 93°F.
- Peak loads were above 23,300 MW on all days of the event. Load peaked at 24,774 MW during HE 19 on August 4.

[16] Master Local Control Center Procedure No. 2 (M/LCC 2, Abnormal Conditions Alert) notifies market participants and power system operations personnel when an abnormal condition is affecting the reliability of the power system, or when such conditions are anticipated. The ISO expects these entities to take certain precautions during M/LCC 2 events, such as rescheduling routine generator maintenance to a time when it would be less likely to jeopardize system reliability.

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

- Weather and load forecasts were accurate on most days of the event. Temperatures were 4-5°F warmer than expected during three hours each on August 6 and 7. The only day with a large sustained load forecast error was August 5, when actual loads were about 950-1,310 MW less than the forecast during HE 17-21.
- On August 4, the ISO declared a system-wide M/LCC 2 event due to an anticipated capacity deficiency from 16:00-22:00. M/LCC 2 was also in effect on August 8 from 09:30-22:00, again due to an anticipated capacity deficiency.
- Generator and transmission outages were minimal and did not have significant impacts on the system.
- Day-ahead Hub LMPs peaked at $321.11/MWh on August 4, while hourly real-time Hub LMPs peaked at $365.86/MWh on August 8. TMOR and TMNSR pricing occurred on August 6.
- NCPC payments totaled $3.3 million during the event.

The following sections discuss more in-depth aspects of system and market performance during the heat wave events.

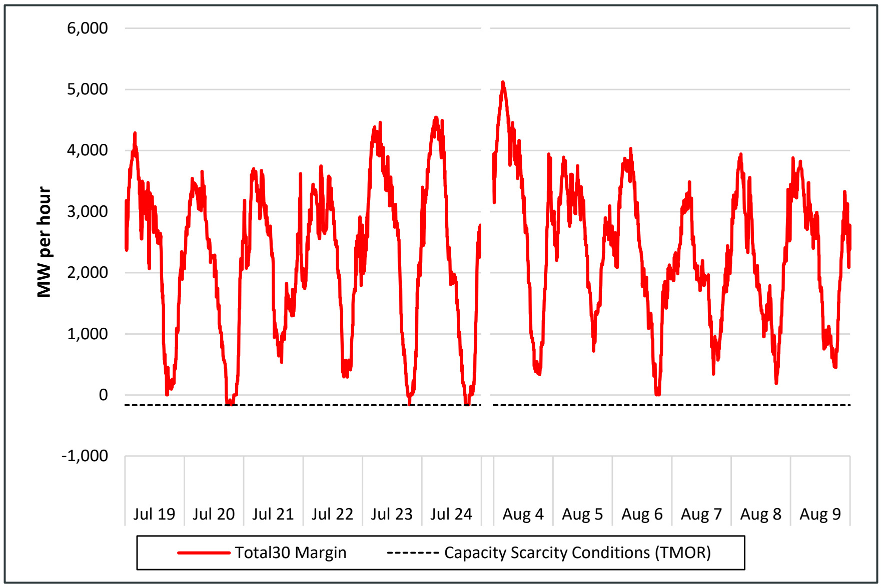
Reserve Margin

The real-time reserve margin measures additional available generation capacity over the load and reserve requirement. If margins are low, the ISO may need to commit additional generators or redispatch online resources, resulting in elevated LMPs. The margin for the total 30-minute reserve product (Total30) during the heat wave is shown in Figure 3-3 below. The black dotted line represents the threshold for capacity scarcity conditions for the TMOR product.[17] If the Total30 margin dips below this threshold (-160 MW), then the TMOR reserve constraint penalty factor of $1,000/MWh would be in effect. This is set at -160 MW rather than 0 MW because the ISO adds a 30-minute replacement reserve requirement of 160 MW for the summer and 180 MW for the winter months. The replacement reserve was added to the requirement in 2016 as an additional measure to protect against reserve shortages. Per control room operating procedures, the ISO will not activate emergency procedures to maintain the replacement reserve requirement.[18]

[17] A shortage of ten-minute non-spinning reserve (TMNSR) can also trigger capacity scarcity conditions.

[18] ISO New England Operating Procedure No. 8 (Operating Reserve and Regulation) is available at: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf

Figure 3-3: Reserve Margins from the Pricing Market Case During Heat Waves

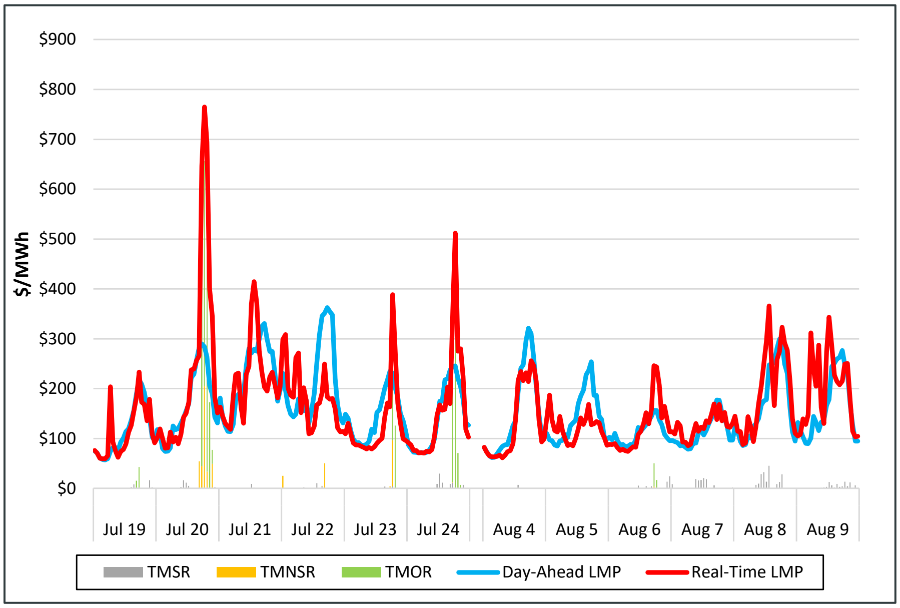


The figure shows low margins around the evening peak on most days of the heat wave, which is expected given the high loads. On July 20, the Total30 reserve margin was below 0 for 180 minutes total, reaching as low as -160 from 17:20 to 18:20. This day had the fourth highest peak load of the season (24,608 MW) and several notable unplanned generator outages. Real-time LMPs, which are discussed further below, peaked during the evening on July 20, reflecting the tight system conditions. The Total30 margin also dropped below 0 on July 23, July 24, and August 6. As a result, non-zero TMOR pricing occurred on each of these days. However, there were no capacity scarcity conditions because only the replacement reserve portion of the margin was negative.

LMPs & Reserve Prices

Hourly Hub day-ahead and real-time energy prices during the heat wave events are shown alongside hourly reserve prices in Figure 3-4 below.

Figure 3-4: Hourly Hub LMPs and Reserve Prices During Heat Waves



Day-ahead Hub LMPs peaked at $362.74/MWh during HE 18 on July 22. Real-time LMPs peaked at $764.88/MWh during HE 19 on July 20, the day with the tightest system conditions of the summer. This hour also saw the highest reserve pricing of the summer, at $656.69/MWh (hourly price). Non-spinning reserve pricing occurred on six of the twelve heat wave days. Overall, the July heat wave saw higher energy prices, partially due to higher natural gas prices compared to the August heat wave. Additionally, unplanned generator outages had a more substantial impact on the system during the July event.

Market Competitiveness

Mitigation: Overall, the frequency of mitigation during the heat waves was relatively low, and did not indicate any significant concerns. During the July 19-24 event, only ten asset-hours of mitigation occurred. All mitigations were for manual dispatch energy. From August 4-9, there were 26 asset-hours of mitigation, and 20 of these asset-hours were reliability mitigations for the same generator. As Section 4.2 discusses, these reliability commitment mitigations occurred in Southeastern Massachusetts/Rhode Island (SEMA-RI), and were related to a localized need for special constraint resource (SCR) commitments on Martha's Vineyard. The other six asset-hours of mitigation during the August event were for manual dispatch energy. Manual dispatch energy mitigation occurs when generators are manually dispatched by the ISO. During the system events, about 9% of manual dispatch asset-hours were mitigated. Both reliability commitment mitigation and manual dispatch energy mitigation have tight conduct test thresholds (10%).

If we had seen a large increase in mitigation activity, it could raise concerns about participants attempting to exercise market power during tight system conditions. We did not observe this, and the results above indicate that there were not many instances of the potential exercise of market power that required mitigation within our current rules. The mitigation process worked consistent with its current design during the heat waves.

RSI and Pivotal Suppliers: The residual supply index (RSI) measures the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. When the RSI is below 100, it means: 1) that there is at least one pivotal supplier; and 2) that there are increased opportunities to exercise market power. Table 3-1 below shows the average daily RSI and the percentage of five-minute intervals with pivotal suppliers during the heat wave events.

Table 3-1: Residual Supply Index and Intervals with Pivotal Suppliers During Heat Waves (Real-Time)

Day	RSI	% of intervals with at least 1 pivotal supplier
July 19	99.2	54%
July 20	97.2	68%
July 21	98.5	67%
July 22	98.9	58%
July 23	100.8	47%
July 24	99.5	59%

Day	RSI	% of intervals with at least 1 pivotal supplier
August 4	102.9	38%
August 5	99.7	48%
August 6	98.2	65%
August 7	96.9	81%
August 8	98.1	64%
August 9	98.8	58%

On most of the heat wave days, the RSI was just below the competitive level of 100, indicating that a small amount of the largest supplier's available energy and reserves was needed to meet load and the total reserve requirement. The percentage of real-time intervals with pivotal suppliers was larger than the quarterly average (34%) on each heat wave day, and ranged from 38% to 81%. These values are not surprising given the high loads and low reserve margins on many of the system event days. Despite the low reserve margins, we did not observe a large increase in mitigation activity, and we did not have any notable concerns with market participant behavior during the heat waves.

NCPC: Uplift payments totaled $6.0 million during the July event and $3.3 million during the August event. During both heat waves, most (66-81%) uplift was paid out in real-time, and economic uplift comprised the majority (93%) of payments. During the July event, one oil generator received $0.9 million in uplift, equivalent to 15% of uplift payments for the period. The rest of the July event payments were split among 463 generators, ARDs, and DRRs, with all remaining units receiving less than 5% of the total share of payments each. During the August event, two oil generators received $1.3 million in uplift total, 39% of uplift during the period. The remainder of the August event payments were split between 233 units, and not any of those received more than 8% of the total share.

Payments during the two events primarily went to fast-start resources that did not recover their costs in real-time ($2.2 million), non-fast-start resources supplementally committed for system reliability ($1.7 million), and resources that followed dispatch instructions when LMPs incented them to deviate from instructions due to fast-start pricing ($1.3 million). Other large sources of payments included:

- resources committed in economic merit that did not recover their costs ($0.7 million);

- resources dispatched at the request of local transmission providers for managing constraints on the distribution system ($0.4 million); and
- resources receiving compensation for dispatch lost opportunity cost ($0.6 million).

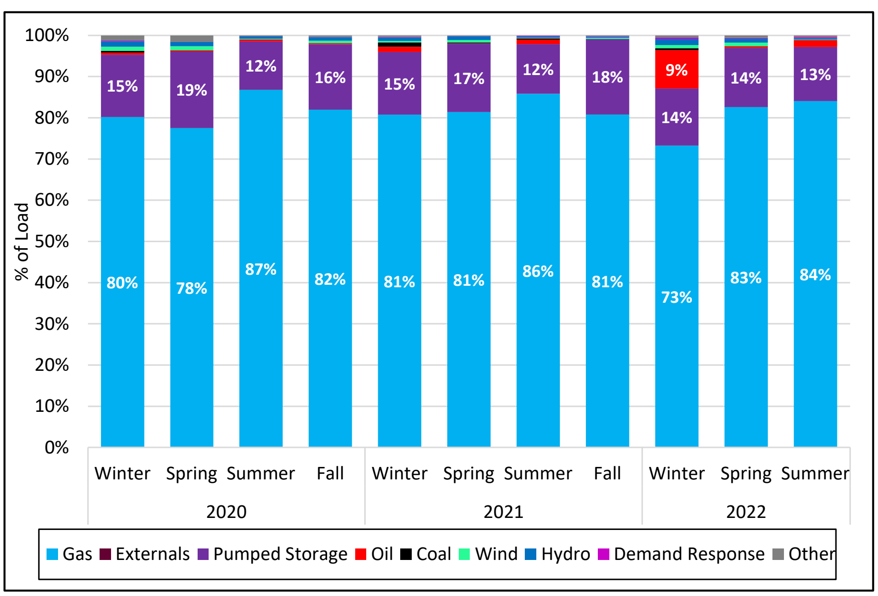
3.3 Marginal Resources and Transactions

The LMP at a pricing location is set by the cost of the next megawatt (MW) the ISO would dispatch to meet an incremental change in load at that location. The resource that would provide this next megawatt, and set price, is termed the "marginal" resource. Analyzing marginal resources by transaction type can provide additional insight into day-ahead and real-time pricing outcomes.

In this section, marginal units by transaction and fuel type are reported on a load-weighted basis. The methodology accounts for the contribution that a marginal resource makes to the overall price paid by load. When more than one resource is marginal, the system is typically constrained and marginal resources likely do not contribute equally to meeting load across the system. For example, resources within an export-constrained area are not able to fully contribute to meeting the load for the wider system. Consequently, the impact of these resources on the system LMP is muted.

In the day-ahead market, a greater number of transaction types can be marginal; these include virtual bids and offers, fixed and priced-demand, generator supply offers, demand response offers, and external transactions. In contrast, only physical supply, demand response, pumped-storage demand, and external transactions can set price in the real-time market. In practice, marginal resources in the real-time market are typically generators (predominantly natural gas-fired generators) and pumped-storage demand. The percentage of load for which each fuel type set price in the real-time market by season is shown in Figure 3-5 below.[19]

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

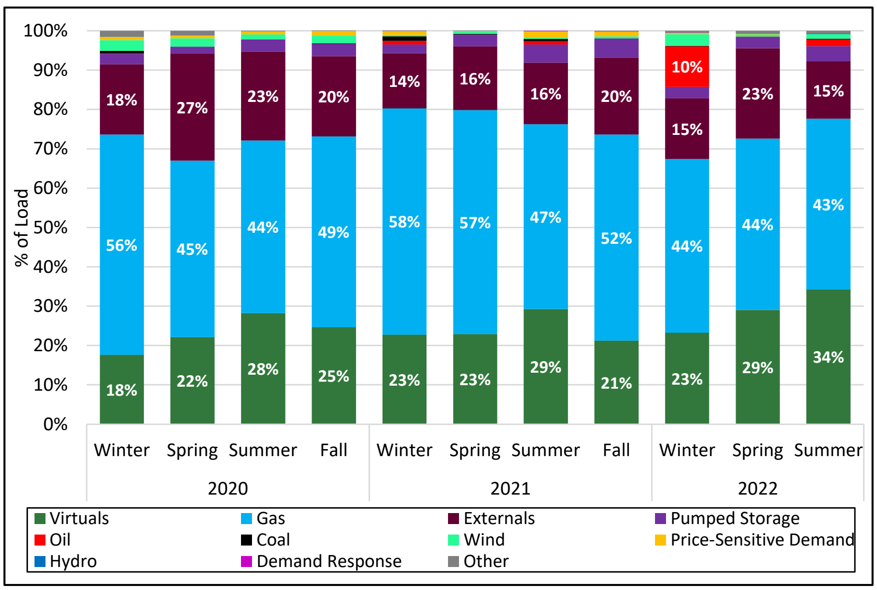


[19] "Other" category contains wood, biomass, black liquor, fuel cells, landfill gas, nuclear, propane, refuse, and solar.

Natural gas-fired generators set price for 84% of total load in Summer 2022. Gas-fired generators are often the most expensive units operating, and therefore set price frequently. More expensive coal- and oil-fired generators set price in the real-time market for about 1% of total load, primarily during periods of tight system conditions. Tighter system conditions in Summer 2022 compared to Summer 2021 led to oil setting price for more load (1.6% vs. 1.1%), primarily based on the dispatch of fast-start oil-fired generators. Wind was marginal for 1% of total load in Summer 2022, most of which was located in local export-constrained areas. Wind generators located in export-constrained areas can only deliver the next increment of load to a small number of locations within the export-constrained area. This occurs when the transmission network that moves energy out of the constrained area is at maximum capacity. Load that is outside the export-constrained area has no way of consuming another megawatt of the relatively inexpensive wind output.

The percentage of load for which each transaction type set price in the day-ahead market since Winter 2020 is illustrated in Figure 3-6 below.

Figure 3-6: Day-Ahead Marginal Units by Transaction and Fuel Type

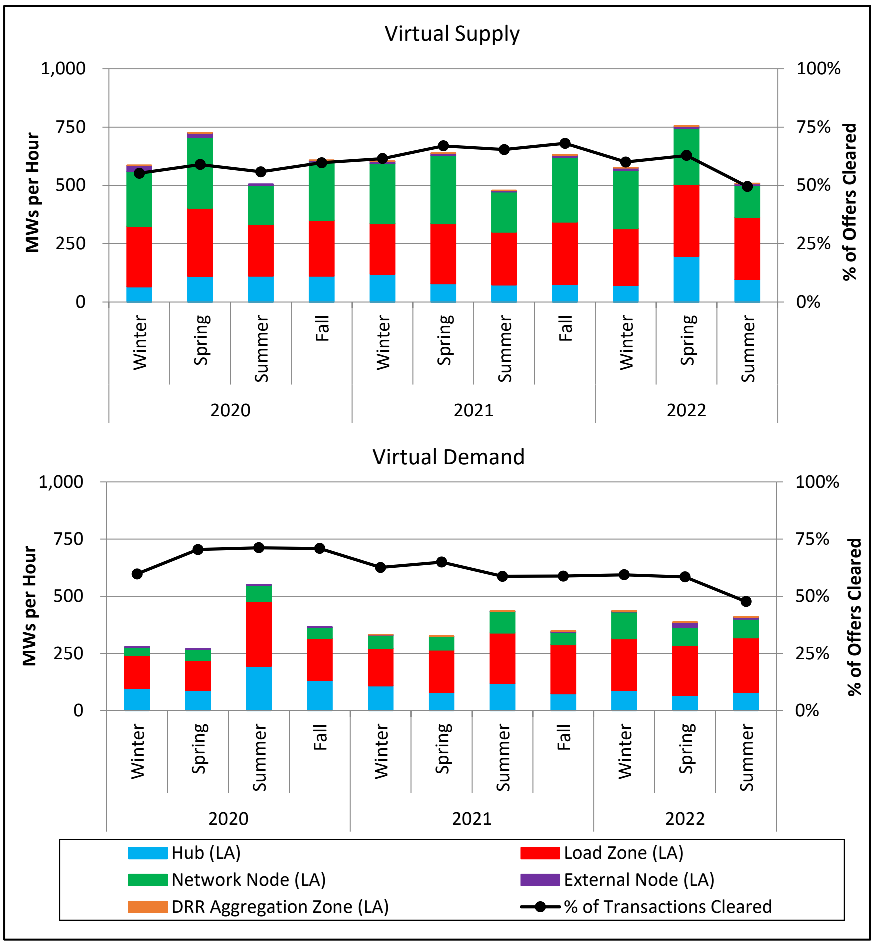


Gas-fired generators were the most common marginal resource type in the day-ahead market, setting price for 43% of total day-ahead load in Summer 2022. This was in line with the previous quarters. Similar to 2021, virtual demand bids set price for more load in Summer 2022 (16%) compared to Spring 2022 (9%). Virtual participants submit a higher volume of virtual demand bids near the margin in an attempt to profit from higher real-time prices on warmer summer days, when reserve margins are lower, and there is greater probability of tight system conditions. Oil-fired generators set price for 1.8% of load in Summer 2022, compared to 0.8% in Summer 2021. The increase was driven by long-lead-time oil-fired generators and fast-start oil generators, primarily during the July 19 to July 24 M/LCC2 event. Market outcomes during the event are discussed in Section 3.2.

3.4 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 3-7 below. Cleared transactions are divided into groups based on the location type where they cleared: Hub (blue), load zone (red), network node (green), external node (purple) and Demand Response Resource (DRR) aggregation zone (orange). The line graph (right axis) shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

Figure 3-7: Average Hourly Cleared Virtual Transactions and Percentage of Cleared Transactions



In Summer 2022, total cleared virtual transactions averaged approximately 916 MW per hour, which was similar to Summer 2021 (914 MW per hour) and a 20% decrease compared to Spring 2022 (1,141 MW per hour).

Cleared virtual demand averaged 409 MW per hour in Summer 2022, up 6% from Spring 2022 (386 MW per hour) and down 6% from Summer 2021 (436 MW per hour). Cleared virtual demand typically increases from Spring to Summer as participants aim to capitalize (or hedge) on higher real-time prices resulting from tighter system conditions during the summer, especially on hot days with high loads. For example, on days when temperatures peaked at 90°F or higher, participants cleared an average of 530 MW of virtual demand, compared to 409 MW on average for all of Summer 2022. However, this was 260 MW lower than in Summer 2021 when participants cleared an average of 790 MW of virtual demand on days when temperatures peaked above 90°F. Three participants led to this decrease as they combined to clear 267 MW less virtual demand on average compared to Summer 2021 (63 MW vs. 329 MW).[20] In Summer 2022, participants cleared 58% (or 238 MW) of virtual demand bids at load zones, 20% (or 82 MW) at network nodes, 20% (or 80 MW) at the Hub, and 2% (or 8 MW) at external nodes. DRR aggregation zones accounted for less than 1% of cleared virtual demand.

Total cleared virtual supply averaged 507 MW per hour in Summer 2022, down 33% from Spring 2022 (755 MW per hour) and down up 6% from Summer 2021 (479 MW per hour). Virtual supply often clears at higher volumes than virtual demand due to the growing amount of solar settlement-only generation (SOG) and the day-ahead bidding behavior of wind generation. By the end of Summer 2022, solar SOGs reached an installed capacity of over 1,880 MWs. Since settlement-only generators do not participate in the day-ahead market, participants clear virtual supply on days where solar generation is expected to be high. Larger volumes of virtual supply also clear at network nodes compared to virtual demand. This activity is often related to virtual participants trying to capture differences between day-ahead and real-time prices in export-constrained areas, particularly areas with wind generation. Typically, wind generators make high-priced energy offers in the day-ahead market, but produce energy at low, or even negative, prices in the real-time market. However, wind production drops during summer and wind-related profit opportunities fall.[21] In Summer 2022, participants cleared 53% (or 267 MW) of cleared virtual supply offers at load zones, 27% (or 137 MW) at network nodes, 19% (or 96 MW) at the Hub and 2% (or 8 MW) at external nodes.[22]

[20] Of the three participants who cleared substantially less virtual demand on hot summer days, two consisted of participants with physical generation, and one participant that only trades virtual supply and demand.

[21] During Summer 2022 wind generation averaged 299 MW, down from 488 MW in Spring 2022.

[22] DRR aggregation zones accounted for 0.012% of all virtual supply.

3.5 Net Commitment Period Compensation

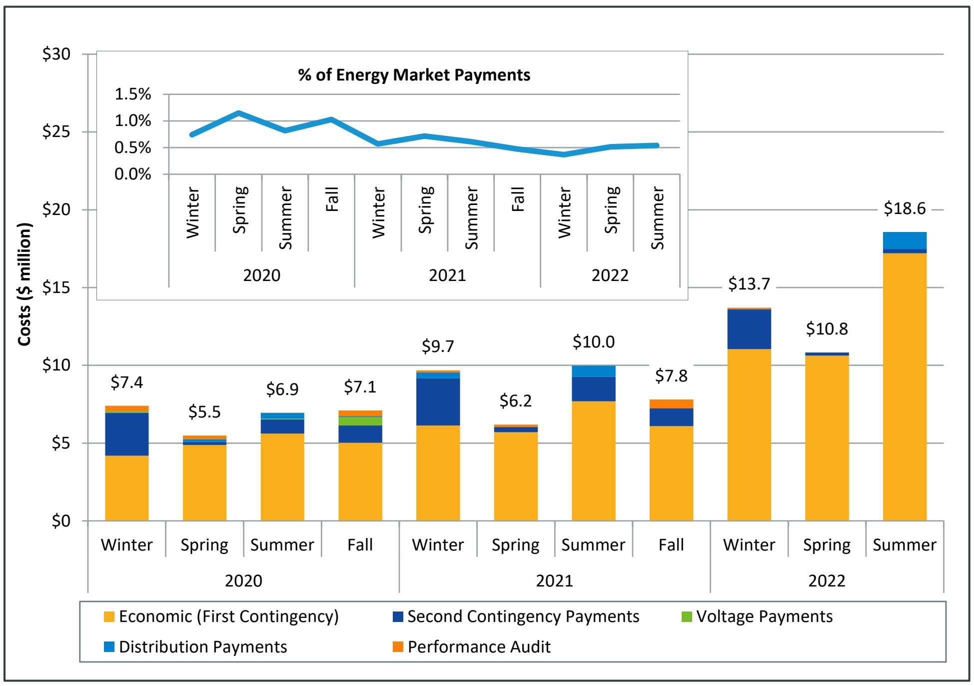
Net Commitment Period Compensation (NCPC), commonly known as uplift, is a make-whole payment resources receive in two circumstances:

1) when energy prices are insufficient to cover production costs; or
2) when resources forego profits (i.e., incur an opportunity cost) by following ISO dispatch instructions.

Uplift is paid to resources that provide a number of services, including first- and second-contingency protection, voltage support, distribution system protection, and generator performance auditing.[23]

Payments by season and by uplift category are illustrated below in Figure 3-8. The inset graph shows uplift payments as a percentage of total energy payments.

Figure 3-8: NCPC Payments by Category ($ millions)



Summer 2022 uplift payments totaled $18.6 million, an increase of $8.6 million, or 86%, compared to Summer 2021. Economic payments comprised approximately 93% of total payments and were the primary driver of the increase.[24] Despite the large increase, total uplift payments as a percentage of energy payments remained low at 0.5% in Summer

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

[24] Economic payments increased by $9.5 million and distribution payments increased by $0.4 million. Second contingency payments decreased by $1.3 million.

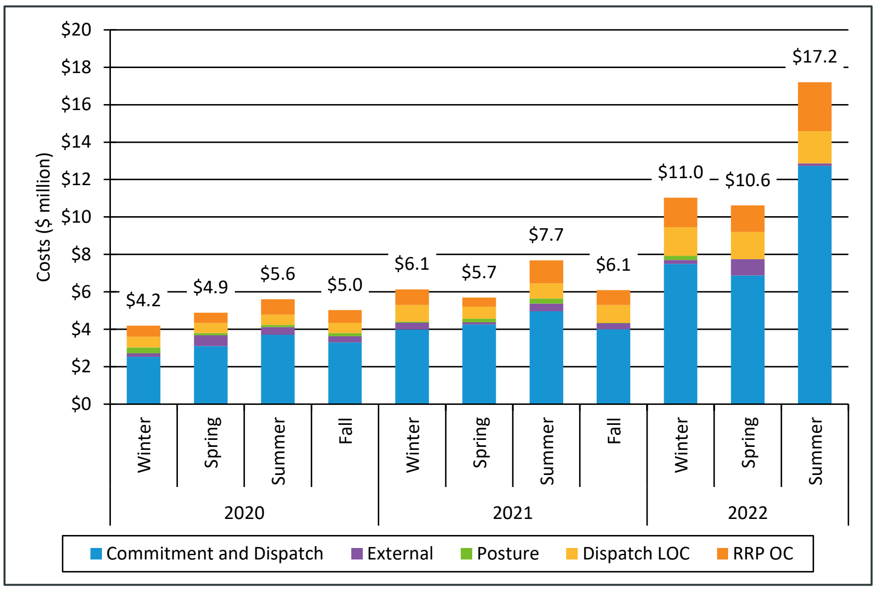
2022, a slight decrease from 0.6% in Summer 2021. Fuel prices drive LMPs, generator costs, and energy payments.

Economic uplift includes payments made to:

1. generators whose costs exceed revenue when committed or dispatched to maintain total-system reliability; and
2. generators that incur an opportunity cost by operating at an ISO-instructed dispatch point below their economic dispatch point.[25]

Figure 3-9 below shows economic payments by subcategory.

Figure 3-9: Economic Uplift by Season and Subcategory



As illustrated by Figure 3-9, commitment and dispatch payments continue to make up the majority of economic uplift, representing 74% of these payments.[26] Commitment and dispatch payments increased by 156% from $5.0 million to $12.7 million between Summer 2021 and Summer 2022, driven by an increase in fuel prices.

[25] Includes external, posture, dispatch lost opportunity cost, and rapid response pricing opportunity cost NCPC.

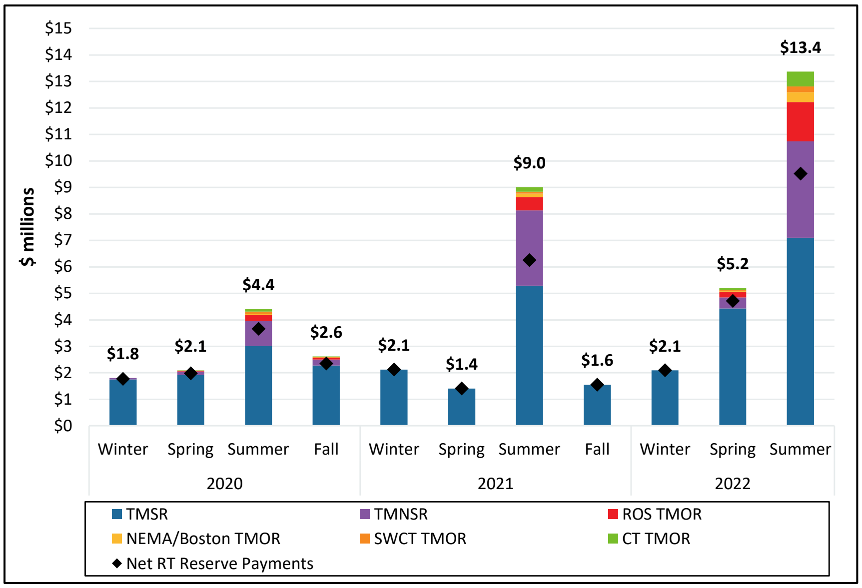
[26] Commitment and dispatch payments, called commitment-out-of-merit (COOM) and dispatch-out-of-merit (DOOM) by the ISO, are made to resources that operate at a loss in the energy market when their commitment costs exceed their energy revenue or they are dispatched out-of-merit. A generator need not be "out-of-merit" to receive this NCPC (i.e. they are generally committed as part of the economic least-cost solution but still operate at a loss).

3.6 Real-Time Operating Reserves

Bulk power systems must be able to quickly respond to contingencies, such as the unexpected loss of a large generator. To ensure that adequate backup capacity is available, the ISO procures reserve products through the locational Forward Reserve Market (FRM) and the real-time energy market. The ISO's market software determines real-time prices for each reserve product. Non-zero real-time reserve pricing occurs when the software must re-dispatch resources to satisfy the reserve requirement.

Real-time reserve payments by product and by zone are illustrated in Figure 3-10 below. Real-time reserve payments to generators designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a generator is not paid twice for the same service. Net real-time reserve payments, which were $9.5 million in Summer 2022, are shown as black diamonds in Figure 3-10.

Figure 3-10: Real-Time Reserve Payments by Product and Zone



Real-time reserve payments totaled $13.4 million in Summer 2022, $4.4 million (48%) higher than in Summer 2021. The increase was driven by the need to redispatch the system to maintain adequate off-line reserves during heat-wave events in July and August, which Section 3.2 discusses in more detail. Because of the tight conditions, ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR) payments were $3.6 and $2.6 million, respectively. The heat wave periods accounted for 76% of the total non-spinning reserve payments, which were $2.6 million (69%) higher than Summer 2021. Additionally, TMSR payments increased by $1.8 million due to higher re-dispatch costs for energy based on increased gas prices and tight system conditions. The frequency of reserve pricing by product and zone along with the average price during these intervals for the past three summer seasons is provided in Table 3-2 below.[27]

[27] Non-zero reserve pricing occurs when there is an opportunity cost associated with dispatching the system in order to hold generators back for reserves or a reserve deficiency in the energy and reserve co-optimization process.

Table 3-2: Hours and Level of Non-Zero Reserve Pricing

Product	Zone	Summer 2022		Summer 2021		Summer 2020	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	**System**	$19.98	343.1	$14.27	385.5	$6.96	506.3
TMNSR	**System**	$204.82	20.4	$120.74	23.5	$57.14	16.3
TMOR	**System**	$231.08	14.9	$154.98	7.0	$85.04	5.8
TMOR	**NEMA/Boston**	$231.08	14.9	$154.98	7.0	$85.04	5.8
TMOR	**CT**	$231.08	14.9	$154.98	7.0	$85.04	5.8
TMOR	**SWCT**	$231.08	14.9	$154.98	7.0	$85.04	5.8

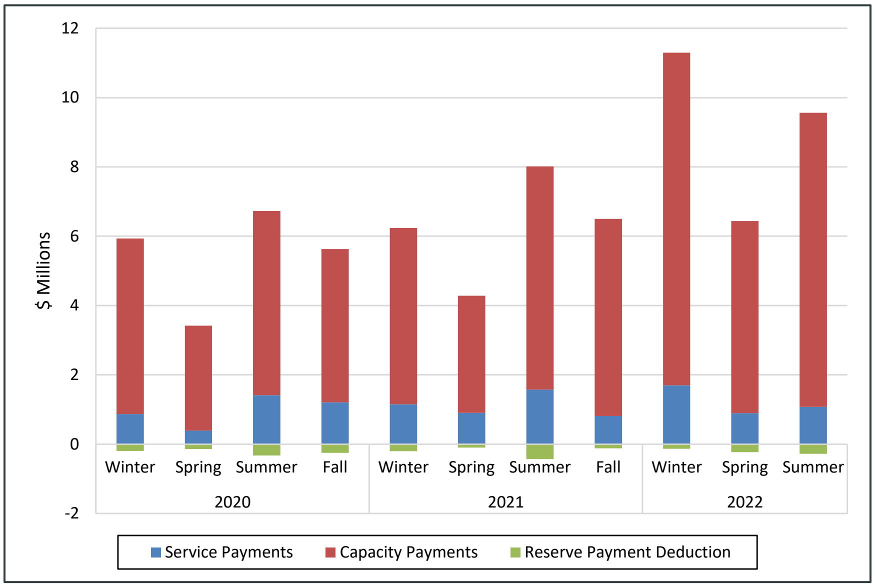
The system TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 343 hours (16% of total hours) during Summer 2022. This was lower than the number of hours of non-zero reserve pricing in Summer 2021. In the hours when the system TMSR price was above zero, the price averaged $19.98/MWh, a 40% increase from the prior summer. High reserve prices caused by tight system conditions and high gas prices during the July and August heat waves led to particularly high non-zero average TMSR prices ($78.09/MWh in 50 hours)compared to the rest of Summer 2022($9.97/MWh in 293 hours).

There were 20 hours of TMNSR pricing and 15 hours of TMOR pricing throughout the quarter. Half of non-spinning pricing took place during several days of tight system conditions in July and August, which are discussed in Section 3.2. Additionally, non-zero TMNSR reserve prices increased by 70% relative to Summer 2021. This is consistent with the increase in real-time energy prices ($46.07/MWh) compared to Summer 2021 (115%).

3.7 Regulation

Regulation is an essential reliability service provided by generators and other resources in the real-time energy market. Generators providing regulation allow the ISO to use a portion of their available capacity to match supply and demand (and to regulate frequency) over short-time intervals. Quarterly regulation payments are shown in Figure 3-11 below.

Figure 3-11: Regulation Payments ($ millions)



Total regulation market payments were $9.3 million during the reporting period, up approximately 22% from $7.6 million in Summer 2021, and up by 49% from $6.2 million in Spring 2022. The increase in payments from Summer 2021 primarily reflects an increase in energy market opportunity costs for generators providing regulation; average real-time energy market Hub LMPs were significantly higher in Summer 2022 relative to Summer 2021, leading to a $2 million increase in capacity payments. The increase in capacity payments was partially offset by a $0.5 million decline in service payments. Compared to Spring 2022, two factors resulted in the 49% increase in regulation payments: increased regulation requirements (by 27%, representing typical seasonal variation) and increased energy market opportunity costs (resulting from higher summer LMPs) that raised capacity payments by $2.9 million, relative to the earlier period.

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 by quarter using two structural market power metrics at the system level. Section 4.2 provides statistics on system and local market power flagged by the automated mitigation system, and on the amount of actual mitigation applied, whereby a supply offer was replaced by the IMM's reference level.

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 widely-used metrics identify instances when the largest supplier has market power.[28] 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. This analysis presents the average RSI for all five-minute real-time pricing intervals by quarter.

Pivotal suppliers are identified at the five-minute level by comparing the real-time supply margin[29] to the sum of each participant's total supply that is available within 30 minutes.[30] When a participant's available supply exceeds the supply margin, they are considered 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.

[28] 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.

[29] 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*]

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

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

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

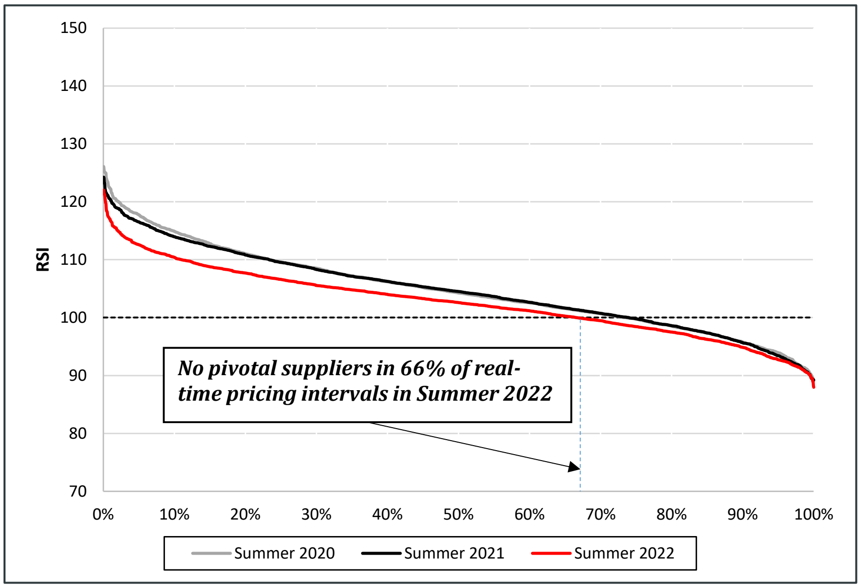
Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2020	108.6	8%
Spring 2020	109.2	8%
Summer 2020	104.8	27%
Fall 2020	105.1	24%
Winter 2021	107.9	8%
Spring 2021	106.6	14%
Summer 2021	104.7	27%
Fall 2021	105.0	24%
Winter 2022	106.5	12%
Spring 2022	106.7	19%
Summer 2022	102.6	34%

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 2022 was 34%, which was higher than that of the previous two summers (both 27%), and the highest value of the reporting period. The increase was due to lower total 30 minute reserve margins, which decreased by an average of 268 MW compared to Summer 2021. The decrease was due to several factors, including: 1) a higher reserve requirement; and 2) a reduction in offline reserves from two generators that shed their CSOs for FCA 13 (June 2022 – May 2023). The heat wave events also contributed to the higher frequency of pivotal suppliers. If we exclude these periods from the calculation, the frequency decreases from 34% to 30%. As shown in Section 3.2, the percentage of intervals with pivotal suppliers on each heat wave day was larger than the quarterly average, ranging from 38% to 81% per day.

Duration curves that rank the average hourly RSI over each spring 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 2022, the RSI was lower than in the previous two summers across nearly all ranked observations due to the lower reserve margins discussed above. The Summer 2021 and 2020 duration curves were similar.

4.2 Energy Market Supply Offer Mitigation

The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power.[31] Under certain conditions, we will mitigate generator offers. Mitigation results in a participant's financial parameters for a generator supply offer (i.e., start-up, no load, and segment energy offer prices) being replaced with "reference" values. The reference values are estimated and maintained by the IMM; these values are used in mitigation to reduce impacts on energy market pricing (LMPs) and uplift payments (NCPC) from participant offers that appear to overstate a generator's operating costs.

Appendix A of the ISO's Market Rule 1 outlines the circumstances under which the IMM may mitigate energy market supply offers.[32] These circumstances are summarized in Table 4-2 below.

Table 4-2: Energy Market Mitigation Types

Mitigation type	Structure test	Conduct test threshold	Impact test
General Threshold Energy (real-time only)	Pivotal Supplier	Minimum of $100/MWh and 300%	Minimum of $100/MWh and 200%
General Threshold Commitment (real-time only)		200%	n/a
Constrained Area Energy	Constrained Area	Minimum of $25/MWh and 50%	Minimum of $25/MWh and 50%
Constrained Area Commitment (real-time only)		25%	n/a
Reliability Commitment	n/a	10%	n/a
Start-Up and No-Load Fee	n/a	200%	n/a
Manual Dispatch Energy		10%	n/a

We administer seven types of ex-ante supply offer mitigation, and apply up to three criteria when determining whether to mitigate a supply offer.[33] The criteria are:

- *Structural test:* Certain market circumstances may confer an advantage to suppliers. This may result from 1) a supplier being "pivotal" (i.e., load cannot be satisfied without that supplier) or 2) a supplier operating within an import-constrained area (with reduced competition).

[31] This review of supply offers is automated (along with the offer mitigation process), and occurs within the ISO's energy market software.

[32] See Market Rule 1, Appendix A, Section III.A.5.

[33] Ex-ante mitigation refers to mitigation applied prior to the finalization of the day-ahead schedules and real-time commitment/dispatch. There is one additional mitigation type specific to dual-fuel generators not listed in the summary table. Dual-fuel mitigation occurs after-the-fact when the supply offer indicates a generator will operate on a higher-cost fuel than it actually uses (e.g., if offered as using oil, but the generator actually runs using natural gas). This mitigation will affect the amount of NCPC (uplift) payments the generator is eligible to receive in the market settlements.

- *Conduct test:* Represents a determination that the financial parameters of a supply offer appear to be excessively high, relative to a benchmark offer value (a “reference” value).[34] The conduct test applies to all mitigation types.
- *Impact test:* Represents a determination that the original supply offer would have a significant impact on energy market prices (LMPs).[35] This test only applies to general threshold energy and constrained area energy mitigation types.

Energy Market Mitigation Frequency

Energy market supply offers are mitigated only when an offer has failed all applicable tests for a particular mitigation type. This section summarizes three types of mitigation data: structural test failures, generator commitment or dispatch hours, and mitigation occurrences. The structural test represents an initial condition for applying conduct and market impact mitigation tests for generators located in constrained areas or associated with pivotal suppliers (general threshold energy mitigation). For other mitigation types, the commitment or dispatch of a generator triggers the application of the conduct test, when determining whether to mitigate a supply offer.

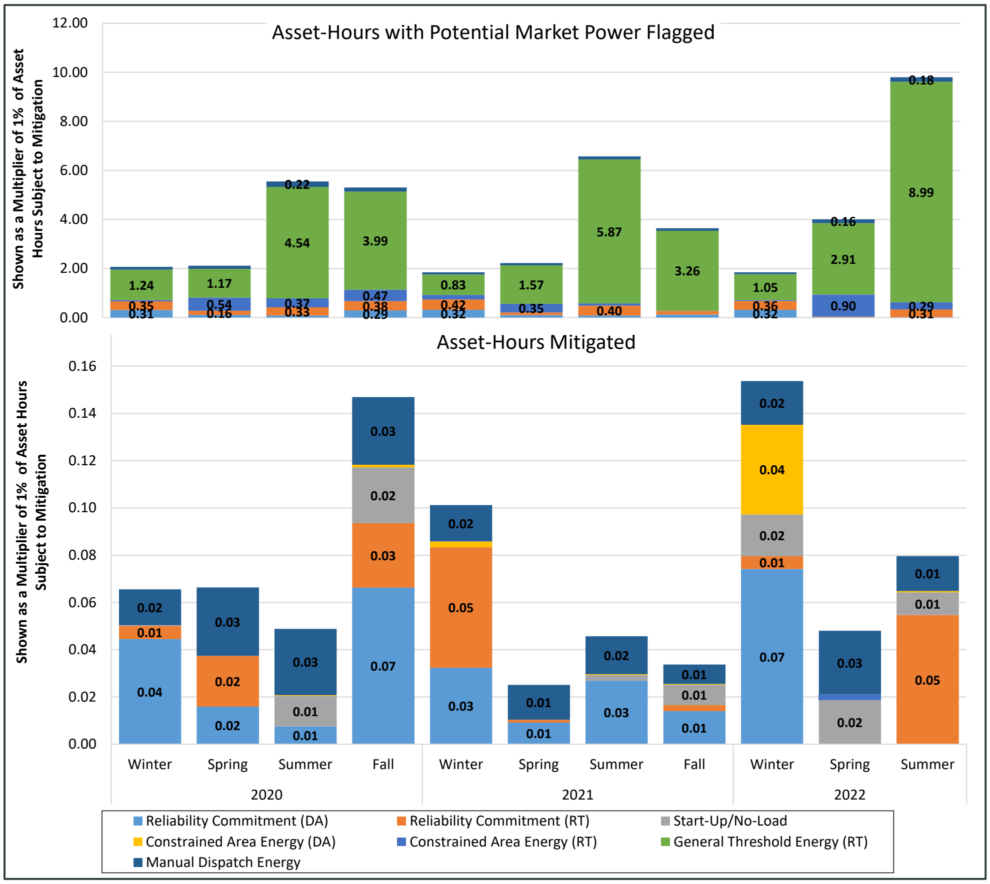
An indication of mitigation frequency, relative to opportunities to mitigate generators, is illustrated in Figure 4-2 below.[36] It compares asset-hours of structural test failures for dispatch or commitment (depending on mitigation type) to asset-hours of mitigations. To provide additional context, the values in the figure have been scaled relative to one percent of total asset-hours subject to potential mitigation.

[34] See Market Rule 1, Appendix A, Section III.A.7, regarding the determination of reference values.

[35] For a description of the application of these mitigation criteria (tests), see Appendix A, Section III.A.5.

[36] Asset-hours refer to the commitment and operational hours of a generator. 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 a 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[37]



On average in each quarter, there are approximately 300 thousand asset-hours of ISO-committed generation that are subject to the IMM's mitigation rules; in Summer 2022, 325 thousand asset-hours were subjected to the IMM's mitigation rules, with one percent of those hours equaling 3,250 asset-hours. Structural test failures in the Summer 2022 totaled approximately 32,000 asset-hours, which represents 10% of asset-hours subject to mitigation rules or ten times 1% of total asset hours subject to mitigation. Likewise, mitigation asset-hours represent a very small fraction of potential asset-hours subject to mitigation. In the figure, real-time reliability commitment mitigation totaled just 178 asset-hours for Summer 2022, equaling 0.05 asset-hours scaled to 1% (i.e., 178/3,253).

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 for structural test failures, commitment or dispatch. The highest frequency of mitigation occurred for reliability commitments (light blue and orange shading); this resulted from a relatively tight conduct test threshold, with any participant supply offer more than 10% above the IMM's reference offer value being mitigated. General threshold (pivotal supplier) mitigation and constrained area mitigation (green, dark blue and

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[37] Because the general threshold commitment and constrained area commitment conduct tests did not result in any mitigations during the review period, 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.

yellow shading) have had the lowest mitigation frequency at close to 0% over the review period. Both of these mitigation types have relatively tolerant conduct test and market impact test thresholds, reducing the likelihood of mitigation given a structural test failure.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs (such as local second contingency protection).[38] These commitments frequently reflect the reliability needs associated with transmission line outages and upgrades, as well as very localized distribution system support. For Summer 2022, Southeastern Massachusetts/Rhode Island (SEMA-RI) had the highest frequency of reliability commitment asset-hours, equaling 95% of all reliability commitments. This reflects a localized need for "special constraint resource" (SCR) commitments on Martha's Vineyard during the summer months. These commitments provided support to the local distribution system. All of the reliability commitment mitigations during Summer 2022 occurred in SEMA-RI, and were related to the SCR commitments. Overall, reliability mitigations increased significantly between Summer 2021 (87 asset-hours) and Summer 2022 (178 asset-hours).[39]

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).[40] 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. All generators subject to this mitigation over the review period had natural gas as a primary fuel type, and generators associated with just three participants accounted for 94% of these mitigations. There were 31 asset-hours of start-up and no-load mitigation in Summer 2022.

Constrained area energy (CAE) mitigation:[41] 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 over the review period has been approximately 1% (of structural test failure asset-hours), as only eight asset-hours of CAE mitigation have occurred in the real-time energy market and only 143 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. Over the review period, most of the failures occurred in Winter 2022 (89%); these mitigations

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[38] This mitigation category applies to most types of "out-of-merit" commitments, including local first contingency, local second contingency, special constraint resource, 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.

[39] 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 approximately 69% of the reliability commitment asset-hours in the real-time energy market.

[40] The conduct test for this mitigation type compares a participant's offers for no-load, start-up and incremental energy cost up to economic minimum to the IMM's reference values for those same parameters.

[41] 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.

resulted from congestion along a frequently-binding constraint, the New England West-East Constraint. In Summer 2022, there were just two hours of day-ahead CAE mitigation and no hours of real-time mitigation. Structural test failures were also infrequent at just 956 asset-hours. This compares to Spring 2022 mitigations of eight asset-hours in the day-ahead market and 3,066 asset-hours of structural test failures.

General threshold energy mitigation: This mitigation type also applies three tests prior to mitigation. This mitigation type has the lowest frequency of any mitigation type, because it also has the most tolerant conduct test and market impact thresholds of any mitigation type. General threshold energy mitigation did not occur over the review period. This happened in spite of 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 66% of structural test failures and four participants accounted for 78% of structural test failures over the review period. The frequency of pivotal supplier asset-hours increased significantly in Summer 2022 (by 54%), compared to Summer 2021. The increase in Summer 2022 is generally consistent with the IMM's pivotal supplier data included in Section 4.1.[42]

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 has occurred with the second highest frequency of any mitigation type (at 26% on average) over the review period. Like reliability commitment mitigation, manual dispatch energy mitigation has a relatively tight conduct test threshold (10%). The dispatch hours for this mitigation type, shown in Figure 4-2, simply refer to asset-hours of manually-dispatched generators in the real-time energy market. As these data indicate, 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 had 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 2022, there were 585 asset-hours of manual dispatch and 48 hours of mitigation. Spring 2022 experienced slightly fewer asset-hours of manual dispatch (536), but more asset-hours of manual dispatch mitigation (92). Compared to Summer 2021, manual dispatch asset-hours increased by 44% (405) in Summer 2022, but mitigation asset-hours declined by 8% (52).

[42] As noted in Section 4.1 (Pivotal Supplier and Residual Supply Indices), the mitigation software's pivotal supplier test is different from pivotal supplier metric presented in Section 4.1. The IMM has an outstanding recommendation that the ISO update the mitigation software's pivotal supplier test. (For example, see the recommendations section of the 2020 Annual Markets Report.)

Section 5
Forward Markets

This section covers activity in the Forward Capacity Market (FCM), in Financial Transmission Rights (FTRs), and in the Winter 2022/23 Forward Reserve Auction.

5.1 Forward Capacity Market

The Forward Capacity Market (FCM) is a long-term market designed to procure the resources needed to meet the region's local and system-wide resource adequacy requirements.[43] The region developed the FCM in recognition of the fact that the energy market alone does not provide sufficient revenue to facilitate new investment or, in many cases, cover the cost of maintaining and operating existing resources. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue and thereby induces suppliers to undertake the investments necessary for reliable electric power service.

During any three-month period there can be FCM activity for up to four commitment periods. The initial capacity auction occurs three years and three months before the commitment period begins.[44] Between the initial auction and the commitment period, there are three discrete opportunities to adjust annual capacity supply obligations (CSOs) called annual reconfiguration auctions. The three auctions are run by the ISO, where participants can submit supply offers to take on obligations, or submit demand bids to shed obligations.

Monthly reconfiguration auctions and bilateral trading begin a month after the third annual reconfiguration auction, and occur two months before the relevant delivery month. Like the annual auctions, participants can buy or sell obligations. Buying an obligation means that the participant will provide capacity during a given period. Participants selling capacity reduce their CSO. Trading in monthly auctions adjusts the CSO position for a particular month, not the whole commitment period. The following sections summarize FCM activities during the reporting period, including total payments and CSOs traded in each commitment period.

The capacity commitment period (CCP) associated with Summer 2022 started on June 1, 2022 and will end on May 31, 2023. The corresponding Forward Capacity Auction (FCA 13) resulted in a lower clearing price than the previous auction while still obtaining sufficient resources needed to meet forecasted demand. The auction procured 34,839 megawatts (MW) of capacity, which exceeded the 33,750 MW Net Installed Capacity Requirement (Net ICR), at a clearing price $3.80/kW-month, 18% lower than the previous year's $4.63/kW-month. The $3.80/kW-month clearing price was applied to all capacity zones within New England. Price separation occurred at only one import interface; New Brunswick cleared capacity at a price of $2.68/kW-month. The results of FCA 13 led to an estimated total annual cost of $1.65 billion in capacity payments, $0.47 billion lower than capacity payments incurred in FCA 12.

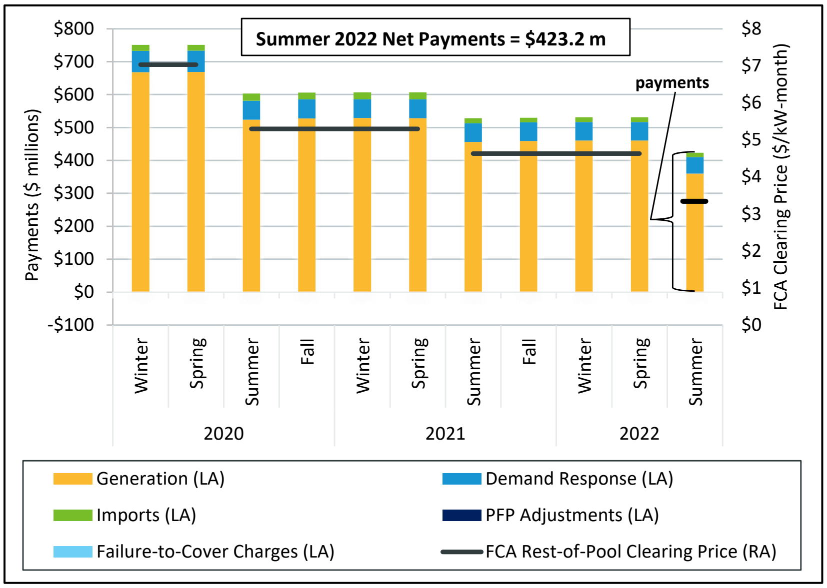
Total FCM payments, as well as the clearing prices for Winter 2020 through Summer 2022, are shown in Figure 5-1 below. The black lines (corresponding to the right axis, "RA") represent the

[43] In the capacity market, resource categories include generation, demand response and imports.

[44] Each capacity commitment period is a twelve-month period starting on June 1 of a year and ending on May 31 of the following year.

FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The dark blue bar represents Pay-for-Performance (PFP) adjustments, while the light blue bar represents Failure-to-Cover charges.

Figure 5-1: Capacity Payments ($ millions)



In Summer 2022, capacity payments totaled over $423 million.[45] Total payments were down 20% from Summer 2021 ($530 million), in line with the 18% decrease in clearing price from FCA 12 ($4.63/kW-month) to FCA 13 ($3.80/kW-month). A large influx of lower-priced, new capacity displaced higher-priced, existing capacity in FCA 13; over 1500 MW of new capacity offered at or below the auction clearing price while over 2,100 MW of existing capacity delisted above the clearing price benchmark.

Approximately $84 thousand in Failure-to-Cover (FTC) charges were administered in Summer 2022. 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. The intent of this charge is to incent resources with CSOs to meet their obligations and is based on the capability of resources compared to their CSOs. Beginning in Summer 2022, the FTC charge rate calculation changed to better represent the value of undemonstrated capacity. Prior to June 2022, the FTC charge rate was calculated as the maximum clearing price of all primary and reconfiguration auctions associated with a capacity commitment period. As of June 2022, the ISO reruns the third Annual Reconfiguration Auction of each capacity commitment period with all undemonstrated capacity submitted as mandatory demand bids; the resulting clearing price establishes the FTC charge rate for the capacity commitment period.

Secondary auctions allow participants the opportunity to buy or sell capacity after the initial auction. A summary of prices and volumes associated with reconfiguration auction and bilateral

[45] Final payments account for adjustments to primary auction CSOs. Adjustments include annual reconfiguration auctions, annual bilateral periods, monthly reconfiguration auctions, monthly bilateral periods, peak energy rent adjustments, performance and availability activities, and reliability payments.

trading activity during Summer 2022 alongside the results of the relevant primary FCA are detailed in Table 5-1 below.

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

					Capacity Zone/Interface Prices ($/kW-mo)			
FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)*	Cleared MW	Maine	Phase I/II	Highgate	New Brunswick
FCA 13 (2022 - 2023)	Primary	12-month	3.80	34,839				
	Monthly Reconfiguration	Aug-22	0.50	415				
	Monthly Bilateral	Aug-22	1.40	77				
	Monthly Reconfiguration	Sep-22	0.78	697				
	Monthly Bilateral	Sep-22	0.66	171				
	Monthly Reconfiguration	Oct-22	0.60	880				
	Monthly Bilateral	Oct-22	3.80	46				
FCA 14 (2023 - 2024)	Primary	12-month	2.00	33,956				
	Annual Reconfiguration (2)	12-month	0.80	197/365**	0.78		0.78	0.78
FCA 15 (2024- 2025)	Primary	12-month	2.61	34,621				
	Annual Reconfiguration (1)	12-month	0.95	280/256**	0.85		0.85	0.85

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

Two Annual Reconfiguration Auctions (ARAs) occurred in Summer 2022: the first ARA for CCP 15 occurred in June and the second ARA for CCP 14 occurred in August. The first ARA for CCP 15 cleared 280 MW of supply and 256 MW of demand, increasing total system capacity by 25 MW. The rest-of-pool price was $0.95/kW-month, much less than the primary auction clearing price of $2.61/kW-month. The second ARA for CCP 13 removed capacity from the system, clearing 197 MW of supply and 365 MW of demand. The clearing price of the ARA ended at $0.80/kW-month, a 60% decrease from the primary auction clearing price of $2.00/kW-month. Compared to their corresponding FCAs, the Net Installed Capacity Requirements (Net ICRs) decreased for both ARA 1 of CCP 15 and ARA 2 of CCP 14, leading to the drop in clearing prices.. The lower Net ICRs were driven largely by updates to the peak load forecast for the associated capacity periods. The load forecast used in ARA 1 of CCP 15 dropped 1,800 MW from FCA 15 and the load forecast used in ARA 1 of CCP 14 dropped 1,300 MW from FCA 14.[46]

Three monthly reconfiguration auctions (MRAs) took place in Summer 2022: the August 2022 auction in June, the September 2022 auction in July, and the October 2022 auction in August. Clearing prices were relatively constant and extremely low over the three auctions, starting at $0.50/kW-month for August, increasing slightly to $0.78/kW-month for September, and settling to $0.60/kW-month for October. Cleared volumes were relatively low in the August and September MRAs, reaching only 415 MW and 697 MW, respectively. October marked the beginning of the winter capacity period, characterized by increases in qualified capacity due to

[46] More information on changes in net ICR assumptions for 2022 reconfiguration auctions can be found here: https://www.iso-ne.com/static-assets/documents/2021/09/a02_pspc_2021_10_05_icr_related_values_for_aras_2022.pptx

decreases in ambient air temperatures. As qualified capacity increased, cleared volumes in the October MRA increased as well, up to 880 MW.

5.2 Financial Transmission Rights

Financial Transmission Rights (FTRs) are financial instruments that entitle the holders to receive compensation for congestion costs that occur in the day-ahead energy market. FTRs are sold in annual and monthly auctions, both of which conduct separate auctions for on-peak and off-peak hours. The amount of FTRs awarded in each auction is based on a market feasibility test that ensures that the transmission system can support the awarded set of FTRs during the relevant period. FTRs awarded in either of the two annual auctions have a term of one year, while FTRs awarded in a monthly auction have a term of one month. FTR auction revenue is distributed to Auction Revenue Rights (ARRs) holders, who are primarily congestion-paying Load Serving Entities (LSEs) and transmission customers.

FTRs settle on a monthly basis. Payments to the holders of FTRs with positive target allocations in a month come from three sources:[47]

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

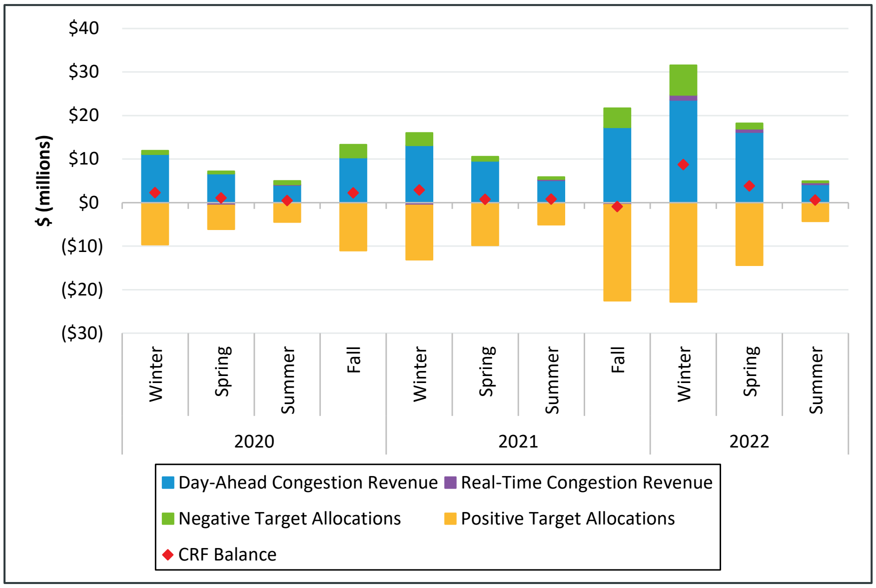
If the revenue collected from these three sources in a month exceeds the payments to the holders of FTRs with positive target allocations in that month, the excess revenue carries over to the end of the calendar year. However, there is not always sufficient revenue collected from these three sources to pay the holders of FTRs with positive target allocations in a month. In this case, the payments to holders of FTRs with positive target allocations are prorated. Any excess revenue collected during the year is allocated to these unpaid monthly positive target allocations at the end of the year, to the extent possible.

In general, 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 (i.e., FTRs are usually *fully funded*). This can be seen in Figure 5-2 below, which shows, by quarter, the amount of congestion revenue from the day-ahead and real-time markets, the amount of positive and negative target allocations, and the congestion revenue fund (CRF) balance.[48] 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.

[47] Target allocations for each FTR are calculated on an hourly basis by multiplying the MW amount of the FTR by the difference in the day-ahead congestion components of the FTR's sink and source locations. Positive target allocations (credits) occur when the congestion component of the sink location is greater than the congestion component of the source location. Negative target allocations (charges) occur in the opposite situation.

[48] The CRF balances depicted in Figure 5-2 are simply the sum of the month-end balances for the three months that comprise the quarter. The month-end balances are calculated as $\sum(DA\ Congestion\ Revenue + RT\ Congestion\ Revenue + Negative\ Target\ Allocations + Positive\ Target\ Allocations)$ and do not include any adjustments (e.g., surplus interest, FTR capping). While a positive CRF balance for a quarter indicates that the revenue collected from the three funding sources exceeded the total positive target allocations for the *quarter*, it does not guarantee that this was the case for each month within the quarter. As mentioned in the text above, it is important to note that FTRs settle on a monthly basis.

Figure 5-2: Monthly On-peak FTR MW by Auction



FTRs in July 2022 were fully funded, while FTRs in June and August were underfunded. However, for 2022, there was a positive congestion revenue fund surplus at the end of August, so these FTRs will likely be fully-funded with the year-end surplus. Positive target allocations amounted to $4.3 million in Summer 2022. This represents a decrease of 70% relative to Spring 2022 ($14.4 million), largely as a result of decreased congestion driven by intermittent renewable generation in several export-constrained areas and reduced congestion over the Roseton interface. Positive target allocations also decreased by 14% relative to Summer 2021 ($5.1 million). Day-ahead congestion revenue in Summer 2022 ($4.1 million) followed a similar pattern, decreasing by 74% relative to Spring 2022 ($16.2 million) and decreasing by 19% from Summer 2021 ($5.1 million). Negative target allocations in Summer 2022 ($0.4 million) decreased by 72% from their value in Spring 2022 ($1.3 million), while negative target allocations decreased by 32% compared to their Summer 2021 level ($0.5 million). Real-time congestion revenue was $0.4 million in Summer 2022, down 45% from Spring 2022 ($0.8 million) and up 72% from Summer 2021 ($0.2 million).

At the end of August 2022, the congestion revenue fund had a surplus of $7.8 million. As mentioned above, surpluses like this carry over until the end of the year, when they are used to pay any unpaid monthly positive target allocations. Any remaining excess at the end of the year is then allocated to payers of congestion costs.

5.3 Forward Reserve Market

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 2022, the ISO held the forward reserve auction for the Winter 2022-2023 delivery period (i.e., October 1, 2022 to May 31, 2023).[49]

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 real-time, 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).

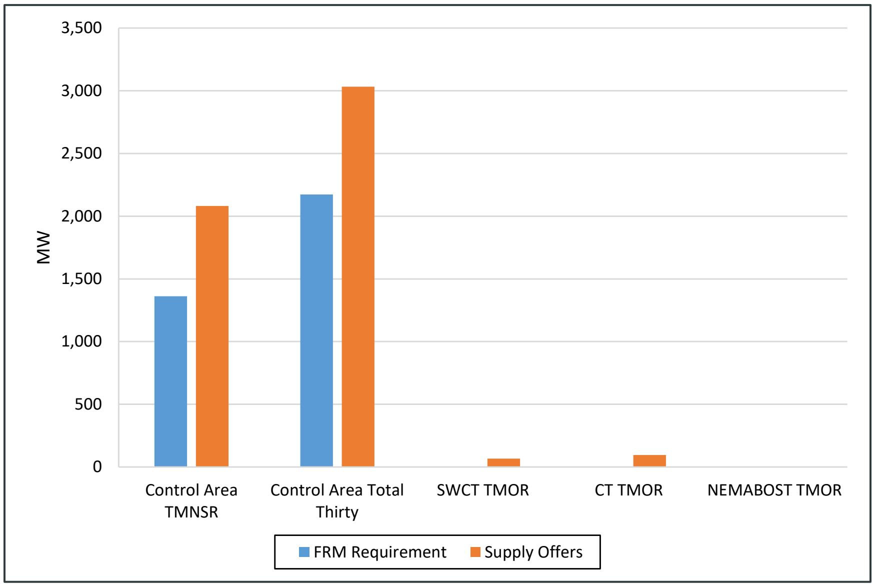
The requirements for the Winter 2022-2023 auction are illustrated in Figure 5-3 below. These requirements were specified for the ISO New England system and three local reserve zones.[50] The figure also illustrates the total quantity of supply offers available to satisfy the reserve needs in the auction.[51]

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

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

[51] 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 to TMOR supply.

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



Two reserve products had system 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. For TMNSR, the requirement was based on the expected single contingency of the Hydro Quebec Phase II Interconnection, and was estimated as a 1,361 MW TMNSR reserve need. The system-wide TMOR requirement was based on the expected single contingency of the Seabrook nuclear generator, and was estimated as an 812 MW TMOR need.[52] The total thirty-minute requirement (depicted in the figure) is the sum of the TMNSR and incremental TMOR requirements (i.e., 1,361 + 812).[53] Offered reserve was adequate to satisfy requirements for both system-level products.

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).[54] 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.

[52] ISO New England Memorandum to Market Participants (Subject: Assumptions and Other Information for the Winter 2022-2023 Forward Reserve Auction), published July 21, 2022, 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.

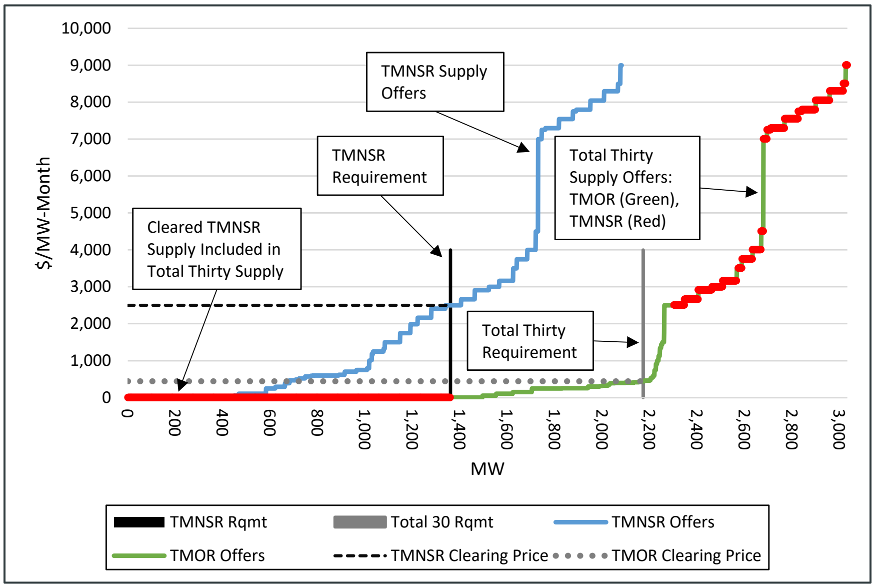
[53] The system TMOR requirement indicated in the ISO's auction assumptions represents an incremental requirement, in excess of the TMNSR requirement. The *total* thirty minute requirement for the auction is the sum of the TMNSR requirement and the system (incremental) TMOR requirement.

[54] 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). The transmission capacity used to adjust the local requirement is referred to as "external reserve support."

5.3.2 System Supply and Auction Pricing

As noted previously, system-wide supply offers in the Winter 2022-2023 auction exceeded the requirements for both TMNSR and TMOR. Adequate supply ensures that the ISO can successfully obtain forward obligations to meet expected reserve needs in the auction. Figure 5-4 below provides the requirements, system-wide supply curves, and clearing prices for both TMNSR and TMOR.

Figure 5-4: Supply Curves, Requirements and Clearing Prices, System-Wide TMOR & TMNSR



With system-wide requirements of 1,361 MW for TMNSR and 2,173 MW for total thirty, system-wide supply offers for the two products resulted in clearing prices of $2,500/MW-month for TMNSR and $439/MW-month for total thirty (black and gray dashed/dotted lines in the figure). TMNSR supply in the figure is depicted by the blue line; the total thirty-minute supply curve is depicted with both red and green shading, since both TMNSR supply offers (red shading) and TMOR supply offers (green shading) can be used to meet the total thirty-minute requirement.

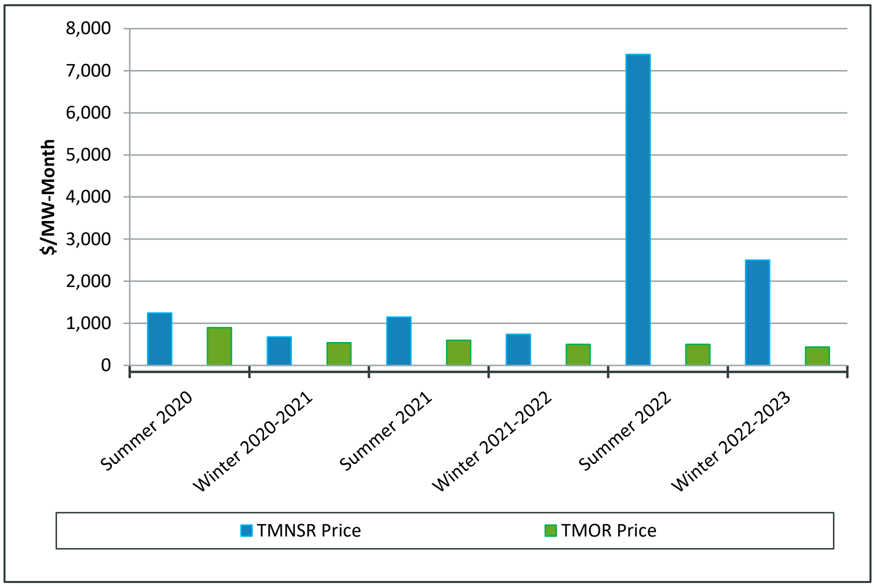
While TMNSR supply can be used to meet thirty-minute reserve needs, thirty-minute supply offers – as a lower-quality product – cannot be used to meet TMNSR needs. Given that, TMNSR supply is shown relative to the TMNSR requirement; all TMNSR and TMOR supply then can be used to meet the total thirty-minute requirement. The TMNSR supply needed to meet the TMNSR requirement helps to satisfy the total thirty-minute reserve requirement and is shown at $0/MW-month in the TMOR supply curve (as depicted in the figure). The remaining uncleared TMNSR supply and TMOR supply determine the pricing for meeting the total thirty-minute requirement.[55]

[55] The TMNSR supply that clears to meet the TMNSR requirement effectively reduces the total thirty requirement to the incremental TMOR requirement (i.e., 812 MW). TMOR supply, plus TMNSR not cleared to meet the TMNSR requirement, can be used to meet the incremental TMOR requirement. The clearing for the incremental TMOR requirement results in the system-wide TMOR/total thirty auction price.

5.3.3 Price Summary

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

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

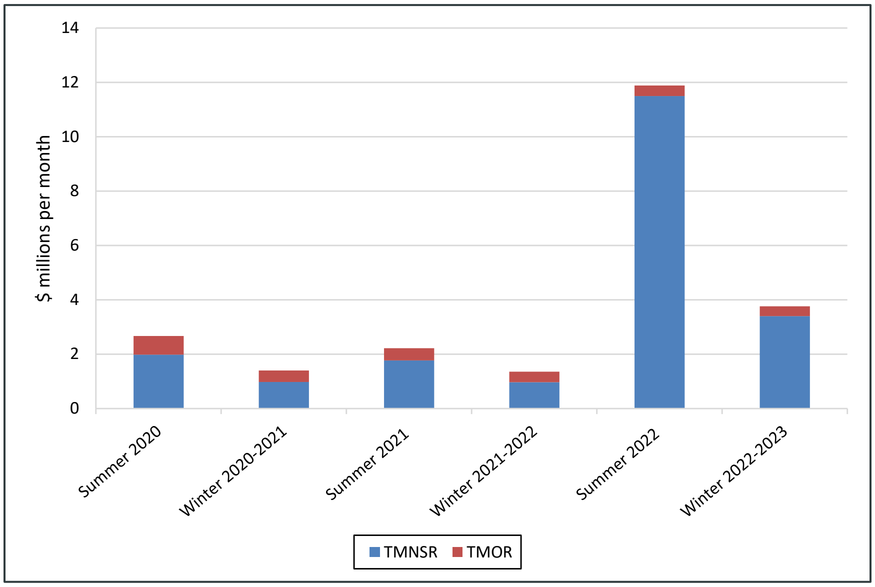


The clearing prices declined in the Winter 2022-2023 auction compared to the Summer 2022 auction (TMNSR: $7,386/MW-month; TMOR: $499/MW-month). The decline in the Winter auction TMNSR clearing price resulted from a decrease in the TMNSR requirement (by 13%, which decreased the TMNSR clearing price by approximately $500/MW-month all other factors equal) and significantly reduced offer prices. The reduction in the TMOR clearing price for the Winter auction resulted from lower TMOR offer prices.

In the Winter 2022-2023 auction, TMNSR cleared at a higher price than TMOR (TMNSR: $2,500/MW-month; TMOR: $439/MW-month). Compared to the Winter 2021-2022 auction, TMNSR cleared at a higher price and TMOR cleared at a lower price (Winter 2021-2022: TMNSR equaled $740/MW-month and TMOR prices equaled $499/MW-month). The increase in the TMNSR clearing price resulted from increased TMNSR offer prices for the 2022-2023 auction. The decline in TMOR prices resulted from a reduction in TMOR offer prices in the 2022-2023 auction.

The decrease in TMNSR clearing price for the Summer 2022 auction also significantly decreases expected gross FRM payments for the Winter 2022-2023 auction. Figure 5-6 indicates the monthly gross payments (i.e., excluding penalties) available to participants with TMNSR and TMOR FRM obligations.

Figure 5-6: Gross Monthly FRM Payments



While gross monthly payments for auctions preceding Summer 2022, ranged from $1.4 to $2.7 million, the significant increase in the TMNSR clearing price for the Summer 2022 auction elevated gross payments to $11.9 million per month for the Summer deliver period. Expected gross payments declined significantly with the reduced TMNSR pricing for the Winter 2022-2023 auction, falling to $3.8 million per month. 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.

5.3.4 Structural Competitiveness

The structural competitiveness of the Forward Reserve Market can be measured by the Residual Supply Index (RSI). RSI measures the extent to which an individual participant has market power and controls enough supply to be able to increase price above a competitive level. In other words, the RSI measures the percentage of the forward reserve requirement that can be met without the largest FRM portfolio offer. If the requirement cannot be met without the largest supplier, then that supplier is pivotal. The RSI is calculated based on the FRM offer quantities.

The RSI for TMNSR is computed at a system level based on the total quantity of TMNSR offers across all reserve zones, excluding the largest TMNSR offer quantity by a single market participant; this supply (minus the largest supplier) is compared to the TMNSR requirement. If the requirement can be met without the largest supplier, the RSI will be equal to or greater than 100; if the requirement cannot be met without the largest supplier, the RSI will be less than 100. The RSI calculation for system-wide total thirty (TMOR) follows the same formulation, considering offered total thirty supply, the largest total thirty supplier, and the total thirty requirement.[56] Because the local reserve zones did not have a local FRM reserve requirement in the auctions covered by this report, the RSI is not applicable at the local level.

The heat map table –Table 5-2 below – shows the offer RSI for system TMNSR and TMOR for zones with a non-zero TMOR requirement. The colors indicate the degree to which structural market power was present, starting with low RSIs shown in red, followed by white and green colors, with the latter indicating that there was still ample offered supply without the largest supplier.

Table 5-2: Offer RSI in the FRM for System-Wide TMNSR and TMOR

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI Total Thirty (System-wide)
Summer 2020	84	97
Winter 2020-21	102	115
Summer 2021	92	108
Winter 2021-22	110	116
Summer 2022	78	90
Winter 2022-23	109	112

An RSI value less than 100 (shown in red) indicates the presence of at least one pivotal supplier, which means the auction was not structurally competitive. Pivotal suppliers may be able to strategically offer reserves at uncompetitive prices.

For the Winter periods, the TMNSR RSI values have been greater than 100, indicating that those auctions were structurally competitive. The Summer periods have had TMNSR RSI values of less than 100, indicating that the auctions were structurally uncompetitive. For the Summer 2022 auction, the TMNSR requirement did not change significantly from the prior summer auction, but supply in the auction declined by approximately 800 MW; the change in supply resulted in the decline in the RSI. The Summer 2021 auction's RSI was higher than the Summer 2020 RSI, with a small increase in supply and a small reduction in requirement. The Summer 2020 results had an increased requirement, coupled with a small net reduction in supply offers.

The system-wide total thirty RSI values were consistent with a structurally competitive level, except for the Summer 2020 and 2022 auctions. In 2020 auction, the RSI estimate was just slightly below the competitive level, reflecting slightly reduced supply and a slightly increased reserve requirement in that auction (relative to the prior summer auction). In Summer 2022, a small increase in the requirement and an approximately 200 MW reduction in supply offers resulted in the RSI decline, compared to Summer 2021.

[56] Starting with the Spring 2021 QMR, the reported total thirty (TMOR) RSI values were revised based on an updated methodology. Previously, the total thirty/TMOR RSI system-wide calculation included both TMNSR and TMOR supply, and compared that supply to the incremental TMOR requirement (e.g., 786 MW in Summer 2021), rather than comparing that supply to the total thirty-minute requirement (2,348 in Summer 2021). The previous formulation of the RSI calculation overstated the potential competitiveness of TMOR supply offers, by understating the actual thirty-minute requirement. The revised system-wide total thirty RSI is now calculated by comparing all supply offers in the auction (TMNSR and TMOR) to the total thirty-minute requirement.