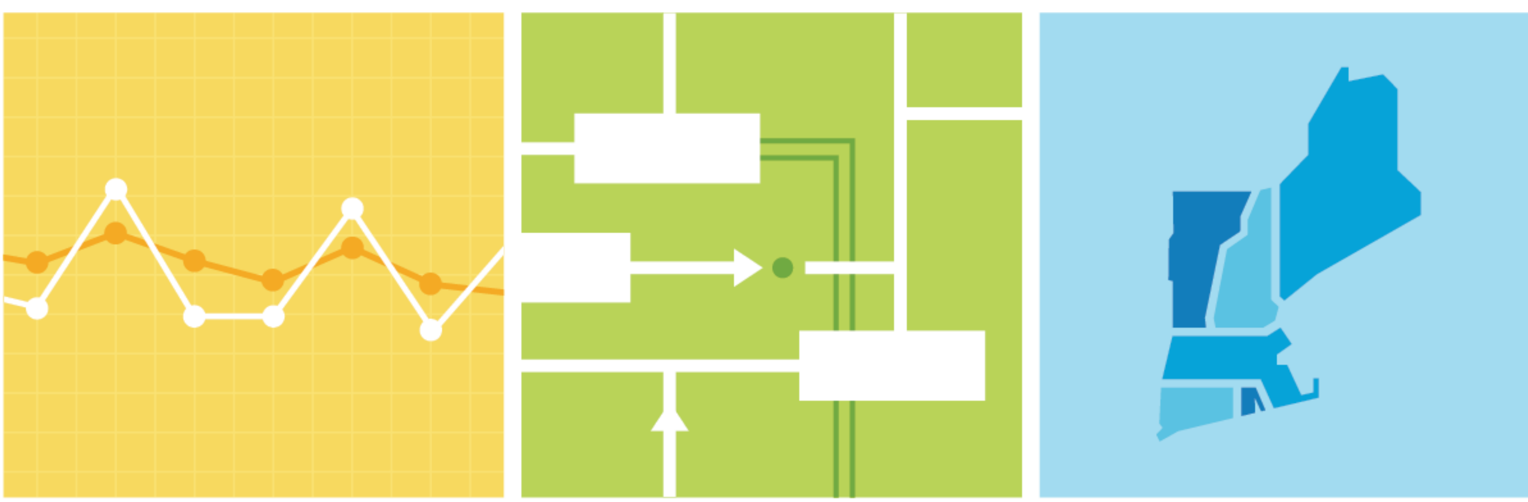
Winter 2020
Quarterly Markets Report

By ISO New England's Internal Market Monitor

MAY 4, 2020

ISO-NE PUBLIC



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Preface

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

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

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

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

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

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

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

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Section 1
Executive Summary

This report covers key market outcomes and the performance of the ISO New England wholesale electricity and related markets for Winter 2020 (December 1, 2019 through February 29, 2020).[3]

Fuel Markets and Weather: During Winter 2020, natural gas prices in New England were lower than the previous winter due to milder weather and lower natural gas prices at supply basins. There were no notable events related to fuel prices.

- There were no extended cold spells in Winter 2020, and average temperatures were warmer (33°F compared to 30°F and 29°F in Winter 2019 and Winter 2018, respectively).
- Supply basin natural gas prices, which influence the New England natural gas price, saw historic lows due to increased production and storage.[4]
- Oil-fired generation accounted for just 0.2% of energy production, a similar value to Winter 2019, and a decrease from 4.5% in Winter 2018.

Fuel Price Adjustments: Section 2.2 of this report covers our analysis of the impact of seasonality on 1) the timing and volume of natural gas transactions in ISO-NE, and 2) any resulting effects on participant Fuel Price Adjustments (FPAs).[5] Key observations of this analysis include:

- Participants submit a larger proportion of FPAs in the winter than in the summer. Only between 10% and 20% of relevant volumes are transacted on ICE by the time most FPAs are submitted (09:45). This indicates that participants may have limited information with which to estimate their fuel costs in their day-ahead offers.
- Occasionally, the spread between FPA requests and final index prices can decrease significantly over the course of a morning, indicating potential improvements in price information and FPA quality over time.
- The analysis suggests that extending the time at which the DAM closes would likely provide value to the market through added price discovery and decreased price uncertainty, which may reduce the supply offers and reference levels that include price risk premiums. The benefit of this extension would appear to be greater in certain seasons (i.e., more extreme winters).

Energy Market Opportunity Costs: From December 2018, Energy Market Opportunity Cost (EMOC) adders for oil-fired generators were included 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. This should help ensure that oil-fired generators are dispatched when

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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] Henry Hub and Marcellus Shale.

[5] Because of differences in the timelines for energy and natural gas markets, reference levels for day-ahead energy offers use natural gas indices derived from the prior gas day. Participants can use FPAs to update their fuel costs and reference levels if there are discrepancies between the existing and expected index values.

most needed, and reduce the need for operators to manually intervene in the market by posturing resources.[6]

During Winter 2020:

- Periods of very cold weather did not sustain long enough to put sufficient strain on natural gas supply and oil inventories.
- The EMOC adder never increased above zero for any generator in the program. As a result, energy market opportunity costs had no impact on the supply curve over the winter period.
- There was no posturing of oil-fired generators.
- The forecasted natural gas and energy prices used to calculate EMOCs appeared to have greater accuracy when overall prices were lower. In Winter 2020, the gas price forecast had a mean absolute forecast error of $0.57/MMBtu while the day-ahead and real-time LMP forecasts had mean absolute errors of $5.48/MWh and $8.31/MWh, respectively.

The Fourteenth Forward Capacity Auction (FCA14): The fourteenth Forward Capacity Auction (FCA 14) was held in February 2020 and covers the capacity commitment period (CCP) beginning June 1, 2023 through May 31, 2024. Below are the highlights from the auction:

- There was a surplus of qualified and cleared capacity compared to the Net Installed Capacity Requirement (NICR).
    - The auction cleared 33,956 MW, a surplus of 1,466 MW over NICR, at a price of $2.00/kW-month across the entire system.
    - Payments for FCA 14 ($1 billion) are projected to be the lowest since the inception of the Forward Capacity Market.
- Considering pre-auction mitigations, excess capacity, and liquidity of dynamic de-list bids, we found no evidence of uncompetitive behavior during FCA 14.
- A total of 2,085 MW dynamically de-listed in rounds four and five; including 900 MW of oil-fired generation and 1,000 MW of gas-fired generation.
- New cleared capacity totaled 637 MW, and primarily consisted of resources with a renewable technology resource (RTR) exemption, or passive demand response resources.[7]
- The substitution auction following FCA 14 did not take place because all active demand bids either 1) failed to clear capacity in the FCA or 2) were ineligible because their true costs of obtaining a Capacity Supply Obligation (CSO) exceeded the FCA clearing price.

Reference Levels for Multi-Stage Generators: Section 4 of this report covers our analysis on the limitations of calculating correct reference levels for multi-stage generators (combined cycle generators that consist of two or more gas turbines connected to a shared steam turbine). Under the current framework, most multi-stage generators only specify cost and efficiency parameters for one default configuration, even though several of them regularly operate in configurations other than the default. The cost differences between configurations are substantial enough to raise concerns about generators being mitigated to below cost, or not being mitigated when they should be.

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

[7] The RTR designation allows a limited amount of renewable resources to participate in the auction without being subject to the minimum offer-price rule.

Given these concerns, we recommend that the ISO consider improvements to its handling of reference levels for multi-stage generators. These improvements include:

- Encourage or require participants to set up configuration-specific cost and efficiency parameters for all operating configurations, and to keep this information up to date.
- Allow participants the flexibility to set active configurations at the hourly level in advance, and during, the operating day.

Wholesale Costs: The total estimated wholesale market cost of electricity was $1.78 billion, down 32% from $2.59 billion in Winter 2019. The decrease was driven by lower energy and capacity costs in Winter 2020.

Energy costs totaled $1.01 billion; down 36% (or $567 million) from Winter 2019 costs. Lower energy costs were a result of lower natural gas prices, which decreased by 41% relative to Winter 2019 prices.

Capacity costs totaled nearly $751 million, down 24% (by $242 million) over the previous Winter. Beginning in Summer 2019, lower capacity clearing prices from the tenth Forward Capacity Auction (FCA 10) contributed to lower wholesale costs relative to the previous FCA. Last year, the capacity payment rate was $9.55/kW-month in all capacity zones except SEMA/Rhode Island.[8] This year, the payment rate for new and existing resources was lower, at $7.03/kW-month. The lower clearing prices caused capacity costs to decrease.

Energy Prices: Day-ahead and real-time energy prices at the Hub averaged $30.32 and $29.97 per megawatt hour (MWh), respectively, a 31-35% decrease compared to Winter 2019 prices.

- Day-ahead and real-time energy prices continued to track with natural gas prices.
- Gas prices averaged $3.40/MMBtu in Winter 2020, a decrease of 41% compared to $5.76/MMBtu in the prior Winter.
- Hourly load averaged 13,975 MW, down by 3.5% (≈ 500 MW) on the previous winter. The decrease was driven by warmer temperatures along with increased energy efficiency and behind-the-meter solar generation.
- Energy market prices did not differ significantly among the load zones. Prices were slightly (2-3%) lower in Connecticut, a trend that has appeared in recent years, likely due to newer highly efficient generation in the load zone.

Net Commitment Period Compensation: NCPC payments totaled $7.4 million, a similar total to Winter 2019 payments ($7.3 million). NCPC payments represented less than 1.0% of total wholesale energy costs in both Winter 2020 and Winter 2019. The majority of NCPC (57%) was for first contingency protection ("economic" NCPC). The ISO paid out most of the first contingency payments in the real-time market.

At $2.8 million, local second-contingency protection (LSCPR) payments accounted for 37% of total NCPC payments. These payments increased by $1.7 million relative to Winter 2019. Most (94%) LSCPR payments occurred in December, and were paid to generators that were committed in the day-ahead market to meet reliability needs in Southeast Massachusetts (SEMA) due to a planned transmission outage.

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[8] As a result of inadequate supply, the payment rate in SEMA/Rhode Island was higher than in other zones.

Real-time Reserves: Real-time reserve payments totaled $1.8 million, a 40% decrease from $3.0 million in Winter 2019. Most (97%) reserve payments were for spinning reserve (TMSR).

The frequency of non-zero ten-minute spinning reserve pricing in Winter 2020 was higher than in Winter 2019. However, the average non-zero hourly spinning reserve price decreased relative to Winter 2019, from $16.31 to $7.56/MWh.

***Regulation*:** Total regulation market payments were $5.7 million, down 30% from $8.2 million in Winter 2019. The decrease in payments reflects the significantly lower energy market prices in Winter 2020, which resulted in lower energy market opportunity costs for regulation resources.

Financial Transmission Rights: The volume of FTR transactions that cleared in the three prompt-month auctions for January, February, and March 2020 ranged from 22,988 MW to 26,833 MW. The cleared volumes and levels of participation were consistent with other recent prompt-month auctions. The volume of FTR transactions that cleared in the out-month auctions administered in January, February, and March was relatively low.[9] The number of participants in these out-month auctions ranged from 10 to 18, which is about one-third to one-half of the level of participation seen in the prompt-month auctions.

[9] On September 17, 2019, the ISO implemented the Balance of Planning Period (BoPP) project, which increased opportunities for market participants to reconfigure their monthly Financial Transmission Rights (FTR) positions following the two annual auctions. In additional to buying and selling FTRs for a given month during the prior month ("prompt-month"), participants also can buy and sell monthly FTRs positions over the remainder of the year before the "prompt-month" auctions take place. The new auctions are called "out-month" auctions.

Section 2
Assessment of Winter 2019/20 Market Issues

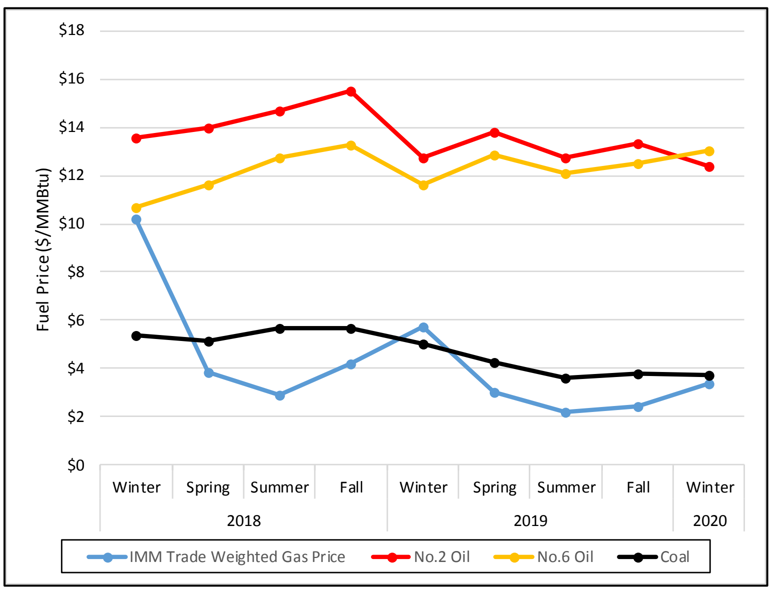
This section of the report focuses on a number of issues specific to winter in the New England markets. We draw comparisons with previous winters in New England – a season when the natural gas system can become constrained due to high heating demand for gas. The first two subsections provide our observations on natural gas prices and activity, while the third subsection reviews Energy Market Opportunity Costs (EMOCs).

2.1 Fuel Markets and Weather

During winter in New England, natural gas pipelines can become constrained during cold spells, leading to extremely high natural gas prices. For instance, the "cold snap" in Winter 2018 led to constrained natural gas pipelines and high gas prices, which pushed gas-fired generators up the supply stack and out of economic merit order. During Winter 2020, the market did not experience any such events, because the natural gas system was less constrained due to milder weather and lower natural gas prices at supply basins.

Fuel Prices: For the most part, New England's electricity prices are driven by fuel costs and the operating efficiency of combustion generators. Average quarterly prices for gas, coal and oil are shown in Figure 2-1 below.

Figure 2-1: Fuel Prices

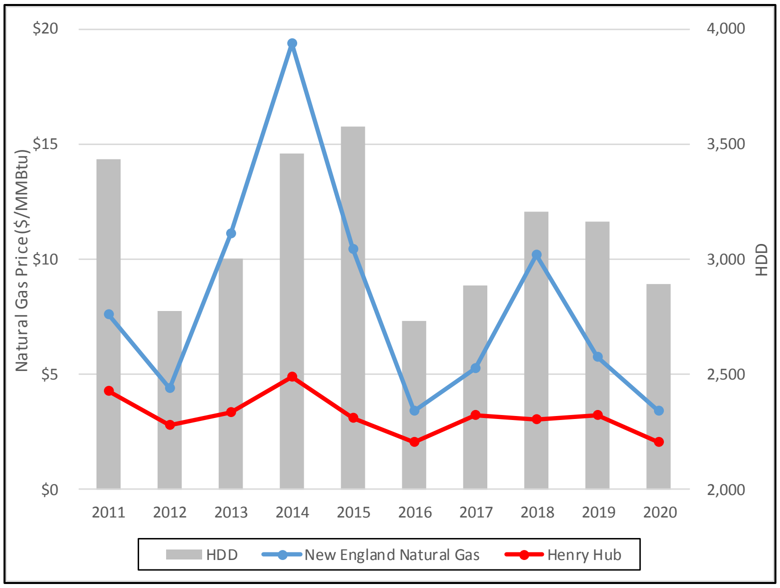


Compared to Winter 2019, prices decreased for natural gas (41%), coal (26%), and No.2 oil (3%), while No.6 Oil increased (12%). The large decrease in natural gas prices further increased the spread between the estimated costs of operating a gas-fired generator versus an oil-fired generator.

Natural Gas: In Winter 2020, natural gas prices averaged $3.40/MMBtu, a 41% ($2.36/MMBtu) decrease compared to Winter 2019, and a 67% ($6.79/MMBtu) decrease compared to Winter

2018. Warmer temperatures in New England and lower natural gas prices at supply basins caused New England gas prices to decrease year over year. Figure 2-2 illustrates the New England natural gas price (blue) over the previous 10 winters and compares it to natural gas prices at Henry Hub (red). Heating degree-days (gray) are shown in the bar charts on the secondary axis.

Figure 2-2: New England Winter Natural Gas Price, Henry Hub Prices and Heating Degree Days



During the winter, cold weather drives natural gas prices in New England because the natural gas infrastructure can become constrained and natural gas-fired generators must compete for fuel against heating demand. In Winter 2020, temperatures were mild and there were no extended cold spells, like in Winters 2014 and 2018. New England temperatures averaged 33°F compared to 30°F and 29°F in Winter 2019 and Winter 2018, respectively.

Along with warmer weather and the absence of cold spells, New England natural gas prices were lower due to lower prices at supply basins. Without regional natural gas supply basins, the New England natural gas price is influenced by prices from across the country. In Winter 2020, natural gas prices at supply basins were at historic lows, owing to greater year-over-year increases in production relative to the year-over-year increases in consumption and higher storage levels than previous years.[10] Henry Hub natural gas prices averaged $2.03/MMBtu, the lowest average winter price since at least 2005. Together, the warmer New England weather and lower supply basin prices led to the lowest average winter New England natural gas prices for, at least, the past 10 years. The low New England natural gas prices contributed to lower LMPs, which caused oil-fired generators to be uneconomic, on average, every day during Winter 2020.[11]

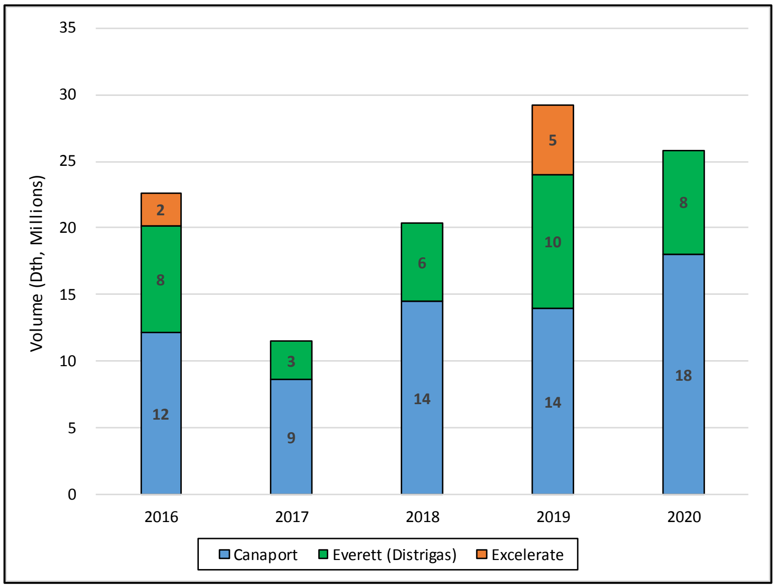
LNG: When natural gas pipelines become constrained in the winter, liquefied natural gas (LNG) can provide another source of natural gas delivery into New England pipelines which can help alleviate constraints and reduce gas prices. There are three operational LNG import facilities

[10] For more information on natural gas storage inventories, see the EIA Weekly Storage Reports.

[11] Oil-fired generators only accounted for 0.20% of electricity supply, compared to 0.15% and 4.54% percent in Winters 2019 and 2018, respectively.

that deliver gas into New England: Excelerate, Canaport and Everett (Distrigas).[12] The volume of deliveries into each facility for the past five winters is illustrated in Figure 2-3 below, along with total LNG deliveries into New England.

Figure 2-3: LNG Sendout by Facility[13]



Outside of Winter 2017, New England has seen at least 20 million Dth of LNG deliveries into the interstate natural gas pipelines each winter. LNG injections in Winter 2020 were 25.8 million Dth, a 12% decrease compared to Winter 2019 and a 27% increase compared to Winter 2018. Lower levels of LNG injection from the Everett (Distrigas) terminal and the Excelerate buoy caused overall LNG deliveries to fall. LNG injection from the Everett (Distrigas) facility fell year over year (10.0 million to 7.8 million Dth) while the Excelerate buoy received no LNG shipments during the most recent winter. Overall, the decrease in LNG in Winter 2020 resulted in 3.4 million Dth less of LNG supply, or enough natural gas to power a 200 MW gas-fired generator for the entire winter.[14]

2.2 Fuel Price Timing and Volatility Analysis

This section of the report examines the impact of seasonality on 1) the timing, volume, and price distribution of natural gas transactions in ISO-NE, and 2) any resulting effects on participants' fuel price adjustments (FPAs).[15] This section stems from the ISO's proposal to

[12] The Canaport LNG facility is located in New Brunswick, Canada but delivers natural gas into New England via the Maritimes & Northeast pipeline.

[13] LNG delivery data is sourced from Genscape.

[14] Assuming a standard efficiency of 7,800 Btu/KWh.

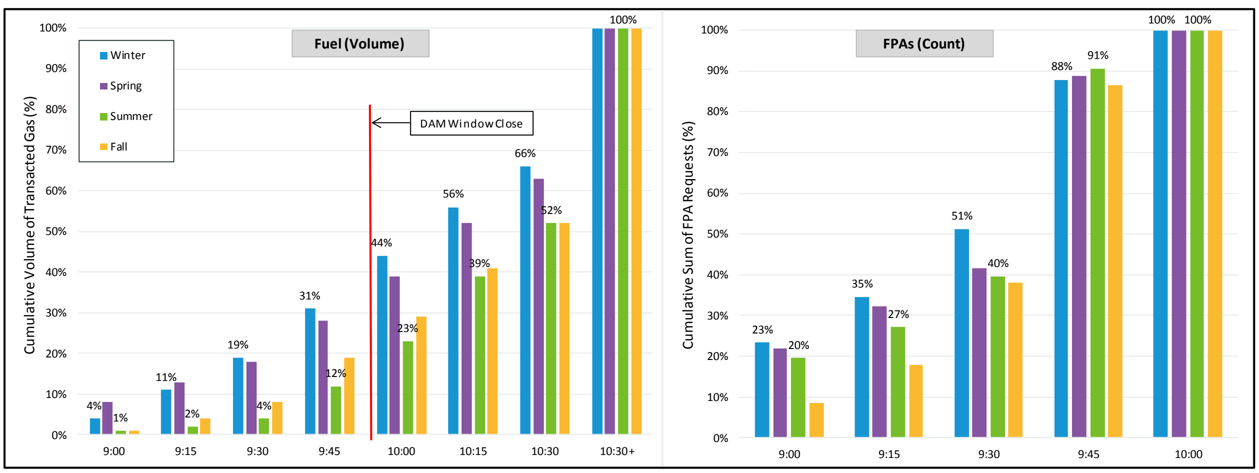
[15] Note that gas transaction data in this section are specific to only the Algonquin Citygates and Algonquin Citygates (Non-G) hubs and only include the Next Day Gas strip for the Firm Physical product. The IMM chose these strip and product attributes because they form the basis of the fuel input in the IMM's marginal cost reference level calculations. The IMM chose to show only Algonquin under the assumption that it is representative of the other hubs. Likewise, the FPA data contain only FPAs made prior to the day-ahead market for the period consistent with the fuel strip. The data include information between December 2017 and February 2020 (three winters and two sets of the other seasons). The IMM chose December 2017 as the start date to capture the "cold snap" in that corresponding winter.

modify the day-ahead market (DAM) submission window from 10:00 AM to 10:30 AM to provide "suppliers additional time to consider information before finalizing their day-ahead offers and bids."[16] The analysis suggests that extending the time at which the DAM closes would likely provide value to the market through added price discovery and decreased price uncertainty, which may reduce the supply offers and reference levels that include price risk premiums. The benefit of this extension would appear to be greater in certain seasons (i.e., more extreme winters).

We calculate a resource's cost-based reference level using the volume-weighted average price of the next-day trading strip. Because of differences in the timelines for energy and natural gas, reference levels for day-ahead offers use natural gas indices derived from the prior gas day. Participants can use FPAs to update their fuel costs (and, consequently, their reference levels) should differences exist between the existing and expected index values. A detailed explanation of FPAs and the FPA process can be found in the Appendix of this report.

The cumulative proportion of natural gas transaction volumes (left) and FPA requests (right), broken out by season and 15-minute time intervals immediately preceding and following the day-ahead market close are presented in Figure 2-4 below.[17] As noted in a previous footnote, the FPA data only include FPAs requested for the timeframe consistent with the next-day gas strip. The graph labels proportions for winter and summer.

Figure 2-4: Cumulative Next-Day Firm Physical Natural Gas Volumes and FPA Requests, by Time Interval and Season, December 2017 through February 2020



As seen in Figure 2-4, participants transacted less than half of all volume (23% in summer and 44% in winter) by the DAM offer deadline of 10:00.[18] These volumes rise by between 20% and 30% using the modified offer deadline being proposed by the ISO (10:30), giving participants additional price discovery with which to craft more accurate supply offers and reference levels.

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[16] See ISO New England presentation to NEPOOL Markets Committee, entitled "Day-Ahead Energy Offer Window Modification & Clean-Up Changes," April 7, 2020. https://www.iso-ne.com/committees/markets/markets-committee/

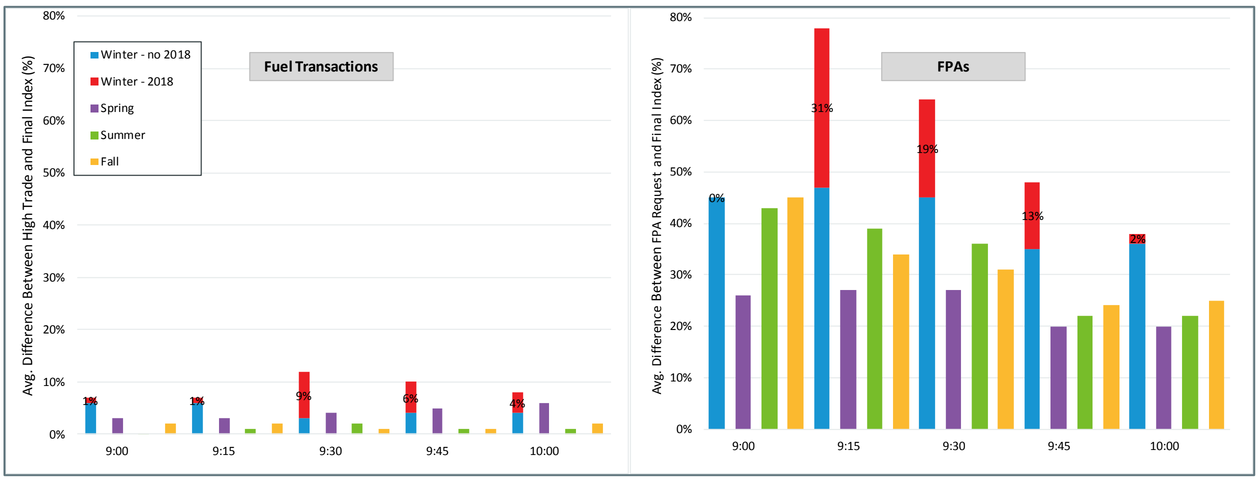
[17] The day-ahead market closes at 10:00, while the gas-trading window on ICE extends from roughly 08:00 to 15:00. The IMM consultation window for FPA processing in day-ahead market reference levels ends at 09:30, while the automatic processing of these FPAs ends at 10:00.

[18] More volume transacts in winter than in summer – with typical winter 09:30 volumes exceeding summer 09:30 volumes by over 400%, and winter 10:00 volumes exceeding summer 10:00 volumes by over 100%.

As shown on the right side of the graph, by the time that 90% of all FPAs are submitted (09:45), only between 10% (summer) and 20% (winter) of relevant volume will be transacted on ICE by this time. This indicates that participants may have limited information with which to estimate their fuel costs in their day-ahead offers, resulting in biases in both (described below).

Figure 2-5 provides information on the average price spread in natural gas transactions (left) and FPA requests (right), broken out by season and time interval. For natural gas transactions, we calculate the spread using the average daily high trade made by the relevant daily interval and the settled fuel index price. For FPAs, we calculate the spread using the average FPA request and the settled fuel index price.[19] The chart also breaks out the additional premium observed in Winter 2018. Note that the exact magnitude of the values in the graph is less important than the general trend.

Figure 2-5: Natural Gas and FPA Price Spread, by Time Interval, and Season



As indicated in Figure 2-5, in more mild winters (2019/2020), we observed about a 5% spread between the average high-priced trade on ICE and the final settled index price – a value that holds relatively constant across all time intervals in these winters. This spread increased in Winter 2018, peaking at an average daily difference of 12% at 09:30. In extreme periods (like those in Winter 2018), the high trade likely serves as a key input to participant FPAs. We observed a similar, albeit more heightened, pattern with FPA data, where winter FPA spreads exceeded spreads for the other seasons and Winter 2018 added a significant premium in addition.[20] Additionally, the FPA spread magnitude decreases significantly over the course of a morning (as much as 20% in the summer months and 40% in extreme winters), indicating potential improvements in price information and FPA quality over the course of the morning.

[19] To assess a true uncertainty premium, we would need to know the actual costs incurred by the participant, a value we can only approximate with the settled index.

[20] A few notes on the difference in magnitude between ICE transactions and FPA requests. First, the ICE data contain only completed transactions and not bid/ask information or quotes from other vendors, which may be significantly different, and may form the basis of participant FPA expectations. Second, transactions on ICE take place routinely every day, whereas FPA requests are likely to cluster in stressed periods; so while the underlying populations of participants may be the same, the timing of the activities may be significantly different.

2.3 Energy Market Opportunity Cost

On December 1, 2018, energy market reference levels began including an opportunity cost (EMOC) adder for resources that maintain an oil inventory.[21] The update was motivated by concerns that, during sustained cold weather events, generators were unable to make energy supply offers that incorporated opportunity costs associated with the depletion of their limited fuel stock. 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.

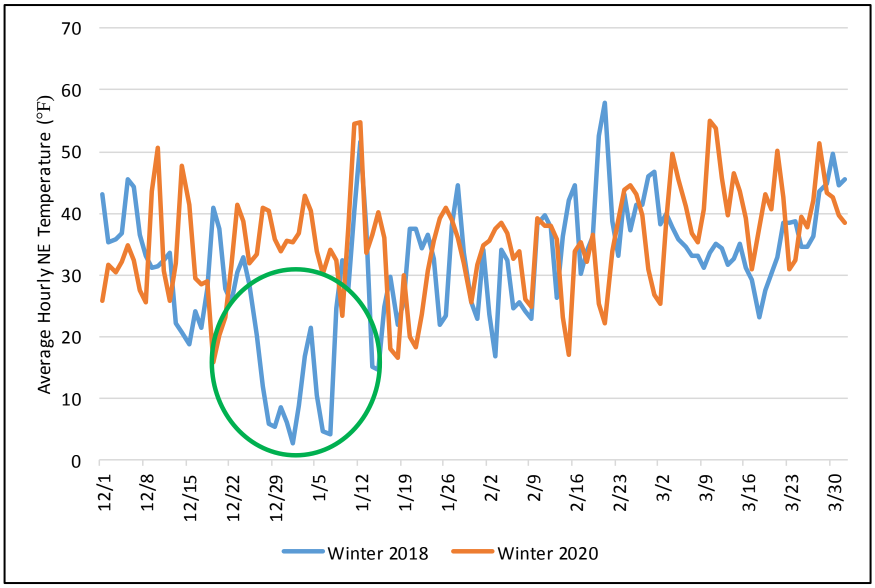
We calculate generator-specific EMOC adders with a mixed-integer programming model that was developed by the ISO and runs automatically each morning. For a given forecast of LMPs and fuel prices, the model seeks to maximize an asset's net revenue by optimizing fuel use over a seven-day horizon, subject 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 6:30 pm, 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.

Winter 2020 was mild and the EMOC adder never increased above zero for any asset that was part of the program. As a result, energy market opportunity costs had no impact on the supply curve over the winter period.[22] During the winter, episodes of very cold weather did not sustain long enough to put sufficient strain on the natural gas supply and, consequently, oil inventories. A cold snap like the one that initiated the posturing of oil-fired generators in Winter 2018 did not occur and no oil-fired generators were postured this past winter. Figure 2-6 shows New England hourly temperatures over both seasons. While there were very cold periods in Winter 2020, they were short-lived when compared with the persistent extreme cold of Winter 2018, which is highlighted on the graph by the green circle.

[21] https://www.iso-ne.com/static-assets/documents/2018/10/a7_memo_re_energy_market_opp_costs_for_oil_and_dual_fuel_revised_edition.pdf

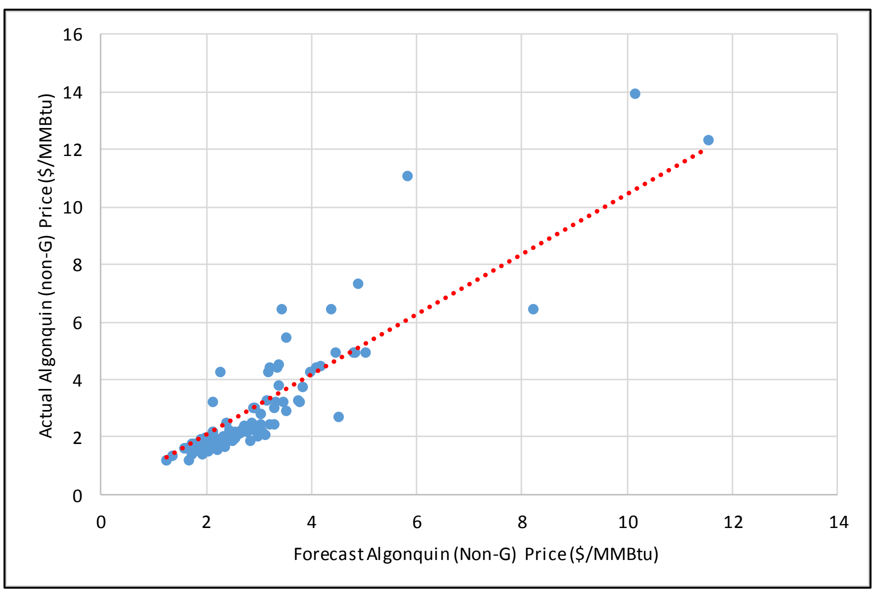
[22] Only hydro units with specific calculation methodologies had hours with non-zero opportunity costs.

Figure 2-6: Average Hourly NE Temperatures Winter 2018 and Winter 2020



One of the primary drivers of the EMOC estimate is the fuel price forecast; particularly the natural gas price forecast due to its high volatility. While previously the ISO produced its own forecast of gas prices, this winter the ISO began calculating EMOCs using gas price forecasts developed by a third-party vendor. A scatter plot of the forecasted values against the actual values for next day gas is shown Figure 2-7 below.

Figure 2-7: Actual vs. Forecast Daily Algonquin Gas (Non-G) Index Price (Winter 2020)



It is clear that the model performs better when gas prices and volatility are low. Across all winter hours, the gas forecast had a mean absolute forecast error of $0.57/MMBtu.

The third-party vendor also supplies hourly day-ahead and real-time LMP price forecasts that serve as primary inputs for the EMOC model. Scatter plots of these forecasts against actual values are shown in Figure 2-8 and Figure 2-9 below. Both forecasts appear to have greater accuracy when overall prices are lower. Over the course of the winter, the day-ahead LMP forecast had a mean absolute error of $5.48/MWh and the real-time LMP forecast had a mean absolute error of $8.31/MWh.

Figure 2-8: Actual Day-ahead Hub LMP vs. Forecast Day-ahead Hub LMP (Winter 2020)

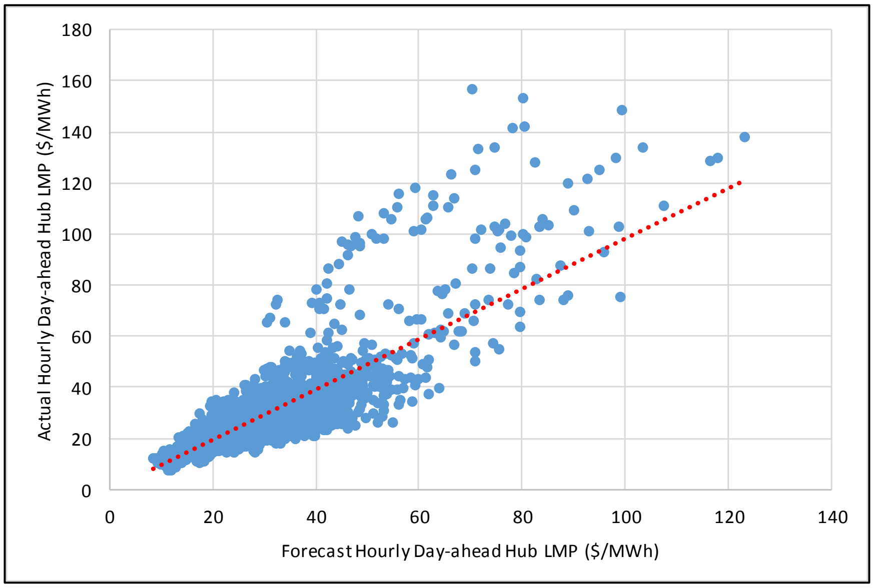
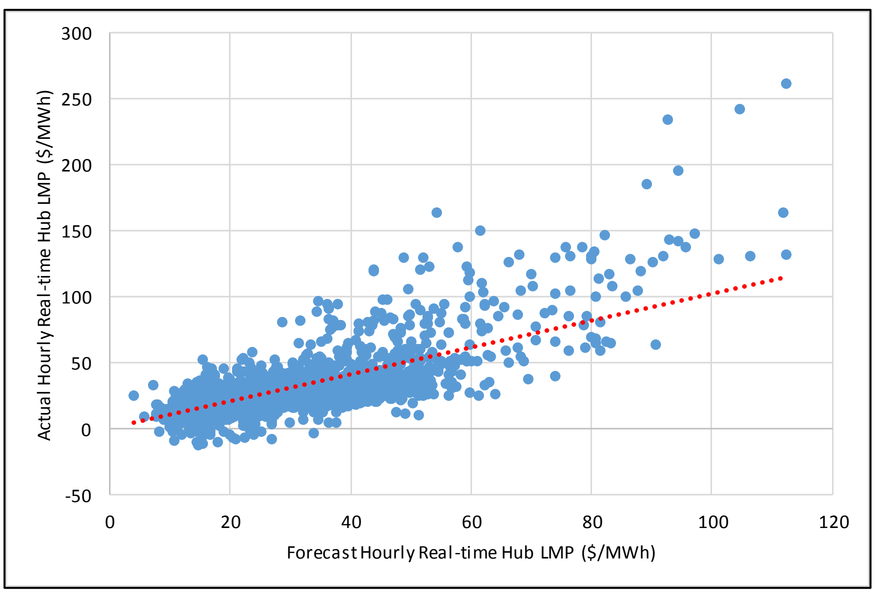


Figure 2-9: Actual Real-Time Hub LMP vs. Forecast Real-Time Hub LMP (Winter 2020)



While the accuracy of various forecasting methodologies can be debated, it is clear that the primary driver of energy market opportunity cost is the weather. Without a period of sustained extreme cold weather to put strain on the gas system it is unlikely that non-zero energy market opportunity costs will materialize.

Section 3
Review of the Fourteenth Forward Capacity Auction

This section presents a review of the fourteenth Forward Capacity Auction (FCA 14), which was held in February 2020 and covers the capacity commitment period (CCP) beginning June 1, 2023 through May 31, 2024. The section covers the our assessment of market competiveness (including IMM mitigation), key auction inputs, and overall outcomes.

At the beginning of the auction, qualified capacity (41,915 MW) exceeded the Net Installed Capacity Requirement (32,490 MW) by 9,425 MW. The surplus grew from FCA 13 (8,781 MW) as a result of a 1,260 MW reduction in the Net Installed Capacity Requirement (NICR) from the prior year. The auction closed in the fifth round with a surplus capacity of just under 1,500 MW relative to NICR. As capacity exited the auction, prices fell below the dynamic de-list bid threshold (DDBT) price of $4.30/kW-month in the fourth round. The auction continued into the fifth round (starting price $3.00/kW-month), and cleared at $2.00/kW-month across the entire system. Payments for FCA 14 ($1 billion) are projected to be the lowest since the inception of the forward capacity market.

A total of 2,085 MW dynamically de-listed in rounds four and five; including 900 MW of oil-fired generation, and 1,000 MW of gas-fired generation. New cleared capacity totaled 637 MW, and primarily consisted of resources with a renewable technology resource (RTR) exemption, or passive demand response resources.[23] The substitution auction following FCA 14 did not take place because all active demand bids either 1) failed to clear capacity in the FCA or 2) were ineligible because their true costs of obtaining a CSO, known as test prices, exceeded the FCA clearing price.

3.1 Review of FCA 14 Competitiveness

We review competitiveness before and after the auction occurs. Prior to the auction, we may mitigate bids and offers for various reasons described below. After the auction, we review participant behavior, the presence of market power, and whether market power potentially impacted auction outcomes. Based on the pre-auction mitigations, excess capacity during the auction, and liquidity of dynamic de-list bids, we find no evidence of uncompetitive behavior during the FCA.

3.1.1 Buyer-Side Market Power

A market participant attempting to exercise buyer-side market power will try to offer capacity below cost in an effort to *decrease* the clearing price. A depressed clearing price benefits capacity buyers over capacity suppliers. To guard against price suppression, we evaluate financial information from new capacity resources for out-of-market revenues or other payments that would allow the market participant to offer capacity below cost.[24] We either replace the out-of-market revenues with market-based revenues or remove them entirely, and

[23] The RTR designation allows a limited amount of renewable resources to participate in the auction without being subject to the minimum offer-price rule.

[24] Out-of-market revenues are defined in Section III.A.21.2 of the tariff.

the offer is recalculated to a higher, competitive price (i.e., we mitigate the offer). In FCA 14, we reviewed 149 resources from 26 participants, accounting for 3,535 MW of capacity.[25] The difference between the MW-weighted average submitted price ($2.75/kW-month) and the price that went into the auction ($5.27/kW-month) for resources that were mitigated highlights the degree to which the buyer-side market power mitigation measures protect price formation from the price-suppressing effects of out-of-market revenues.

3.1.2 Seller-Side Market Power

A market participant attempting to exercise seller-side market power will try to economically withhold capacity during the FCA – for a single year or permanently - in an effort to *increase* the clearing price above a competitive level. An inflated clearing price can benefit the remaining resources in the market participant's portfolio, as well as the portfolios of other suppliers. A market participant would only attempt this if they believed (1) their actions would inflate the clearing price and (2) the revenue gain from their remaining portfolio would more than offset the revenue loss from the withheld capacity.

For market power mitigation purposes, we evaluate new import resources without transmission investments for seller-side market power.[26] In FCA 14, we reviewed 11 such resources that submitted 2,300 MW of supply offers. We disagreed with the price of 26%, or 590 MW, of that capacity. We also reviewed 900 MW of general static de-list bids from 11 resources. We disagreed with the price of five of the bids, accounting for 84% of total capacity. The magnitude of general static de-list price differences (exclusive of imports) reflected an average change of $6.90/kW-month to $4.61/kW-month. The 33% reduction in static de-list bid prices decreases the ability of suppliers to exercise market power should they be found to be pivotal (described below).

3.1.3 Pivotal Supplier Test

As outlined in Section III.A.24, we use a Pivotal Supplier Test (PST) to determine which, if any, suppliers of capacity may have the ability to exercise seller-side market power.[27] A supplier is deemed pivotal if, after removing the entirety of their capacity, the respective zone is unable to meet its corresponding capacity requirement.[28] If a supplier is pivotal, their associated static de-list bids and/or new supply offers (for the previously specified import types) will enter the auction with a mitigated price.[29]

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[25] These values represent new supply generation and demand response resources that received a qualification determination notification. New supply imports are included in the seller-side market power section below.

[26] New imports resources with associated transmission investment are evaluated for buyer-side market power.

[27] As defined in Section III.A.23.4 of the Tariff, for the purposes of this test, "the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade)." Note that because this PST does not include proposed new capacity, the resulting pivotal determinations are likely conservative.

[28] The IMM conducts the PST at both the system and the import-constrained zonal levels; consequently, the relevant capacity requirements are the Installed Capacity Requirement net of HQICCS (Net ICR) at the system level and the Local Sourcing Requirement (LSR) at the import-constrained zonal level.

[29] Barring the exceptions outlined in Section III.A.23.2.

For FCA 14, we conducted the PST at the system-level and for the Southeast New England (SNE) capacity zone. In order to be pivotal in either location, a supplier needed an *effective* capacity portfolio of approximately 3,650 MW and 1,100 MW, respectively.[30] No suppliers met this criterion at the system level, while four met it at the zonal level. None of the pivotal suppliers in SENE submitted de-list bids for review and therefore had no mechanism to exercise market power in this form.

The test process above does not measure a participant's ability to exercise market power beyond the beginning of the auction. Because capacity conditions change in the auction (new resources leave, existing capacity de-lists, the quantity demanded changes), a supplier that was not pivotal at the start of the auction may become pivotal in the auction.[31] This is increasingly likely as the auction proceeds into later rounds and the capacity margin decreases. Heading into the fifth round, capacity exceeded demand by 2,480 MW, meaning that a supplier would need a portfolio of at least this size to exercise unilateral market power. Only one supplier had a portfolio this large, and did not attempt to remove that level of capacity during this round. The fact that there was only one system-level pivotal supplier entering the final round (none at the zonal level), and that the supplier did not attempt to remove the necessary quantity of capacity, further suggests there was sufficient competition across the system to support competitive price levels.

3.1.4 Intra-round dynamic de-lists

The fourth and fifth rounds of the auction were conducted below the dynamic de-list bid threshold (DDBT). Under the Tariff, we do not review bids from existing resources below the DDBT, a proxy price intended to represent the net going forward costs of the likely marginal resource.[32] The dynamic de-list bids in the fourth round came from 18 suppliers accounting for 424 MW. Twenty participants offered 3,684 MW of de-lists bids in the final round. The supply curve in these rounds was relatively flat, which would make it difficult for a market participant to profit from economic withholding given the small impact that would have on clearing prices.

3.2 Auction Inputs

FCA 14 was the first 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.[33] Prior to FCA 14, a transitional approach was taken, with the demand curve reflecting a hybrid of the previous linear demand curve and the new convex-shaped MRI curve.[34] The transitional curve adopted a "shelf", which is discussed in more detail below.

[30] Here, the term effective means "respective of test specifications." For instance, if a supplier had 2,000 MW of import capacity at an interface with a CTL of 100 MW, the IMM would only count 100 MW toward their portfolio.

[31] In fact, suppliers that have been deemed pivotal prior to the auction may not be pivotal to start the auction (if the quantity demanded along the sloped demand curve is greater than NICR or LSR, respectively).

[32] https://www.ferc.gov/CalendarFiles/20180309160822-ER18-620-000.pdf

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

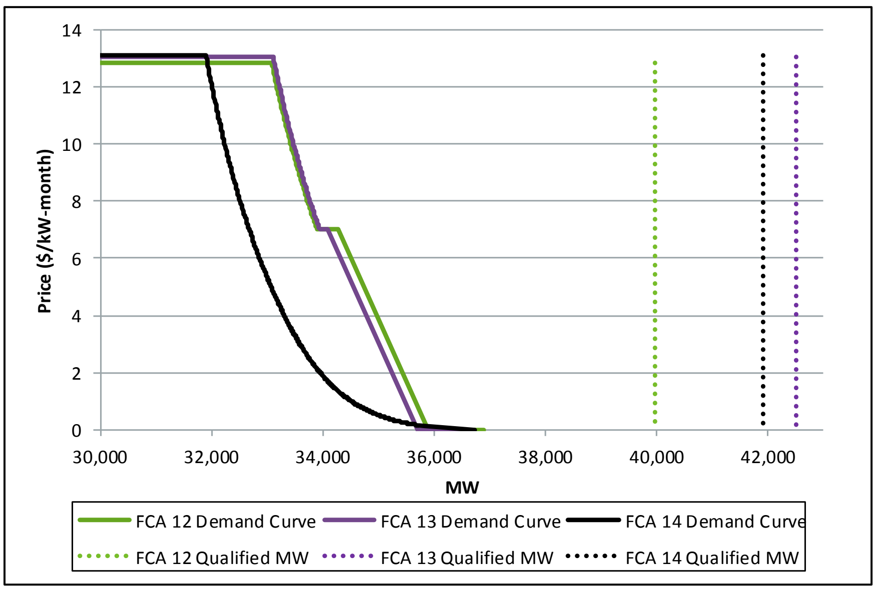
[34] The transition period begins with FCA 11 and can last for up to three FCAs, unless certain conditions relating to Net ICR growth are met, pursuant to Section III.13.2.2.1 of the Tariff.

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.[35] Net Installed Capacity Requirement (Net ICR) and Net Cost of New Entry (Net CONE) are used as the scaling points for the MRI curve. Net CONE changed due to updated reference technologies in FCA 12.[36] The reference technology for FCAs 12 -14 reflects costs of a combustion turbine ($8.19/kW-month in FCA 14), which was selected as the most economically efficient resource the ISO reviewed. The Net ICR value for FCA 14 was 32,490 MW, or 1,260 MW lower than in FCA 13. The decrease is primarily due to updates to the 2019 long-term forecast, which resulted in lower peak load forecasts for FCA 14. Some of the updates include:[37]

- Incorporation of a second weather variable (i.e., cooling degree days)
- Separation of the July and August monthly peak demand models
- Shortening the historical weather period from 40 years to 25 years

This year-over-year Net ICR decrease caused a significant inward shift of the demand curve compared to prior auctions. The difference between demand curves and qualified capacity for FCAs 12, 13, and 14 are shown in Figure 3-1 below.

Figure 3-1: Net ICR and System Demand Curves



As indicated, two key drivers of large capacity margin for FCA 14 were the inward demand shift between FCAs 13 and 14, and the outward supply shift in qualified capacity between FCAs 12 and 13. The latter shift in supply was due to the increase in existing capacity over prior FCAs, and high levels of new supply participating in the FCA. Qualified capacity slightly decreased from FCA 13 to FCA 14 due to less new supply. Still, heading into FCA 14, the system had more capacity relative to the demand curve than the prior auctions. Given these changes, and holding

[35] 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".

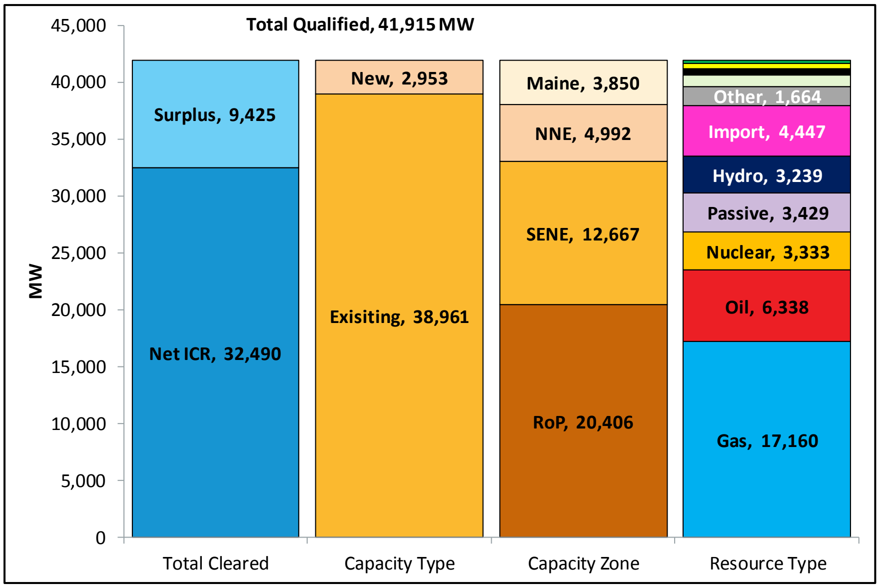
[36] The market rule requires the ISO to recalculate Net CONE with updated data at least every three years. See Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(a).

[37] For more information see https://www.iso-ne.com/static-assets/documents/2019/09/a9_icr_and_tie_benefits_for_fca_14.zip

all else constant, one might expect relatively lower capacity prices in FCA 14 compared to FCAs 12 and 13.

As mentioned above, the amount of qualified capacity can play an important role in auction outcomes. Figure 3-2 below shows that participants provided 41,915 MW of qualified capacity in FCA 14. The three bars to the right show the breakdown of the total qualified capacity amount across three dimensions, capacity type, capacity zone and resource type.

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



Overall, in FCA 14, qualified capacity exceeded Net ICR by 9,425 MW, or almost 29%. New qualified capacity totaled 2,953 MW, a decrease of almost 900 MW from the FCA 13 value (3,840 MW). While each of the prior five FCAs qualified at least 500 MW of new gas-fired generation projects, no new gas-fired generation projects qualified in FCA 14. The decline in clearing prices and increase in capacity surplus over the past several FCAs signaled to potential new generators that the market is long, and load is not willing to pay for higher cost projects. Due to minimum offer floor price rules, new supply can only stay in the auction to a pre-determined price. Many of these prices are above the FCA 14 clearing price of $2.00/kW-month.

The first orange bar (by Capacity Type) shows that the qualified capacity from existing resources exceeded the Net ICR by about 6,500 MW.[38] Approximately 1,400 MW of capacity from Mystic 8 and 9, two combined cycles in the SENE zone retained for fuel security, entered into the auction as existing price-taking capacity, as approved by the FERC.[39]

The second orange bar (by Capacity Zone) shows the 12,667 MW of qualified capacity in SENE which exceeded the Local Sourcing Requirement (LSR) by roughly 2,900 MW. The Northern

[38] 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 14 that increased New England's import capability. Treating imports elsewhere classified as "new" would conflate the actual amount of new capacity on the system. The capacity of an oil-fired resource in Southeast New England (SENE) is not included as qualified capacity because the resource's retirement de-list bid was above the starting price.

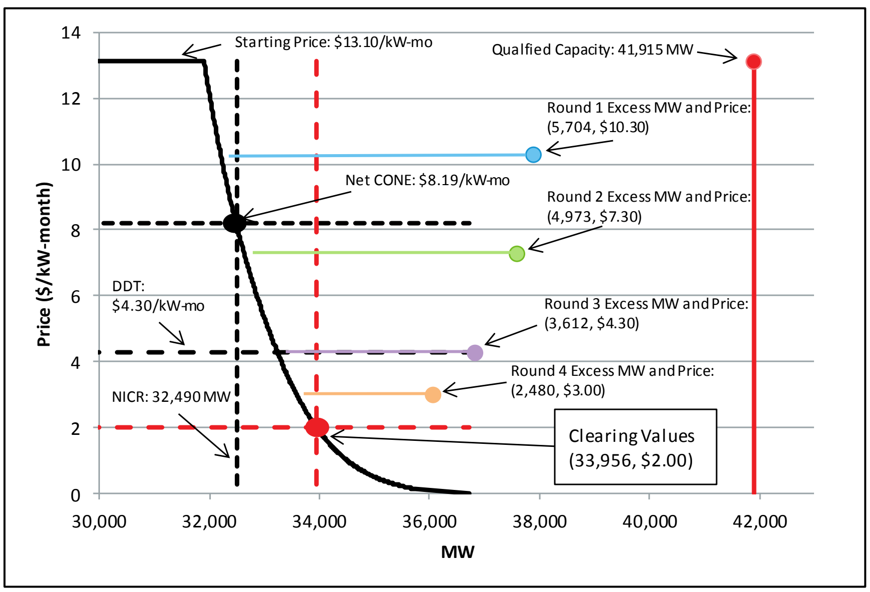
[39] Order Accepting Compliance Filing and Requiring Informational Filings, 165 FERC ¶ 61,202 at P 82.

New England (NNE) capacity zone had 8,842 MW of qualified capacity - 400 MW more than the maximum capacity limit (MCL), indicating an excess over the maximum amount of resources that could be purchased in the zone. Maine, modelled as an export-constrained zone nested within NNE, had 3,850 MW of qualified capacity, slightly under the MCL of 4,020 MW. The final bar breaks down qualified capacity by resource type. We provide more information on total qualified and cleared capacity by resource type in Section 3.4 below.

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. These factors which include the auction parameters provided by the ISO as well as participant behavior are summarized in Figure 3-3 below. On the *demand* side, the demand curve, Net CONE, and Net ICR are shown in black (values discussed in Section 3.2 above). On the *supply* side, the qualified and cleared capacities are shown as solid and dashed red lines, respectively. The clearing price of $2.00/kW-month can be seen at the intersection of the cleared MW (dotted red line) and the demand curve (solid black line), below the DDBT price of $4.30/kW-month (black dashed line). Lastly, the blue, green, purple, and orange markers represent the end-of-round prices, and the corresponding dots depict excess end-of-round supply.[40]

Figure 3-3: System-wide FCA 14 Demand Curve, Prices, and Quantities



The auction closed in the fifth round for the whole system. The fourth round opened with 3,612 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.[41] 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 the IMM's cost review or mitigation. Despite the fact that the fourth round

[40] The colored dots and lines move from cooler colors at high prices and capacity, to warmer colors at lower prices and less capacity.

[41] Excess system capacity only includes import capacity up to the capacity transfer limit.

closed at $3.00/kW-month, existing resources submitted just 424 MW of de-list bids. The auction continued into the fifth round with excess supply of 2,480 MW.

In the fifth round, existing resources submitted 3,684 MW of de-list bids, and 600 MW of new supply submitted offers to exit the auction. Nine resources, including six existing resources and three new active demand response resources, set the price at $2.00/kW-month. The market-clearing engine, which selects capacity to maximize social surplus while setting supply equal to demand, partially cleared the six existing resources and did not clear the new resource capacity (as they had not elected to be rationable).[42]

3.3.1 Results of the Substitution Auction (CASPR)

For the past two years, the Competitive Auctions with Sponsored Policy Resources (CASPR) initiative has been in effect for the Forward Capacity Auction. The ISO implemented CASPR to address two issues: 1) consumers may end up paying for capacity through both the FCM and through subsidies for state-mandated new supply resources and 2) capacity market prices could be depressed below competitive levels if a large quantity of unmitigated new subsidized resources enter the market.

CASPR provides a market-based mechanism for state-sponsored resources to enter the FCM while maintaining competitive prices in the primary auction. The fundamental component of CASPR is the Substitution Auction (SA) that takes places promptly after the primary FCA and serves to coordinate the entry of subsidized new resources with the exit of existing capacity resources. In the substitution auction, existing capacity resources that retained capacity obligations in the primary FCA and 'opted in' to the SA may transfer their obligations to new resources that did not clear in that first stage because of the Minimum Offer Price Rule (MOPR). The SA clearing price can be positive or negative. When the price is positive, existing resources pay the subsidized new resources for accepting capacity obligations and they retain the difference between what they receive as a CSO payment and what they pay the subsidized resources to assume the obligations. If the SA price is negative, then the subsidized resources are willing to pay to take on the obligation for the first year, which would be offset by positive capacity payments in future years when they would be treated as existing capacity. Either way, the existing resources that transfer their obligations in the SA retire from the FCM permanently.

Note, demand bids in the SA from existing resources are capped at the FCA clearing price because this is the most that an existing resource should be willing to pay a new resource to take on its capacity obligation. If an existing resource were to offer higher than the FCA clearing price in the SA, then it would be willing to pay to get out of the capacity obligation that it just acquired.

Unlike the FCA in which the ISO must procure sufficient capacity to meet capacity targets, the quantity of capacity that clears the SA is dependent on the amount of capacity offered by existing participants and the quantity demanded by new entrants. In FCA 13, the SA cleared 54 MW at a price of $0/kw-month. One participant shed their obligation of 54 MW, which was obtained by a new entrant seeking to acquire up to 273 MW of capacity obligation. An additional 271 MW of supply offers that had elected to participate in the SA were removed before the SA because either they cleared in the FCA, or their offer price was greater than the

[42] Rationability refers to a resource's ability to clear within a range of a capacity. A non-rationable resource either clears all or none of their offer segment.

FCA clearing price, i.e., existing capacity would have to pay them more than the FCA price to take on their obligation.

It is possible that a participant would be willing to accept a lower FCA clearing price than their true cost of obtaining a CSO if they believe it would gain them entry to the SA where they would buy out of their obligation. This behavior could suppress FCA clearing prices as the subsidy is seen to move backward from the SA auction into the primary FCA. For FCA 14, we introduced a process to mitigate this effect, we calculate an estimate of the true cost of obtaining a CSO, known as a test price, and remove any resource whose test price is above the FCA clearing price from the SA.

This year, the SA did not proceed. While there were 292 MW of supply seeking to acquire capacity obligations, there was no demand because the existing capacity resources either exited the FCA without a CSO or we deemed them ineligible because their test price was greater than the FCA clearing price. Fourteen existing resources with a combined capacity of 445 MW elected to participate in the substitution auction. The weighted-average submitted test price was $4.83/kW-month. The IMM reviewed and denied 10 resources (above the 3 MW threshold), with a combined capacity of 443 MW. The weighted-average IMM-determined test price was $12.54/kW-month. Since the auction cleared at $2/kW-month, none of these resources were eligible to participate in the substitution auction.[43]

While only 54 MW of subsidized new resources have obtained a CSO through the SA so far, the SA has the capability to accommodate the entry of significant subsidized resources over time. At present, a segment of subsidized resources continues to obtain CSOs in the primary FCA though the renewable technology resource (RTR) exemption, which allows a limited quantity of subsidized resources to be exempt from the MOPR.[44] When the RTR exemption has phased out, all subsidized resources that do not receive a CSO in the primary FCA will participate in the SA. More competitive supply will likely encourage increased participation from existing resources that would provide demand. In addition, the SA will be more effective as states provide estimates on the quantity and timing of when new subsidized resources will seek CSOs. This will enable existing CSO holders to better time their exit from the capacity market.

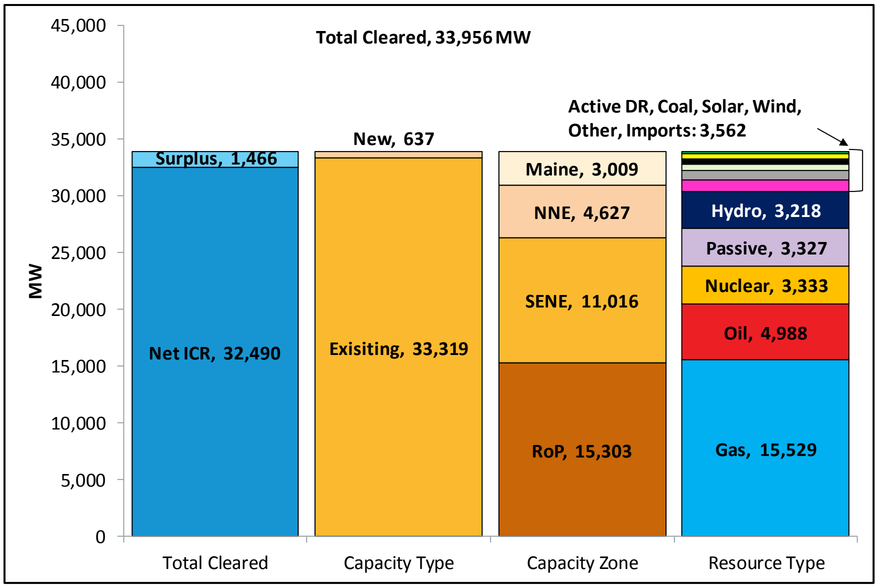
[43] For more information on test prices, see Section 6.7.2 of the 2019 AMR.

[44] A Forward Capacity Market rule establishing a benchmark price called an offer-review trigger price, which forms the lower limit on offer prices the internal market monitor will review to prevent new resources from entering the FCM at prices below their costs, presuming that new supply offers below the threshold are not attempts to suppress the clearing price.

3.4 Cleared Capacity

The amount of 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, the amount of cleared capacity in FCA 14 exceeded system-wide requirements.

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



As excess supply declined during the auction, total surplus fell from 9,425 MW of qualified capacity to 1,466 MW of cleared capacity. The 7,959 MW difference stems from existing resources de-listing, and new supply resources exiting the market at prices greater than the $2.00/kW-month clearing price. The first orange bar (capacity type) illustrates that existing capacity accounted for over 98% of cleared capacity. Interestingly, 635 of the 637 MW of new capacity were either resources with a renewable technology resource (RTR) exemption (described in more detail below), or passive demand response resources.

Resources with an RTR exemption accounted for 50% of total new cleared capacity in FCA 14. The RTR designation allows a limited amount of renewable resources to participate in the auction without being subject to the minimum offer-price rule. In order to claim the exemption, resources must receive out-of-market revenue sources and qualify as a renewable or alternative energy resource under a New England state's renewable portfolio standards located within that state.[45] Entering the auction there were only 336 RTR MW available to the entire pool of 775 MW of RTR qualified resources. Consequently, each resource had their final qualified capacity prorated by 45%. By the end of the auction, 325 of the resources partially cleared 317 MW, leaving 19 MW of RTR exempt capacity available for FCA 15.

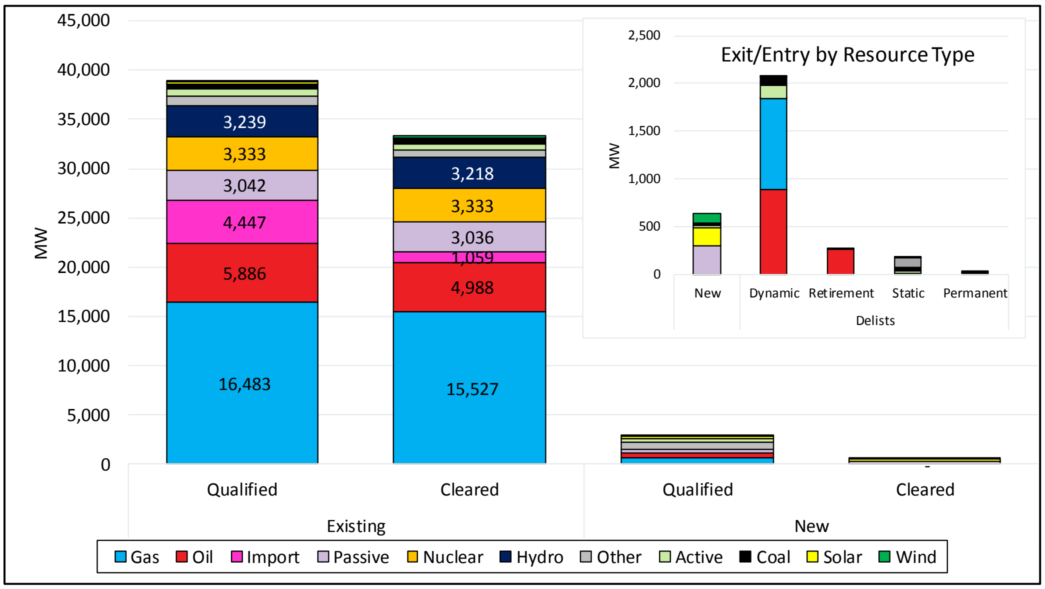
The second set of orange bars (by Capacity Zone) shows sufficient capacity cleared in SENE compared to the LSR (11,016 MW versus 9,757 MW). NNE cleared 7,636 MW of capacity and Maine cleared 3,009 MW, both below their respective MCLs. That is to say, enough capacity

[45] For more information see https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/qualification-process-for-new-generators

stayed in SENE, and enough capacity left NNE and Maine, so that no zonal prices separated from the system price. The final bar (by Resource Type) illustrates that gas-fired resources made up nearly half of total cleared capacity. Oil-fired resources comprised the second largest group of capacity resources (15%), despite low capacity factors in the energy market.[46]

Figure 3-5 breaks down qualified and cleared capacity by new and existing resource types. There can be up to four different bars for a resource type (qualified-existing, cleared-existing, qualified-new, and cleared-new). Additionally, the inset graph displays new entry and de-lists (static, dynamic, permanent, and retirement) by resource type.

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



Imports, gas-fired, and oil-fired resources made up the largest declines in existing capacity. Only 24% (1,059 MW) of qualified imports (4,447 MW) cleared the auction. Gas-fired and oil-fired existing capacity fell due to retirements and dynamic de-list bids (breakdown provided in the inset graph). Of the 258 MW of capacity that retired (third bar), 257 MW came from oil-fired resources built prior to 1971. As mentioned above, rounds four and five occurred below the DDBT. Therefore, any existing resource was able to submit de-list bids subject to reliability review. A total of 2,085 MW dynamically de-listed, with 995 MW (42%) coming from oil-fired resources, and 956 MW (46%) from gas-fired resources.

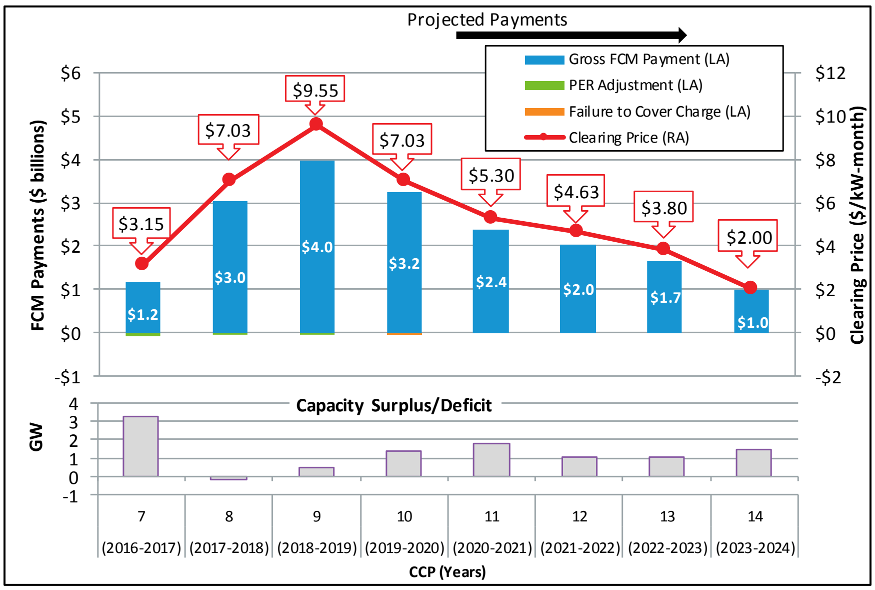
New cleared capacity in FCA 14 accounted for 637 MW, approximately half of the average cleared new capacity over the past five auctions. As the capacity price fell, new resources exited the auction because either 1) auction price fell below their offer floor price, or 2) they chose to remove their capacity based on low FCM revenue. As stated above, most of the new capacity that cleared were either resources that claimed RTR exemptions, or passive demand response resources that benefit from low offer floor prices.

[46] See section 2.2.1 for more information on capacity factors.

3.5 Comparison to Other FCAs

Underlying FCA clearing prices and volumes drive trends in FCM payments. Payments for CCPs 7 -14 are shown in Figure 3-6 below, alongside the Rest-of-Pool clearing price for existing resources. The blue bars represent gross FCM payments by commitment period. Payments for CCPs 9-13 are projected payments based on FCA outcomes, as those periods have not yet been settled.[47] The green bar represents PER adjustments made in past commitment periods. The red line series represents the existing resource clearing price in the Rest-of-Pool capacity zone.[48] 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.

Figure 3-6: FCM Payments by Commitment Period



The graph shows that as the capacity surplus has increased, or has been relatively high in recent auctions, the clearing prices and estimated payments have declined significantly from the FCA 9 peak. Projected payments for FCA 14 are $1 billion, down from $1.7 billion in the prior auction.

[47] Payments for incomplete periods, CCP 10 through CCP 14, have been estimated as: $FCA\ Clearing\ Price \times Cleared\ MW \times 12$ for each resource.

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

Section 4
Reference Levels for Multi-Stage Generators

Nineteen combined cycle generators (with a nameplate capacity of 12,800 MW) in the ISO New England system consist of two or more gas turbines connected to a shared steam turbine. In this section we refer to these plants as multi-stage generators. These resources can operate in different configurations, which correspond to the number of online gas turbines. For example, we refer to a multi-stage generator operating with one gas turbine turned on as a 1x1 configuration generator (i.e., one gas turbine plus the steam turbine), and a multi-stage generator operating with two gas turbines turned on as a 2x1 configuration generator (two gas turbines plus the steam turbine). The 1x1 configuration is associated with the lowest energy output of the generator.

In 2017, we reviewed the potential market and system efficiencies of allowing supply offers for each configuration for multi-stage generators.[49] Specifically, we found that reliability commitments of multi-stage generators on their 2x1 full configuration, during times when a 1x1 configuration would have satisfied the reliability need, resulted in excess NCPC costs and had a depressing effect on energy prices in the reliability area.

In that report, we recommended that the ISO evaluate alternative approaches to modeling multi-stage generators. One option is to make the current pseudo combined cycle modeling capability mandatory for all multi-stage generators. Alternately, the ISO could implement a more dynamic approach that models specific configurations and accounts for transition times and costs between them. However, the latter approach is complex and may be costly to implement. The chosen approach should rely on a cost-benefit analysis.

Given that this area is not part of the ISO's workplan, and is unlikely to be developed for some time, we are recommending related changes that could be made to the market power mitigation function in the meantime. We believe these changes will be less resource-intensive and complex to adopt, compared to incorporating multi-stage generation modeling into the day-ahead and real-time market and systems software. Our proposal is to provide generators with the ability to dynamically select their active or planned configuration and to adjust reference levels to be consistent with their operating costs and their supply offers. This will address the current risk of false positive and negative mitigation, given the potentially high costs differences between configurations.

Issues With Establishing Configuration-Specific Reference Levels

A multi-stage generator's cost and efficiency parameters can differ substantially depending on the operating configuration. However, there are currently several factors that may prevent or discourage generators from entering this information for *all* of their operating configurations into the energy market. This can not only diminish the effectiveness of the market power

[49] See section 5, *Participation of Multi-Stage Generators in the Energy Market*, of the IMM's Fall 2017 Quarterly Markets Report, at https://www.iso-ne.com/static-assets/documents/2018/02/2017-fall-quarterly-markets-report.pdf

mitigation rules, but can deter a generator from offering configurations that may be more cost effective to consumers.

In most cases, the reference levels used in energy market mitigation only reflect the attributes of a single default configuration. This is problematic because generators could be mitigated below their actual costs when running on a less efficient configuration than the default setting (a false positive). Alternatively, if the generator runs on a more efficient configuration than the default setting, reference levels are too high and the mitigation process could fail to mitigate the potential exercise of market power (a false negative).

Generators currently have the ability to specify configuration-level parameters in the Customer Asset Management System (CAMS)[50] and select an active configuration prior to the operating day. However, most generators do not provide configuration-specific cost and efficiency values for reference level calculations, other than for a single default configuration. This may be because participants are not required to provide additional configuration-specific parameters, or because they are not aware of the option. Even if a generator does provide parameters for all configurations, the available options offer only limited flexibility. Generators can only select one configuration per operating day, and they cannot make changes to the selected configuration past 6 pm prior to the operating day.

These issues also extend to multi-stage generators that are modeled as pseudo-combined cycle (PCC) assets in the energy market.[51] Under the PCC framework, participants can voluntarily model multi-stage generators as multiple independent assets in the energy market, with each PCC asset consisting of one combustion turbine and a pro-rata portion of the steam turbine. Of the nineteen multi-stage generators in the market, nine have opted to be treated as PCC generators. The reference levels for PCC assets are based on a 1x1 configuration, even though these generators often operate with more than one PCC asset on at a time. Whenever more than one PCC asset within the same plant is running simultaneously, the generator's true cost and efficiency parameters are those of a 2x1 or 3x1 configuration, not the 1x1 configuration used to establish reference levels, and reference levels tend to be overstated.

Costs Differences Between Configurations

Though data for configuration-specific cost and efficiency parameters are not available for most multi-configuration generators, information from a number of generators submitted to the IMM shows notable cost differences between different configurations at the same plant.

Multi-stage generators have greater efficiency and thus lower marginal costs when running with all gas turbines on (a 2x1 or 3x1 configuration), compared to running in a 1x1 configuration. Available data show that marginal cost estimates for 1x1 configurations can vary from about 10% to 40% above marginal costs for the maximum-output configuration at the same plant. Cost differences between configurations vary by season and generator technology type. The difference in estimated marginal costs raises concerns because the reference levels

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[50] Specifically, this is done through the Internal Market Monitor's Asset Characteristics (IMMAC) module of CAMS.

[51] To better reflect some of the characteristics of multi-stage generators, ISO-NE implemented Pseudo-Combined Cycle (PCC) rules in 2006. Prior to 2006, all multi-stage generators were modeled as a single asset, which ignored their ability to run with one or more gas turbines offline. The PCC rules make it possible for just one PCC asset to clear in the energy market. The rules were intended to improve commitment flexibility and reduce the cost of reliability commitments when the generator is not needed at its maximum-output configuration.

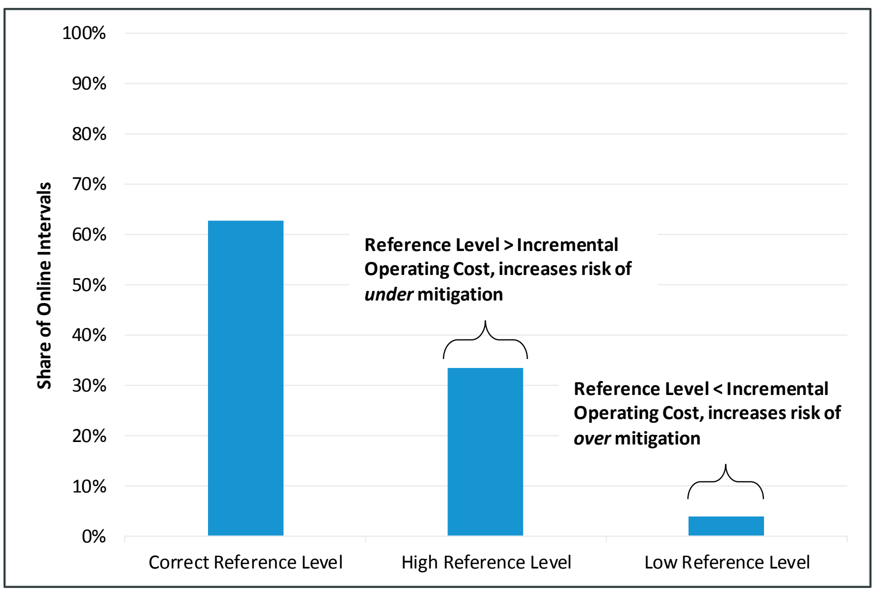
used in mitigation could be substantially different from a generator's actual operating costs. For example, if a generator runs in a 1x1 configuration and enters an offer consistent with that configuration, they could be mitigated if their reference levels are based on their more efficient full configuration. In this case, the mitigation software would mitigate the generator to an incorrect cost.

Frequency of Configuration Changes

Operational data suggests that most multi-stage combined cycle generators run in configurations other than their default configuration often enough to warrant a more robust option for defining configuration-specific parameters. For PCC generators, this analysis determined the operating configuration of the multi-stage generator based on how many of its associated PCC assets were online for each interval. For non-PCC multistage generators, this analysis determined operational ranges for each configuration, and calculated the estimated configuration using real-time output and ecomax values.

Below, Figure 4-1 shows a breakdown of the implied operating configurations of online multi-stage generators in real-time, compared to the default configurations that determine generator reference levels. The results are shown for real-time intervals from January 2019 through March 2020.

Figure 4-1: Real-Time Multi-Stage Generator Operating Configuration Compared to Default Configuration Reference Levels, January 2019-March 2020[52]



From January 2019 through the end of Winter 2020, multi-stage generators operated at configurations consistent with their reference levels for about 60% of the time that they were online. Both types of multi-stage generators (those modeled as PCC assets and those not modeled as PCC assets) appeared in this category.

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52 This analysis only had access to configuration-specific reference level information for certain generators. For those with missing information, we assume that higher-output configurations are more efficient, and thus have lower marginal costs, than lower output configurations (i.e. the incremental operating cost hierarchy is 1x1 > 2x1 > 3x1).

The “High Reference Level” category shows that multi-stage generators ran at configurations that were more efficient than their default configuration about 30% of the time. In these instances, the generator’s actual incremental operating costs were likely lower than the reference levels calculated for the default operating configuration. This mismatch increases the risk of the mitigation process failing to mitigate the potential exercise of market power for these generators. The generators in the “High Reference Level” category were all PCC assets, which have reference levels based on a default 1x1 configuration. The frequency of non-default operating configurations varied widely across these nine generators, ranging from 21% to 75% of the real-time intervals during which each generator was online.

The “Low Reference Level” category shows that multi-stage generators operated at configurations that were less efficient that their default configurations 4% of the time. The 10 generators that appeared in this category are those that are not modeled as PCC assets. When these generators operate at less efficient configurations, rather than at their default configuration (2x1 or 3x1), there is an increased risk that they will be mitigated below their actual incremental operating costs. The frequency of non-default operating configurations ranged from 1% to 32% of the real-time intervals during which each non-PCC generator was online.

Recommendations

Given the cost differences between configurations and how common it is for multi-stage generators to run in configurations other than their default, we recommend that the ISO consider improvements to the mitigation rules and systems to allow for dynamic selection of reference levels. These improvements should:

- Encourage or require participants to set up configuration-specific cost and efficiency parameters for all operating configurations, and to keep this information up to date. This would be a similar approach currently used in selecting fuels, or blends of fuels, as part of the supply offer submission process, which are in turn used in marginal cost reference level calculations.
- Allow participants the flexibility of setting active configurations at the hourly level, day-ahead and intra-day

Section 5
Overall Market Conditions

This section provides a summary of key trends and drivers of wholesale electricity market outcomes from Winter 2018 through Winter 2020. Selected key statistics for load levels, day-ahead and real-time energy market prices, and fuel prices are shown in Table 5-1 below.

Table 5-1: High-level Market Statistics

Market Statistics	Winter 2020	Fall 2019	Winter 2020 vs Fall 2019 (% Change)	Winter 2019	Winter 2020 vs Winter 2019 (% Change)
Real-Time Load (GWh)	30,522	27,500	11%	31,276	-2%
Peak Real-Time Load (MW)	19,035	19,162	-1%	20,773	-8%
Average Day-Ahead Hub LMP ($/MWh)	$30.32	$24.69	23%	$46.93	-35%
Average Real-Time Hub LMP ($/MWh)	$29.97	$24.98	20%	$43.65	-31%
Average Natural Gas Price ($/MMBtu)	$3.40	$2.44	40%	$5.76	-41%
Average Oil Price ($/MMBtu)	$13.03	$12.48	4%	$11.61	12%

To summarize the table above:

- Lower natural gas prices ($3.40/MMBtu vs $5.76/MMBtu) drove the decrease in energy costs in Winter 2020 compared to Winter 2019. Lower national hub gas prices and fewer constraints on the gas pipeline system contributed to reduced New England gas prices.

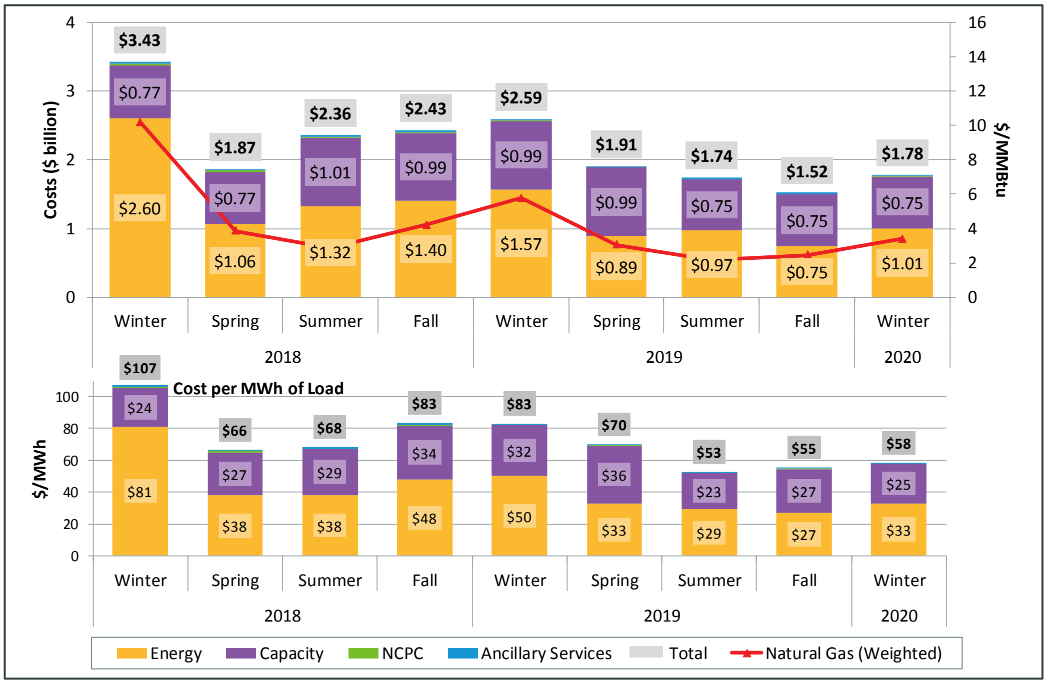
- Total load in Winter 2020 (30,522 GWh) was 2% lower than in Winter 2019 (31,276 GWh). Higher average temperatures in Winter 2020 (33^0F vs 30^0F) contributed to lower total demand.

- Average day-ahead LMPs in Winter 2020 were $30.32/MWh, 35% lower than in Winter 2019. As discussed above, lower gas prices in Winter 2020 ($3.40/MMBtu) compared to Winter 2019 ($5.76/MMBtu) led to lower LMPs.

5.1 Wholesale Cost of Electricity

The estimated wholesale electricity cost (in billions of dollars) for each season by market, along with average natural gas prices (in $/MMBtu) is shown in Figure 5-1 below. The bottom graph shows the wholesale cost per megawatt hour of real-time load served. [53,54]

Figure 5-1: Wholesale Market Costs and Average Natural Gas Prices by Season



In Winter 2020, the total estimated wholesale cost of electricity was $1.78 billion (or $58/MWh per unit of load), a decrease of 32% compared to $2.59 billion in Winter 2019, and an increase of 17% over the previous quarter (Fall 2019). Natural gas prices continued to be a key driver of energy prices.

Energy costs were $1.01 billion ($33/MWh) in Winter 2020, 36% lower than Winter 2019 costs, driven by a 41% decrease in natural gas prices. Energy costs made up 57% of the total wholesale cost. The share of each wholesale cost component is shown in Figure 5-2.

Capacity costs are driven by clearing prices in the primary capacity auctions, and totaled $751 million ($25/MWh), representing 42% of total costs. Beginning in Summer 2019, lower capacity clearing prices from the tenth Forward Capacity Auction (FCA 10) contributed to lower wholesale costs relative to the previous FCA. Last year, the capacity payment rate was

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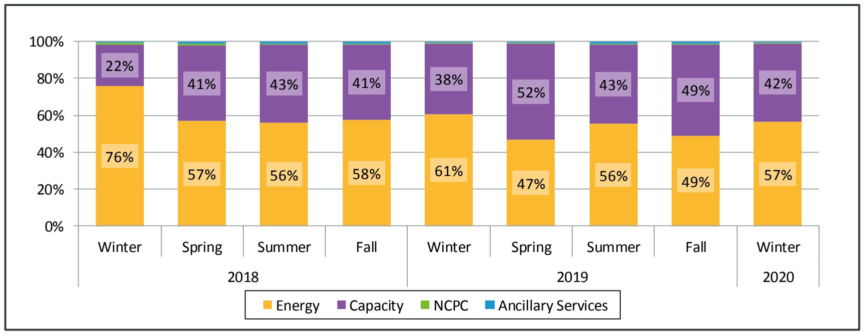
[53] The total cost of electric energy is approximated as the product of the day-ahead load obligation for the region and the average day-ahead locational marginal price (LMP) plus the product of the real-time load deviation for the region and the average real-time LMP. Transmission network costs as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

[54] 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.

$9.55/kW-month in all capacity zones except SEMA/Rhode Island.[55] This year, the payment rate for new and existing resources was lower, at $7.03/kW-month. The lower clearing prices caused capacity costs to decrease.

At $7.4 million ($0.24/MWh), Winter 2020 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 6.4 contains further details on NCPC costs.

Figure 5-2: Percentage Share of Wholesale Cost

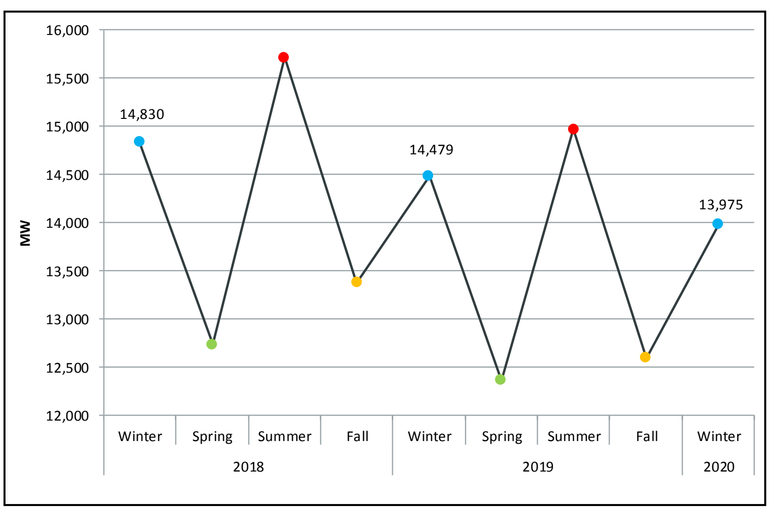


Ancillary services, which include operating reserves and regulation, totaled $12.6 million ($0.41/MWh) in Winter 2020, representing less than 1% of total wholesale costs. Ancillary service costs decreased by 41% compared to Winter 2019, and decreased by 20% compared to Fall 2019.

5.2 Load

As discussed above, warmer temperatures along with increased energy efficiency and behind-the-meter solar generation in Winter 2020 resulted in lower average wholesale loads.[56] Average hourly load by season is illustrated in Figure 5-3 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer and the yellow dots represent fall.

Figure 5-3: Quarterly Average Load



[55] As a result of inadequate supply, the payment rate in SEMA/Rhode Island was higher than in other zones.

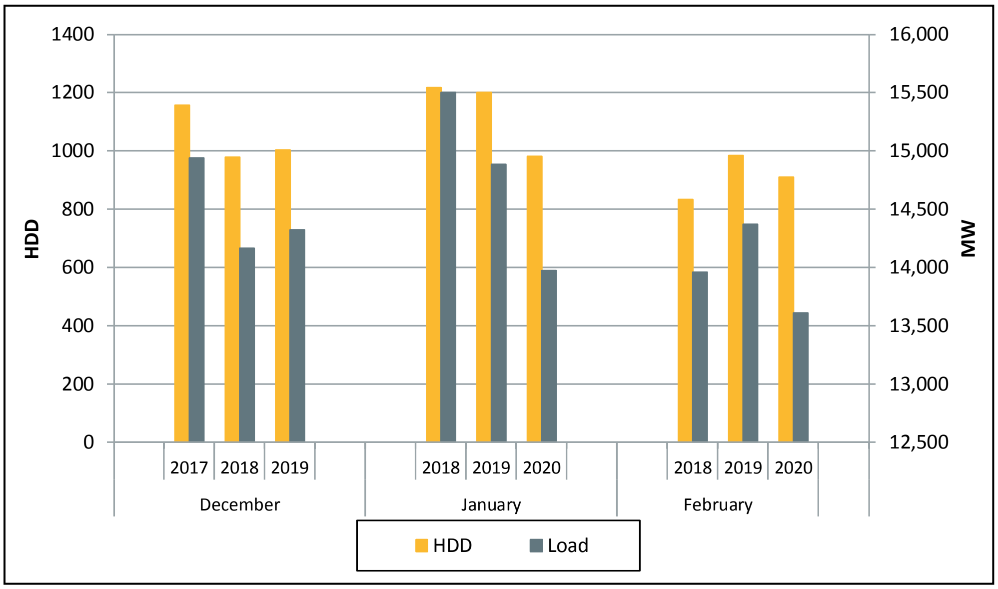
[56] In this section, "load" typically refers to *Net Energy for Load* (NEL). NEL is calculated by summing the metered output of native generation, price-responsive demand, and net interchange (imports minus exports). NEL excludes pumped-storage demand. "Demand" typically refers to metered load. (NEL – Losses = Metered Load).

Average hourly load during Winter 2020 was 13,975 MW, a 3% decrease compared to Winter 2019 and a 6% decrease compared to Winter 2018. This was largely driven by warmer temperatures, continued increases in energy efficiency, and to a lesser extent, behind-the-meter solar generation. The average temperature in Winter 2020 was 33°F, compared to 30°F in Winter 2019 and 29°F in Winter 2018.

Load and Temperature

The monthly breakdown of average load compared to the total heating degree-days (HDD) over the last three winter seasons is shown in Figure 5-4 below.[57]

Figure 5-4: Monthly Average Load and Monthly Heating Degree Days



Warmer weather during January and February 2020 led to lower real-time loads as indicated by the generally lower monthly total HDDs compared the prior seasons. January 2020 temperatures averaged 34°F, a 7°F increase from January 2019 (27°F) and 8°F increase from January 2018 (26°F). The warmer January weather caused average loads to decrease by 915 MW year over year. Average temperatures in February 2020 were 4°F warmer (34°F vs. 30°F) year over year, leading to a 5% decrease (767 MW) in wholesale load. However, despite colder temperatures (34°F vs. 36°F), February 2020 had lower loads than February 2018 (13,607 MW vs. 13,956 MW). This follows the long-term trend of declining wholesale electricity load due to increased energy efficiency and behind-the-meter photovoltaic generation.

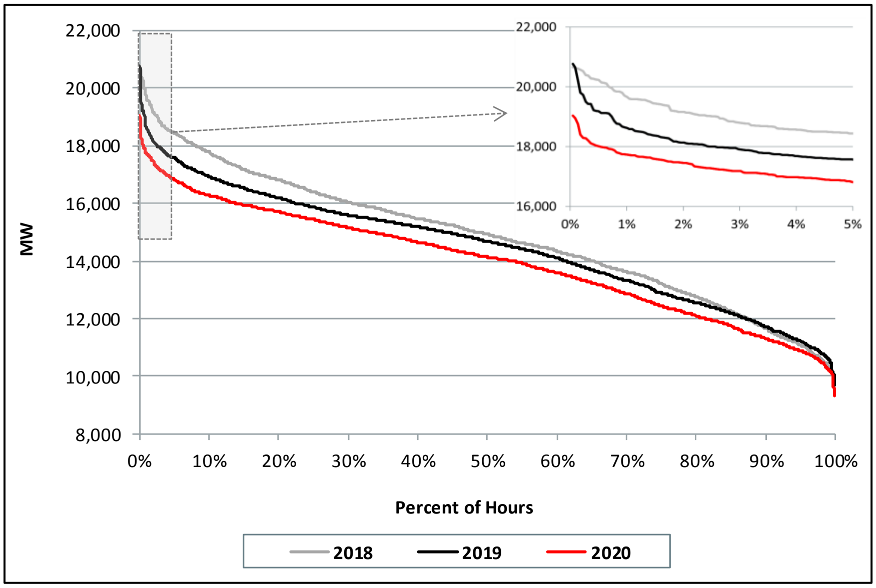
Peak Load and Duration Curves

The system load for New England over the last three winter seasons is shown as load duration curves in Figure 5-5 with the inset graph showing the 5% of hours with the highest loads. A load duration curve depicts the relationship between load levels and the frequency that load levels

[57] 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.

occur. Winter 2020 is shown in red, Winter 2019 is shown in black and Winter 2018 is shown in gray.

Figure 5-5: Seasonal Load Duration Curves



The red line shows Winter 2020 had lower loads than both Winter 2019 and Winter 2018 across nearly all hours. In Winter 2020, loads were higher than 16,000 MW in less than 14% of hours, compared to about 22% and 31% in Winter 2019 and Winter 2018 respectively. During the highest load periods of the season, loads were lower due to less extreme weather. During peak hours, Winter 2020 load levels were lower than both Winter 2019 and 2018. Loads during the top 5% of hours in 2020 averaged 17,394 MW, 833 MW lower than in Winter 2019 (18,227 MW). Average loads during the top 5% hours in 2018 were significantly higher (19,158 MW) due to the cold snap.

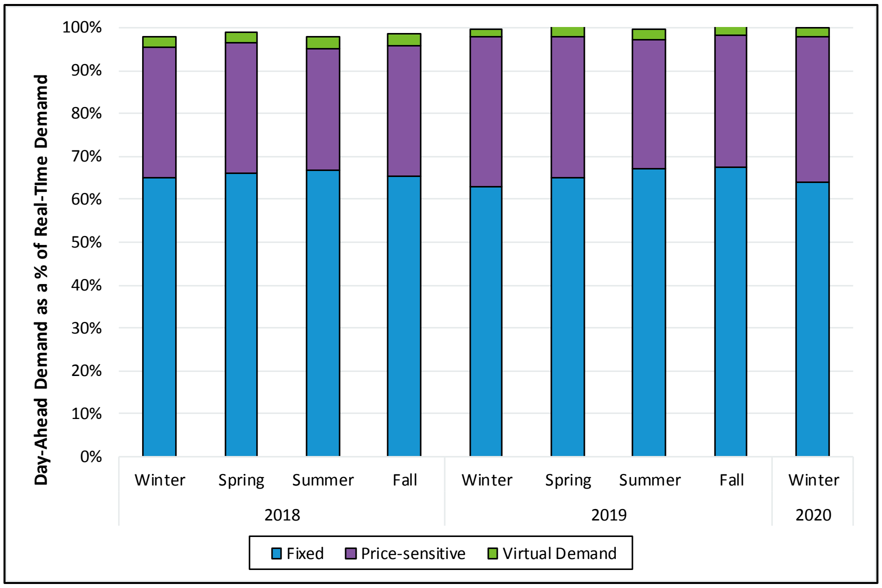
Load Clearing in the Day-Ahead Market

In recent periods, there have been higher percentages of real-time demand clearing in the day-ahead market. The amount of demand that clears in the day-ahead market is important, because along with the ISO's Reserve Adequacy Assessment, it influences the generator commitment decision for the operating day.[58] For example, when low levels of demand clear in the day-ahead market, supplemental supply commitments or additional dispatch may be needed to meet real-time demand. This can lead to higher real-time prices. The day-ahead cleared demand as a

[58] The Reserve Adequacy Assessment (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 the capacity to the market.

percentage of real-time demand is shown in Figure 5-6 below. Day-ahead demand in broken down by bid type: fixed (blue) price-sensitive (purple) and virtual (green) demand.[59]

Figure 5-6: Day-Ahead Cleared Demand by Bid Type



Day-ahead cleared demand as a percent of real-time demand in Winter 2020 was unchanged compared to Winter 2019 (99.9%) higher than Winter 2018 (98.1%). Year over year, fixed demand increased by 0.9% (64.0% vs. 63.1%), but the increased fixed demand was offset by an equivalent decrease (0.9%) in price-sensitive demand. Virtual demand was relatively unchanged year over year.

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

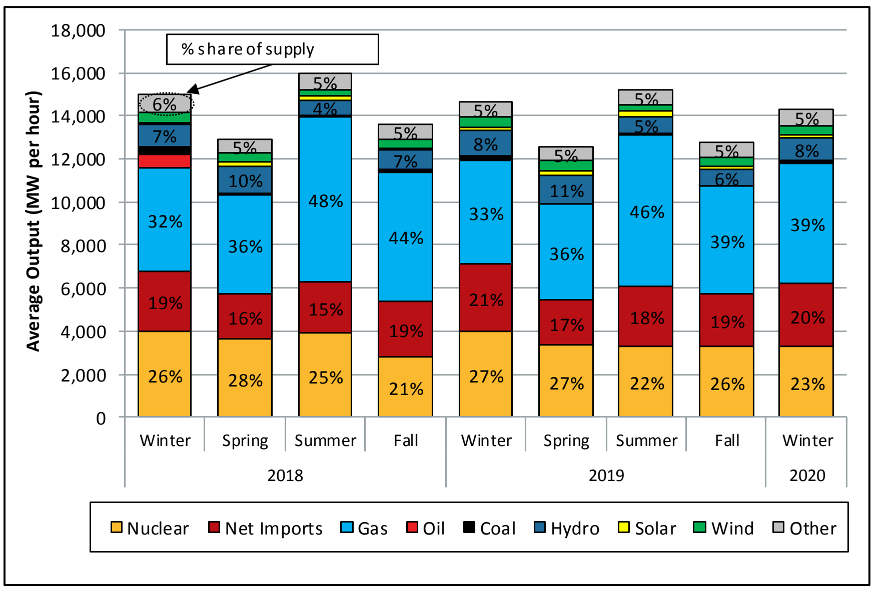
5.3 Supply

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

5.3.1 Generation by Fuel Type

The breakdown of actual energy production by fuel type provides useful context for the drivers of market outcomes. The share of energy production by generator fuel type for Winter 2018 through Winter 2020 is illustrated in Figure 5-7 below.[60] The bar's height represents average electricity generation, while the percentages represent percent share of generation from each fuel type.[61]

Figure 5-7: Share of Electricity Generation by Fuel Type



Notes: "Other" category includes battery storage, demand response, landfill gas, methane, refuse, steam, and wood.

The majority of New England's generation comes from nuclear generation, gas-fired generation, and net imports (netted for exports). These three together accounted for 83% of total energy production in Winter 2020. Natural gas generation shares increased from 33% in Winter 2019, to 39% in Winter 2020. Low gas prices coupled with generation from new highly efficient gas power plants contributed to the year-over-year increase. Nuclear production shares fell from 27% (4,000 MW per hour) in Winter 2019, to 23% (3,300 MW per hour) in Winter 2020. This was primarily due to the retirement of Pilgrim Nuclear Plant, a 680 MW generator in Southeastern Massachusetts, in June 2019.

[60] "Other" category includes battery storage, demand response, landfill gas, methane, refuse, steam, and wood.

[61] Electricity generation in Section 5.3.1 equals native generation plus net imports.

5.3.2 Imports and Exports

New England was a net importer of power from its neighboring control areas of Canada and New York during Winter 2020.[62] On average, the net flow into New England was about 2,900 MW per hour. New England met about 21% of its Winter 2020 average load (NEL) with power imported from New York and Canada. This is slightly higher than the average of the prior eight seasons (18%). Figure 5-8 shows the average hourly gross import, export and net interchange power volumes by external interface for the last nine quarters.

Figure 5-8: Average Hourly Real-Time Imports, Exports, and Net Interchange

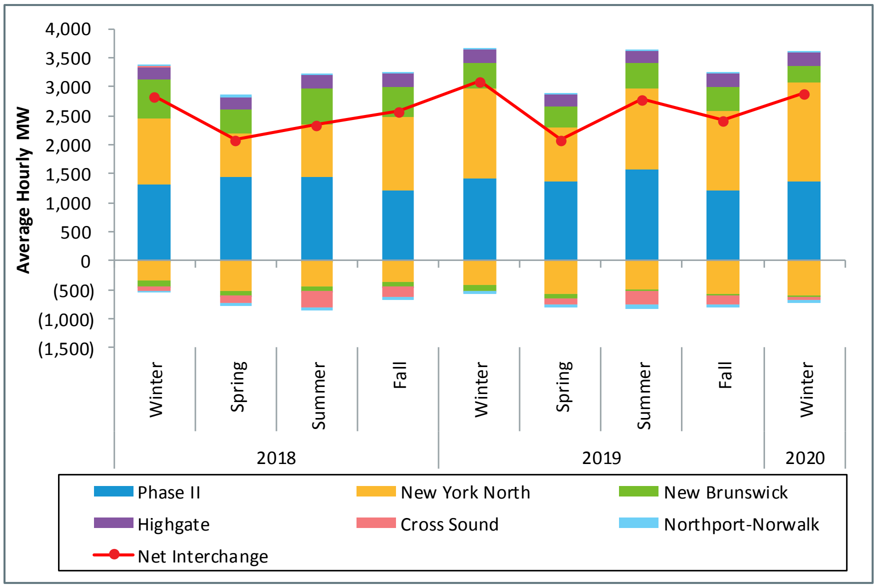


Figure 5-8 illustrates that net interchange and imports generally rise in the summer and winter quarters when New England energy prices and demand tend to be higher. The average hourly net interchange value of 2,900 MW was up 19% from Fall 2019, when average hourly net interchange was 2,441 MW per hour. The Winter 2020 net interchange value reflects a 7% decrease from Winter 2019, when average hourly net interchange was 3,110 MW per hour.

One of the primary reasons for the decrease in net interchange between Winter 2019 and Winter 2020 is because average net interchange decreased at the New Brunswick interface by over 100 MW per hour. There was also a modest increase in exports over the Cross Sound Cable between these periods. Net interchange levels over the two largest interfaces, New York North and Phase II, were consistent with Winter 2019. Net interchange at each of these interfaces decreased by around 2% from the prior winter.

The New Brunswick interface saw a decrease in cleared import transactions in both the day-ahead and real-time markets. Most notably, cleared import transactions decreased by between 55% - 65% in January and February 2020 when compared to January and February 2019. The main driver behind this decrease in cleared import volumes was a slight decrease in the volume

[62] 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.

of very low fixed import offers and a larger decrease in the volume of low-priced import offers. In Winter 2020, the hourly average cleared MW with an offer price in the range of $10-$30/MWh decreased by 135 MW an hour. For reference, this represents a 64% decrease from an hourly average of 212 cleared MW an hour in this price range in Winter 2019. This was the result of one market participant changing their offer behavior.

The largest share of imports into New England in Winter 2020 (47%) came from the New York North interface, where an average of 1,707 MW was imported. This represents a 9% increase from Winter 2019 (1,563 MW). Winter 2020 also saw a large increase in exports at the New York North interface; these exports averaged 588 MW per hour. This is a 40% increase from Winter 2019, when exports at the NYN interface averaged 419 MW per hour. Phase II contributed 38% of the total average hourly imports during Winter 2020. Hourly imports at Phase II averaged 1,381 MW per hour, down slightly from Winter 2019 (1,415 MW per hour).

Section 6
Day-Ahead and Real-Time Markets

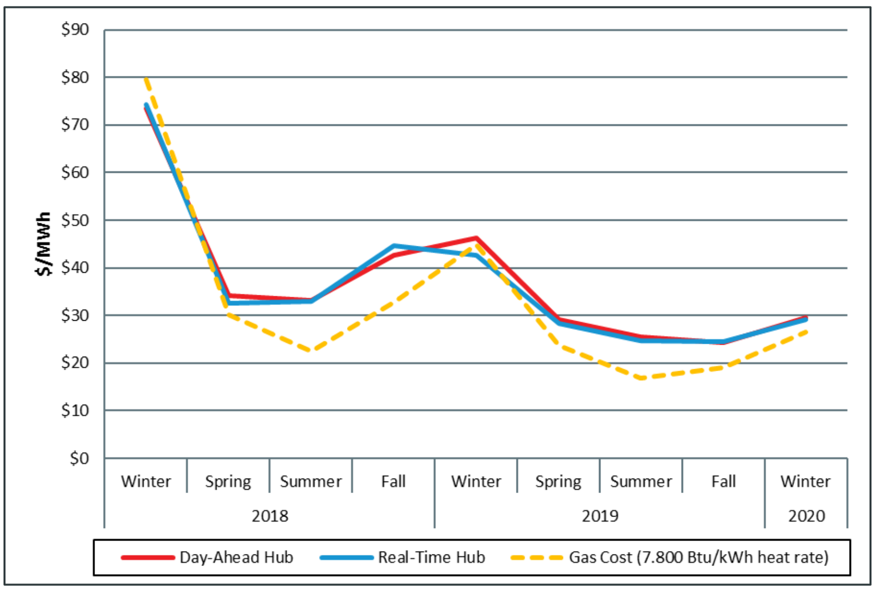
This section covers trends in, and drivers of, spot market outcomes, including the energy markets, and markets for ancillary services products: operating reserves and regulation.

6.1 Energy Prices

The average real-time Hub price for Winter 2020 was $29.97/MWh, similar to the average day-ahead price of $30.32/MWh. These were the lowest average Winter Hub LMPs since Winter 2016.

Day-ahead and real-time prices, along with the estimated cost of generating electricity using natural gas, are shown in Figure 6-1 below. The natural gas cost is based on the average natural gas price each season and a generator heat rate of 7,800 Btu/kWh.[63]

Figure 6-1: Simple Average Day-Ahead and Real-Time Hub Prices and Gas Generation Costs



As Figure 6-1 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 $26.55/MWh in Winter 2020. Average electricity prices were about $4/MWh higher than average estimated Winter 2020 gas costs in the day-ahead market. This spread was larger than in the previous two winters. In Winter 2019, average day-ahead electricity prices were $2/MWh higher than average estimated gas costs. In Winter 2018, average day-ahead Hub LMPs were $5/MWh *lower* than average estimated gas costs due to a

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

"cold snap" event, when generation costs for natural gas-fired generators averaged $211/MWh. The higher positive spread between electricity prices and gas generation costs in Winter 2020 was driven, primarily, by record low gas prices.

In Winter 2020, average day-ahead and real-time prices were lower than Winter 2019 prices, by about $17 and $14/MWh (down 31% to 35%), respectively. This is consistent with the change in natural gas prices, which decreased by 41%. Lower loads, which averaged 500 MW less compared to the previous winter, also put downward pressure on LMPs.

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 6-2.

Figure 6-2: Simple Average Day-Ahead and Real-Time Prices by Location and Gas Generation Costs

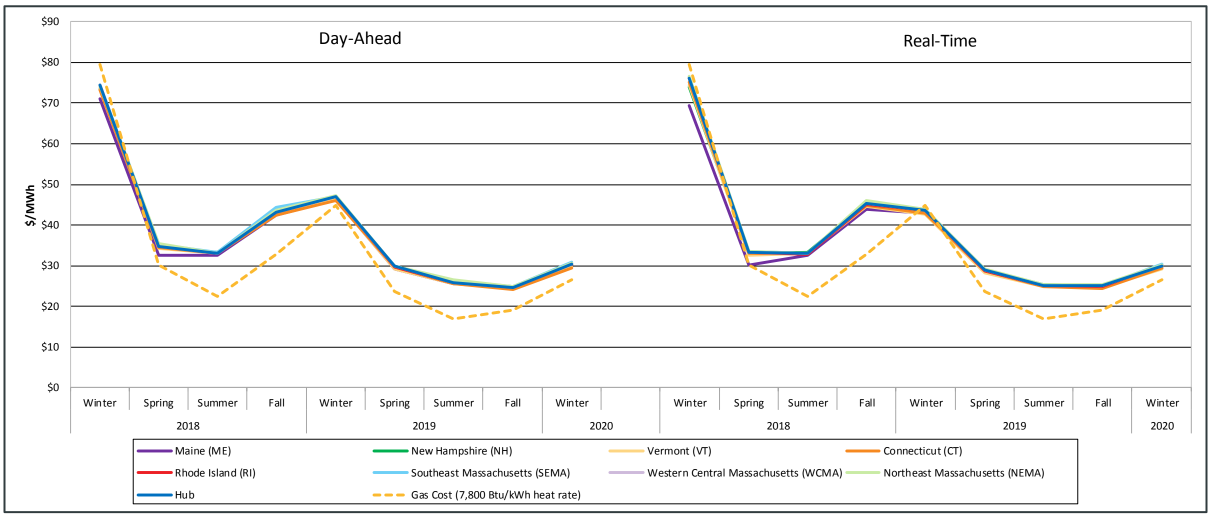


Figure 6-2 illustrates that load zone prices did not differ significantly from Hub prices in either market.[64] The Connecticut load zone saw the largest differences, with prices averaging slightly lower than the Hub price, a difference of 2% and 3% in the day-ahead and real-time markets, respectively. Connecticut has been export-constrained more frequently in recent years, likely due to the addition of new highly efficient gas-fired generators in the load zone.

6.2 Marginal Resources and Transactions

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

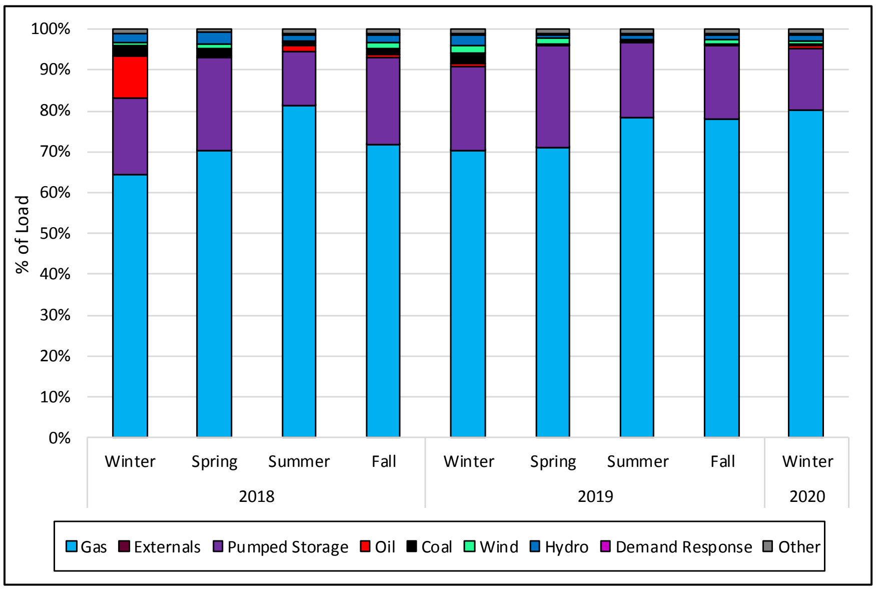
In this section, marginal units by transaction and fuel type are reported on a load-weighted basis. The methodology accounts for the contribution that a marginal resource makes to the overall price paid by load. When more than one resource is marginal, the system is typically constrained and marginal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

[64] 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.

contribute to meeting the load for the wider system. Consequently, the impact of these resources on the system LMP is muted.

In the day-ahead market, a greater number of transaction types can be marginal; these include virtual bids and offers, fixed and priced-demand, generator supply offers and external transactions. By contrast, only physical supply, pumped-storage demand, and external transactions can set price in the real-time market. In practice, marginal resources in the real-time market are typically generators (predominantly natural gas-fired generators) and pumped-storage demand. The percentage of load for which resources of different fuel types were marginal in the real-time market by season is shown in Figure 6-3 below.[65]

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



Natural gas-fired generators set price for about 80% of total load in Winter 2020, which is a 10% increase from Winter 2019, and slightly higher than Fall 2019. Lower gas prices compared to Winter 2020 allowed gas-fired generators to offer energy at lower prices throughout the winter. Gas-fired generators are often the most expensive units operating, and therefore set price frequently. More expensive coal- and oil-fired generators were not required to meet system demand, and therefore set price less frequently.

In addition to their relative cost, many gas-fired generators are eligible to set price due to their dispatchability. By contrast, nuclear generation accounts for about one quarter of native generation in New England, but does not set price. Nuclear generators in New England are offered at a fixed output, meaning once they are brought online they can only produce at one output level. By definition, if load changes by one megawatt they cannot increase or decrease their output to meet the demand, and are therefore ineligible to set price.

Pumped-storage units (generators and demand) set price for about 15% of total load in Winter 2020, down from 21% in Winter 2019. The 6% decline was driven by fewer pricing intervals where a pumped storage generator set price. Pumped-storage units generally offer energy at a price that is close to the margin. They are often called upon when conditions are tight due to

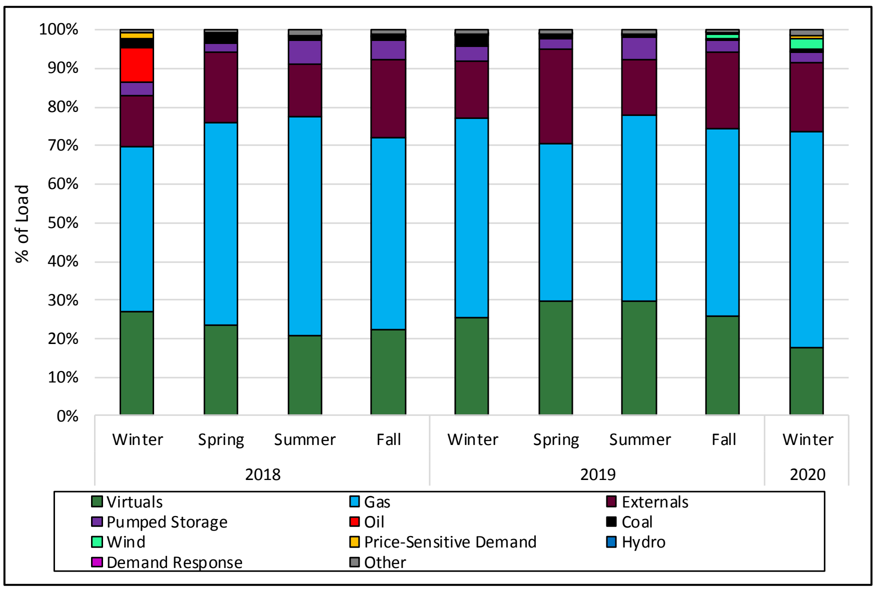
[65] "Other" category contains wood, biomass, black liquor, fuel cells, landfill gas, nuclear, propane, refuse, and solar.

their ability to start up quickly and their relatively low commitment costs compared with fossil fuel-fired generators. Since the system margins were higher in Winter 2020, and gas-fired generators were less expensive to operate, pumped-storage generators had fewer opportunities to set price.

Wind was marginal for 1% of total load; most of which was located in *local export-constrained areas*, where the impact on the average load price was limited. Wind generators located in an export-constrained area can only deliver the next increment of load to a small number of locations located within the export-constrained area. This is because the transmission network that moves energy out of the constrained area is at maximum capacity. Load that is outside the export-constrained area has no way of consuming another megawatt of the relatively inexpensive wind output.

The percentage of load for which each transaction type set price in the day-ahead market since Winter 2018 is illustrated in Figure 6-4 below.

Figure 6-4: Day-Ahead Marginal Units by Transaction and Fuel Type

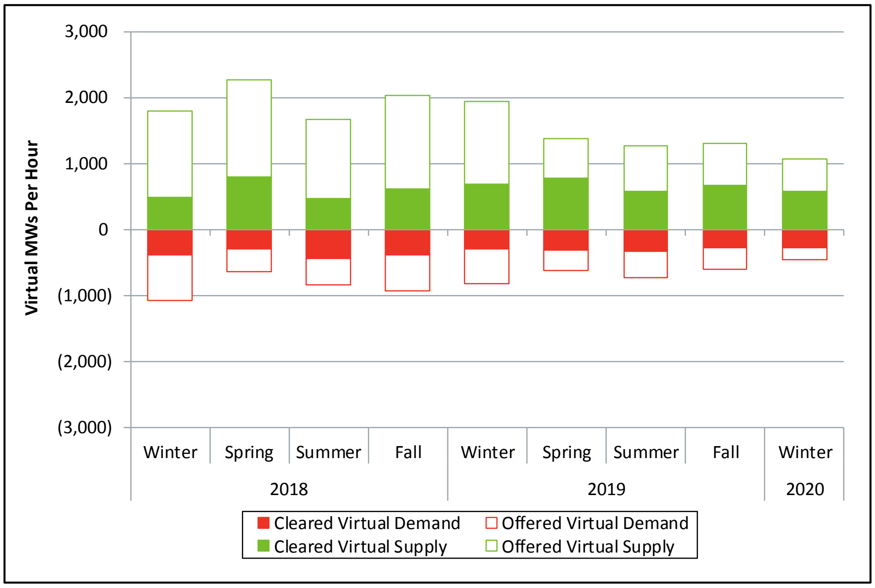


Gas-fired generators were the most frequent marginal resource type in the day-ahead market; they set price for 56% of total day-ahead load in Winter 2020. The increase from Winter 2019 was due to both new efficient combined-cycle generators setting price, and existing gas-fired generators setting price more frequently than prior winters. The increase in gas-fired generators setting price offset a decline in virtual supply setting price at the Hub and load zones. Some virtual suppliers bid around the margin, attempting to profit from lower real-time prices. However, real-time prices were only 1% lower than day-ahead prices in Winter 2020, compared to 7% lower in Winter 2019. The absence of profit opportunities may have contributed to the reduction in virtual supply setting price.

6.3 Virtual Transactions

In the day-ahead energy market, participants submit virtual demand bids and virtual supply offers to capture differences between day-ahead and real-time LMPs. The primary function of these virtual transactions is to improve the day-ahead dispatch model to better reflect real-time conditions. Virtual transactions that are profitable based on price differences between the day-ahead and real-time markets generally improve price convergence. Offered and cleared virtual transaction volumes from Winter 2018 through Winter 2020 are shown in Figure 6-5 below.

Figure 6-5: Total Offered and Cleared Virtual Transactions (Average Hourly MW)



In Winter 2020, total offered virtual transactions averaged approximately 1,530 MW per hour, which was 20% lower than the average amount offered in Fall 2019 (1,909 MW per hour) and 45% lower than the average amount offered in Winter 2019 (2,778 MW per hour). Over the period from Winter 2018 to Winter 2019, the average amount of offered virtual transactions was 2,811 MW per hour. However, the average amount of offered virtual transactions over the last four quarters (i.e., Spring 2019 to Winter 2020) has been only 1,857 MW per hour. Offered virtual transactions decreased during this period primarily because one participant significantly reduced their virtual transaction activity. Between Winter 2018 and Winter 2019, this participant submitted over 900 MW per hour of virtual transactions, on average. In the last four quarters, this participant's submissions averaged less than five MW per hour.

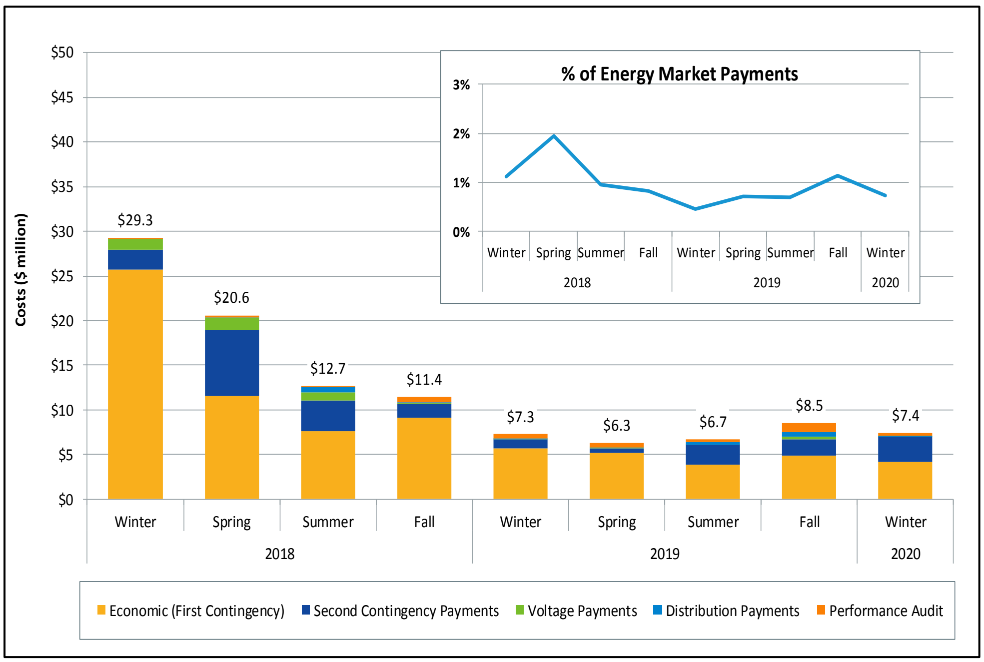
On average, 866 MW per hour of virtual transactions cleared in Winter 2020, which represents a decrease of 8% compared to Fall 2019 (942 MW per hour) and a decrease of 12% compared to Winter 2019 (987 MW per hour). Cleared virtual supply amounted to 586 MW per hour, on average, in Winter 2020, down 13% from Fall 2019 (672 MW per hour) and down 14% from Winter 2019 (685 MW per hour). Meanwhile, cleared virtual demand amounted to 279 MW per hour, on average, in Winter 2020, up 3% from Fall 2019 (270 MW per hour) and down 8% from Winter 2019 (303 MW per hour).

6.4 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 over the last three years. The data shows that total uplift payments continue to decrease year over year.

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

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

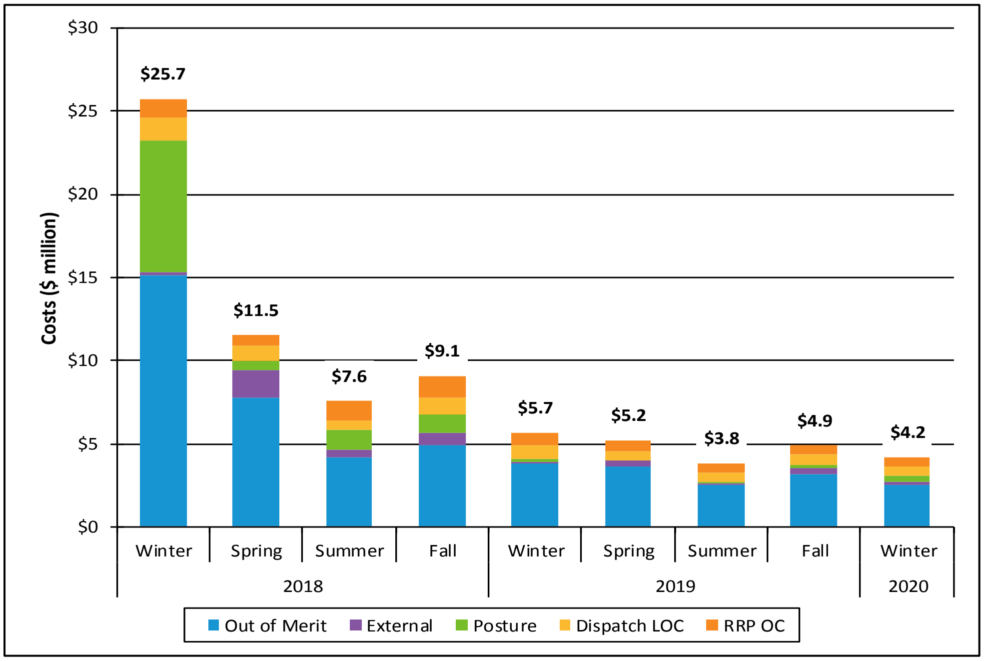


Total NCPC payments in Winter 2020 amounted to $7.4 million, which was consistent with Winter 2019 (increase of $0.1 million). With a decrease in total energy payments of about $567 million from Winter 2019, total NCPC payments as a percentage of total energy payments rose in Winter 2020 from 0.5% to 0.7%. The majority of uplift (57%) during the reporting period continued to be economic ($4.2 million), with most ($3.4 million) economic payments occurring in the real-time market. Compared to Winter 2019, economic NCPC fell by $1.5 million.

[66] NCPC payments include *economic/first contingency NCPC payments*, *local 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).

Economic uplift includes payments made to resources providing first-contingency protection as well as resources that operate at an ISO instructed dispatch point below their economic dispatch point (EDP). This deviation from their EDP creates an opportunity cost for that resource. Figure 6-7 below shows economic payments by category.

Figure 6-7: Economic Uplift by Season by Sub-Category



As seen in Figure 6-7, out-of-merit payments routinely make up the majority of economic NCPC. These payments fell by 33% between Winter 2019 and Winter 2020, from $3.8 million to $2.6 million. Posturing payments more than doubled, but remained relatively low, from $0.15 million to $0.31 million.[67] These payments were made to three fast-start, pumped storage generators over 10 days in December 2019 and January 2020 to maintain system reliability. Dispatch and rapid-response pricing opportunity cost payments decreased by $0.42 million, from $1.59 million to $1.17 million.

The next largest category of uplift during the reporting period was for local second-contingency protection (LSCPR), accounting for 37% of all uplift payments. LSCPR payments totaled $2.8 million, up by $1.7 million from the Winter 2019. Most of LSCPR NCPC payments (94%) were made in December. These payments went to generators that were committed in the day-ahead market to meet reliability needs in SEMA due to a planned transmission outage that lasted from late November through late December.

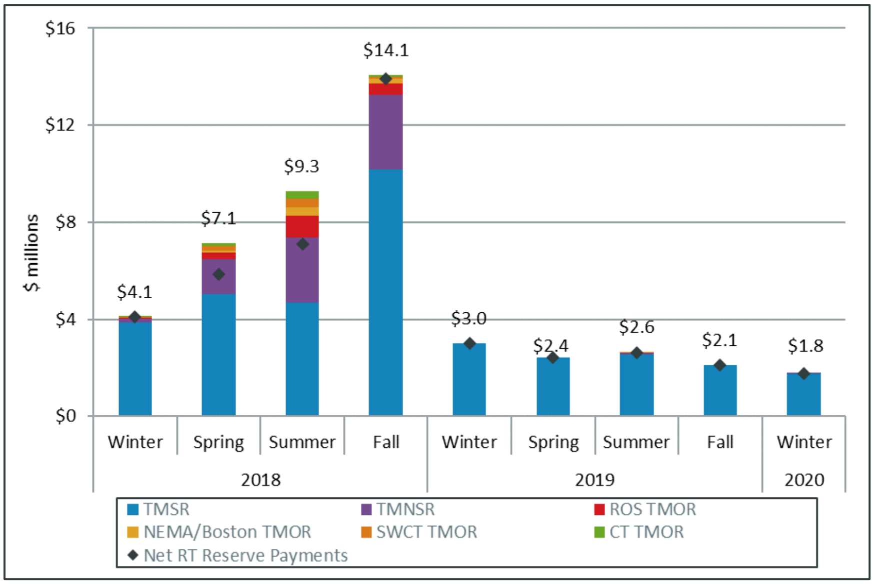
6.5 Real-Time Operating Reserves

Real-time reserve payments by product and by zone are illustrated in Figure 6-8 below. Real-time reserve payments to generators designated to satisfy forward reserve obligations are reduced by a forward reserve obligation charge so that a generator is not paid twice for the

[67] Posturing payments are made to a generator that followed an ISO manual action that altered the resource's output from its economically-optimal dispatch level in order to create additional reserves.

same service. Net real-time reserve payments, which were $1.8 million in Winter 2020, are shown as black diamonds in Figure 6-8.

Figure 6-8: Real-Time Reserve Payments by Product and Zone



Winter 2020 reserve payments were down $1.2 million from Winter 2019. The decline resulted from lower energy prices. The majority of Winter 2020 reserve payments were ten-minute spinning reserve (TMSR) payments.

The frequency of non-zero reserve pricing by product and zone along with the average price during these intervals for the past three winter seasons is provided in Table 6-1 below. [68]

Table 6-1: Hours and Level of Non-Zero Reserve Pricing

Product	Zone	Winter 2018		Winter 2019		Winter 2020	
		Hours of Non-zero Pricing	*Avg. Price $/MWh*	*Hours of Non-zero Pricing*	*Avg. Price $/MWh*	*Hours of Non-zero Pricing*	*Avg. Price $/MWh*
TMSR	System	316.1	$17.47	297.1	$16.31	394.1	$7.56
TMNSR	System	1.3	$124.51	0.0	$0.00	0.6	$74.24
TMOR	System	1.3	$124.51	0.0	$0.00	0.0	$0.00
	NEMA/Boston	1.3	$124.51	0.0	$0.00	0.0	$0.00
	CT	1.3	$124.51	0.0	$0.00	0.0	$0.00
	SWCT	1.3	$124.51	0.0	$0.00	0.0	$0.00

The TMSR clearing price was positive (i.e., there was non-zero reserve pricing) in 394 hours (18% of total hours) during Winter 2020, higher than the hours of non-zero reserve pricing Winter 2019. In the hours when the TMSR price was above zero, the price averaged $7.56/MWh, a 54% decrease from the prior winter season and consistent with the decrease in real-time energy prices. A lower average TMSR price helps explain the decrease in total reserve payments compared to the prior winter season.

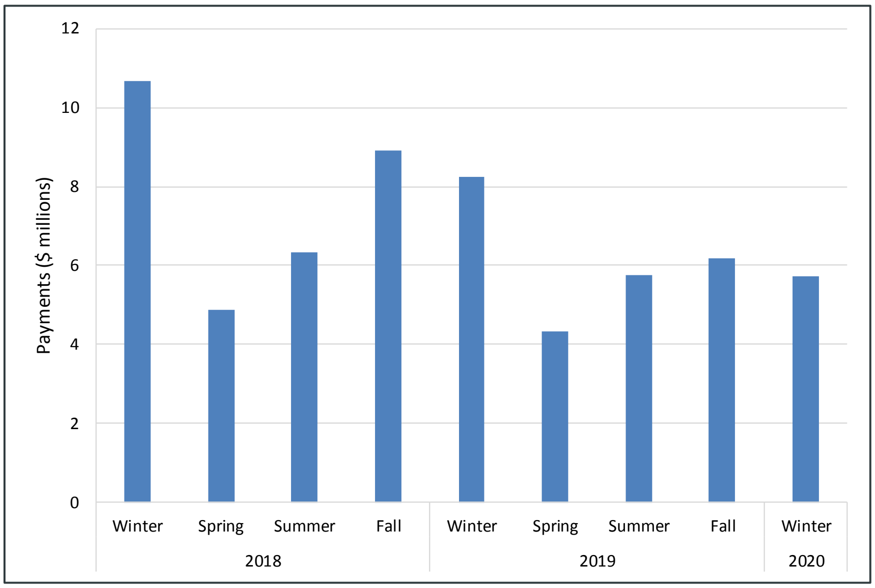
[68] Non-zero reserve pricing occurs when there is an opportunity cost associated with dispatching the system in order to hold generators back for reserves or a reserve deficiency in the energy and reserve co-optimization process.

There were 35 minutes of non-zero ten-minute non-spinning reserve (TMNSR) or thirty-minute operating reserve (TMOR) pricing in Winter 2020. As Table 6-1 shows, the frequency of TMNSR and TMOR pricing were also small in previous winter seasons.

6.6 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 6-9 below.[69]

Figure 6-9: Regulation Payments ($ millions)



Total regulation market payments were $5.7 million during the reporting period, down approximately 30% from $8.2 million in Winter 2019, and down by 7% from $6.2 million in Fall 2019. The decrease in payments from Winter 2019 to 2020 reflects significantly lower energy market prices in Winter 2020 (and energy market opportunity costs for regulation resources), compared to Winter 2019. The small decline in payments comparing Fall 2019 to Winter 2020 reflects a modest reduction in regulation requirements during the winter period.

[69] As noted in the Spring 2016 Quarterly Markets Report, both regulation capacity and service requirements were increased due to the modification of calculations performed in accordance with NERC standard BAL-003, Frequency Response and Frequency Bias Setting. These changes were implemented in April 2016.

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 fourteenth capacity commitment period (2023/24) is covered in Section 3 of the report.

7.1 Forward Capacity Market

The Forward Capacity Market (FCM) is a long-term market designed to procure the resources needed to meet the region's local and system-wide resource adequacy requirements.[70] The region developed the FCM in recognition of the fact that the energy market alone does not provide sufficient revenue to facilitate new investment or, in many cases, cover the cost of maintaining and operating existing resources. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue and thereby induces suppliers to undertake the investments necessary for reliable electric power service.

The ISO introduced Pay-for-Performance (PFP) rules beginning on June 1, 2018 to incent reliable operation during scarcity conditions.[71] Prior to June 1, 2018, resource owners faced de minimis financial penalties when unable to perform during periods of scarcity. The PFP rules improve the underlying market incentives by replicating performance incentives that exist in a fully functioning and uncapped energy market. Pay-for-performance rules provide a two-settlement construct that links payments to performance during scarcity conditions. Without this linkage, participants lack the incentive to make investments that ensure their resources perform when needed most. Also, absent these incentives, participants that have not made investments to ensure their resources' reliability are more likely to clear in future FCAs because they can offer at lower prices. This can create a structural bias in the FCM to clear less reliable resources, which, over time, erodes system reliability. Paying for actual performance during scarcity conditions incents resource owners to make investments and perform routine maintenance to ensure resource readiness to provide energy or operating reserves during scarcity conditions.

Pay-for-performance works as follows: a resource owner is compensated for that resource's capacity supply obligation (CSO) held in a given month, but is subject to adjustments based on its performance during scarcity conditions. The PFP design replaced the shortage event rules in place through May 31, 2018. PFP is based on a two-settlement market built around the delivery of energy and operating reserves when they are needed most. If a resource fails to perform relative to expectations, it must buy the difference back at a performance payment rate. Under-performers compensate over-performers, with few exceptions.[72] Additionally, energy market only assets (known as PFP-only resources) are compensated for their contribution to load and

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

[71] A scarcity condition occurs for the system or for certain capacity zones in five-minute increments. For more information, see Section III.13.7.2.1 of the tariff.

[72] Energy efficiency resources are provided an exemption during off-peak periods. See III.13.7.2.2 of the tariff for actual capacity provided calculations.

reserve requirements. Since they hold no CSO, PFP-only resources cannot under-perform and can only receive compensation for over-performance during scarcity conditions.

During any three-month period there can be FCM activity for up to four commitment periods. The initial capacity auction occurs three years and three months before the commitment period begins.[73] Between the initial auction and the commitment period, there are six discrete opportunities to adjust annual CSOs. Three of those are bilateral auctions where obligations are traded between resources at an agreed upon price and approved by the ISO. The other three are reconfiguration auctions run by the ISO, where participants can submit supply offers to take on obligations, or submit demand bids to shed obligations.

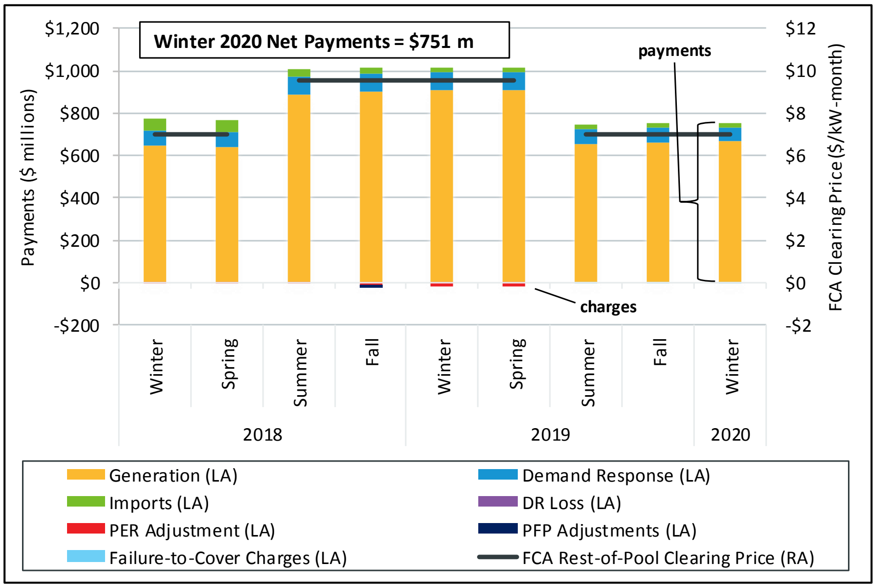
Monthly reconfiguration auctions and bilateral trading begin a month after the third annual reconfiguration auction, and occur two months before the relevant delivery month. Like the annual auctions, participants can buy or sell obligations. Buying an obligation means that the participant will provide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

The current capacity commitment period (CCP) started on June 1, 2019 and ends on May 31, 2020. The conclusion of the corresponding Forward Capacity Auction (FCA 10) resulted in a lower clearing price than the previous auction while obtaining sufficient resources needed to meet forecasted demand. The auction procured 35,567 megawatts (MW) of capacity, which exceeded the 34,151 MW Installed Capacity Requirement (ICR), at a clearing price $7.03/kW-month. The clearing price of $7.03/kW-month was 26% lower than the previous year's $9.55/kW-month. This clearing price was applied to all resources within New England as well as the imports from Québec. However, the clearing price was $6.26/kW-month for New York imports and $4.00/kW-month for New Brunswick imports. The results of FCA 10 led to an estimated total annual cost of $2.99 billion in capacity payments.

Total FCM payments, as well as the clearing prices for Winter 2018 through Winter 2020, are shown in Figure 7-1. 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 red bar represents reductions in payments due to Peak Energy Rent (PER) adjustment. The dark blue bar represents Pay-for-Performance (PFP) adjustments, while the light blue bar represents Failure-to-Cover charges.

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

Figure 7-1: Capacity Payments ($ millions)



Total net FCM payments decreased significantly from Winter 2019. In Winter 2020 capacity payments totaled $751 million, which accounts for adjustments to primary auction CSOs.[74] The $7.03/kW-month clearing price in FCA 10 was a 26% decrease from the previous FCA clearing price of $9.55/kW-month.

In Winter 2020, there were approximately $0.2 million in Failure-to-Cover (FTC) charges. The FTC charge is a negative adjustment to the FCM credit, which is applied when a resource has not demonstrated the ability to cover its CSO. The intent of this charge is to incent resources with CSOs to meet their obligations and is based on the capability of resources compared to their CSOs.

Secondary auctions allow participants the opportunity to buy or sell capacity after the initial auction. A summary of prices and volumes associated with the reconfiguration auction and bilateral trading activity during Winter 2020, alongside the results of the relevant primary FCA are detailed in Table 7-1.

[74] Adjustments include annual reconfiguration auctions, annual bilateral periods, monthly reconfiguration auctions, monthly bilateral periods, peak energy rent adjustments, performance and availability activities, and reliability payments.

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

FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)*	Cleared MW	Capacity Zone/Interface Prices ($/kW-mo)	
					New Brunswick	New York AC Ties
FCA 10 (2019-20)	Primary	12-month	7.03	35,567	4.00	6.26
	Monthly Reconfiguration	Feb-20	0.66	1,406		
	Monthly Bilateral	Feb-20	0.88	204		
	Monthly Reconfiguration	Mar-20	0.58	1,184		
	Monthly Bilateral	Mar-20	0.57	203		
	Monthly Reconfiguration	Apr-20	0.44	764		
	Monthly Bilateral	Apr-20	1.95	108		

**bilateral prices represent volume weighted average prices*

Three monthly reconfiguration auctions took place in Winter 2020. Cleared volumes decreased from 1,406 MW in February 2020, to 764 MW in April 2020. Over the same period prices fell from $0.66/kW-month to $0.44/kW-month. The decline in volumes and prices were primarily driven by the bidding behavior of three resources. The three resources offered roughly 1,900 MW (30% of total demand bids) into each auction. In the February and March auctions, they entered 30% of their demand at or below $0.40/kW-month. In the April auction, they offered 90% at or below $0.40/kW-month. The reduction in their price, coupled with a relatively consistent supply curve, led to lower volumes and prices in April.

7.2 Financial Transmission Rights

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

FTRs settle on a monthly basis. Payments to the holders of FTRs with positive target allocations in a month come from three sources:[75]

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

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

On September 17, 2019, ISO-NE implemented the Balance of Planning Period (BoPP) project for FTRs. This project increased the number of opportunities that market participants have to reconfigure their monthly FTR positions following the two annual auctions. Prior to the implementation of this project, market participants could only purchase or sell FTRs for a specific month in the auction that occurred during the month prior to that effective month. For example, if a market participant wanted to buy FTRs that would be effective for December 2019, it would have to wait until the monthly auction that took place in November 2019. Under the BoPP design, ISO-NE now administers monthly FTR auctions for not just the next month (now called the prompt-month auction), but also for all the other months remaining in the calendar year (called the out-month auctions). This means that a participant that wants to buy December 2019 FTRs no longer has to wait until November 2019; it can purchase these FTRs in any of the out-month auctions that take place earlier in the year. However, the out-month auctions don't make available any additional network capacity than was made available in the second annual auction (in contrast to the prompt-month auctions, which do make additional capacity available).[76]

The implementation of BoPP was coordinated with the October 2019 prompt-month auction, whose bidding window was open from September 17-19, 2019. During this bidding window, participants could also submit bids and offers for the November 2019 and December 2019 out-month auctions. FTRs purchased or sold in these out-month auctions are sometimes referred to as the "October 2019" vintage of the November 2019 or December 2019 FTR contracts.

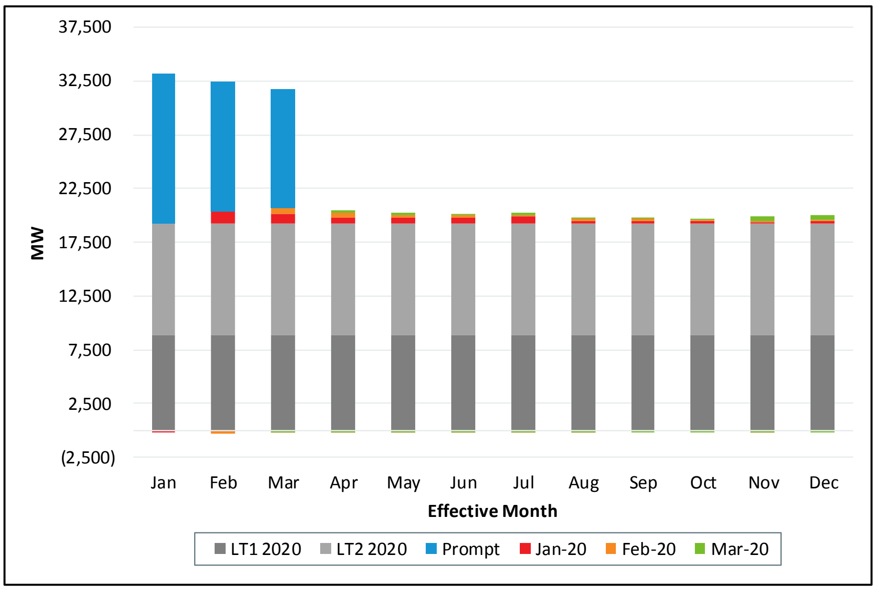
[75] Target allocations for each FTR are calculated on an hourly basis by multiplying the MW amount of the FTR by the difference in the day-ahead congestion components of the FTR's sink and source locations. Positive target allocations (credits) occur when the congestion component of the sink location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

[76] The first round of the annual auction makes available 25% of the transmission system capability. The second round of the annual auction makes available an additional 25%, meaning that a total of 50% of the network capability is sold in the two annual auctions. The prompt-month auctions make available an additional 45% of the network capability, meaning that 95% of the network capability is sold by the time the effective month arrives. The out-month auctions do not make available any additional network capability beyond that which was made available in the second round of the annual auction. However, FTRs can still be purchased in the out-month auctions on paths that weren't completely subscribed in the second annual auction, as the result of counterflow FTR purchases, or as the result of FTR sales.

Auction Activity

The MW amount of cleared, on-peak FTRs for each month in 2020 is broken down by the FTR auction in which the transaction occurred in Figure 7-2 below.[77] Cleared FTR purchases are shown as positive values, while cleared FTR sales are shown as negative values. The gray bars indicate FTR transactions that cleared in either the first or second annual auctions (LT1 and LT2), the blue bars indicate FTR transactions that cleared in a prompt-month auction, and the red, orange, and green bars indicate FTR transactions that cleared in an out-month auction. For example, the red bars reflect purchases and sales that were made in the out-month auctions that occurred at the same time as the January 2020 prompt-month auction (i.e., the January 2020 vintage FTRs).

Figure 7-2: Monthly On-peak FTR MW by Auction



The prompt-month auctions for January 2020, February 2020, and March 2020 were all conducted in Winter 2020. The volume of FTR transactions that cleared in these three prompt-month auctions – 26,833 MW, 23,875 MW, and 22,988 MW, respectively – was consistent with the other recent prompt-month auctions.[78] Thirty-three bidders participated in the January 2020 prompt-month auctions. The prompt-month auction for the February 2020 on-peak period had 36 participants and 35 for the off-peak period. The March 2020 prompt-month auctions had identical levels of participation to the February 2020 prompt-month auctions. In general, these levels of participation are consistent with recent prompt-month auctions.

At the same time as the January 2020 prompt-month auctions, the ISO administered out-month auctions for February 2020 through December 2020. The volume of FTR transactions that cleared in these out-months auctions was quite low – between 509 MW and 2,202 MW, depending on the specific month. The volume of transactions clearing in the out-month auctions that took place concurrently with the February 2020 prompt-month auctions was even lower – between 240 MW and 1,055 MW, depending on the month. Similarly, the volume of

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[77] The exhibit for 2020 off-peak FTRs looks very similar to the on-peak one and so it is not included in this report.

[78] These totals reflect the sum of the FTR purchases and sales made in both the on-peak and off-peak prompt-month FTR auctions.

transactions clearing in the out-month auctions that took place concurrently with the March 2020 prompt-month auctions decreased even further – between 190 MW to 1,041 MW, depending on the month. Between 10 and 18 participants participated in the out-month auctions that occurred in Winter 2020, which is about one-third to one-half the level of participation seen in the prompt-month auctions.

The total auction revenue for the prompt-month auctions that were conducted in Winter 2020 (i.e., the prompt-month auctions for January 2020, February 2020, and March 2020) was $3.3 million, which represents a 3% increase compared to the prompt-month auctions that were conducted in Fall 2019 ($3.2 million), and a 57% decrease compared to the prompt-month auctions that took place in Winter 2019 ($7.6 million). The total auction revenue of the out-month auctions that were conducted in Winter 2020 was only $34 thousand.

FTR Funding

FTRs in December 2019 and January 2020 were fully funded, meaning that enough congestion revenue and revenue from negative target allocations was collected to pay the positive target allocations in those months. However, FTRs in February 2020 were not fully funded. In February 2020, FTR holders with positive target allocations received only 96.3% of the revenue to which they were entitled. However, there was a surplus in January 2020 ($0.5 million). As mentioned above, surpluses like this are carried over until the end of the year, when they are used to pay any unpaid monthly positive target allocations. Any remaining excess at the end of the year is then allocated to those entities that paid the congestion costs.

Appendix: Overview of FPA Process

Fuel Price Adjustments (FPAs) provide a means for participants to reflect their expected fuel costs 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, we calculate 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.[79] To provide additional insight into how FPAs impact reference levels, the Incremental Energy formula of the cost-based reference level methodology is shown below:[80]

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

Without an FPA, we estimate 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.[81] FPA requests for the DA market must be submitted by the close of the DA 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 a participant's ability to reflect their costs through supply offers rather than after-the-fact uplift payments, it also comes with an obligation of verification. We conduct a cost verification through *ex-post* documentation. To lessen the ability of a participant to exercise market power, we also have the ability to set a limit on requested FPA prices.

We use 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

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79 See Tariff Section III.A.7.5.

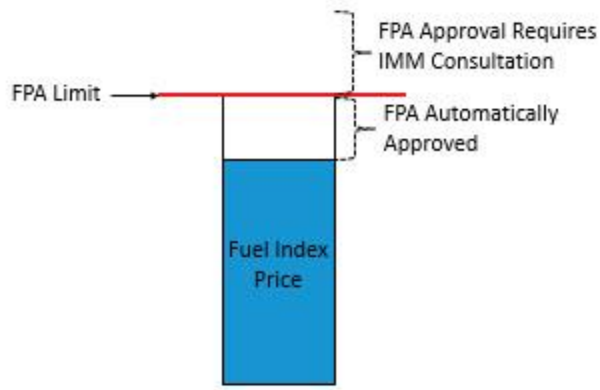
80 Similar formulae are also used to estimate no-load and start-up costs, but are not shown here to preserve space.

81 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.

from the Intercontinental Exchange (ICE), actual and forecast weather, and generator gas consumption.

Once submitted, FPAs are either approved at the requested price or capped at the FPA Limit (see Figure A-1 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 us to provide additional documentation for the increased cost. We will draw on our 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.

Figure A-1: FPA Processing Overview



In addition to this *ex-ante* measure, we require 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).