ISO New England's Internal Market Monitor

Winter 2016

Quarterly Markets Report

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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 administered by the ISO 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, 2015 to February 29, 2016 (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:

[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").

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

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

Section 1
Executive Summary

This report presents metrics and analysis of the performance of ISO New England wholesale electricity and related markets for the Winter of 2016 (December 2015 through February 2016).[3]

1.1 Summary of Market Outcomes and Performance

- The total estimated wholesale market costs were $1.34 billion in the reporting period, a 57% decrease compared to the same period in 2015 (Winter 2015).
    - Lower natural gas prices were the primary driver for the decrease in total energy costs. Natural gas prices averaged $3.35/MMBtu. This is a 68% decrease from Winter 2015.
- In Winter 2016, the average hourly demand was 14,304 MW, compared to 15,606 MW in the same season of 2015, a decrease of over 8%. This decrease is explained by milder winter weather. The average temperature in Winter 2016 was 35°F, a large increase compared to the average temperature of 25°F in Winter 2015. The peak real-time load, which occurred on February 15, 2016 during the reporting period, was 19,524 MW, 5% lower than the peak load observed in Winter 2015.
- Day-ahead and real-time energy market prices at the Hub averaged $30.32/MWh and $27.58/MWh respectively. Day-ahead prices were 61% lower and real-time prices were 64% lower than Winter 2015 prices. These outcomes were driven by low natural gas prices and lower demand.
- Total real-time reserve payments were $2.2 million, a $5.4 million decrease from Winter 2015, and Regulation payments totaled $5.3 million, a $3.0 million decrease. The decrease in total real-time reserve payments compared to Winter 2015 was due to mild temperatures and lower loads throughout the reporting period, which contributed to the lower reserve prices and pricing frequencies. Regulation payments declined from Winter 2015 levels as the result of reduced natural gas and electricity market prices.
- Net Commitment Period Compensation (NCPC) payments totaled $15.6 million, a 55% decrease from Winter 2015. The decrease in real-time NCPC payments in Winter 2016 was largely attributable to a drop in second contingency NCPC payments. Milder winter weather and lower loads, compared to previous winters, resulted in fewer resources called on to provide local second contingency protection.
- The tenth Forward Capacity Auction (FCA 10) was held on February 8, 2016. The auction clearing price was $7.03/kW-month for all resources within New England

[3] In previous Quarterly Markets Reports, market outcomes were covered by calendar quarter. With this and future quarterly reports, outcomes will be reviewed by season as follows: Winter (December through February), Spring (March through May), Summer (June through August) and Fall (September through November).

and imports from Québec. The clearing price for New York imports was $6.26/kW-month, and $4.00/kW-month for New Brunswick imports. The auction procured 35,567 MW of capacity and satisfied the capacity requirement of 34,151MW. Of the 35,567 MW procured, 1,800MW (or 5%) comprised new capacity, with 1,459 from new generation resources and 371 MW from new demand resources. The IMM concluded that the outcome of the auction system-wide was competitive. Section 3 includes a detailed discussion of the tenth FCA.

Section 2
Summary of Market Outcomes and System Conditions

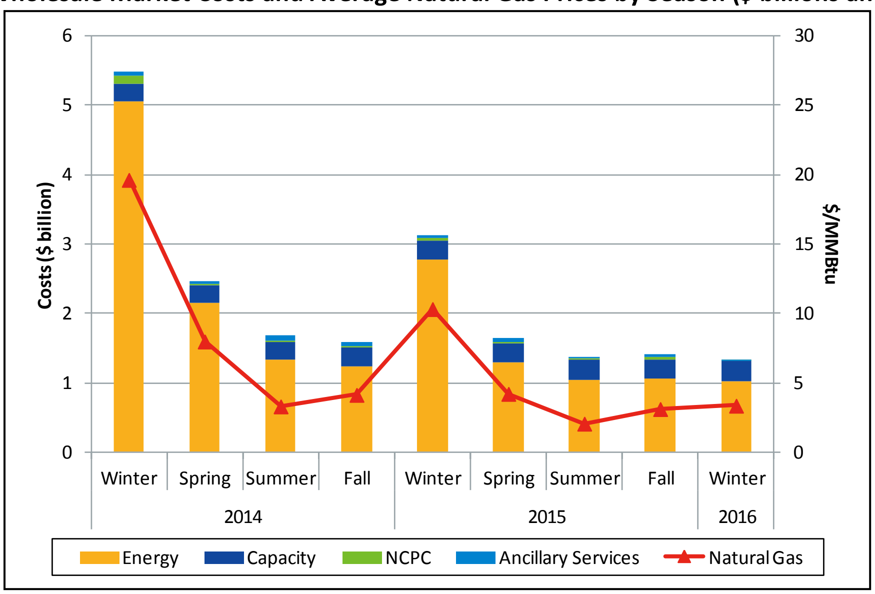
This section summarizes the region's wholesale electricity market outcomes and measures of market performance and competitiveness.

2.1 Market Outcomes

2.1.1 Total Wholesale Electricity Market Value

In Winter 2016, the total estimated market cost decreased by about 57% compared to the same season last year ($1.34 billion compared to $3.13 billion), and decreased by 5% when compared to Fall 2015 ($1.40 billion).[4] Winter 2016 Net Commitment Period Compensation (NCPC) costs of $16 million were 55% lower than Winter 2015 NCPC costs and 60% lower than Fall 2015 NCPC costs. Ancillary service costs, which include reserve and regulation payments, totaled $19 million in Winter 2016, a decrease of 64% when compared to Winter 2015 and a decrease of 26% when compared to Fall 2015, respectively. Figure 2-1 shows the estimated wholesale electricity cost for each season (in billions of dollars) by market, along with average natural gas prices (in $/MMBtu).

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



As illustrated in Figure 2-1, natural gas prices were a key driver behind changes in energy costs. The decrease in natural gas prices in Winter 2016 compared to Winter 2015 resulted in lower energy costs. There was a slight decrease in energy costs in Winter 2016 compared to Fall 2015, despite higher average load levels and higher average natural gas prices in the winter months. This was driven by a number of factors. First, in Fall 2015 there were a significant number of outages of large baseload generators, meaning that less efficient and more expensive generation resources

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

were needed to meet load. Second, Fall 2015 had higher peak loads particularly during the first two weeks of September with high temperatures, resulting in relatively higher energy prices. Finally, there were fewer instances of reserve pricing in Winter 2016 compared to Fall 2015, which resulted in significantly lower real-time reserve payments (see Section 2.1.3.3).

2.1.2 Key Market Statistics

Table 2-1 shows selected key statistics for load levels, real-time and day-ahead energy market prices, and fuel prices.

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

	Winter 2016	Fall 2015	Percent Change Winter 2016 to Fall 2015	Winter 2015	Percent Change Winter 2016 to Winter 2015
Real-Time Load (GWh)	31,241	29,649	5%	33,709	-7%
Weather Normalized Real-Time Load (GWh)	31,947	29,317	9%	32,946	-3%
Peak Real-Time Load (MW)	19,524	24,368	-20%	20,583	-5%
Average Day-Ahead Hub LMP ($/MWh)	30.32	32.47	-7%	77.51	-61%
Average Real-Time Hub LMP ($/MWh)	27.58	31.53	-13%	76.64	-64%
Average Natural Gas Price ($/MMBtu)	3.35	3.11	8%	10.31	-68%

The following factors contributed to the differences in Winter 2016 market outcomes compared to Winter 2015:

- Lower natural gas prices in Winter 2016 were the primary driver for lower day-ahead and real-time prices when compared to the same season last year.
    - Natural gas prices during the reporting period decreased by 68% from Winter 2015.
    - Oil prices were also 48% lower during the reporting period compared to Winter 2015.
- The real-time load in Winter 2016 was 7% lower than the real-time load in Winter 2015.
- The peak real-time load, which occurred on February 15, 2016, was 19,524 MW, 5% lower than the peak load observed in Winter 2015.

2.1.3 Real-Time Markets

2.1.3.1 Real-Time Energy Market

The average real-time Hub energy price was $27.58/MWh in the reporting period. Real-time energy prices in Winter 2016 were markedly lower than the two preceding winters, down 80% compared to Winter 2014 and 64% compared to Winter 2015. This decline in winter season energy prices tracks very closely with the decline in natural gas prices over the same period. Winter 2016 natural gas prices dropped significantly compared to both the Winter 2014 and Winter 2015 seasons (*i.e.*, 83% and 68%, respectively). Energy prices did not differ significantly among the load zones.[5] Figure 2-2 shows the seasonal average real-time energy prices and the estimated cost of gas generation based on a unit heat rate of 7,800 Btu/kWh and the Tennessee Gas Pipeline Zone 6 index price.

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

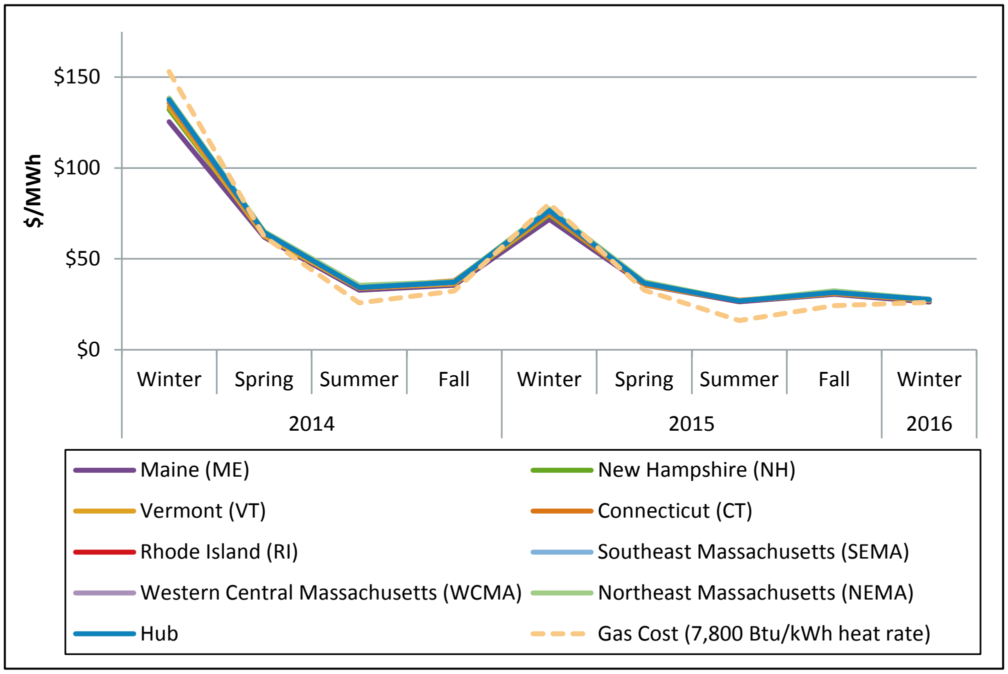


Figure 2-2 illustrates that average real-time energy prices tend to track closely with the cost of natural gas. This is shown by the movement in the zonal energy price trend lines and the natural gas cost trend line. As discussed in Section 2.1.1, there was a slight reversal in this trend between Fall 2015 and Winter 2016 when, despite higher natural gas prices, energy prices were lower. This was the result of a significant number of outages of baseload generation in Fall 2015, peakier load in the Fall compared to Winter and fewer instances of real-time reserve pricing in Winter 2016. As discussed in Section 2.1.2, Winter 2016 gas prices and peak and average load values were lower than Winter 2015 values. These factors are, in large part, why Winter 2016 energy prices were well below those of prior winters. According to the U.S. Energy Information Administration (EIA), increases in domestic natural gas production, above-average storage inventories, and lower heating demand during the 2015-16 winter season contributed to gas prices falling well below recent historical prices.[6]

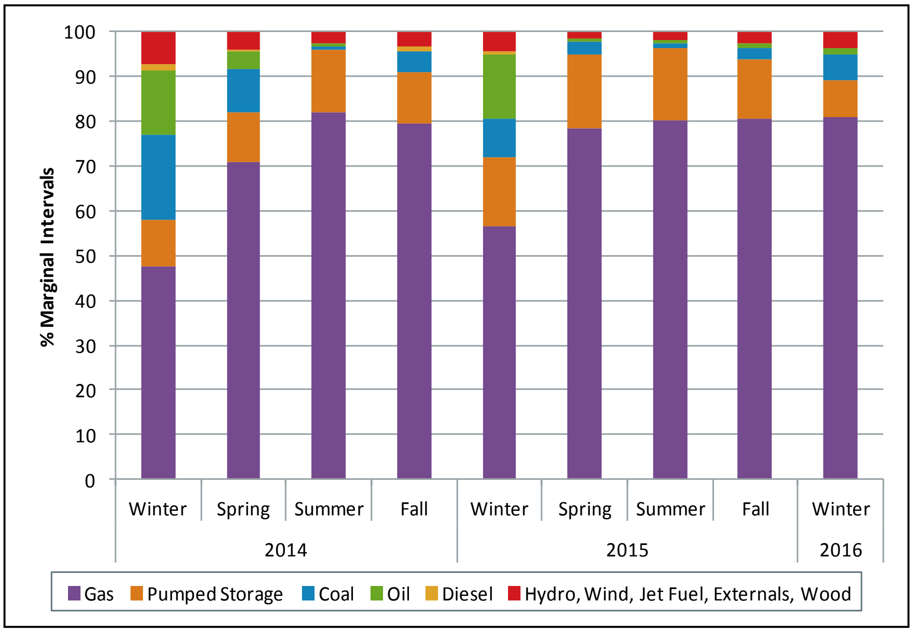
The LMP at a pricing location is set by the cost of the next megawatt the ISO would dispatch to meet an incremental change in load at that location. The resource that sets price is called the marginal unit. The price of electricity changes as the price of the marginal unit changes and the price of the marginal generating unit is largely determined by its fuel type and heat rate. Because of this,

[5] 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.

[6] US Energy Information Administration. Short Term Energy Outlook January 2016. Washington, DC: US Department of Energy, January 2016. https://www.eia.gov/forecasts/steo/archives/Jan16.pdf. Pages 9 – 10.

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 by Season



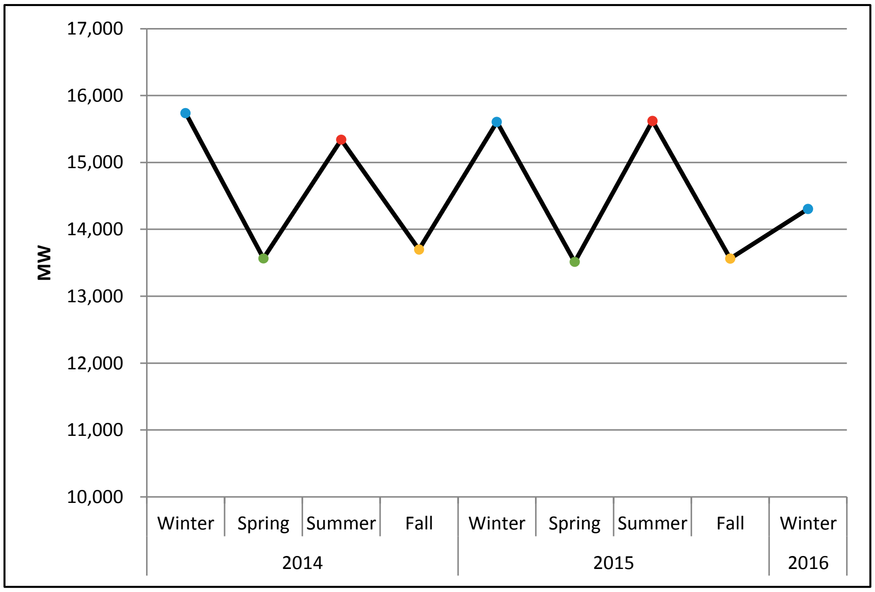
In the reporting period, units burning natural gas were marginal (*i.e.*, setting the price) during 81% of the pricing intervals, followed by pump storage units (including pumping demand), which were marginal in 8% of the pricing intervals. Units burning coal, oil, diesel, jet fuel, wood, traditional hydro units, and external transactions were marginal in the remaining pricing intervals.

As seen in the figure above, gas displaced oil as the price-setting fuel in a number of intervals in Winter 2016 compared to the last two winters. This is because gas prices in Winter 2016 were, on average, significantly lower than gas prices in the last two winters, and were significantly lower relative to oil prices. Additionally, the Winter 2016 average real-time load was also lower than the previous two winters, meaning that load could be satisfied with relatively less expensive generation.

2.1.3.2 Load Summary

Figure 2-4 illustrates average hourly load by seasonal quarter. 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

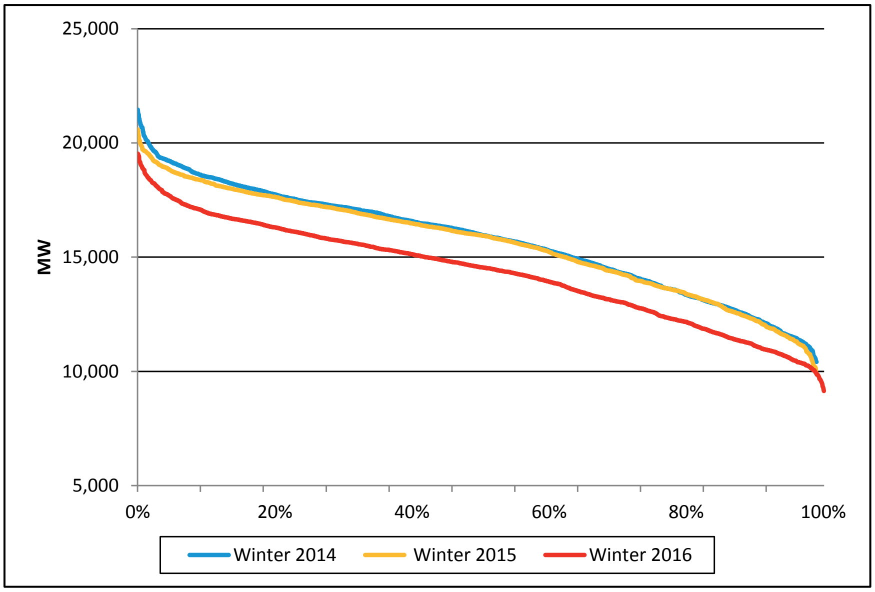


As shown in Figure 2-4, the average hourly load in the reporting period was lower than average load levels in the past two winter seasons. In Winter 2016, the average hourly load was 14,304 MW. This was an 8% decrease compared to the Winter 2015 value of 15,606 MW.[7] Warmer temperatures in Winter 2016 help explain why the average hourly load was lower compared to the past two winter seasons. The average temperature in Winter 2016 was 35°F, a large increase compared to the average temperature of 25°F in Winter 2015.

Another way to examine load is to sort all the hourly load values (i.e. 2,184 hourly values in the reporting period) from highest to lowest for any given period. The resulting curve is called a *load duration curve.* By plotting several seasonal load duration curves, one can easily observe differences between periods. Also, since the load duration curves have the same number of observations (hours), the horizontal axis can be expressed as a percentage of the total number of hours in the period of interest as shown in Figure 2-5. The percent axis allows one to quickly view what percentage of hours are above or below a particular load level.

[7] The terms "demand" and "load" are used interchangeably and are intended to have the same meaning in this report.

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



The figure illustrates the same trend as Figure 2-4 above, that loads were consistently lower in winter 2016 when compared to 2014 and 2015.

The peak hourly demand in the reporting period occurred on February 15 at 7:00 PM and was 19,524 MW. This was lower than the Winter 2015 peak of 20,583 MW, which occurred on January 8. The lowest hourly demand in the reporting period occurred on December 26 at 3:00 AM and was 9,136 MW. Total energy sales were 31,241 GWh in the reporting period, a decrease of 7% compared to Winter 2015's sales of 33,708 GWh.

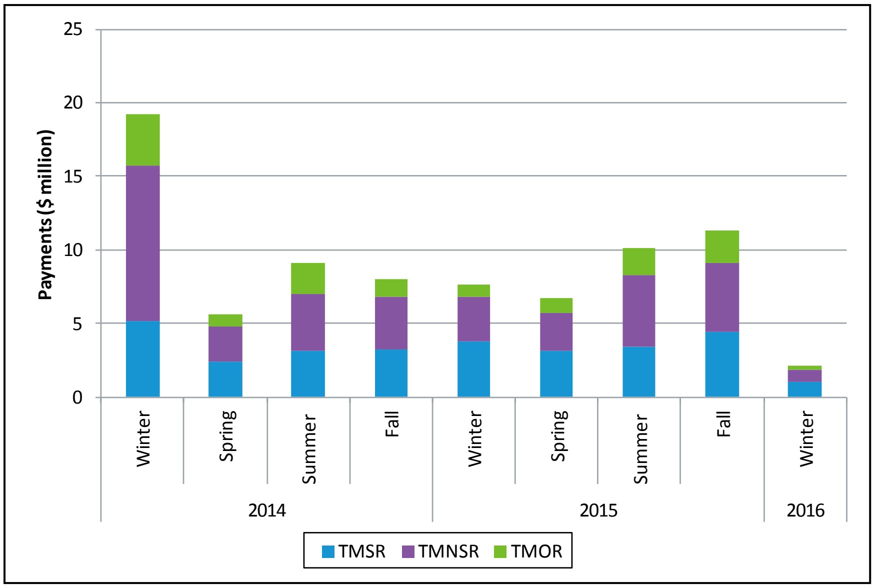
2.1.3.3 Real-Time Operating Reserves

Total real-time reserve payments were $2.2 million in Winter 2016, a 71% decrease compared to Winter 2015 payments of $7.6 million.[8] The decrease in total payments compared to Winter 2015 was primarily the result of lower prices and pricing frequencies for all reserve products. The frequency of ten minute spinning reserve (TMSR) pricing decreased from 6.8% to 5.1%, the frequency of ten minute non-spinning reserve (TMNSR) pricing decreased from 0.5% to 0.3%, and the frequency of thirty minute operating reserve (TMOR) pricing decreased from 0.5% to 0.3%. Average non-zero TMSR prices decreased from $38.37/MWh to $17.98/MWh, average non-zero TMNSR prices decreased from $362.55/MWh to $108.28/MWh, and average non-zero TMOR prices decreased from $336.51/MWh to $108.28/MWh. Real-Time reserve payments also decreased by 81% compared to Fall 2015 payments of $11.4 million for similar reasons.

Figure 2-6 shows the total real-time reserve payments by season from Winter 2014 through Winter 2016.

[8] Payment data represent total payments for Real-Time reserves, and are not net of settlement adjustments for forward reserve obligation charges.

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

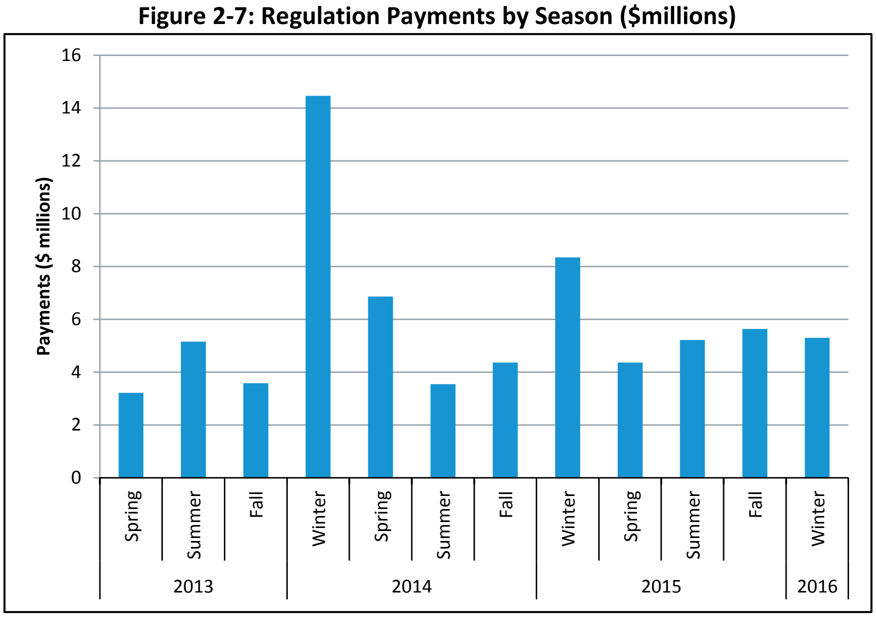


As shown in Figure 2-6, the real-time reserve payments were significantly lower in Winter 2016 compared to the past two winters. This was due to mild temperatures and lower loads throughout the reporting period, which contributed to the lower reserve prices and pricing frequencies. Additionally, as seen in the figure above, operating reserve payments can vary significantly over time. This is the result of a variety of factors including system and resource conditions, fuel prices, Real-Time LMP variation, and changes to operating reserve requirements and pricing rules.

2.1.3.4 Regulation Market

Total regulation market payments were $5.3 million during the reporting period, down 6% from $5.6 million in Fall 2015, and down 36% from $8.3 million in Winter 2015. Payments declined significantly from Winter 2015 levels as a result of significantly reduced natural gas and electricity market prices. Quarterly regulation payments are shown in Figure 2-7 below.

Figure 2-7: Regulation Payments by Season ($millions)

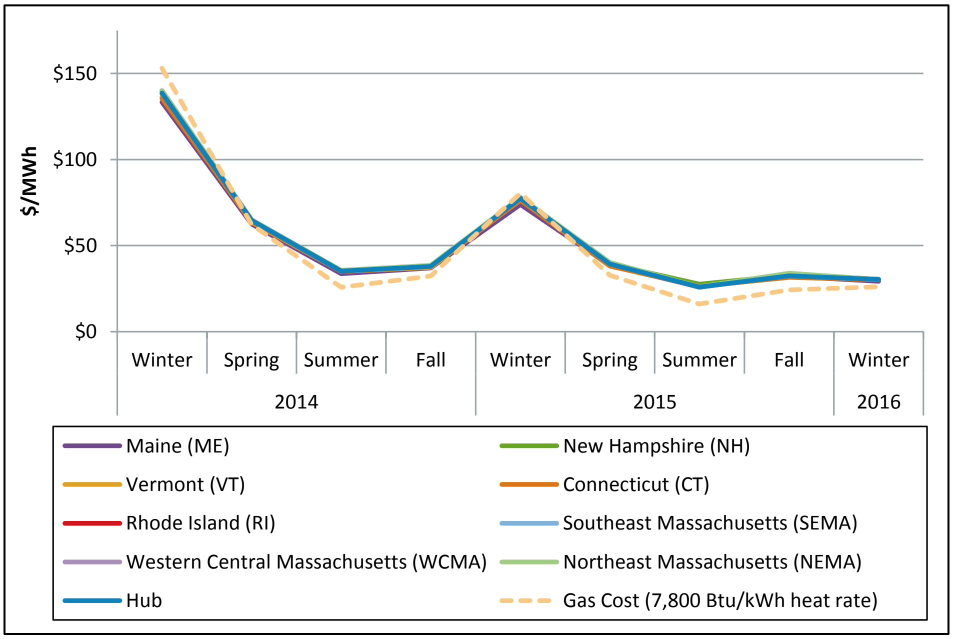


2.1.4 Forward Markets

2.1.4.1 Day-Ahead Energy Market

The average day-ahead Hub price for Winter 2016 was $30.32/MWh, a decrease of 7% from the Fall 2015 average of $32.47/MWh. Day-ahead energy prices remained correlated with natural gas prices and were lower than preceding winters by similar magnitudes as those discussed of real-time prices in Section 2.1.3.1. Prices did not differ significantly among the load zones. Figure 2-8 below depicts seasonal quarterly average day-ahead energy prices and estimated cost of gas generation (assuming a unit heat rate of 7,800 Btu/kWh and the Tennessee Gas Pipeline Zone 6 index price).

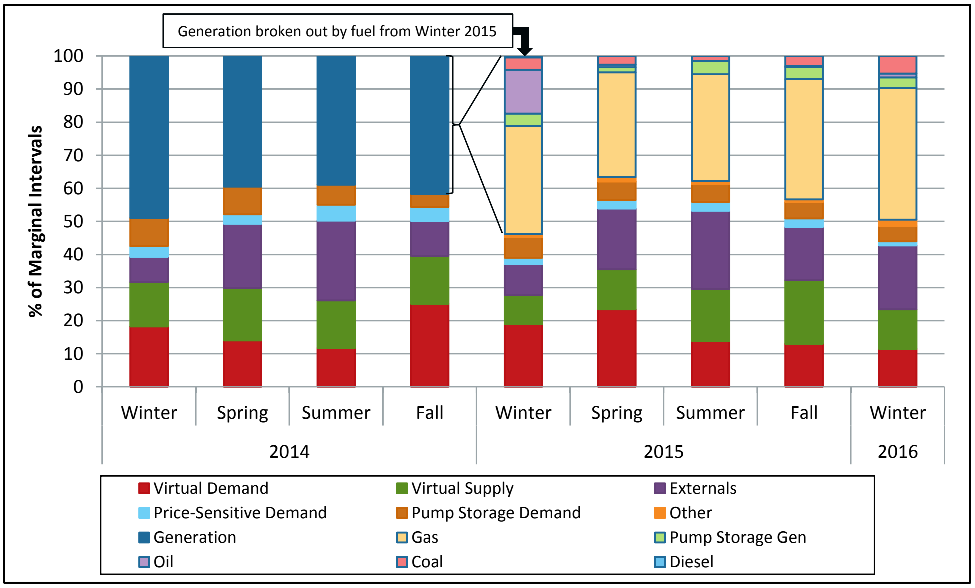
Figure 2-8: Simple Average Day-Ahead Prices and Gas Generation Costs by Season



As shown in Figure 2-8, average day-ahead energy prices decreased relative to Fall 2015 prices and were down significantly relative to prices in the two preceding winter periods. Day-ahead energy prices in this most recent winter were 78% lower compared to Winter 2014 and 61% lower compared to Winter 2015. As discussed in Section 2.1.3.1, the downward trend in energy prices tends to track very closely with trends in natural gas prices as domestic gas production outpaced demand in 2015. The average day-ahead Hub price was roughly 10% higher than the average real-time Hub price of $27.58/MWh (Section 2.1.3.1).

Figure 2-9 below shows the percentage of time that each resource type set price in the day-ahead market since Winter 2014. Beginning in 2015, the graph illustrates a breakdown of the generators category (large blue bar, years 2011-2014) by generator fuel type (bars outlined in blue). With the introduction of Energy Market Offer Flexibility (EMOF) in December 2014, generators submit information regarding fuel in their supply offer. This provides better information on the fuel underlying the marginal unit than existed prior to EMOF. The metric has been adjusted accordingly starting with Winter 2015.

Figure 2-9: Day-Ahead Marginal Units by Fuel Type by Season

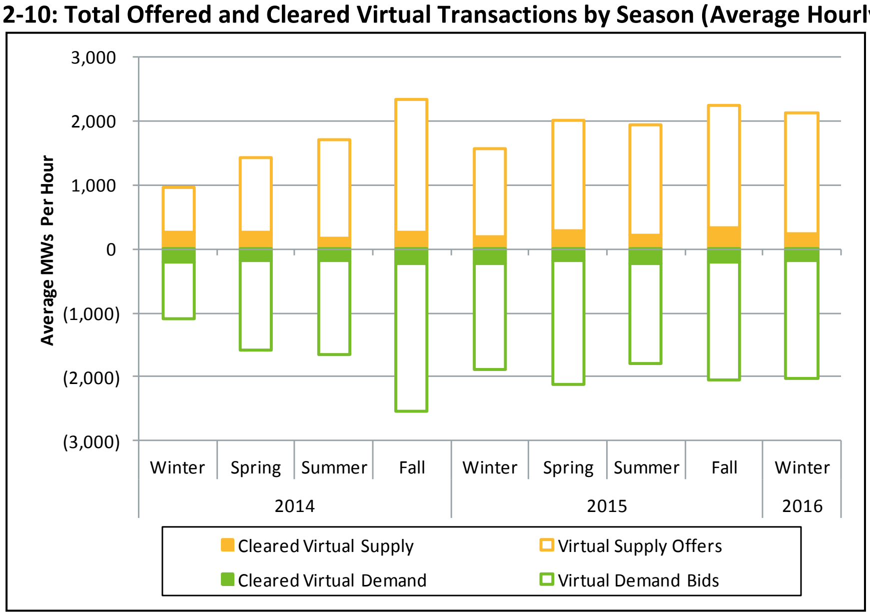


Similar to the real-time market, low gas prices and relatively low load levels led gas-fired generators to be marginal in more price-setting intervals than generators of any other fuel type. In addition to generators, there are many other entities that can set price in the day-ahead market, including price-sensitive demand, priced external transactions, and virtual transactions.

During the reporting period, generators set price approximately 51% of the time in the day-ahead market. Virtual transactions (virtual supply and demand) set price approximately 23% of the time, and external transactions set price approximately 19% of the time. Price-sensitive demand (including pump storage demand) was marginal in the remainder of the price-setting intervals at 6%.

Figure 2-10 shows virtual transaction volumes from Winter 2014 through Winter 2016.

Figure 2-10: Total Offered and Cleared Virtual Transactions by Season (Average Hourly MW)



In the reporting period, submitted virtual demand bids and virtual supply offers averaged approximately 4,162 MW per hour, a 3% decrease when compared with Fall 2015, and a 20% increase when compared with Winter 2015. Cleared virtual transactions decreased by 21% compared with Fall 2015 and decreased by 1% when compared with Winter 2015. In the reporting period, 10% of the megawatt quantity of virtuals bids and offers cleared in the day-ahead market.

2.1.4.2 Financial Transmission Rights

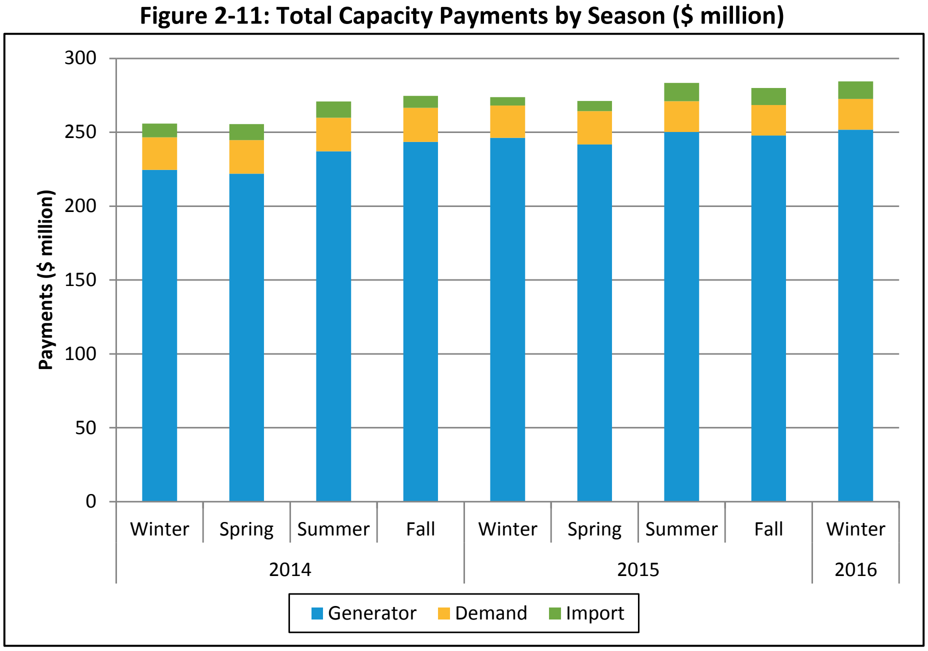
Three Financial Transmission Rights (FTR) auctions were conducted during the reporting period for a combined total of 86,526 MW of FTR transactions. The total amount distributed as Auction Revenue Rights (ARRs) was $1.7 million. Thirty-two bidders in December, thirty-five bidders in January and thirty-four 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 systemwide resource adequacy requirements. 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. If the capacity market does not replace this "missing" revenue, suppliers could not expect to recover their total costs and would not enter the marketplace—or would soon exit. In this event, additional demand would go unserved and reliable service would not be achieved. 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.

Payments. Figure 2-11 shows the total FCM payments by resource type for Winter 2014 through the end of the reporting period.

Figure 2-11: Total Capacity Payments by Season ($ million)



In Winter 2016, capacity payments totaled $285 million, and the forward capacity auction initial supply credit was based on a clearing price of $3.43/kW-month.[9] The supply credit paid for capacity supply obligations (CSO) can be adjusted based upon bilateral and reconfiguration auction activity, computed values for Peak Energy Rent (PER), the participation of the ISO in reconfiguration auctions, and actual resource performance, which are accounted for in the data above.

Auctions. Reconfiguration auctions take place before and during the capacity commitment period[10] to allow participants with CSOs to trade out of their positions with other participants that wish to assume additional CSOs. Annual reconfiguration auctions (ARAs) allow participants to acquire one-year commitments and are held approximately two years, one year, and just before the capacity commitment period begins. Monthly reconfiguration auctions are held beginning with the first month of a capacity commitment period and adjust the annual commitments during the commitment period.

Several monthly reconfiguration auctions were conducted and contracts were bilaterally traded during the reporting period. Monthly reconfiguration auctions and bilateral trades for the months of February, March, and April 2016 took place during the reporting period. There was one annual bilateral trade period conducted in the reporting period.

Annual reconfiguration auction (ARA). The third annual bilateral trade period (including the third annual reconfigureation auction) for the 2016-2017 commitment period took place in December 2015 and exchanged 285.8 MW in capacity at $3.33/kW-month.

Monthly reconfiguration auctions. Figure 2-12 shows bid/offered and cleared MWs by monthly auction. Supply offers are offers to sell (or shed) capacity while demand bids are bids to buy capacity.

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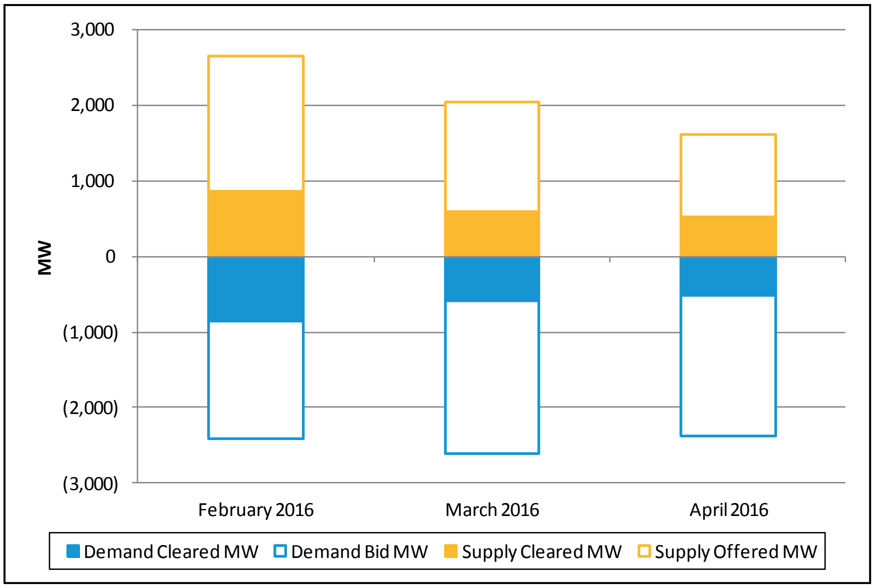
[9] The clearing price for the 2015/16 capacity commitment period (FCA 6) was set by an administrative floor price.

[10] 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 2-12: Bid/Offered and Cleared MW, February-April 2016 Monthly Reconfiguration Auctions



The reconfiguration auctions cleared significantly below the annual price of $3.43/kW-month from the primary auction. The clearing prices for the February, March, and April 2016 reconfiguration auctions were $0.92, $0.50, and $0.55 per kW-month, with cleared capacity in each auction being 854 MW, 595 MW, and 518 MW respectively. For most auctions the reconfiguration prices have been lower than the FCA price. In FCA 1 through FCA 7, there was an abundance of capacity and many FCA prices cleared at the floor. There is no floor in reconfiguration auctions and in some cases the monthly price cleared close to $0/kW-month. The floor price was eliminated in the primary auction starting with FCA 8.

Bilateral contract periods. Table 2-2 shows acquired and transferred MW by resource type for the three bilateral trading periods in the reporting period.

Table 2-2: Acquired and Transferred MW for the February-April 2016 Bilateral Contract Periods[11]

Month	Resource Type	Acquired MW	Transferred MW	Net MW
February 2016	Demand Response	18	56	(37)
	Generator	195	88	107
	Import	0	70	(70)
February 2016 Total		214	214	0
March 2016	Demand Response	17	64	(47)
	Generator	185	67	117
	Import	0	70	(70)
March 2016 Total		201	201	0
April 2016	Demand Response	25	76	(51)
	Generator	128	7	121
	Import	0	70	(70)
April 2016 Total		153	153	0
Total Winter 2016		**1,137**	**1,137**	***0***

Exchanged MWs in the bilateral trading periods ranged from 153 MW to 214 MW. Capacity-weighted prices for the bilateral trading periods were $1.82/kW-month in February, $1.96/kW-month in March, and $2.73/kW-month in April, compared to a clearing price of $3.43/kW-month in the primary FCA.

2.2 System Conditions

2.2.1 Net Commitment Period Compensation

In Winter 2016, total Net Commitment Period Compensation (NCPC) payments totaled $15.6 million. This is a 55% decrease compared to the same season last year ($34.9 million) and 60% decrease compared to Fall 2015 ($39.3 million).

NCPC is a method of providing a make-whole payment to resources when market payments are insufficient to cover production costs. Resources committed and dispatched economically (in-merit), as well as resources dispatched out of economic-merit order for reliability purposes, may require make-whole payments. NCPC is paid to resources for providing first- and second-contingency protection, voltage support and control, and distribution system protection in either the day-ahead or real-time energy markets, and for generator performance auditing.[12]

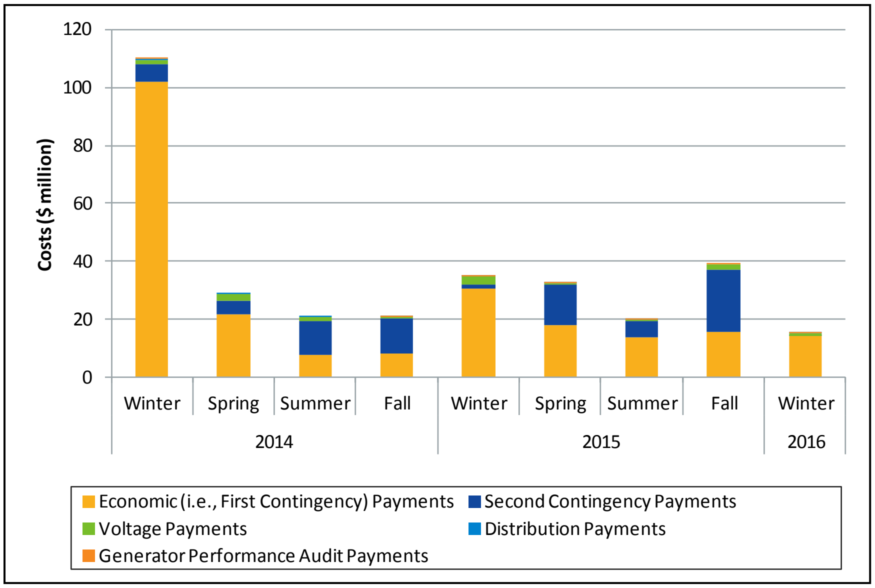
The majority of NCPC incurred during the reporting period was for first contingency protection. Of the approximately $12.0 million of total NCPC paid in the real-time market, $11.1 million was paid

[11] The sum of the individual components in this table may not match the subtotal amount due to rounding.

[12] 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*.

in real-time first contingency NCPC.[13] Of the approximately $3.5 million of total NCPC paid in the day-ahead market, $3.2 million was paid in day-ahead first contingency NCPC. NCPC payments by season and category are shown in Figure 2-13.

Figure 2-13: NCPC Payments by Season and Category ($ millions)



The decrease in NCPC payments in Winter 2016 compared to Fall 2015 was largely attributable to the drop in second contingency NCPC payments. Second contingency payments in Winter 2016 were less than $0.02 million, a decline of nearly 100% from the $21.6 million in second contingency NCPC payments made in Fall 2015. Milder winter weather and lower loads, compared to previous winters, resulted in fewer resources called on to provide local second contingency protection. The high payments in Winter 2014 reflect higher natural gas costs during that period (i.e., higher operating costs for generators) and concerns about natural gas scarcity and system reliability impacts in the Day-Ahead and Real-Time energy markets.

2.2.2 Net Interchange

In the reporting period, New England was a net importer of power with most of the imported energy coming from Canada.[14] Net interchange with neighboring areas averaged 2,775 MW per

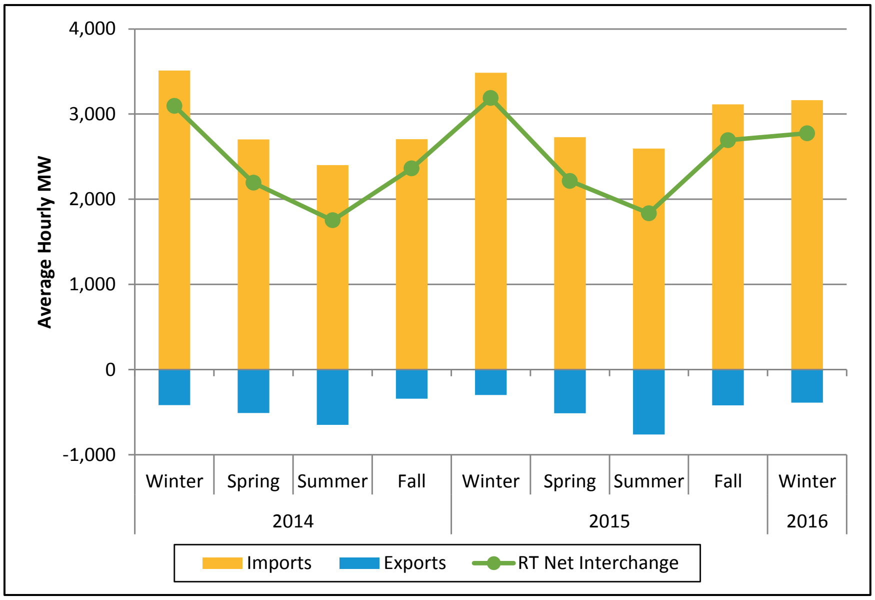
[13] *Economic/first contingency NCPC payments* include:

- Reliability costs paid for generation committed and dispatched to provide energy on short notice and create operating reserves that allow the system to recover from the loss of the first contingency within the specified period.
- Reliability costs paid for the commitment and dispatch of generation to provide systemwide stability or thermal support or to meet systemwide electric energy needs during the daily peak load hours.
- Reliability costs incurred for generation committed for daily peak load hours but are still on-line after the daily peak load hours to satisfy minimum run-time requirements.

[14] New England has transmission connections with Canada and New York; Quebec (via the HQ Phase II and HQ Highgate interfaces), New Brunswick and New York (via the New York-North, Northport-Norwalk and the Cross Sound Cable interfaces). The Canadian interfaces total approximately 2,600 MW (New England/New Brunswick: 1,000 MW, Highgate HVDC: 200 MW, and Phase II HVDC: 1,400 MW) in import capability. Under normal circumstances, the Canadian interfaces import power into New England. The New York Interfaces are as follows: The New York-North interface has a

hour for the reporting period, a 3% increase compared with Fall 2015 and a 13% decrease when compared to Winter 2015. This was primarily due to a decrease in imports from the Roseton (NY) location. Figure 2-14 shows imports, exports, and net interchange by season.

Figure 2-14: Imports, Exports, and Net Interchange by Season



The figure shows that net interchange has been seasonal in nature, with more imports occurring during the winter months over the past few years. The increase in net imports in Fall 2014 and Winter 2015 was partially due to the unplanned loss of the Cross Sound cable, which was the result of a transformer fire in New Haven. The Cross Sound Cable is predominantly a net exporter of power to New York.

2.3 Market Competitiveness

The structural competitiveness of the wholesale electricity market was evaluated by calculating the Herfindahl-Hirschman Index (HHI) metric. The result of this analysis is that system-wide concentration remains low. Generally, in lower concentrated markets, participants are less likely to have the ability to exercise market power. However, this is not to say that market power does not exist during certain system conditions. In such cases, a suite of mitigation rules are in place and are automatically triggered to mitigate the effect of market power on outcomes in the day-ahead and real-time energy markets.

The HHI is a commonly used measure of market concentration. It is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers.[15] The

net import capability of 1,400 MW and a net export capability of approximately 1,200 MW. This interface can import power to, or export power from New England. Northport-Norwalk has a capability of approximately 200 MW and is generally a net exporter of power to New York. The Cross Sound Cable is a DC Converter with a capability of approximately 330 MW and power is generally exported to New York.

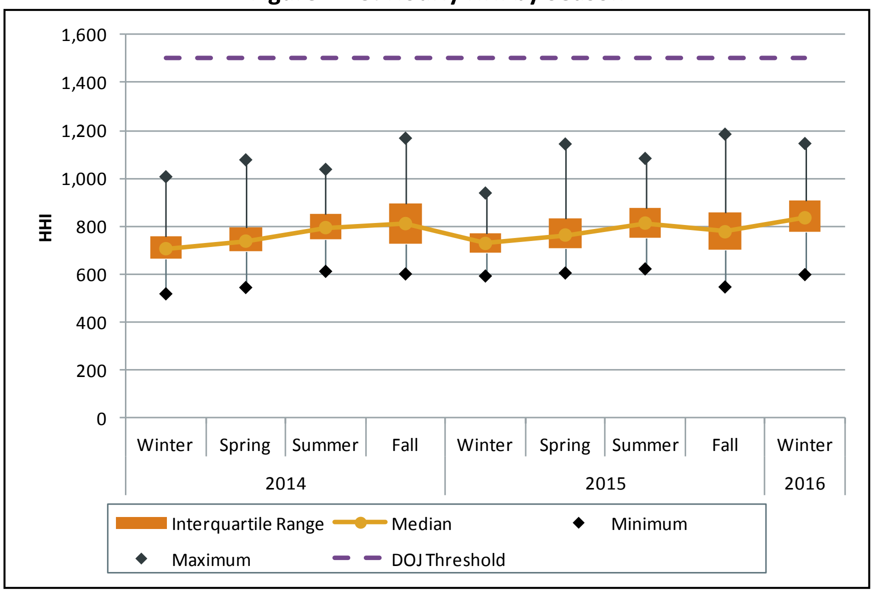
[15] The HHI is calculated as follows:

$$H = \sum_{i=1}^{N} s_i^2$$

HHI accounts for the relative size distribution of firms in a market. It approaches zero when a market is occupied by a large number of firms of relatively equal size and reaches its maximum of 10,000 points when a market is controlled by a single firm. The HHI increases as the number of firms in the market decreases and as the disparity in size between those firms increases.[16] This analysis accounts for affiliations between lead market participants.[17,18] Accounting for affiliations produces an HHI that better reflects the concentration of control in the market.

The box and whisker plot below (Figure 2-15) illustrates statistics for hourly HHI results for each season between Winter 2014 and Winter 2016. The bottom of the whisker represents the lowest hourly HHI while the top of the whisker represents the highest hourly HHI. The box shows the interquartile range; capturing the range of hourly results from the 25th to 75th percentile. The bottom of the box is the 25th percentile and the top of the box is the 75th percentile of hourly HHI values. The median HHI for each season is represented by the horizontal line within each box.

Figure 2-15: Hourly HHI by Season



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where s_i is the market share of firm i in the market, and N is the number of firms. The Herfindahl Index (H) ranges from $1/N$ to one, where N is the number of firms in the market. Equivalently, if percents are used as whole numbers, as in 75 instead of 0.75, the index can range up to 100^2, or 10,000.

[16] The Department of Justice defines markets with an HHI below 1,500 points to be unconcentrated, an HHI between 1,500 and 2,500 points to be moderately concentrated, and an HHI above 2,500 points to be highly concentrated. US Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines* (Washington, DC: US Department of Justice and Federal Trade Commission, August 19, 2010), http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

[17] This issue was addressed in *ISO New England's Internal Market Monitor Second Quarter 2015 Quarterly Markets Report* (October 1, 2015), http://www.iso-ne.com/static-assets/documents/2015/10/qmr_q2_2015_10_1_2015_for_filing.pdf. Further enhancements to the IMM's competitiveness measures, that take account of affiliations, are being developed and will be included in future reports.

[18] The mapping of assets to ultimate parent companies is based on information provided to the ISO by participants. The mapping of assets to ultimate parent company will be periodically updated as new information becomes available.

The results of the HHI analysis for the reporting period indicate that the wholesale electric energy markets in New England are well within the "not concentrated" range.[19] The median HHIs for the past nine seasons ranged from 706 in Winter 2014 to 835 in Winter 2016. Although the reporting period had the highest median HHI of the previous nine seasons, this is not a cause for concern. Even in the maximum HHI hour, 1,145, supply was unconcentrated by Department of Justice standards.

[19] HHI ignores transmission constraints and contractual entitlements to generator output, which would have the effect of increasing and decreasing concentration, respectively. The net effect has not been measured; however, given the low level of overall concentration even if these effects produced a net increase in concentration, the impact would likely not change our assessment.

Section 3
Review of the Tenth Forward Capacity Auction

This section presents a review of the tenth Forward Capacity Auction (FCA), which covers the commitment period from June 1, 2019 to May 31, 2020.

The FCA modeled two capacity zones: the Southeastern New England ("SENE") capacity zone and the Rest-of-Pool capacity zone. The SENE capacity zone is a combination of the Northeastern Massachusetts/Boston, Southeastern Massachusetts, and Rhode Island Load Zones. The Rest-of-Pool capacity zone includes the Connecticut, Maine, Western/Central Massachusetts, New Hampshire, and Vermont Load Zones.

As described below, the capacity zones and external interfaces closed at different rounds of the auction and at different prices.

- Resources in the SENE and Rest-of-Pool capacity zones and the Phase I/II HQ interface cleared at $7.03/kW-month.
- The New York AC Ties external interface cleared at $6.26/kW-month.
- The New Brunswick external interface cleared at $4.00/kW-month.

3.1 Sloped Demand Curve

The system-wide sloped demand curve, along with supply offers and de-list bids, are key inputs into the determination of the clearing price. The sloped demand curve results in the quantity of capacity demanded increasing linearly as the capacity price decreases. The curve is intended to improve price formation – specifically, to reduce price volatility and establish efficient price signals to maintain the region's long-run reliability criteria.

The curve's shape is defined by pertinent financial and reliability parameters, such as the FCA starting price of $17.296/kW-month and net Cost of New Entry (net CONE) value of $10.81/kW-month. The curve is designed to procure capacity sufficient to meet New England's resource adequacy requirements over time.[20]

3.2 Requirements and Resource Qualification

Table 3-1 shows qualified and required capacity by capacity zone. Over 34 GW of capacity was needed system-wide. The SENE zone was determined to be import constrained prior to the auction and had a Local Sourcing Requirement (LSR) of 10,028 MW. Table 3-1 also summarizes the existing and newly qualified capacity by zone and compares that capacity to the relevant capacity requirement (i.e., the Net Installed Capacity Requirement - NICR and the LSR).

[20] *See ISO New England Inc. and the New England Power Pool*, Docket No. ER14-1639-000 (filed April 1, 2014), pp. 7-8, for a discussion of the principles that are considered in designing a demand curve.

Table 3-1: Qualified Capacity Compared to Requirements, FCA 10 (MW)

Zone	Existing	New	Total	Capacity Requirement
SENE	10,399	2,246	12,646	10,028
Rest-of-Pool	22,288	4,244	26,531	n/a
Total	**32,687**	**6,490**	**39,177**	**34,151**

System-wide, existing capacity (32,687 MW) was approximately 1,460 MW less than the NICR of 34,151 MW. As existing capacity was required to satisfy the capacity requirement all existing resources were determined to belong to a pivotal supplier for purpose of applying seller-side market power mitigation to de-list bids.

Table 3-2 shows the breakdown of qualified capacity by resource type for each zone. Most import capacity qualifies as new capacity and receives a one year CSO.[21]

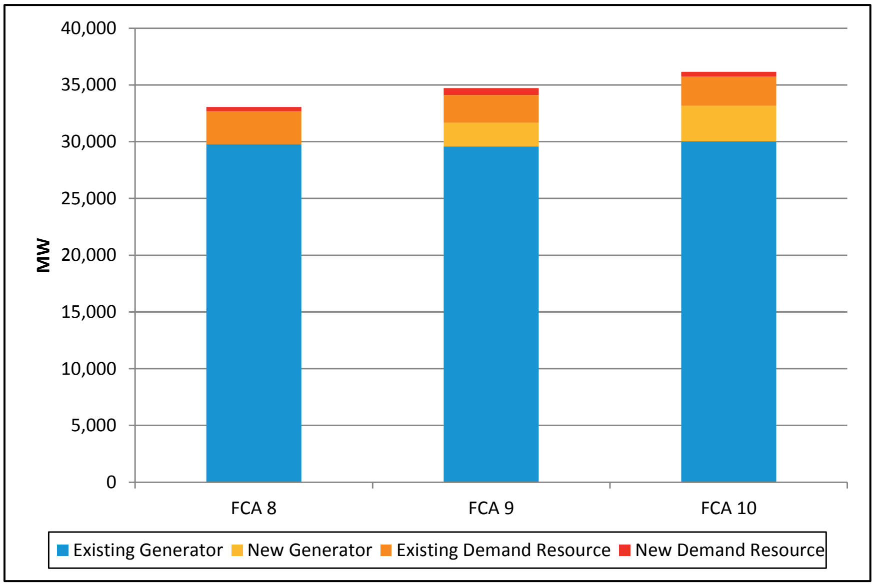
Table 3-2: Qualified Capacity by Resource Type and Qualification Status, FCA 10 (MW)

Zone	Existing			Existing Total	New			New Total	Total
	Demand	Generator	Import		Demand	Generator	Import		
SENE	1,131	9,268	0	10,399	199	2,047	0	2,246	12,646
Rest-of-Pool	1,439	20,760	89	22,288	230	1083	2,931	4,244	26,531
Total	2,570	30,028	89	32,687	429	3,130	2,931	6,490	39,177

Figure 3-1 shows existing and new qualified capacity for demand resources and generators. It shows that over the past two auctions there has been an increase in the participation of new generation.

[21] Imports are new in every auction except if an import capacity resource that has cleared in a prior FCA with a multi-year capacity contract selling/importing capacity into New England. This is limited to grandfathered import capacity resources listed in the Market Rule (Section III.13.1.3.3.C).

Figure 3-1: Qualified Capacity for Demand Resources and Generators, FCA 8 - FCA 10



Total qualified capacity for demand resources and generators increased by 4% in FCA 10 compared to FCA 9. New qualified capacity for demand resources and generators increased by 31% when compared to FCA 9, and 739% when compared to FCA 8. In FCA 10, Rest-of-Pool had almost 1,100 MW of new generation that participated in the auction, and SENE had about 2,050 MW of new generation that participated in the auction.

3.3 Auction Results

Table 3-3 below summarizes the auction results by round. Rest-of-Pool, SENE, and the external interface at the NY AC ties closed in round four of the auction, while the external interface at New Brunswick closed in round five.

Table 3-3: Results by Auction Round, FCA 10

Auction Rounds	System-wide (Includes SENE)	External Interface NY AC Ties	External Interface New Brunswick
Round 1 Pricing	$17.296-$14.500	$17.296-$14.500	$17.296-$14.500
Round 1 Capacity Excess	*3,531*	*1,201*	*356*
Round 2 Pricing	$14.500-$11.500	$14.500-$11.500	$14.500-$11.500
Round 2 Capacity Excess	*2,830*	*975*	*356*
Round 3 Pricing	$11.500-$8.500	$11.500-$8.500	$11.500-$8.500
Round 3 Capacity Excess	*1,733*	*379*	*356*
Round 4 Pricing	$8.500-$5.500	$8.500-$5.500	$8.500-$5.500
Round 4 Capacity Excess	*0*	*0*	*356*
Round 5 Pricing			$5.500-$2.750
Round 5 Capacity Excess			*0*
Capacity Clearing Price – New and Existing	***$7.030***	***$6.260***	***$4.000***

System-wide. The auction started with a price of $17.296/kW-month. The auction ended in the fourth round when the quantity of supply fell below system-wide demand when a new capacity offer was withdrawn.

At the end of the fourth round of the auction, supply over the New Brunswick external interface exceeded the interface's capacity transfer limit; therefore, one additional round below $5.500 kW-month was conducted for the New Brunswick interface.

SENE. Although the SENE capacity zone was modeled as an import-constrained zone, there were sufficient resources within the capacity zone to meet the zone's Local Sourcing Requirement. Therefore, there was no price separation between the zones and resources in both SENE and Rest-of-Pool will receive the same price of $7.03/kW-month.

Interfaces. At the $7.03/kW-month clearing price for the Rest-of-Pool capacity zone, the New York AC Ties external interface and the New Brunswick external interface each had a greater amount of capacity offered than the interface's capacity transfer limit allowed. As a result, these external interfaces were treated in the auction in a manner that is analogous to separately modeled export-constrained capacity zones. Separate capacity clearing prices were determined for the New York AC Ties external interface and the New Brunswick external interface, of $6.26 and $4.00/kW-month, respectively, with the latter requiring a fifth round of bidding.

De-List bids. Table 3-4 shows delisted capacity that was accepted in the auction.

Table 3-4: Delisted Capacity by Zone and Resource Type, FCA 10 (MW)

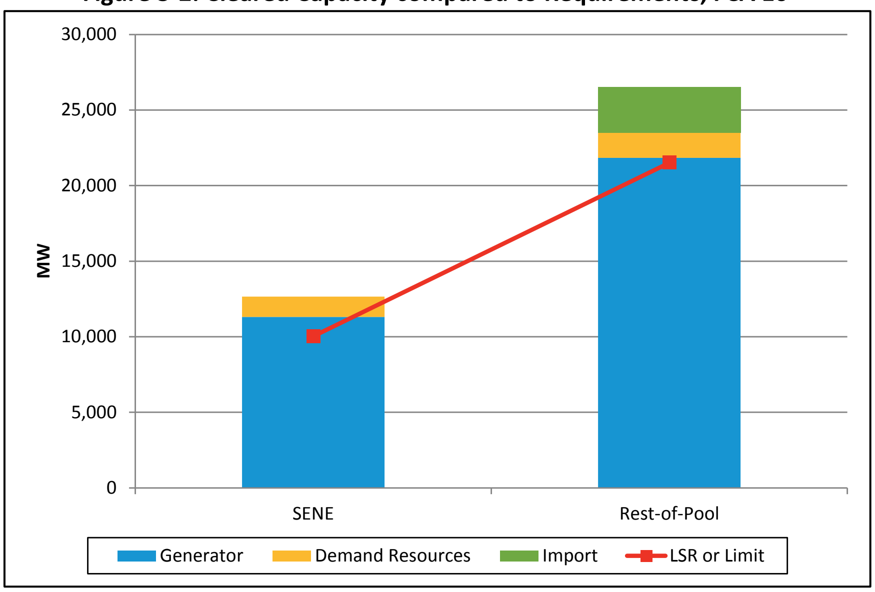
Zone	Demand	Generator	Total
SENE	65	3	68
Rest-of-Pool	130	113	243
Total	**195**	**116**	**311**

For FCA 10, 53 existing resources submitted delist bids in the auction. The ISO accepted 39 of these resources for a total of 311 MW and therefore shed their CSO. All of the delist bids were for a single year, allowing these resources to retain the option of re-entering the capacity market during FCA 11.

3.4 Cleared Capacity and Competitiveness of the Auction

Figure 3-2 below summarizes the cleared capacity (MW) from the auction, by capacity zone and resource type.[22]

Figure 3-2: Cleared Capacity compared to Requirements, FCA 10



Total capacity of 35,567 MW of capacity was procured in the auction, slightly above the Installed Capacity Requirement of 34,151 MW, as allowed for, and priced, under the sloped demand curve construct. Overall, generators represented approximately 84% of cleared capacity, while demand and import resources each represented 8%. These results by resource type are comparable to prior auctions.

Of the 35,567 MW procured, 1,800MW (or 5%) comprised new capacity, with 1,459 from new generation resources and 371 MW from new demand resources.

[22] The capacity requirement and excess capacity values are implied values for Rest-of-Pool, as those values are not explicitly modeled for the auction. The requirement for Rest-of-Pool is implied by the NICR less the zonal requirement and the excess capacity in SENE.

Competitiveness. There were insufficient existing resources, on a system-wide basis, to satisfy the Installed Capacity Requirement (ICR). As a result, the IMM determined that all participants with existing resources were pivotal suppliers. The IMM reviewed all submitted de-list bids and imposed mitigation, when appropriate. New resources, with the exception of New Import Capacity Resources, can leave the auction at any price at or above their New Resource Offer Floor Price. Sufficient new resources remained in the auction long enough such that the outcome of the auction system-wide was competitive and no anti-competitive behavior was observed.