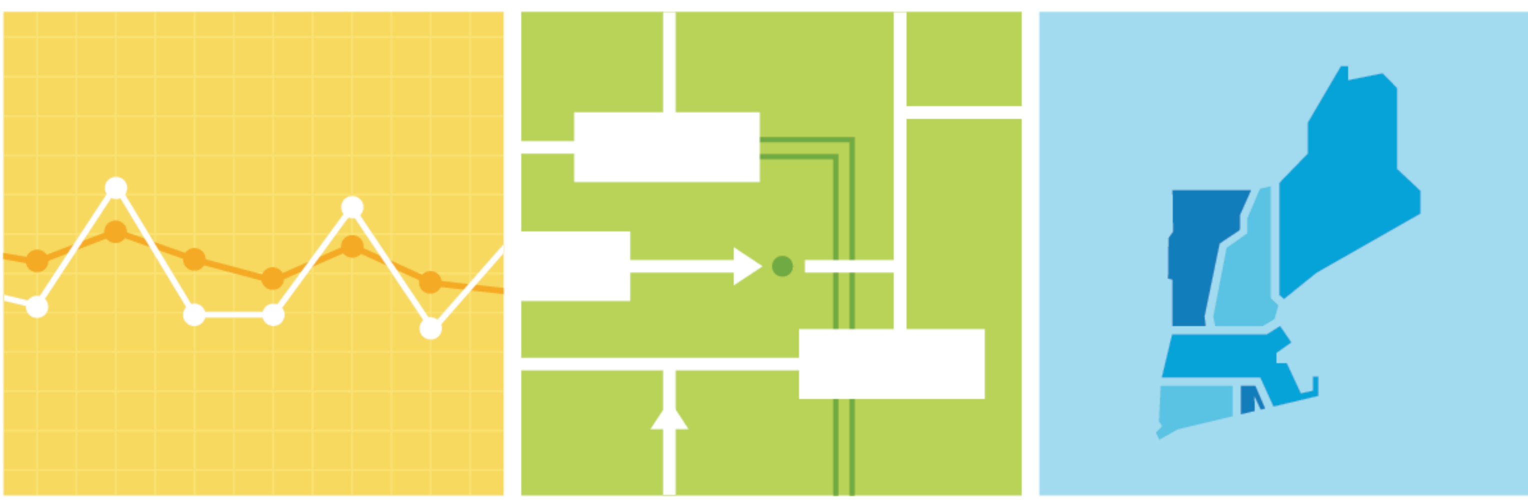
Winter 2023
Quarterly Markets Report

By ISO New England's Internal Market Monitor

MAY 30, 2023



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Preface

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

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

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

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

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

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

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

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Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Winter 2023 (December 1, 2022 through February 28, 2023).[3]

Wholesale Costs: The total estimated wholesale market cost of electricity was $3.31 billion, down 23% from $4.29 billion in Winter 2022. The decrease was driven by lower energy costs in Winter 2023.

Energy costs totaled $2.64 billion; down 29% (or $1.09 billion) from Winter 2022 costs. Lower energy costs were a result of lower natural gas prices, which decreased by 37% relative to Winter 2022 prices.

Capacity costs totaled $629 million, up 26% (by $31 million) from last fall. Beginning in Summer 2022, the capacity number includes supplemental payments to the Mystic 8 and 9 generators. These payments totaled $213 million in Winter 2023, and caused year-over-year capacity costs to increase despite lower clearing prices in Forward Capacity Auction (FCA 13) compared to the previous auction. Last year, the capacity payment rate for all new and existing resources was $4.63/kW-month. This year, the payment rate for new and existing resources was lower, at $3.80/kW-month.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $78.29 and $79.52 per megawatt hour (MWh), respectively, a 29% and 25% decrease compared to Winter 2022 prices.

- Natural gas prices averaged $9.15/MMBtu in Winter 2023, down 37% compared to $14.41/MMBtu during the prior Winter.
- Day-ahead and real-time energy prices continued to trend in the same direction as natural gas prices. However, during Winter 2023, oil generation was frequently in-merit during the two cold snap periods, and there were fewer net imports compared to Winter 2022. These factors offset some of the downward pressure of lower gas prices on LMPs.
- Energy market prices did not differ significantly among the load zones.

Notable Events During Winter 2023: While average natural gas and energy prices were lower in Winter 2023 compared to Winter 2022, two cold snap periods resulted in notably high natural gas and energy prices. The highest daily average natural gas prices of Winter 2023 occurred on December 24-27 ($33.52-$35.99/MMBtu) and February 3-4 ($37.47-49.68/MMBtu).[4] Oil generation was in-merit frequently during these periods.

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[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).

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

Below are highlights of system events, the supply mix, marginal units, fuel markets, and mitigation issues:

- On December 24, 2022, the ISO declared M/LCC 2 (Abnormal Conditions Alert) at 16:00 due to an imminent capacity deficiency driven by cold weather, unplanned generator outages, and reductions in net imports.[5] Conditions grew tighter, and capacity scarcity conditions occurred from 16:40-18:00. The ISO declared OP-4 actions 1, 2, 3, and 5 between 16:30 and 17:70.[6]
    - Reductions in net interchange were driven by fewer net imports over the Canadian interfaces in real-time compared to the day-ahead schedule. The Canadian regions that typically export into New England faced high demand and transmission system issues.
    - Several generator outages occurred just before and throughout the day on December 24 due to mechanical issues. Out-of-service generation that tripped on December 23 and December 24 totaled about 2,180 MW.
    - There was a shortage of thirty-minute operating reserves (TMOR) for 85 minutes, and a shortage of ten-minute non-spinning reserves (TMNSR) for 5 minutes. The high scarcity prices associated with these products resulted in a peak Hub LMP of $2,816/MWh at 17:10.
    - Energy payments on December 24 totaled $86.9 million (3% of energy payments for the quarter), while uplift payments totaled $1.5 million (12% of uplift payments for the quarter).
    - As stipulated under the pay for performance rules, deviations from obligated performance during the capacity scarcity conditions were settled at the performance payment rate of $3,500/MWh. Credits and charges totaled $35.9 million each. Performance varied widely by fuel type. Import transactions and nuclear resources saw the largest payments, while gas and dual-fuel generators incurred the most charges.

- Most Winter 2023 oil-fired generator commitments occurred during the two cold snap periods when gas prices exceeded $30/MMBtu (7% of hours in the quarter). During these events on December 24-27 and February 3-4, oil generation represented 26% and 20% of total generation, respectively.
- Over all hours of the quarter, oil generation made up just 2% of total generation, or 329 MW per hour, on average. This amount was split almost evenly between dual-fuel combined cycle units, dual-fuel non-combined cycle units, and oil-only generators.
- There were no significant gas-related reliability impacts for the ISO, as generator reductions from failures to obtain gas and generator limitations resulting from gas pressure issues were relatively rare.
- In general, generators' oil supplies were sufficient to replace gas generation during periods of tight gas supplies. Fuel switching occurred consistent with energy market incentives.
- Injections of liquefied natural gas (LNG) into New England's pipelines have decreased since Winter 2021. Rising global LNG prices were the main driver of New England's low level of LNG injections in Winter 2023.

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

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

- The number of fuel price adjustment (FPA[7]) requests this winter increased by 22% compared to last winter. The increase was driven by factors including greater fuel price volatility and uncertainty.

Energy Market Opportunity Costs: In December 2018, we began including Energy Market Opportunity Cost (EMOC) adders for oil-fired generators in energy market reference levels. The EMOC adder is designed to allow generators to reflect their expected value of limited production capability in supply offers. Consequently, oil-fired generators should be dispatched when most needed, reducing the need for operators to manually intervene in the market by posturing resources.[8] Generally, we expect to see EMOCs when oil prices are forecasted to be close enough to gas prices that an oil-fired generator would be in merit long enough to physically exhaust their oil inventory within a seven-day horizon.

During Winter 2023:

- Prolonged periods of high natural gas prices were highly correlated with occurrences of EMOC adders.
- Throughout the quarter, 11 generators received EMOC adders for their oil inventories in both the day-ahead and real-time markets.
  - Seven of the assets were dual-fuel capable while the remaining four generate on oil only.
  - The EMOC adders were split across six days in the day-ahead market, averaging around $31/MWh. Real-time EMOC adders were split across 19 days for eight different generators and averaged around $35/MWh.
- The cold snap around Christmas Eve 2022 saw the largest count of non-zero EMOC adders, with 11 different generators affected on one or more days in the period from December 23 to December 28.

The Seventeenth Forward Capacity Auction (FCA17): The seventeenth Forward Capacity Auction (FCA 17) was held in March 2023 and covers the capacity commitment period (CCP) beginning June 1, 2026 through May 31, 2027. Below are the highlights from the auction:

- There was a surplus of qualified and cleared capacity compared to the Net Installed Capacity Requirement (NICR).
  - Qualified capacity (37,386 MW) exceeded the Net Installed Capacity Requirement (30,305 MW) by 7,081 MW. The surplus increased from FCA 16 (5,985 MW) as a result of a 1,340 MW (4%) decrease in the Net ICR year-over-year.
  - System-wide surplus capacity cleared 1,065 MW above NICR.
- There was no price separation between capacity zones in FCA 17, and only one interface (New Brunswick) had a separate clearing price from the rest of the system.
  - All capacity zones cleared at $2.59/kW-month
  - New Brunswick interface cleared at $2.55/kW-month
- Expected payments for FCA 17 ($0.9 billion) decreased by 9% compared to FCA 16, driven by a lack of price separation in the Southeastern New England capacity zone and a lower amount of system-wide cleared capacity.

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[7] Fuel Price Adjustments (FPAs) provide a means for participants to reflect their expected fuel cost in their reference levels in the event that the fuel cost differs significantly from the fuel index.

[8] A resource is postured when it is directed to operate below its economic dispatch point for reliability reasons.

- Based on the pre-auction mitigations, excess capacity during the auction, and liquidity of dynamic de-list bids, we found no evidence of uncompetitive behavior during FCA 17.
- A total of 2,228 MW dynamically de-listed in FCA 17, including 800 MW of gas-fired generation, 780 MW of oil-fired generation, and 438 MW of coal-fired generation.
- New cleared capacity totaled 773 MW, primarily consisting of battery storage projects (400 MW), solar projects (124 MW), and passive demand response (122 MW).
- The substitution auction following FCA 17 did not take place as there were no active demand bids entered.

Net Commitment Period Compensation (NCPC): NCPC payments totaled $12.3 million, a 10% decrease compared to Winter 2022 payments of $13.7 million. NCPC payments represented 0.5% of total wholesale energy costs in Winter 2023, consistent with historical levels.

- The majority of NCPC (94%) was in the economic category, which includes payments to resources providing first-contingency protection and payments to resources operating below their economic dispatch point at the instruction of the ISO.
- Most economic payments occurred in the real-time market.
- About 12% of all NCPC payments for the quarter occurred on December 24, 2022, the day of the shortage event.

The decrease in NCPC between Winter 2022 and Winter 2023 was driven by a $2 million decrease in local second-contingency protection resource (LSCPR) payments. In Winter 2022, most LSCPR payments went to generators committed in the day-ahead market to meet reliability needs in Maine, New Hampshire and SEMA/Rhode Island due to planned transmission outages and binding transmission constraints. Winter 2023 LSCPR payments totaled just $0.56 million.

Real-time Reserves: Real-time reserve payments totaled $6.4 million and were substantially higher compared to Winter 2022 ($2.1 million). The increase was driven by high reserve payments on December 24, 2022, which totaled $5.2 million and made up 81% of reserve payments for the quarter.

Most Winter 2023 reserve payments went to resources providing TMSR ($5.3 million), while relatively small amounts went to resources providing TMNSR ($0.5 million) or TMOR ($0.7 million). The average non-zero hourly spinning reserve price in Winter 2023 ($31.13/MWh) was nearly double that of Winter 2022($16.24/MWh). The average TMNSR and TMOR prices in Winter 2023 were very high ($682.89/MWh and $490.95/MWh, respectively) due to reserve constraint penalty factor (RCPF) pricing during the December 24 event.[9]

[9] RCPFs represent the highest marginal cost the market software will incur in order to meet reserve requirements. For more information about RCPFs, see Section III.2.7A (c) of Market Rule 1.

***Regulation*:** Total regulation market payments were $12.1 million, up 8% from $11.2 million in Winter 2022. The small increase in payments reflects a modest increase in regulation capacity prices and payments, which was partially offset by a decline in service prices and payments.

Financial Transmission Rights: The main drivers of congestion in Winter 2023 were: 1) the New York-New England interface binding due to large spreads between power prices in New England and New York; 2) wind and hydro generation exporting power over the limited transmission network in eastern Maine; and 3) transmission work in Connecticut. FTRs were fully funded in December 2022, January 2023, and February 2023. Positive target allocations totaled $17.7 million in Winter 2023, down 22% from Winter 2022 ($22.8 million). Day-ahead congestion revenue also decreased in Winter 2022, totaling $20.7 million compared to $23.5 million in Winter 2022. Negative target allocations (-$1.5 million) were 78% lower than their Winter 2022 level (-$6.9 million). Real-time congestion revenue in Winter 2023 (-$0.7 million) remained modest and was generally in-line with recent historical levels. At the end of February 2023, the congestion revenue fund had a surplus of $2.9 million.

Section 2
Assessment of Winter 2023 Market Issues

This section focuses on winter-specific issues in the New England markets. During winter in New England, cold weather can cause natural gas pipelines to become constrained, giving rise to high natural gas prices. As temperatures fall, natural gas heating demand increases and natural gas-fired generators must compete for limited pipeline capacity.

In Winter 2023, while average natural gas and energy prices were lower compared to the previous winter, two cold snap periods caused a sharp rise in prices. The highest natural gas prices were observed during December 24-27 and February 3-4. These extreme weather conditions led to a significant reliance on oil generation, which accounted for a substantial portion of total generation during those periods.

The ISO faced multiple challenges during Winter 2023. On December 24, an Abnormal Conditions Alert was declared due to cold weather, unplanned generator outages, and reduced net imports. As the situation worsened, capacity scarcity conditions occurred, and various OP-4 actions were implemented. The decrease in net interchange was primarily driven by fewer net imports from Canada, as the Canadian regions faced high demand and transmission system issues. Similarly, cold temperatures on February 4 led New England to become a net exporter over Phase II for the first time since May 2016.

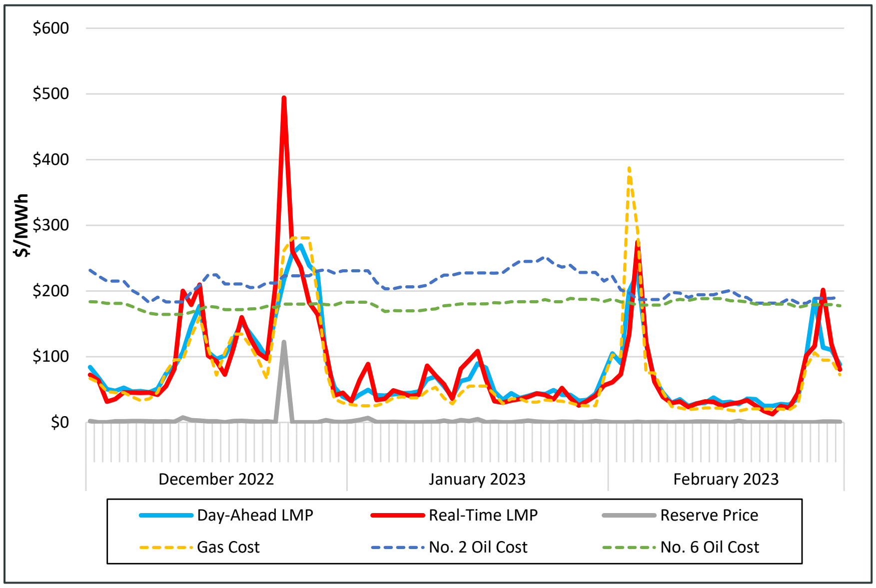
Despite the challenges, the ISO did not experience significant gas-related reliability impacts. Generators were able to switch to oil supplies as needed, aligning with market incentives. However, there has been a decline in liquefied natural gas (LNG) injections into New England's pipelines since Winter 2021, primarily due to rising global LNG prices.

Additionally, there was an increase in fuel price adjustment (FPA) requests compared to the previous winter. The rise in FPA requests can be attributed to factors such as greater price volatility and uncertainty in the fuel markets.

2.1 Daily Fuel Prices, LMPs, and Reserve Prices

Daily average Hub LMPs, real-time reserve prices, and natural gas generation costs for Winter 2023 are shown in Figure 2-1 below. The natural gas generation costs are based on the daily average natural gas price and a generator heat rate of 7,800 Btu/kWh.

Figure 2-1: Daily Average Hub LMP, Reserve Price, and Natural Gas Generation Costs



Average natural gas and energy prices were lower in Winter 2023 compared to Winter 2022. However, certain cold days during Winter 2023 saw higher natural gas and energy prices than any day during the previous winter. The highest daily average natural gas prices of Winter 2023 occurred on December 24-27 ($33.52-$35.99/MMBtu) and February 3-4 ($37.47-$49.68/MMBtu). Both of these periods saw cold temperatures relative to the quarterly average of 35°F. Daily lows ranged from 8°F to 25°F on December 24-27, while February 3-4 saw the coldest temperatures of the period with lows of -6°F to -10°F. The highest hourly day-ahead Hub LMP of the quarter was $374.98/MWh on December 26, 2022, while the highest hourly real-time price was $2,254.34/MWh during the shortage conditions on December 24, 2022. LMPs were also high during the February cold snap, peaking at $329.98/MWh in the day-ahead market on February 3, and at $461.52/MWh in real-time on February 4.

Overall, day-ahead and real-time Hub LMPs averaged $78.29/MWh and $79.52/MWh in Winter 2023, respectively, a 25-29% decrease compared to Winter 2022. As Figure 2-1 shows, LMPs generally move with natural gas costs. However, during the periods with the highest gas prices (most notably February 3 to 4), LMPs fell below the cost to generate on natural gas. During these periods, the effect of high natural gas prices on LMPs was partially offset by oil-fired generation displacing gas-fired generation. Oil-fired generators set price for 5% of real-time load in Winter 2023, which was lower than the Winter 2022 value (9%) but still significant. Lower average loads in Winter 2023 compared to Winter 2022 (13,875 MW vs. 14,488 MW) also put downward pressure on average LMPs.

2.2 Supply Mix, Fuel Inventory and Oil

Tight natural gas supplies during the winter months can lead to reliability concerns for the delivery of wholesale electricity. The ISO monitors the availability of generators' fuel oil supplies, and works with the natural gas pipelines in the region to understand potential gas system issues that might limit generators' operation. In Winter 2023, the New England region experienced cold temperatures and high natural gas prices during two cold snap periods in December and February. The high gas prices (signaling tight supplies) did not lead to any significant reliability impacts for the ISO, as generator reductions from failures to obtain gas were relatively rare.

The following subsections discuss the supply mix, fuel inventory, and the natural gas market, with a special focus on winter issues.

2.2.1 Supply Mix

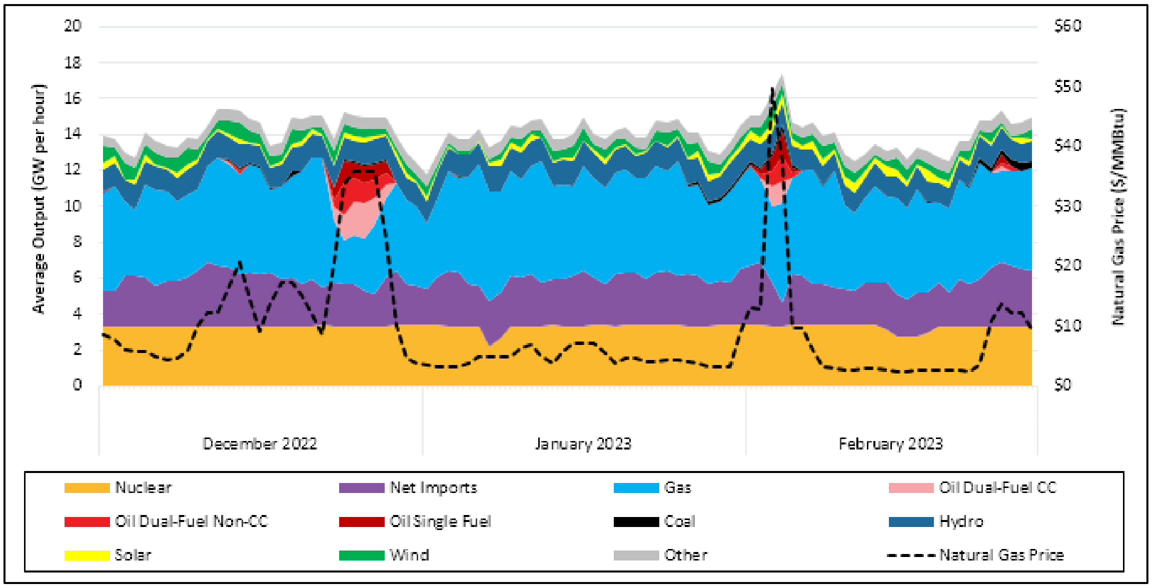
The real-time supply mix in New England during Winter 2023 predominantly consisted of power from gas-fired and nuclear generation and power flowing from neighboring control areas.[10] However, the supply mix changed quite considerably at times when natural gas prices were high. During these periods, oil production increased as oil-only generators became "in-merit" and dual-fuel generators operated on less-expensive fuel oil.

The relationship between natural gas prices and oil generation can be seen in Figure 2-2. It depicts the average daily price of natural gas in New England and the average supply per hour by fuel type for each day in Winter 2023.[11] Each bar's height represents the average hourly electricity generation from that fuel type on that day, which is measured on the left vertical axis. The right vertical axis measures the price of gas.

[10] As discussed in Section 4.3.1, nuclear generation, gas-fired generation, and net imports accounted for 79% of total energy production in Winter 2023.

[11] Electricity generation equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, wood, and demand response. Additionally, oil generation is divided into three categories in order to provide further insight about the class of oil-fired generator that ran. These three categories are: (1) dual-fuel combined cycle units; (2) dual-fuel non-combined cycle units, and (3) single fuel units.

Figure 2-2: Real-Time Generation Obligation by Fuel Type and Gas Price



With the exception of two notable periods with elevated gas prices, oil-fired generation accounted for a negligible share of total energy production in Winter 2023.[12] The first of those periods coincided with the arrival of Winter Storm Eliot on December 23. The cold temperatures associated with the storm drove average daily gas prices above $30/MMBtu between December 24 and December 27. During this four-day period, generation from oil-fired resources increased to nearly 4,000 MW per hour, representing about 26% of total generation. The second notable period occurred between February 3 and February 4, when extreme cold conditions – the average temperature in New England was as low as -10 °F – led gas prices to exceed $50/MMBtu. Generation from oil-fired resources averaged nearly 3,500 MW per hour over this two-day stretch, representing 20% of total generation. Over all hours in Winter 2023, oil generation accounted for 2% of total generation, or 329 MW per hour on average. This was comprised of 121 MW (37%) from dual-fuel combined cycle units, 110 MW (33%) from dual-fuel non-combined cycle units, and 98 MW (30%) from oil-only generators.

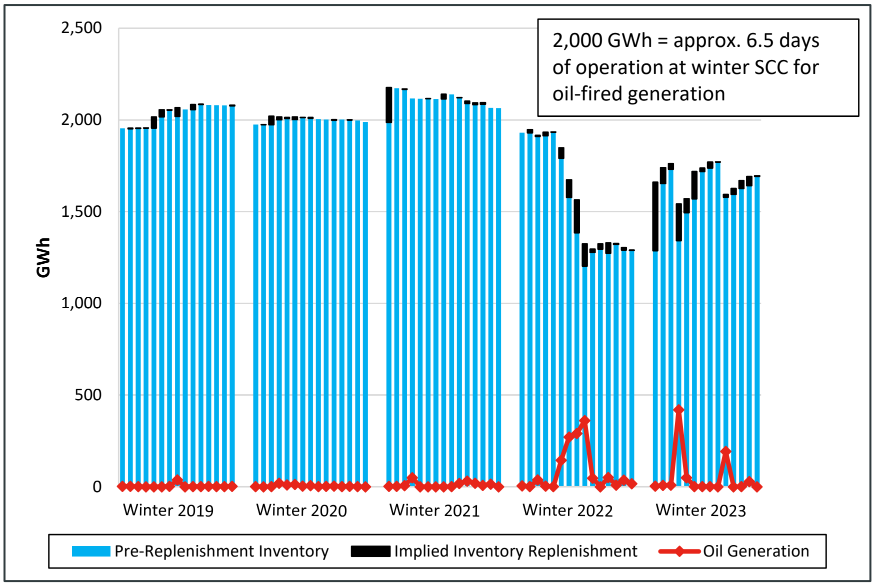
2.2.2 Fuel Oil Inventory

Oil usage by generators was relatively limited during Winter 2023. In general, throughout the winter period, generators' oil supplies were sufficient to replace gas generation during periods of tight gas supplies and high natural gas prices. Figure 2-3 shows weekly fuel oil inventories for generators over the past five winter periods. The oil inventory values (blue and black bars) in the figure have been coupled with the oil-fired generation (red line) that utilized the oil inventories.[13]

[12] Outside the periods of December 24-27, 2022, and February 3-4, 2023, oil-fired generation averaged just 83 MW per hour, accounting for only 0.6% of total generation.

[13] All values in the figure are shown in gigawatt-hour (GWh) equivalents and reflect oil inventory quantities based the ISO's periodic winter inventory surveys; we prepared the generation estimates, based on participant reporting of the fuel type utilized in energy market supply offers. The oil inventory replenishment values are estimates based on current and prior period oil inventories and oil-fired generation. The height of the bars indicates the available oil inventory at the beginning of each period. (Inventories are surveyed weekly from December through the following March.)

Figure 2-3: Winter Fuel Oil Inventories



During Winter 2023, oil inventories did not decline significantly (ending down just 1.4% compared to early December inventories). The stability of the inventories resulted from participants' replenishment of inventories following the two periods of heightened oil usage and a relatively mild winter period that did not require significant prolonged oil-fired generation. Oil-fired generation in Winter 2023 averaged just 2% of the supply mix. By contrast, Winter 2022 had significantly more oil usage by generators than other winters during the five-year period. Natural gas prices during Winter 2022 were the highest on average since Winter 2014, and significant oil usage occurred during January of that period; overall, oil generation averaged 9% of the supply mix in Winter 2022. Replenishment of oil inventories was relatively modest in Winter 2022, resulting in an inventory decline of 33%. In Winters 2019-2021, very modest levels of oil-fired generation resulted in very stable oil inventory levels throughout the winter periods.

While winter oil inventories have been sufficient to ensure system reliability over the review period, New England does face a number of fuel-related risks. These risks include oil tank capacity being concentrated among a relatively small number of large, older generators that have less flexible operating parameters, making intra-day commitment to respond to operating contingencies more difficult.[14] For example, in Winter 2022, these generators accounted for approximately 68% of oil storage capacity, an average of approximately 57% of oil inventories, and provided 47% of oil-fired generation.[15] Participants with oil generation also need to maintain and replenish inventories during the winter period, to ensure adequate inventories throughout the winter period. For Winter 2024 and Winter 2025, the ISO is implementing an Inventoried Energy Program to financially incent the maintenance of adequate inventory levels. The program will help to reduce the financial uncertainty of forward purchases of fuel that can be stored and that allow for "just-in-time" delivery (such as fuel oil or firm delivery gas contracts).[16]

[14] These stations account for 6 out of 74 oil storage tanks across all of the all-fired generators.

[15] These stations also have approximately 400 MW of fast-start generation capacity.

[16] For example, see Overview of ISO-NE's Inventoried Energy Program (https://www.iso-ne.com/static-assets/documents/2019/09/2019-10-01-egoc-a4.1-overview-of-iso-ne-inventoried-energy-program-v1.pdf).

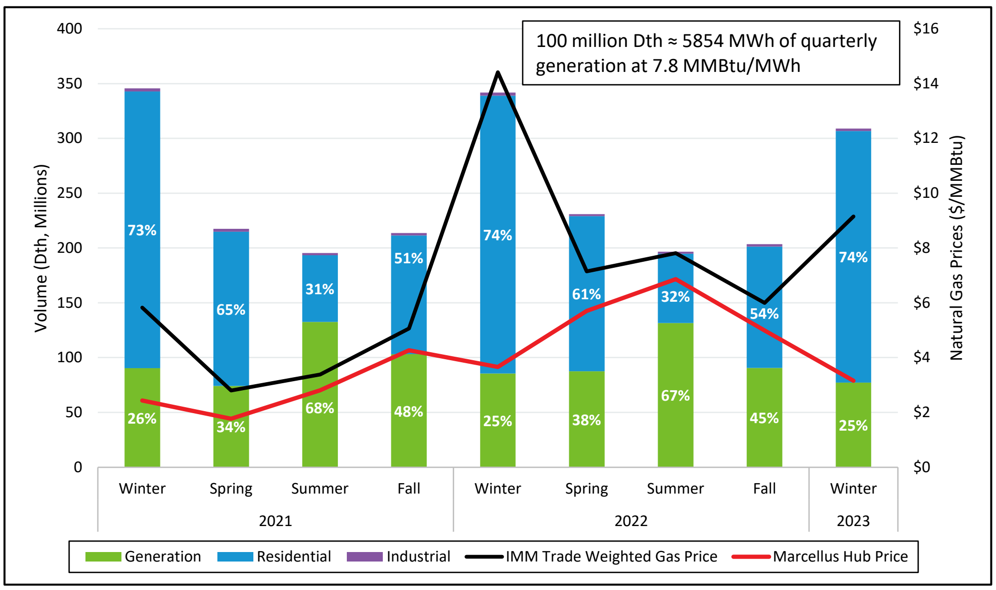
2.2.3 Natural Gas Usage and LNG Supply

With natural gas-fired generation powering over 60% of New England's fleet, periods of cold winter weather can lead to intense competition for limited pipeline gas and LNG supply. For instance, a cold snap in Winter 2018 led to constrained natural gas pipelines when prices reached a record daily high of nearly $62/MMBtu.[17] This pushed gas-fired generators up the supply stack and out of economic merit order. Average natural gas prices were relatively lower in Winter 2023, with the quarterly price averaging $9.15/MMBtu, down $5.26 (37%) from Winter 2022.

Natural Gas Usage

As temperatures fall in the winter months, residential heating demand increases and natural gas-fired generators must compete for limited pipeline capacity. The volume of gas demand by sector, alongside the average quarterly New England and Marcellus Hub natural gas prices, are shown in Figure 2-4 below.[18]

Figure 2-4: Natural Gas Demand by Sector



Total natural gas demand reached almost 310 million Dth in Winter 2023, a 10% (33 million Dth) decrease from Winter 2022, driven by milder winter conditions. Temperatures were generally higher year-over-year, with January 2023 averaging 11 degrees warmer than January 2022.

Shares of gas demand by sector remained relatively constant year-over-year. The generation sector demands roughly 67% of all natural gas during the summer months when residential heating demand decreases and electricity demand increases. As temperatures decrease going into the winter months, the residential sector procures about 74% of all gas demand, primarily for

[17] The $62/MMBtu natural gas price represents an average price for the electric day (HE 1- HE24) and not the gas day. A gas day ranges from HE 10 on one day to HE 9 the following day

[18] All natural gas demand and LNG sendout data is sourced from Wood Mackenzie. Natural gas demand from the industrial sector is shown, but the sector only procures around 1% of gas demand in every quarter.

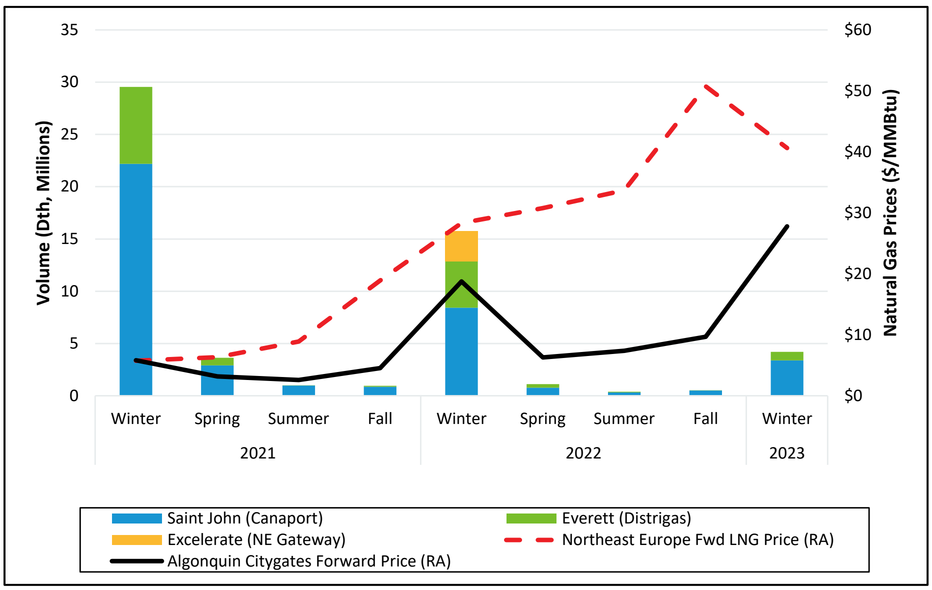
residential heating. On the coldest days of Winter 2023, February 3-4, daily average temperature dropped to 2 degrees, resulting in above-average residential demand shares closer to 85%.

The Marcellus hub price typically provides a proxy of the New England natural gas price for three quarters out of the year. When residential demand increases sharply in the winter months, New England natural gas pipelines become regionally constrained which is reflected in a larger price divergence from the Marcellus hub.

LNG Supply

When natural gas pipelines become constrained in the winter, liquefied natural gas (LNG) can provide another source of natural gas delivery into New England pipelines. The additional natural gas can help alleviate constraints and increase the supply of natural gas available to gas generators. There are three operational LNG import facilities that inject gas into New England: Excelerate, Saint John, (formally Canaport), and Everett (Distrigas).[19] The volume of injections into the interstate pipelines from each facility for the past three years is illustrated in Figure 2-5 below. The lines (right axis) show the forward LNG contracts for Northwest Europe LNG (red dashed) and Algonquin Citygates (black solid).[20]

Figure 2-5: LNG Sendout by Facility



Since Winter 2021, LNG sendout into New England's pipelines has decreased significantly. Winter 2022 saw 15.8 million Dth (47% decrease year-over-year) of sendout and Winter 2023 saw only 4.2 million Dth (39% decrease year-over-year) of sendout. Assuming a standard efficiency of 7,800 Btu/KWh, the 4.2 million Dth of LNG sendout in Winter 2023 is equivalent to the fuel needed to run

[19] The Saint John LNG facility is located in New Brunswick, Canada but delivers natural gas into New England via the Maritimes & Northeast pipeline. The volume from the Everett (Distrigas) represents flows from the facility into the interstate gas pipelines.

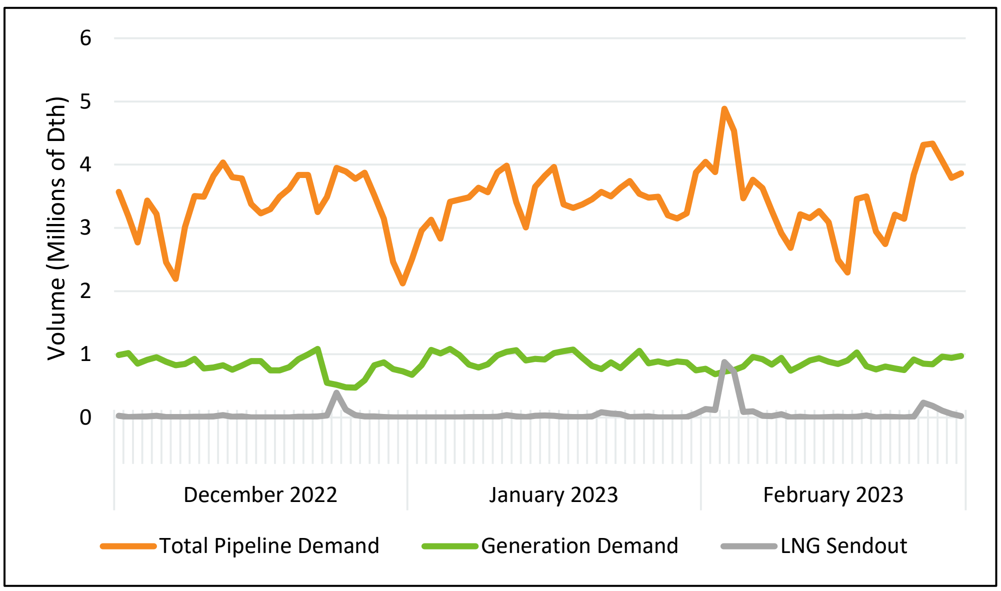
[20] LNG sendout does not include LNG burned by the Mystic power plants attached to the Everett LNG terminal. Future LNG prices are two-month forward prices provided by the Argus Media Group. Algonquin Citygates future prices are provided by the Intercontinental Exchange for the corresponding forward time period.

a 250 MW generator for all hours in the quarter. In comparison, the 29.5 million Dth of LNG sendout in Winter 2021 is equivalent to 1,753 MW of hourly gas generation over the winter months.

Rising global LNG prices were the main driver of low LNG sendout to New England in Winter 2023. Typically, LNG shipments to New England are procured if the price of LNG is equal to or less than the expected price at Algonquin Citygates. However, global LNG prices have increased at a much faster rate than New England natural gas prices, making imports of LNG into New England relatively uneconomic. Since 2021, Northeast Europe's forward price of LNG has increased by 605%, from $5.76/MMBtu in Winter 2021 to $40.61/MMBtu in Winter 2023, while Algonquin Citygates forward price of gas has only increased by 378%, from $5.82/MMBtu in Winter 2021 to $27.79/MMBtu in Winter 2023.

The sendout of liquefied natural gas (LNG) increases pipeline gas availability during periods of extremely cold weather or significant operational constraints. In Winter 2023, total LNG sendout (gray) relative to generation (green) and total pipeline demand (orange) is shown in Figure 2-6.

Figure 2-6: New England Pipeline Demand and LNG Sendout (Winter 2023)



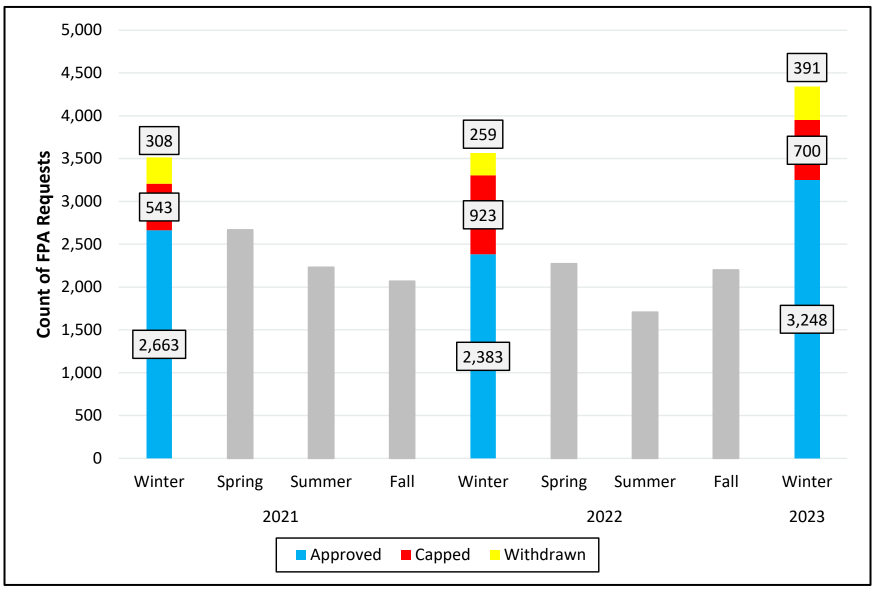
On February 3rd, total pipeline demand reached a quarterly-high of 4.9 million Dth and the spot natural gas price rose to $76/MMBtu. LNG terminals responded to the high price signals and provided 0.9 million Dth of LNG sendout, enough to cover all of New England's active gas-fired generation.

2.3 Fuel Price Adjustments

In this subsection, we provide an overview and analysis of Fuel Price Adjustment (FPA) requests for Winter 2023. Participants use FPAs to reflect their expected fuel cost in their reference levels in the event that the fuel cost differs significantly from the fuel index. As part of the FPA request assessment, we use a proprietary model to estimate a reasonable upper bound for natural gas prices ("FPA Limit").[21] For more details on how FPAs are processed, see Appendix: Overview of FPA Process, at the end of this report.

In Winter 2023, we received FPA requests from 24 participants for 59 generators, which is in line with Winters 2021 and 2022. Figure 2-7 shows the number of FPA requests by season over the last few years.

Figure 2-7: FPA Requests, by Year, Season, and Status



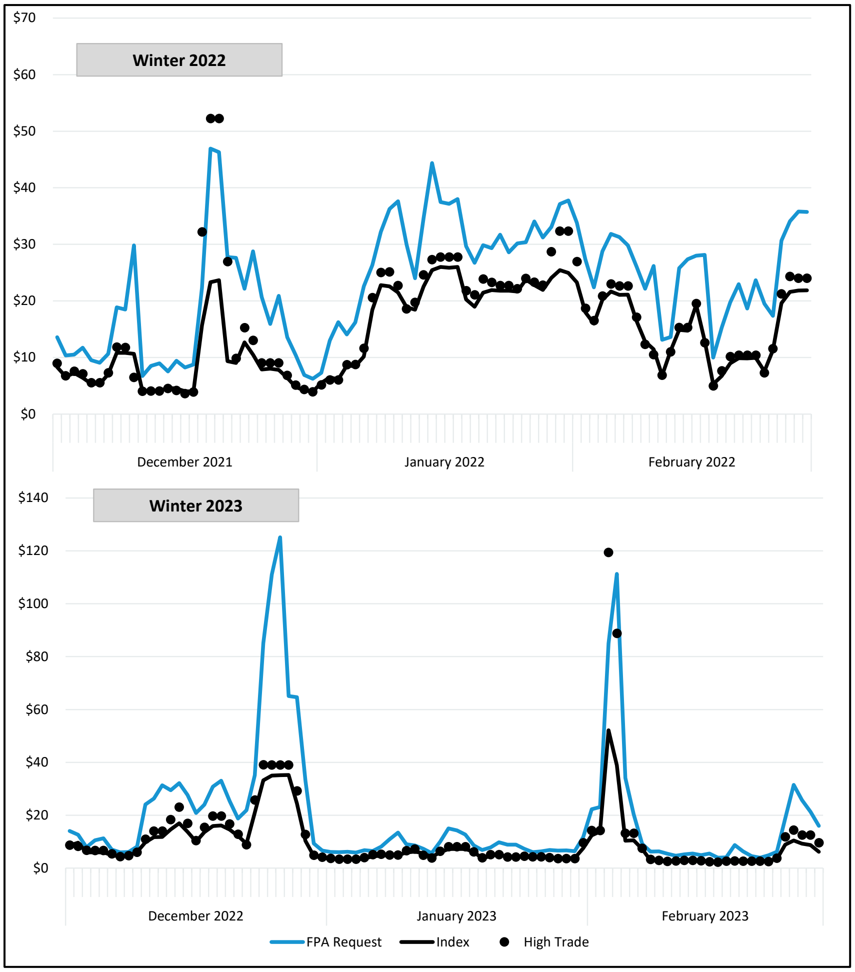
On average, the number of FPA requests spikes in the winter compared to other seasons. Total FPA requests exceeded previous winters by more than 22%, even though the unique number of participants who submitted FPAs did not change. This increase indicates both greater price volatility, price uncertainty, and additional factors discussed regarding Figure 2-8 below. Consistent with prior years, the majority of FPAs (~82%) were made for the day-ahead market.[22]

The following figure shows the average settled natural gas index price, average volume-weighted high-priced trade, and requested FPA price on a daily basis for the last two winter periods. FPA request data reflects simple averages because participants do not submit volume data (gas or energy) associated with the FPA. Subsequently, the hourly values roll into daily averages.

[21] Once processed, FPAs fall into one of three categories: approved, capped, or withdrawn. "Approved" indicates that the requested price was approved (either automatically or through IMM intervention) and used to update reference levels; "capped" indicates that the requested FPA price exceeded the FPA Limit (even after IMM intervention, if applicable); and "withdrawn" indicates that the FPA request was withdrawn prior to being effective (i.e., was not used as part of any mitigation conduct tests.)

[22] Note that unless an FPA is withdrawn or overridden by another FPA, it will roll-over into the real-time market.

Figure 2-8: Average Index Price, High Trade, FPA Request, and Effective FPA



The spread between average FPA requests and settled index prices (113%) increased compared to the prior winter (66%). Index price volatility had a large impact on requested FPAs. When there is less liquidity and more volatility in the gas market, we expect to receive more FPA requests from participants. This occurs because participants expect to pay for gas above the index price during tight gas market conditions.

2.4 Gas Pricing Review

Limited gas pipeline infrastructure and the absence of local supply of natural gas in New England can lead to procurement challenges for operators of natural gas for power plants.[23] When the pipelines were built in New England, gas utilities committed to long-term contracts, whereas generators typically do not enter into these expensive contracts in order to keep costs low and remain competitive in the electricity market.[24] During extremely cold periods, the pipelines run at

[23] Pipelines in New England include Portland Natural Gas, Tennessee Gas, Algonquin, Iroquois, and Maritimes and Northeast. Additionally, there are three operational LNG import facilities that inject gas into New England: Excelerate, Saint John (formally Canaport), and Everett (Distrigas).

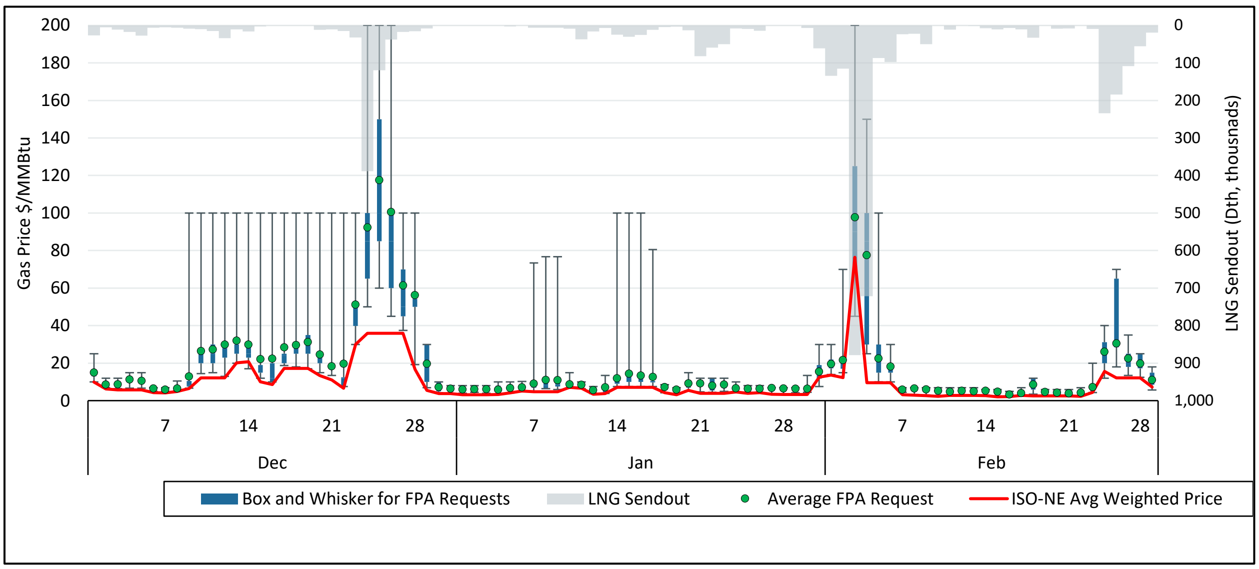
[24] See the ISO's discussion on gas infrastructure constraints https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints.

near capacity just to meet heating demand, which limits the ability for gas generators to receive fuel. Gas-fired power plant operators offer into the energy market based on their expected operating costs which are primarily driven by gas prices. When the gas pipeline system is constrained, there are limited options to procure gas. One option is LNG, which flows from the east coast and provides counterflow to alleviate pipeline constraints. As natural gas prices increase with higher demand and constrained supply into New England, LNG has greater incentive to inject gas into the pipeline. Therefore, some FPAs on days when the gas pipeline is constrained will likely be based on a combination of gas and LNG, and will be reflected in energy offers.

To evaluate the impact of natural gas market activity on energy prices, we focus on how these FPA requests compare to index prices. We then assess the impact of FPAs on the energy market by comparing with counterfactual estimates.

Figure 2-9 shows the daily average ISO-NE weighted gas price, a box and whisker chart for FPA requests, and LNG send out to New England.[25,26]

Figure 2-9: FPA Requests and Average Gas Weighted Prices



Increased LNG sendout to New England (gray bars) lines up with periods with the highest index prices and FPA requests, notable on December 24-26 and February 3-4.[27] With high natural gas demand, low trading volumes on exchanges and high natural gas price uncertainty, participants become more likely to rely on LNG to meet incremental fuel needs.

[25] There are no volumes associated with FPA requests, so the green dot represents a simple average for the day. The box and whisker represents the daily high, low, and inter-quartile range of FPA requests.

[26] The following explains the box and whisker plot from top to bottom. The top of horizontal market represents the maximum FPA request. The top of the blue bar is the 75th percentile. The green dot is the average, or 50th percentile. The bottom of the blue bar is the 25th percentile, which means the height of the blue bar shows the inter-quartile range. The bottom horizontal market represents the minimum FPA request.

[27] There were many days throughout December and January with a small number of high FPA requests. This is represented by the fact that the dark blue interquartile range does not extend in the upward direction toward the high trade. These represent unique requests and are not representative of tight gas pipeline conditions.

When system conditions are tight in the energy market, we monitor pivotal suppliers to ensure they do not withhold supply in an effort to drive up energy prices. When New England's natural gas pipelines operate near full capacity, there may be an analogous opportunity for gas suppliers to exercise market power. However, we have neither the mandate nor the data to evaluate this hypothesis. What we observe through daily monitoring and FPA consultations is that when the pipelines operate at or near full capacity, and trading on exchanges is limited, there are large spreads in the FPA requests submitted by participants, even on the same pipelines. This is indicative that there may be inefficient gas market outcomes driving inflated prices and payments in the energy market.

We estimated the impact of FPA-based offers on the energy market for days with especially tight gas-market conditions. Figure 2-10 below, highlights an analysis of FPA impacts on LMPs on December 24, 2022 and February 3 and 4, 2023.[28] The black line, charted on the left axis, shows the Hub LMP. Two IMM-estimated values also share the left axis:

- The first is the *Supply Offer*, represented with a series of gray bars. The top of the gray bars show the average offer prices of generator segments that reflect approved FPAs. The bottom of the gray bars represent an IMM estimate of these same segments if they were priced using the relevant market index price. The difference (the bar height) represents the average markups of FPA-based offers when compared with offers at index.
- The second is the *Counterfactual LMP*, represented by a red line. The red line dips below the black line in periods we estimated high-FPA offers had an impact on energy prices when compared with offers at index (i.e., if generators offered at index, market prices would have been lower). Comparing this red line to the black line gives a sense of the estimated LMP impact if FPA-based offers were instead based on the index price. When the red line is hidden by the black line, we did not estimate any impact on price from FPAs during the hour.

On the right axis, we show an estimate of the number of FPA-based offered MWs that were not dispatched, but would have been dispatched if they were based on the generator's gas index price. This metric is shown in black bars at the bottom of the chart. These bars give a sense of the quantity of energy that was "pushed out-of-merit" by an FPA, against being offered at index.

[28] This metric shows real-time prices and LMP impacts. We did not consider the price impacts of uncommitted generation in this analysis, only committed but undispatched generation. This could result in estimated impacts lower than actual impacts.

Figure 2-10: FPA Price Impacts on December 24, 2022 and February 3-4, 2023

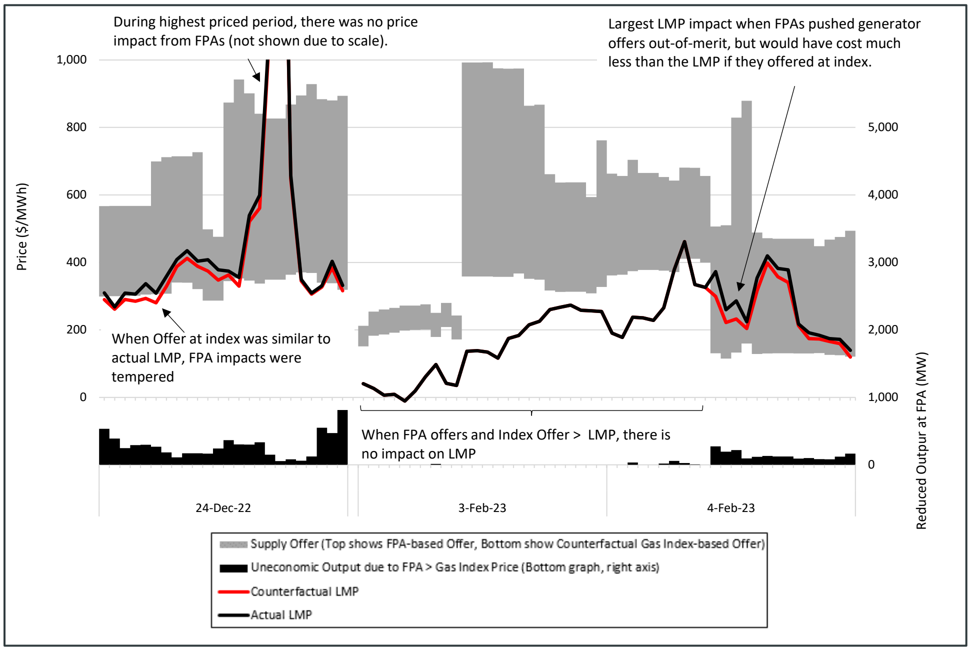


Figure 2-10 highlights a few key takeaways. First, the LMP impacts of FPAs were relatively modest over these three days. Most notable, all day on February 3, and up to 10:00 on February 4, we estimated there were no impacts of FPAs on LMPs. This is because offers based on both FPAs and the index price were above the LMP (the gray bars are completely above the LMPs). So offers based on FPAs would not have been in-merit if they were offered at index.

On December 24, the estimated LMP impact was small. We estimated an average impact of $19/MWh, only 4% of the average LMP during the day. Although there were many MWs pushed "out-of-merit" because of FPAs (shown by the black bars at the bottom), the actual LMP hovered around the index-based offers (the black line was close to the bottom of the gray bars). If these FPA-based offers were offered based on the index, the LMP would only decrease slightly because the index-based offers would set price. Also of note on December 24, we estimated there were no price impacts during HE 18, the hour with the highest prices. Each generator produced as much energy plus reserves as possible during the shortage conditions, and we estimated that would be true for both FPA-based or index-based offers, resulting in no price impact.

From 10:00 through 18:00 on February 4, we observed the largest estimated impact from FPA-based offers. Our estimated impact of FPA-based offers was about $38/MWh on average, or 11% of the Hub LMPs. During these times, actual LMPs were between the FPA-based offers and the IMM-calculated offers based on index. This indicates that not only was there out-of-merit generation offered based on FPAs that would have been in-merit if offered based on index (shown by the black bars at the bottom of the graph), but that this generation would have been priced significantly below the LMP if based on index (the bottom of the gray bar is below the black line).

2.5 Energy Market Opportunity Cost Adjustments to Marginal Cost Reference Levels

Energy market reference levels include an energy market opportunity cost (EMOC) adder for resources that maintain an oil inventory. This enhancement to reference levels, implemented in 2018, was motivated by concerns that, during sustained cold weather events, generators were unable to incorporate opportunity costs associated with the depletion of their limited fuel stock into their energy supply offers due to the risk of market power mitigation. Such an event arose during Winter 2018 - which resulted in ISO operators posturing oil-fired generators to conserve oil inventories. During cold weather events, the inclusion of opportunity costs in energy offers enables the market to preserve limited fuel for hours when it is most needed to alleviate tight system conditions.

We calculate generator-specific EMOC adders with a mixed-integer programming model that was developed by the ISO and runs automatically each morning. For a given forecast of LMPs and fuel prices, the model seeks to maximize an oil-fired generator's net revenue by optimizing fuel use over a seven-day horizon, subject to constraints on fuel inventory and asset operational characteristics. Opportunity costs produced by the model are available to participants an hour before the day-ahead market closes and, since December 2019, a real-time opportunity cost update is available at 18:30, on the day prior to real-time operation. The real-time update of the opportunity cost calculation is based on data that is available after the day-ahead market closes but prior to the start of the real-time market. This calculation incorporates updated fuel price forecasts to produce more accurate opportunity costs for the real-time market.

While the calculation of EMOCs is complicated and dependent on a number of variables (gas and oil price forecasts, fuel inventory levels, and generator characteristics), it is possible to develop a general sense about when EMOCs are likely to occur. Primarily, we should expect to see EMOCs for a generator when oil prices are forecasted to be close enough to gas prices that an oil-fired generator would be in merit long enough to physically exhaust their oil-fired inventory. This type of scenario would typically occur during an extended period of very cold weather when demand for natural gas is highest because natural gas is used for both heating and electricity generation in New England.

Table 2-1 below displays EMOC summary statistics for December 2022 through February 2023.

Table 2-1: EMOC Summary Statistics (Dec 2022 - Feb 2023)

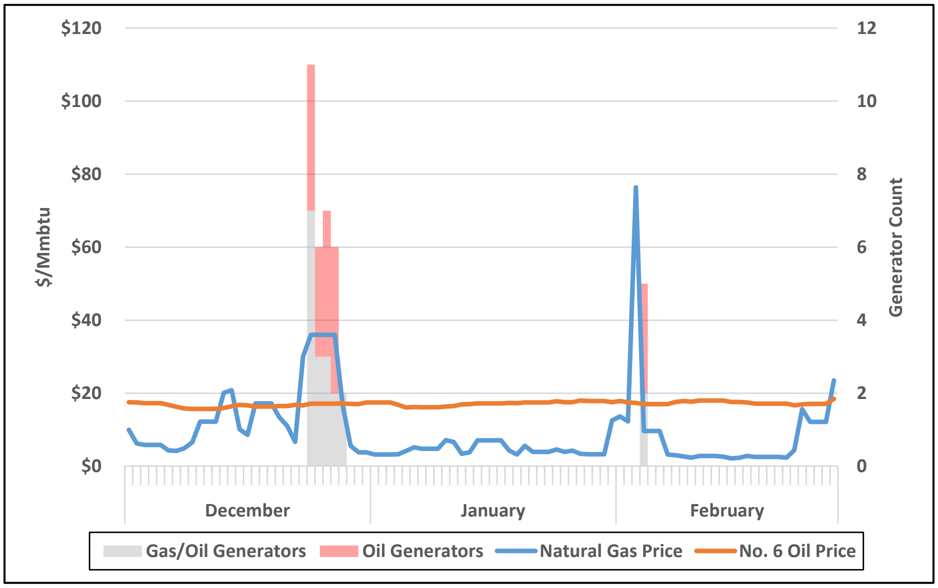
Market Type	Generator Count	Avg. EMOC ($/MWh)	Avg. NG Price ($/MMBtu)	Avg. Oil Price ($/MMBtu)
Day Ahead	11	$28.21	$31.39	$17.12
Real Time	8	$35.09	$12.59	$16.91

From December 1, 2022, to February 28, 2023, eleven generators received EMOC adders for their oil inventories in both the day-ahead and real-time markets. Seven of the generators are dual-fuel capable while the remaining four generate on oil only. The EMOC adders were split across six days in the day-ahead market, averaging around $28/MWh.

In the real-time market, EMOC adders can either continue from their day-ahead value or be revised using updated fuel prices. Real-time EMOC adders were split across 19 days for eight different generators and averaged around $35/MWh.[29]

The distribution of generators that received EMOC adders in the day-ahead market from December 2022 to February 2023 are shown in Figure 2-11 below. The natural gas and No.6 oil prices (left axis) are imposed over the count of generators that received non-zero EMOC adders (right axis). Dual fuel (gas- or oil-fired) generators are shown with gray shading; oil-only generators are shown with red shading.

Figure 2-11: Day-Ahead Non-Zero EMOC Generator Count and New England Fuel Prices



Due to New England's dependence on natural gas generation, increases in natural gas prices typically increase energy market prices, making oil-fired generation economical and incentivizing dual-fuel generators to switch to the lower-priced fuel of oil. Both actions deplete oil reserves and increase the likelihood of an EMOC adder applied to reference levels. From December 2022 to February 2023, EMOC adders were required following periods of sustained, cold weather. The cold snap around Christmas Eve 2022 allocated EMOC adders to 11 different generators from December 23 to December 28, while the sub-zero temperatures of February 3 and 4 saw five generators receive EMOC adders.

The utilization of EMOC adders by market participants remains difficult to assess because an asset's true fuel cost will likely differ from the fuel index values that we use to estimate the opportunity cost. In addition, the EMOC model does not consider fuel resupply in its look-ahead. Consequently, the model may sometimes produce an opportunity cost for an asset when there is no actual opportunity cost because the asset is not fuel-limited in practice. Oil delivery during harsh winter conditions can be uncertain, and the ISO decided that it was better for the model to assume no delivery when there may be one, rather than the alternative. Otherwise, assets that did not receive their oil delivery in time would not have an opportunity cost adder and would be more likely to burn though their remaining inventory prematurely.

2.6 Market Performance on December 24, 2022

This section of the report looks specifically at how the New England electricity markets performed during the capacity scarcity conditions (CSC) that occurred on December 24, 2022.

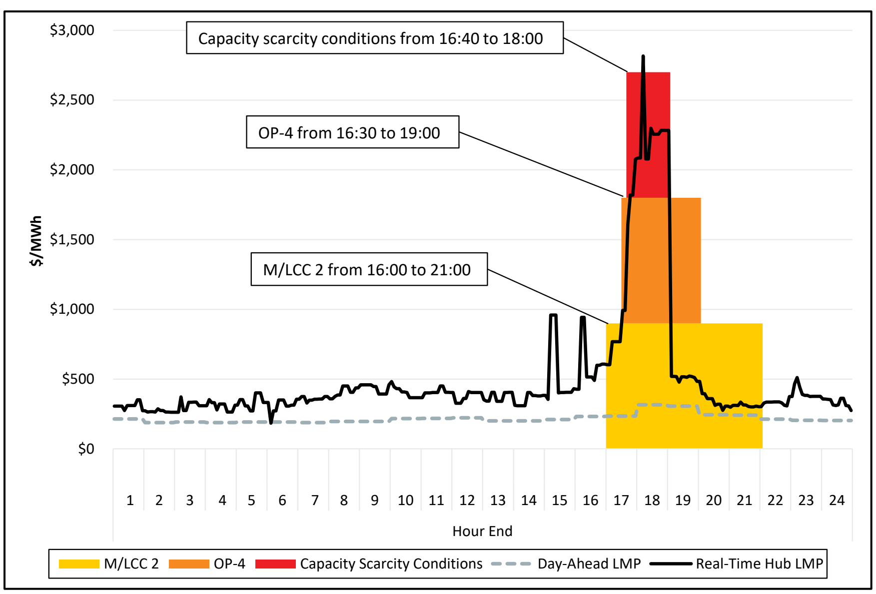
2.6.1 Event Overview

On Saturday, December 24, 2022, the ISO experienced its first CSC in over four years. The ISO initiated emergency procedures in response to tight system conditions that resulted from multiple factors, including cold weather, unplanned generator outages, and reductions in net imports.

A steep drop in temperatures beginning on December 23 led to increased demand for both natural gas and energy. Despite the cold temperatures, there was minimal load forecast error, and enough demand cleared in the day-ahead market to satisfy real-time energy needs. Oil-fired generation was in merit, displacing a significant portion of relatively more expensive gas-fired generation in the day-ahead supply mix. However, unanticipated real-time events led to stressed system conditions: First, multiple generators tripped offline late on December 23 and throughout the day on December 24. Second, real-time net imports into New England were much lower than the day-ahead scheduled amount, driven by high demand and transmission system issues in the Canadian control areas.

The conditions led to operating reserve deficits and high energy prices. A timeline of the ISO's emergency procedure actions is shown in Figure 2-12 below along with energy prices.

Figure 2-12: December 24 Event Timeline



The following sections detail the factors that contributed to the event, the market outcomes, and an assessment of how the market performed.

2.6.2 Drivers of Tight System Conditions

Weather and Load: On the day before the shortage event, Winter Storm Elliott brought strong winds and precipitation to the region and caused around 200,000 retail customer outages. Temperatures declined rapidly between December 23 and 24, resulting in a steep increase in residential natural gas demand. Below, Figure 2-13 shows actual and forecasted temperatures and loads on December 23 and 24. The red and blue dots represent the daily high and low values, respectively. The bars show the temperature load forecast errors. The load forecast error bars (yellow) are flipped so that their direction is consistent with the expected impact of the temperature forecast error (i.e., lower temperatures result in higher loads than forecast). Figure 2-14 compares day-ahead cleared demand to real-time metered load.

Figure 2-13: Actual and Forecasted Temperatures and Loads, Dec. 23-24

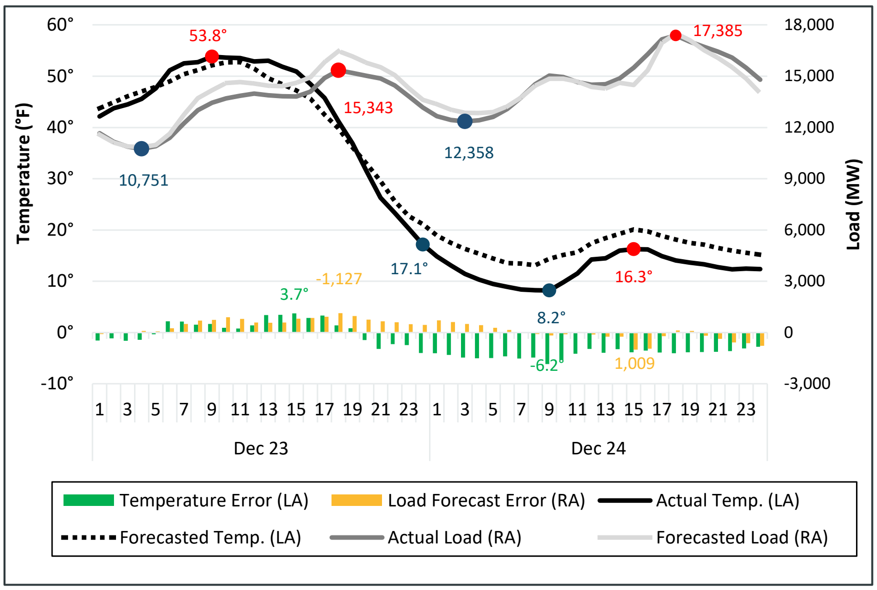
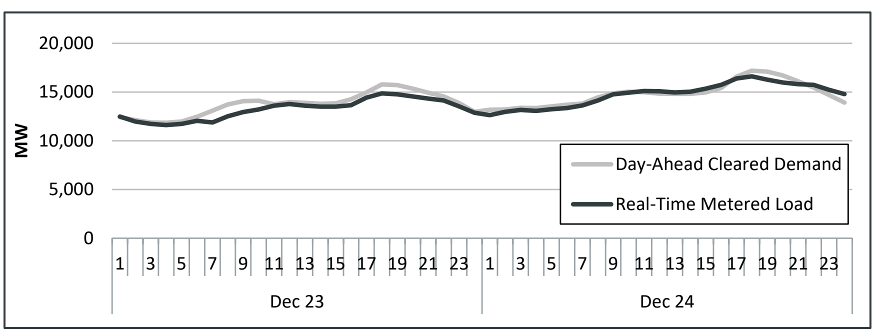


Figure 2-14: Day-Ahead Cleared Demand vs. Real-Time Load, Dec. 23-24

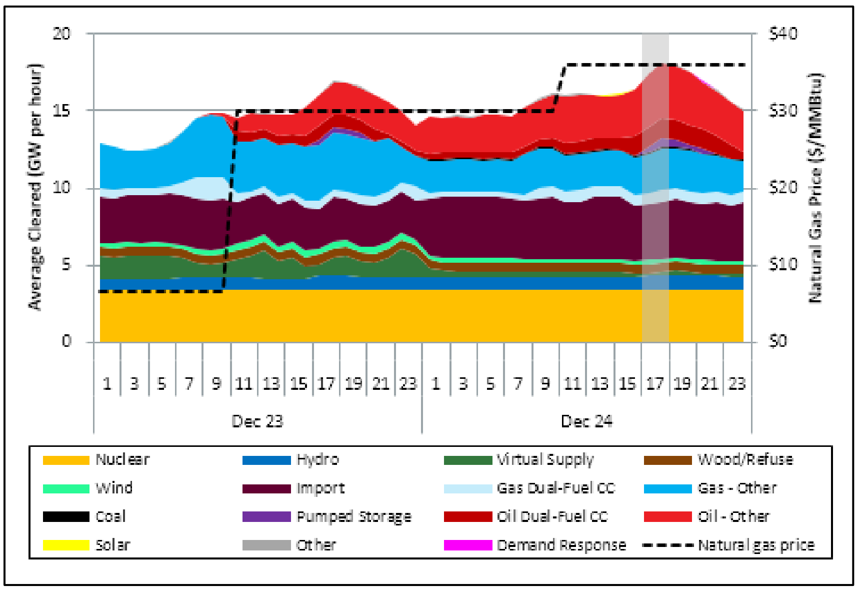


Temperatures peaked at 54°F on December 23, then declined to just 8°F during the morning on December 24 and remained low throughout the day. Additionally, actual temperatures were several degrees lower than the forecast on December 24. These cold temperatures led to high natural gas and energy demand in both New England and neighboring control areas. In particular, high demand in Quebec resulted in lower net exports to New England in real-time relative to the day-ahead schedule.

The colder temperatures resulted in some load forecast error on December 24, with actual loads coming in 575 MW to 1,010 MW greater than the forecast between HE 12 and HE 16, and from HE 22 through the end of the day. Despite the load forecast error, real-time load was close to or under day-ahead cleared demand for most of the day, indicating that enough demand cleared in the day-ahead market to satisfy real-time energy needs.

Supply Mix: Higher gas prices resulted in oil generation being committed in the day-ahead energy market on December 23 and 24. This can be seen in Figure 2-15 below, which shows the hourly cleared MWs in the day-ahead market by fuel type.[30] To provide additional insight, this figure separates out oil and gas generation that was associated with dual-fuel combined cycle units. For example, generation from dual-fuel combined cycle units that cleared day-ahead awards on oil are labeled as "Oil Dual-Fuel CC" while day-ahead awards associated with all other oil generation is labeled as "Oil - Other." The right vertical axis corresponds to the price of gas.

Figure 2-15: Day-Ahead Generation Obligation and Gas Price, Dec. 23-24

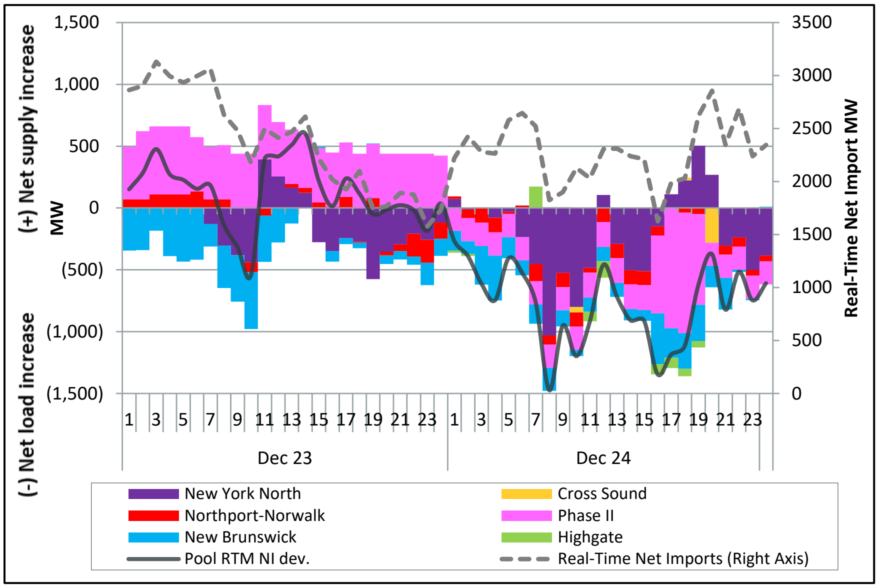


Oil-fired generation began clearing more energy in the day-ahead market beginning at HE 11 on December 23 when the average hourly gas price rose from $6.66/MMBtu to $30.05/MMBtu. Gas prices continued their upward climb on December 24, rising to an average system gas price of $35.99/MMBtu. Production from oil generation increased even further in response to the higher gas prices, and day-ahead awards associated with oil-fired generation rose to upwards of 27% of the system total. Despite the higher gas prices over these two days, some gas-fired resources continued to clear day-ahead energy awards. Gas-fired generation accounted for roughly 22% of all energy awards in the day-ahead market over this period.

Net Imports: During the capacity scarcity condition, real-time net imports from neighboring control areas decreased relative to day-ahead cleared net imports. Deviations between day-ahead cleared and real-time scheduled MWs by interface are illustrated in Figure 2-16 below.

[30] The "Other" category includes energy storage, propane, landfill gas, and other biomass solids.

Figure 2-16: Day-Ahead vs. Real-Time Net Import Deviations By Interface



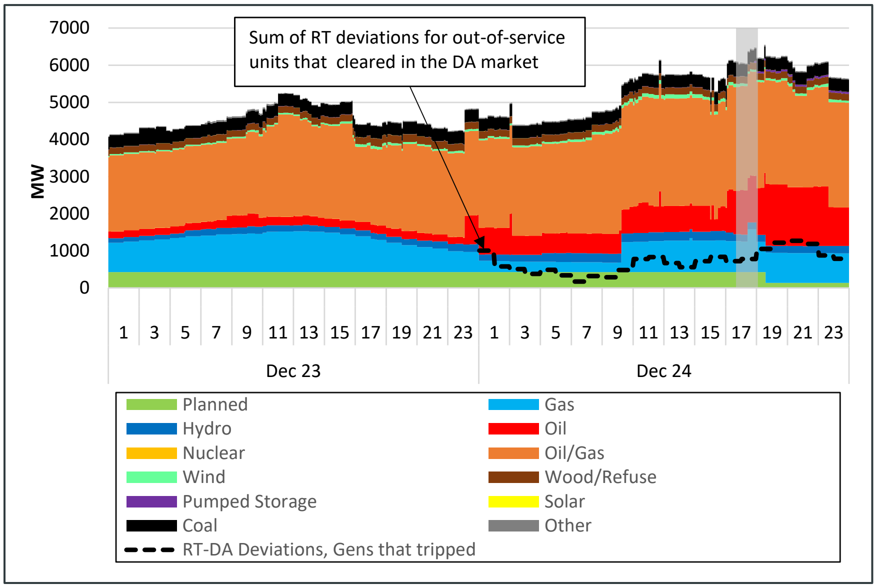
On December 24, there was a substantial decline in real-time net imports compared to the day-ahead schedule. From HE 08 to HE 11 and HE 14 to HE 18, there were 910-1,475 MW fewer net imports in real-time. Around the time of the capacity scarcity conditions in the afternoon, the most substantial reductions in net imports occurred over the Canadian interfaces due to high demand and transmission system issues there. The reductions over the Phase II intertie with Quebec were the most notable. The high demand in Quebec was likely due to increased electrification, which leads to stressed system conditions there during regional cold snaps.[31] Phase II underperformed compared to seasonal averages on December 24. On December 24, the second coldest day of Winter 2023, net interchange at Phase II was 1,320 MW from HE 01 to HE 15, the full total transfer capability (TTC) of the interface on that day. However, net interchange averaged just 681 MW from HE 16 to HE 19, including just 535 MW in HE 17 and HE 18 when capacity scarcity conditions led to a shortage event.[32] Net interchange at Phase II returned to 1,320 MW from HE 20 to HE 24.

Unplanned Generator Outages: The system lost a large volume of generation capacity shortly before and during the operating day on December 24 due to unplanned generator outages. The outages were driven by mechanical problems rather than by fuel availability issues. While out-of-service capacity varied throughout the day based on the start and end times of the outages, the sum of out-of-service generation that tripped on December 23 and December 24 was about 2,180 MW. Most of the resources that tripped were older, lower capacity factor, generators that are typically only committed during tight system conditions, such as those seen during this event. Figure 2-17 illustrates out-of-service generation capacity, with unplanned outage capacity further broken out by generator type. The capacity shortage condition is indicated by the gray area.

[31] Quebec's grid is discussed more in the following article: Hydro-Québec expects record demand as extreme cold spell looms.

[32] For more on the capacity scarcity conditions on December 24, 2022, see Section 2.5.

Figure 2-17: Planned and Unplanned Outages By Generator Type[33]



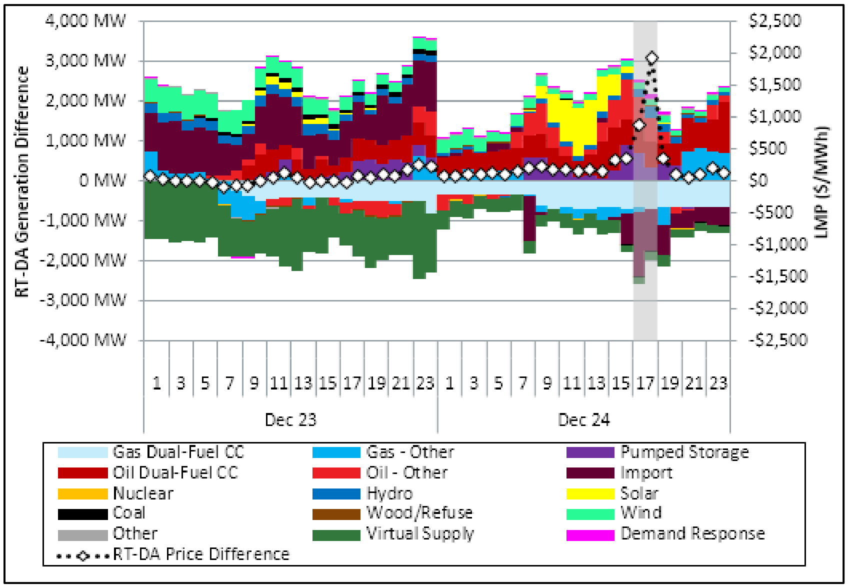
Over the two-day period, total generation that was out of service peaked during the capacity scarcity conditions. Total *unplanned* outage capacity (including unplanned outages that began before December 23) ranged from about 5,610 to 6,050 MW during the hours with capacity scarcity conditions (HE 17 and 18) on December 24, an increase of about 1,470-1,900 MW compared to the previous day. The following bullet points detail the most impactful generator outages that contributed to the tight system conditions:

- Three large oil-fired generators, totaling 1,365 MW, tripped between just before midnight on December 23 and during the afternoon of December 24.
- Around 380 MW of gas generation went out of service in the morning on December 24.
- Another 350 MW of gas generation tripped offline during the capacity scarcity conditions in HE 18.

Supply Mix Changes: The unplanned outages and net import deviations resulted in changes to the real-time supply mix compared to the day-ahead mix. The breakdown in differences between day-ahead and real-time generation obligations is shown in Figure 2-18 below.

[33] This figure combines outage data from the Control Room Operations Window (CROW) system with real-time operational data. If a generator has a physical reduction logged in CROW, or if its real-time operational capability is less than its seasonal claimed capability, that generation is considered out of service (accounting for overlaps). Accounting for real-time operational data is necessary because not all outages are required to be logged in CROW.

Figure 2-18: Differences between Hourly Real-time and Day-Ahead Generation Obligations and LMPs



During several hours on December 24, there was significantly less real-time gas generation compared to the day-ahead schedule, primarily due to generator trips and a large (660 MW) dual-fuel generator switching to oil in real-time. Additionally, large decreases in imports occurred leading up to and during the capacity scarcity conditions.[34] During the shortage event, there was increased fast-start generation from pumped-storage and oil-fired generators.

Most of the additional real-time generation commitments were made by the market software rather than manually by the operators. From HE 17 to HE 18, the real-time market software committed 2,560-2,680 MW of fast-start generation. The system operators manually committed 175-200 MW of generation during the same period.

[34] Figure 2-18 illustrates supply-side deviations, and therefore shows imports rather than net interchange (which accounts for exports).

2.7 Energy Prices, Reserve Prices, and Uplift

Energy and reserve prices from December 24 are shown in Figure 2-19 below, while reserve margins for each reserve requirement are shown in Figure 2-20. The timeframe of the capacity scarcity conditions is highlighted in gray.

Figure 2-19: Five-Minute Energy and Reserve Prices, System Level

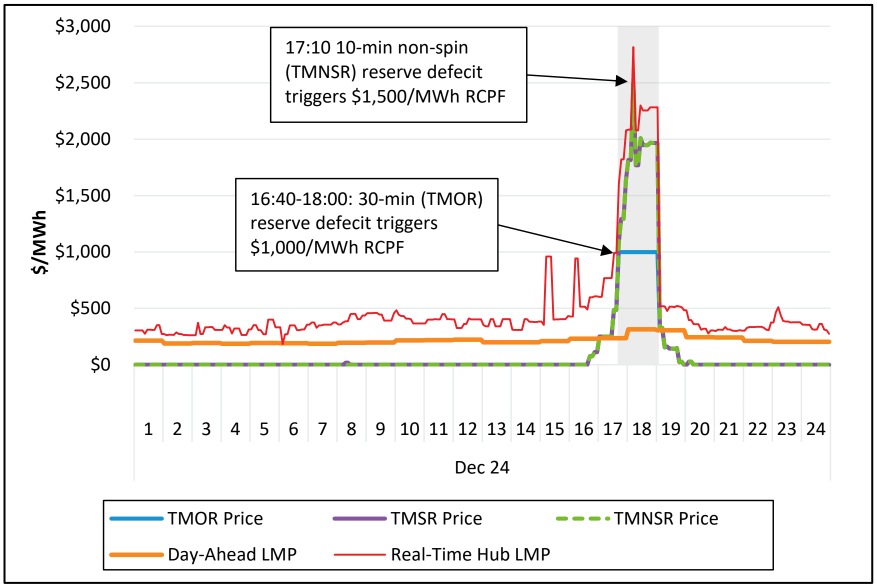
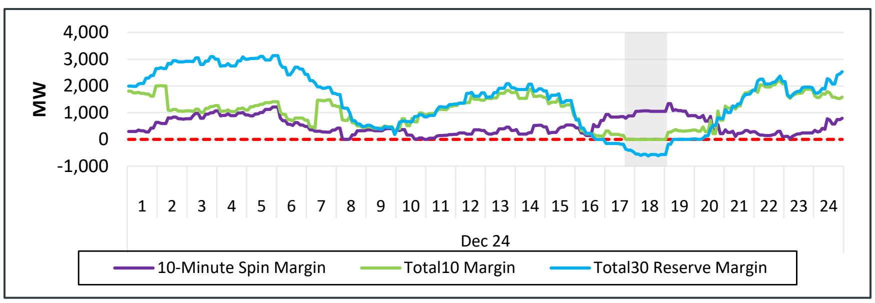


Figure 2-20: Reserve Margins



Day-ahead and real-time Hub prices averaged $217.27/MWh and $494.52/MWh, respectively. Real-time prices were significantly higher than day-ahead prices for most of the day, but the most prominent deviations occurred from HE 15 to HE 19, when real-time prices averaged about $777/MWh higher than day-ahead prices.

Real-time prices first jumped to around $1,000/MWh at 15:10, before the capacity scarcity conditions began at 16:40. Five-minute real-time Hub prices peaked at $2,816/MWh from 17:10 to 17:15, when the reserve price was $2,500/MWh. Price separation between the load zones and the Hub (not shown in the graph) was minimal during the capacity scarcity conditions. Compared to the Hub, price separation during HE 17 and 18 ranged from -3% to 1%.

The majority of the high energy prices during the CSC was due to high reserve pricing which was incorporated into the LMP. During the scarcity event, there were deficits in both the thirty-minute operating reserve (TMOR) requirement and the ten-minute reserve requirement. These deficits triggered reserve constraint penalty factors (RCPFs) of $1,000/MWh and $1,500/MWh, respectively. The TMOR penalty factor was in effect from 16:40 to 18:00, a total of 17 five-minute pricing intervals; in one of these intervals, the ten-minute penalty factor was also activated. The ten minute spinning reserve (TMSR) requirement did not bind at any time during the event. Yet, the TMSR price reached $2,500/MWh because reserve price are "cascaded" to ensure that higher quality reserve products are paid at least as much as lower quality reserve products.

After HE 18, reserve margins increased as load decreased from the day's peak. At 18:05, the TMOR deficit ended, causing the TMOR price to decline to $322/MWh and bringing an end to the capacity scarcity conditions.

Uplift: On December 24, NCPC payments totaled $1.5 million, which represented only a small percentage (1.8%) of total energy market payments on that day. Nearly all the NCPC payments (97%) on December 24 occurred in the real-time market. Over half of the real-time NCPC payments (54%) were made to units for lost opportunity cost recovery (i.e., dispatch lost opportunity cost NCPC and rapid response pricing NCPC) rather than production cost recovery.

2.7.1 Two-Settlement System Outcomes

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

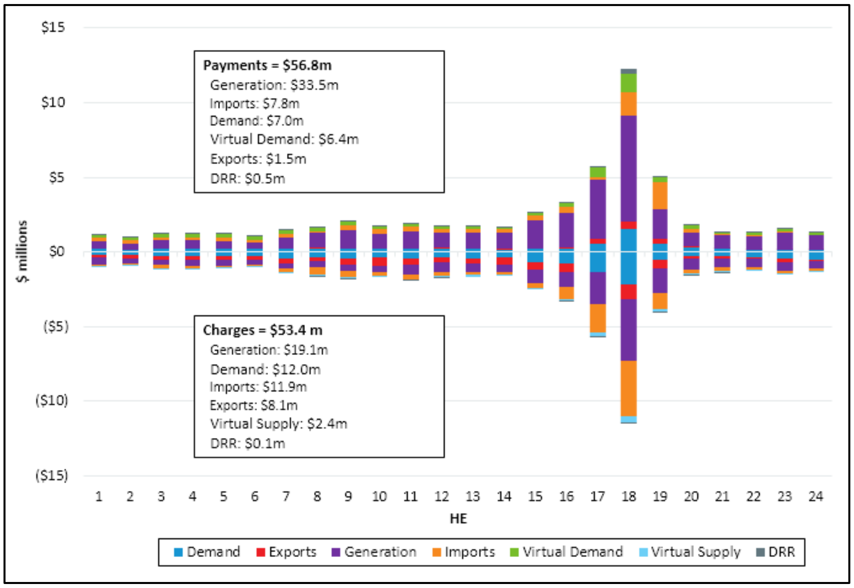
Energy Charges and Payments

Total energy charges to load on December 24 amounted to an estimated $86.9 million. Of this, $81.7 million (94%) in charges were made in the day-ahead market, while net real-time charges accounted for the remaining $5.2 million (6%).[35] Gross payments for real-time deviations totaled $56.8 million, while gross charges totaled $53.4 million.[36] Real-time energy charges and payments by hour are shown in Figure 2-21 below.

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

[36] These totals are the gross payments and charges that resulted from participant deviations from day-ahead obligations by activity type (load, generation, etc.) and location. In contrast, the $5.2 million represents net real-time charges that resulted from real-time load obligation deviations.

Figure 2-21: Real-Time Deviation Energy Charges and Payments, Dec 24



Generation incurred the largest gross real-time charges ($19.1 million) on December 24.[37] In aggregate, under-performing generators produced between 900 to 2,500 MW per hour less in real time compared to their day-ahead awards. Given that numerous units with day-ahead awards experienced unplanned outages on December 24, these real-time charges to generators are to be expected. There were also significant charges to demand ($12.0 million) as some load-serving entities had to buy more energy in real-time than they had purchased in the day-ahead market. Large charges also went to imports ($11.9 million) and exports ($8.1 million). On the payments side, the majority of payments went to generators ($33.5 million) that produced more energy in real time than they had cleared in the day-ahead market. Significant payments were also made to imports ($7.8 million), demand ($7.0 million), and virtual demand ($6.4 million).

Forward Capacity Market (FCM) Pay-for-Performance

On December 24, 17 consecutive five-minute intervals of system-wide scarcity conditions triggered the first Pay-for-Performance (PfP) event since 2018. During this period, each participant's capacity supply obligation was multiplied by the balancing ratio to calculate a capacity resource's expected obligation to provide energy or reserves during the scarcity condition.[38] Resources without a CSO receive PfP payments for any energy or reserves provided. Resources are credited or charged the PfP rate of $3,500/MWh for deviations from their forward capacity position.

The Pay-for-Performance settlement effectively reduces a resource's base capacity revenue for underperforming resources, and increases revenue for over performing resources. The transfer is among supply resources, meaning that load is not exposed to PFP risk. A resource's financial

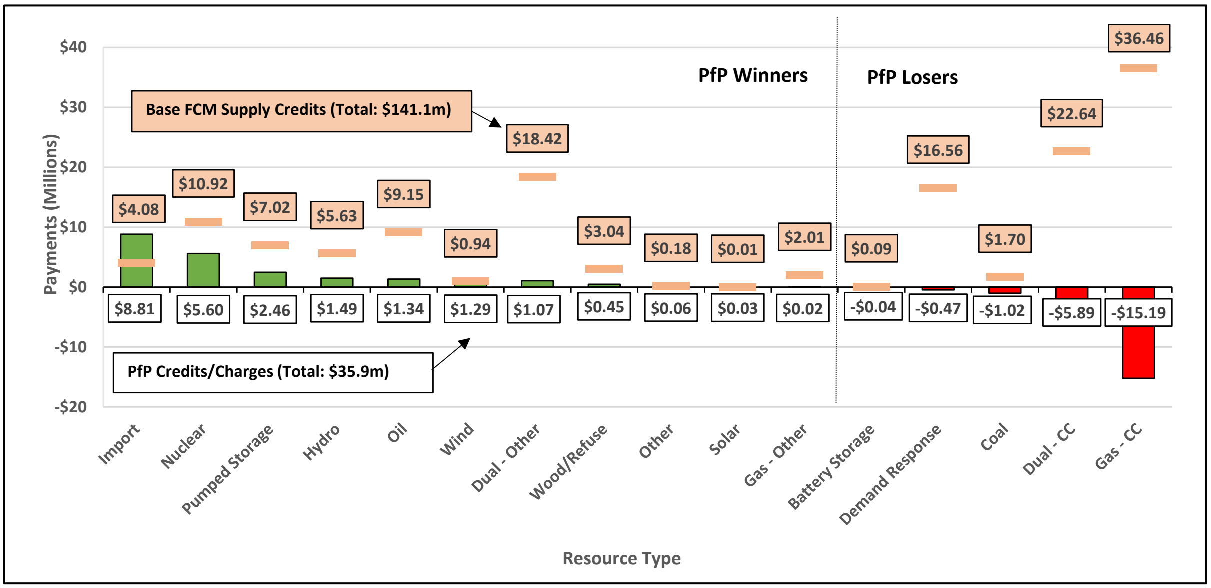
[37] Gross real-time charges to generation are calculated in three steps. First, each participant's negative generation deviation at each location (their day-ahead generation in excess of their real-time generation) is calculated. Second, that negative generation deviation is multiplied by the LMP at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

[38] For more information on the balancing ratio, see Section III.13.7.2.3 of the tariff.

obligation is based on its position in the forward capacity auction, which can be adjusted in secondary auctions before the delivery month. Gross capacity payments for December 2022 totaled $141.1 million

For this event, the balancing ratio was 67%, meaning capacity resources were expected to provide an average of 67% of their contracted capacity in the form of energy or reserves. Aggregated by fuel type and ranked, we show resource performance through PfP charges and credits alongside gross FCM credits in Figure 2-22 below.[39]

Figure 2-22: Capacity Market Settlements by Fuel Type (December 2022)



Import resources were the best-performing resource type, with over $6.5 million (74%) of their total $8.81 million in PfP payments going to import transactions without an associated CSO. Following import resources, *nuclear resources* received the second highest net PfP payment; these generators operate as baseload resources at their full CSO MW during all hours and typically over-perform relative to their CSO. Import resources and nuclear resources were two of the best performing resource groups during the 2018 PfP event as well.

Gas-fired and dual-fuel resources were the worst performers. While cold weather led to forced outages for some of the gas fleet, gas resource under-performance was generally a result of high gas prices and operational inflexibility. Spot natural gas prices climbed to over $30/MMBtu, pushing gas generation out of economic merit order in favor of relatively cheaper oil generation in the day-ahead energy market.[40] Once system conditions tightened in real time and system-wide LMPs increased significantly, operating limitations, such as start-up and notification times, prevented many gas-fired resources from coming online in time to contribute to meeting the load and reserve requirement during the CSC.

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

[40] More information on fuel prices in Q4 2022 can be found in Section 2.2.2

2.8 Market Performance on February 3-4, 2023

This section of the report looks at market performance during a "cold snap" that occurred on February 3-4, 2023.

2.8.1 Event Overview

Friday, February 3 and Saturday, February 4 saw the coldest temperatures of Winter 2023, with daily lows of -6°F and -10°F, respectively. These days also saw the highest daily average natural gas prices of Winter 2023 ($37.47-49.68/MMBtu). Similar to the December 24 event, oil-fired generation was in merit and made up a significant portion of the supply stack, and there were fewer real-time imports compared to the day-ahead schedule due to high demand in Canada. In fact, on February 4, New England became a net *exporter* over Phase II for the first time since May 2016. February 4 also saw several unplanned generator outages, resulting in a total loss of about 2,400 MW at the peak compared to the day-ahead schedule. Participants responded to the tight conditions by self-scheduling additional generation in real-time.

While there were no capacity scarcity conditions or significant reserve pricing, LMPs were high during the February cold snap, peaking at $329.98/MWh in the day-ahead market on February 3, and at $461.52/MWh in real-time on February 4. The following subsections discuss the event in detail, its outcomes, and an assessment of how the market performed.

2.8.2 Drivers of Tight System Conditions

Weather and Load: The cold temperatures on February 3 and 4 resulted in the highest loads of the season and an increase in residential natural gas demand. Below, Figure 2-23 shows actual and forecasted temperatures and loads on February 3 and 4. The red and blue dots represent the daily high and low values, respectively. The green bars show the temperature load forecast errors. The load forecast error bars (yellow) are flipped so that their direction is consistent with the expected impact of the temperature forecast error (i.e., lower temperatures result in higher loads than forecast). Figure 2-24 compares day-ahead cleared demand to real-time metered load.

Figure 2-23: Actual and Forecasted Temperatures and Loads, February 3-4

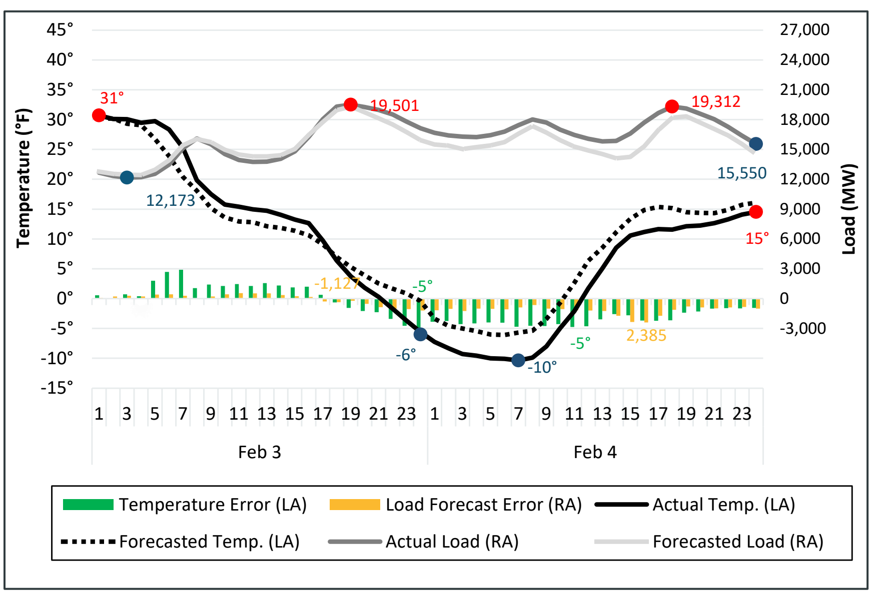
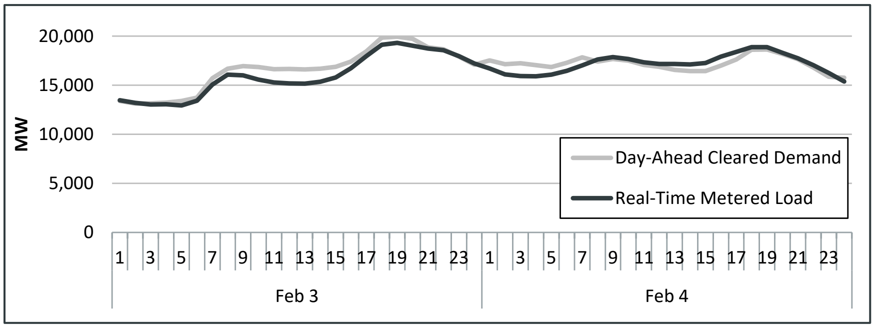


Figure 2-24: Day-Ahead Cleared Demand vs. Real-Time Load, February 3-4



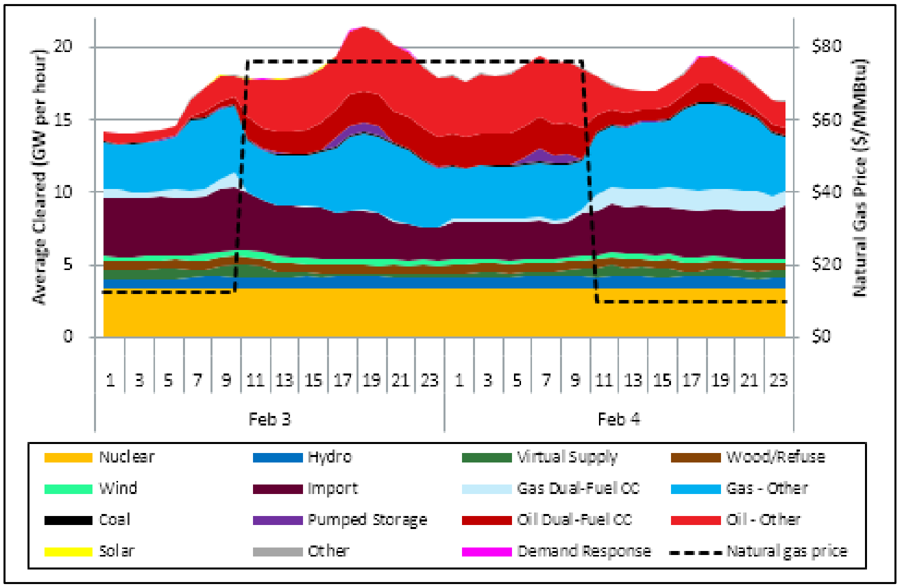
Temperatures began falling below 0°F around HE 22 on February 3, and remained below 0°F through HE 11 on the following day. Actual temperatures were slightly warmer than the forecast during the morning and midday hours on February 3, and load forecast error (yellow bars) was minimal. By the end of the day on February 3, actual temperatures were 5°F colder than the forecast, and remained 4-5°F below the forecast until HE 12 on February 4. There was also significant temperature forecast error during the evening peak on February 4, with actual temperatures again dropping about 4°F below the forecast during HE 16-19. Actual loads were about 650-2,385 MW greater than the forecast from HE 21 on February 3 until HE 19 on February 4, with the largest errors occurring during the evening peak hours on February 4. The peak loads on February 3 (19,501 MW) and February 4 (19,312 MW) were the two highest daily peak loads of Winter 2023.

Despite the higher loads than forecast, Figure 2-24 shows that real-time load came in close to or under day-ahead cleared demand for most of the period. This trend reversed just before the evening peak on February 4, and actual loads were 770-920 MW greater than the day-ahead cleared amount during HE 15-17.

Supply Mix: Similar to December 23-24, 2022, high gas prices led to an increase in energy production from oil-fired generators on February 3-4. This can be seen in Figure 2-23 below, which shows the hourly cleared MWs in the day-ahead market by fuel type.[41] To provide additional insight, this figure separates out oil and gas generation that was associated with dual-fuel combined cycle units. For example, generation from dual-fuel combined cycle units that cleared day-ahead awards on oil are labeled as "Oil Dual-Fuel CC" while day-ahead awards associated with all other oil generation is labeled as "Oil - Other." The right vertical axis measures the price of gas.

[41] The "Other" category includes energy storage, propane, landfill gas, and other biomass solids.

Figure 2-25: Day-Ahead Generation Obligation and Gas Price, Feb. 3-4

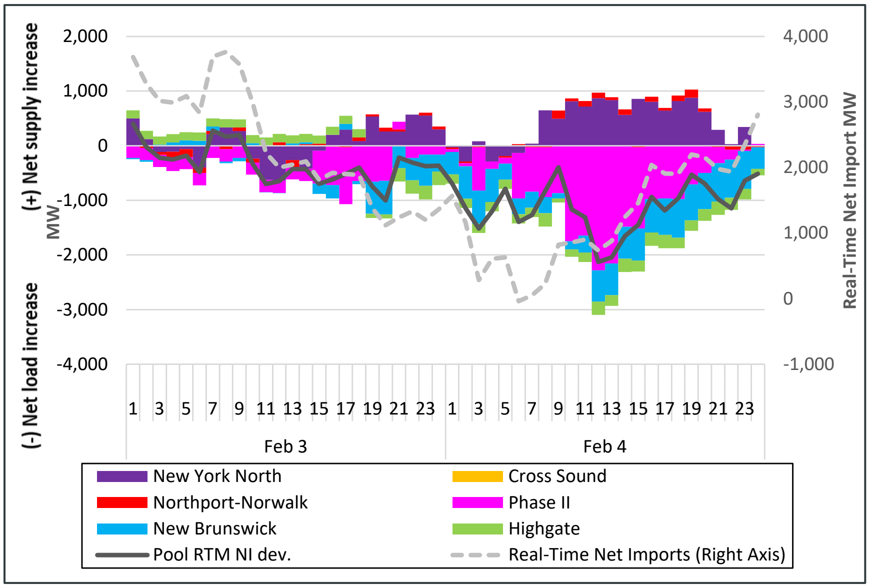


In response to the extreme cold weather experienced during this period, the average price of gas in New England soared to $76.42/MMBtu for the February 3 gas day.[42] During this 24-hour period of elevated gas prices, oil-fired generation cleared additional energy awards in the day-ahead market. Oil-fired generation accounted for upwards of 34% of the system total during some hours of this period and accounted for 22% for the two days. While gas-fired generators continued to clear day-ahead energy awards during the 24-hour period of elevated gas prices, almost none of these were dual-fuel combined cycle units. Many of these units instead ran on less expensive oil. In fact, day-ahead awards associated with dual-fuel combined cycle units running on oil accounted for as much as 12% of the supply total during some hours on the February 3 gas day.

Net Imports: On February 3 and 4, real-time net imports from neighboring control areas decreased relative to day-ahead cleared net imports. Deviations between day-ahead cleared and real-time scheduled MWs by interface are illustrated in Figure 2-26 below.

[42] A "gas day" is a 24-hour period during which gas is nominated and scheduled. It starts at HE 11 eastern time and ends at HE 10 eastern time the following day.

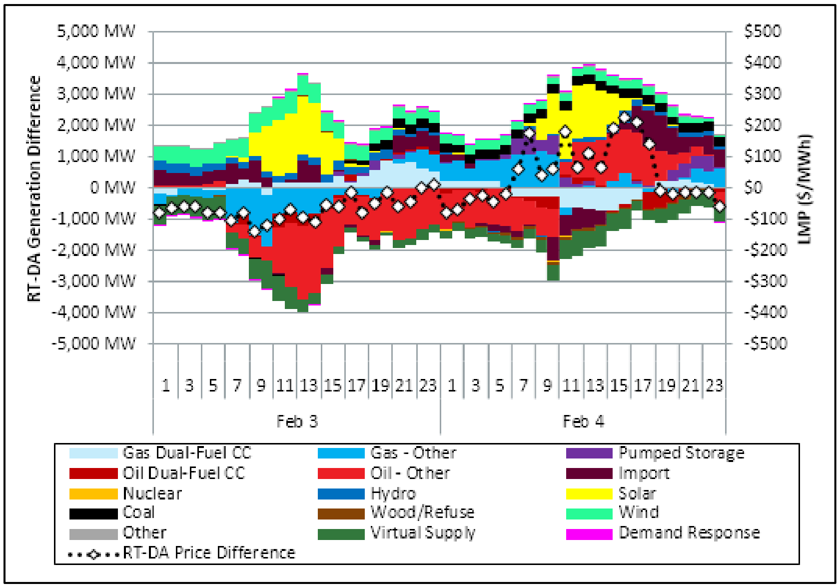
Figure 2-26: Day-Ahead vs. Real-Time Net Import Deviations By Interface



On February 3 and February 4, net interchange at Phase II averaged 1,021 MW and 137 MW, respectively. On February 3, from HE 01 to HE 14, net interchange at Phase II averaged 1,320 MW, the full TTC, but averaged just 604 MW over the rest of the day (HE 15 to HE 24). On February 4, the cold temperatures persisted and New England became a net *exporter* over Phase II for the first time since 2016 from HE 03 to HE 13. Over these 11 hours, net *exports* averaged 598 MW, and reached a high of 799 MW in HE 08. Additionally, New England exported over both the Highgate and New Brunswick interfaces on this day, the other two interfaces connecting New England and Canada.

Supply Mix Changes: There were changes in the real-time supply mix compared to the day-ahead mix on February 3 and 4 as a result of unplanned generator outages, additional renewable generation, and supplemental commitments by system operators, among other factors. The breakdown in differences between day-ahead and real-time generation obligations is shown in Figure 2-27 below.

Figure 2-27: Differences between Hourly Real-time and Day-Ahead Generation Obligations and LMPs



On February 3, there was less generation needed in real-time compared to the day-ahead cleared amount for several hours. There was also a large volume of additional renewable generation in real-time, as shown by the yellow and light green bars in Figure 2-27. These factors led to gas and oil generation being backed down, particularly around midday, and resulted in lower real-time energy prices compared to day-ahead prices.

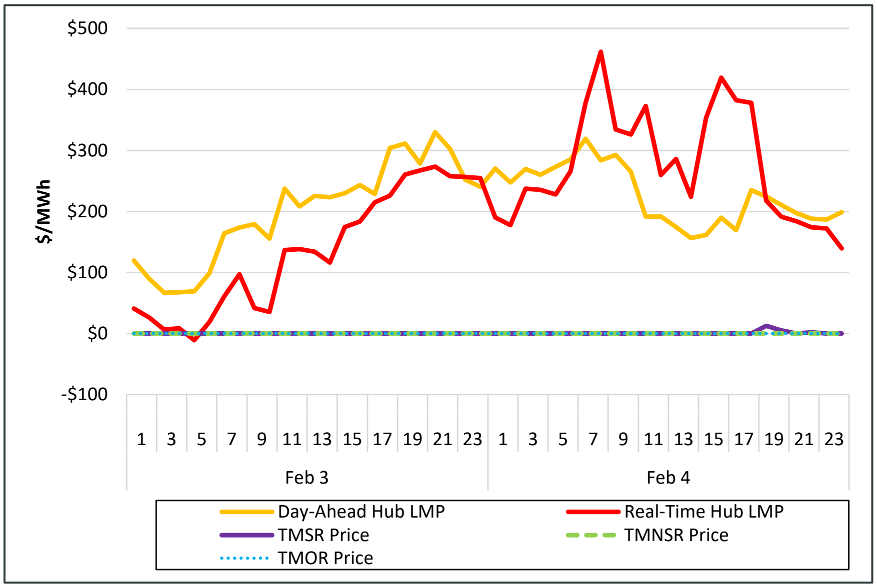
On February 4, there were fewer net imports in real-time, and additional generation was needed compared to the day-ahead cleared amount around the evening peak. There were also several unplanned generator outages, which contributed to the negative oil and dual-fuel deviations shown in Figure 2-27 on February 4. Multiple generators went out of service due to mechanical issues in the evening on February 3 and throughout the day on February 4, resulting in a total deviation of nearly 2,400 MW during the evening peak on February 4.[43] Some of the losses were replaced by additional real-time self-scheduled generation. From HE 11-23 on February 4, output from generators that self-scheduled in real-time was 1,450 to 2,530 MW greater than the day-ahead cleared amount. Additionally, the ISO operators made supplemental commitments for capacity concerns, with an hourly output of about 200 to 660 MW during HE 08-21 on February 4. Despite the unplanned outages and fewer net imports in real-time (discussed further below), non-spinning reserve margins remained adequate and the system did not see capacity scarcity conditions.

[43] Note that Figure 2-27 does not show this 2,400 MW deviation because the data in the graph is aggregated by fuel type.

2.8.3 Energy Prices, Reserve Prices, and Uplift

The high natural gas prices on February 3 and 4 resulted in high energy prices. Energy and reserve prices are shown in Figure 2-28 below.

Figure 2-28: Five-Minute Energy and Reserve Prices, System Level



On February 3, day-ahead energy prices at the Hub peaked at $329.98/MWh during HE 21. Real-time prices were lower than day-ahead prices during most hours, due to lower real-time generation needs compared to the day-ahead cleared amount and a large volume of additional renewable generation in real-time. The trend reversed on February 4, when losses in net imports relative to the day-ahead schedule and unplanned generator outages affected the supply mix. Hourly real-time Hub prices peaked at $461.52 during HE 08 on February 4, about $178 higher than the day-ahead price during that hour.

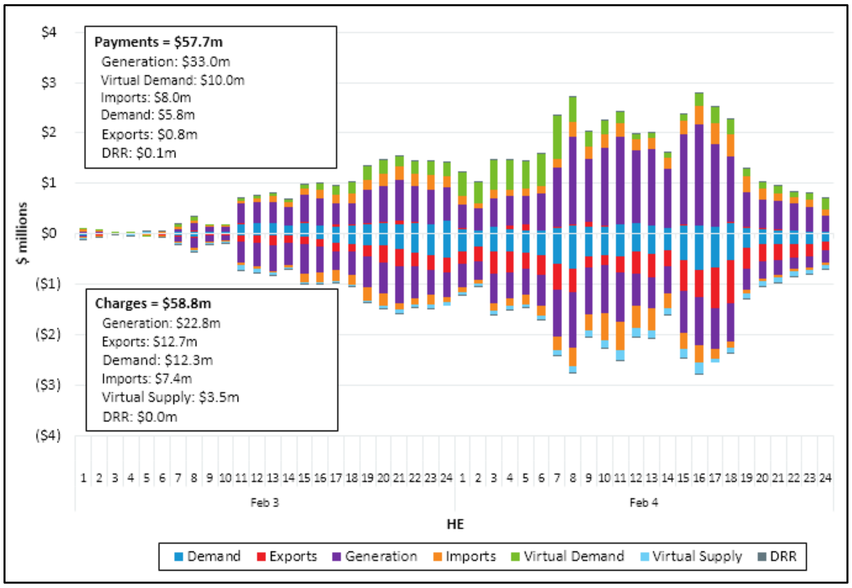
The only type of reserve pricing that occurred during the period was TMSR pricing (purple line). TMSR pricing was minimal, ranging from $2 to $13/MWh for three hours in the evening on February 4.

NCPC: About $1.1 million in NCPC was paid on February 3 and 4 with about $1.0 million paid on February 4 alone. Despite the relatively high payments on the 4, NCPC was less than 1% of energy payments on the day. Payments were spread amongst many assets, with one exception. One asset received $346k on February 4 after the ISO ordered them to remain online for reliability.

2.8.4 Two-Settlement System Outcomes

Total energy charges to load on February 3 and 4 amounted to an estimated $192.3 million. Of this, $183.8 million (96%) in charges were made in the day-ahead market, while net real-time charges accounted for the remaining $8.5 million (4%). Gross payments for real-time deviations totaled $57.7 million, while gross charges totaled $58.8 million.[44] Real-time energy charges and payments by hour are shown in Figure 2-29 below.

Figure 2-29: Real-Time Energy Charges and Payments, Feb 3-4



The largest real-time energy charges on February 3 and 4 were incurred by generators. Collectively, this group was charged $22.8 million over this two-day period as a result of producing less generation in real-time than they had cleared in the day-ahead market. Significant charges were also incurred by exports ($12.7 million), demand ($12.3 million), and imports ($7.4 million). Meanwhile, generators that over-produced relative to their day-ahead obligations were the largest recipient of real-time energy market payments. Collectively, this set of generators received $33.0 million. Other recipients of noteworthy real-time payments included virtual demand ($10.0 million), imports ($8.0 million), and demand ($5.8 million).

[44] These totals are the gross payments and charges that resulted from participant deviations from day-ahead obligations by activity type (load, generation, etc.) and location. By contrast, the $8.5 million represents net real-time charges that resulted from real-time load obligation deviations.

Section 3
Review of the Seventeenth Forward Capacity Auction

This section presents a review of the seventeenth Forward Capacity Auction (FCA 17), which was held in March 2023 and covers the capacity commitment period (CCP) beginning June 1, 2026 through May 31, 2027. The section includes an assessment of market competiveness (including IMM mitigation), key auction inputs, and overall outcomes.

We begin with a summary of FCA 17 outcomes. At the beginning of the auction, qualified capacity (37,386 MW) exceeded the Net Installed Capacity Requirement (Net ICR) of 30,305 MW by 7,081 MW. The surplus increased from FCA 16 (5,985 MW) as a result of a 1,340 MW (4%) decrease in the Net ICR year-over-year, and no major resource retirements. FCA 17 cleared 31,370 MW of capacity, resulting in a surplus of 1,065 MW above Net ICR. There was no price separation between capacity zones in FCA 17, and only one interface (New Brunswick) had a different clearing price to the rest of the system:

- All capacity zones cleared at $2.59/kW-month
- New Brunswick interface cleared at $2.55/kW-month

Payments for FCA 17 are expected to be $0.9 billion, a decrease of 9% from FCA 16, resulting from a lack of price separation in the Southeastern New England capacity zone (which occurred in the prior auction) and a lower amount of system-wide cleared capacity.

A total of 2,228 MW of capacity dynamically de-listed in FCA 17[45]; including 800 MW of gas-fired generation, 780 MW of oil-fired generation, and 438 MW of coal-fired generation. New entry of capacity totaled 773 MW, primarily consisting of battery storage projects (400 MW), solar projects (124 MW), and passive demand response (122 MW). The substitution auction following FCA 17 did not take place as no active demand bids entered.

3.1 Review of FCA 17 Competitiveness

We review competitiveness both before and after the primary auction occurs. Prior to the auction, certain bids and offers can be mitigated to IMM-determined values if they are inconsistent with a resource's capacity costs. After the auction, participant behavior is reviewed in light of the presence of market power; we then evaluate for the potential to exercise of market power. Based on the pre-auction mitigations, excess capacity during the auction, and liquidity of dynamic de-list bids, we found no evidence of uncompetitive behavior during FCA 17.

In FCA 17, the IMM reviewed 454 MW of general static de-list bids from three resources. We mitigated the price of one bid accounting for 16 MW, or 4%, of general static de-list bids. When a static de-list bid price is mitigated to a lower price, it limits the ability of suppliers to exercise market power should we determine that they are pivotal (described below). In addition to low volumes of static de-list bids, FCA 17 saw only three retirement de-list bids totaling 8 MW. We do not review retirement de-list bids below 20 MW.

[45] A dynamic de-list bid is a one year de-list bid submitted at a price below the Dynamic De-list Bid Threshold (DDBT), which was $2.59/kW-month in FCA 17. Dynamic de-list bids are not subject to mitigation from the IMM.

In FCA 17, we reviewed 65 MW of new supply offers from ten resources. We mitigated the price of five offers accounting for 30 MW, or 46%, of all new supply offers. When a new supply offer is mitigated to a higher price, it limits the ability of suppliers to exhibit buyer-side market power through clearing price suppression. IMM mitigation of new supply offers decreased significantly from last year due to lower Offer Review Trigger Prices (ORTPs) for most technology types.[46]

Pivotal Supplier Test (PST) and Residual Supply Index (RSI)

For FCA 17, we conducted the PST at the system level prior to the start of the auction. In order to be pivotal system-wide, a supplier needed an effective capacity portfolio of approximately 3,639 MW; no suppliers met this criterion at the system level.

The RSI was measured for the entire system using the Net ICR as the demand benchmark. The RSI was 102%, up slightly from 101% in FCA 16; a lower Net ICR increased the pre-auction supply margin. RSI increases at the system level indicate fewer opportunities for pivotal suppliers and seller-side market power.

Intra-Round Activity

The auction entered the fourth round with 3,053 MW of excess capacity at the dynamic de-list bid threshold (DDBT) price of $2.59/kW-month. We do not review de-list bids below the DDBT because the threshold represents the anticipated, competitive clearing price of the auction. The low volume of pivotal supplier de-list bids combined with the bid prices occurring below the DDBT makes the exercise of supplier-side market power unlikely.

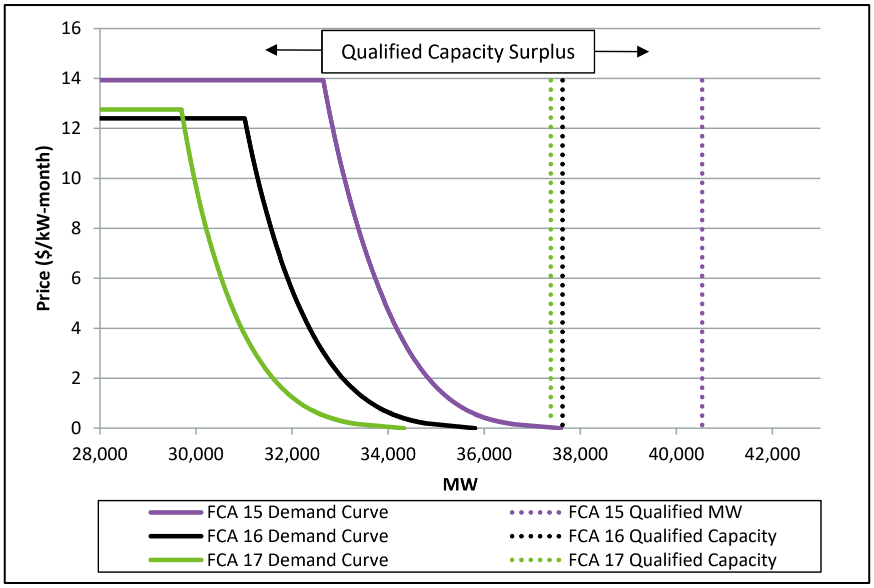
3.2 Auction Inputs

FCA 17 was the fourth auction with a demand curve that relied solely on the Marginal Reliability Impact (MRI) methodology in the calculation of the sloped system and zonal demand curves. The MRI methodology estimates how an incremental change in capacity affects system reliability at various capacity levels.[47] The difference between demand curves and qualified capacity for FCAs 15, 16, and 17 are shown in Figure 3-1 below.

[46] The ISO calculates Offer Review Trigger Prices as the minimum capacity price a new resource would need to be economic in New England's energy market. ORTPs can be found on the ISO's website here.

[47] For more information on why the ISO implemented a sloped demand curve, see Section 6.1 of the 2019 AMR.

Figure 3-1: Net ICR and System Demand Curves



The MRI curve is scaled to show prices that load is willing to pay at various levels of capacity, which in turn provides various levels of system reliability.[48] ICR and Net Cost of New Entry (Net CONE) are used as the scaling points for the MRI curve. The Net CONE for FCA 17 was $7.36/kW-month; the value reflects the breakeven capacity payment needed to cover the costs of a combustion turbine, which was selected as the most economically viable resource in the FCA 16 Net CONE study.[49] The Net ICR value for FCA 17 was 30,305 MW, 1,340 MW lower than in FCA 16. The decrease was driven by a decrease in the future load forecast and an increase in neighboring control area tie benefits.[50] The Net ICR decrease resulted in a significant inward shift of the demand curve compared to prior auctions. In FCA 17, qualified capacity saw a decrease of only 244 MW compared to FCA 16, primarily due to a reduction in new qualified capacity.

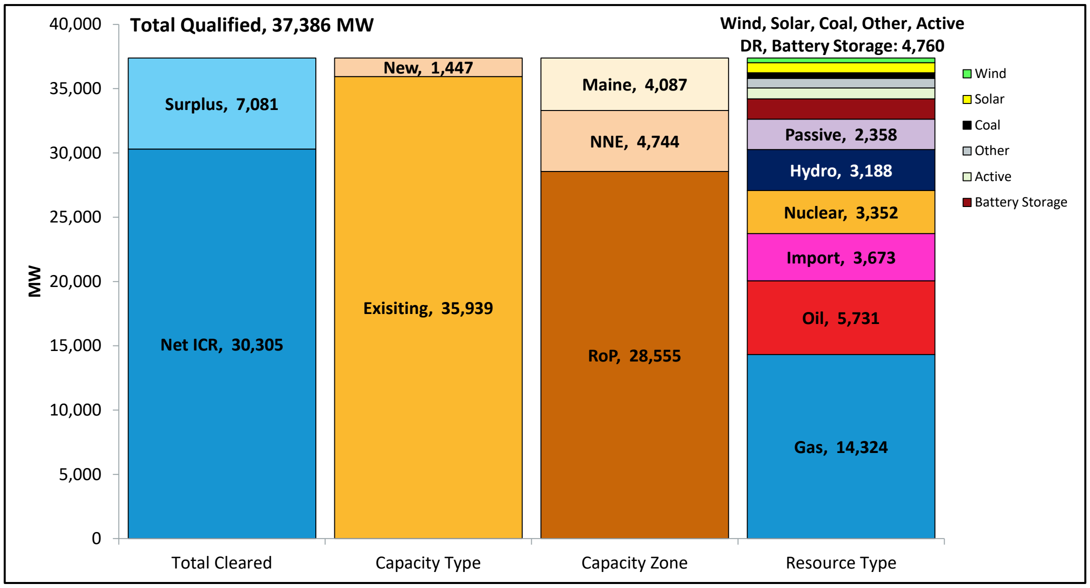
Figure 3-2 below provides a breakdown of the 37,386 MW of qualified capacity in FCA 17. The three bars to the right show the breakdown of total qualified capacity across three dimensions: capacity type, capacity zone and resource type.

[48] The system planning criteria are based on the probability of disconnecting load no more than once in ten years due to a resource deficiency (also referred to as Loss of Load Expectation or "LOLE".

[49] The market rule requires the ISO to recalculate Net CONE with updated data at least every three years. See Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(a). The study composed for the updated FCA 16 Net CONE calculation can be found here.

[50] For more information see: https://www.iso-ne.com/static-assets/documents/2022/11/icr_for_fca_17.pdf.

Figure 3-2: Qualified Capacity across Capacity Type, Zones, and Resource Type



Overall, in FCA 17, qualified capacity exceeded Net ICR by 7,081 MW, or 23%. The first orange bar (by Capacity Type) shows that the qualified capacity from existing resources exceeded the Net ICR by 5,634 MW.[51]

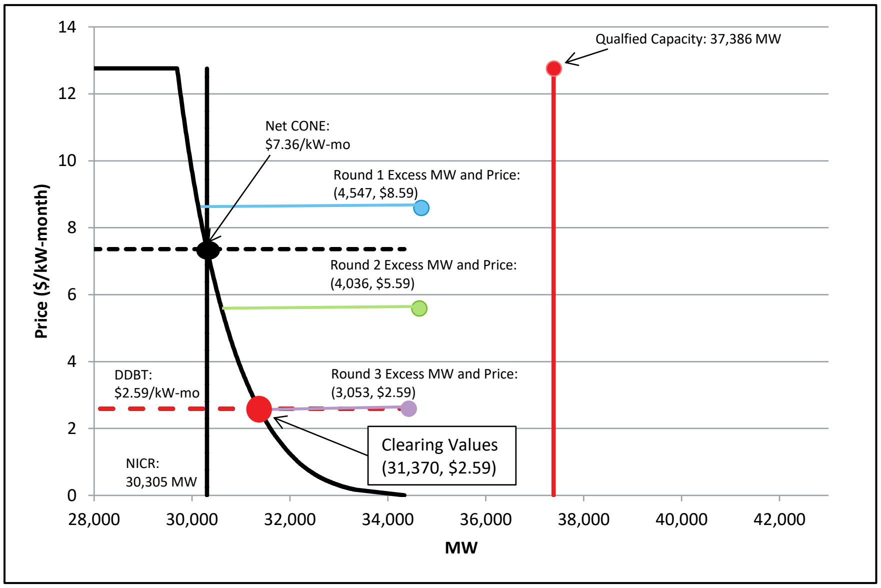
The second orange bar (by Capacity Zone) shows the Northern New England (NNE) capacity zone had 8,831 MW of qualified capacity, 236 MW more than the maximum capacity limit (MCL) of 8,595 MW for the zone. Maine, modelled as an export-constrained zone nested within NNE, had 4,087 MW of qualified capacity. This is just above the MCL of 4,065 MW, meaning some new capacity would need to leave the auction in order to accommodate the export limit. The final bar breaks down qualified capacity by resource type.

3.3 Auction Results

In addition to the amount of qualified capacity eligible to participate in the auction, several other factors contribute to auction outcomes. On the *demand* side, the demand curve, Net CONE, and Net ICR are shown in black. On the *supply* side, the qualified and cleared capacities are shown as solid and dashed red lines, respectively. The clearing price of $2.59/kW-month can be seen at the intersection of the cleared MW (dotted red line) and the demand curve (solid black line) and right at the Dynamic De-list Bid Threshold (DDBT) price of $2.59/kW-month. Lastly, the blue, green and purple markers represent the end-of-round prices, and the corresponding dots depict excess end-of-round supply.

[51] While certain imports are classified as new for other purposes in the FCA (see Section III.3.1.3 of the tariff), the IMM treats all qualified and cleared imports as existing for this report because there were no import resources in FCA 17 that increased New England's import capability.

Figure 3-3: System-wide FCA 17 Demand Curve, Prices, and Quantities



The auction closed in the fourth round for all capacity zones and interfaces. The fourth round opened with 3,053 MW of excess capacity at the system level (purple dot) and a price equal to the DDBT price, meaning existing resources could submit dynamic de-list bids to exit the market.[52]

In the fourth round, 3,477 MW of existing resources submitted de-list bids, with 2,457 MW placed one tenth of a cent below the DDBT of $2.59/kW-month. At the same price, 825 MW of import resources attempted to remove their capacity from the auction. Since the capacity leaving the auction exceeded the excess capacity entering the fourth round, one dynamic de-list bid was rationed down to match system supply to system demand. The rationed dynamic de-list bid placed at $2.59/kW-month set the auction clearing price for all capacity zones.

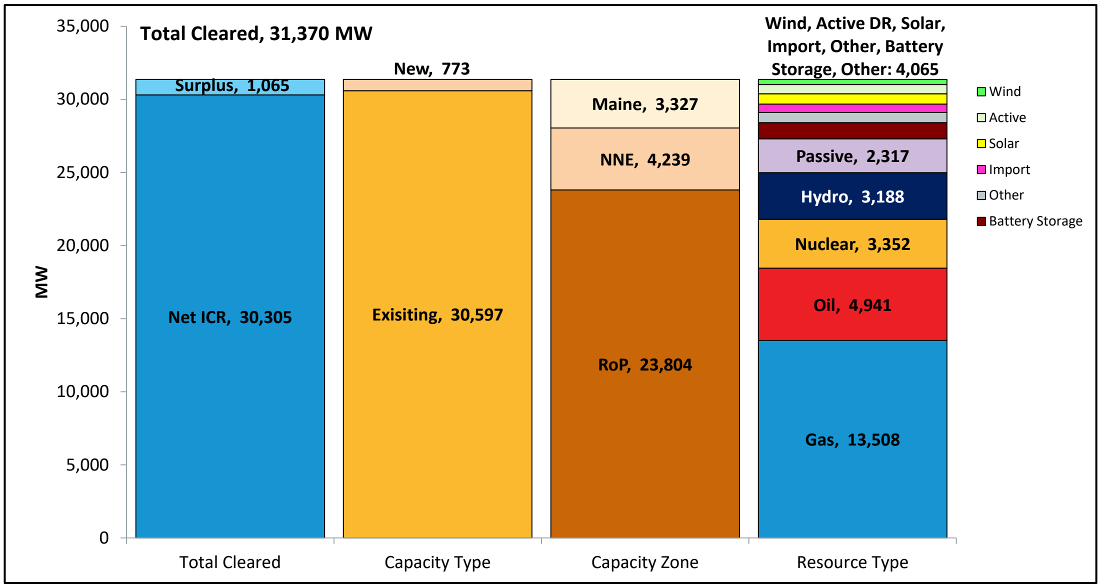
Price separation occurred at the New Brunswick interface because total supply over the interface exceeded the import limit. A rationed import offer placed at $2.55/kW-month was the final offer to clear over the interface before the import limit was reached.

3.4 Cleared Capacity

Cleared capacity across several dimensions including capacity type, capacity zone, and resource type is shown in Figure 3-4 below. The height of each grouping equals total cleared capacity. As indicated in the first column, the amount of cleared capacity in FCA 17 exceeded system-wide requirements.

[52] Excess system capacity only includes import capacity up to the capacity transfer limit. Given the surplus capacity conditions associated with prices below the dynamic de-list bid threshold, it is difficult for a participant to profitably exercise market power. Therefore, dynamic de-list bids are not subject to IMM cost review or mitigation.

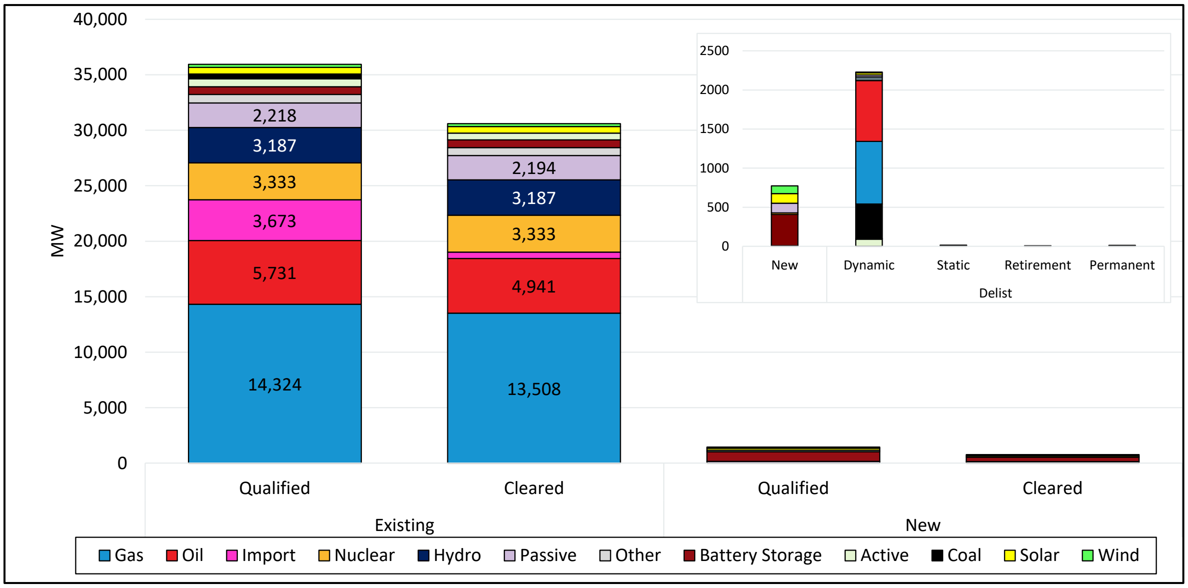
Figure 3-4: Cleared Capacity across Capacity Type, Zones, and Resource Type



As excess supply declined during the auction, total surplus relative to Net ICR fell from 7,081 MW of offered capacity to 1,065 MW of cleared capacity. The first orange bar (capacity type) illustrates that existing capacity accounted for 98% of cleared capacity. The second set of orange bars (by Capacity Zone) shows NNE cleared 7,566 MW and Maine cleared 3,327 MW of capacity, both below their respective Maximum Capacity Limits. The final bar (by Resource Type) illustrates that gas-fired resources made up the largest portion of total cleared capacity at 43%. Import resources saw the largest change in cleared capacity shares, decreasing from 5% (1,504 MW) in FCA 16 to 2% (567 MW) in FCA 17.

Qualified and cleared capacity by new and existing resource types are broken down in Figure 3-5 below. There can be up to four different bars for each resource type (qualified-existing, cleared-existing, qualified-new, and cleared-new). Additionally, the inset graph displays new entry and de-list bids (static, dynamic, permanent, and retirement) by resource type.

Figure 3-5: Qualified and Cleared Capacity by Resource Type



Imports, oil-fired, and coal-fired resources made up the largest percentage of reductions in existing capacity. Of the 3,673 MW of qualified imports, only 15% (567 MW) cleared in FCA 17.[53] Coal-fired generation did not clear any of their qualified capacity due to significant dynamic de-list bids from two resources. The dynamic de-list bid threshold was $2.59/kW-month; below the threshold, any existing resource can submit a one-year dynamic de-list bid without mitigation review. In FCA 17, 2,228 MW of capacity dynamically de-listed, with the largest shares coming from gas-fired resources (800 MW) and oil-fired resources (778 MW).

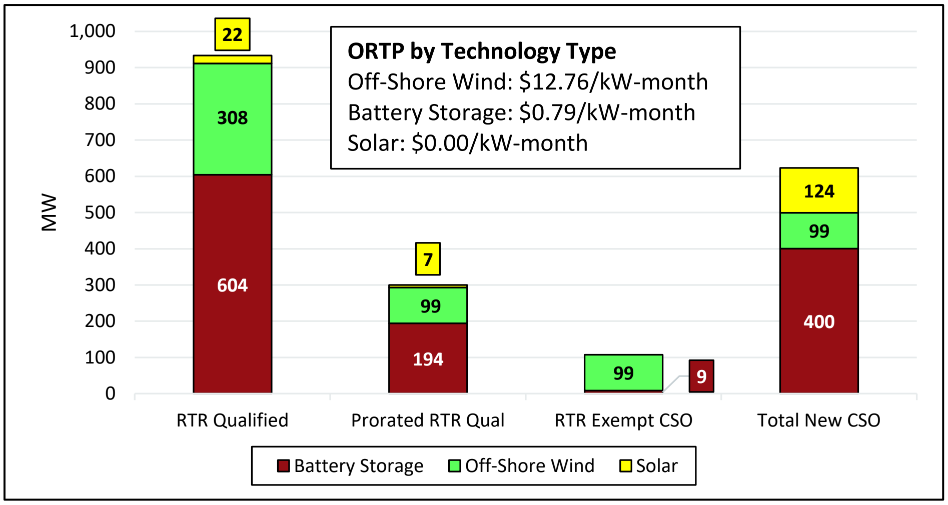
New cleared capacity in FCA 17 accounted for 773 MW, or 2%, of cleared capacity, a 34% increase from new cleared capacity in FCA 16 (576 MW). The largest new entrants were battery storage projects that cleared 400 MW of new capacity. The other renewable energy projects, solar and wind, cleared 124 MW and 99 MW of new capacity, respectively.

Sponsored Policy Entry through Renewable Technology Resource (RTR) Exemption

The renewable technology resource (RTR) exemption allowed a fixed 300 MW of state-sponsored renewable resources to qualify for FCA 17 without being subject to IMM buyer-side mitigation rules. The total qualified and cleared MW of sponsored policy resources (battery storage, wind, and solar projects) in FCA 17 are shown in Figure 3-6 below.

[53] While all other types of existing resources enter the FCA as fixed capacity, import resources must qualify and receive a new CSO every FCA. As a result, imports leaving the auction are not included in de-list MWs since de-list bids are only available to existing resources.

Figure 3-6: Sponsored Policy Resource MW (FCA 17)



In total, 934 MW of sponsored policy resources applied for the 300 MW RTR exemption in FCA 17. Of the 300 MW of qualified resources, only 108 MW received a CSO in the auction. The remaining 192 MW of RTR-exempt resources (185 MW of battery storage and 7 MW of solar) withdrew from FCA 17 post-qualification. Leftover MW from the FCA 17 RTR exemption will rollover into the next FCA, making 592 MW of exempt MW available to sponsored policy resources in FCA 18.

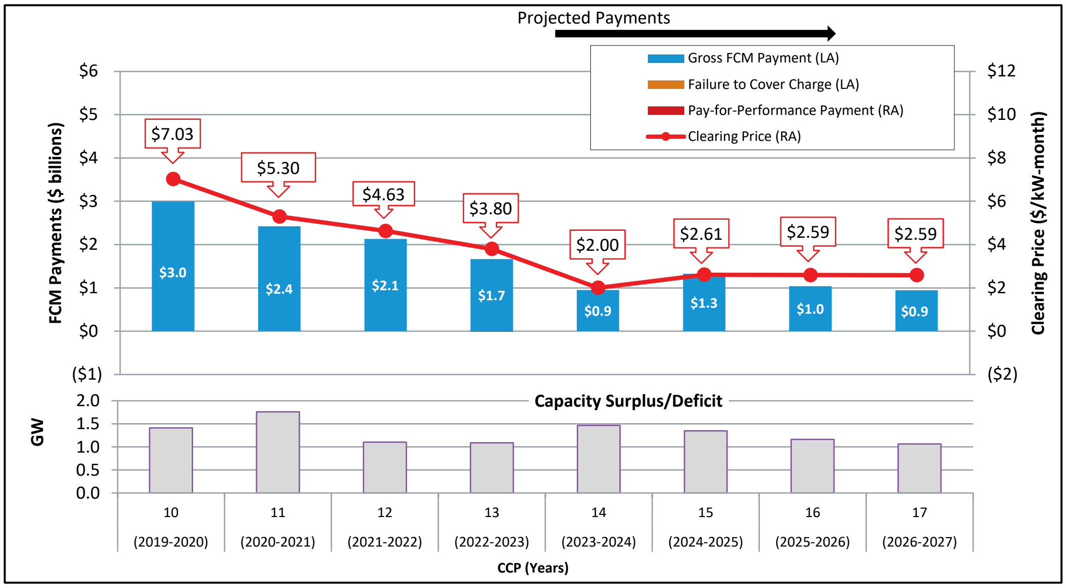
3.5 Comparison to Other FCAs

Underlying FCA clearing prices and volumes drive trends in FCM payments. Payments for capacity commitment periods (CCPs) 10 through 17 are shown in Figure 3-7 below, alongside the Rest-of-Pool clearing price for existing resources. The blue bars represent gross FCM payments by commitment period. Payments for CCPs 13 through 17 are projected payments based on FCA outcomes, as those periods have not yet been settled.[54] The red bar represents Pay-for-Performance (PfP) payments made in past commitment periods. The red line series represents the existing resource clearing price in the Rest-of-Pool capacity zone.[55] Payments correspond to the left axis while prices correspond to the right axis. Lastly, the purple bars below the payments represent a capacity surplus (positive) or deficiency (negative) compared to Net ICR.

[54] Payments for incomplete periods, CCP 13 through CCP 17, have been estimated as: $FCA\ Clearing\ Price \times Cleared\ MW \times 12$ for each resource.

[55] The Rest-of-Pool capacity zone is made up of all unconstrained import/export capacity zones.

Figure 3-7: FCM Payments by Commitment Period



The graph shows that a significant capacity surplus has led to as steady decline in capacity prices and payments since FCA 10. Projected payments for FCA 17 are $0.9 billion, relatively constant from the prior auction. The lack of price separation between capacity zones led to the small year-over-year decrease in projected payments for FCA 17 despite an identical Rest-of-Pool clearing price as FCA 16.

3.6 Assessment of the Methodology for Determining the Dynamic Delist Bid Threshold Price

In 2020, ISO-NE reviewed and significantly revised the approach to calculating the Dynamic Delist Bid Threshold (DDBT) price to better approximate the next FCA's clearing price in both a dynamic and transparent manner[56]. The new methodology has now been in place for two auctions, FCA 16 and 17. In FCA 16, the price cleared just below the DDBT and in FCA 17, the price cleared at the DDBT. In both FCAs, there was a significant volume of dynamic de-lists bids within a close range in the final auction round. Some stakeholders have expressed a concern that this may be symptomatic of an issue with the new methodology. The underlying concern seemed to be that the DDBT is having an impact on participant' willingness to undergo an IMM cost review and therefore may be unduly affecting auction outcomes. Some expressed a desire to add additional bandwidth to the formulation. We agree that it is important to review the performance and appropriateness of the market power mitigation thresholds.

Based on our analysis, we conclude that the DDBT methodology under current market conditions is performing as intended and appears to strike an appropriate balance between its competing objectives. To summarize our findings:

- While it is certainly plausible that some resources owners may be willing to accept a lower price in the DDBT range and avoid the static de-list process, there is no clear means of quantifying the extent and avoided costs associated with this path.

[56] See https://www.iso-ne.com/static-assets/documents/2020/12/ddbt_filing.pdf

- Under current market conditions, the methodology already incorporates an adjustment or margin; for FCA 17 this was $0.955/kW-month or almost 60%. At the cleared FCA 17 volume this equates to $360 million – a significant buffer in dollar terms.
- The IMM does not have visibility into resources' capacity costs in the DDBT range. However, we have found that clearing prices for FCA 16 and 17 have generally been consistent with our estimate of the minimum costs of a capacity supply obligation based on a range of resource performance levels and the ISO's expected number of scarcity events at current surplus levels. However, we note that actual scarcity event hours have been substantially fewer than that forecast by the ISO. Participants may be reflecting an expectation of fewer performance events in their de-list bids, in addition to their avoidable operating and capital costs.
- Finally, the high volume of bid prices within close proximity of the DDBT indicates that participants are engaging in some level of strategic bidding, as opposed to avoidable cost-based bidding, since it is highly unlikely that the resources have such uniform costs. However, there is a significant amount of competition between existing resources, as well as new resources, at this price level and the market supply curve is very elastic (flat). Therefore, our assessment indicates that any one participant is very unlikely to be able to economically withhold capacity to benefit its portfolio.

Recap: Purpose of the DDBT and New Methodology

The DDBT value is part of the FCA mitigation design intended to protect the market from impacts of seller-side market power. It generally serves as a cut-off point for IMM cost review of de-list bids. Bids above the DDBT, are submitted –and fixed - well before the FCA. Static de-list bids are mitigated if deemed to be uncompetitive and if the participant has market power (i.e., is pivotal). Bids below the DDBT, known as dynamic de-list bids, can be submitted once the auction rounds fall below the DDBT and are not subject to IMM cost review and therefore cannot be mitigated.

The new methodology sets the DDBT value at an estimate of the FCA's clearing price, or close to that price. That way, only bids that are expected to be at or above the marginal clearing price, and that can impact price, are reviewed. The methodology balances the following goals:

(1) Prevent the exercise of supplier-side market power.
(2) Limit unnecessary administrative interference in the FCM that may reduce the market's efficiency.

A lower DDBT produces better results in preventing market power. However, a lower DDBT increases administrative interference in the market and may reduce the market's efficiency. When the market conditions are such that the exercise of market power can have a larger impact on the FCA's clearing price, the value of DDBT is lower. These market conditions align with steeper supply and demand curves and thus higher capacity prices. Conversely, if the expected market conditions are such that the impact on the clearing price from withholding capacity would likely be small, the new methodology incorporates an adder or margin so that the value of DDBT could be raised. These market conditions are consistent with surplus conditions, and the low capacity prices of the last few FCAs.

The DDBT values and their inputs for the past two FCAs, as well as the next FCA, are shown in the Table 3-1 below.[57]

Table 3-1: DDBT Inputs and Values for FCA 16 to FCA 18

Steps	Parameter	FCA 16	FCA 17	FCA 18
Step 1: Preliminary DDBT Value				
(1)	PFCA (t-1)	$2.61	$2.59	$2.59
(2)	P*	$0.43	$0.68	$4.06
(3)= Avg [(1) + (2)]	**DDBT (unadj.)**	**$1.52**	**$1.64**	**$3.33**
Step 2: Adjusted DDBT Value				
(4)	Net CONE	$7.47	$7.36	$9.08
(5) = 0.75 * (4)	Max	$5.60	$5.52	$6.81
(6) = 0.75 * (1)	Min	$1.96	$1.94	$1.94
(7) = (5) >= (3) >= (6)	**DDBT (adj.)**	**$1.96**	**$1.94**	**$3.33**
Step 3: Margin Adder				
(8) = [(5) - (7)] / (5)	Margin	$0.65	$0.65	$0.51
(9) = (7) + (8)	**DDBT Price**	**$2.61**	**$2.59**	**$3.84**

Notably, at current surplus market conditions the methodology incorporates a margin of between $0.51 to $1.09/kW-mo (difference between rows (3 and 9).

[57] 1) The preliminary value is the result of a simple average of two prices: the previous FCA's clearing price and the price at which the last FCA's total cleared capacity would intersect with the estimated system-wide demand curve for the next FCA (P*). This uses the most recent information available.
(2) The preliminary clearing price calculated in (1) is adjusted if it is greater than an established limit (maximum DDBT value) or lower than an established limit (minimum DDBT value). The goal is to avoid drastic changes in the preliminary value of the DDBT and to balance the main two goals. The maximum value is set as 75% of NET CONE and the minimum value is set as 75% of the last FCA's clearing price.
(3) Once steps (1) and (2) have been completed, the final DDBT value is calculated by adding an adjustment or margin. The margin will be equal to the difference between 75% of NET CONE and the preliminary DDBT, and dividing the result by 75% of NET CONE. The resulting value will be multiplied by $1.00/kW-month. This last step adjusts the resulting preliminary DDBT value from (1) and (2) such that the final DDBT value balances better the two conflicting goals. Therefore, the lower the preliminary DDBT value, the larger the margin. And, conversely, the larger the preliminary DDBT, the smaller the margin.

Level of Dynamic De-List bids and Concentration around the DDBT

We reviewed the dynamic de-list bids submitted over the past seven auctions and looked for any noticeable change in bid levels before and after the DDBT methodology was introduced in FCA 16. While bid values are commercially sensitive and therefore not published in this report, in Table 3-2 we present high-level statistics describing system capacity conditions over the seven FCAs and the MW quantity of de-list bids.

Table 3-2: FCA and De-List Bid Summary Statistics

FCA	Excess Capacity Start FCA	Excess Procured Capacity	Clearing Price	Static De-List	Dynamic De-List	DDBT
	% over Qualified Cap.	% over Net ICR	$/kW-mo	MW	MW	$/kW-mo
11	18.62%	5.17%	$5.297	243	187	$5.500
12	18.51%	3.27%	$4.631	29	1,431	$5.500
13	26.02%	3.23%	$3.800	669	852	$4.300
14	29.01%	4.51%	$2.001	171	2,085	$4.300
15	21.85%	4.06%	$2.611	138	902	$4.300
16	18.91%	3.68%	$2.591	65	1,535	$2.610
17	23.37%	3.51%	$2.590	16	2,228	$2.590

Although there has not been a particular trend in the number of dynamic de-list bids submitted and the capacity associated with them in the last two FCAs[58], we observed that the price distribution of de-list bids was more concentrated near and under their respective DDBT levels in FCA 16 and 17 than in other FCAs. This result is consistent with the expectation that, as the auction's price drops due to surplus conditions, the market has a flatter supply curve that would reflect similar costs for different suppliers.

We further found that about 38% of the capacity offered in FCA 17 and in either FCA 15 or FCA 14, at 1 cent below the DDBT of $2.591/kW-month, was also offered at a price just below or close to the DDBT of $4.300/kW-month in FCA 14 and FCA 15. Therefore, the concentration of dynamic de-list bids close to the DDBT value is not a new behavior to the revised methodology, but it was more pronounced in the past two auctions. This result would be consistent with the hypothesis that some resources owners may be willing to accept a lower price in the DDBT range and avoid the static de-list process.

However, the IMM does not have a means of estimating the revenues participants might be willing to forego to avoid the static de-list bid route. For instance, a participant with a 400 MW resource

[58] Since FCA 11, the average capacity offered has been 2,979 MW, and the average number of submissions was 136.

willing to accept a price $1/kW-mo lower than its true costs, would be accepting a $4.8 million revenue shortfall. In summary, higher price concentration of de-list bid prices in the FCA 16 and FCA 17 is consistent with the lower DDBT, as resources will have similar costs.

Comparison of Dynamic De-List Bids to Estimated Minimum Bids

A resource owner will face a decision whether to either stay or exit the FCM. The resource will stay in the FCM as long as the revenues from the capacity market are expected to be greater than the cost of remaining in the market, i.e., the cost of holding a capacity supply obligation. Revenues from the FCM have two components: base and performance revenues. The base revenue is a function of the resource's CSO and the FCA's clearing price, and performance payments are a function of the resource's performance during scarcity condition events. A resource that is not part of the FCM would still be eligible for performance payments during capacity scarcity conditions and would avoid penalties from underperformance without a CSO.

We performed a simulation to gain more insight into the minimum auction's price that would make the resource owner indifferent between the alternatives of remaining or exiting the capacity market.[59] The results of the simulation showed that, on average, to stay in the FCM, it would require a clearing price (minimum de-list bids) of about $2.62/kW-month for neutral performers, $2.27/kW-month for over-performers and $2.74/kW-month for underperformers, given the number of expected scarcity hours for the level of surplus in the FCA 16 and FCA 17.[60][61]

The actual dynamic de-list bids in the FCA 16 and FCA 17 were close to the respective DDBT levels of $2.609/kW-months and $2.590/kW-month. Thus, the comparison between the simulated and actual dynamic de-list bids indicates that the bids could reflect, in fact, the risk of taking a CSO for neutral and underperformers, and their decision to leave the auction under the DDBT. However, it is also possible that participants are not perceiving the scarcity events as a major risk given that the average actual duration of scarcity conditions is 0.82 hours per year since PFP was implemented in June 2018. In this case, the average minimum de-list bids could have been under $1.00/kW-month.

Market Power Assessment in DDBT Range

The IMM assessed whether the DDBT methodology appropriately accounts for market power concerns. A supplier could exercise marker power and increase the auction's clearing price by submitting a de-list bid for a portion of its capacity portfolio at a price above the true cost of supplying capacity. The de-list bid could increase the auction's clearing price which could enable the supplier to profit from the higher price paid to its remaining portfolio.

Although it is unlikely that there was any net benefit from economic withholding of capacity under surplus conditions in the last round of the auction,[62] the IMM studied the relationship between the bidding strategy and the individual participants' base revenues in FCA 16 and FCA 17. The results

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[59] A competitive dynamic de-list bid should be a function of the avoidable operating and capital cost associated with taking on a CSO and the expected performance payments during scarcity condition events. IMM does not have information on the resource's cost below the DDBT and, therefore, a full assessment of the dynamic de-list bids to see if the level is consistent with cost of taking on a CSO is not feasible.

[60] Neutral, over and under performance is defined as the difference between the resource performance and balancing ratio.

[61] The number of expected scarcity hours for 1,200 MW of surplus experienced is 5.5 and 4.2 for hours in FCA 17 and FCA 16, respectively.

[62] The surplus at the beginning of the last round was about 3,054 MW and 3,115 MW in the FCA 17 and FCA 16, respectively.

of the study supported the hypothesis that the delisting/bidding strategy of the significant majority of participants (~85-95%), was driven by resource cost considerations, rather than any attempt to maximize revenues through economic withholding. Further, given the degree of competition in the last round of FCA 16 and FCA 17 (more than a 3,000 MW surplus), the exercise of market power was not a concern; it would not have been possible for individual suppliers to impact the clearing price of the auction.[63] Thus, we conclude that the DDBT value did not raise any market power concerns; it was not set too high such as to undermine the first objective of the methodology.

[63] There was substantial amount of new supply, including renewables and imports, competing with existing resources at the start of the last round in the FCA 17 and FCA 16.

Section 4
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes from Winter 2022 through Winter 2023. Selected key statistics for load levels, day-ahead and real-time energy market prices, and fuel prices are shown in Table 4-1 below.

Table 4-1: High-level Market Statistics

Market Statistics	Winter 2023	Fall 2022	Winter 2023 vs Fall 2022 (% Change)	Winter 2022	Winter 2023 vs Winter 2022 (% Change)
Real-Time Load (GWh)	29,973	26,797	12%	31,294	-4%
Peak Real-Time Load (MW)	19,647	17,752	11%	19,766	-1%
Average Day-Ahead Hub LMP ($/MWh)	$78.29	$60.58	29%	$110.34	-29%
Average Real-Time Hub LMP ($/MWh)	$79.52	$60.28	32%	$105.48	-25%
Average Natural Gas Price ($/MMBtu)	$9.15	$6.00	53%	$14.41	-37%
Average No. 6 Oil Price ($/MMBtu)	$17.05	$19.33	-12%	$16.08	6%

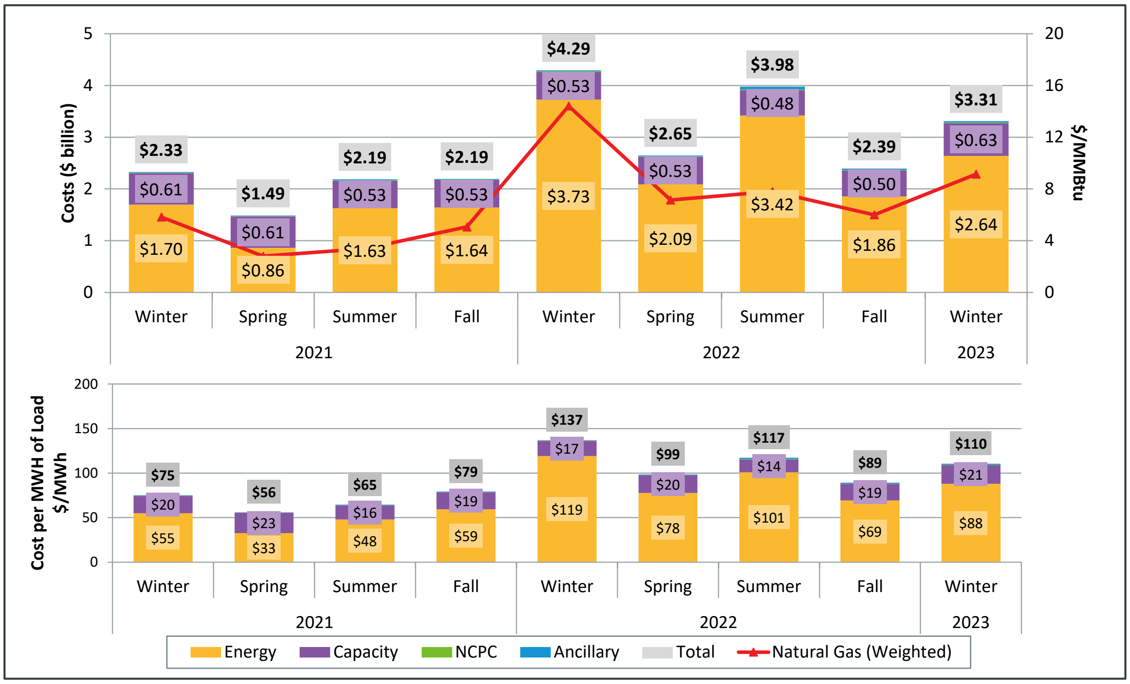
To summarize the table above:

- Lower average natural gas prices ($9.15/MMBtu vs $14.41/MMBtu) drove the decrease in energy costs in Winter 2023 compared to Winter 2022. Gas prices decreased 37% year-over-year. Section 2.4 above discusses gas prices in more detail. While average natural gas prices were lower year-over-year, the two cold snap periods of Winter 2023 saw higher gas prices than any day during the previous winter. The maximum gas price in Winter 2023 was $49.68/MMBtu, compared to $29.42/MMBtu in Winter 2022.
- Lower gas prices were the primary driver of a $78.29/MWh average day-ahead LMP, 29% lower than in Winter 2022 ($110.34/MWh). The decrease in gas prices outpaced energy prices due to fewer net imports and increased generator outages in Winter 2023 compared to Winter 2022.

4.1 Wholesale Cost of Electricity

The estimated wholesale electricity cost (in billions of dollars) for each season by market and the average natural gas price (in $/MMBtu) are shown in Figure 4-1 below. The bottom graph shows the wholesale cost per megawatt hour of real-time load served. [64,65]

Figure 4-1: Wholesale Market Costs and Average Natural Gas Prices by Season



In Winter 2023, the total estimated wholesale cost of electricity was $3.31 billion (or $110/MWh), a decrease of 23% compared to $4.29 billion in Winter 2022, and an increase of 38% over the previous quarter (Fall 2022). Natural gas prices continued to be a key driver of energy prices. The share of each wholesale cost component is shown in Figure 4-2 below.

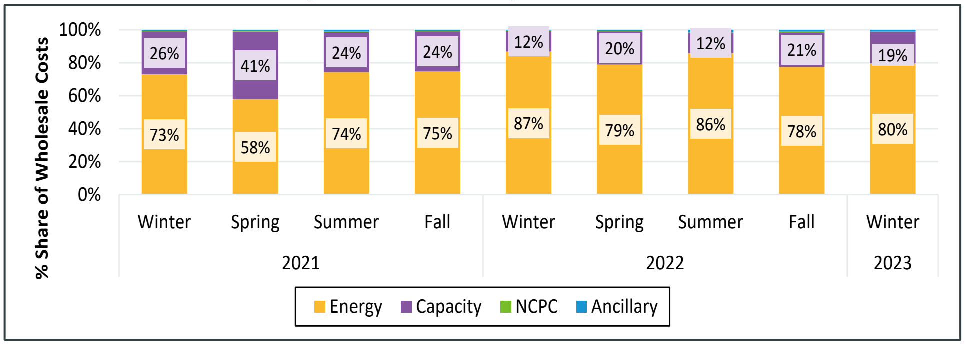
Energy costs were $2.64 billion ($88/MWh) in Winter 2023, 29% lower than Winter 2022 costs, driven by a 37% decrease in natural gas prices. Energy costs made up 80% of the total wholesale costs.

[64] In previous reports, we used system load obligations and average hub LMPs to approximate energy costs. Beginning with the Winter 2022 report, we updated the methodology to reflect energy costs based on location-specific load obligations and LMPs. These changes are reflected in all 11 seasons of data.

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

Capacity costs are driven by clearing prices in the primary capacity auctions (in this reporting period, FCA 13), and totaled $629 million ($21/MWh), representing 19% of total costs. The current capacity commitment period (CCP13, June 2022 – May 2023) cleared at $3.80/kw-month. This was 18% lower than the primary auction clearing price of $4.63/kW-month for the prior capacity commitment period. Additionally, beginning in Summer 2022, the capacity figure includes supplemental payments to the Mystic 8 and 9 generators. These payments totaled $213.5 million in Winter 2023. Section 7.1 discusses recent trends in the Forward Capacity Market in more detail.

Figure 4-2: Percentage Share of Wholesale Cost



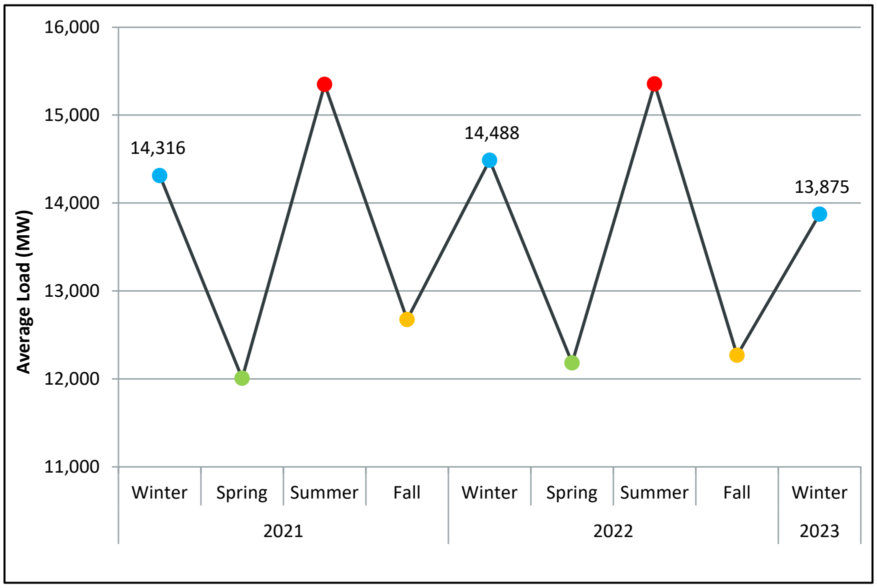
At $12.4 million ($0.41/MWh), Winter 2023 Net Commitment Period Compensation (NCPC) costs represented less than 1% of total energy costs, a similar share compared to other quarters in the reporting horizon. Section 5.4 contains further details on NCPC costs.

Ancillary services, which include operating reserves and regulation, totaled $29.2 million ($0.98/MWh) in Winter 2023. Ancillary service costs increased by 70% compared to Winter 2022, driven by higher reserve payments. One of the major reasons for the reserve payment increase was the tight system conditions that occurred on December 24, 2022. On this day alone, gross real-time reserve payments totaled $5.2 million.

4.2 Load

In Winter 2023, average load decreased 4.2% compared to Winter 2022 due to warmer weather, especially during January 2023. Additionally, growing behind-the-meter photovoltaic generation and energy efficiency continued to contribute to lower loads in every month.[66] Average hourly load by season is illustrated in Figure 4-3 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer and the yellow dots represent fall.

Figure 4-3: Average Hourly Load



In Winter 2023, loads averaged 13,875 MW, a 4.2% (or 613 MW) decrease compared to Winter 2022 (14,488 MW). Average load fell year-over-year due to fewer Heating Degree Days (HDDs), especially during January 2023 when average temperatures were 11°F warmer than January 2022 (36°F vs. 25°F).[67] Additionally, behind-the-meter photovoltaic generation increased by nearly 23 MW (202 MW vs. 180 MW), contributing to lower wholesale load.

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

[67] 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.

Load and Temperature

The stacked graph in Figure 4-4 below compares average monthly load (right axis) to the monthly total number of heating degree days (left axis).

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

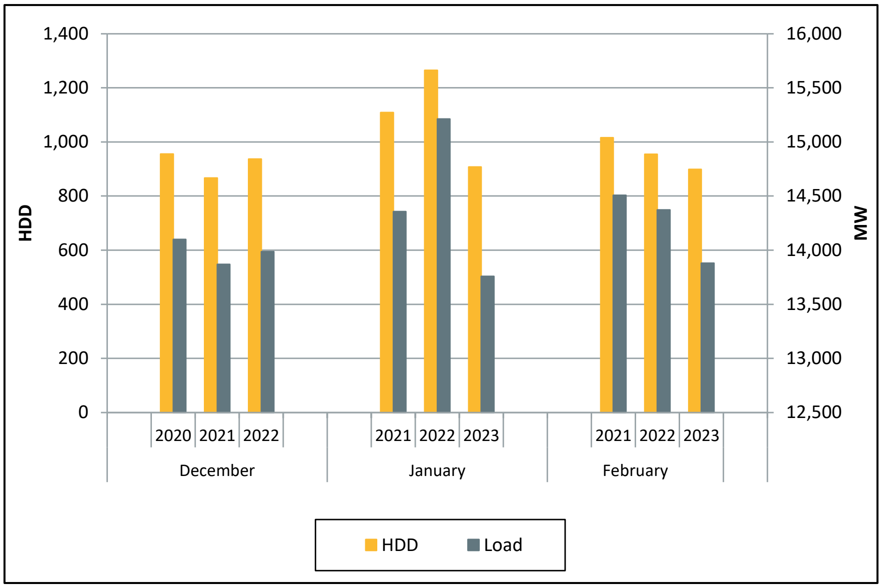


Figure 4-4 shows that average monthly load was higher year-over-year in December 2022 and lower year-over year for both January 2023 and February 2023. In all three months, temperature differences drove the year-over-year changes in average monthly load. In December 2022, average temperatures decreased by 2ºF compared to December 2021 (35ºF vs. 37ºF). The colder weather led to 70 more HDDs (937 vs. 867) and a 119 MW increase in average load (13,988 MW vs. 13,869 MW). January 2023 had the largest change in average load, with average load decreasing by 1,454 MW compared to January 2022 (13,758 MW vs. 15,212 MW). In January 2023, temperatures averaged 36ºF, the warmest January of the last ten years and an 11ºF increase compared to January 2022 (25ºF). The warmer temperatures lead to decreased heating demand with HDDs decreasing from 1,265 to 908 year-over-year. In February 2023, temperatures averaged 33ºF, a 2ºF increase compared to February 2022 (31ºF). The warmer weather led to a decrease of 56 HDDs (898 vs. 954) and 493 MW decrease in average loads year-over-year (13,879 MW vs. 14,372 MW).

Peak Load and Load Duration Curves

New England's system load over the past three winter seasons is shown as load duration curves in Figure 4-5 below with the inset graph showing the 5% of hours with the highest loads. A load duration curve depicts the relationship between load levels and the frequency in which loads occur at that level or higher. Winter 2023 is shown in red, while Winter 2022 is shown in black and Winter 2021 is shown in gray.

Figure 4-5: Load Duration Curve

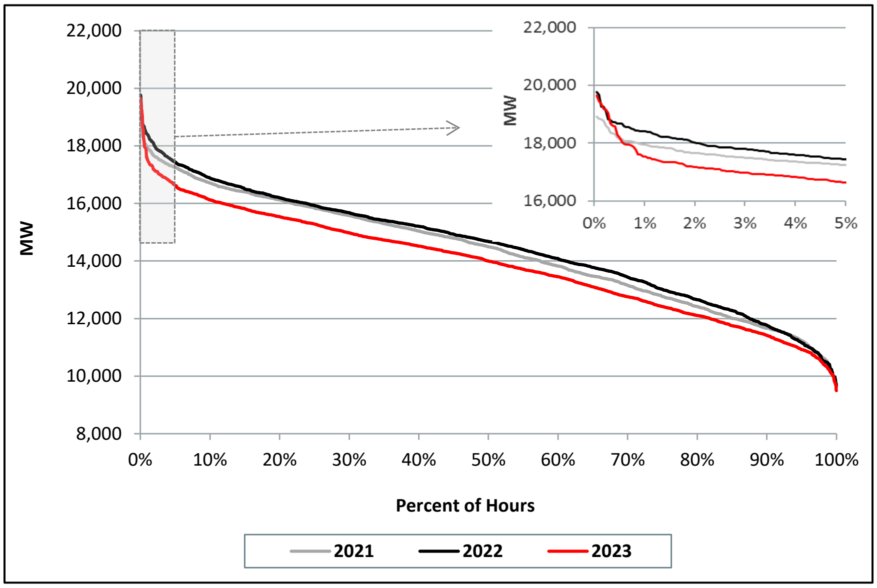


Figure 4-5 shows that loads in Winter 2023 were lower across more than 99% of all observations when compared to both Winter 2022 and 2021. In Winter 2023, loads were higher than 15,000 MW in over 29% of all hours compared to nearly 44% and 41% in Winter 2022 and 2021, respectively. In Winter 2023, peak loads (inset graph) were also mostly lower than the prior two winters. In the top 5% of all hours, load averaged 17,277 MW in Winter 2023, which was 731 MW lower than Winter 2022 (18,007 MW) and 393 MW lower than Winter 2021 (17,669 MW). During the top 0.5% of all hours, Winter 2023 load levels were similar to levels in Winter 2022 and higher than levels in Winter 2021. The top 0.5% of loads in Winter 2023 all occurred on February 3 and February 4, 2023 when cold weather lead to increased heating demand. Over these two days temperatures averaged 8°F, with hourly temperatures reaching as low as -10°F, the coldest hour since 2016.

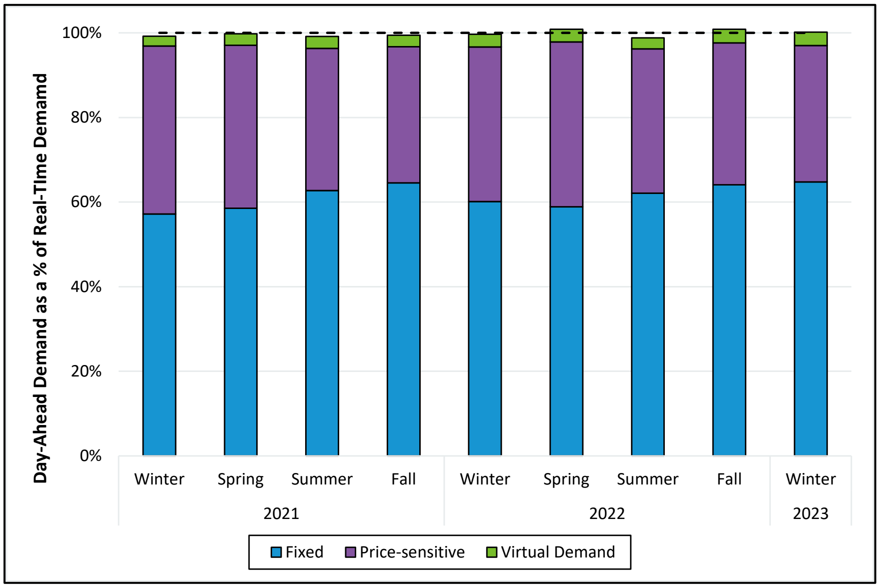
Load Clearing in the Day-Ahead Market

The amount of demand that clears in the day-ahead market is important because, along with the ISO's Reserve Adequacy Analysis, it influences generator commitment decisions for the operating day.[68] Low demand clearing in the day-ahead market may warrant supplemental generation commitments to meet real-time demand. Commitments that occur after the day-ahead market process can lead to higher real-time prices compared to day-ahead prices, assuming all else equal. The day-ahead cleared demand as a percentage of real-time demand is shown in Figure 4-6 below.

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

Day-ahead demand is broken down by bid type: fixed (blue), price-sensitive (purple) and virtual (green) demand.[69]

Figure 4-6: Day-Ahead Cleared Demand as a Percent of Real-Time Demand



In Winter 2023, participants cleared 100.2% of their real-time demand in the day-ahead market, which was up from 99.7% in Winter 2022. Participants cleared higher levels of fixed demand (64.8% vs. 60.1%) compared to Winter 2022. Virtual demand's contribution increased from 3.0% to 3.1% year-over-year. However, decreased levels of price-sensitive demand offset some of the increase in fixed demand and virtual demand. In Winter 2023, price-sensitive demand accounted for 32.3% of real-time demand compared to 36.5% in Winter 2022. Although price-sensitive demand bids are submitted with a MW quantity and corresponding price, the majority of these bids are priced well above the day-ahead LMP. Such transactions are, in practical terms, fixed demand bids. Therefore, the shift from price-sensitive demand bids to fixed demand bids resulted in no significant market impacts.

[69] Day-ahead cleared demand is calculated as fixed demand + price-sensitive demand + virtual demand. Real-time metered load is calculated as generation + settlement-only generation – asset-related demand + price-responsive demand + net imports – losses. This is different from the ISO Express report, which defines day-ahead cleared demand as fixed demand + price-sensitive demand + virtual demand - virtual supply + asset-related demand. Real-time load is calculated as generation – asset-related demand + price-responsive demand + net imports – losses. We have found that comparing the modified definition of day-ahead cleared demand and real-time metered load can provide better insight into day-ahead and real-time price differences.

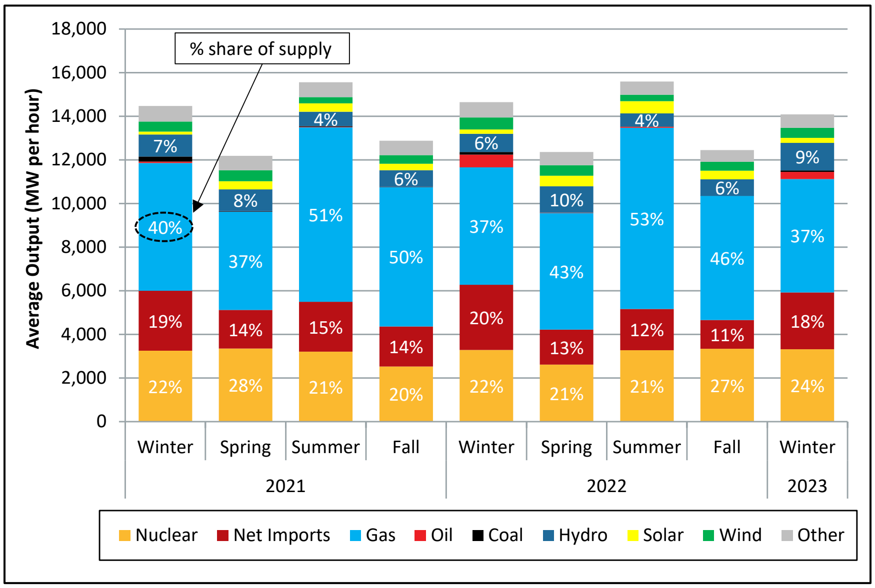
4.3 Supply

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

4.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The shares of energy production by generator fuel type for Winter 2021 through Winter 2023 are illustrated in Figure 4-7 below. Each bar's height represents the average electricity generation from that fuel type, while the percentages represent the share of generation from that fuel type.[70]

Figure 4-7: Share of Electricity Generation by Fuel Type



Average output in Winter 2023 (14,092 MW per hour) was 560 MW per hour less than in Winter 2022 (14,652 MW per hour). The largest season-over-season decrease occurred in net imports (imports netted for exports), which fell by 380 MW per hour between Winter 2022 (2,987 MW per hour) and Winter 2023 (2,607 MW per hour). Most of this decrease in net interchange occurred at the three external interfaces shared with New York, where net interchange fell by 307 MW from Winter 2022 (1,153 MW per hour) to Winter 2023 (846 MW per hour).[71] Oil generation also decreased considerably, dropping by 253 MW per hour between Winter 2022 (582 MW per hour) and Winter 2023 (329 MW per hour). Meanwhile, the majority of New England's energy continued to be provided by nuclear generation, gas-fired generation, and net imports. Together, these categories accounted for 79% of total energy production in Winter 2023.

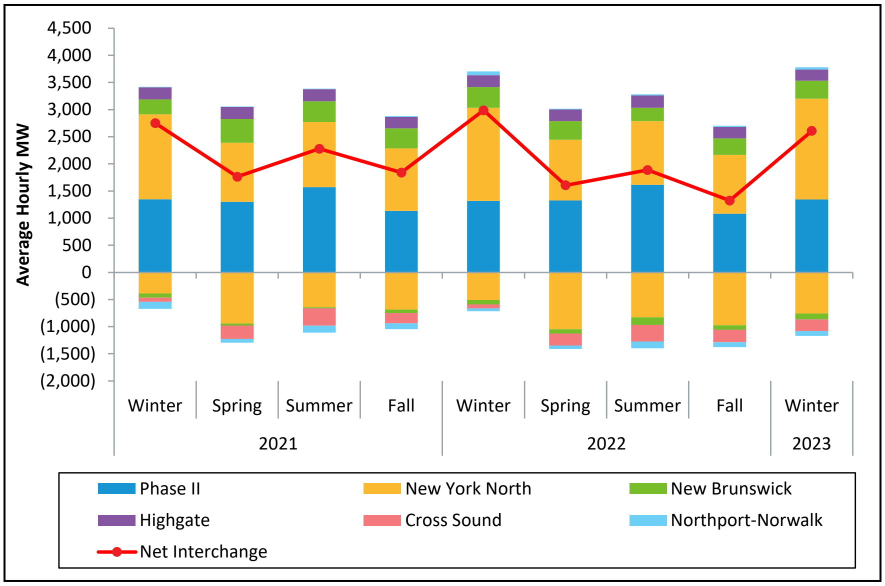
[70] Electricity generation equals native generation plus net imports. The "Other" category includes energy storage, landfill gas, methane, refuse, steam, wood, and demand response.

[71] See Section 4.3.2 for more information about imports and exports.

4.3.2 Imports and Exports

New England continued to be a net importer of power from its neighboring control areas of Canada and New York in Winter 2023.[72] On average, the net flow of energy into New England was 2,607 MW per hour. Total net interchange represented 19% of load (NEL), similar to levels from Winter 2022 (21%) and Winter 2021 (19%). The average hourly import, export, and net interchange power volumes by external interface for the last nine quarters are shown in Figure 4-8 below.

Figure 4-8: Average Hourly Real-Time Imports, Exports, and Net Interchange



Hourly net interchange averaged 2,607 MW, up 97% (or 1,284 MW) from Fall 2022 (1,323 MW) and down 13% (or 380 MW) from Winter 2022 (2,987 MW). Hourly net interchange increases from fall to winter when cold weather leads to a constrained natural gas system in New England. During the winter, natural gas-fired generators compete with heating demand for limited natural gas supply. This leads to upward pressure on natural gas and LMPs during the winter and incentivizes higher volumes of imports from neighboring regions.

Compared to Winter 2022, hourly average net interchange fell by 380 MW due to decreased net interchange over all three New York interfaces. The New York price premium increased across all three interfaces due to increased congestion. Increased transmission work in New York has contributed to high congestion and increased prices on the New York side of the interface. While average imports from Canada decreased slightly (1,761 MW vs. 1,834 MW) over the reporting period, Canadian imports fell drastically during the extreme weather events. A more detailed explanation of trends and drivers in flows from Canada and New York, especially at Phase II and New York North, which together accounted for 94% of total net imports is discussed below.

[72] 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 continues to account for the largest share of net interchange (51%) into New England. Phase II's share of total net interchange drops in the winter as net interchange rises at other interfaces, especially New York North. In Winter 2023, average net interchange at Phase II (1,335 MW) increased by 22 MW compared to Winter 2022 (1,314 MW).

While average net interchange at Phase II was in line with prior winters, levels of net interchange typically fell during periods of cold weather this winter despite high loads and LMPs in New England. This was likely due to increased electrification and growing demand in Quebec, which leads to stressed system conditions in Quebec during regional cold snaps.[73] Phase II underperformed compared to seasonal averages on December 24, 2022, February 3, 2023 and February 4, 2023, the three coldest days of the season. On December 24, 2022, the second coldest day of Winter 2023, net interchange at Phase II was 1,320 MW from HE 01 to HE 15, the full total transfer capability (TTC) of the interface on that day. However, net interchange averaged just 681 MW from HE 16 to HE 19, including just 535 MW in HE 17 and HE 18 when capacity scarcity conditions led to a shortage event.[74] Net interchange at Phase II returned to 1,320 MW from HE 20 to HE 24.

On February 3 and February 4, 2023, net interchange at Phase II averaged 1,021 MW and 137 MW, respectively. On February 3, 2023, temperatures averaged 15°F, but got progressively colder throughout the day. From HE 01 to HE 14, net interchange at Phase II averaged 1,320 MW, the full TTC, but averaged just 604 MW over the rest of the day (HE 15 to HE 24). Cold temperatures persisted into February 4, 2023, averaging 2°F over the day. The cold temperatures led New England became a net *exporter* over Phase II for the first time since 2016 from HE 03 to HE 13. Over these 11 hours, net *exports* averaged 598 MW, and reached a high of 799 MW in HE 08. Additionally, New England exported over both the Highgate and New Brunswick interfaces on this day, the other two interfaces connecting New England and Canada.

New York Interfaces

In Winter 2023, net interchange from New York decreased by 308 MW, on average, compared to Winter 2022 (845 MW vs. 1,153 MW). Net interchange fell at all three interfaces in line with changes in the day-ahead price spread between New England and New York. At New York North, net interchange averaged 1,107 MW, a 102 MW decrease from Winter 2022 (1,210 MW). Net interchange fell due to an increased price spread between New York and New England. In Winter 2022, New York prices at the New York North interface were $2.52/MWh higher than New England. The price spread increased to $3.10/MWh in Winter 2023. Despite generally higher prices in New York, participants may be willing to take a loss on imports into New England. This behavior is likely due to contracts outside of the ISO New England market. Participants may import power across interfaces to fulfill bilateral contracts, such as power purchase agreements, or to meet clean energy standards by purchasing renewable energy certificates (REC). For example, a participant may be willing to take a loss on an import transaction over the New York North interface, because they would receive a lower priced REC from New York compared to one in New England.

[73] Quebec's grid is discussed more in the following article: Hydro-Québec expects record demand as extreme cold spell looms.

[74] For more on the capacity scarcity conditions on December 24, 2022, see Section 2.5.

Net *exports* increased(i.e., decrease in net interchange) over both interfaces connecting New England and Long Island. At the Cross Sound Cable interface net *exports* increased from 76 MW in Winter 2022 to 212 MW in Winter 2023. At Northport-Norwalk, net *exports* averaged 50 MW, after being a net *importer* in Winter 2022. (19 MW of net *imports*). Price spreads at both interfaces changed this winter, with prices being *higher* in New England during Winter 2022, but *lower* in New England during Winter 2023.

Section 5
Day-Ahead and Real-Time Markets

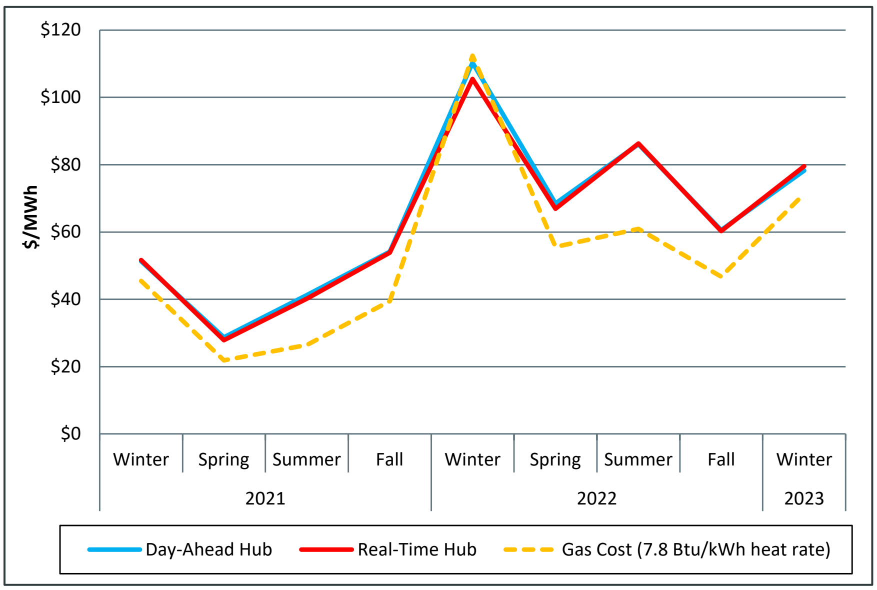
This section covers trends in, and drivers of, spot market outcomes, including the energy markets, and markets for ancillary services products: operating reserves and regulation.

5.1 Energy Prices

The average real-time Hub price for Winter 2023 was $79.52/MWh, 2% higher than the average day-ahead price of $78.29/MWh. Compared to Winter 2022, average real-time and day-ahead Hub prices decreased by 25% and 29%, respectively, driven by a 37% decrease in average natural gas prices.

Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas, are shown in Figure 5-1 below. The natural gas cost is based on the seasonal average natural gas price and a generator heat rate of 7,800 Btu/kWh.[75]

Figure 5-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



As Figure 5-1 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 as less efficient generators, or generators burning more expensive fuels, are required to meet the region's higher demand.

Gas costs averaged $71.35/MWh in Winter 2023. Average electricity prices were about $7/MWh higher than average estimated Winter 2023 gas costs in the day-ahead market, a similar spread to that of Winter 2021 ($6/MWh). During Winter 2022, average day-ahead electricity prices were about $2/MWh lower than average estimated gas costs. As a result of high natural gas prices, oil generators were in merit more often in Winter 2022 compared to other winter seasons. This put

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

downward pressure on LMPs. See Section 5.2 for additional information on marginal resources and transactions.

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 5-2.

Figure 5-2: Simple Average Day-Ahead and Real-Time Prices by Location and Gas Generation Costs

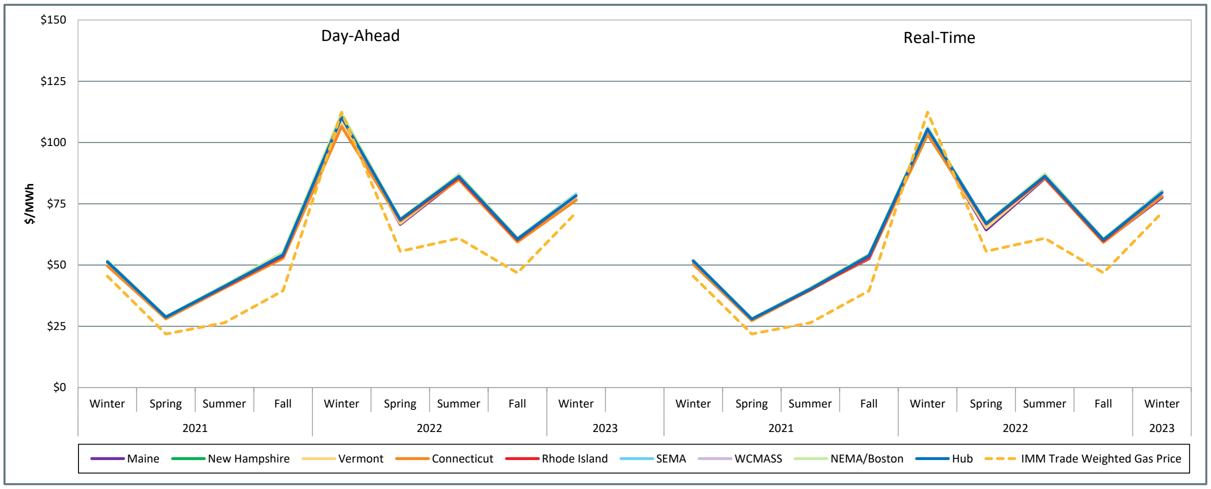


Figure 5-2 illustrates that load zone prices did not differ significantly from Hub prices in either market.[76] All zonal average prices were within 2% of the average Hub price.

5.2 Marginal Resources and Transactions

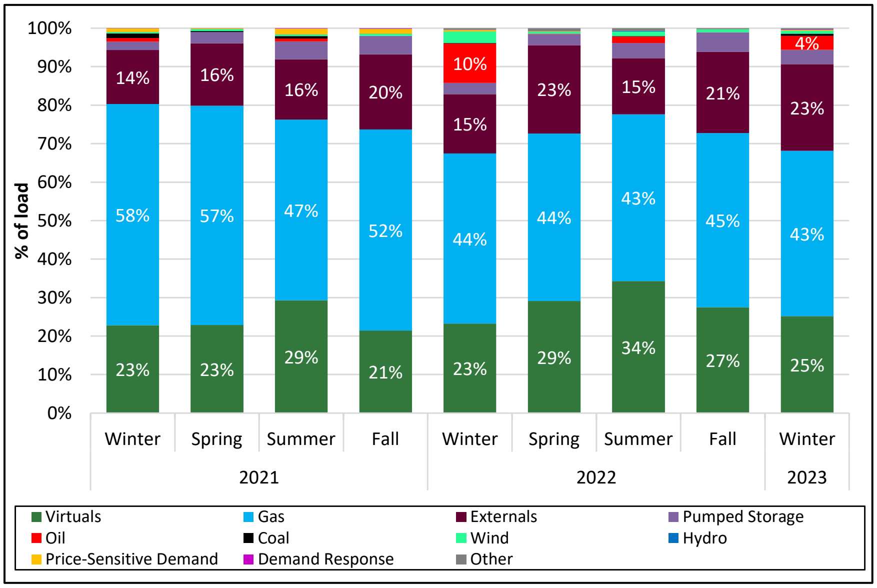
This section reports marginal units by transaction and fuel type on a load-weighted basis. When more than one resource is marginal, the system is typically constrained and marginal resources likely do not contribute equally to setting price for load across the system. The methodology employed in this section accounts for these differences, weighting the contribution of each marginal resource based on the amount of load in each constrained area.

[76] 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.

Day-ahead Energy Market

The percentage of load for which each transaction type set price in the day-ahead market since Winter 2021 is illustrated in Figure 5-3 below.

Figure 5-3: Day-Ahead Marginal Units by Transaction and Fuel Type

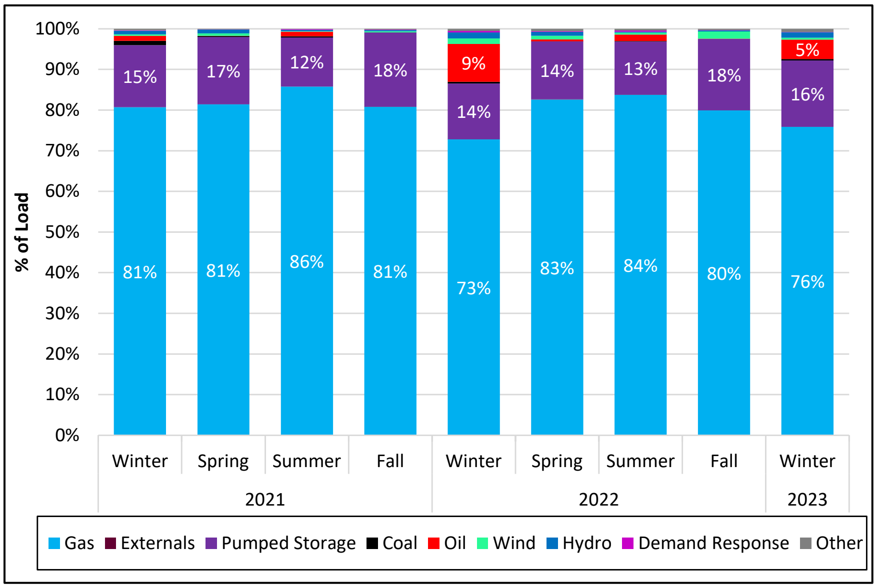


Gas-fired generators were the most common marginal resource type in the day-ahead market, setting price for 43% of total day-ahead load in Winter 2023. However, oil-fired generators and dual-fuel generators operating on oil were able to set price more frequently in Winter 2023 than in prior seasons as a result of higher gas prices. Oil-fired generation set price for 4% of load in the day-ahead market in Winter 2023, up from zero percent in Fall 2022. Virtual transactions and external transactions set price for 48% of load, which was almost identical to their sum in Fall 2022 (49%).

Real-time Energy Market

The percentage of load for which each fuel type set price in the real-time market since Winter 2021 is shown in Figure 5-4 below.[77]

Figure 5-4: Real-Time Marginal Units by Fuel Type



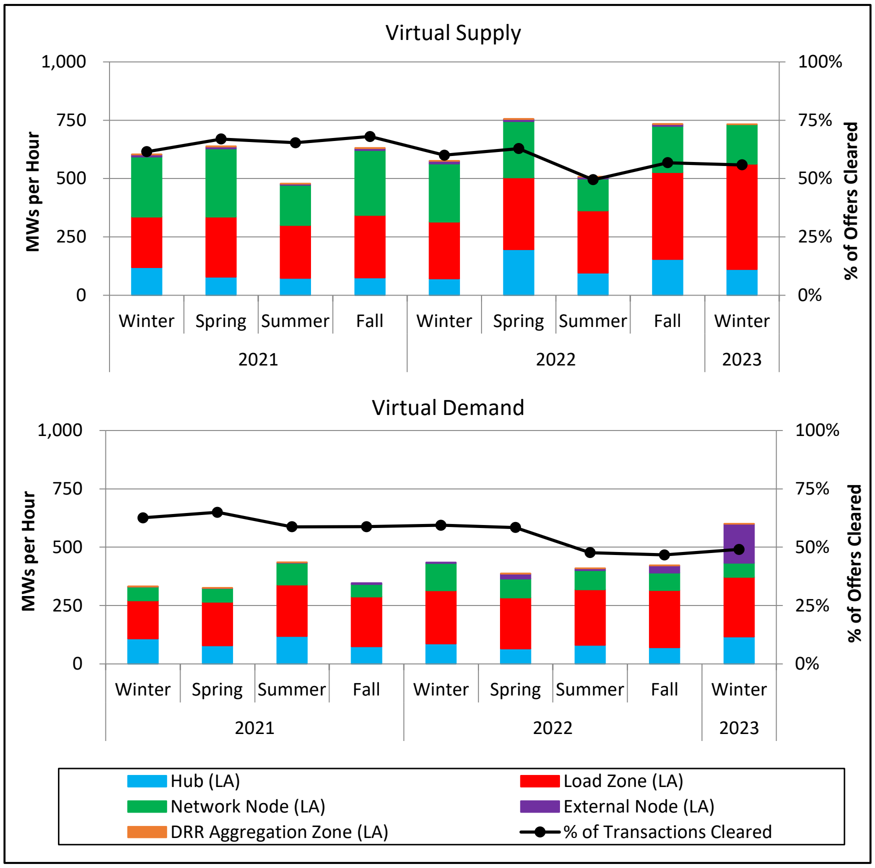
Similar to the day-ahead market, natural gas-fired generators set price for highest percentage of load in the real-time market in Winter 2023 (76%). However, oil-fired generators and dual-fuel generators operating on oil set price for a modest share of load in Winter 2023. Oil-fired generation set price for five percent of load in the real-time market in Winter 2023, down slightly from the level in Winter 2022 (9%). Meanwhile, pumped storage (generation and demand) set price for 16% of load in Winter 2023, a level that was in-line with others over the reporting period.

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

5.3 Virtual Transactions

In the day-ahead energy market, participants submit virtual demand bids and virtual supply offers to profit from differences between day-ahead and real-time LMPs. Generally, profitable virtual transactions improve price convergence and help the day-ahead dispatch model better reflect real-time conditions. The average volume of cleared virtual supply (top graph) and virtual demand (bottom graph) are shown on the left axis in Figure 5-5 below. Cleared transactions are divided into groups based on the location type where they cleared: Hub (blue), load zone (red), network node (green), external node (purple) and Demand Response Resource (DRR) aggregation zone (orange). The line graph (right axis) shows cleared transactions as a percentage of submitted transactions, both for virtual supply and virtual demand.

Figure 5-5: Cleared Virtual Transactions by Location Type



In Winter 2023, total cleared virtual transactions averaged approximately 1,343 MW per hour, a 33% increase compared to Winter 2022 (1,011 MW per hour) and a 16% increase compared to Fall 2022 (1,154 MW per hour).

Total cleared virtual supply averaged 743 MW per hour in Winter 2023, up 1% from Fall 2022 (733 MW per hour) and up 29% from Winter 2022 (575 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 Winter 2023, solar SOGs reached an installed capacity of over 2,000 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, even in winter when solar generation underperforms compared to the rest of the year. 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 offer high-priced energy in the day-ahead market, but produce energy at low, or even negative, prices in the real-time market.[78] In Winter 2023, participants cleared 61% (or 451 MW) of cleared virtual supply offers at load zones, 23% (or 169 MW) at network nodes, 15% (or 112 MW) at the Hub and 1% (or 11 MW) at external nodes.[79]

Cleared virtual demand averaged 600 MW per hour in Winter 2023, up 38% from Winter 2022 (435 MW per hour) and up 43% from Fall 2022 (421 MW per hour). In Winter 2023, participants cleared 43% (or 256 MW) of cleared virtual demand offers at load zones, 10% (or 60 MW) at network nodes, 19% (or 117 MW) at the Hub and 28% (or 168 MW) at external nodes.[80] Most of the increase was driven by higher cleared volumes at the Highgate interface, which connects New England with the Hydro-Québec control area. In Winter 2023, participants cleared an average of 140 MW per hour at Highgate after clearing less than 1 MW per hour during the prior 8 seasons. These transactions likely provided participants with either: (1) a financial hedge on deviations between day-ahead and real-time imports at the Highgate interface, or (2) allowed for day-ahead and real-time market transactions to clear volumes up to the 225 MW total transfer capability (TTC) of the interface.[81] On December 24, 2022, reduced real-time imports, including at reductions at Highgate, contributed to capacity-scarcity conditions. Any real-time import reductions needed to be bought back at the higher real-time price leading to significant losses on any real-time deviations. However, virtual demand at Highgate benefited from the high real-time prices and participants made over $1 million on virtual demand at Highgate. These virtual profits likely helped offset any losses on external transactions. Despite the high daily profit, virtual demand lost $642 thousand during Winter 2023 at Highgate. Participants may have been willing to pay for virtual transactions to avoid exposure to the more volatile real-time prices.

[78] In Winter 2023, real-time wind generation averaged 470 MW.

[79] DRR Aggregation Zones accounted for 0.005% of all cleared virtual supply.

[80] DRR Aggregation Zones accounted for 0.001% of all cleared virtual demand.

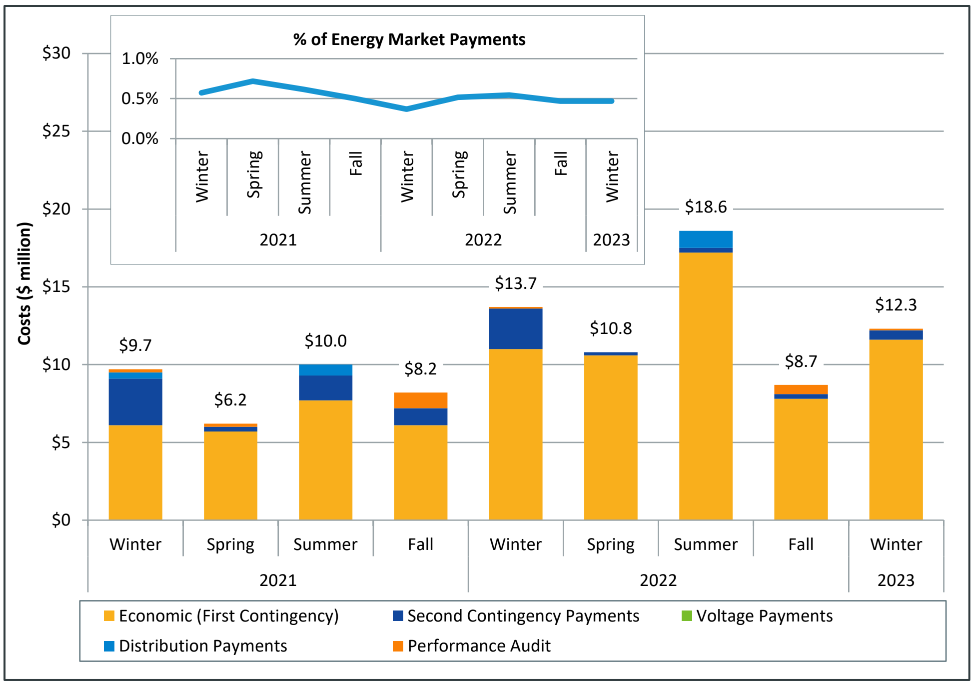
[81] An equivalent volume of day-ahead cleared imports and cleared virtual demand would remove exposure to day-ahead and real-time price differences if the real-time imports were curtailed in real time. Any real-time import deviations would be settled at a higher real-time price. However, virtual demand does not materialize in real-time, and would also be profitable after being sold back at a higher real-time price.

5.4 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC), commonly known as uplift, are make-whole payments provided to resources in two circumstances: 1) when energy prices are insufficient to cover production costs or 2) to account for any foregone profits the resource may have lost by following ISO dispatch instructions. This section reports on quarterly uplift payments and the overall trend in uplift payments since Winter 2021.

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.[82] Payments by season and uplift category are illustrated below in Figure 5-6. The inset graph shows uplift payments as a percentage of total energy payments.

Figure 5-6: NCPC Payments by Category ($ millions)



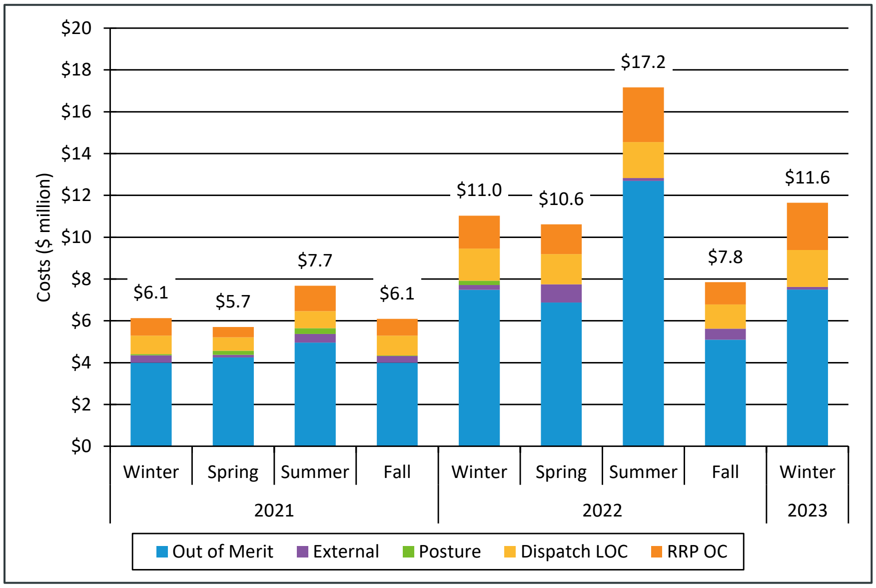
Total uplift payments declined by 10%, from $13.7 million in Winter 2022 to $12.3 million in Winter 2023. Uplift was 0.5% of energy payments, consistent with other seasons in the study period. The majority of uplift (94%) in Winter 2023 continued to be economic ($11.6 million), with most ($9.4 million) economic payments occurring in the real-time market. The decrease in NCPC between Winter 2022 and Winter 2023 was driven by a $2 million decrease in second contingency payments.

Economic uplift includes payments made to resources providing first-contingency protection as well as resources that incur opportunity costs by operating at an ISO-instructed dispatch

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

point below their economic dispatch point (EDP). Figure 5-7 below shows economic payments by sub-category.

Figure 5-7: Seasonal Economic Uplift by Sub-Category



As seen in Figure 5-7, out-of-merit payments generally comprise the majority of economic NCPC. These payments were similar between Winter 2022 and Winter 2023. Dispatch lost opportunity cost (Dispatch LOC) and rapid-response pricing opportunity cost (RRP OC) payments, both real-time only types of uplift, drove the slight increase. Dispatch LOC payments increased by $0.23 million, from $1.53 million in Winter 2022 to $1.77 million in Winter 2023. Similarly RRP OC payments increased by 43% from $1.58 million in Winter 2022 to $2.26 million in Winter 2023. The increase in RRP OC payments indicates that units incurred more opportunity costs due to fast-start pricing rules in Winter 2023 than in Winter 2022.

Second contingency (LSCPR) NCPC accounted for 5% of all uplift payments in Winter 2023. LSCPR payments totaled $0.56 million, down by $2.0 million from Winter 2022. In Winter 2022, most LSCPR NCPC payments (90%) were made in December 2021 to generators that were committed in the day-ahead market to meet reliability needs in Maine, New Hampshire and SEMA/Rhode Island. These reliability commitments were driven by planned transmission outages that were completed by the end of December 2021.

5.5 Real-Time Operating Reserves

This section of the report provides details about real-time operating reserve pricing and payments. ISO-NE procures three types of real-time reserve products: (1) ten-minute spinning reserve (TMSR), (2) ten-minute non-spinning reserve (TMNSR), and (3) thirty-minute operating reserve (TMOR). Real-time reserve pricing (that is non-zero) occurs when the ISO's market software must re-dispatch resources to satisfy a reserve requirement.[83] Resources providing reserves during these periods receive real-time reserve payments.

Real-time Reserve Pricing

The frequency of non-zero reserve pricing by product and zone along with the average price during these intervals for the past three years is provided in Table 5-1 below.

Table 5-1: Hours and Level of Non-Zero Reserve Pricing

Product	Zone	Winter 2023		Winter 2022		Winter 2021	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	**System**	$31.13	169.1	$16.24	223.8	$9.75	379.9
TMNSR	**System**	$682.89	4.3	$0.00	0.0	$0.00	0.0
TMOR	**System**	$490.95	3.7	$0.00	0.0	$0.00	0.0
	NEMA/Boston	$490.95	3.7	$0.00	0.0	$0.00	0.0
	CT	$490.95	3.7	$0.00	0.0	$0.00	0.0
	SWCT	$490.95	3.7	$0.00	0.0	$0.00	0.0

The system TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 169 hours (8% of total hours) during Winter 2023, which was 55 hours (24%) less than in Winter 2022 and 211 hours (55%) less than in Winter 2021. One of the primary reasons for the decrease in non-zero TMSR pricing was the result of an operational change that reduced the percentage of the ten-minute reserve requirement that must be spinning from 31% to 25% on May 31, 2022.[84] This operational change contributed to reducing the average ten-minute spinning reserve requirement from 496 MW in Winter 2022 to 407 MW in Winter 2023. However, the average price during the intervals with non-zero pricing in Winter 2023 ($31.13/MWh) was nearly twice as high as the average price observed in Winter 2022 ($16.24/MWh). Meanwhile, the average TMNSR and TMOR

[83] Real-time operating reserve requirements are utilized to maintain system reliability. There are several real-time operating reserve requirements: (1) the ten-minute reserve requirement; (2) the ten-minute spinning reserve requirement; (3) the minimum total reserve requirement; (4) the total reserve requirement; and (5) the zonal reserve requirements. For more information about these requirements, see Section III.2.7A of Market Rule 1.

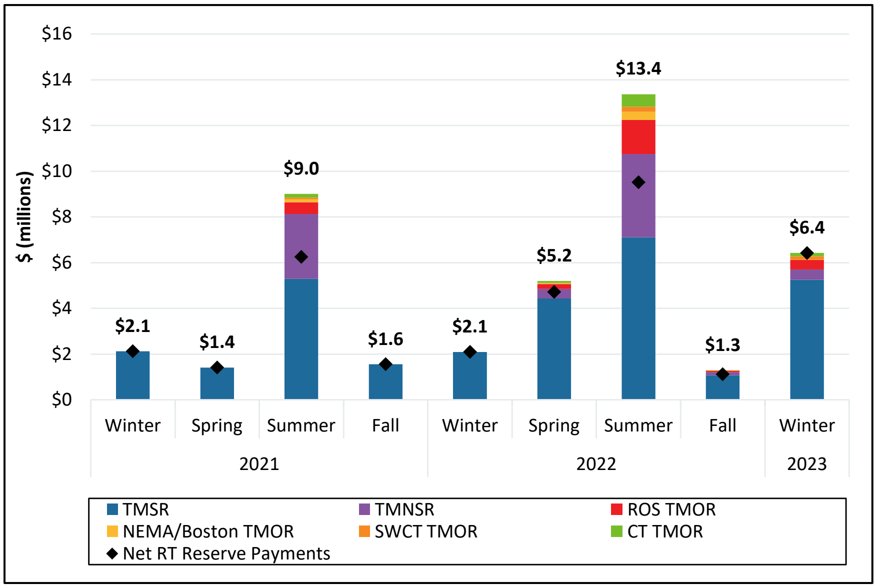
[84] The operational decision to change this percentage stemmed partly from an enhancement of the Energy Management System (EMS) that led to more accurate accounting of reserves.

prices in Winter 2023 were very high ($682.89/MWh and $490.95/MWh, respectively) as a result of reserve constraint penalty factor (RCPF) pricing during the capacity scarcity conditions on December 24.[85]

Real-time Reserve Payments

Real-time reserve payments by product and by zone are illustrated in Figure 5-8 below.[86] The height of the bars indicate gross reserve payments, while the black diamonds show net payments (i.e., payments after reductions have been made to Forward Reserve Market (FRM) units providing real-time reserves).[87]

Figure 5-8: Real-Time Reserve Payments by Product and Zone



Gross reserve payments in Winter 2023 ($6.4 million) were up considerably from Fall 2022 ($1.3 million) and from Winter 2022 ($2.1 million). One of the major reasons for this increase in real-time reserve payments was the tight system conditions that occurred on December 24, 2022.[88] On this day alone, gross real-time reserve payments totaled $5.2 million, representing 81 percent of the payments for the quarter. Net real-time reserve payments in Winter 2023 ($6.4 million) were only slightly reduced from their gross levels. The vast majority of reserve payments in Winter 2023 went to resources providing TMSR ($5.3 million), while relatively small amounts went to resources providing TMNSR ($0.5 million) or TMOR ($0.7 million).

[85] RCPFs represent the highest marginal cost the market software will incur in order to meet reserve requirements. For more information about RCPFs, see Section III.2.7A (c) of Market Rule 1.

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

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

[88] For more information about the reserve conditions on this day, see Section 2.5.3.

Fast-Start Pricing Impact on Reserve Pricing

We have observed significant periods of non-zero pricing (and payments) during times when the reserve constraint is not impacting the physical dispatch of resources and there is a physical surplus of reserves due to fast-start pricing rules. We recommend that the ISO assess this issue.

Reserve prices are intended to:

- Offset lost opportunity costs *when a resource is selected to serve as reserve capacity instead of producing electricity in real-time*,[89] and
- Compensate market participants with on-line and fast-start generators for the increased value of their product *when the reserve constraint is binding* (economically, when reserves become scarce).

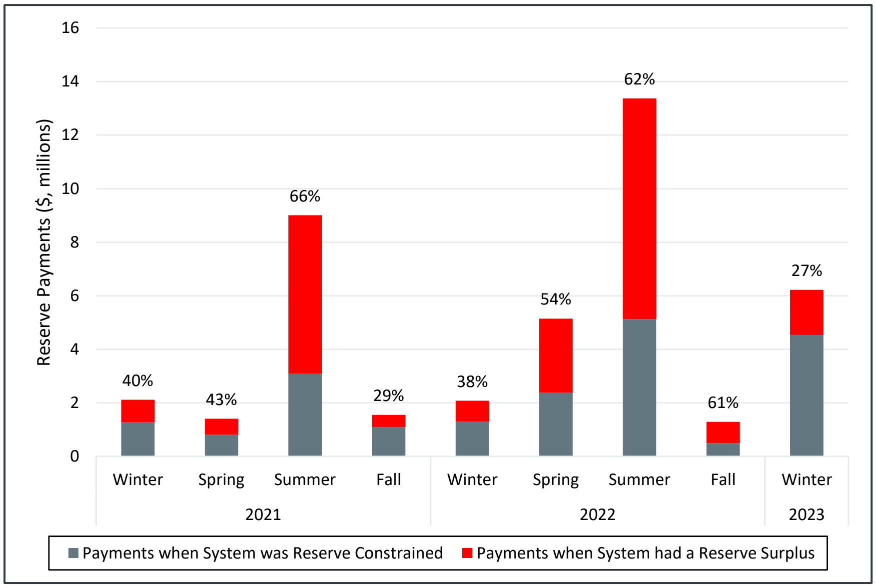
Since fast-start pricing was implemented in 2017, we have observed frequent non-zero reserve pricing in scenarios when resources' dispatch instructions were not impacted by the reserve constraint and the system had a surplus of reserves.

Figure 5-9 below shows payments for the previous nine quarters, separated by whether the system was operating with a physical reserve surplus (i.e., was not reserve constrained) or was *not* operating with a physical reserve surplus (i.e., was physically reserve constrained). The gray bar shows reserve payments when the system did not have a physical reserve surplus (i.e., the physical dispatch was impacted by the reserve constraint). The red bar shows reserve payments when the system had a surplus of reserves (i.e., the physical dispatch was not impacted by the reserve constraint). The percentages at the top of the bars show the percentage of overall reserve payments in each quarter that were made when the system was operating with a reserve surplus.[90]

[89] Because the pricing software frequently generates LMPs that are higher than the dispatch software, there are often cases in which resources are incentivized to increase their output in the presence of the higher prices but no units have been impacted by the reserve constraint. We do not believe these units have been "*selected to serve as reserve capacity instead of producing electricity"* because physically their dispatch has not been impacted by the reserve constraint. In principle, Rapid-Response Pricing Opportunity Cost (RRPOC) NCPC, not reserve pricing, is the mechanism through which the market should compensate these resources. RRPOC NCPC is designed to compensate units when faced with higher fast-start pricing-driven prices, while reserve prices are designed to compensate units for foregoing the energy price when the reserve constraint is binding.

[90] Throughout this section, reserve prices represent incremental reserve prices for each individual product. Because reserve prices are cascaded (TMSR MWs are paid the TMOR price + the incremental TMNSR price + the incremental TMSR price), we first separated each price into their components. When there was a physical reserve surplus for a given product, we set that component =$0. More complex methodologies, taking into account different permutations of pricing and physical outcomes yielded similar results. In regards to this figure, because we are first separating each reserve price into components, these payments are first calculated by product, then summed to get overall payments.

Figure 5-9: Reserve Payments by Physical Reserve Status[91]



In Winter 2023, $1.7 million dollars of reserve payments were made when the system was operating with a reserve surplus, representing 27% of total reserve payments in the period. This represented the smallest percentage of payments made in periods of reserve surplus in the study period. Overall, in the study period there were $22.1 million in reserve payments made when the system was operating with a reserve surplus, making up 52% of total payments.

The highest periods of reserve payments when the system was operating with a reserve surplus were the last two summers. In 2022, there were four separate days between July 20 and July 28 in which over $1 million dollars of reserve payments were made each day during times where there was a physical reserve surplus, accounting for $6 million of the $8 million total payments made when the system had a reserve surplus. In 2021, there were only two such days and payments in times when the system had a reserve surplus were mostly made in early July and late August.

The following chart summarizes the frequency of reserve prices when there is a physical reserve surplus, by reserve product. The height of each bar shows the percentage of time there was a physical reserve surplus when reserve prices were greater than $0. The labels at the top of each bar represent the number of hours there were reserve prices >$0 in each season. The horizontal lines represent the percentage of time there was a physical reserve surplus (i.e., the reserve constraint was not impacting dispatch) in times when there were reserve prices >$0 across the entire study period.

[91] Winter 2023 payments are $0.2 million different from actual payments due to mitigation occurring in the LMP Calculator run of the market software. The total payments here are estimated using the pricing run of the market clearing software to ensure an apples-to-apples comparison with the dispatch run of the market clearing software.

Figure 5-10: Frequency of Physical Reserve Surplus when Reserves are Priced >$0

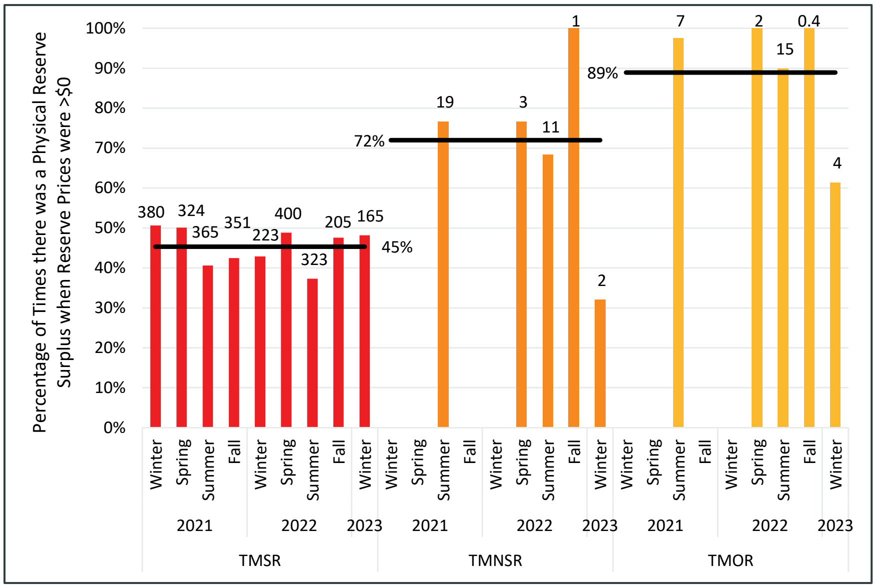


Figure 5-10 highlights the frequency in which reserve prices >$0 were produced when there was a physical reserve surplus. TMSR is the most common product priced >$0, which was priced >$0 in over 300 hours per season on average (shown by the labels above the red bars). Almost half (45%) of the time incremental TMSR prices were >$0 there was a reserve surplus. Although TMNSR and TMOR prices are >$0 much less often than TMSR prices, when they have been priced >$0 in the study period there was a reserve surplus most of the time—72% and 89% of the time, respectively. Despite being relatively infrequent, TMOR and TMNSR prices are generally much higher so payments from these two products made up 62% of the total payments in the study period (not shown).

The separation of pricing and dispatch under fast-start pricing rules introduced reserve pricing challenges. Physically (i.e., in the dispatch software), generation up to EcoMin must be producing energy and generators cannot be dispatched below EcoMin to provide reserves; these reserves are unattainable. Fast-start pricing rules relax fast-start units' EcoMin in the pricing software to give the appearance of a larger dispatchable range, which allows fast-start units to set price more often. However, the ISO's fast-start pricing design does not allow the expanded dispatchable range (i.e., the range between 0 MW and EcoMin) to provide reserves for pricing purposes because these reserves are physically unattainable.[92] This methodology produces tradeoffs:

- Pro: It ensures the system does not appear to have more reserves than are physically attainable and reserve prices are always produced when the reserve constraint is impacting physical dispatch.
- Con: Under certain circumstances, the system can appear to have less reserves than are physically available at no cost to the system, thus it over-values reserves in many scenarios when the reserve constraint is *not* impacting physical dispatch and the system is operating with a reserve surplus.

[92] The ISO considered different reserve accounting methodologies for pricing when fast-start pricing was implemented and chose not to allow physically unattainable reserves between 0 MW and EcoMin to contribute reserves for pricing.

This was an intentional decision when fast-start pricing was implemented. However, the frequency in which we have observed reserve pricing when there is not a physical reserve constraint binding has exceeded the frequency in which we expected these scenarios to occur. Additionally, the cost of reserve payments in these intervals warrants more work to develop a better solution.

The following example presents the mechanics that drive the over-valuation of reserves when the system has a surplus of reserves.

Illustration of Reserve Pricing when there is no Reserve Scarcity

The following illustration highlights a simple example of reserve pricing when there is a physical reserve surplus. This example applies the following assumptions:

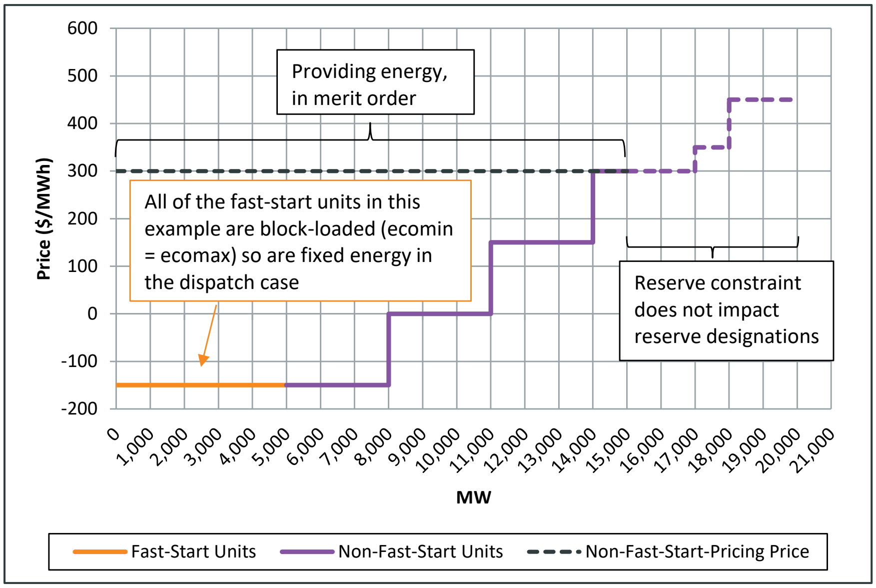
Table 5-2: Fast-Start Pricing Reserve Prices without Scarcity Example

	Fast-Start Resources	Non-Fast-Start Resources
Sum of Committed EcoMin	5,000 MW	0 MW
Sum of Committed EcoMax	5,000 MW	15,000 MW
Commitment Costs	$100/MW	$100/MW
Marginal Costs	$300	Increasing from -$150 to $450
Load	15,000 MW	
Reserve Requirement	4,000 MW	

In this example, there are 5,000 MW of block-loaded fast-start resources committed in this interval. The fast-start units have commitment costs (start-up + no-load) of $100/MW and marginal costs of $300. There are 15,000 MW of non-fast-start resources that are fully flexible – they can be dispatched anywhere between their collective EcoMin of 0 MW and collective EcoMax of 15,000 MW. The non-fast-start resources have increasing marginal costs from -$150 to $450 and commitment costs of $100/MW (not used in this example).

Figure 5-11, below shows the optimization that produces dispatch instructions. For the purpose of producing dispatch instructions, all physical parameters of fast-start resources are respected.

Figure 5-11: Fast-Start Pricing Dispatch Optimization (All Physical Constraints Respected)



In Figure 5-11, units are dispatched in merit order. The reserve constraint does not impact the system dispatch (i.e., the reserve constraint is non-binding) because the 4,000 MW reserve requirement is easily met by the 5,000 MW of attainable, higher-cost energy that is out-of-merit (i.e., there is a 1,000 MW reserve surplus). This excess, attainable energy essentially providing reserves 'for free.' The 5,000 MW of fast-start energy at the bottom of the supply curve is must-take—it is at the bottom of the curve because dispatching in this range would produce dispatch signals that are physically infeasible.

Figure 5-12 below shows the shift in the supply curve when fast-start ("EcoMin") constraints are relaxed. This example represents neither the dispatch nor pricing optimization but is included to illustrate how the supply curve changes, ignoring the reserve requirement for the moment.

Figure 5-12: Fast-Start Physical Constraint Relaxation and Supply Curve Shift

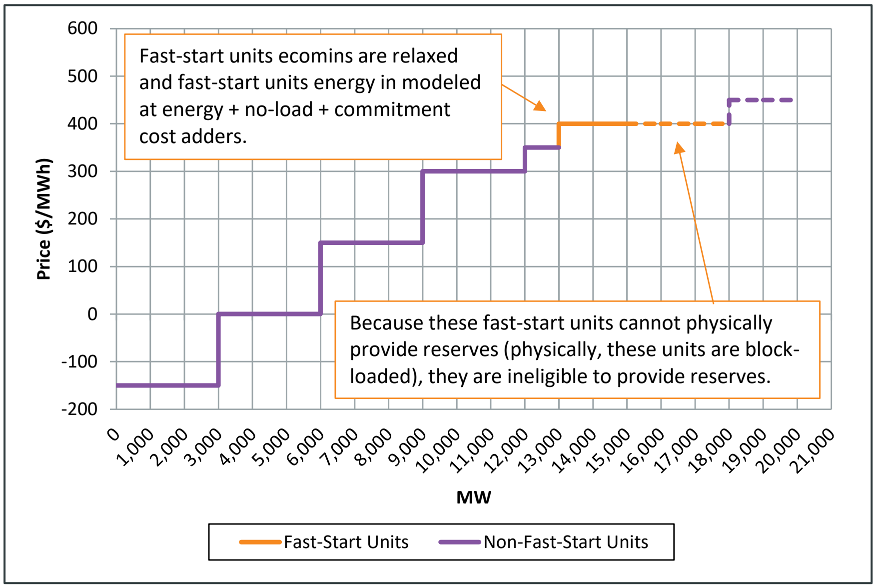


Figure 5-12 highlights the shift in the supply curve that occurs due to the relaxation of fast-start resource constraints. The fast-start resource commitment costs ($100/MW) are added to their incremental energy offers ($300) and the fast-start resources' physically "fixed" energy now appears as dispatchable segments. The ISO's methodology dictates that for pricing purposes this available fast-start energy (the orange dotted line) cannot provide reserves "for free" because these reserves are physically unattainable.

To meet the reserve requirement, the dispatch must be adjusted so additional non-fast-start resources provide reserves. Figure 5-13 below shows the pricing optimization, including the 4,000 MW reserve requirement. In this solution, fast-start unit parameters are relaxed and the offers move up the supply curve (shown in Figure 5-12), but the modeled energy and reserve designations in the pricing optimization are impacted by the 4,000 MW reserve requirement.

Figure 5-13: Fast-Start Pricing Case (Fast-Start Physical Constraints Relaxed)

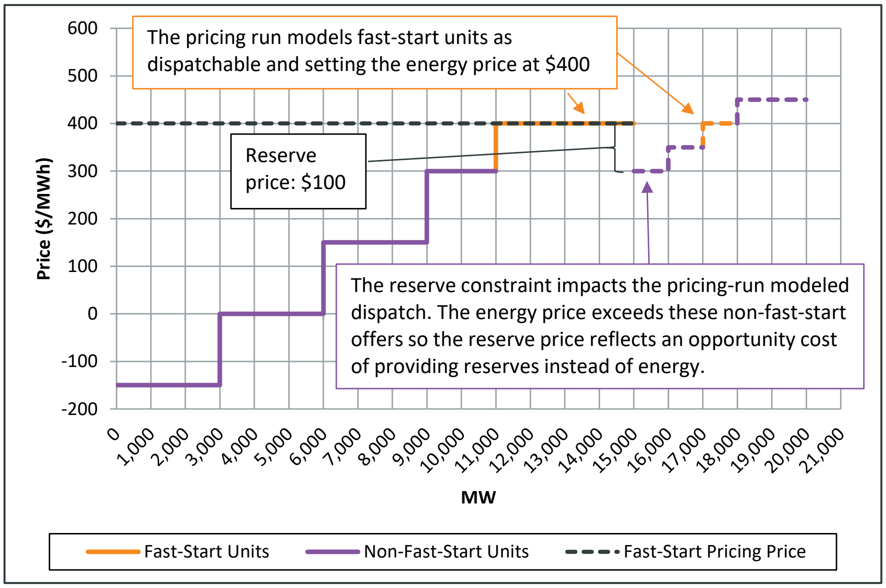


Figure 5-13 shows that the reserve constraint has an impact on the pricing optimization. The dotted purple line between 15,000 MW and 17,000 MW shows non-fast-start offers designated as reserve *in the pricing optimization,* so the 4,000 MW reserve requirement is met. The pricing optimization met the reserve requirement using reserves from lower-cost assets to meet the modeled reserve requirement and energy from these higher-priced fast-start units that cannot provide reserves because they are physically unattainable. This results in the appearance of an opportunity cost for reserve-designated units that are incentivized to provide energy at the higher energy price ($400/MWh). The highest opportunity-cost unit that is providing reserves is foregoing $100 in profit by not selling energy ($400 in energy revenue forgone, minus their $300 incremental energy cost), so the pricing optimization produced a reserve price is $100.

In this example, the reserve price produced by the pricing solution is $100 (Figure 5-13), despite a physical reserve surplus of 1,000 MW (Figure 5-11). In this scenario, 5,000 MW are paid the reserve price of $100, for a total reserve settlement of $500,000. Although some units (3,000 MW of non-fast-start offers that are not dispatched despite being in-the-money) do incur an opportunity cost in this scenario (totaling $250,000, 2,000 MW incurred an opportunity cost of $100 and 1,000 MW incurred an opportunity cost of $50), we do not believe these units should receive reserve payments because the opportunity costs are incurred due to higher LMPs, rather than physical reserve scarcity.[93] Additionally, because reserve prices are uniform, in this scenario an additional 2,000 MW of non-fast-start units priced at $450 would receive reserve payments despite incurring no opportunity cost. Because the physical reserve constraint is not binding, we do not believe these units should be paid the reserve price.

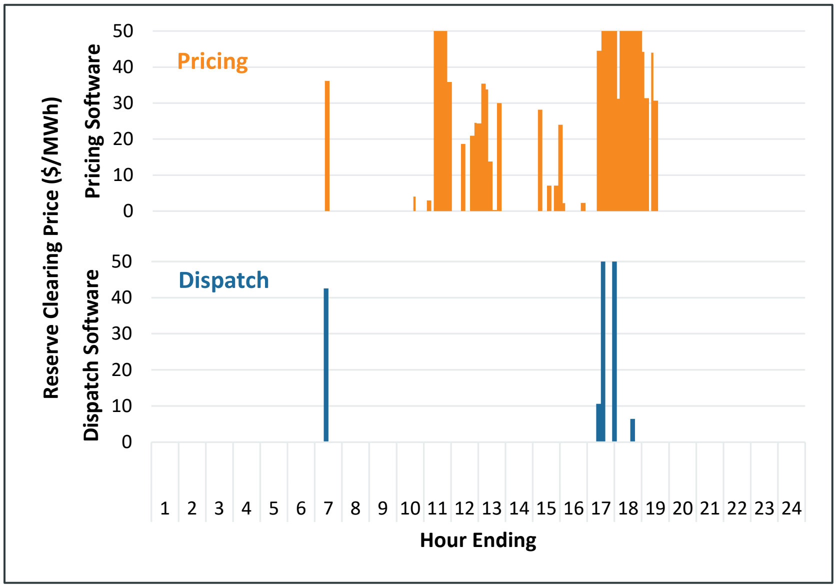
As an example, Figure 5-14 below, shows reserve clearing prices from the pricing and dispatch software on December 12, 2022.[94] On this day the ten-minute-spinning-reserve (TMSR) reserve constraint penalty factor (RCPF) bound for over three hours despite a TMSR surplus. The pricing

[93] In other scenarios in which units incur an opportunity cost due to fast-start pricing, these units are compensated using RRPOC NCPC.

[94] Reserve clearing prices from the dispatch software are not used in market settlement.

software (top orange bars) represents the fast-start pricing (actual) case. The dispatch software (bottom blue bars) represents the non-fast-start pricing (counterfactual) case.

Figure 5-14: Reserve Prices in the Pricing vs. Dispatch Software on December 12th, 2022



shows that fast-start pricing can have a substantial impact on the frequency of non-zero reserve prices. On July 24th, fast-start pricing generated TMSR RCPF pricing for almost two hours, despite the RCPF binding for only 20 minutes in the counterfactual case (i.e., there was never a physical shortage of TMSR reserves). Additionally, there was non-zero reserve pricing, designed to signal that the optimal dispatch had to be adjusted to meet the reserve requirement, in five and a half hours, although the physical dispatch was only adjusted in less than one hour. Overall, there were $81 thousand in reserve payments when there was a physical reserve surplus on this day.

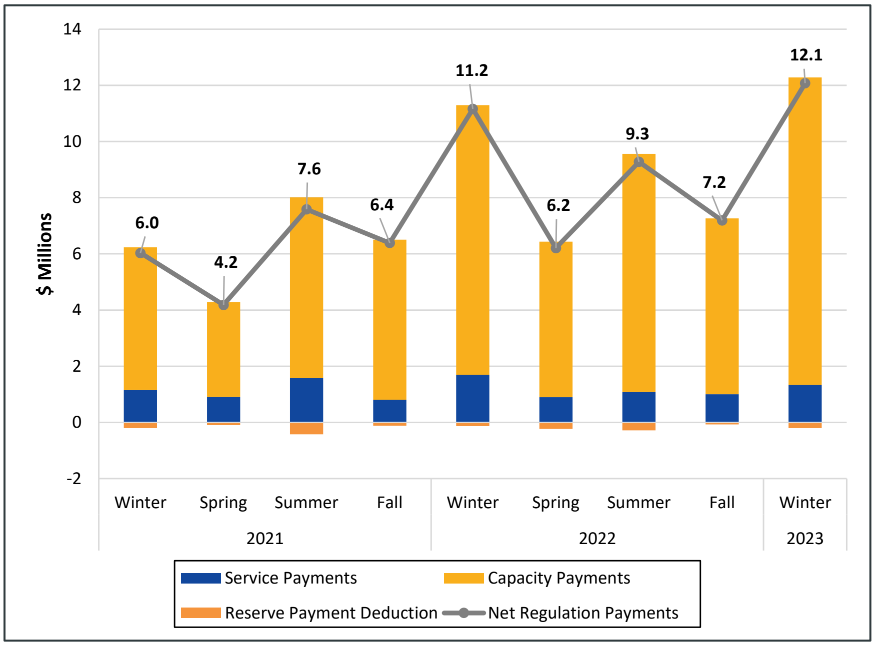
Recommendation

We recommend that the ISO revisits reserve pricing mechanics under fast-start pricing to address the frequency of reserve pricing when there is a physical reserve surplus.

5.6 Regulation

Regulation is an essential reliability service provided by generators and other resources in the real-time energy market. Generators providing regulation allow the ISO to use a portion of their available capacity to match supply and demand (and to regulate frequency) over short-time intervals. Quarterly regulation payments are shown in Figure 5-15 below.

Figure 5-15: Regulation Payments ($ millions)



Total regulation market payments were $12.1 million during the reporting period, up approximately 68% from $7.2 million in Fall 2022, and up by 8% from $11.2 million in Winter 2022. The increase in payments compared to the Fall period resulted predominately from significantly higher regulation capacity prices (79% increase) in Winter 2023. This increase in capacity pricing resulted from increased energy market opportunity costs and incremental cost savings for regulation resources in Winter 2023. The modest increase in regulation payments between Winter 2022 and Winter 2023 reflects a modest increase in capacity prices and payments, which was partially offset by a decline in service prices and payments.

Section 6
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 6.1 evaluates energy market competitiveness by quarter using two structural market power metrics at the system level. Section 6.2 provides statistics on system and local market power flagged by the automated mitigation system, and on the amount of actual mitigation applied, whereby a supply offer was replaced by the IMM reference level.

6.1 Pivotal Supplier and Residual Supply Indices

This analysis examines opportunities for participants to exercise market power in real time using two metrics: the pivotal supplier test (PST) and the residual supply index (RSI).[95]

When a participant's available supply exceeds the supply margin[96], they are considered pivotal.[97] We calculate the percentage of five-minute pricing intervals with at least one pivotal supplier by quarter. The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. The average RSI and the percentage of five-minute intervals with pivotal suppliers are presented in Table 6-1 below.

Table 6-1: Residual Supply Index and Intervals with Pivotal Suppliers (Real-Time)

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

[95] 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.

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

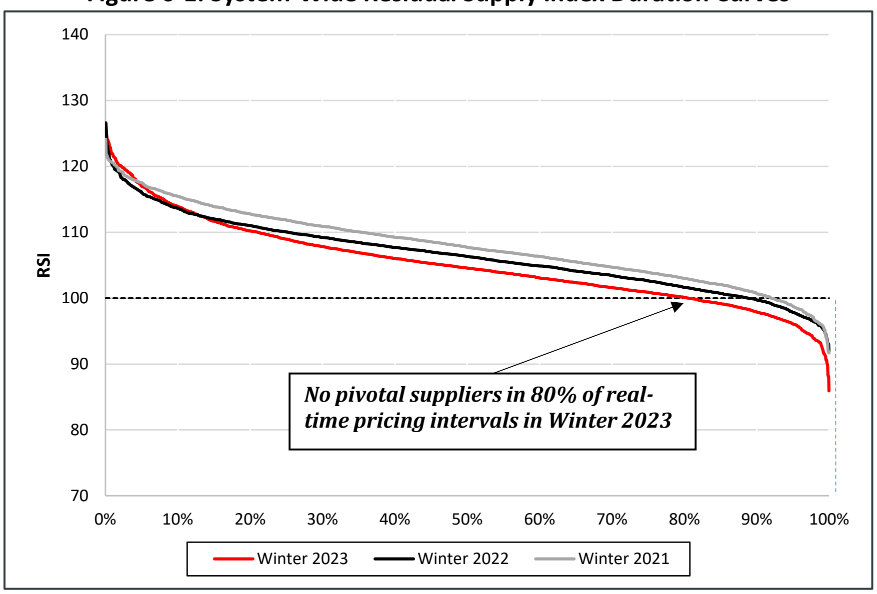
[97] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

The 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 frequency of pivotal suppliers in Winter 2023 was 20%, which was higher than that of the previous two winters (12% and 8%), but lower than that of Summer and Fall 2022. The year-over-year increase was due to lower total 30-minute reserve margins, which decreased by an average of 226 MW compared to Winter 2022. When reserve margins are lower, it is more likely that the largest supplier is needed to meet load and the reserve requirement. The lower reserve margins resulted from several factors, including: 1) a higher reserve Total30 requirement (up 28 MW); 2) a reduction in offline reserves from two generators that shed their CSOs for FCA 13 (June 2022 – May 2023); 3) increased generator outages (up by about 130 MW); and 4) generators providing more energy and fewer reserves during due to lower net imports and increased outages.

Duration curves that rank the average hourly RSI over each fall quarter in descending order are illustrated in Figure 6-1 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 6-1: System-Wide Residual Supply Index Duration Curves



In Winter 2023, the RSI was lower than in the previous two winters across most ranked observations due to the lower reserve margins discussed above. The lowest hourly RSI value of Winter 2023 was 85.9, and occurred during the shortage event on December 24, 2022.

6.2 Energy Market Supply Offer Mitigation

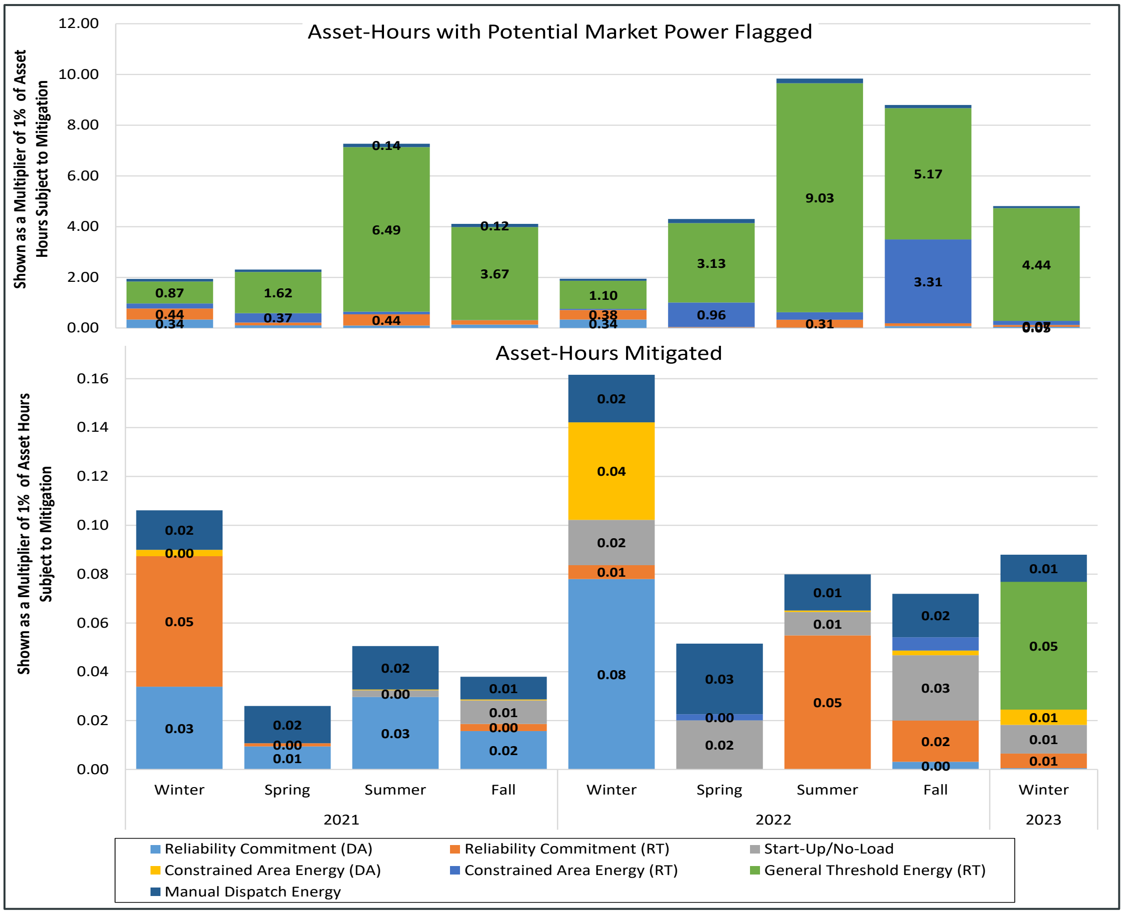
As in earlier periods, the mitigation of energy market supply offers occurred infrequently in Winter 2023.

Energy Market Mitigation Frequency

This section summarizes three types of mitigation data: structural test failures, generator commitment or dispatch hours, and mitigation occurrences. An indication of mitigation frequency relative to opportunities to mitigate generators is illustrated in Figure 6-2 below.[98] It compares asset hours of structural test failures for dispatch and commitment (depending on mitigation type) to asset hours of mitigations. To provide additional context, the values in the figure have been scaled relative to one percent of total asset hours subject to potential mitigation.

[98] 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 6-2: Energy Market Mitigation[99]



In general, the data in Figure 6-2 indicate that mitigation occurs very infrequently relative to the initial triggers for potential mitigation: ISO commitment and operation of a generator and energy market mitigation thresholds (i.e., structural test failures, commitment or dispatch). The highest frequency of mitigation occurs for reliability commitments (light blue or orange shading); this results from a relatively tight conduct test threshold, with any participant supply offer more than 10% above the IMM reference offer value being mitigated. General threshold (pivotal supplier) mitigation and constrained area mitigation (green, dark blue, and yellow shading) have had the lowest mitigation frequency at close to 0% over the review period; the decrease in mitigations in Winter 2023, compared to the prior winter, resulted from a decline in constrained area energy mitigation. The Winter 2022 increase in constrained area energy mitigation (in the day-ahead energy market) resulted from a frequently-binding transmission constraint (New England West-East constraint) during that period. Overall, there were 294 asset hours of mitigation in Winter 2023, compared to 327 thousand asset hours subject to potential mitigation.

[99] 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.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs (such as local second contingency protection).[100] These commitments frequently reflect the reliability needs associated with transmission line outages and upgrades, as well as very localized distribution system support. Over the review period, SEMA-RI and Maine had the highest frequency of reliability commitment asset hours, 43% and 35% respectively in the day-ahead energy market. This is consistent with transmission upgrades that occurred in SEMA-RI over the past two years, and with the frequency of localized transmission issues within Maine. Reliability commitment mitigations also occurred frequently in SEMA-RI and Maine: 45% of mitigations occurred in SEMA-RI and 18% occurred in Maine in the day-ahead market.[101] Overall, reliability mitigations decreased significantly between Winter 2022 (248 asset hours) and Winter 2023 (two asset hours). The decline in mitigations is consistent with an 86% decrease in reliability commitment asset hours.

Start-up and no-load commitment mitigation: This mitigation type, like reliability commitments, occurs based on a generator's commitment and does not rely on a structural test failure. It uses a very high conduct test threshold (200% applied to the start-up, no-load, and offer segment financial parameters) to guard against the potential commitment of generators that are not covered by other mitigation types and that appear to have grossly over-stated their commitment costs (relative to reference values).[102] Grossly over-stated commitment costs are likely to lead to unnecessary uplift payments. These mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate. There were 39 asset hours of start-up and no-load mitigation in Winter 2023, compared to 59 asset hours of mitigation in Winter 2022. All generators subject to this mitigation over the review period had natural gas as a primary fuel type, and generators associated with just three participants accounted for 88% of these mitigations; in Winter 2023, one of these participant accounted for 59% of start-up and no-load mitigation.

Constrained area energy (CAE) mitigation:[103] This mitigation type applies three tests prior to mitigation: structural, conduct and market impact. With relatively tolerant conduct and market impact test thresholds, the frequency of mitigation is low relative to the frequency of structural test failures. The frequency of mitigation given a structural test failure (i.e., generator located in an import-constrained area) in the real-time energy market has been approximately 0% (of structural test failure asset hours) over the review period, as only 25 asset hours of CAE mitigation has occurred in the real-time energy market and only 166 asset hours of mitigation have occurred in the day-ahead energy market. The frequency of structural test failures follows the incidence of transmission congestion and import-constrained areas within New England. In Winter 2023, there were very few hours of structural test failures (552 asset hours) in the real-time market, and there were no asset hours of constrained area energy mitigation. In the day-ahead market for Winter 2023, there were 21 hours of mitigation. Mitigations declined significantly compared to Winter 2022 (127 asset hours of mitigation), when congestion resulting from a frequently-binding

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

[101] 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.

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

[103] 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.

constraint in December 2021 increased structural test failures and mitigation for that period (the New England West-East Constraint).

General threshold energy mitigation: This mitigation type also applies three tests prior to mitigation. This mitigation type typically has the lowest mitigation frequency of any mitigation type, because it also has the most tolerant conduct test and market impact thresholds of any mitigation type. This occurs in spite of this mitigation type having the highest frequency of structural test failures (i.e., pivotal supplier asset hours) for any mitigation type. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators. Two participants accounted for 68% of the structural test failures and five participants accounted for 84% of structural test failures over the review period.[104] Prior to Winter 2023, general threshold energy mitigation did not occur over the review period. During Winter 2023, however, there were 175 asset hours of general threshold energy mitigation.

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 22% 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 Winter 2023, there were 262 asset hours of manual dispatch and 37 asset hours of mitigation. These levels are roughly comparable to Winter 2022, with 267 asset hours of manual dispatch and 62 asset hours of mitigation.

[104] As noted in section 6.1 (Pivotal Supplier and Residual Supply Indices), the mitigation software's pivotal supplier test is different from the pivotal supplier metric presented in section 6.1 We have 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 7
Forward Markets

This section covers activity in the Forward Capacity Market (FCM), and in Financial Transmissions Rights (FTRs). The recently-conducted Forward Capacity Auction for the sixteenth capacity commitment period (2025/26) is covered in Section 3 of the report.

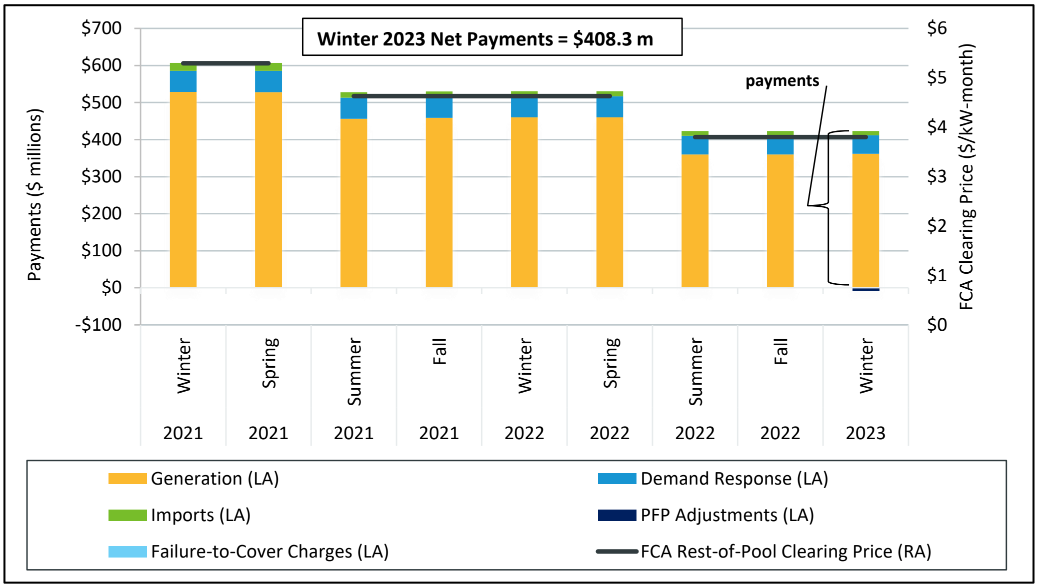
7.1 Forward Capacity Market

The capacity commitment period (CCP) associated with Winter 2023 started on June 1, 2022 and will end on May 31, 2023. The corresponding Forward Capacity Auction (FCA 13) resulted in a lower clearing price than the previous auction while still obtaining sufficient resources needed to meet forecasted demand. The auction procured 34,839 megawatts (MW) of capacity, which exceeded the 33,750 MW Net Installed Capacity Requirement (Net ICR). During FCA 13, Killingly Energy Center added 632 MW of new gas/oil generation and Mystic 8 and 9 (~1,400 MW total) were retained by the ISO for winter fuel security.[105] The auction cleared at a price of $3.80/kW-month, 18% lower than the previous year's $4.63/kW-month. The $3.80/kW-month clearing price was applied to all capacity zones within New England. Price separation occurred at only one import interface; New Brunswick cleared capacity at a price of $2.68/kW month. The results of FCA 13 led to an estimated total annual cost of $1.65 billion in capacity payments, $0.47 billion lower than capacity payments incurred in FCA 12.

Total FCM payments, as well as the clearing prices for Winter 2021 through Winter 2023, are shown in Figure 7-1 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.

[105] From June 2022 to May 2024, Mystic 8 and 9 will receive supplemental payments per their cost-of-service agreement with the ISO. During Winter 2023, the two Mystic units received a total of $284.6 million in cost-of-service payments.

Figure 7-1: Capacity Market Payments



In Winter 2023, capacity payments totaled $415.7 million. Gross payments reached $423.3 million, but the December 2022 Pay-for-Performance event transferred $7.6 million of capacity performance payments to non-FCM assets. Total payments were down 22% from Winter 2022 ($533.1 million), driven by an 18% decrease in the clearing price from FCA 12 ($4.63/kW-month) to FCA 13 ($3.80/kW-month). A large influx of lower-priced, new capacity displaced higher-priced, existing capacity in FCA 13; over 1,500 MW of new capacity offered at or below the auction clearing price while over 2,100 MW of existing capacity de-listed above the clearing price benchmark.

Approximately $13 thousand in Failure-to-Cover (FTC) charges were administered in Winter 2023. The FTC charge is a negative adjustment to the FCM credit which is applied when a resource has not demonstrated the ability to cover its CSO.

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 Winter 2023 alongside the results of the relevant primary FCA are detailed in Table 7-1 below.

Table 7-1: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

					Capacity Zone/Interface Prices ($/kW-mo)			
FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)*	Cleared MW	Maine	Phase I/II	Highgate	New Brunswick
FCA 13 (2022 - 2023)	Primary	12-month	3.80	34,839				
	Monthly Reconfiguration	Feb-23	2.01	1,343				
	Monthly Bilateral	Feb-23	0.21	132				
	Monthly Reconfiguration	Mar-23	0.70	962				
	Monthly Bilateral	Mar-23	0.10	132				
	Monthly Reconfiguration	Apr-23	1.49	1,133				
	Monthly Bilateral	Apr-23	3.80	3				

**bilateral prices represent volume weighted average prices*

Three monthly reconfiguration auctions (MRAs) took place in Winter 2023: the February 2023 auction in December, the March 2023 auction in January, and the April 2023 auction in February. Clearing prices for all three auctions remained consistently below the associated FCA clearing price, with the highest clearing price occurring in February at $2.01/kW-month. Cleared volumes remained relatively steady, with February clearing the largest volume at 1,343 MW.

7.2 Financial Transmission Rights

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

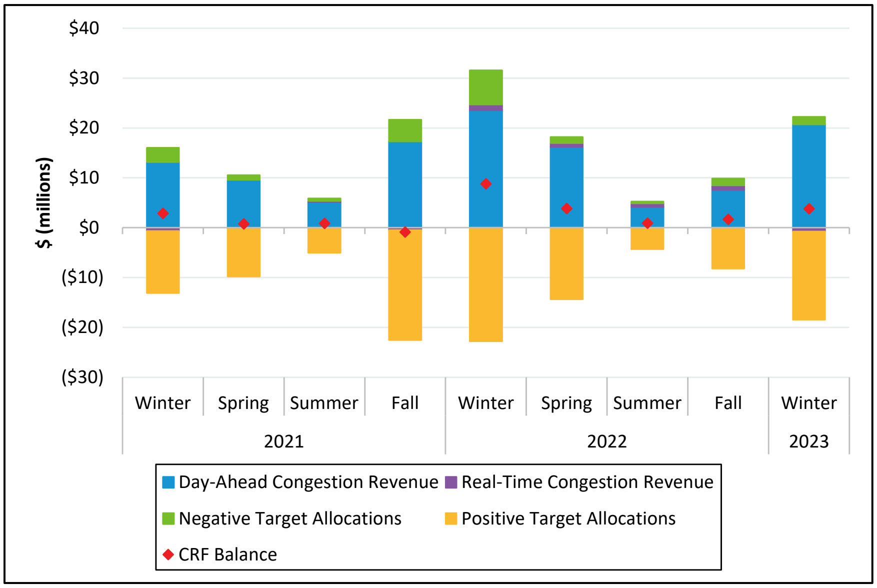
1) the holders of FTRs with negative target allocations;
2) the revenue associated with transmission congestion in the day-ahead market;
3) the revenue associated with transmission congestion in the real-time market.

Figure 7-2 below shows, by quarter, the amount of congestion revenue from the day-ahead and real-time energy markets, the amount of positive and negative target allocations, and the congestion revenue fund (CRF) balance.[106,107]

[106] The CRF balances depicted in Figure 7-2 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).

[107] Figure 7-2 depicts positive target allocations as negative values, as these allocations represent outflows from the CRF. Meanwhile, negative target allocations are depicted as positive values, as these allocations represent inflows to the CRF.

Figure 7-2: Congestion Revenue and Target Allocations by Quarter



Day-ahead congestion revenue amounted to $20.7 million in Winter 2023. This represents an increase of 175% relative to Fall 2022 ($7.5 million) but a decrease of 12% relative to Winter 2022 ($23.5 million). Positive target allocations in Winter 2023 ($17.7 million) followed a similar pattern, increasing by 115% relative to Fall 2022 ($8.2 million) but decreasing by 22% from Winter 2022 ($22.8 million). Negative target allocations in Winter 2023 (-$1.5 million) rose by 11% from their Fall 2022 level (-$1.4 million) but fell 78% from their Winter 2022 level (-$6.9 million).[108] Meanwhile, real-time congestion revenue in Winter 2023 (-$0.7 million) remained relatively modest and was generally in-line with recent historical levels.

FTRs were fully funded in December 2022, January 2023, and February 2023.[109] At the end of 2022, the congestion revenue fund had a surplus of $10.9 million. Surpluses like this carry over until the end of the year and are then used to cover any unpaid monthly positive target allocations. In 2022, $0.2 million went to positive target allocations that had been underfunded during the year.[110] The remaining $10.8 million was then allocated to entities that had paid congestion costs during the year. At the end of February 2023, the congestion revenue fund had a surplus of $2.9 million.

Several of the more impactful transmission constraints in Winter 2023 are listed below. The description attached to each constraint provides some insight into why it experienced congestion in the quarter.

- **New York – New England (NYNE)**: This interface constraint is used to manage the flow of power over seven AC transmission lines that interconnect the New York and New England control areas. Despite this interface being at its full operational capability for most of

[108] The New England West-East (NE_WE) interface bound periodically in the day-ahead energy market throughout Winter 2022 creating substantial negative target allocations during that season.

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

[110] FTRs were not fully funded in June 2022, when 94.5% of positive target allocations were funded, nor in August 2022, when 91.3% of positive target allocations were funded.

Winter 2023, it bound frequently in all three months. Congestion at this interface is quite common during the winter months when imports into New England tend to increase as the result of large spreads between power prices in New England and New York. In Winter 2023, the average day-ahead price at the New England Hub exceeded that for Zone G in New York by over $10/MWh.[111]

- **Keene Road Export (KR-EXP)**: This interface is used to manage the power flows from an area in eastern Maine that has a high concentration of intermittent generators. Despite being at its full operational capability for almost the entirety of Winter 2023, this interface constraint bound frequently, leading to congestion in both the day-ahead and real-time energy markets.

- **Berlin 1771 (BERLIN 1771)**: This line is part of the 115kV system in southwestern Connecticut. This constraint bound periodically in the day-ahead market in December 2022 and January 2023 as a result of nearby transmission work. Outages like this can reduce the transfer capability of the transmission system and alter the flow of power, leading to more congestion.

[111] NYISO Zone G (also called Hudson Valley) is a load zone in the New York control area. See: https://www.nyiso.com/documents/20142/1397960/nyca_zonemaps.pdf

Appendix: Overview of FPA Process

Fuel Price Adjustments (FPAs) provide a means for participants to reflect their expected fuel cost in their reference levels in the event that it differs significantly from the corresponding fuel index. As outlined in Section III.A.3.4(ii) of the Tariff, the submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its supply offer. When a participant submits an FPA, the IMM calculates the reference level for that resource using the cost-based methodology, which uses documented cost information provided by the participant to estimate incremental energy offers.[112] To provide additional insight into how FPAs impact reference levels, the Incremental Energy formula of the cost-based reference level methodology is shown below:[113]

$$\begin{aligned} \textit{Incremental Energy} \\ &= (\textit{incremental heat rate} * \textit{fuel costs}) + (\textit{emissions rate} \\ &* \textit{emissions allowance price}) + \textit{variable operating and maintenance costs} \\ &+ \textit{opportunity costs} \end{aligned}$$

Without an FPA, the IMM estimates the fuel costs in the preceding equation using automated index-based cost data received from third party vendors. Because the indices are based on historical transactions (in the case of natural gas, the weighted average price of the preceding day's next-day trading strip), they may not reflect current market prices. If the reference level is set too low, a resource runs the risk of inappropriate mitigation and failure to recover its operating costs. By overriding the fuel costs in the previous equation, FPAs provide a way to update fuel costs and reference levels in real time.

While FPAs can be submitted for market days up to seven days in the future, they are most commonly submitted in association with offers into the day-ahead (DA) and real-time (RT) energy markets.[114] FPA requests for the DA market must be submitted by the close of day-ahead market window (10:00 AM Eastern Time), while FPA requests for the RT energy market can be submitted up to 30 minutes before the start of the operating hour in which they would take effect.

While the automated processing of FPAs increases the participant's ability to reflect their costs through supply offers rather than after-the-fact uplift payments, it comes with an obligation of verification. To lessen this concern and the ability of a participant to exercise market power, the IMM has two tools: an ability to set a limit on requested FPA prices, and cost verification through *ex-post* documentation.

The IMM uses a proprietary model to estimate a reasonable upper bound for natural gas prices ("FPA Limit"). More specifically, the model uses a variety of forecasting techniques to create probabilistic estimates of pipeline-specific natural gas prices paid by generators for next day and same day delivery of natural gas. The model uses data on regional natural gas transactions from the Intercontinental Exchange (ICE), actual and forecasted weather, and generator gas consumption.

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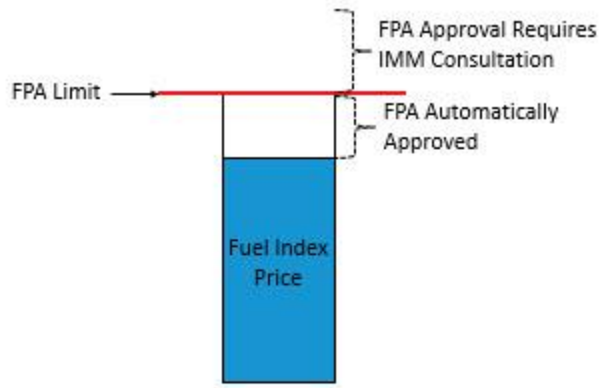
[112] See Tariff Section III.A.7.5.

[113] Similar formulae are also used to estimate no-load and start-up costs, but are not shown here to preserve space.

[114] The software suspends the processing of FPA requests for market days greater than one day out until the beginning of the day before the requested market day.

Once submitted, FPAs are either approved at the requested price or capped at the FPA Limit (see Figure below). As outlined in III.A.3 of the Tariff, if a participant's fuel cost expectation exceeds the FPA Limit, they may consult with the IMM to provide additional documentation for the increased cost. The IMM will draw on its visibility into all FPA requests as well as ICE bids, offers, and transactions to either: 1) manually approve the participant-specific FPA request; 2) raise the FPA limit to more accurately reflect market conditions; or 3) keep the FPA request capped.

FPA Processing Overview



In addition to this *ex-ante* measure, the IMM requires that within five business days of the FPA submittal, the participant must provide supporting documentation in the form of an invoice or purchase confirmation, a quote from a named supplier, or a price from a publicly available trading platform or reporting agency. Should the participant fail to provide this documentation, it can lose the right to use the FPA mechanism (per Section III.A.3.4 of the Tariff).