ISO New England's Internal Market Monitor

Winter 2017

Quarterly Markets Report

Internal Market Monitor

May 5, 2017

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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.***

This report covers the winter period from **December 1, 2016 to February 28, 2017** (the "reporting period"). The report contains our analyses and summaries of market performance. All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.[1]

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media

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

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

Section 1
Executive Summary

This report covers key market outcomes and the performance of ISO New England wholesale electricity and related markets for the Winter of 2017 (December 2016 through February 2017).[3] The inputs and results of the eleventh forward capacity market, which was conducted in February 2017, are also summarized.

1.1 Summary of Market Outcomes and Performance for Winter 2017

- The total estimated wholesale market costs were $1.7 billion in the reporting period, a 27% increase compared to the same period in 2016 (Winter 2016).
    - Higher natural gas prices were the primary driver for the increase in total energy costs. Natural gas prices averaged $5.29/MMBtu. This is a 55% increase compared to Winter 2016.
    - Colder weather and higher natural gas prices in December 2016 drove much of the year-over-year increase in electricity prices and wholesale costs. In December 2016, natural gas prices averaged $6.85/MMBtu, more than 200% higher than the average price of $2.26/MMBtu in December 2015. The day-ahead Hub LMP averaged $53.28/MWh, an approximate increase of 140% over December 2015 prices. January and February 2017 gas and electricity prices were relatively close to average prices in the same months of 2016.

- In Winter 2017, the average hourly demand was 14,320 MW, comparable to the same season of 2016, due to similar average temperatures. Colder weather and higher demand in December 2016 was offset by milder weather and lower demand in January and February 2017 compared to the same months in the prior winter.

- Day-ahead and real-time energy market prices at the Hub averaged $41.57/MWh and $39.89/MWh, respectively. Day-ahead prices were 37% higher and real-time prices were 45% higher than Winter 2016 prices. These outcomes were driven by higher natural gas prices.

- Total real-time reserve payments in Winter 2017 were $1.8 million, an 18% ($388,000) decrease from $2.2 million in Winter 2016 and a 48% decrease from last quarter. The decrease in total payments compared to Fall 2016 was driven primarily by an 80% reduction in payments to resources inside the Northeast Massachusetts and Boston (NEMA) load zone. During last fall, transmission projects resulted in the NEMA area being frequently import-constrained and re-dispatch of local generation was required to satisfy the area's thirty-minute operating reserve requirement. The re-dispatch of internal generators elevated area prices relative to the rest of the system. The frequency of these events was lower but still occurred within the NEMA area during the winter.

[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).

- Regulation payments totaled $7.9 million, a 49% increase from $5.3 million in Winter 2016. Regulation payments in Winter 2017 rose compared to earlier periods primarily as a result of increased regulation clearing prices. The pricing increase reflected adjustments made to participant offers (for energy market opportunity costs and incremental cost savings); unadjusted participant offers did not reflect a significant increase from earlier periods.[4]

- Net Commitment Period Compensation (NCPC) payments in the quarter totaled $18.2 million, a 22% increase from Winter 2016. The increase was primarily driven by an increase in second contingency payments made in Winter 2017. The high second contingency payments were the result of reliability commitments made within the NEMA load zone. Transmission outages and upgrades limiting transfer capability within the NEMA load zone required additional reliability commitments within the load zone. These generators were subsequently paid NCPC and made whole to their offers for periods during which they were committed for reliability and could not recover their full costs though the LMP.

- Winter 2017 coincides with the commitment period associated with FCA 7. In FCA 7, the NEMA-Boston zone cleared at $15.00/kW-month for new resources and $6.66/kW-month for existing resources, and the Rest-of-Pool cleared at the floor price of $3.15/kW-month. In Winter 2017, capacity payments totaled $287 million. Total payments for capacity provided during Winter 2017 were within 1% of the Winter 2016 and Fall 2016 payments.

1.2 Summary of Forward Capacity Auction #11

- FCA 11 was the first auction to incorporate the marginal reliability impact curve. The auction cleared system wide in the fifth round when an existing resource submitted a dynamic de-list bid. The clearing price was $5.30/kW-month with cleared capacity of 35,835 MW, a surplus of 1,760 MW over the Net Installed Capacity Requirement. Clearing prices did not separate in the export-constrained Northern New England (NNE) and import-constrained Southeastern New England (SENE) capacity zones. There was price separation at the New Brunswick interface, which still had 700 MW of excess capacity over its capacity transfer limit participating in the auction at the end of round five. The auction continued into the sixth round and cleared at a price of $3.38/kW-month. The IMM found that the auction outcomes were competitive.

- The system-wide clearing price declined by 25%, from $7.03/kW-month in FCA 10 to $5.30/kW-month in FCA 11. Projected payments are estimated at approximately $2.3 billion, which is the lowest total since FCA 7.

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[4] Energy market opportunity costs reflect an estimate by the ISO of the foregone net revenue incurred by a generator to provide regulation, rather than providing energy in the energy market. Incremental cost saving represents the reduction in total system cost provided by a specific regulation offer, when compared to the next most expensive offer. This compensation replicates a “Vickery” approach to compensating lumpy “supply,” and is intended to provide regulation resources with payments approximating the system opportunity cost of obtaining regulation.

Section 2
Summary of Market Outcomes and System Conditions

This section summarizes the region's wholesale electricity market outcomes and measures of market performance.

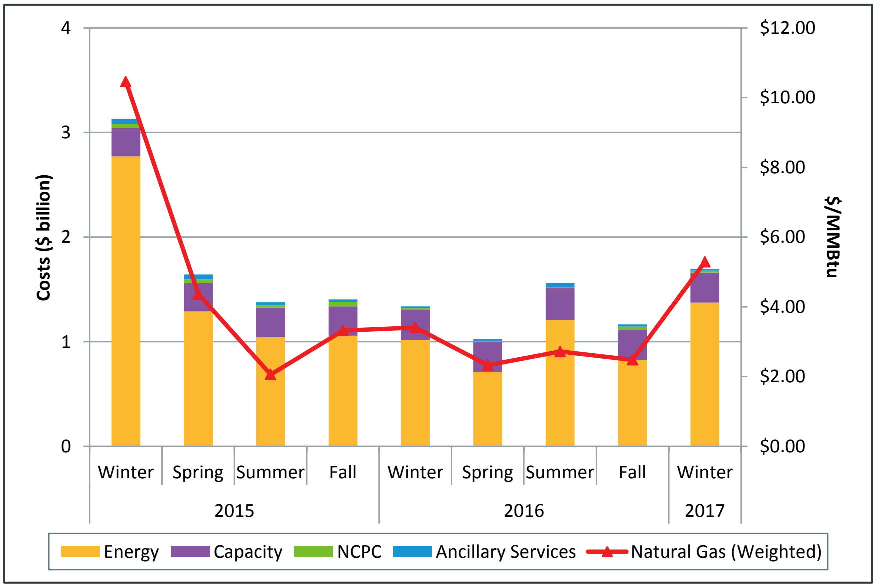
2.1 Market Outcomes

The following subsections present and discuss key trends and drivers of market outcomes from Winter 2015 (beginning December 2014) through Winter 2017.

2.1.1 Total Wholesale Electricity Market Value

The estimated wholesale electricity cost for each season (in billions of dollars) by market, along with average natural gas prices (in $/MMBtu) is shown in Figure 2-1 below.[5, 6]

Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Season ($ billions and $/MMBtu)



In Winter 2017, the total estimated wholesale market cost of electricity was $1.7 billion, an increase of about 27% compared to $1.3 billion in Winter 2016 and an increase of 46% over the previous quarter (Fall 2016). Figure 2-1 illustrates how natural gas prices were a key driver behind energy costs from 2015 to 2017. The increase in natural gas prices in Winter 2017 relative to Winter 2016 and Fall 2016 resulted in higher energy costs.

[5] 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.

[6] 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.

At $18 million, Winter 2017 Net Commitment Period Compensation (NCPC) costs represented approximately 1% of the total wholesale cost. NCPC costs were 22% higher than Winter 2016 NCPC costs, but 46% lower than Fall 2016 NCPC costs. NCPC is discussed further in Section 2.2.1 below. Ancillary services, which include operating reserves and regulation, totaled $18 million in Winter 2017. Ancillary services costs decreased by 7% and 15% when compared to Winter 2016 and Fall 2016, respectively.

2.1.2 Key Market Statistics

Selected key statistics for load levels, real-time and day-ahead energy market prices, and fuel prices are shown in Table 2-1 below.

Table 2-1: Key Statistics on Load, LMPs, and Natural Gas

	Winter 2017	Fall 2016	Percent Change Winter 2017 to Fall 2016	Winter 2016	Percent Change Winter 2017 to Winter 2016
Real-Time Load (GWh)	30,933	28,849	7%	31,329	-1%
Weather-normalized Real-Time Load (GWh)	31,550	28,828	9%	31,948	-1%
Peak Real-Time Load (MW)	19,581	23,066	-15%	19,562	0%
Average Day-Ahead Hub LMP ($/MWh)	$41.57	$25.16	65%	$30.32	37%
Average Real-Time Hub LMP ($/MWh)	$39.89	$24.72	61%	$27.58	45%
Average Natural Gas Price ($/MMBtu)	$5.29	$2.48	113%	$3.41	55%

The price of natural gas was the biggest contributing factor that explains the differences between Winter 2017 and Winter 2016 market outcomes. There were only modest differences in electricity demand during the period.

- Higher natural gas prices were the primary driver for higher day-ahead and real-time LMPs. Natural gas prices increased by 55% compared to the prior winter. Natural gas prices tend to be higher in the winter months when the demand for natural gas increases. The impact of natural gas prices on LMPs is further examined in Figure 2-2 and Figure 2-9.
- The total real-time load in Winter 2017 was comparable (only 1% lower) to last winter. The peak load for Winter 2017 was <1% higher than the peak load from the prior winter. Changes in load are further discussed in Section 2.1.3.2.

2.1.3 Real-Time Markets

2.1.3.1 Real-Time Energy Market

The average real-time Hub energy price was $39.89/MWh in Winter 2017, a 61% increase compared to the preceding quarter (Fall 2016). Real-time prices continued to follow the cost of natural gas generation, which we estimated to be $41.25/MWh, on average, during the reporting period. Compared to the prior winter, real-time energy prices were higher by 45% which also corresponds with a 55% increase in natural gas prices between these periods. Energy prices did not differ significantly among the load zones in the quarter, but were 3% and 2% lower in Maine and Vermont, respectively.[7] Renewable type generation resources located in export-constrained areas of northern New England were frequently setting energy prices in these areas. Figure 2-2 shows the seasonal average real-time energy prices and the estimated cost of gas generation. The cost of gas generation is based on a unit heat rate of 7,800 Btu/kWh and average natural gas prices during each period.

Figure 2-2: Simple Average Real-Time Energy Prices and Gas Generation Costs

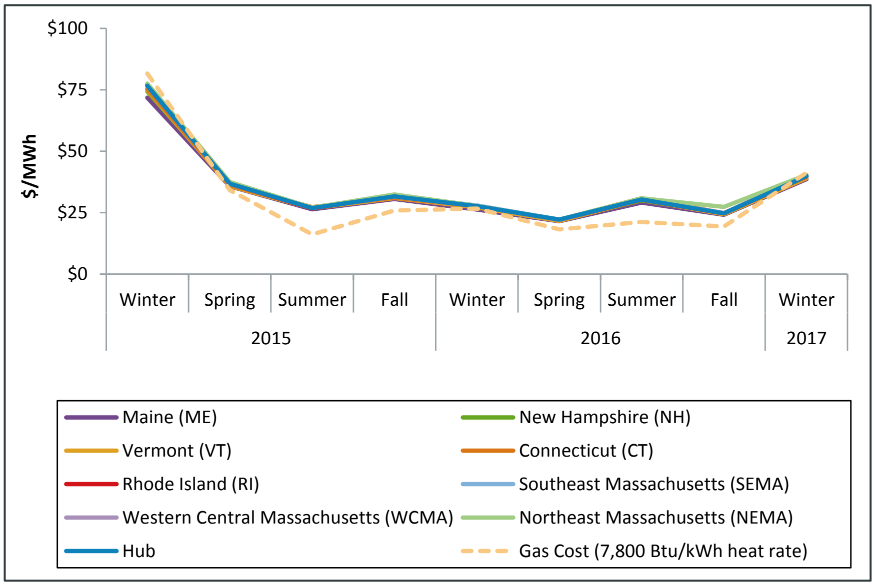


Figure 2-2 illustrates how average real-time energy prices tend to track closely with the cost of natural gas generation in New England. This is shown by the movement in the zonal energy price trend lines and the natural gas cost trend line (the dashed yellow line series). As noted above, natural gas prices were 55% higher in Winter 2017 compared to Winter 2016. Colder temperatures during December 2016 compared with December 2015 drove most of the year-over-year change in quarterly average gas prices. In December 2016 natural gas and real-time electricity prices averaged $6.85/MMBtu and $53.83/MWh, respectively. This was an approximate increase of 200% and 150% over December 2015 natural gas and electricity prices, respectively. Milder weather conditions in January and February began to moderate peak season gas prices. January and February 2017 natural gas and electricity prices were both relatively close to average prices in the same months of 2016.

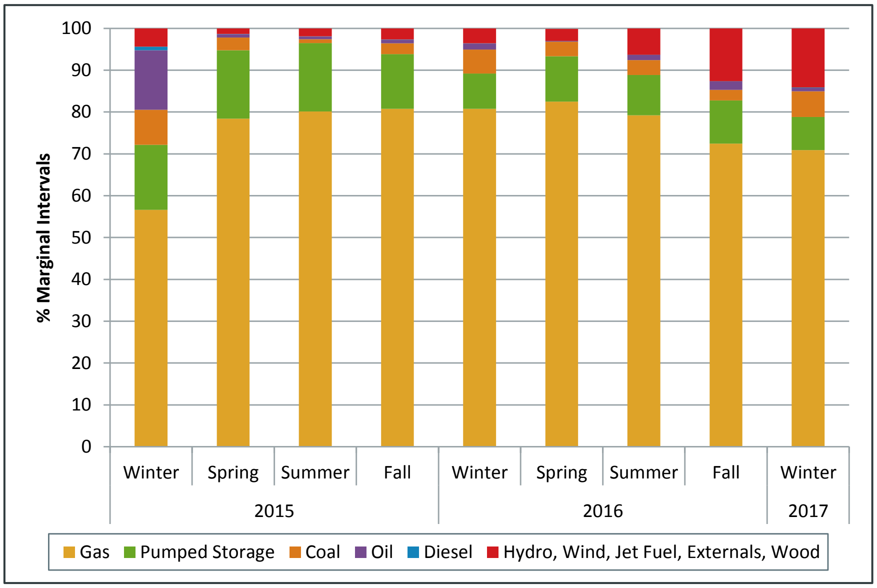
The premium in Northeast Massachusetts and Boston (NEMA) real-time prices of $2.54/MWh during Fall 2016 was reduced to just $0.45/MWh (1% above the hub price) in the reporting period. There were fewer instances when transmission, load, and generation patterns required using more-expensive local NEMA resources to meet the area's load and reserve requirements during Winter 2017.

Analyzing the real-time marginal unit by fuel type provides additional insight into real-time pricing outcomes. The LMP at a pricing location is set by the cost of the next megawatt the ISO would dispatch to meet an incremental change in load at that location. The resource that sets price is

[7] A *load zone* is an aggregation of pricing nodes within a specific area; there are currently eight load zones in the New England region that correspond to the reliability regions.

called the marginal unit. The price of electricity changes as the price of the marginal unit changes and the price of the marginal generating unit is largely determined by its fuel type and heat rate. Examining marginal units by fuel type helps us understand changes in electricity prices. Figure 2-3 below shows the percentage of time resources of different fuel types were marginal by season.

Figure 2-3: Real-Time Marginal Units by Fuel Type



In the reporting period, units burning natural gas were marginal (*i.e.*, setting the price) in 71% of the pricing intervals, followed by units in the "other" category, which were marginal in 14% of the pricing intervals. Pumped storage units were marginal in 8% of intervals. Units burning coal, oil, and diesel were marginal in the remaining pricing intervals. Most of the price-setting units in the "other" category were wind units, which set price 11% of the time. Most of these wind units are located where the transmission system is regularly export-constrained. This means that the wind units frequently set price within their constrained region while another unit(s) set price for the rest of the system. Wind was the single marginal fuel type on the system in <1% of all five-minute intervals.[8]

As seen in Figure 2-3 above, the composition of marginal units in Winter 2017 was different from previous winter seasons. The largest difference from the previous two winters was the frequency of marginal wind units. The difference is driven by the Do Not Exceed (DNE) dispatch rules which went into effect on May 25, 2016.[9] DNE incorporates wind and hydro intermittent units into unit

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[8] When the transmission system is unconstrained there will be at least one marginal unit. When it is constrained, there will be more than one. As a suitable example in this case, if a transmission line is at capacity in a local area of the system and limits the ability to export wind generation from that area, price could be set for a small number of pricing nodes behind that constraint by a wind generator. The price at all other nodes on the system would be set by another generator, which is frequently a thermal generator.

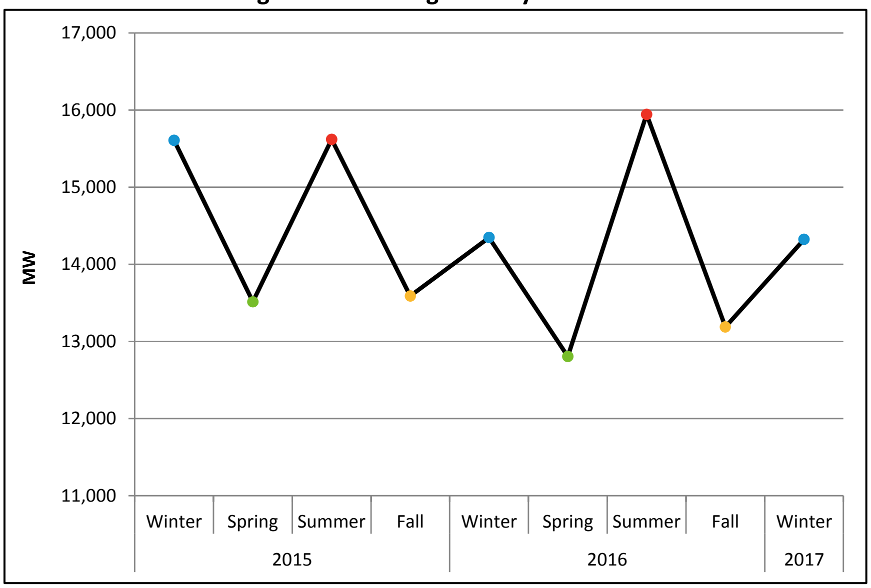
[9] *ISO New England Inc. and New England Power Pool*, Do Not Exceed ("DNE") Dispatch Changes, ER15-1509-000 (filed April 15, 2015); Order Conditionally Accepting, In Part and Rejecting, In Part, Tariff Revisions and Directing Compliance Filing, 152 FERC ¶ 61,065 (2015). In a subsequent filing, the Filing Parties modified the DNE Dispatch changes to remove the exclusion of DNE Dispatchable Generators from the regulation and reserves markets, to comply with the Commission's order on the original rule changes. The Commission accepted the ISO's compliance filing in a subsequent order. *ISO New England Inc. and New England Power Pool*, Compliance Filing Concerning DNE Dispatch Changes, ER15-1509-002 (filed August 21, 2015); Letter Order Accepting DNE Dispatch Compliance Filing, ER15-1509-002 (issued October 1, 2015.

dispatch, making the units eligible to set price. Previously, these units had to self-schedule their output in the real-time market and, therefore, could not set price. The other noticeable difference between Winter 2017 and Winter 2015 is the reduction in the frequency of marginal oil generators between the two periods. As shown in Figure 2-2, Winter 2015 gas prices were relatively high compared to Winter 2016 and Winter 2017. This resulted in oil generation being more competitively priced in relation to gas generation and more oil generation setting price.

2.1.3.2 Load Summary

Average hourly load by seasonal quarter is shown in Figure 2-4 below. The blue dots represent winter, the green dots represent spring, the red dots represent summer, and the yellow dots represent fall.

Figure 2-4: Average Hourly Demand



The average hourly load of 14,320 MW in Winter 2017 was comparable to Winter 2016 (14,345 MW), due to similar overall weather conditions. Warmer temperatures during the past two winters contributed to a decrease in heating load compared to 2015. Temperatures averaged 33°F in Winter 2017, compared to 35°F in the prior winter. Average load in Winter 2015 was noticeably higher at 15,606 MW due to much colder temperatures, averaging 25°F.

Of the three months in Winter 2017 (December 2016, January and February 2017), January and February were warmer than the same months in 2016. The average temperatures in January and February 2017 were three and two degrees warmer, respectively, compared to the corresponding months in 2016. The warmer temperatures during January and February were offset by much colder weather during December 2016. The average temperature in December 2016 (32°F) was 11 degrees below December 2015, leading to higher electricity and natural gas heating demand. In December 2016, natural gas prices averaged $6.85/MMBtu, more than 200% higher than the average price of $2.26/MMBtu in December 2015.

Another way to examine load is to sort all the hourly load values from highest to lowest for any given period. The resulting curve is called a *load duration curve*. The horizontal axes of the load duration curve are expressed as a percentage of the total number of hours in the period of interest as shown in Figure 2-5. By plotting several seasonal load duration curves, one can easily observe differences between periods.

Figure 2-5: Seasonal Load Duration Curves (MW)[10]

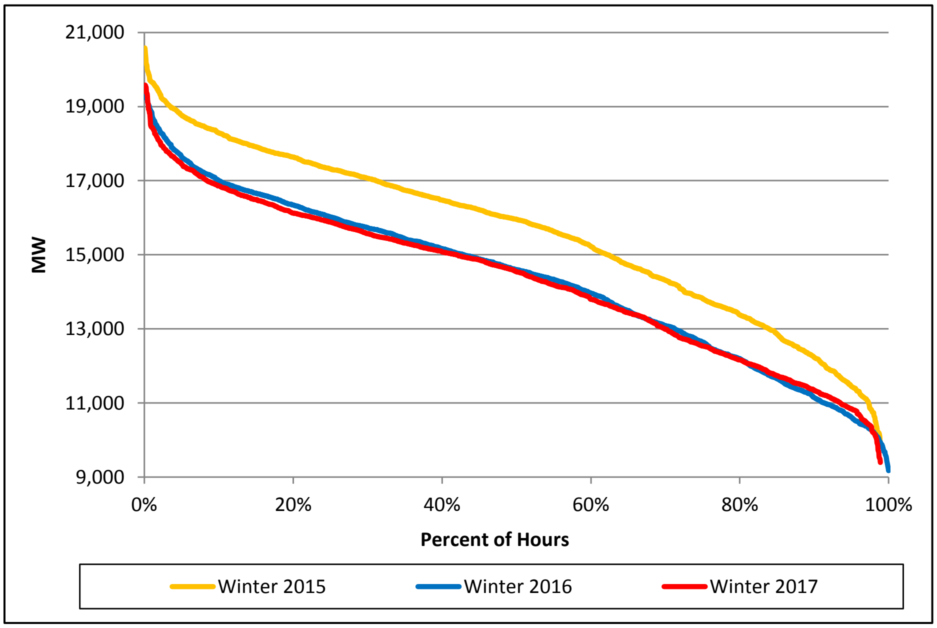


Figure 2-5 illustrates a similar trend in Winters 2016 and 2017, but consistently lower load levels compared to Winter 2015. The peak hourly load in the reporting period, which occurred on December 15, 2016) was 19,581 MW. This was similar to the peak hourly load from last winter of 19,561 MW, but lower than the Winter 2015 peak load of 20,583 MW.

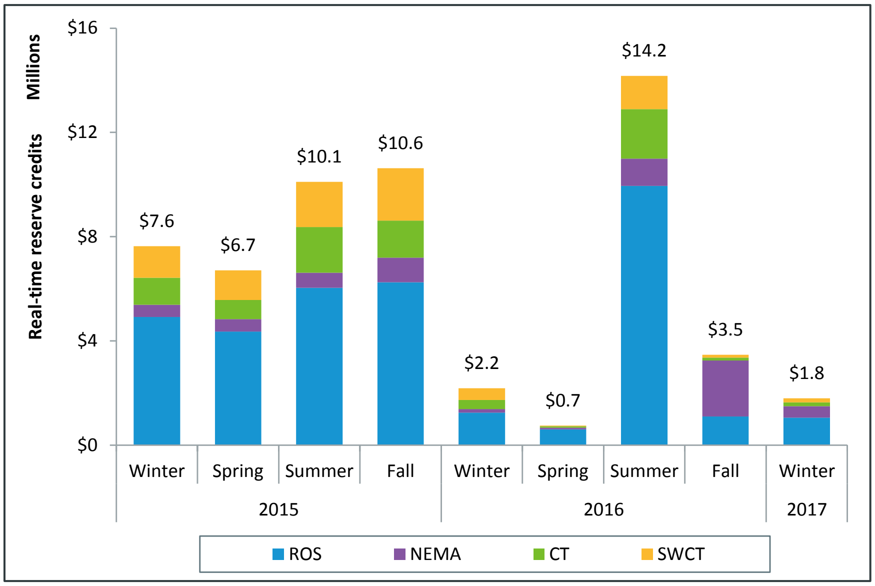
2.1.3.3 Real-Time Operating Reserves

Real-time reserve payments totaled $1.8 million during Winter 2017, which is 48% lower than the $3.5 million paid in Fall 2016. The overall decrease in reserve payments relative to Fall 2016 was driven primarily by an 80% reduction in payments to resources inside the NEMA load zone. During last fall, transmission projects resulted in the NEMA area being frequently import-constrained and re-dispatch of local generation was required to satisfy the area's thirty-minute operating reserve requirement. The re-dispatch of internal generators elevated NEMA prices relative to the rest of the system. The frequency of these events was lower but still occurred within the NEMA area during the winter.

Total real-time reserve payments by reserve zone for the seasonal quarter from Winter 2015 through Winter 2017 are plotted in Figure 2-6 below. Note that these figures are intended to show the value of real-time reserves and therefore are the gross real-time credits for providing reserve products at the respective real-time clearing price. The netting of real-time payments for a participant's forward reserve market obligations is not accounted for in these totals.

[10] The Winter 2016 load duration curve is slightly longer than the other two curves due to an extra 24 hourly observations due to the leap year.

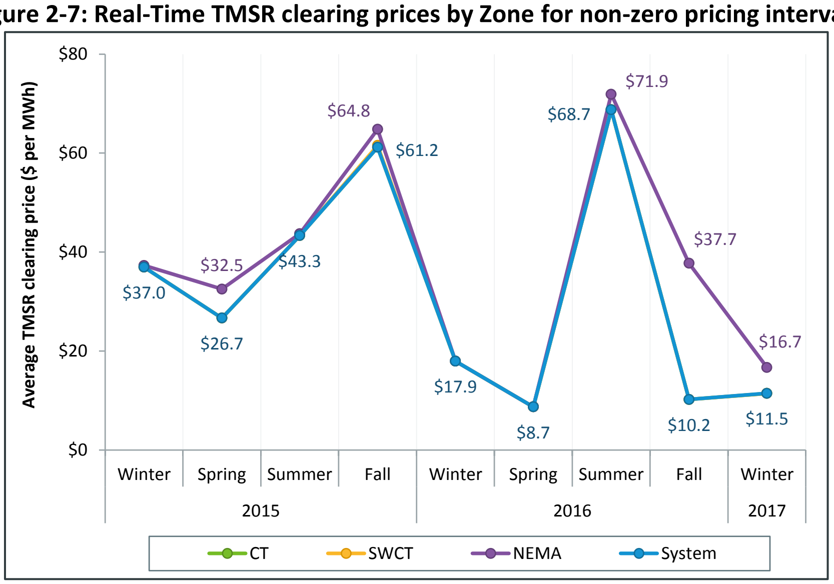
Figure 2-6: Real-Time Reserve Payments by Zone ($ million)



As shown in Figure 2-6, total real-time reserve payments were lower in Winter 2017 compared to Fall 2016 but on par with Winter 2016. Compared with Fall 2016, total payments were down $1.7 million and the reduction in payments just within the NEMA area was a comparable amount. In comparison with Winter 2016, total payments were lower by $388,000, or 18%, in Winter 2017.

A measure of the average real-time ten-minute spinning reserve (TMSR) clearing price for each zone and the system by quarter is illustrated in Figure 2-7 below.[11] For this presentation the average prices are computed using the 5-minute prices over all intervals when any of the zonal or system clearing prices for TMSR is not zero. This measure indicates the relative value of reserves across the areas of the system for each quarterly period.

Figure 2-7: Real-Time TMSR clearing prices by Zone for non-zero pricing intervals



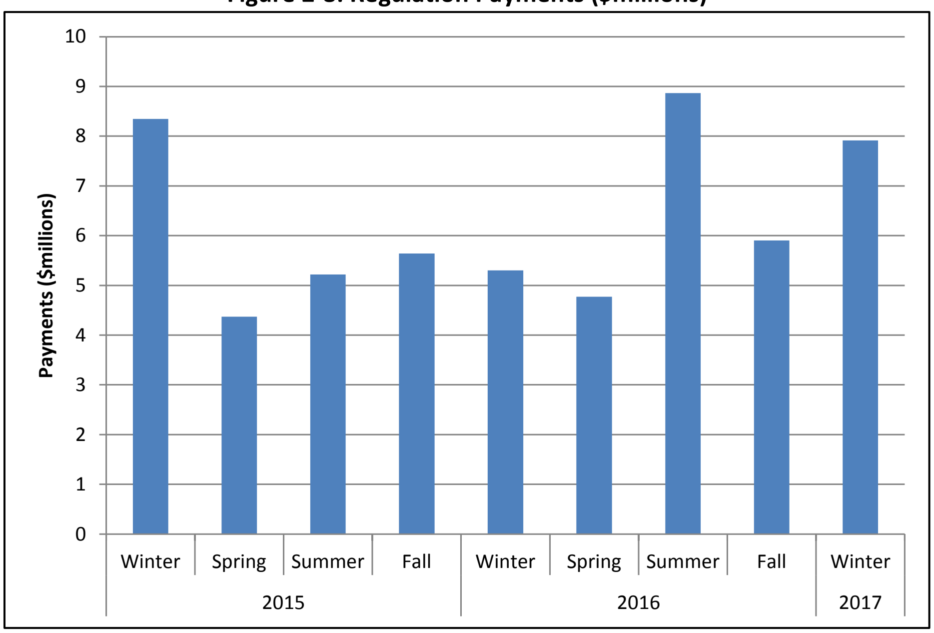
[11] TMSR prices also reflect non-zero prices of the non-spinning reserve products. This is due to the pricing hierarchy, which ensures that the higher quality products are valued at least equal to the price of lower quality products.

As shown in Figure 2-7, the reserve clearing prices for the system (the blue line series) were slightly higher in Winter 2017 compared to Fall 2016. In the reporting period, the average system-wide TMSR price was $11.50/MWh, an increase of 12% relative to the Fall 2016 average price of $10.20/MWh. System-wide TMSR pricing occurred more frequently in Winter 2017 than Fall 2016, but there was no other significant change in system-wide reserve pricing observations. In contrast, the frequency of NEMA zone pricing for the local area thirty-minute operating reserve declined relative to the prior quarter. Fewer NEMA-only pricing intervals produced a corresponding drop the zone's average TMSR price (purple line series) relative to the rest of the system during the reporting period.[12] The average price of $16.70/MWh for the NEMA zone in Winter 2017 was lower by 56% compared to the average Fall 2016 price of $37.70MWh. The lower NEMA price reflects the less frequent need to re-dispatch generation within NEMA to maintain area reserve requirements during the winter and corresponds with the decline in zonal reserve payments discussed above.

2.1.3.4 Regulation Market

Quarterly regulation payments are shown in Figure 2-8 below.[13]

Figure 2-8: Regulation Payments ($millions)



Total regulation market payments were $7.9 million during the reporting period, up 34% from $5.9 million in Fall 2016, and up 49% from $5.3 million in Winter 2016. Regulation payments in Winter 2017 rose compared to earlier periods, primarily as a result of increased regulation clearing prices. The pricing increase reflects adjustments that are made to participant offers (for energy market opportunity costs and incremental cost savings) by the ISO; unadjusted participant offers do not reflect a significant increase from earlier periods.[14] During typical New England Winters, elevated

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[12] Thirty-minute operating reserve (TMOR) pricing cascades up to ten-minute reserve prices consistent with the fact that ten-minute reserve can substitute for thirty-minute reserve capacity.

[13] 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.

[14] Energy market opportunity costs reflect an estimate by the ISO of the foregone net revenue incurred by a generator to provide regulation, rather than providing energy in the energy market. Incremental cost saving represents the reduction

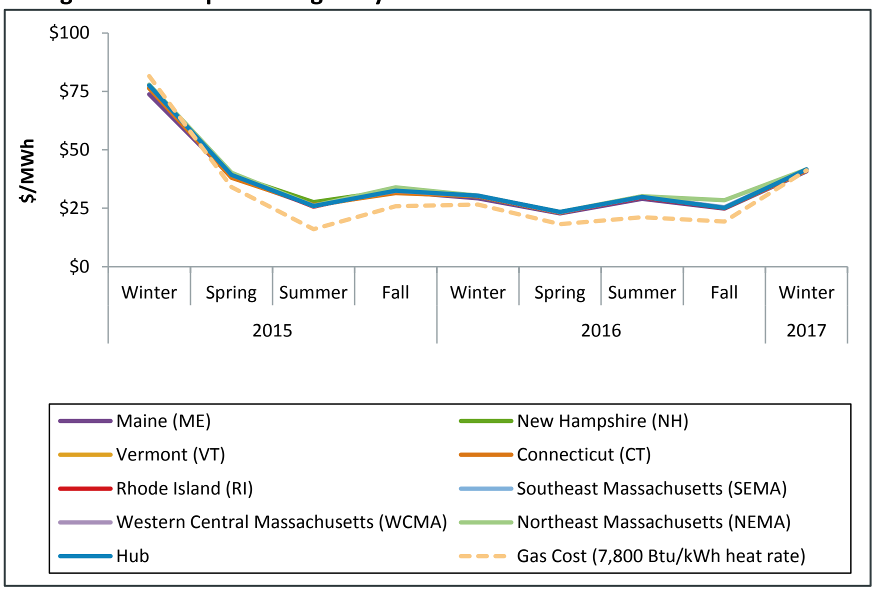
regulation prices frequently occur, reflecting both increased fuel costs and increased energy market opportunity costs. A mild winter quarter in 2016 resulted in unusually low regulation payments, compared to Winter 2015 and Winter 2017.

2.1.4 Forward Markets

2.1.4.1 Day-Ahead Energy Market

The average day-ahead Hub price for Winter 2017 was $41.57/MWh, an increase of 65% from the Fall 2016 average of $25.16/MWh. Similar to real-time energy prices, day-ahead market prices remained correlated with natural gas prices and prices did not differ significantly among the load zones, with the exception of prices in the Maine and Vermont zones which were slightly lower in day-ahead as well as real-time as discussed in section 2.1.3.1 above. Figure 2-9 below depicts seasonal quarterly average day-ahead energy prices and the estimated cost of gas generation (assuming a unit heat rate of 7,800 Btu/kWh) and average natural gas prices each period.

Figure 2-9: Simple Average Day-Ahead Prices and Gas Generation Costs



As shown in Figure 2-9, average day-ahead energy prices at the Hub increased relative to Winter 2016, but remained below the much higher prices experienced during Winter 2015. Compared to Winter 2016, average day-ahead prices were 37% higher, but relative to Winter 2015 prices were 46% lower in Winter 2017. The relative increase in electricity prices compared with the Winter 2016 and relative decrease compared with Winter 2015 are consistent with the coincident natural gas prices shown by the dashed yellow line series in Figure 2-9. For Winter 2017, the average day-ahead Hub price was 4%, or $1.68/MWh, higher than the real-time Hub price for the period.

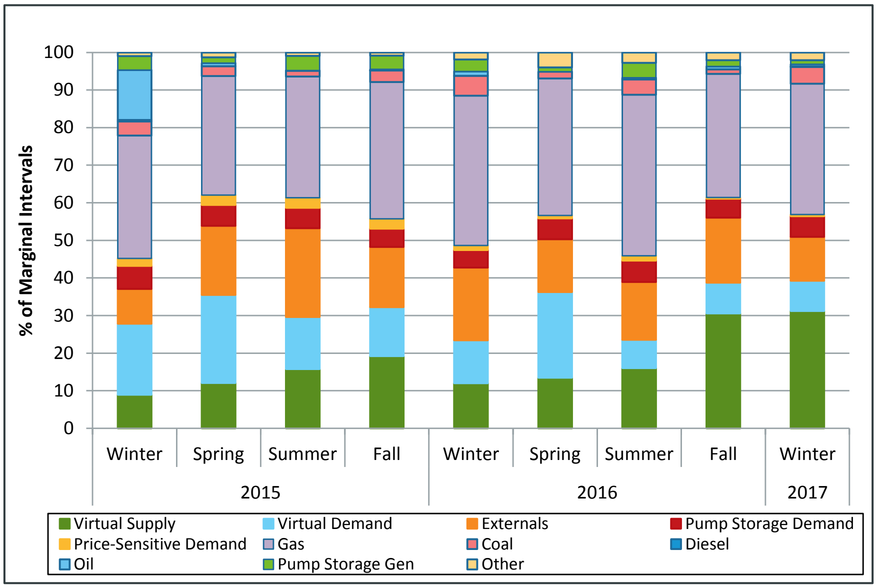
As discussed above in Section 2.1.3.1 colder temperatures and higher natural gas prices during December 2016 compared with December 2015 drove most of the year-over-year change in quarterly average prices. In December 2016 day-ahead energy prices averaged $53.28/MWh, an

in total system cost provided by a specific regulation offer, when compared to the next most expensive offer. This compensation replicates a “Vickery” approach to compensating lumpy “supply,” and is intended to provide regulation resources with payments approximating the system opportunity cost of obtaining regulation.

approximate increase of 140% over December 2015 prices. January and February 2017 day-ahead prices were relatively close to average prices in the same months of 2016.

The percentage of time that each resource type set price in the day-ahead market since Winter 2015 is illustrated in Figure 2-10 below. In addition to generators, there are other entities that can set price in the day-ahead market, including price-sensitive demand, priced external transactions, and virtual transactions. In the graph, marginal units are shown by category, and generators are outlined in blue and broken up by fuel type further within the generator category.

Figure 2-10: Day-Ahead Marginal Units by Resource and Fuel Type

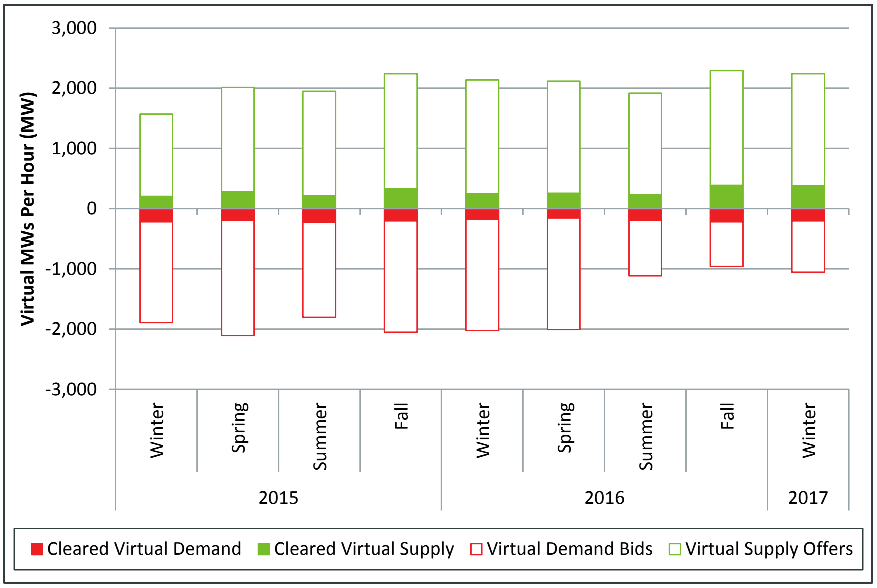


The type and frequency of resources that set price varies from one period to the next. This is due to the mix of resource types participating in both the supply and demand side of the day-ahead market. In the day-ahead market, participants may submit virtual bids and offers, and fixed and priced demand, in addition to supply offers and external transactions. By contrast, only physical supply and external transactions can set price in the real-time market (with natural gas generators generally the dominant price-setters).

The frequency of marginal units by resource type during the reporting period was within a normal range based on historical observations. A large increase in marginal virtual supply offers appeared in Fall 2016, and persisted into Winter 2017. Virtual transactions (virtual supply and demand) set price approximately 39% of the time, which represents an increase from 23% from Winter 2016. This increase is due to a higher frequency of virtual supply offers being marginal in export-constrained areas. In most of these intervals, virtual supply offers were not the only marginal transaction on the system and only set price for the whole system in 13% of hours in Winter 2017. Aside from virtual transactions, generators set price approximately 43% of the time, external transactions set price approximately 12% of the time and price-sensitive demand (including pump storage demand) set price in 6% of price-setting intervals.

Virtual transaction volumes from Winter 2015 through Winter 2017 are shown in Figure 2-11 below.

Figure 2-11: Total Offered and Cleared Virtual Transactions (Average Hourly MW)



In the reporting period, submitted virtual demand bids and virtual supply offers averaged approximately 3,296 MW per hour, a 1% increase from Fall 2016, and a 21% decrease from Winter 2016. Although submitted virtual transactions decreased from last Winter, there was a higher volume of cleared virtual transactions in Winter 2017. The percentage of virtual transactions that cleared was 18% in Winter 2017, much higher than the 10% that cleared in Winter 2016. For comparison, virtual transactions cleared 11%, on average, from Winter 2015 through Spring 2016. The average offer prices of virtual transactions have converged towards the hub LMP compared to last winter.

2.1.4.2 Financial Transmission Rights

Three Financial Transmission Rights (FTR) auctions were conducted during the reporting period for a combined total of 89,422 MW of FTR transactions. The total amount distributed as Auction Revenue Rights (ARRs) was $2.2 million, which was slightly higher than in the previous reporting period. Ongoing congestion due to planned transmission outages continues to result in relatively high ARR payments compared with previous quarters. Thirty-two bidders in December, twenty-nine bidders in January and thirty bidders in February participated in the monthly auctions for the quarter. The level of participation was consistent with prior auctions.

2.1.4.3 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.[15] The FCM is designed to procure and price capacity before the system will need it. 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.

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

During any one 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.[16] Between the initial auction and the commitment period, there are six discrete opportunities to adjust annual capacity supply obligations (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 take on obligations or shed obligations. Trading in monthly auctions adjusts the CSO position for a particular month, not the whole commitment period. The following sections summarize FCM activities during the reporting period, including total payments and trading of CSOs specific to each commitment period.

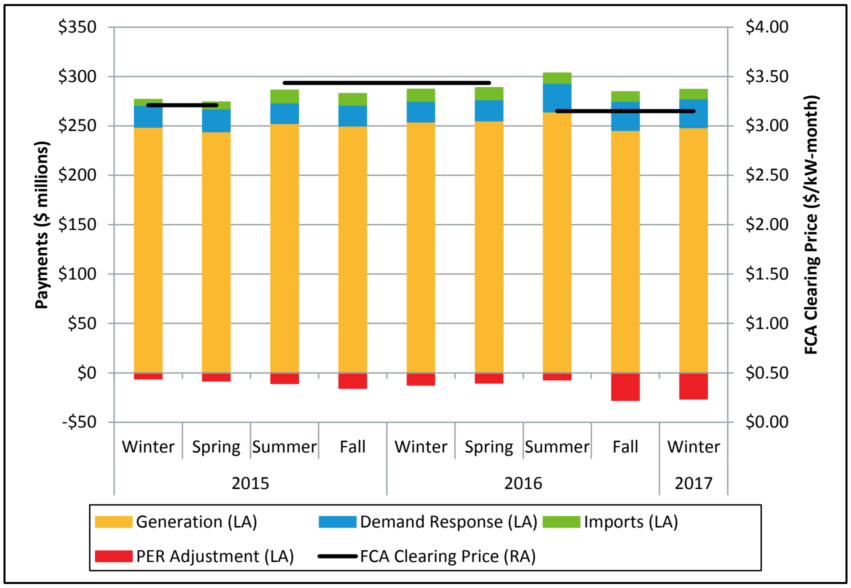
The current commitment period started in Summer 2016 and ends in Spring 2017. In the corresponding Forward Capacity Auction (FCA 7), there was price separation between the NEMA/Boston import-constrained zone and Rest-of-Pool. The price separation was due to inadequate supply in the NEMA/Boston zone. NEMA/Boston cleared at $15.00/kW-month for new resources and $6.66/kW-month for all existing resources. Existing resources were priced using administrative rules designed to protect the market from the exercise of market power. These administrative pricing provisions were used because there was insufficient competition among new resources to set a competitive price. The clearing price for the Rest-of-Pool zone was the floor price of $3.15/kW-month.

Total net FCM payments have declined from the beginning of the commitment period due to peak energy rent reductions. In Winter 2017, capacity payments totaled $287 million, which accounts for adjustments to primary auction CSOs.[17] Figure 2-12 illustrates total FCM payments as well as the existing clearing price for Winter 2015 through Winter 2017. 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.

[16] 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.

[17] 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.

Figure 2-12: Total Capacity Payments ($ millions)



The proportion of payments to each resource type has remained relatively constant over the reporting period. The negative red bar represents the reduction in payments due to Peak Energy Rent (PER) adjustments. The peak energy rent adjustment had more of an effect on capacity payments in Fall 2016 and Winter 2017 than in previous quarters because of high real-time energy prices that occurred in August 2016.[18] In Winter 2017, PER adjustments totaled over $26 million dollars.

Secondary auctions allow participants the opportunity to acquire or shed capacity after the initial auction. Table 2-2 provides a summary of prices and volumes associated with reconfiguration auction and bilateral trading activity during Winter 2017, alongside the results of the relevant primary Forward Capacity Auction (FCA).

Table 2-2: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

FCA #(Commitment Period)	Auction Type	Period	System-wide Price ($/kW-mo)**	Cleared MW	NEMA/Boston
FCA 7 (2016-17)	Primary	12-month	3.15	36,220	15.00/6.66*
	Monthly Reconfiguration	17-Feb	0.50	732	0.75
	Monthly Bilateral	17-Feb	2.51	220	
	Monthly Reconfiguration	17-Mar	0.50	767	2.00
	Monthly Bilateral	17-Mar	2.48	190	
	Monthly Reconfiguration	17-Apr	0.40	752	2.00
	Monthly Bilateral	17-Apr	2.19	124	
FCA 8 (2017-18)	Primary	12-month	15.00/7.03*	33,712	15.00/15.00*
	Annual Bilateral (3)	12-month	4.89	281	

**price paid to existing resources/price paid to new resources*

***prices represent volume weighted average prices for bilaterals*

[18] To read more about the effect of Peak Energy Rent Adjustments on capacity payments, see the IMM's Summer 2016 Quarterly Markets Report: https://www.iso-ne.com/static-assets/documents/2016/11/qmr_2016_q3_summer_11_15_2016.pdf .

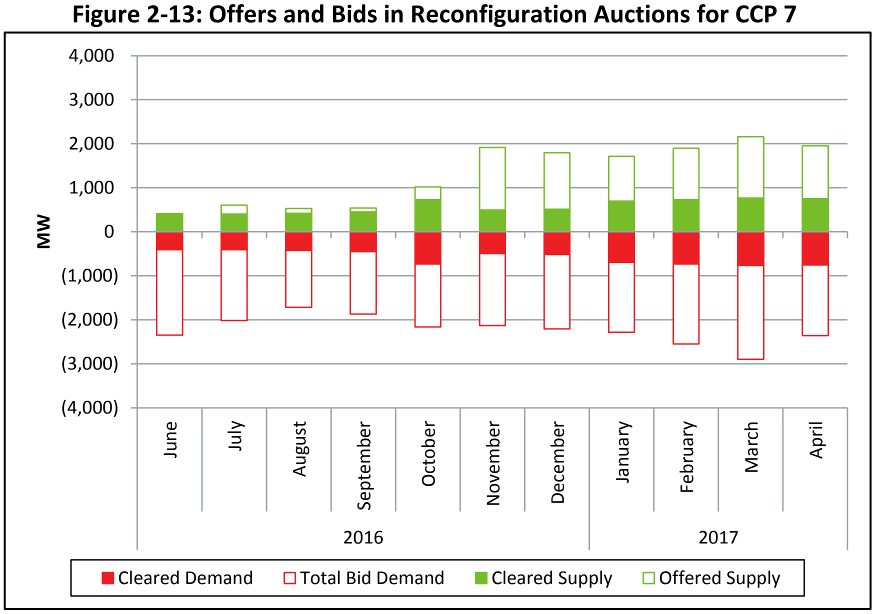
The following two sub-sections provide further detail on the outcomes of the secondary auctions during the reporting period.

FCA 7 Commitment Period

The monthly reconfiguration auctions continued to clear below the FCA clearing price. All capacity zones and interfaces cleared at $0.50/kW-month in February and March, and $0.40/kW-month in April, with the exception of NEMA/Boston. The NEMA/Boston zone cleared at $0.75/kW-month in the February 2017 auction, and $2.00/kW-month in the March and April auctions.

Most thermal generating resources have greater capability during the winter period when ambient temperatures are lower. These resources are able to offer additional capacity (the difference between their winter and summer qualified capacity) into the winter period reconfiguration auction.[19] This causes an increase in offered supply during the winter period. Figure 2-13 shows supply and demand bids in the reconfiguration auctions associated with capacity commitment period (CCP) 7. The green bars represent total supply offers, while the red bars represent total demand bids in monthly reconfiguration auctions. The solid section of each bar illustrates total supply or demand cleared in those auctions

Figure 2-13: Offers and Bids in Reconfiguration Auctions for CCP 7



Up until September, total supply offers (i.e. offers to take on a CSO) were below 650 MW. Since the beginning of the winter period in October, total supply offers increased and ranged from approximately 1,000 MW to 2,200 MW. The increase in supply has been met by an increase in demand. Demand bids gradually increased from 1,700 MW in August 2016, up to as high as 2,900 MW in March 2017. This trend in supply offers is consistent with prior years. The amount of demand bids would have been as high in April 2017, but two demand bids were denied for reliability reasons.

[19] The summer period spans June 1st to October 31st for generators and imports, while demand response summer period is June 1st to November 30th.

There were three bilateral periods that took place during Winter 2017. The transferred and acquired volume in megawatts by bilateral period and resource type are shown in Table 2-3.

Table 2-3: Bilateral Acquired and Transferred MW for Winter 2017

Month	Resource Type	Acquired MW	Transferred MW	Net MW
February 2017	Demand Response	2	62	(60)
	Generator	218	28	190
	Import	-	130	(130)
February 2017 Total		**220**	**220**	**-**
March 2017	Demand Response	1	35	(34)
	Generator	189	25	164
	Import	-	130	(130)
March 2017 Total		**190**	**190**	**-**
April 2017	Demand Response	2	53	(50)
	Generator	121	21	100
	Import	-	50	(50)
April 2017 Total		**124**	**124**	**-**

In the February, March, and April 2017 bilateral periods there were 220 MW, 190 MW, and 124 MW of capacity traded, respectively. Generating resources acquired most of the bilaterally traded MW, while import resources transferred the most, with the exception of April 2017. The volume-weighted prices were $2.51/kW-month in February, $2.48/kW-month in March, and $2.19/kW-month in April.

FCA 8 Commitment Period

The third annual bilateral window for the 2017-2018 commitment period took place in December 2016 and cleared 281 MW of capacity at a volume-weighted price of $4.89/ kW-month.[20] The compares to an initial clearing price for FCA 8 in NEMA/Boston of $15.00/kW-month for existing and new resources. In all other zones, the clearing price was $7.03/kW-month for existing resources and was $15.00/kW-month for new resources.

2.2 System Conditions

The following two subsections cover recent trends and outcomes in Net Commitment Period Compensation (NCPC), or uplift payments, and in flows of power between New England and its neighboring control areas in New York and Canada.

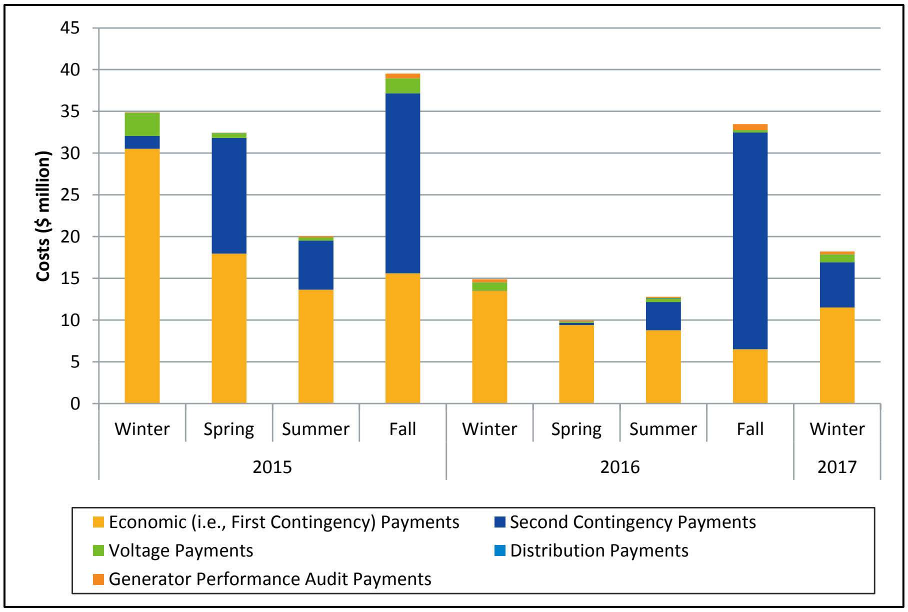
2.2.1 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) is a method of providing a make-whole payment to resources when energy market payments are insufficient to cover production costs. Resources committed and dispatched economically (in-merit), as well as resources dispatched out of

[20] The third bilateral period for capacity commitment period 8 was the first time resources could submit seasonal bilaterals. Seasonal bilaterals are entered into during the annual bilateral periods. Therefore, we add the amount traded to the annual total, and then take the twelve month average of annual and seasonal bilaterals to determine the amount trading during the annual bilateral period. See Section III.13.5.1 of the tariff for more information.

economic-merit order for reliability purposes, may require make-whole payments. NCPC is paid to resources for providing a number of services, including first- and second-contingency protection, voltage support, distribution system protection, and for generator performance auditing.[21] NCPC payments by season and category are illustrated in Figure 2-14.

Figure 2-14: NCPC Payments by Category ($ millions)



In Winter 2017, NCPC payments totaled $18.2 million, representing about 1% of total wholesale costs for the season, a similar share to the preceding two winters. In dollar terms, this is a 22% increase compared to the same season last year ($14.9 million), but 46% less than what was paid last quarter. These differences were mainly driven by changes in second contingency payments between the time periods.

The majority of NCPC (63%) incurred during the reporting period was for first contingency protection. Approximately $5.6 million (49%) of total first contingency NCPC was paid in the day-ahead market, while $5.9 million was paid in real-time. In comparison, $3.2 million was paid in day-ahead economic NCPC and $10.4 million in real-time economic NCPC in Winter 2016. The decrease in real-time first contingency payments in Winter 2017 compared to Winter 2016 can be largely explained by differences in the NCPC rules between the two periods. As mentioned in previous reports, at the end of Winter 2016, modifications to the NCPC rules were implemented that prevent generators from receiving compensation for real-time commitment costs for hours during which their commitment costs are evaluated for day-ahead NCPC compensation. It is estimated that $6.0 million in real-time first contingency NCPC was paid last winter to eligible generators under the prior rules.

[21] 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*.

Payments for second contingency protection accounted for 30% of total NCPC payments in the quarter. Similar to last quarter, the majority of these payments were made in a single load zone. Nearly $4.7 million (87%) of second contingency payments were made to generators in NEMA/Boston as transmission outages and upgrades limiting transfer capability within the load zone continued to result in additional reliability commitments. These committed generators were subsequently paid NCPC and made whole to their offers for periods during which they were committed for reliability and didn't recover their full costs though the LMP.

2.2.2 Net Interchange

New England is typically a net importer of power from both Canada and New York.[22] In the reporting period, New England was a net importer of 2,937 MW per hour, on average. The net import amount corresponds to hourly gross imports of 3,428 MW and gross exports of 491 MW, on average. Winter 2017 net imports were 23% higher than Fall 2016. Figure 2-15 shows the gross import and export power volumes and the net interchange amount by season.

Figure 2-15: Average Hourly Real-Time Imports, Exports, and Net Interchange

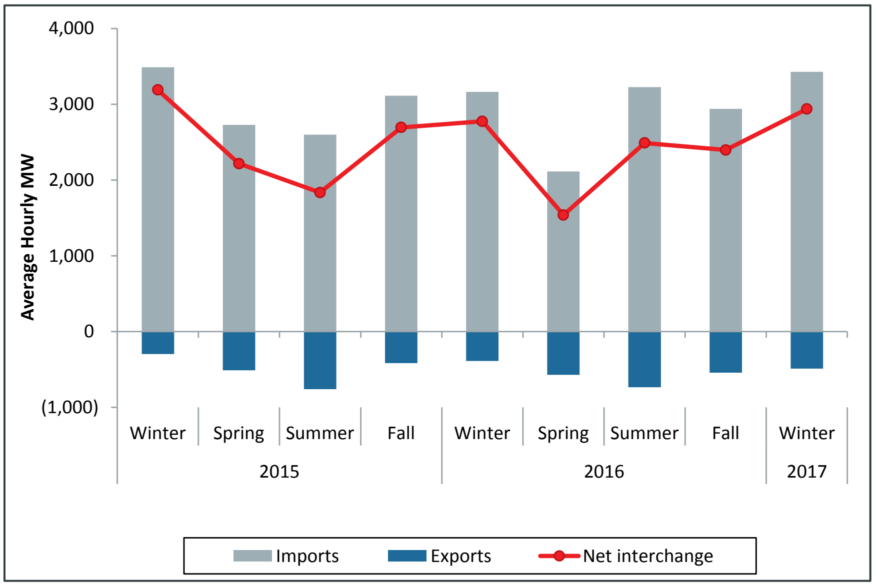


Figure 2-15 shows that net interchange has been seasonal in nature with the highest net imports during the winter season. Over recent years, New England energy prices have tended to be highest during the winter due to natural gas prices as discussed in section 2.1.3.1 above. Higher energy prices attract more transaction offers from participants seeking to profit from price spreads between New England and neighboring control areas. The hourly average Winter 2017 net interchange value of 2,937 MW was on par with the prior two winters. Winter 2016 net interchange was 162 MW per hour lower than Winter 2017, and Winter 2015 was higher by 252 MW per hour. Net imports in Winter 2017 were higher primarily at New York interfaces and about the same at the Canadian interfaces compared to Winter 2016.

[22] 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 Northport-Norwalk Cable that run between Connecticut and Long Island. The interconnections with Canada are the Phase II and Highgate interfaces that both connect with the Hydro Québec control area, and the New Brunswick interface.

Section 3
Summary of Forward Capacity Auction #11

This section presents a review of the eleventh Forward Capacity Auction (FCA 11), which was held in February 2017 and covers the capacity commitment period (CCP) beginning June 1, 2020 through May 31, 2021. The section provides an overview of the qualified capacity that participated in the auction. It subsequently covers auction outcomes, in terms of prices, cleared capacity and an assessment of market competitiveness. Finally, an overview of projected forward capacity market (FCM) payments is shown in the context of annual payments and prices since the first auction.

FCA 11 was the first auction to incorporate 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 impacts system reliability at various capacity levels. The sloped demand curves for constrained capacity zones allows more capacity to clear in the export-constrained zones (or less in the case of an import-constrained zone) at lower prices (or higher for import-constrained zones) compared to the system clearing price.[23] The full MRI system wide curve was not implemented for the FCA 11. Instead, 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.[24]

As discussed further below, there was a surplus of qualified and cleared capacity compared to the Net Installed Capacity Requirement (Net ICR). The auction cleared 35,835 MW, a surplus of 1,760 MW over NICR, at a price of $5.30/kW-month. Additionally, the zonal import or export constraints did not bind and therefore there was no price-separation among the capacity zones. There was an excess of capacity willing to import over the New Brunswick interface, which resulted in a lower export-constrained price of $3.38/kW-month for cleared resources at that interface.

The IMM concluded that the auction outcomes were the result of a competitive auction.

3.1 Resource Qualification

The amount of qualified capacity from new and existing resources compared to the capacity requirement provides an important indication of the level of potential competition in the auction. If the amount of qualified capacity is below NICR, then the system may be unable to meet resource adequacy planning criteria.[25] Depending on the degree to which the system is short and there is inadequate competition, the clearing price can reach the starting price.[26] Figure 3-1 below shows

[23] The capacity zones were Southeastern New England (SENE), Northern New England (NNE), and Rest-of-Pool (RoP). The SENE import-constrained capacity zone includes the NEMA/Boston, Southeastern Massachusetts, and Rhode Island load zones. The NNE export-constrained zone comprises the Maine, New Hampshire, and Vermont load zones.

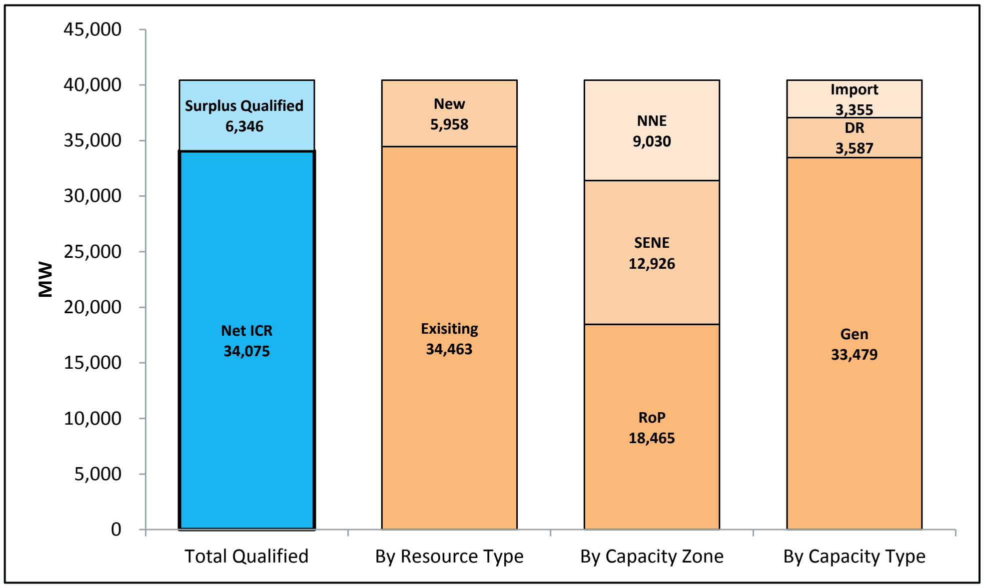
[24] The transition period begins with the eleventh FCA and can last for up to three FCAs, unless certain conditions relating to NICR growth are met, pursuant to Section III.13.2.2.1 of the Tariff.

[25] The Net Installed Capacity Requirement (NICR) is the amount of capacity (MW) needed to meet the region's reliability requirements (after accounting for tie benefits with Hydro-Quebec). Due to transmission limitations there are also local sourcing requirements (LSR) for import-constrained areas and maximum capacity limits (MCL) for export-constrained areas.

[26] The starting price is equal to 1.6 times the net cost of new entry (Net CONE). Net CONE is the netted value equals the estimated CONE net of revenues from energy, reserve, and other markets.

the qualified capacity that participated in the auction compared to NICR (blue bar on the left). The total qualified capacity in FCA 11 was roughly 40,400 MW. The three orange bars to the right show the breakdown of the total qualified capacity amount across three dimensions; resource type, capacity zone and capacity type.

Figure 3-1: Breakdown of the Qualified Capacity in FCA 11



The blue bar shows that there was a surplus of qualified capacity of about 6,350 MW, or almost 19%, above NICR. The first orange bar (by resource type) shows that the qualified capacity from existing resources exceeded the NICR by about 400 MW. There was also a significant amount of interest from new resources at about 6,000 MW, which was comparable to almost 6,500 MW in new qualified resources in FCA 10.

The second orange bar represents qualified capacity by capacity zone. There was sufficient qualified capacity in SENE compared to the Local Sourcing Requirement (LSR), at about 12,900 MW, which was roughly 3,100 MW over the local requirement. The NNE capacity zone had roughly 9,000 MW of qualified capacity, which was slightly over (by about 50 MW) the maximum capacity limit. If all new and existing resources in NNE stayed in the auction to $5.30/kW-month, then the price may have separated. As discussed in the next section, this was not the case.

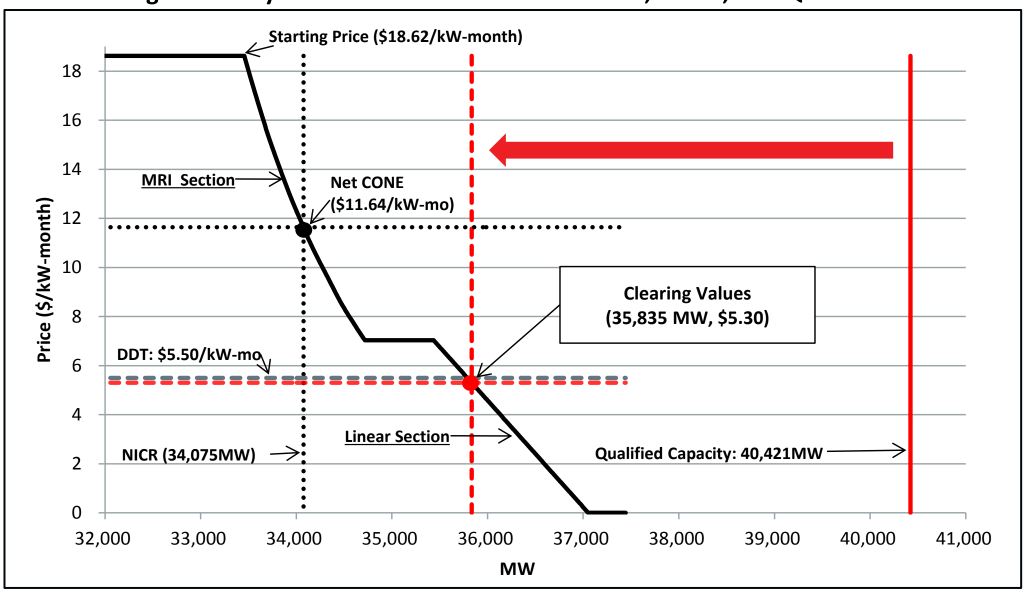
3.2 Auction Outcomes

In addition to the amount of qualified capacity eligible to participate in the auction, there are several other factors that contribute to the outcome. These factors include the auction parameters provided by the ISO as well as participant behavior, which are summarized in this section.

Figure 3-2 below shows the system-wide transitional demand curve (black solid line), which is the combination of the simple linear demand curve and convex MRI curve discussed above (labeled as the MRI Section and the Linear Section). The first sloped section of the demand curve, which begins at the starting price and ends at the horizontal section, is based on the MRI methodology. The horizontal section of the curve begins at the FCA 10 clearing price of $7.03/kW-month and is 720 MW long. The demand curve then becomes linearly sloped down to $0/kW-month. The curve shows the price that load is willing to pay at various levels of capacity, which in turn provides various levels of system reliability. For example, at the NICR value of 34,075 MW, which meets the 1-in-10 year reliability criterion,[27] load is willing to pay the Net Cost of New Entry (Net CONE) price of $11.64/kW-month (the intersection of the dotted black lines).

On the supply side, the qualified and cleared capacities are shown (solid and dashed red lines, respectively). The clearing price of $5.30/kW-month is shown at the intersection of the cleared MW (dotted red line) and the demand curve. This is just below the dynamic de-list bid threshold price of $5.50/kW-month. When clearing prices fall below this threshold, existing resources (that do not have a static or permanent de-list bid in the auction) can actively submit prices in the auction. It also serves as an important threshold for market power mitigation, whereby an existing resource that submits bids above this level is subject to a cost review by the IMM and potential market power mitigation.

Figure 3-2: System-wide FCA 11 Demand Curve, Prices, and Quantities



The descending clock auction closed in the fifth round as qualified capacity exited, and the solid red line moved towards the dotted red line. The auction cleared below the dynamic de-list threshold of $5.50/kW-month when a resource dynamically de-listed and caused supply to fall short of demand, thereby setting the marginal clearing price. The marginal resource submitting the dynamic de-list bids was then rationed to allow for demand to exactly equal supply. The auction cleared 35,835 MW at a price of $5.30/kW-month. As shown in Figure 3-2, supply met demand and price was set along the linear sloped portion of the transitional demand curve. If the ISO had fully implemented the MRI demand curve, then the clearing price would have been lower with less capacity cleared, assuming no change in offer behavior.

There was no price separation between the Rest-of-Pool, the SENE and the NNE zones. There was price separation at the New Brunswick interface, which still had 700 MW of excess capacity over its capacity transfer limit participating in the auction at the end of round five. The auction continued into the sixth round and cleared at a price of $3.38/kW-month. New Brunswick was similarly export-constrained in the prior auction, FCA 10. The New York AC ties interface was also export-

[27] 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"

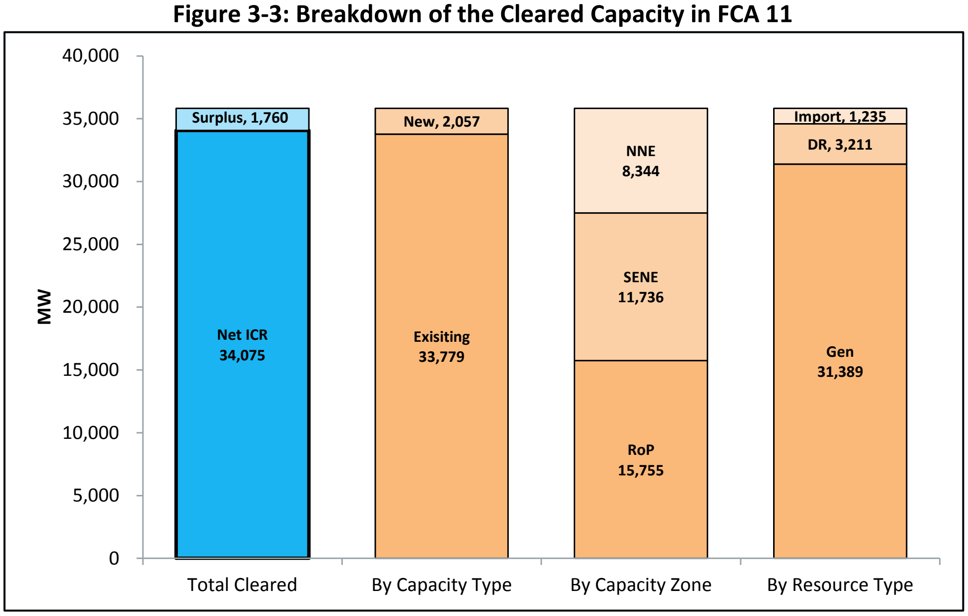
constrained in FCA 10 but was not in FCA 11. In FCA 11, only 530 MW cleared behind the interface, even though the capacity transfer limit was 1,400 MW. This may be due to the expectation of higher prices in New York during the FCA 11 commitment period.

The IMM determined that the outcomes discussed above were the result of a competitive auction. There was a sufficient amount of qualified resources participating in the auction. Further, the capacity market qualification process includes the application of rigorous mitigation rules on existing and new resources. While several of the existing resources were offered into the market by pivotal suppliers, none of the pivotal suppliers had active static de-list bids or offers from new import capacity resources (that are treated similarly to existing resources). Because there were no bids from pivotal suppliers, the IMM did not have to apply market power mitigation to the existing resources belonging to pivotal suppliers.[28] Further, as with existing resources, new capacity resources undergo a mitigation review if the proposed new resource offer floor price is below the relevant competitive benchmark (i.e. the offer review trigger price).

3.3 Cleared Resources

The amount of cleared capacity in FCA 11 exceeded system-wide and capacity zone requirements. The amount of cleared capacity is shown in Figure 3-3 below across several dimensions: constraints, capacity type, and resource type. Each of the bars in Figure 3-3 is equal to the total amount of capacity cleared.

Figure 3-3: Breakdown of the Cleared Capacity in FCA 11

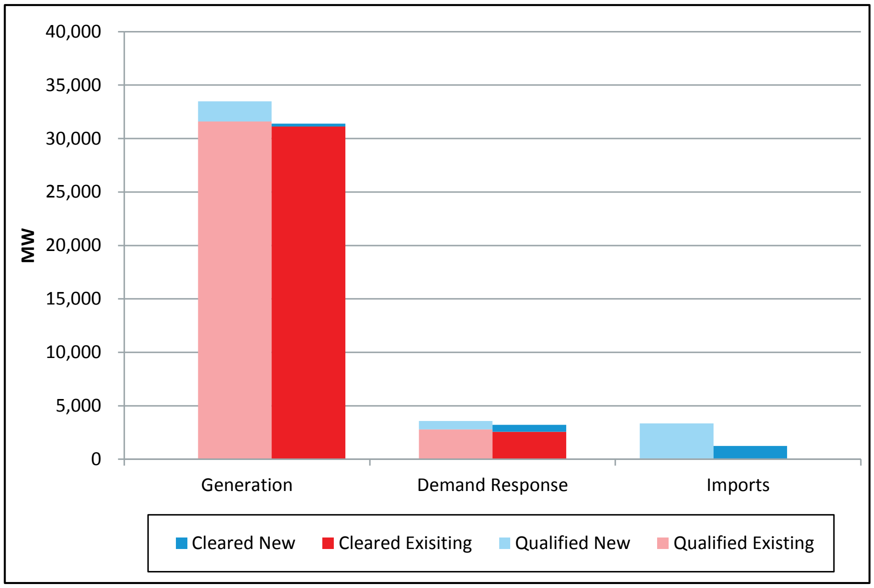


The blue bar shows that cleared capacity exceeded NICR by nearly 1,800 MW, or by over 5%. Moving to the right, the first orange bar (by capacity type) shows that new resource capacity accounted for 6%, or about 2,000 MW, of total cleared capacity. By capacity zone (second orange bar), the cleared amount in NNE was roughly 600 MW short of the maximum capacity limit, and therefore the zonal export constraint was not binding. Neither was the SENE import-constraint; cleared capacity located within the SENE zone was roughly 1,900 MW over the LSR.

[28] See Attachment D page 4 for more information: https://www.iso-ne.com/static-assets/documents/2016/02/er16-___-000_2-29-16_fca_10_results_filing.pdf

Figure 3-4 illustrates qualified and cleared capacity by resource type; generation, demand response and imports. The light red and light blue columns represent *qualified* existing and new capacity, respectively, while the dark red and dark blue columns represent *cleared* existing and new capacity, respectively.

Figure 3-4: Qualified and Cleared Capacity by Resource Type in FCA 11



The highest ratio of qualified to cleared new capacity was among demand response resources. New demand response resources qualified 800 MW of capacity, and cleared 640 MW. Of the 640 MW, passive demand response resources cleared 555 MW of capacity, and active demand response cleared 85 MW.[29] There was 1,800 MW of qualified new capacity from generation, and only 260 MW cleared in the auction. One generating resource, which accounted for 200 MW, was a repowering project, and qualified as a new capacity resource having met the relevant capital expenditure provisions in the tariff.[30]

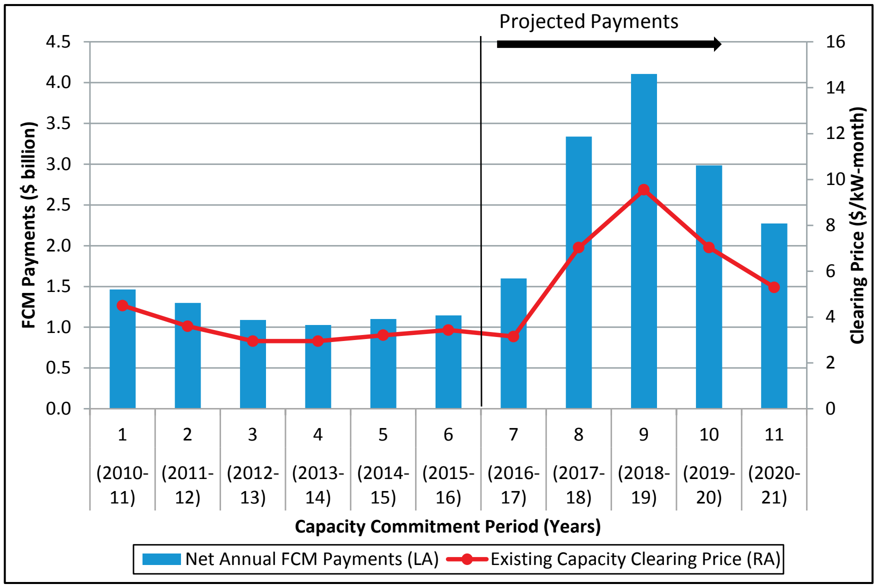
3.4 Estimated FCM Payments

Figure 3-5 below shows capacity market payments (left axis [LA]) alongside the Rest-of-Pool clearing prices (rights axis [RA]) for capacity commitment periods 1-11. CCP 7-11 are estimated payments as they have not been settled and are subject to adjustments.

[29] Passive resources include energy efficiency and load reducing distributing generation projects that provide long term peak capacity reduction. Active demand response resources are dispatchable resources that provide reliability during demand response events.

[30] Repowering involves a large incremental increase in capacity due to upgrades. Once the resource clears new supply, the existing capacity will be permanently de-listed at the start of the commitment period. See Market Rule III.13.2.3.2 (e) for more information.

Figure 3-5: FCM Payments and Res-of-Pool Prices by Commitment Period



Since peak prices in FCA9, clearing prices have declined in both FCAs 10 and 11, resulting in lower projected payments during the corresponding commitment periods. Clearing prices fell 26% to $7.03/kW-month in FCA 10 compared to FCA 9. The projected payments fell from $4 billion dollar in CCP 9 to $3 billion in CCP 10. The system-wide clearing price further declined to $5.30/kW-month in FCA 11. Projected payments are estimated at approximately $2.3 billion, which is the lowest total since FCA 7.