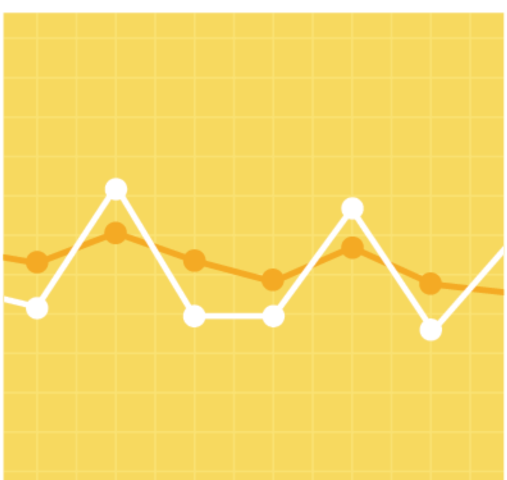
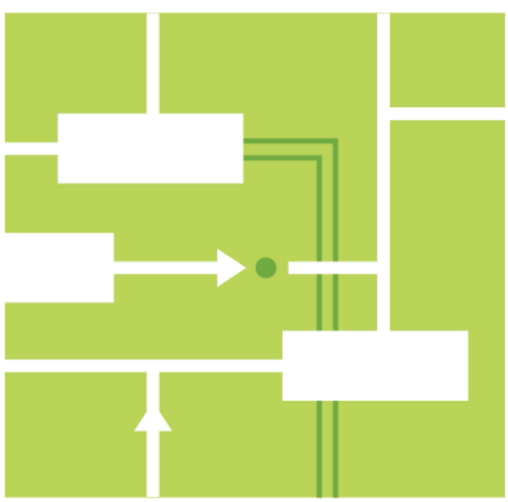
Spring 2022 Quarterly Markets Report

By ISO New England's Internal Market Monitor

AUGUST 19, 2022





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

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Spring 2022 (March 1, 2022 through May 31, 2022).[3]

Wholesale Costs: The total estimated wholesale market cost of electricity was $2.65 billion in Spring 2022, up 78% from $1.49 billion in Spring 2021. Higher energy costs drove the increase in wholesale costs.

Energy costs totaled $2.09 billion in Spring 2022; up 142% (or $1.23 billion) from Spring 2021 costs and consistent with the substantial increase in natural gas prices. Spring 2022 gas prices averaged $7.14/MMBtu, an increase of $4.34/MMBtu or 155% compared to Spring 2021 prices.

Capacity costs totaled $533 million, down 12% (by $74 million) over the previous Spring. Beginning in Summer 2021, lower capacity clearing prices from the twelfth Forward Capacity Auction (FCA 12) drove lower costs relative to the previous FCA. In the prior capacity commitment period (CCP 11, June 2020 – May 2021), the capacity payment rate for all new and existing resources was $5.30/kW-month. This year, the payment rate for new and existing resources was lower, at $4.63/kW-month. Two generators were retained for reliability in FCA 12, putting downward pressure on the clearing price.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $68.49 and $66.91 per megawatt hour (MWh), respectively. Day-ahead and real-time prices were 139-140% higher than Spring 2021 prices, on average.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $7.14/MMBtu in Spring 2022, an increase of 155% compared to $2.80/MMBtu during the prior spring.
- Hourly load averaged 12,153 MW, up 1% (≈ 145 MW) on the previous spring.
- Energy market prices did not differ significantly among the load zones.
- There were three system events during the quarter (March 29, May 18, and May 21) where emergency procedures or unplanned outages resulted in notable real-time pricing outcomes.

Net Commitment Period Compensation: Uplift payments totaled $11.6 million in Spring 2022, an increase of $5.4 million compared to Spring 2021. The increase was primarily due to out-of-merit commitments that occurred on days with unusual system conditions, and an increase in uplift paid to external transactions. Uplift payments represented less than 1% of total wholesale energy costs in Spring 2022, a similar share compared to other quarters in the reporting horizon. The majority of uplift (98%) was for first contingency protection (also known as "economic" uplift). About 70% of economic payments occurred

[3] In Quarterly Markets Reports, outcomes are reviewed by season as follows: Winter (December through February), Spring (March through May), Summer (June through August) and Fall (September through November).

in the real-time market. Compared to Spring 2021, economic payments increased by $5.7 million (from $5.7 million to $11.4 million). This increase was consistent with higher energy prices in Spring 2022 compared to Spring 2021. Additionally, there were multiple system events during Spring 2022 that resulted in out-of-merit commitments.

Real-time Reserves: Real-time reserve payments totaled $5.2 million, a $3.8 million increase from $1.4 million in Spring 2021. The increase was primarily driven by (1) higher natural gas prices leading to higher energy prices, which increased the re-dispatch costs of energy in Spring 2022, and (2) non-spinning reserve pricing that occurred on March 29 due to fuel supply issues and higher than expected loads.

Non-zero ten-minute spinning reserve (TMSR) pricing occurred for 406 hours in Spring 2022, up from 325 hours in Spring 2021. The average non-zero hourly spinning reserve price increased from $7.85/MWh in Spring 2021 to $16.98/MWh in Spring 2022 due to the aforementioned LMP increase.

Regulatio**n:** Total regulation market payments were $6.2 million, up 48% from $4.2 million in Spring 2021. The increase in payments was driven by changes in regulation capacity prices and payments, which increased due to higher LMPs in Spring 2022.

Energy Market Competitiveness: Spring 2022 saw a slightly higher frequency of pivotal suppliers (19%) in the real-time market compared to the two previous spring seasons (14% and 8%). The small increase was due to lower non-spinning reserve margins that resulted from several factors, including slightly higher loads, more generation out of service, and more notable system events with associated tighter margins in Spring 2022 compared to 2021. The average 5-minute real-time energy market residual supply index (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.

Mitigation has continued to occur very infrequently relative to the initial triggers for potential mitigation (i.e., structural test failures, commitment or dispatch). Historically, the highest frequency of mitigation occurs for reliability commitments. However, reliability commitment mitigation decreased down to zero asset-hours in Spring 2022 due to a large decline in reliability commitment asset-hours compared to Spring 2021. After reliability commitment mitigation, manual dispatch energy mitigation occurred with the second highest frequency since the start of the reporting period in Winter 2020. In Spring 2022, there were 536 asset-hours of manual dispatch and 92 asset-hours of mitigation, an increase from Spring 2021, which saw 295 asset-hours of manual dispatch and 47 asset-hours of manual dispatch mitigation. The most common reasons for manual dispatch are (1) when generators provide regulation service in the real-time energy market and (2) when relatively flexible generators are positioned away from the market software-determined dispatch to address short-term issues on the grid.

Financial Transmission Rights (FTRs): FTRs were fully funded in March, April, and May 2022. Positive target allocations totaled $14.4 million, up 50% from Spring 2021. Day-ahead congestion revenue also increased in Spring 2022, totaling $16.2 million compared to $9.6 million in Spring 2021. Negative target allocations ($1.3 million) were 28% higher than their Spring 2021 level ($1.0 million). Real-time congestion revenue was $0.8 million in Spring 2022, a $1.0 million increase from the negative value (-$0.3 million) observed in Spring 2021. At the end of May 2022, there was a congestion revenue fund surplus of $7.3 million for 2022. Surpluses carry over until the end of the year, when they are used to pay any unpaid monthly positive target allocations.

Summer 2022 Forward Reserve Market Auction: In April 2022, ISO New England held the forward reserve auction for the Summer 2022 delivery period (i.e., June 1 to September 30, 2022). System-wide supply offers in the Summer 2022 auction exceeded the requirements for both ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR).

The clearing prices of the TMOR and TMNSR products were $499 and $7,386/MW-month, respectively. The Summer 2022 TMNSR price increased significantly compared to previous auctions due to a large increase in TMNSR offer prices.

The Residual Supply Index (RSI) for the system-level TMNSR product in Summer 2022 was 78, which was below the structurally competitive level of 100 and lower than the Summer 2021 value of 92. The lower RSI was due to an auction supply decrease of approximately 800 MW or 31%. The system-wide total thirty-minute RSI for Summer 2022 of 90 was also structurally uncompetitive, and lower than the Summer 2021 RSI of 108. A small increase in the requirement and a 200 MW reduction in supply offers resulted in the TMOR RSI decrease compared to Summer 2021.

While the Summer 2022 auction for the TMNSR product was not structurally competitive, we reviewed the results for potential physical and economic withholding and found no evidence of the exercise of market power. Offer prices appeared to reflect a plausible range of anticipated costs of providing the service.

Section 2
Overall Market Conditions

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

Table 2-1: High-level Market Statistics

Market Statistics	Spring 2022	Winter 2022	Spring 2022 vs Winter 2022 (% Change)	Spring 2021	Spring 2022 vs Spring 2021 (% Change)
Real-Time Load (GWh)	26,822	31,294	-14%	26,503	1%
Peak Real-Time Load (MW)	18,900	19,766	-4%	18,885	0%
Average Day-Ahead Hub LMP ($/MWh)	$68.49	$110.34	-38%	$28.69	139%
Average Real-Time Hub LMP ($/MWh)	$66.91	$105.48	-37%	$27.89	140%
Average Natural Gas Price ($/MMBtu)	$7.14	$14.41	-50%	$2.80	155%
Average No. 6 Oil Price ($/MMBtu)	$24.35	$16.08	51%	$12.38	97%

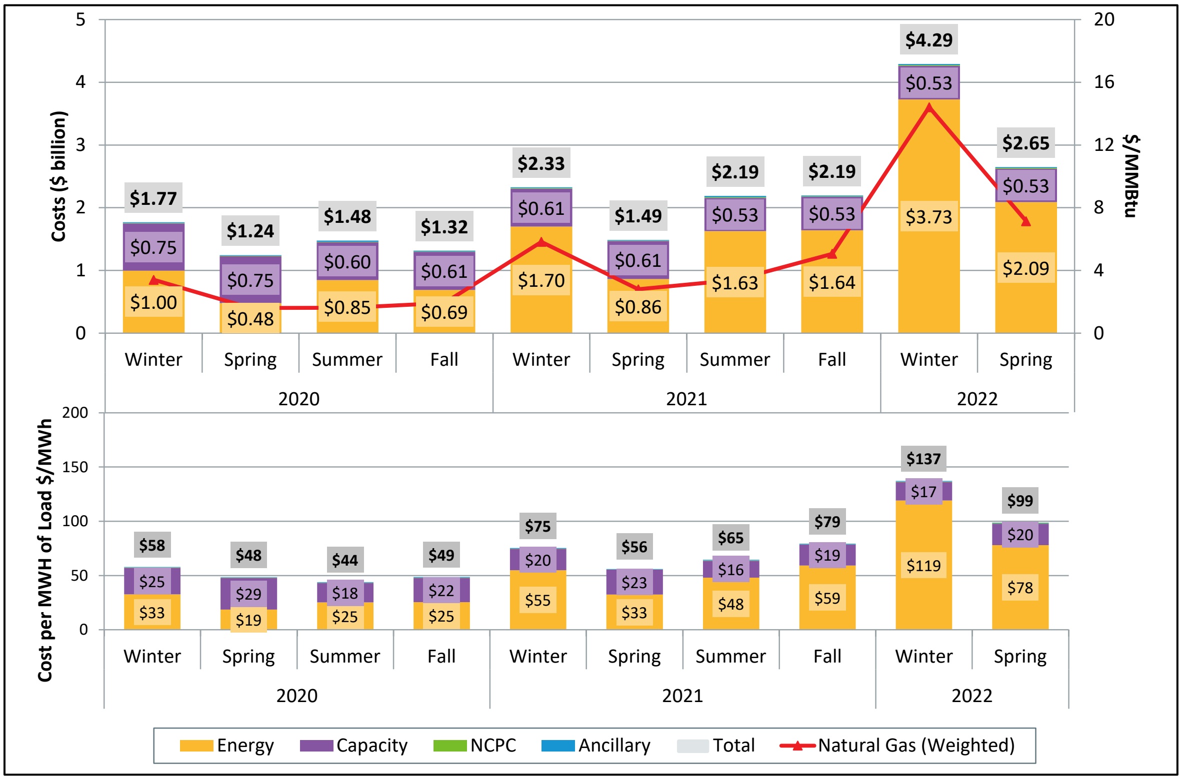
To summarize the table above:

- Average day-ahead LMPs in Spring 2022 were $68.49/MWh, 139% higher than in Spring 2021. Average real-time LMPs were $66.91/MWh, 140% higher than in Spring 2021.
- Average gas prices in Spring 2022 ($7.14/MMBtu) increased significantly from Spring 2021 prices ($2.80/MMBtu). Low nation-wide storage levels, along with increased international prices, put upward pressure on gas prices in Spring 2022. The high prices in New England reflected high prices at the Henry and Marcellus hubs; New England pipeline constraints had little impact on year-over-year gas price changes.

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), are shown in Figure 2-1 below. The bottom graph shows the wholesale cost per megawatt hour of real-time load served.[4,5]

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



In Spring 2022, the total estimated wholesale cost of electricity was $2.65 billion (or $99/MWh of load), a 78% increase compared to $1.49 billion in Spring 2021, and a decrease of 38% over the previous quarter (Winter 2022). Natural gas prices continued to be a key driver of energy prices, and led to substantially higher energy costs this spring compared to Spring 2021. Spring 2022 natural gas prices averaged $7.14/MMBtu, an increase of $4.34/MMBtu or 155% compared to Spring 2021 prices.

Energy costs were $2.09 billion ($78/MWh) in Spring 2022, 142% higher than Spring 2021 costs, driven by the aforementioned increase in average natural gas prices. Energy costs made

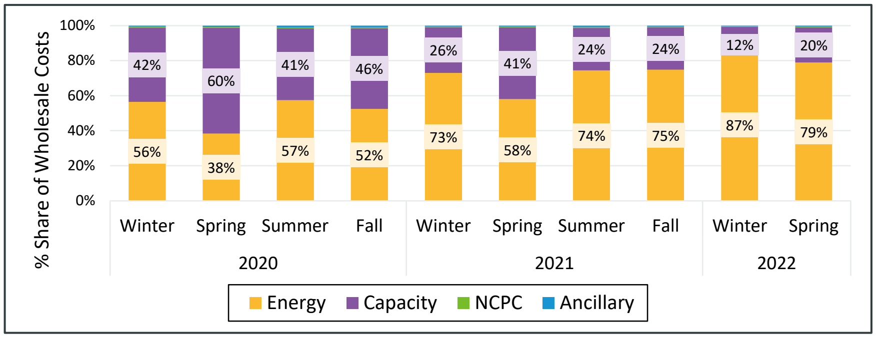
[4] The total cost of electric energy is approximated as the product of the day-ahead load obligation for the region and the average day-ahead locational marginal price (LMP) plus the product of the real-time load deviation for the region and the average real-time LMP. Transmission network costs as specified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

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

up 79% of the total wholesale cost. The share of each wholesale cost component is shown in Figure 2-2 below.

Capacity costs are determined by clearing prices in the primary capacity auctions. In Spring 2022, these costs totaled $533 million ($20/MWh), representing 20% of total costs. Beginning in Summer 2021, capacity market costs decreased relative to previous quarters due to lower forward capacity auction prices. In the prior capacity commitment period (CCP 11, June 2020 – May 2021), the clearing price for all new and existing resources was $5.30/kW-month. In the current capacity commitment period (CCP12, June 2021 – May 2022), the clearing price for all new and existing resources was $4.63/kW-month. Clearing prices fell from FCA 9 to FCA 12 due to lower net installed capacity requirements and lower net costs of new entry.

Figure 2-2: Percentage Share of Wholesale Cost



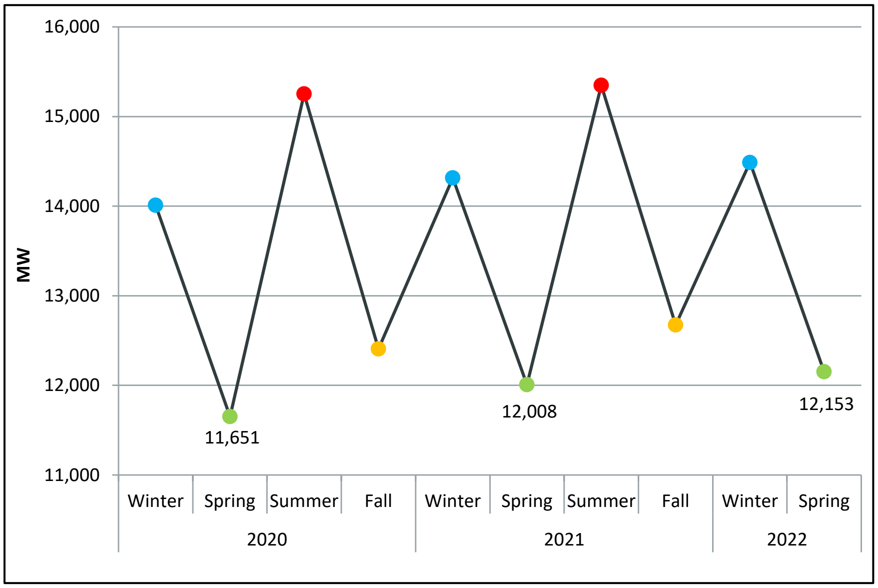
At $11.6 million ($0.43/MWh), Spring 2022 Net Commitment Period Compensation (NCPC) costs represented 0.6% of total energy costs, a similar share compared to other quarters in the reporting horizon. In dollar terms, NCPC costs were $5.4 million higher than in Spring 2021. The increase was due to out-of-merit commitments that occurred on days with unusual system conditions, and an increase in uplift paid to external transactions.

Ancillary service costs, which include operating reserves and regulation, totaled $14.6 million ($0.54/MWh) in Spring 2022, representing less than 1% of total wholesale costs. Ancillary service costs increased by 50% compared to Spring 2022, as higher energy prices resulted in increased reserve and regulation payments.

2.2 Load

In Spring 2022, average loads continued to increase year-over-year. This increase was driven by weather fluctuations, discussed further below. 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 Spring 2022, loads averaged 12,153 MW, a 1% increase from Spring 2021 (12,008 MW) and 4% increase from Spring 2020 (11,651 MW). Load increased year-over-year despite average temperatures remaining constant at 50°F. In Spring 2022, the average temperature was similar to Spring 2021, however an increase in both heating and cooling degree days suggests more temperature variability was the driver behind modestly higher loads.

Load and Temperature

The stacked graphs in Figure 2-4 below show monthly average loads compared to monthly cooling-degree days (tCDD)[6] and heating-degree days (HDD).[7]

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

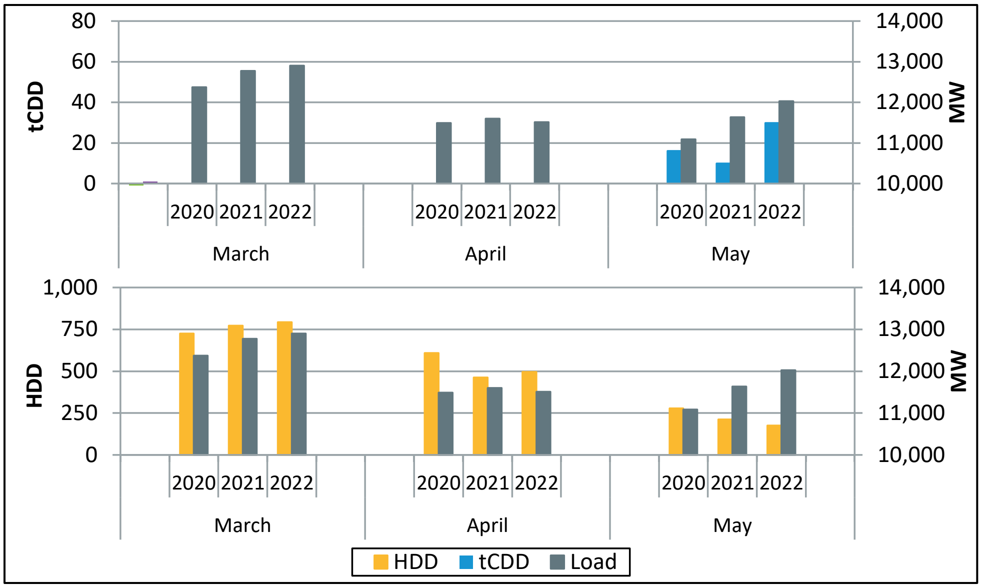


Figure 2-4 shows that loads were higher, on average, in March and May 2022 than in 2021. The main driver of changes in load this quarter was temperature, specifically fluctuations in temperature that caused more HDD in March and April but more tCDD in May compared to 2021. In May 2022, the temperature-humidity index (THI) was higher in Spring 2022 (60) than in Spring 2021 (58). The THI combines both temperature and humidity to measure a degree of comfort an individual might have. This increase in the THI lines up with an increase in tCDD. An increase in tCDD would indicate higher load due to an increase in air-conditioning demand. Similarly, HDD can also explain shifts in load. An increase in HDD in March and April 2022, caused by constant or lower temperatures than in 2021, indicate higher average loads due to heating demand.

Peak Load and Load Duration Curves

The system load for New England over the last three spring seasons is shown as load duration curves in Figure 2-5 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 that load levels occur.

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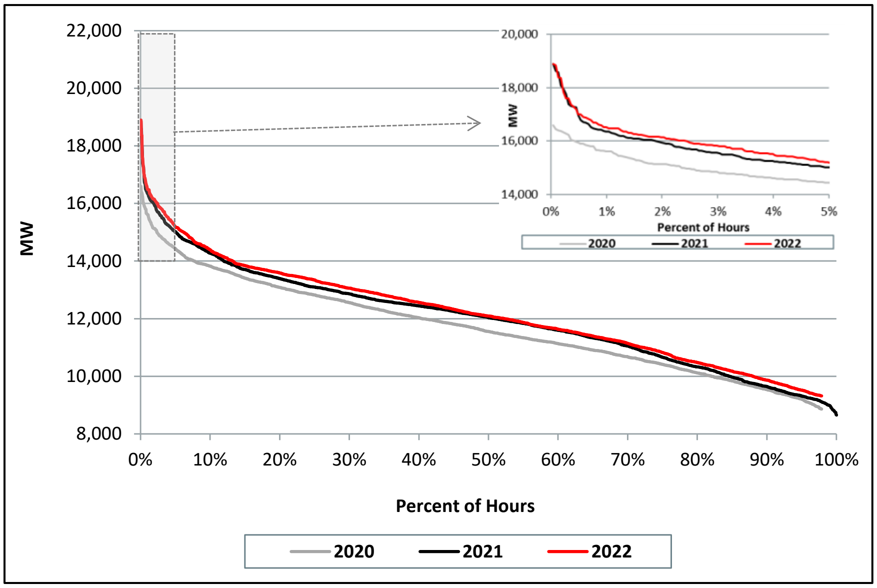
[6] A THI cooling degree day (tCDD) measures how warm an average daily THI is relative to 65°F and is an indicator of electricity demand for air conditioning. It is calculated as the number of degrees (°F) that each day's average temperature is above 65°F. For example, if a day's average temperature is 70°F, the CDD for that day is five.

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

Figure 2-5: Seasonal Load Duration Curves



Spring 2022 had higher loads than Spring 2021 across nearly all hours, and higher loads than Spring 2020 in all hours. In Spring 2022, loads were higher than 13,000 MW in nearly 31% of hours, compared to about 27% and 21% in Spring 2021 and Spring 2020, respectively. During the top 5% of hours, Spring 2022 load levels were similar to Spring 2021 but consistently higher than Spring 2020. Loads during this time in Spring 2022 averaged 16,107 MW, which is 205 MW higher than in Spring 2021 (15,901 MW) and 1,003 MW higher than in Spring 2020 (15,103 MW) when loads were low due to the COVID-19 Pandemic.

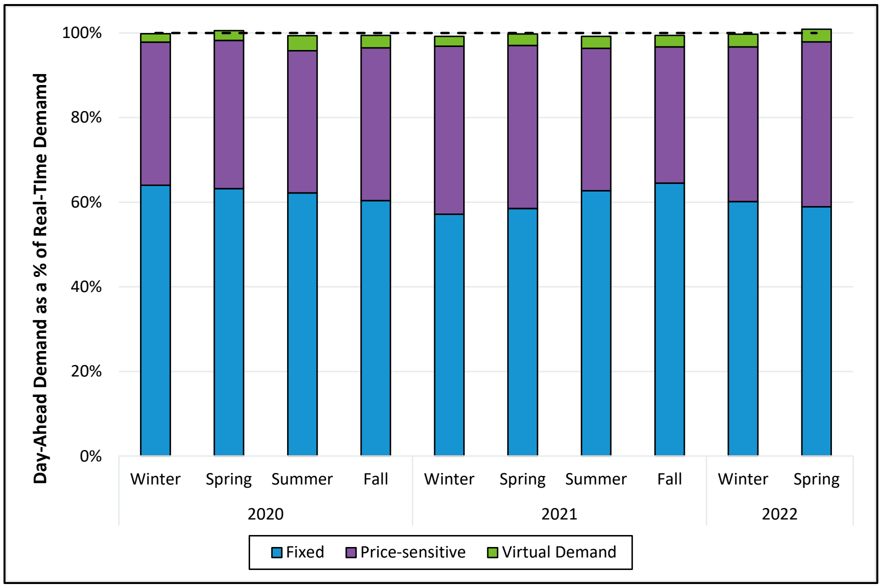
Load Clearing in the Day-Ahead Market

In recent periods, there have been higher percentages of real-time demand 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 (RAA), it influences the generator commitment decision for the operating day.[8] For example, when low levels of demand clear in the day-ahead market, supplemental supply commitments or additional dispatch may be needed to meet real-time demand. This can lead to higher real-time prices. 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.[9] In the figure below, bars that exceed the dashed black line indicate quarters where, on average, more demand cleared in the day-ahead market than actually materialized in the real-time.

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

[9] Day-ahead cleared demand is calculated as fixed demand + price-sensitive demand + virtual demand. Real-time demand is equal to native metered load. 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. 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.

Figure 2-6: Day-Ahead Cleared Demand by Bid Type



Day-ahead cleared demand as a percent of real-time demand was higher in Spring 2022 than in both Spring 2021 and Spring 2020; it was the highest percentage over the reporting period at 100.9%. In Spring 2022, cleared MWs of all bid types increased. Although price-sensitive demand bids are submitted with a MW quantity and corresponding price, the majority of bids are priced well above the LMP. Such transactions are, in practical terms, fixed demand bids. These transactions increased by 0.5%. Virtual demand and fixed demand bids both increased by less than 0.4% above 2021 levels. These increases across all bid types are a contributing factor to lower real-time prices.

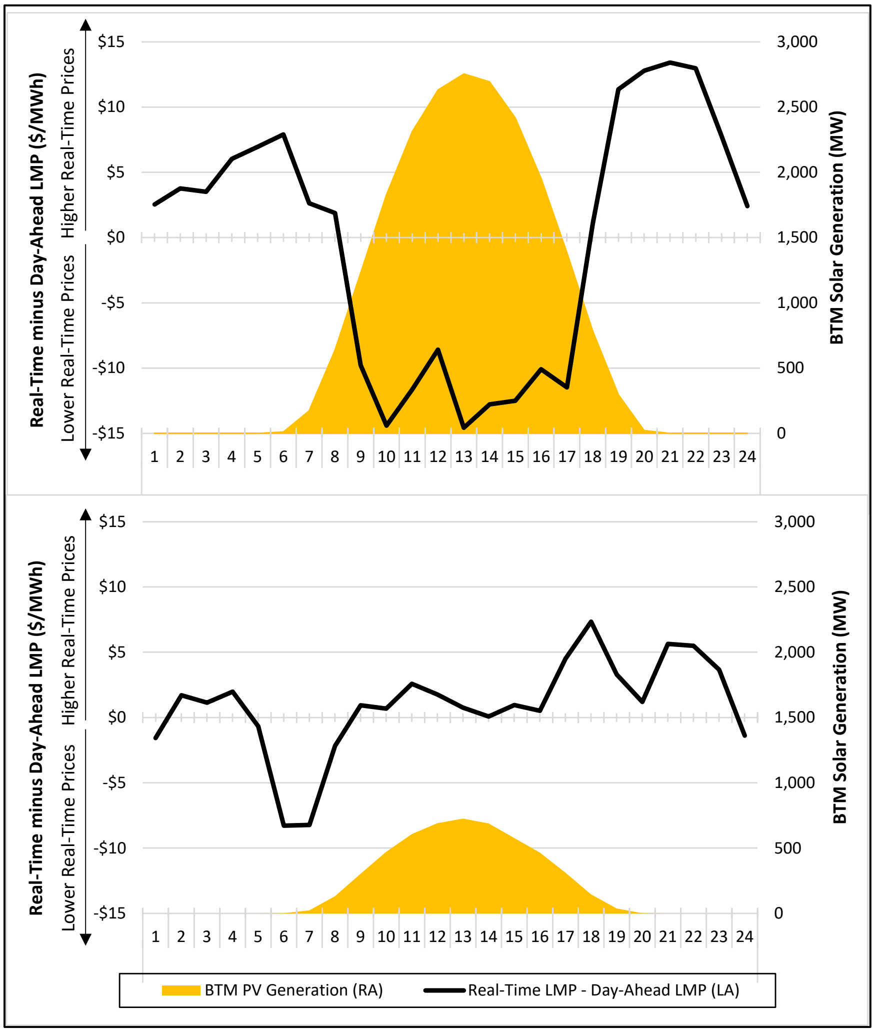
Relationship between Day-Ahead Demand and Behind-the-Meter Solar Generation

During the spring season there were a number of days with significant differences in day-ahead and real-time market outcomes. Specifically, higher volumes of load and supply cleared in the day-ahead market resulting in higher day-ahead prices on days with significant solar output. Our analysis indicates that this was due to the challenges faced by Load Serving Entities (LSEs) of forecasting behind-the-meter (BTM) solar generation and the variability of its expected output.

BTM generation does not participate in the wholesale energy market but directly impacts the level of expected and actual net, or wholesale, load. For example, when LSE's under-forecast BTM solar generation, it will reduce a LSE's real-time load in its market territory compared to its day-ahead cleared amount. This tends to put downward pressure on real-time prices and displace higher-cost wholesale generation that had cleared in the day-ahead market against the higher bid-in load. If not anticipated in the day-ahead market, too much supply may clear against a very inelastic demand curve.

In Spring 2022, real-time LMPs have typically been lower than in the day-ahead market during the middle of the operating day on days with high BTM solar generation. Figure 2-7 below shows the average hourly difference between real-time and day-ahead LMPs (left axis) and the average hourly BTM solar generation (right axis). The figure is broken up into two charts; the top chart shows the 20 days with the *highest* daily BTM solar generation and the bottom chart shows the 20 days with the *lowest* daily BTM solar generation for the Spring 2022.

Figure 2-7: Real-Time and Day-Ahead Hub LMP Difference vs. BTM Solar Generation



On average, real-time prices tend to be lower during the middle of the operating day on days with high BTM solar generation. Between HE 9 – HE 17 on the 20 days with the highest BTM solar generation (top graph), real-time LMPs were an average of 19% *lower* (or $11.76/MWh) than day-ahead LMPs. On the twenty days with the lowest BTM solar generation (bottom graph), price convergence was better with real-time LMPs averaging 2% *higher* (or $1.42/MWh) than day-ahead LMPs between HE 9 and HE 17. However, the LMP difference is not driven by the presence of BTM solar generation, but rather under-forecasting of BTM solar generation by the market and associated over-clearing of load.

If LSEs accurately forecasted BTM solar generation, their real-time load should be in line with their day-ahead cleared demand. On average, LSEs slightly over-cleared in the day-ahead market during spring 2022. However, the over-clearing increases when looking at days with higher BTM solar generation. For example, on days with high BTM solar generation (i.e., top 20 days), LSEs cleared an average of 104.3% of their load in the day-ahead market, contributing to the 19% lower (or $11.76/MWh) real-time LMPs. On days with low BTM solar generation (i.e., bottom 20 days), LSEs cleared an average of 101.9% of their load in the day-ahead market and real-time LMPs were 2% higher (or $1.42/MWh) than day-ahead LMPs.[10]

The IMM reached out to a number of LSEs to understand why over-clearing occurred on days with higher BTM solar generation.[11] All contacted LSEs mentioned issues related to BTM solar generation. Typically, these difficulties involved measuring the growing installed capacity within their respective service areas and forecasting cloud cover.

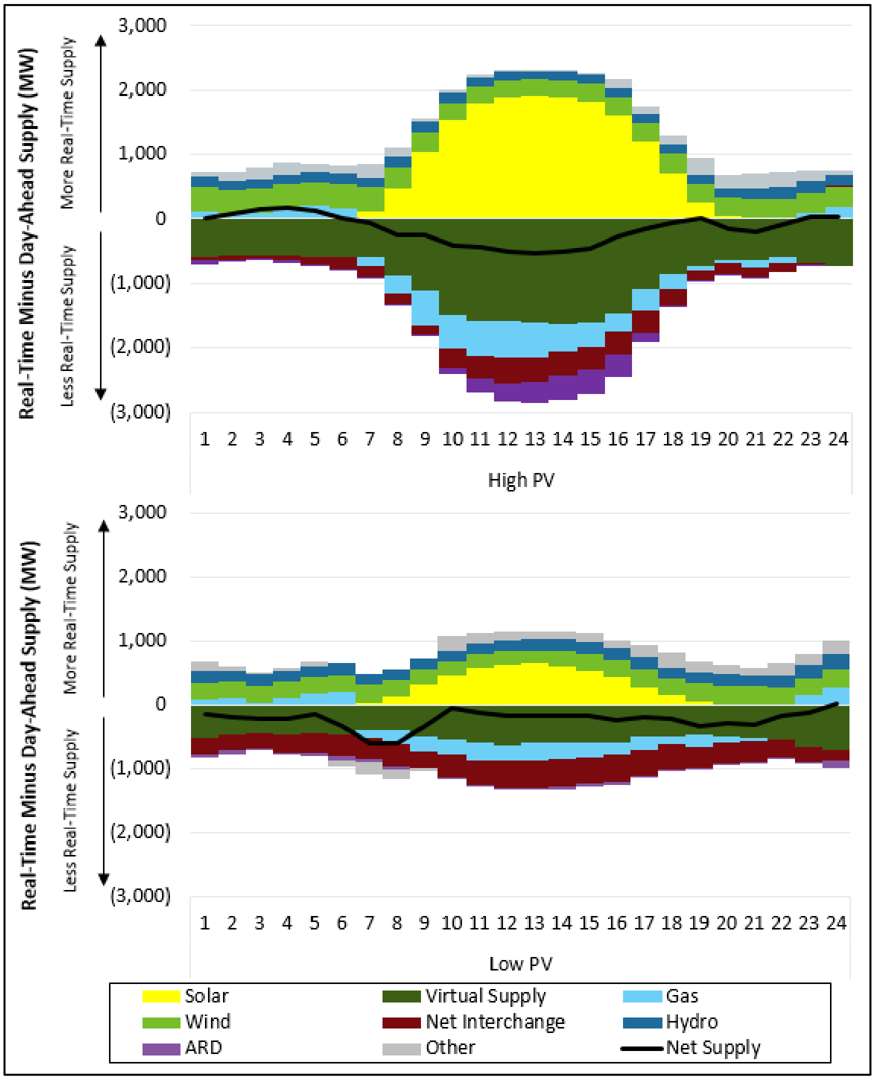
When day-ahead prices are higher than real-time prices, profit opportunities may exist for virtual supply. Virtual supply participants can help clear cheaper supply, displacing some higher-priced generation from clearing in the day-ahead market. This would help price convergence between the day-ahead and real-time market. However, this strategy would not be a simple arbitrage opportunity given the transactions costs (mostly NCPC) and the risks involved with clearing more virtual supply. Virtual supply participants would absorb the risks associated with forecasting BTM solar generation. They could be exposed to higher real-time LMPs and potential scarcity pricing, if real-time solar generation underperforms (or there are unanticipated system issues) and additional, more expensive generation needs to be committed during the operating day.

The over-clearing of demand in the day-ahead market impacts generator commitment and dispatch. On days with high solar generation and over-clearing of demand in the day-ahead market, sufficient generation must be committed in the day-ahead market in order to meet demand. When real-time load is lower than day-ahead cleared demand, excess generation must be backed down to ensure the balance of supply and demand. Figure 2-8 shows the difference between day-ahead cleared MWs and real-time scheduled MWs in hours ending 9 through 17 on the 20 highest and lowest PV days. Bars above zero MWs indicate there was an increase in real-time production from day-ahead schedules, while bars below zero MWs indicate assets produced less than their day-ahead schedules. The solar generators shown below do not include behind-the-meter solar. Only settlement-only solar generators and wholesale solar generators (> 5MW) are shown.

[10] Over-clearing of demand in the day-ahead market has occurred in prior years. During the top 20 BTM solar days in Spring 2021 LSEs cleared an average of 102.0% of their load in the day-ahead market between HE 9 and HE 17. On the lowest 20 BTM solar days LSEs cleared an averaged of 99.9% of their load in the day-ahead market over the same hours.

[11] The contacted LSEs had larger than average deviations and individually represented at least 1% of the total real-time load obligation within the ISO-NE service area.

Figure 2-8: Real-Time and Day-Ahead Average MW Difference by Fuel Type



A majority of wholesale solar generation (yellow) in the ISO-NE service area participates as settlement-only generation. Settlement-only generation does not participate in day-ahead market, so most solar generation shows up only in the real-time. Therefore, solar generation's real-time production is higher than its day-ahead cleared volume. Additionally, the impact of behind-the meter solar generation is shown by the distance between the black Net Supply line and the x-axis, when it is less than zero. Virtual supply (dark green bars) generally offsets much of the increase in wholesale and behind-the-meter solar production. This behavior helps converge day-ahead and real-time prices, but as discussed above, this activity is not risk free. Therefore, virtual participants may not always clear volumes of virtual supply that are equivalent to the real-time production of solar generation, which contributes to the day-ahead and real-time price divergences in the middle of the operating day. On days with over-clearing of demand (driven by behind-the-meter solar generation), gas generators (light blue) are generally "backed down" to make room for the additional solar generation. Net interchange (imports) tends to decrease and ARDs pump more often during peak days due to lower real-time prices. On net, less real-time generation is required to serve load due to the day-ahead over-clearing.

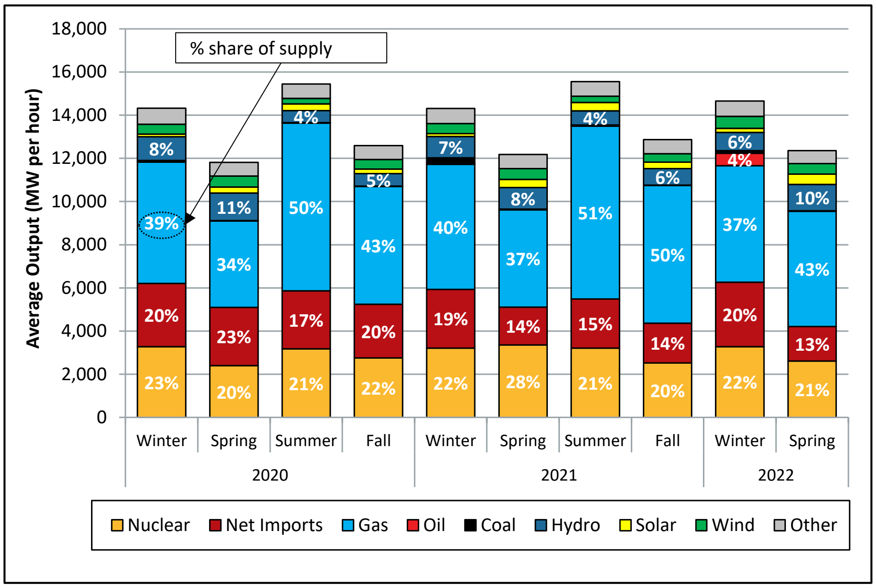
2.3 Supply

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 in the real-time market by generator fuel type for Winter 2020 through Spring 2022 is illustrated in Figure 2-9 below. Each bar's height represents average electricity generation, while percentages represent the percent share of generation from each fuel type.[12]

Figure 2-9: Share of Electricity Generation by Fuel Type



The majority of New England's energy comes from nuclear generation, gas-fired generation, and net imports (netted for exports). Together, these categories accounted for 77% of total energy production in Spring 2022. In Spring 2022, natural gas generation (along with increased hydro generation) offset decreased nuclear generation and low net imports. During this period, gas-fired generators capable of burning natural gas reached an aggregated 60% capacity factor.[13] In Spring 2021 and Spring 2020, gas generation's capacity factor was 56% and 47%, respectively. Even though gas was relatively expensive in Spring 2022 compared to the prior two years, it was still cheaper to operate on natural gas than on more expensive oil in Spring 2022. Less than 15 MW per hour (<1%) on average came from oil generation.

Nuclear production shares decreased from 28% (3,351 MW per hour on average) in Spring 2021, to 21% (2,609 MW per hour on average) in Spring 2022. There were more nuclear outages in Spring 2022 than in Spring 2021, primarily due to planned refueling. On average,

[12] 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.

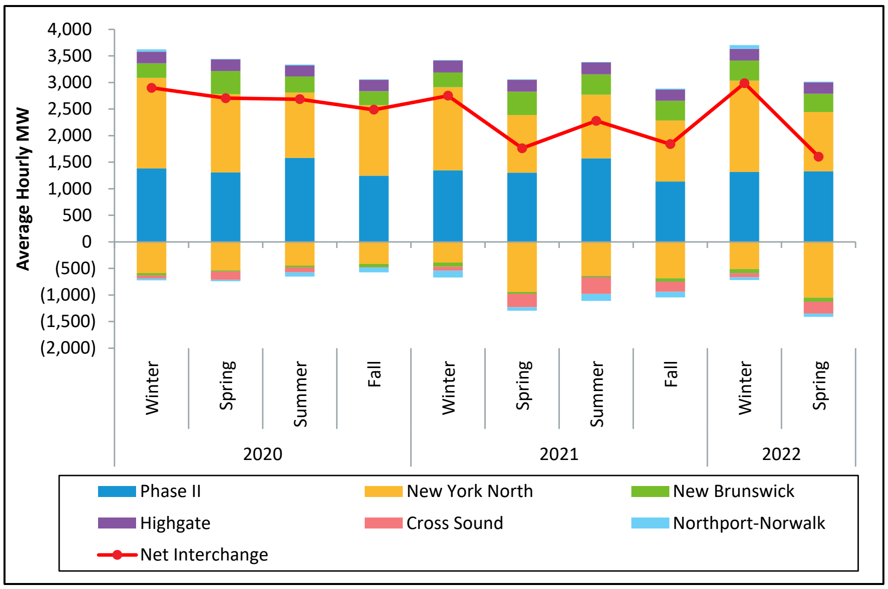
[13] Capacity factors are based on the average output from generators capable of burning gas, divided by the total CSO from generators capable of burning gas.

742 MW of nuclear generation was on outage every hour in Spring 2022 compared to 8 MW in 2021. This increase in outages led to lower capacity factors and shares of total generation for nuclear generation. Net imports in Spring 2022 (13%) were similar to Spring 2021 (14%), but still much lower than Spring 2020 (23%). On average, net imports accounted for 1,604 MW per hour of energy in Spring 2022. As described in Section 2.3.2, net import reductions in Spring 2022 relative to Spring 2021 primarily occurred over the New York North and New Brunswick interfaces.

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 Spring 2022.[14] On average, the net flow of energy into New England was 1,604 MW per hour. The total net imports represented 13% 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 ten quarters are shown in Figure 2-10 below.

Figure 2-10: Average Hourly Real-Time Imports, Exports, and Net Interchange



The average hourly net interchange of 1,604 MW was down 46% from Winter 2022 (2,987 MW) and down 10% from Spring 2021 (1,762 MW). Figure 2-10 illustrates that net interchange and imports generally fall from winter to spring when New England energy prices and demand tend to be lower. Compared to Winter 2022, the fall in net interchange was largely driven by decreased flows over the New York North interface. The decrease in net interchange between Spring 2022 and Spring 2021 was driven by less net interchange over the New Brunswick and New York North interfaces. Net interchange over the largest interface, Phase II, was consistent with Spring 2021 levels.

[14] 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.

Phase II Interface

The Phase II interface contributed the largest share of net interchange (83%) into New England in Spring 2022. This interface contributed an hourly average net interchange of 1,327 MW in Spring 2022, 2% higher than in Spring 2021 (1,302 MW). Average hourly net interchange increased by 1% (or 13 MW) compared to Winter 2022 (1,314 MW).

New York North Interface

The reduction in net interchange over New York North was the major contributor to the overall decrease in net interchange compared to Winter 2022. At the New York North interface, hourly average net interchange decreased by 74 MW compared to Springs 2021 (68 MW vs. 141 MW). The main driver behind this difference was the change in the price spread at the New York North interface, which led to an increase in exports to New York. New England day-ahead prices were $6.95/MWh lower than New York day-ahead prices in Spring 2022 compared to just $2.37/MWh in Spring 2021.

New Brunswick Interface

On average, scheduled import transactions at the New Brunswick interface were 95 MW lower in Spring 2022 than in Spring 2021 (345 MW versus 440 MW). A nuclear generator in New Brunswick was out of service for the majority of Spring 2022. This contributed to the reduced net interchange over New Brunswick.[15] Additionally, scheduled exports to New Brunswick increased by an average of 43 MW compared to Spring 2021 (80 MW vs. 37 MW).

[15] For more information about the nuclear generator outage in New Brunswick, see the following link: https://www.nbpower.com/en/about-us/news-media-centre/news/2022/point-lepreau-nuclear-generating-station-to-begin-planned-maintenance-outage/.

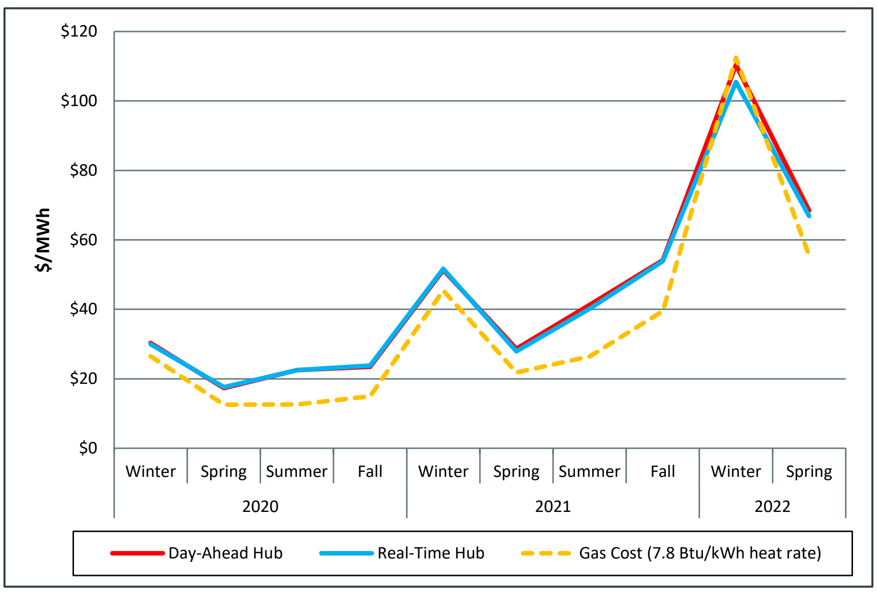
Section 3
Day-Ahead and Real-Time Markets

This section covers trends in, and drivers of, both energy market outcomes and outcomes for the following ancillary service products: operating reserves and regulation.

3.1 Energy Prices

The average real-time Hub price for Spring 2022 was $66.91/MWh, slightly lower than the average day-ahead price of $68.49/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.[16]

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 $56/MWh in Spring 2022.

Average day-ahead electricity prices were $12.92/MWh above average estimated gas costs in Spring 2022, which was higher than the $5.85/MWh spread in Spring 2021. The higher spreads resulted from the substantial increases in natural gas prices and baseload generator outages in Spring 2022 compared to the previous spring. A nuclear generator had a planned refueling outage for several weeks in Spring 2022, so the average out-of-service capacity for nuclear generators rose by 734 MW compared to Spring 2021. This baseload outage, coupled with

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

slightly higher loads and lower net imports, resulted in the dispatch of less efficient, higher cost gas generation.

In Spring 2022, average day-ahead and real-time prices were much higher than in Spring 2021, by about $40 and $39/MWh, respectively. This is consistent with the large change in natural gas prices, which increased by 155%. Additionally, average hourly loads in Spring 2022 were 145 MW higher than in Spring 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

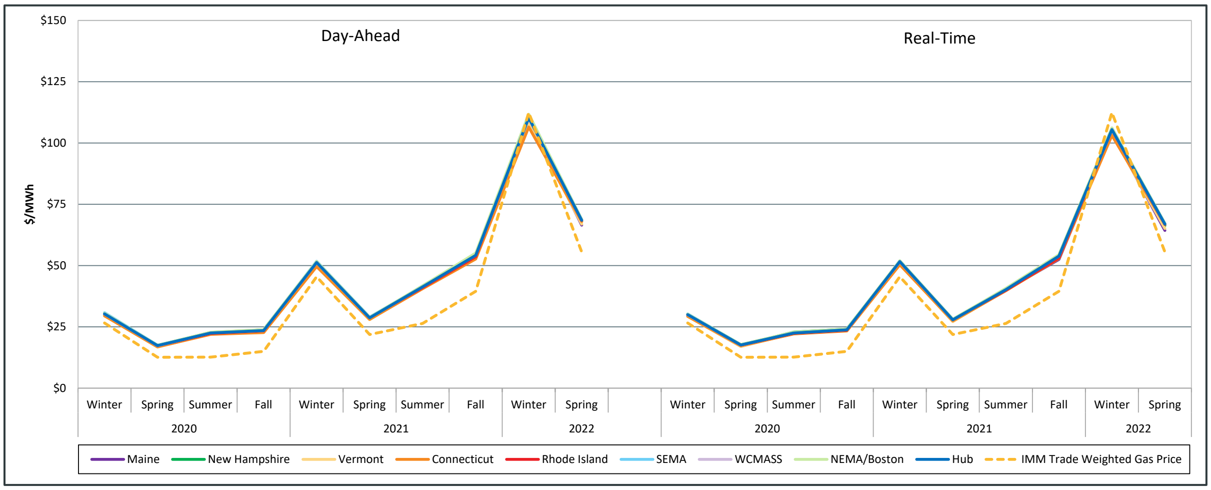


Figure 3-2 illustrates that prices did not differ significantly among the load zones in either market in Spring 2022, indicating that there was relatively little transmission congestion on the system at the zonal level.[17]

3.2 *Real-Time LMPs During System Events In Spring 2022*

Three system events deserve specific mention due to their impact on system operations and market outcomes in Spring 2022. The causes and outcomes of each event are detailed below.

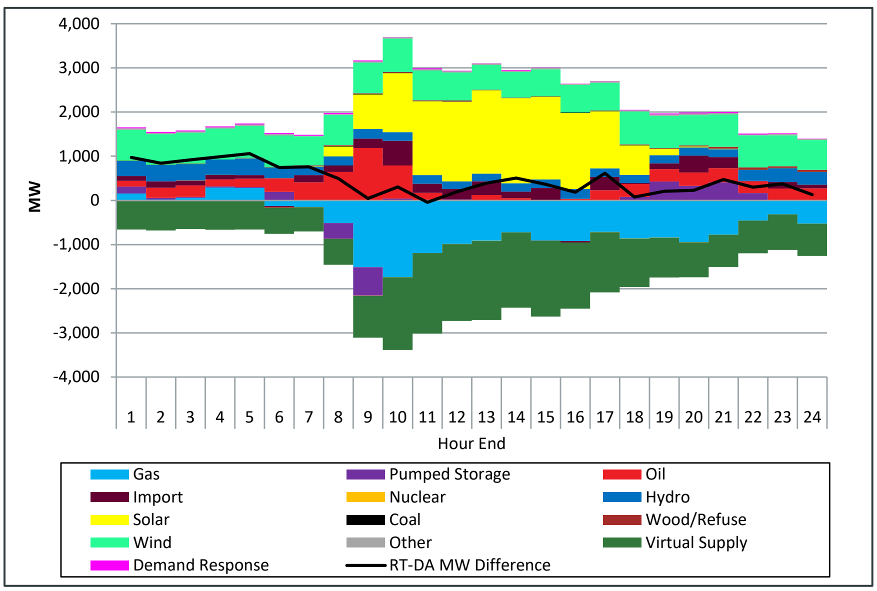
March 29, 2022: Tight System Conditions

- Late in the evening on March 28 and early in the morning on March 29, temperatures were colder than expected and the real-time generation obligation was higher than the day-ahead cleared amount, resulting in pumped-storage generators running over their day-ahead schedules in certain hours. Pumps were dispatched economically according to their bid parameters. By mid-morning on March 29, pumped-storage generators began running out of water after running frequently earlier in the morning, and were not able to fulfill their day-ahead schedules. During HE 08 and HE 09, there was 360-650 MW less pumped-storage generation on the system in real-time compared to the day-ahead cleared amount.

[17] 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.

- Gas pressure issues towards the end to the gas day (early morning hours) resulted in a number of generators being dispatched down to their Economic Minimum levels and producing less than their day-ahead schedules; a total deviation of 300 MW to 870 MW between HE 07 and 13, with peak losses during HE 09 and 10.
- The unplanned gas and pumped-storage generator reductions resulted in tight system conditions. At 6:50, ISO started implementing Pre-OP4 actions to adjust the NYN interface down to its day-ahead value, and to curtail real-time only transactions at non-CTS interfaces. This led to 350 MW of real-time only curtailments on external interfaces in accordance with ISO Operating Procedure #9 during HE 08.[18]
- Operators committed additional offline fast-start generators totaling roughly 1,000 MW of energy during HE 08. They also applied the fast-start reliability (FSR) flag to 32 generators between HE 07 and 09; this flag holds required fast-start generators online by preventing them from receiving a shut-down signal.
- The breakdown in differences between day-ahead and real-time generation obligations is shown in Figure 3-3 below. The stacked area represents the real-time deviations and the black line illustrates the net deviation. The figure illustrates the reduced gas and pumped-storage generation (light blue and purple areas) and increased oil generation (red area) in real-time relative to the day-ahead schedule.

Figure 3-3: Differences Between Real-Time And Day-Ahead Generation Obligations On March 29



- The ISO requested 200 MW in Mutual Reserve Assistance (MRA) from New Brunswick at 07:50. This action provided additional energy for meeting the reserve requirement.
- Hourly real-time prices peaked at $457-$598/MWh during HE 08 and 09. There was ten-minute non-spinning reserve pricing during HE 08-10, and thirty-minute operating reserve pricing during HE 07-10. Hourly reserve prices peaked at $467 during HE 09.

[18] Operating Procedure #9 describes how the ISO schedules and dispatches external transactions. Schedules can be modified or reduced to maintain system reliability. See link for additional details.

https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op9/op9_rto_final.pdf

May 18, 2022: Network Outage

- Beginning around 14:00 on May 18, 2022, a critical hardware malfunction affected the ISO's computer networks. The resulting outage affected the network connectivity of several tools including the standard market design (SMD) applications, email, internal internet, and the ISO's public website. Network connectivity was resolved around 20:00, and power system reliability was not affected. There was no evidence to indicate that the outage was caused by a malicious attack.
- The market software that determines economic dispatch and pricing was also out of service during the network outage. This meant that operators had to commit or dispatch certain generators manually. Additionally, since no LMPs were calculated or published during the outage, the ISO had to reconstitute real-time prices after the event. The last valid real-time market case solution[19] before the outage occurred at 13:50, and the software remained unavailable until 19:35. However, the input data available to the market software was stale until 20:35.
- The ISO reconstituted LMPs associated with the real-time pricing intervals from 13:55-20:35 using established protocols that consider several factors including 1) the market case solutions before and after the event 2) load and reserve margins during the outage, and 3) the offers of fast-start generators that were manually committed during the outage.
- The mitigation software was also out of service during the network outage, but we found no evidence that this exposed the market to the exercise of market power. The outage was unexpected and participants were not able to change their real-time offers due to the unavailability of SMD applications.
- Though there were no system reliability issues, real-time prices were high coming out of the outage. Hourly real-time prices peaked at $353/MWh in HE 21. During this hour, there was less generation from net imports (585 MW) compared to the day-ahead schedule. Scheduling software in neighboring control areas set external transaction amounts during the network outage, and transactions cleared out of merit. About $0.8 million in NCPC payments went to external transactions during HE 16-22. Additional gas generation was needed in real-time, and the TMSR price was $50 during HE 21.

May 21, 2022: Minimum Generation Emergency

- On May 21, the ISO declared a minimum generation emergency event between 12:00 and 14:00. This is a type of abnormal system condition that occurs when the ISO expects that generation and external transactions will exceed system demand, which could result in high system frequencies and unscheduled flows of power into neighboring control areas.[20]
- Heading into the operating day, peak load was expected to be 17,540 MW in the evening, driven by high temperatures. However, actual temperatures were 8-11°F lower than forecasted between HE 12 and HE 19, which led to actual loads 1,151 MW to 1,785 MW under forecast. Hourly forecasted and actual loads are shown in Figure 3-4 below.

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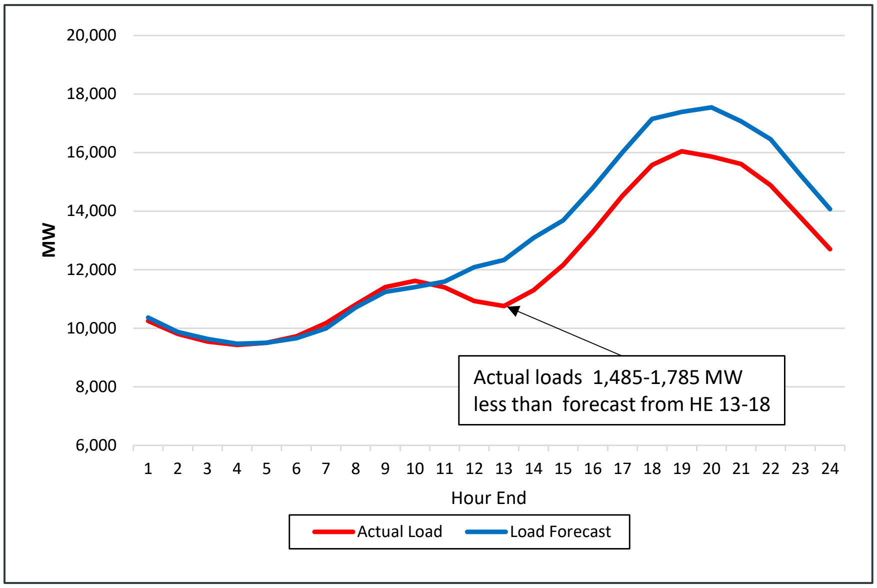
[19] The Unit Dispatch System (or UDS) market case is typically run every 5-20 minutes in real-time. This process determines generator dispatch points, and the prices that flow to the 5-minute LMP calculator.

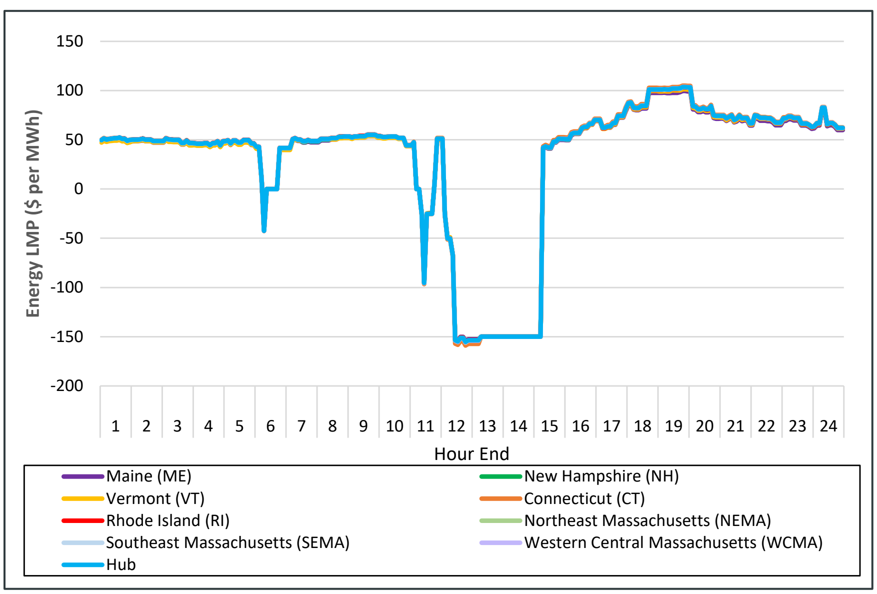
[20] For additional information on minimum generation emergencies, see:
https://www.iso-ne.com/participate/support/faq/minimum-generation-emergency

Figure 3-4: Actual vs. Forecasted OIS Load on May 21



- During the minimum generation emergency, gas generation produced 2,300 to 2,500 MW less in real-time compared to the total day-ahead scheduled amount. The control room reduced transactions across Phase II and Highgate, which led to 500 to 1,200 MW fewer net imports during the event.
- Prices across the system are administratively set at -\$150/MWh during a minimum generation emergency. This occurred for two hours between 12:15 and 14:15. Five-minute real-time Hub prices are shown in Figure 3-5 below.

Figure 3-5: Real-Time Prices On May 21, 2022



- As a result of the administrative pricing, generators and external participants received NCPC to be made whole to their offers. Real-time economic NCPC during the minimum generation emergency totaled \$0.4 million.

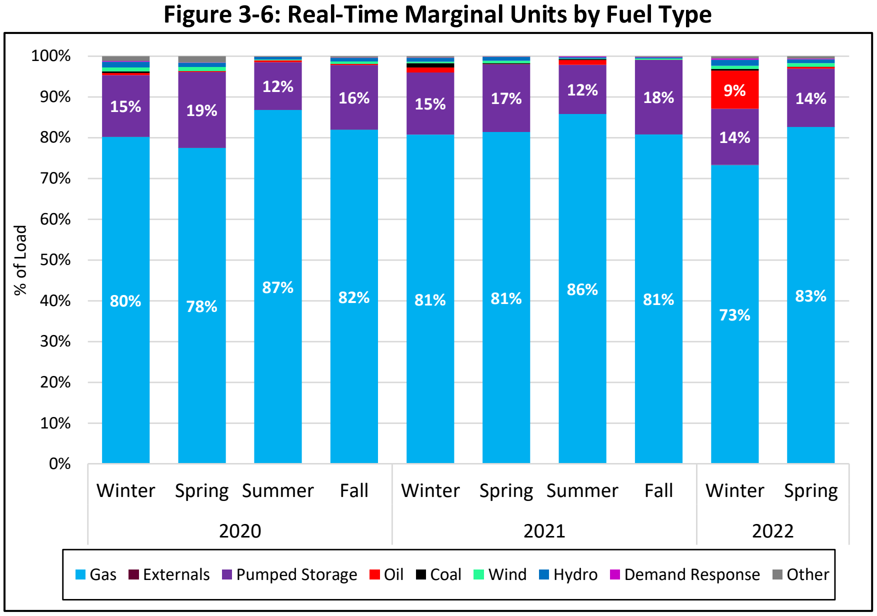
3.3 Marginal Resources and Transactions

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 sets price is termed "marginal". 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 hub 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 and external transactions. By contrast, only physical supply, 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 since Winter 2020 is shown in Figure 3-6 below.[21]

Figure 3-6: Real-Time Marginal Units by Fuel Type



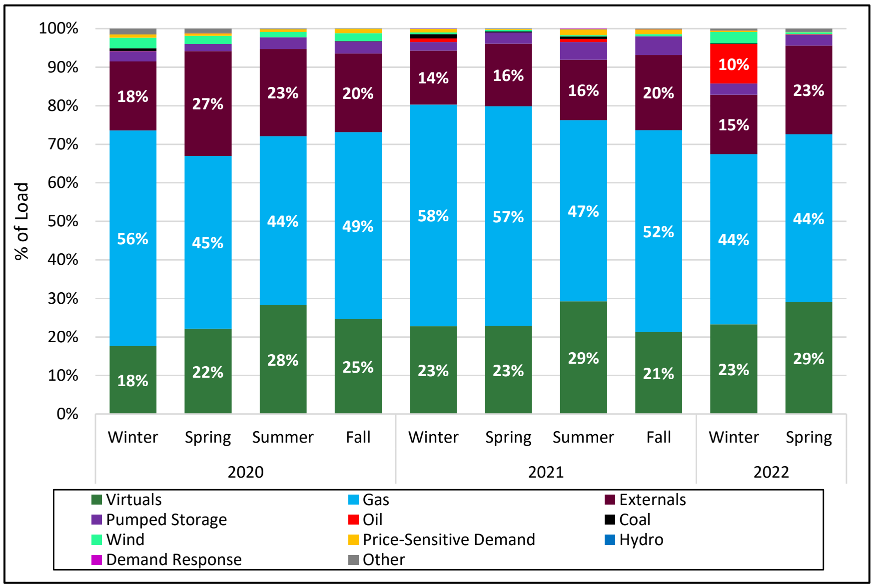
Natural gas-fired generators set price for about 83% of total load in Spring 2022. This is more than in Winter 2022 (73%) and similar to Spring 2021 (81%). While Spring 2022 gas prices were 155% higher than in Spring 2021, they were 50% lower than Winter 2022 prices. High gas prices in Winter 2022 allowed in-merit oil-fired generators to set price for 9% of load. Wind

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

was marginal for 1% of total load in Spring 2022, most of which was located in *local export-constrained areas*, where the impact on the average load price is limited.

The percentage of load for which each transaction type set price in the *day-ahead market* since Winter 2020 is illustrated in Figure 3-7 below.

Figure 3-7: Day-Ahead Marginal Units by Transaction and Fuel Type

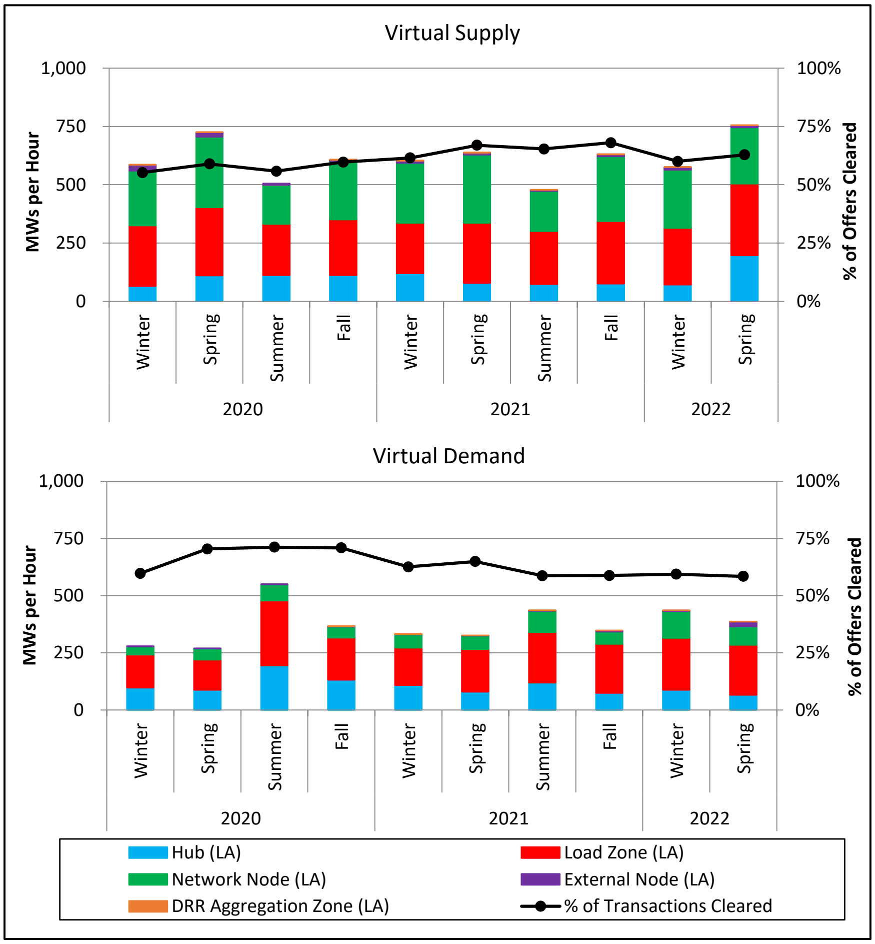


Gas-fired generators were the most common marginal resource type in the day-ahead market, setting price for 44% of total day-ahead load in Spring 2022. Compared to Spring 2021, virtuals and exports set price for 6% and 7% more load, respectively. These types of bids and offers typically cannot set price in the real-time market, and displaced gas on the margin in the day-ahead market. Large, consistent volumes of virtual supply offers by one participant at the Hub led to the increase in virtuals setting price. The offers were frequently priced within $5/MWh of the hub LMP. The increase in marginal externals was driven by increased imports priced around the margin from one participant across multiple interfaces.

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. This indicates virtual transactions 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 3-8 below. Cleared transactions are divided into groups based on the location 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 3-8: Average Hourly Cleared Virtual Transactions and Percentage of Cleared Transactions



In Spring 2022, total cleared virtual transactions averaged approximately 1,141 MW per hour, which was an 18% increase compared Spring 2021 (965 MW per hour) and a 13% increase compared to Winter 2022 (1,011 MW per hour).

Cleared virtual demand amounted to 386 MW per hour on average in Spring 2022, down 11% from Winter 2022 (435 MW per hour) and up 19% from Spring 2021 (326 MW per hour). In Spring 2022, participants cleared 57% (or 218 MW) of virtual demand bids at load zones, 21% (or 81 MW) at network nodes, 17% (or 66 MW) at the Hub, and 6% (or 21 MW) at external nodes. DRR aggregation zones accounted for less than 1% of cleared virtual demand.

Cleared virtual supply totaled 755 MW per hour on average in Spring 2022, up 31% from Winter 2022 (575 MW per hour) and up 18% from Spring 2021 (639 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 Spring 2022, solar SOGs reached an installed capacity of nearly 1,800 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. In Spring 2022, participants cleared 41% (or 308 MW) of virtual supply offers at load zones, 32% (or 241 MW) at network nodes, and 26% (or 197 MW) at the Hub. External nodes and DRR aggregation zones combined to account for just over 1% (or 10 MW) of all cleared virtual supply in Spring 2022.

3.5 Net Commitment Period Compensation

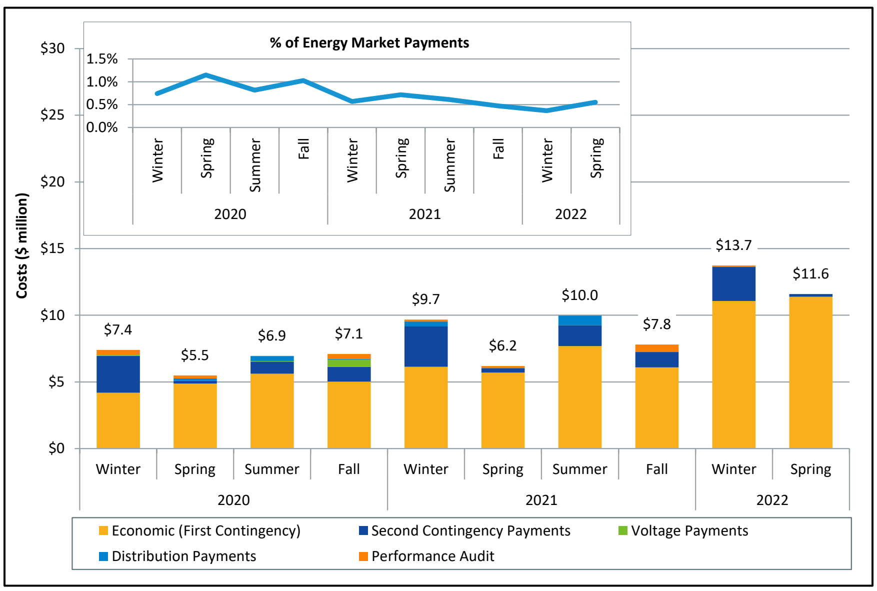
Net Commitment Period Compensation (NCPC), commonly known as uplift, is a make-whole payment resources receive in two circumstances:

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.

This section reports on quarterly uplift payments since Winter 2020. 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.[22]

Payments by season and by uplift category are illustrated below in Figure 3-9. The inset graph shows uplift payments as a percentage of total energy payments.

Figure 3-9: NCPC Payments by Category ($ millions)

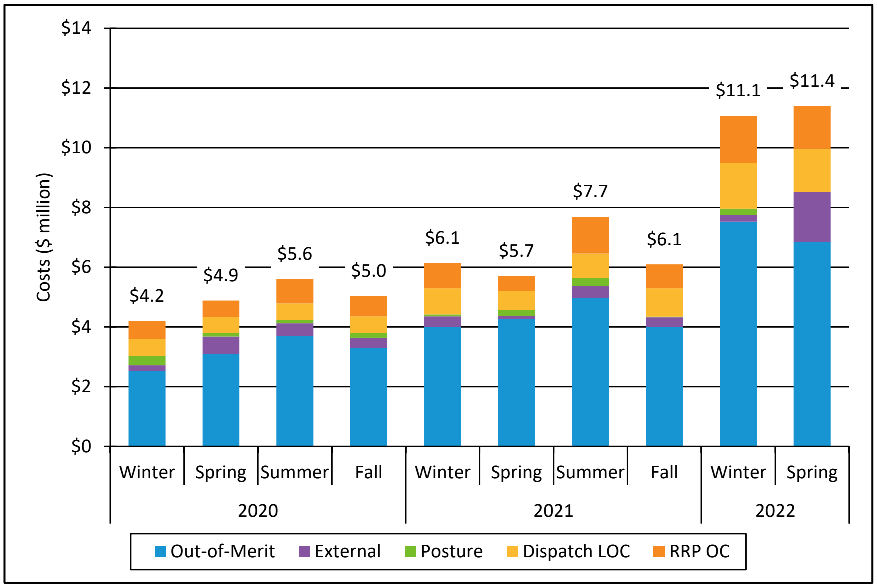


Uplift payments in Spring 2022 totaled $11.6 million, an increase of $5.4 million, or 87%, compared to Spring 2021. Economic payments comprised approximately 98% of total payments and accounted for all of the increase. Despite the large increase, total uplift payments as a percentage of energy payments in Spring 2022 remained low at 0.6% (a slight decrease from 0.7% in Spring 2021). Uplift payments are generally correlated to energy payments–as fuel prices increase, LMPS, generator costs, and energy payments increase.

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

Economic uplift includes payments made to generators whose costs exceed revenue when committed or dispatched to maintain total-system reliability (out-of-merit NCPC), as well as generators that incur an opportunity cost by operating at an ISO-instructed dispatch point below their economic dispatch point (external, posture, dispatch lost opportunity cost, and rapid response pricing opportunity cost NCPC). Figure 3-10 below shows economic payments by category.

Figure 3-10: Economic Uplift by Sub-Category



As illustrated in Figure 3-10, out-of-merit payments continue to make up the majority of economic uplift, representing 60% of these payments.[23] Out-of-merit payments increased by 61% from $4.26 million to $6.85 million between Spring 2021 and Spring 2022, driven by an increase in fuel prices. Spring 2022 external payments were the highest in the study period.

In the day-ahead market, virtual and external transactions can be scheduled to relieve congestion at an external interface. Day-ahead external NCPC accounted for almost $0.3 million in external payments during Spring 2022. At the beginning of March, a planned transmission outage lowered the transfer capability at the New York/New England interface. This limitation also affected the capability of several other interfaces. A combination of virtual and external transactions were cleared at non-New York North interfaces to alleviate congestion and lower the net interchange of that interface to its capability. These counterflow transactions were paid uplift to their offer prices.

In the real-time market, external transactions are scheduled based on ISO-forecasted prices but the transactions are settled based on actual prices. Uplift is paid to external transactions that end up being out-of-rate (based on actual prices) to make them whole to their bid or offer.[24] Real-time external NCPC accounted for almost $1.4 million in external

[23] Out-of-merit payments 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).

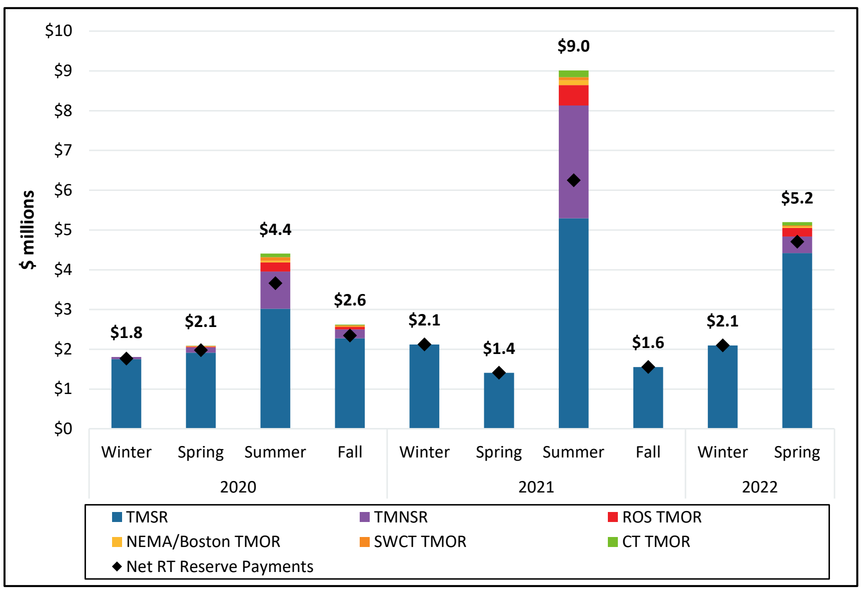
[24] External transactions at the CTS interface (Roseton) are not eligible for this form of NCPC.

payments in Spring 2022. Over a four-day period in mid-April, planned transmission maintenance in Maine contributed to congestion, resulting in negative real-time prices at the New Brunswick external interface. Transactions over this interface that were scheduled in-merit according to the ISO-forecasted price but then fell out-of-merit due to negative actual prices were paid uplift to their bid or offer. In addition, during an unplanned network outage on May 18 from HE 14 to HE 21, the neighboring control areas scheduled and dispatched external transactions. This led to external transactions from Canada clearing out-of-merit and receiving approximately $0.8 million in uplift.[25]

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 adequate capacity is available during such contingencies, the ISO procures reserve products through the locational Forward Reserve Market 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 3-11 below.

Figure 3-11: Real-Time Reserve Payments by Product and Zone



Gross real-time reserve payments totaled $5.2 million in Spring 2022 up from $1.4 million in Spring 2021. The 268% increase in gross reserve payments was driven primarily by two factors. First, gas prices increased 155%, from $2.80/MMBtu in Spring 2021 to $7.14/MMBtu in Spring 2022. High gas prices led to higher energy prices, which increased the re-dispatch costs of energy in Spring 2022.

Second, there were just under three hours of non-spinning reserve pricing on March 29, with average non-zero prices of $290/MWh (TMNSR) and $193/MWh (TMOR). The high prices were

[25] These external credits are expected to be clawed back in the next re-settlement period and will be updated in future reports.

due to morning fuel supply issues at gas-fired and pumped-storage generators. This led to tight total 10-minute and total 30-minute reserve margins. The total 10-minute margin was negative in the pricing run for 30 minutes, which triggered the replacement reserve constraint penalty factor price of $250/MWh. Section 3.2 discusses March 29 outcomes in more detail.

Net real-time reserve payments, which are either equal to or lower than gross payments, include a reduction for generators designated to satisfy forward reserve obligations, so that a generator is not paid twice for the same service. Due to the claw backs for TMNSR and TMOR payments on March 29, net real-time reserve payments were $4.7 million, $0.5 million less than gross payments.

The frequency of non-zero reserve pricing by product and zone along with the average price during these intervals for the past three spring seasons is provided in Table 3-1 below.[26]

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

Product	Zone	Spring 2022		Spring 2021		Spring 2020	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	**System**	$16.98	405.8	$7.85	325.0	$6.19	489.7
TMNSR	**System**	$290.32	3.0	$0.00	0.0	$59.79	2.3
TMOR	**System**	$193.40	1.9	$0.00	0.0	$80.66	0.6
TMOR	**NEMA/Boston**	$193.40	1.9	$0.00	0.0	$80.66	0.6
TMOR	**CT**	$193.40	1.9	$0.00	0.0	$80.66	0.6
TMOR	**SWCT**	$193.40	1.9	$0.00	0.0	$80.66	0.6

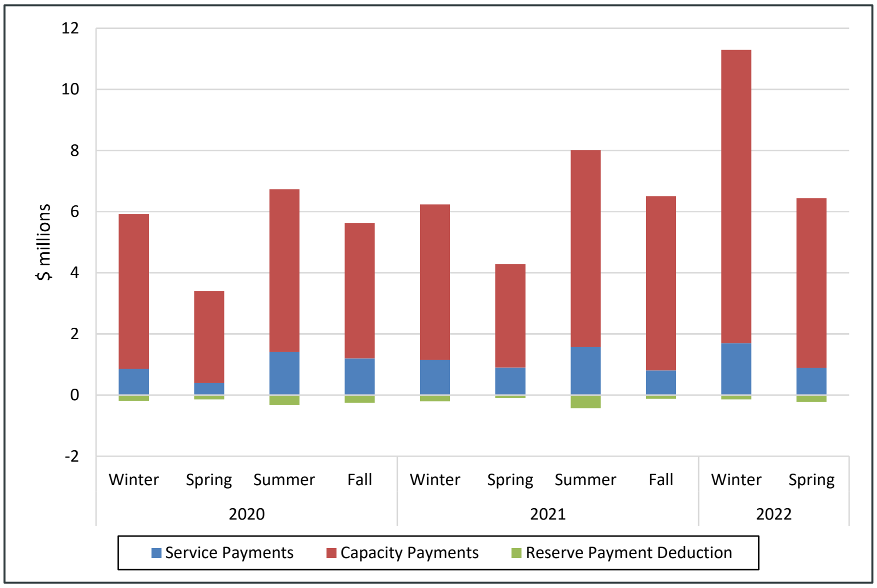
The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 406 hours (18% of total hours) during Spring 2022. In the hours when the TMSR price was above zero, the price averaged $16.98/MWh, an increase consistent with high energy prices in Spring 2022 compared to Spring 2021. As described above, TMNSR (three hours) and TMOR (two hours) pricing occurred on March 29. These prices were higher than the non-spinning prices in Spring 2020, when energy and gas prices were lower.

[26] 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.

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 3-12 below.

Figure 3-12: Regulation Payments ($ millions)



Total regulation market payments were $6.2 million during the reporting period, down approximately 44% from $11.2 million in Winter 2022, and up by 48% from $4.2 million in Spring 2021. The change in overall regulation payments relative to the earlier periods is largely explained by changes in regulation capacity prices and payments. Regulation capacity prices are affected by real-time energy market LMPs, through the inclusion of energy market opportunity costs in regulation capacity payments. Real-time energy market LMPs for Spring 2022 declined by 37% relative to Winter 2022 and increased by 140% relative to Spring 2021.

Section 4
Energy Market Competitiveness

One of ISO New England's three critical goals is to administer competitive wholesale energy markets. Competitive markets help ensure that consumers pay fair prices and incentivize generators to make short- and long-run investments that preserve system reliability. Section 4.1 evaluates energy market competitiveness at the quarterly level. First, this section presents two metrics on system-wide structural market power. Next, the section provides statistics on system and local market power flagged by the automated mitigation system. We also discuss the amount of actual mitigation applied for instances where supply offers were replaced by the IMM's reference levels.

4.1 Pivotal Supplier and Residual Supply Indices

This analysis examines opportunities for participants to exercise market power in the real-time energy market using two metrics: 1) the pivotal supplier test (PST) and 2) the residual supply index (RSI). Both of these widely-used metrics identify instances when the largest supplier has market power.[27] The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier would be needed to meet demand, and could exercise market power if permitted. Further, if the RSI is less than 100, there is one or more pivotal suppliers. 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[28] to the sum of each participant's total supply that is available within 30 minutes.[29] When a participant's available supply exceeds the supply margin, they are 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.

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

[27] Many resources in New England are owned by companies that are subsidiaries of larger firms. Consequently, tests for market power are conducted at the parent company level.

[28] The real-time supply margin measures the amount of available supply on the system after load and the reserve requirement are satisfied. It accounts for ramp constraints and is equal to the Total30 reserve margin: Gen_{Energy} + $Gen_{Reserves}$ + [*Net Interchange*] -*Demand* - [*Reserve Requirement*]

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

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

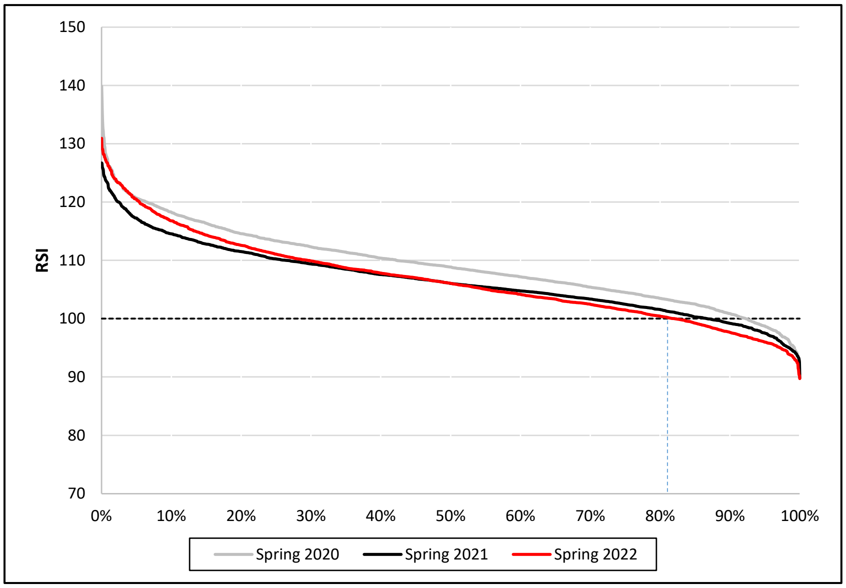
Quarter	RSI	% of Intervals With At Least 1 Pivotal Supplier
Winter 2020	108.6	8%
Spring 2020	109.2	8%
Summer 2020	104.8	27%
Fall 2020	105.1	24%
Winter 2021	107.9	8%
Spring 2021	106.6	14%
Summer 2021	104.7	27%
Fall 2021	105.0	24%
Winter 2022	106.5	12%
Spring 2022	106.7	19%

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 in recent quarters, ranging from 8% to 27%. The high RSI values and the low frequency of pivotal suppliers indicate that there were limited opportunities for any one supplier to exercise market power over the last ten quarters.

Spring 2022 saw a slightly higher frequency of pivotal suppliers (19%) compared to the two previous spring seasons (14% and 8%). The small increase was due to lower non-spinning reserve margins that resulted from several factors, including slightly higher loads, more generation out of service, and more notable system events in Spring 2022 compared to 2021.

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 Spring 2022, the RSI was lower than in Spring 2021 during about 50% of hours. The Spring 2020 RSI was higher across almost all ranked observations compared to Spring 2021 and 2022, likely due to lower loads associated with the start of the COVID-19 pandemic in March and April 2020.

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.[30] 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.[31] These circumstances are summarized in Table 4-2 below.

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

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

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.[32] 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).
- *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).[33] 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).[34] 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 in constrained areas or associated with pivotal suppliers

[32] 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.

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

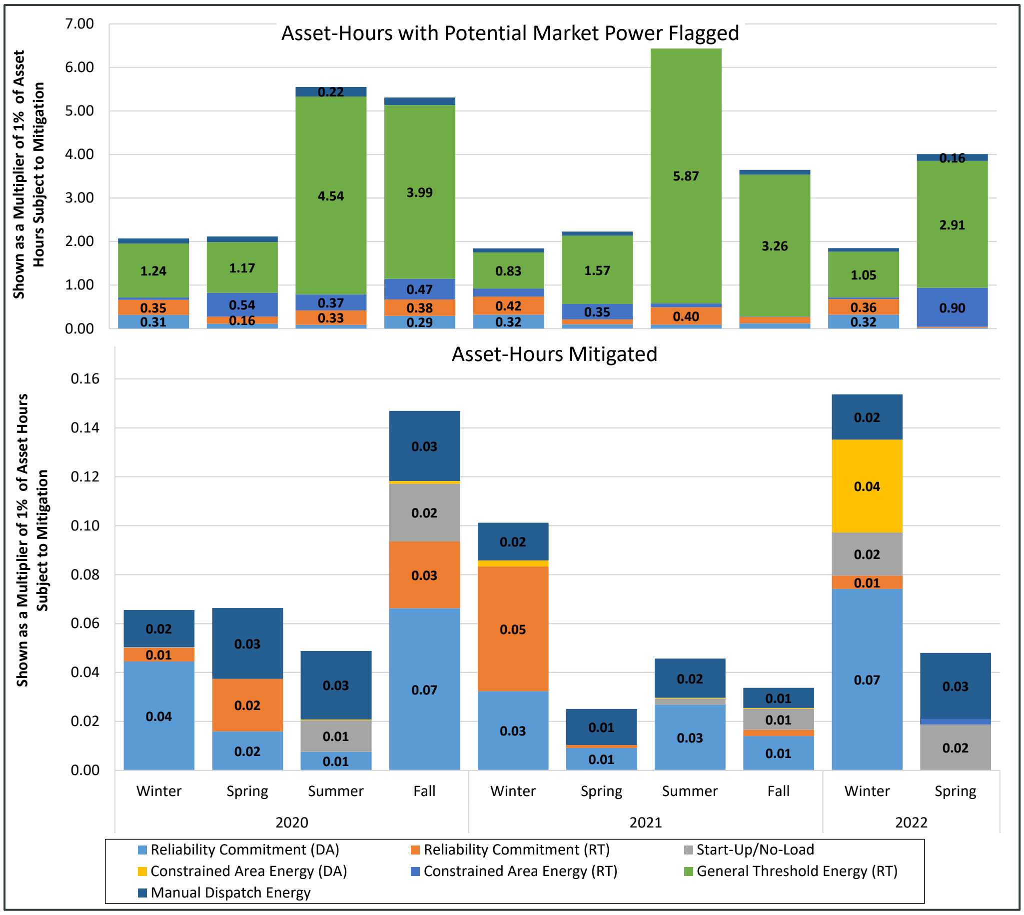
[34] For a description of the application of these mitigation criteria (tests), see Appendix A, Section III.A.5.

(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 by comparing asset-hours of structural test failures, of dispatch or of commitment (depending on mitigation type) against asset-hours of mitigations is illustrated in Figure 4-2 below.[35]

[35] 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, SUNL commitment hours are not shown because mitigation hours equal commitment hours.

Figure 4-2: Energy Market Mitigation[36]



In general, the data in Figure 4-2 indicate that mitigation occurs very infrequently relative to the initial triggers for potential mitigation (i.e., structural test failures, commitment or dispatch). The highest frequency of mitigation during the review period occurred for reliability commitments; 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 types 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).[37] These commitments

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[36] 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.

[37] This mitigation category applies to most types of "out-of-merit" commitments, including local first contingency, local second contingency, voltage, distribution, dual-fuel resource auditing, and any manual commitment needed for a reason other than meeting system load and operating reserve constraints. See Market Rule 1, Appendix A, Section III.A.5.5.6.1.

frequently reflect the reliability needs associated with transmission line outages and upgrades, as well as very localized distribution system support. Over the review period, Southeastern Massachusetts/Rhode Island (SEMA-RI) and Maine had the highest frequency of reliability commitment asset-hours, 51% and 30% respectively in the day-ahead energy market. This is consistent with transmission upgrades that occurred in SEMA-RI over the past several years, and with the frequency of localized transmission issues within Maine. Reliability commitment mitigations also occurred most frequently in SEMA-RI and Maine: 55% of mitigations occurred in SEMA-RI and 17% occurred in Maine in the day-ahead market.[38] Overall, reliability mitigations decreased significantly between Spring 2021 (29 asset-hours) and Spring 2022 (0 asset-hours). This decline is consistent with a sizable decline in reliability commitment asset-hours, which went from 327 to 67 asset-hours between Spring 2021 and Spring 2022.

Start-up and no-load commitment mitigation: This mitigation type, like reliability commitment, 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 and no-load 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 start-up and no-load costs (relative to reference values). 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 three participants accounted for 94% of these mitigations. There were 64 asset-hours of start-up and no-load mitigation in Spring 2022. This is a slight increase over Winter 2022, when 59 asset-hours of mitigation occurred; no instances of start-up and no-load mitigation occurred in Spring 2021.

Constrained area energy (CAE) mitigation:[39] 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) has been approximately 0% (of structural test failure asset-hours) over the review period, as only eight asset-hours of CAE mitigation have occurred in the real-time energy market and only 141 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. The structural test failures have been spread throughout New England, with 22% in Connecticut, 29% in SEMA-RI, 16% in Western and Central Massachusetts, and 7% to 11% frequency occurring in the other load zones. In Spring 2022, there were a large number of structural test failures (3,066 asset-hours) in the real-time market (an increase of 172% compared to Spring 2021), but there were only eight asset-hours of constrained area energy mitigation. The large number of structural test failures resulted primarily from transmission work that resulted in a large number of generators being on the import-constrained side of a transmission constraint. While the constraint did not frequently bind and resulted in modest congestion, it led to a significant increase in asset-hours of structural test failures, because of the large number of generators

[38] 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.

[39] 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.

that were affected. These structural test failures were spread throughout New England, with 88% of the occurrences in CT, NEMA-Boston, SEMA-RI, and Western and Central Massachusetts. In the day-ahead market for Spring 2022, there were no instances of CAE mitigation.

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 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 the structural test failures and four participants accounted for 79% of structural test failures over the review period. The frequency of pivotal supplier asset-hours increased in Spring 2022 (by 4,969 asset hours or 100%), compared to Spring 2021. This change is directionally consistent with the factors noted in section 4.1.[40] Spring 2022 experienced higher load levels and more out-of-service generation (compared to Spring 2021), leading to increased instances of pivotal suppliers. These factors reduced supply margins (i.e., excess supply available to satisfy demand), and resulted in more instances of suppliers with larger generation portfolios being flagged as pivotal for meeting system demand.

Manual dispatch energy mitigation: Manual dispatch energy mitigation occurs when a generator is manually dispatched by the ISO. Behind reliability commitment mitigation, this mitigation type occurs with the second highest frequency of any mitigation type (accounting for 27% of mitigations over the review period). Like reliability commitment mitigation, manual dispatch energy mitigation has a relatively tight conduct test threshold (10%). Manual dispatch is relatively infrequent in the real-time energy market, with just a few hundred asset-hours occurring each quarter. Combined-cycle generators have the highest frequency of manual dispatch; this is consistent with manual dispatch frequently occurring in the context of (1) regulation service provided to the real-time energy market and (2) the need for relatively flexible generators to be positioned away from the market software-determined dispatch to address short-term issues on the transmission grid. In Spring 2022, there were 536 asset-hours of manual dispatch and 92 asset-hours of mitigation. Spring 2021 experienced fewer asset-hours of manual dispatch (295) and fewer asset-hours of manual dispatch mitigation (47). For Winter 2022, manual dispatch asset-hours (267 asset-hours) and mitigations (62 asset-hours) also were lower than for Spring 2022.

[40] 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 Summer 2022 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.[41] 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.[42] Between the initial auction and the commitment period, there are further opportunities to shed or take on Capacity Supply Obligations (CSOs) through annual and monthly reconfiguration auctions. Formerly, three of the annual auctions were bilateral auctions, where obligations were traded between resources at an agreed upon price and approved by the ISO. The other three were annual reconfiguration auctions run by the ISO, where participants submitted supply offers to take on obligations, or submitted demand bids to shed obligations. After June 1, 2019, the annual bilateral auctions were replaced with the incorporation of Annual Reconfiguration Transactions (ARTs) into the remaining three annual reconfiguration auctions.

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 reconfiguration auctions, participants can acquire or shed obligations. 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 current capacity commitment period (CCP) started on June 1, 2021 and ends on May 31, 2022. The conclusion of the corresponding Forward Capacity Auction (FCA 12) resulted in a lower clearing price than the previous auction while obtaining sufficient resources needed to meet forecasted demand. The auction procured 34,828 megawatts (MW) of capacity, which exceeded the 33,725 MW Net Installed Capacity Requirement (Net ICR), at a clearing price of $4.63/kW-month. The clearing price of $4.63/kW-month was 13% lower than the previous capacity period's $5.30/kW-month; two generators were retained for reliability in FCA 12, putting downward pressure on the clearing price as their 1,278 MW of capacity was entered into the auction at $0.00/kW-month. The $4.63/kW-month clearing price was applied to all

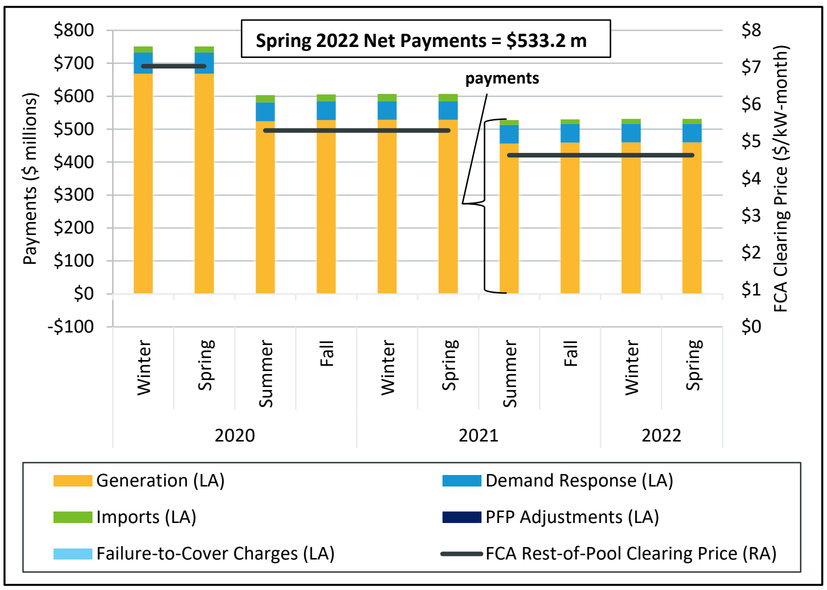
[41] In the capacity market, resource categories include generation, demand response and imports.

[42] 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.

capacity zones within New England. Price separation occurred at two import interfaces, Phase I/II and New Brunswick, with final clearing prices of $3.70/kW-month and $3.16/kW-month, respectively. The results of FCA 12 led to an estimated total annual cost of $2.02 billion in capacity payments, $0.40 billion lower than capacity payments incurred in FCA 11.

Total FCM payments, as well as the clearing prices for Winter 2020 through Spring 2022, are shown in Figure 5-1 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively. The dark blue bar represents Pay-for-Performance adjustments, while the light blue bar represents Failure-to-Cover charges.

Figure 5-1: Capacity Payments



Total net FCM payments in Spring 2022 decreased from one year ago, reaching a total of $533.2 million (accounting for adjustments to primary auction CSOs).[43] The 13% decrease in capacity clearing price ($5.30/kW-month in Spring 2021 to $4.63/kW-month in Spring 2022) contributed to the lower FCM payments.

In Spring 2022, there were just over $0.2 million in Failure-to-Cover (FTC) charges. The FTC charge is a negative adjustment to the FCM credit that 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.

Secondary auctions allow participants the opportunity to acquire or shed capacity after the initial auction. A summary of prices and volumes associated with the reconfiguration auction and bilateral trading activity during Spring 2022 alongside the results of the relevant primary FCA are detailed in Table 5-1 below.

[43] Adjustments include annual reconfiguration auctions, annual bilateral periods, monthly reconfiguration auctions, monthly bilateral periods, performance and availability activities, and reliability payments.

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

FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)*	Cleared MW	Capacity Zone/Interface Prices ($/kW-mo)		
					Phase I/II	Highgate	New Brunswick
FCA 12 (2021-2022)	Primary	12-month	4.63	34,828	3.70		3.16
	Monthly Reconfiguration	May-22	0.63	942		0.50	0.50
	Monthly Bilateral	May-22	1.64	4			
FCA 13 (2022 - 2023)	Primary	12-month	3.80	34,839			
	Annual Reconfiguration (3)	12-month	0.40	77/1035**			
	Monthly Reconfiguration	Jun-22	0.50	461			
	Monthly Bilateral	Jun-22	1.46	74			
	Monthly Reconfiguration	Jul-22	0.60	557			
	Monthly Bilateral	Jul-22	0.91	174			

**bilateral prices represent volume weighted average prices*

***represents cleared supply/demand*

One annual reconfiguration auction took place in Spring 2022: the third annual reconfiguration auction for CCP 2022-2023. The auction cleared at $0.40/kW-month, well below the FCA clearing price of $3.80/kW-month for CCP 13 (2022-2023). In total, 77 MW of supply cleared against 1,035 MW of cleared demand. The over-clearing of demand led to 958 MW of capacity leaving the system for CCP 13 (2022-2023) and was prompted by a 6% (2,160 MW) decrease in Net ICR from FCA 13 to ARA 3.[44]

Three monthly reconfiguration auctions (MRAs) took place in Spring 2022: the May 2022 auction in March, the June 2022 auction in April, and the July 2022 auction in May. Clearing prices remained relatively constant over the three months with all MRAs clearing between $0.50 and $0.63/kW-month. From May 2022 to June 2022, cleared MW decreased significantly from 942 MW to 461 MW. June marks the beginning of the summer period in the forward capacity market; gas- and oil-fired resources are awarded less qualified capacity in these months due to higher ambient air temperatures. With less qualified capacity available to fossil-fuel resources in the summer, MRA cleared MW volumes tend to decrease as well.

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

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

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:[45]

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

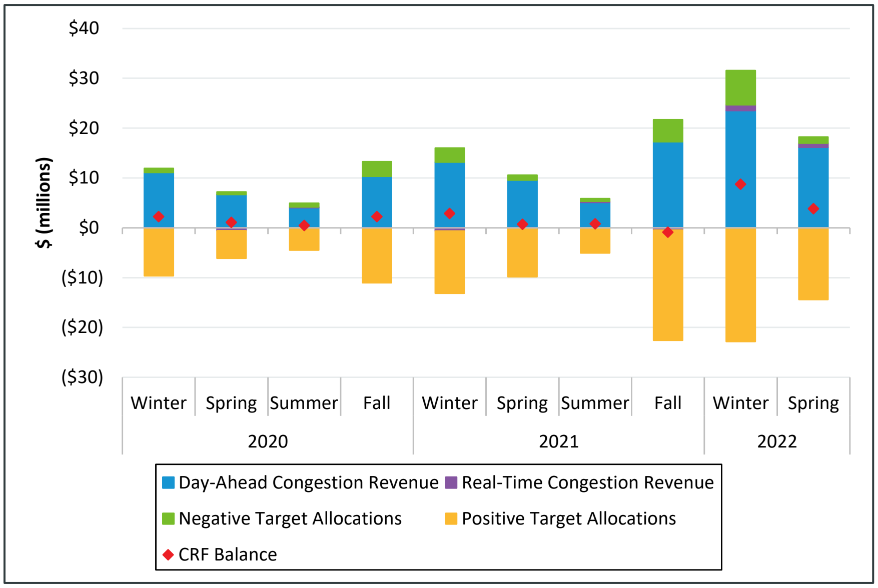
If the revenue collected from these three sources in a month exceeds the payments to the holders of FTRs with positive target allocations in that month, the excess revenue carries over to the end of the calendar year. However, there is not always sufficient revenue collected from these three sources 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.[46] 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.

[45] 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.

[46] 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: Congestion Revenue and Target Allocations by Quarter



FTRs in March 2022, April 2022, and May 2022 were fully funded. Positive target allocations amounted to $14.4 million in Spring 2022. This represents a decrease of 37% relative to Winter 2022 ($22.8 million) and an increase of 50% relative to Spring 2021 ($9.6 million). Day-ahead congestion revenue in Spring 2022 ($16.2 million) followed a similar pattern, decreasing by 31% relative to Winter 2022 ($23.5 million) and increasing by 69% from Spring 2021 ($9.6 million). Negative target allocations in Spring 2022 ($1.3 million) decreased significantly from their value in Winter 2022 ($6.9 million), largely as a result of reduced congestion associated with the New England West-East interface constraint. However, negative target allocations were 28% higher than their Spring 2021 level ($1.0 million). Real-time congestion revenue was $0.8 million in Spring 2022, which is around 32% lower than Winter 2022 ($1.1 million). The real-time congestion revenue was in the opposite direction of the Spring 2021 value (-$0.3 million).[47]

At the end of May 2022, there was a congestion revenue fund surplus of $7.3 million for 2022. 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 those entities that paid congestion costs during the year.

[47] Real-time congestion revenue can be positive or negative because it is dependent on deviations from day-ahead schedules.

5.3 Forward Reserve Market

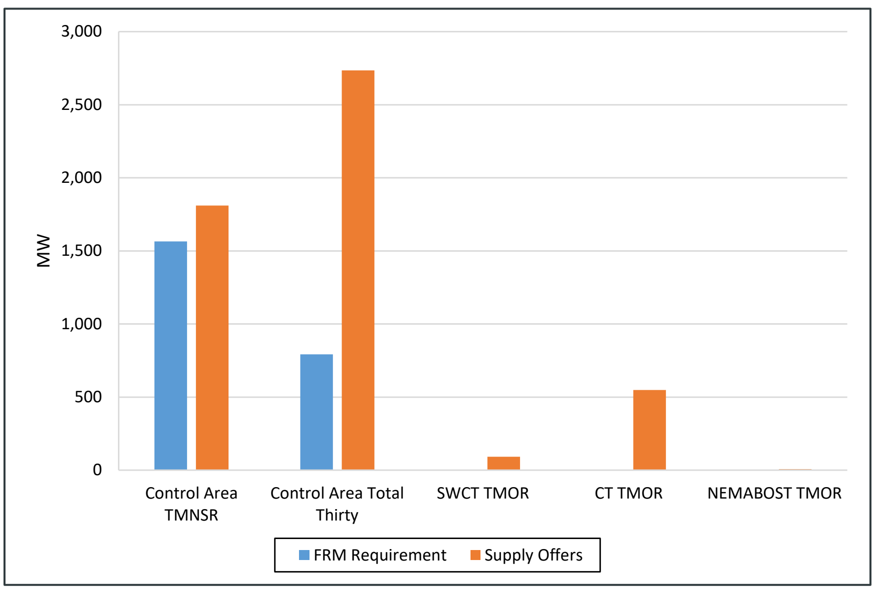
Twice each year, ISO New England holds forward reserve auctions. The ISO uses forward reserve auctions to enter into forward obligations with participants to provide operating reserves in the real-time energy market. These forward obligations are intended to ensure the delivery of adequate operating reserves for both the ISO New England system-wide and local reserve zones. During April 2022, the ISO held the forward reserve auction for the Summer 2022 delivery period (i.e., June 1, 2022 to September 30, 2022).[48]

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 Summer 2022 auction are illustrated in Figure 5-3. These requirements were specified for the ISO New England system and three local reserve zones.[49] The figure also illustrates the total quantity of supply offers available in the auction to satisfy the reserve needs.[50]

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



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

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

[50] Because thirty-minute operating reserve (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

For the system, requirements were set for two reserve products: ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR).[51] 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 1,564 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 a 792 MW TMOR need; the total thirty-minute requirement (depicted in the figure) is the sum of the TMNSR and incremental TMOR requirements (i.e., 1,564 + 792).[52] Supplies were 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).[53] 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.

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.

[51] ISO New England Memorandum to Market Participants (Subject: Assumptions and Other Information for the Summer 2022 Forward Reserve Auction), published March 17, 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.

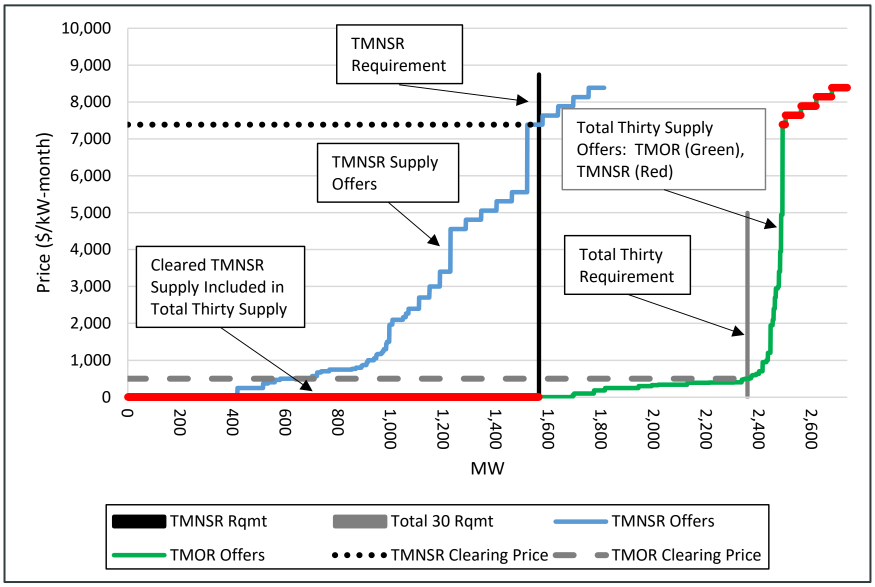
[52] The system TMOR requirement indicated in the ISO's auction assumptions represents an incremental requirement, in excess of the TMNSR requirement. The *total* thirty minute requirement for the auction is the sum of the TMNSR requirement and the system (incremental) TMOR requirement.

[53] 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).

5.3.2 System Supply and Auction Pricing

As noted previously, system-wide supply offers in the Summer 2022 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 system-wide total thirty minute reserves.

Figure 5-4: Requirements and Supply Curves, System-wide TMOR & TMNSR



With system-wide requirements of 1,564 MW for TMNSR and 2,356 MW for total thirty, system-wide supply offers for the two products resulted in clearing prices of $7,386/MW-month for TMNSR and $499/MW-month for total thirty (black and gray dotted/dashed lines in the figure). (The TMNSR and TMOR clearing prices are discussed in the next subsection.) 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.

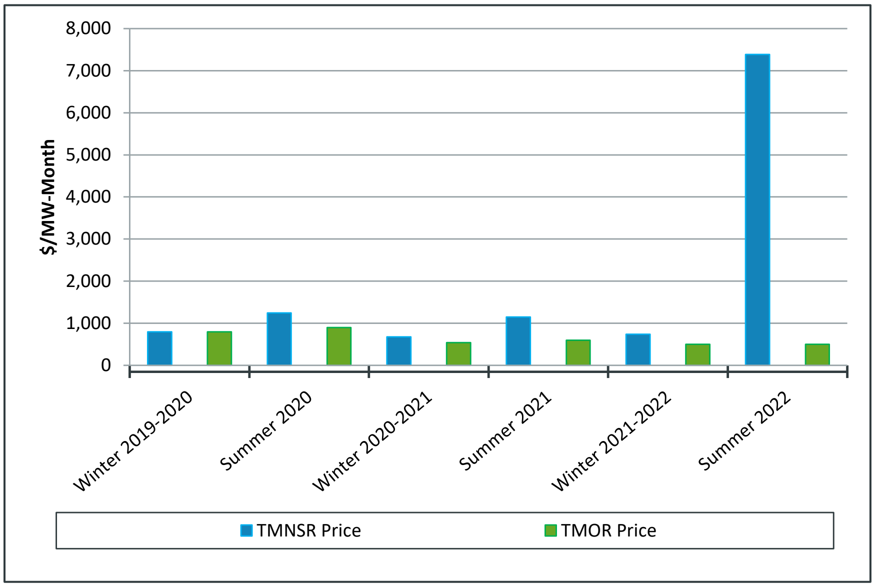
While TMNSR supply can be used to meet thirty-minute reserve needs, thirty-minute supply offers – as a lower-quality product – cannot be used to meet TMNSR needs. Given that, TMNSR supply is shown relative to the TMNSR requirement; all TMNSR and TMOR supply then can be used to meet the total thirty-minute 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 Figure 5-4). The remaining uncleared TMNSR supply and TMOR supply determine the pricing for meeting the total thirty-minute requirement.[54]

[54] The TMNSR supply that clears to meet the TMNSR requirement effectively reduces the total thirty requirement to the incremental TMOR requirement (i.e., 792 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

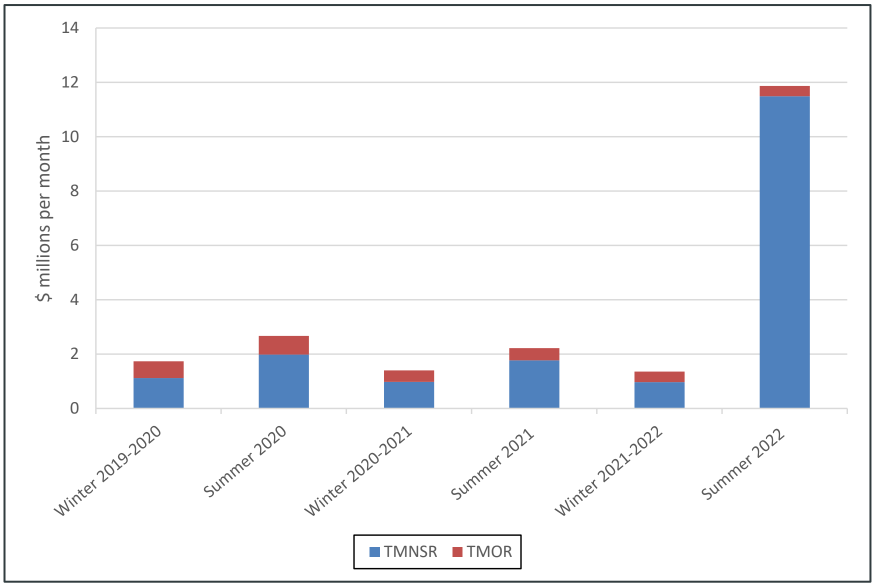


In the Summer 2022 auction, TMNSR cleared at a higher price than TMOR; the TMNSR price was $7,386/MW-month and the TMOR price was $499/MW-month. The Summer 2022 clearing price for TMOR was at the same level as the preceding Winter 2021-2022 TMOR clearing price. Compared to the Summer 2021 auction, TMOR prices declined by 17% from $600/MW-month to $499/MW-month. The decline resulted primarily from lower TMOR offers, as the total thirty requirement between the auctions differed by only eight MWs.

The TMNSR prices in Summer 2022 increased significantly, compared to the earlier auctions. This increase reflects a significant increase in TMNSR offer prices. While pricing for the first 900 MW of TMNSR supply did not change appreciably compared to Summer 2021, supply offer pricing above that point on the supply curve increased by as much as 540%.

The increase in TMNSR clearing price for the Summer 2022 auction also significantly increases the gross FRM payments, compared to earlier auctions. Figure 5-6 indicates the monthly gross payments (i.e., excluding penalties) provided 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. 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 minute reserves follows the same formulation, considering offered total thirty supply, the largest total thirty supplier, and the total thirty requirement.[55]

The heat map table –Table 5-2 below – shows the offer RSI for system-wide TMNSR, system-wide total thirty, and local zone 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 TMNSR (system-wide) and TMOR (zones)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI Total Thirty (System-wide)	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Winter 2019-20	120	118	N/A	N/A	N/A
Summer 2020	84	97	N/A	N/A	N/A
Winter 2020-21	102	115	N/A	N/A	N/A
Summer 2021	92	108	N/A	N/A	N/A
Winter 2021-22	110	116	N/A	N/A	N/A
Summer 2022	78	90	N/A	N/A	N/A

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 Summer periods, the TMNSR RSI values were less than 100, indicating that these auctions were structurally uncompetitive. For the Summer 2022 auction, the requirement did not change significantly from the prior summer auction, but supply in the auction did decline by approximately 800 MW; the change in supply resulted in the decline in the RSI. The Summer 2020 results had an increased requirement (up an additional 4% compared to Summer 2019), coupled with a small net reduction in supply offers (approximately 2% compared to the prior Summer), resulting in the RSI below 100. The Summer 2021 RSI improved somewhat compared to the Summer 2020 RSI, with a small increase in supply and a small reduction in requirement. The Winter auctions all had RSIs greater than 100, and were structurally competitive.

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

[55] Starting with this report, the reported total thirty (TMOR) RSI values are being 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.

resulted in the RSI decline, compared to Summer 2021. The decline in total thirty supply in Summer 2022 was the result of numerous supply offer changes (both increases and reductions in supply) compared to the prior summer auction.

Because the local reserve zones did not have a local FRM reserve requirement in the auctions covered by this report, an RSI is not applicable at the local level.

5.3.5 Auction Competitiveness

As noted in the prior subsection of this report, the Summer 2022 auction for the TMNSR product was not structurally competitive.

The FRM is not subject to offer price mitigation and it is often structurally uncompetitive, i.e., demand is fixed and supply is limited. However, the IMM reviews each auction to assess whether the auction results are consistent with the results we would expect from a competitive process i.e., did participants that had marker power make competitive offers that reflected their anticipated costs?

In evaluating the competitiveness of this auction, we reviewed potential physical and economic withholding and found no evidence of the exercise of market power.

- Bid in supply was consistent with prior auctions including auctions when there was no pivotal supplier.
- Offer prices appeared to reflect a plausible range of anticipated costs of providing the service. Note, offer prices can vary significantly depending on the participant generation portfolio and expectation of market conditions. The FRM auction offer cap (set at $9,000/MW-month) suggests that a large range of auction offers may fall within a reasonable range. The reasonableness of auction offers depends on factors such as expectations about reserve revenue (which is sensitive to the likelihood of incurring reserve constraint penalty factor reserve pricing), foregone energy market net revenue, and the likelihood of incurring FRM failure-to-reserve and failure-to-activate penalties.[56]

[56] See the testimony of Christopher Parent to the Federal Energy Regulatory Commission, regarding the methodology for setting the FRM offer price cap (February 10, 2016, ER-16-921-000, Revisions to the Forward Reserve Market Offer Cap and Elimination of Price Netting).