ISO New England's Internal Market Monitor

Fall 2016

Quarterly Markets Report

Internal Market Monitor
January 27, 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 fall period from **September 1, 2016 to November 30, 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:

[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 presents metrics and analysis of the performance of ISO New England wholesale electricity and related markets for the Fall of 2016 (September 2016 through November 2016).[3]

1.1 Summary of Market Outcomes and Performance for Fall 2016

- The total estimated wholesale market costs were $1.17 billion in the reporting period, a 17% decrease compared to the same period in 2015 (Fall 2015).
    - Lower natural gas prices were the primary driver for the decrease in total energy costs. Natural gas prices averaged $2.45/MMBtu. This is a 9% decrease from last quarter and a 21% decrease compared to Fall 2015.
- In Fall 2016, the average hourly demand was 13,157 MW, compared to 13,524 MW in the same season of 2015, a decrease of 3%. Mild weather in Fall 2016 helps explain why the average hourly load was slightly lower compared to the past two fall seasons. The peak real-time load during the reporting period, which occurred on September 9, 2016, was 23,066 MW, 5% lower than the peak load observed in Fall 2015.
- Day-ahead and real-time energy market prices at the Hub averaged $25.16/MWh and $24.72/MWh, respectively. Day-ahead prices were 23% lower and real-time prices were 22% lower than Fall 2015 prices. These outcomes were driven by lower natural gas prices and lower demand. Average prices in the Northeast Massachusetts and Boston (NEMA) load zone were higher than the average Hub price by $2.54 and $3.22/MWh (10-13%) in the day-ahead and real-time market, respectively. Transmission work during the season limited the ability of that area to access relatively cheaper generation from the rest of the system. Therefore, local load and reserve needs were met to a greater degree by more expensive native generation in NEMA.
- Total real-time reserve payments were $3.5 million, a 67% decrease from $10.6 million in Fall 2015. The decrease in total payments compared to Fall 2015 was mainly due to lower average prices for all reserve products. Although total payments decreased, relatively high NEMA/Boston TMOR pricing in the quarter was the result of local reserve constraints binding in that local reserve zone. These constraints were due to transmission projects that restricted the local region from accessing relatively cheaper generation from the rest the system.
- Regulation payments totaled $5.9 million, a 5% increase from $5.6 million in Fall 2015. Increased regulation requirements resulted in the relatively small increase in regulation payments between the current quarter and the same quarter last year.

[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).

- Net Commitment Period Compensation (NCPC) payments in the quarter totaled $33.5 million, a 15% decrease from Fall 2015, mainly due to a decrease in first contingency payments between the two periods. The decrease in first contingency payments in Fall 2016 compared to Fall 2015 payments of $15.6 million can be largely explained by differences in the NCPC rules between the two periods.[4] Even though first contingency payments decreased between the two periods, second contingency payments remained high and increased compared to Fall 2015. 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 committed 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.

- Fall 2016 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 all existing resources, and the Rest-of-Pool cleared at the floor price of $3.15/kW-month. In Fall 2016, capacity payments totaled $285 million. This represents a 1% increase in capacity payments compared to Fall 2015 of $283 million and a 7% decrease from Summer 2016 payments of $303 million. One reason for lower FCM payments in Fall 2016 was the 290% increase (from $7 .1 million to $27.7 million) in Peak Energy Rent (PER) adjustments from Summer 2016.

[4] 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. *See ISO New England Inc. and New England Power Pool*, Market Rule 1 Revisions to the NCPC Credit Rules, Docket No. ER16-250-000 (filed November 3, 3015).

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 the key trends and drivers of market outcomes from Winter 2014 (beginning December 2013) through the Fall 2016 quarter. It covers key market statistics and trends in the wholesale cost of electricity and describes outcomes in the ISO's real-time and forward markets.

2.1.1 Total Wholesale Electricity Market Value

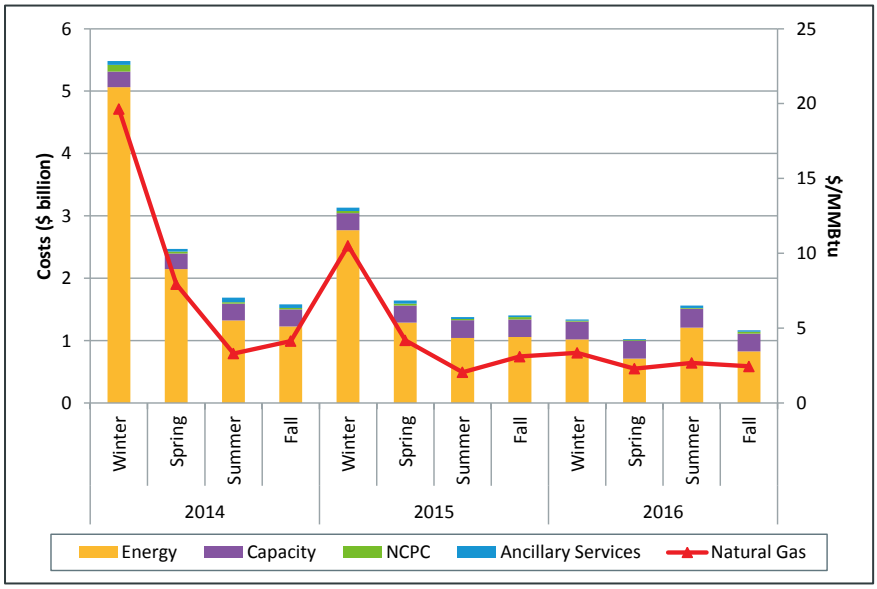
Figure 2-1 on the following page shows the estimated wholesale electricity cost for each season (in billions of dollars) by market, along with average natural gas prices (in $/MMBtu).[5] In Fall 2016, the total estimated market cost decreased by about 17% compared to the same quarter last year ($1.17 billion in Fall 2016 compared to $1.40 billion in Fall 2015), and decreased by 25% when compared to the previous quarter, Summer 2016 ($1.56 billion).[6]

By contrast, Fall 2016 Net Commitment Period Compensation (NCPC) costs of $33.5 million were 15% lower than Fall 2015 NCPC costs though significantly higher than Summer 2016 NCPC costs. These changes are explained in section 2.2.1 below. Ancillary service costs, which include reserve and regulation payments, totaled $21 million in Fall 2016, a decrease of 18% when compared to Fall 2015, and a decrease of 45% when compared to Summer 2016.

[5] The natural gas average prices used throughout this report are based on the Next Day Tennessee Gas Pipeline Co. - Zone 6, 200 Line index price as reported by the Intercontinental Exchange.

[6] 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.

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



Natural gas prices are a key driver behind changes in energy costs in New England. The decrease in natural gas prices in Fall 2016 compared to Fall 2015 resulted in lower energy costs. Additionally, lower natural gas prices in Fall 2016 resulted in lower energy costs compared to the previous reporting period of Summer 2016.

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

	Fall 2016	Summer 2016	Percent Change Fall 2016 to Summer 2016	Fall 2015	Percent Change Fall 2016 to Fall 2015
Real-Time Load (GWh)	28,812	35,159	-18%	29,678	-3%
Weather Normalized Real-Time Load (GWh)	28,828	34,898	-17%	29,317	-2%
Peak Real-Time Load (MW)	23,066	25,521	-10%	24,368	-5%
Average Day-Ahead Hub LMP ($/MWh)	$25.16	$29.83	-16%	$32.47	-23%
Average Real-Time Hub LMP ($/MWh)	$24.72	$30.35	-19%	$31.53	-22%
Average Natural Gas Price ($/MMBtu)	$2.45	$2.68	-9%	$3.11	-21%

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

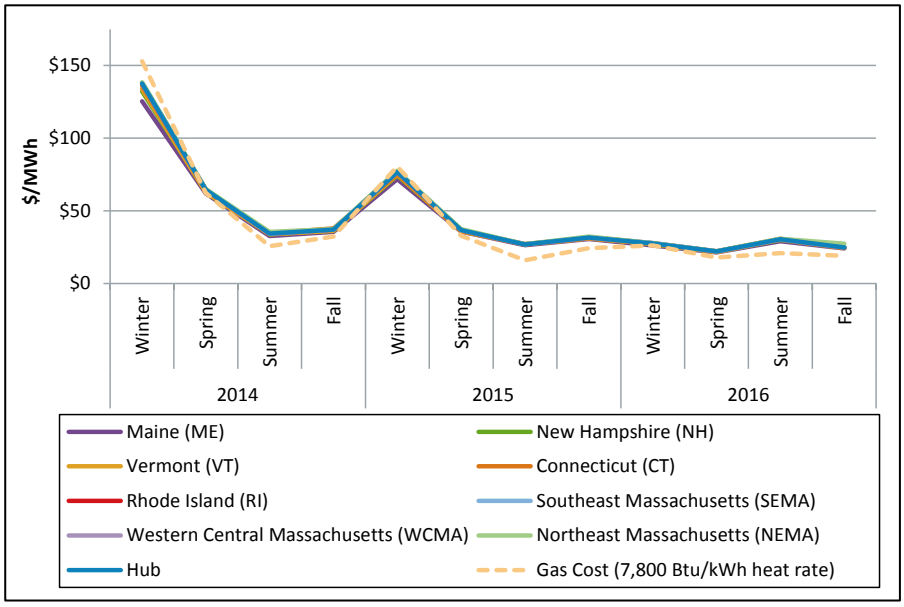
- Lower natural gas prices in Fall 2016 were the primary driver for lower day-ahead and real-time LMPs. Natural gas prices during the reporting period decreased by 21% compared to gas prices the prior fall.
- The real-time load in Fall 2016 was also 3% lower than the real-time load in Fall 2015. The peak load for Fall 2016 was 5% (1,302 MW) lower than the peak load from the prior fall.

2.1.3 Real-Time Markets

2.1.3.1 Real-Time Energy Market

The average real-time Hub energy price was $24.72/MWh in the reporting period, a decrease of 19% compared to the preceding quarter (Summer 2016). Real-time prices continue to follow the cost of natural gas generation. Compared to the prior fall, real-time energy prices were lower by 22%, which corresponds with the 21% decline in natural gas prices across these same periods. Energy prices did not differ significantly among the load zones in the quarter, with the exception of prices in the Northeast Massachusetts and Boston (NEMA) load zone.[7] Transmission work during the season limited the ability of that area to access relatively cheaper generation from the rest of the system. Therefore, local load and reserve needs were met to a greater degree by more expensive native generation in NEMA. The average real-time LMP in NEMA was $27.27/MWh, a premium above the Hub of $2.54/MWh, or 10%. 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

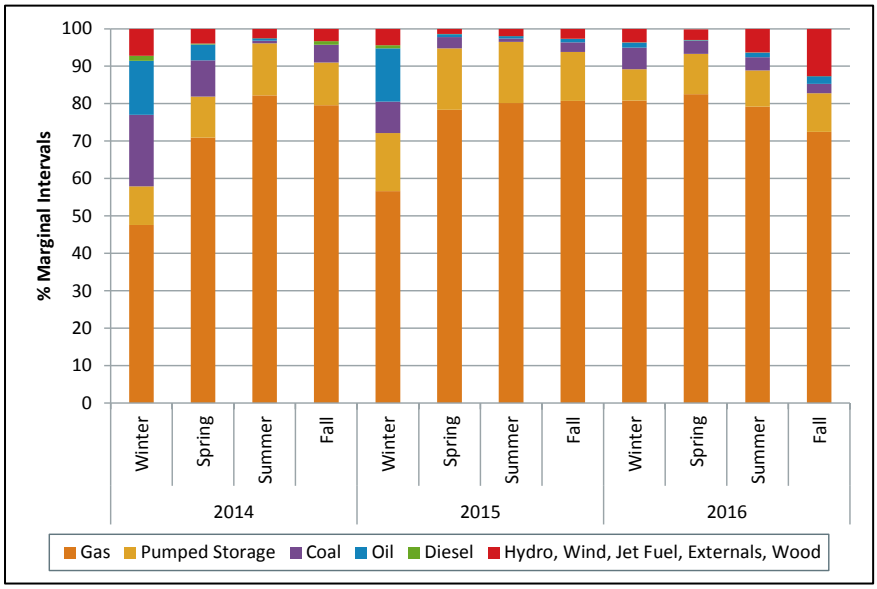


[7] A *load zone* is an aggregation of pricing nodes within a specific area; there are currently eight load zones in the New England region that correspond to the reliability regions.

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 21% lower in Fall 2016 compared to Fall 2015. According to the U.S. Energy Information Administration (EIA), temperatures in Fall 2016 were warmer than the 5-year average, which contributed to lower residential and commercial gas demand for heating.[8]

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 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 72% of the pricing intervals, followed by units in the "other" category, which were marginal in 13% of the pricing intervals. Pumped storage units were marginal in 10% 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

[8] US Energy Information Administration. Natural Gas Weekly Update for week ending November 30, 2016. Washington, DC: US Department of Energy, November 2016. http://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2016/12_01/.

Additionally, it is worth noting that pipeline capacity serving the New England region increased during the period when the Algonquin Incremental Market ("AIM") was put into service at the beginning of November. The AIM project increased the region's gas supplies by 342 million cubic feet per day, which is a 30% increase in the capacity of the Algonquin pipeline. An assessment of the possible impact of this project on natural gas prices is not available at this time.

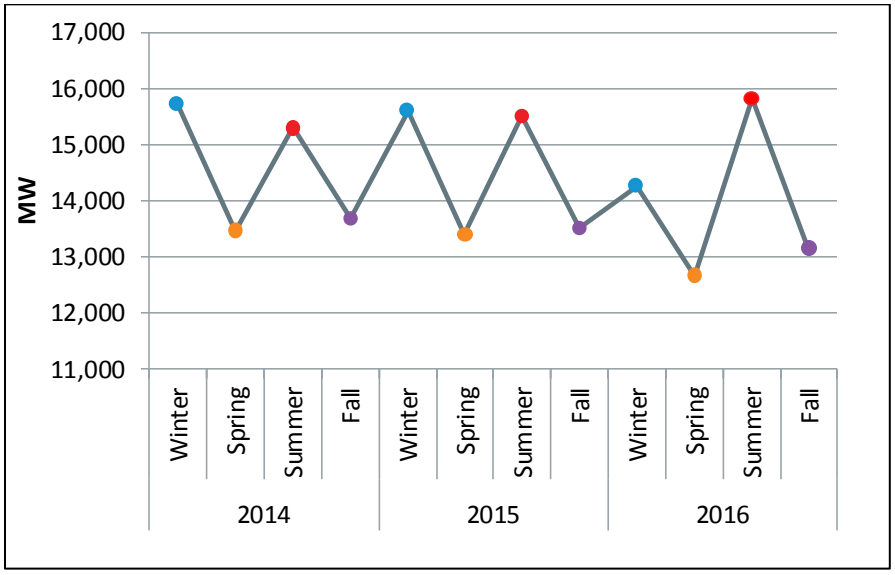
of the system. Wind was the single marginal fuel type on the system in <1% of all five-minute intervals.

As seen in the figure above, the composition of marginal units in Fall 2016 was generally similar to previous fall seasons. The largest difference 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 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.

2.1.3.2 Load Summary

In Fall 2016, the average hourly load was 13,157 MW, a 3% decrease compared to the Fall 2015 value of 13,524 MW and a 4% decrease compared to the Fall 2014 value of 13,682 MW.[10] Figure 2-4 below illustrates average hourly load by seasonal quarter. The blue dots represent winter, the yellow dots represent spring, the red dots represent summer, and the purple dots represent fall.

Figure 2-4: Average Hourly Demand



Mild weather in Fall 2016 helps explain why the average hourly load was slightly lower compared to the past two fall seasons. Of the three months in the quarter (September, October, and November), September 2016 was particularly milder, which tends to reduce cooling demand. During September 2016 there were significantly fewer hours during which temperatures exceeded

[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.

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

80°F and the average temperature was 65°F compared to the September 2015 average of 67°F. November 2016 was warmer, on average, than November 2014 and the same as November 2015. The average temperature in November 2016 was 44°F compared to the November 2014 average temperature of 41°F, likely reducing heating demand.

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.

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

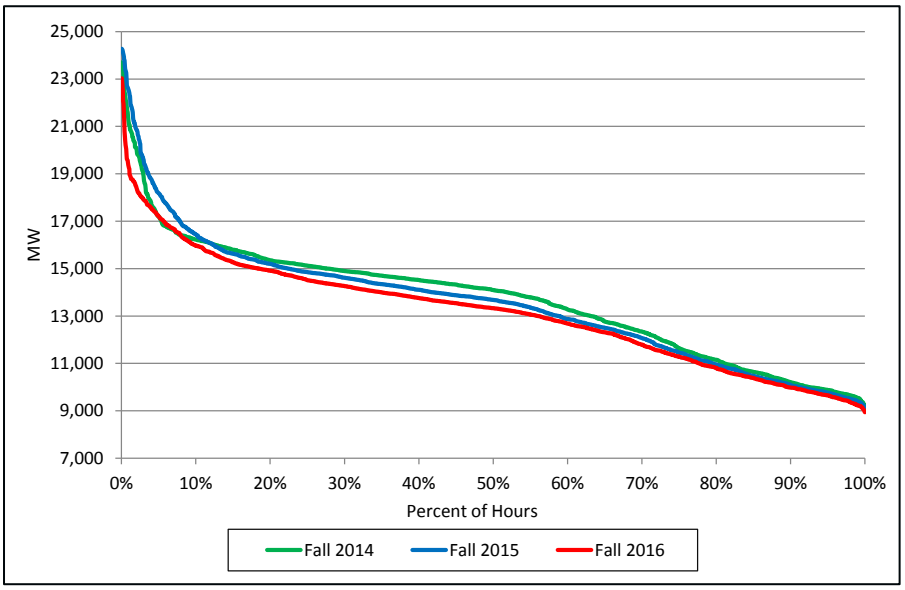


Figure 2-4 and Figure 2-5 both illustrate the trend of load level being consistently lower in Fall 2016 when compared to Fall 2015 and Fall 2014.

The peak hourly demand in the reporting period occurred on September 9 at 5:00 PM and was 23,066 MW. This was lower than the Fall 2015 peak of 24,368 MW. The lowest hourly demand in the reporting period was 8,941 MW, lower than that of the prior two fall periods.

2.1.3.3 Real-Time Operating Reserves

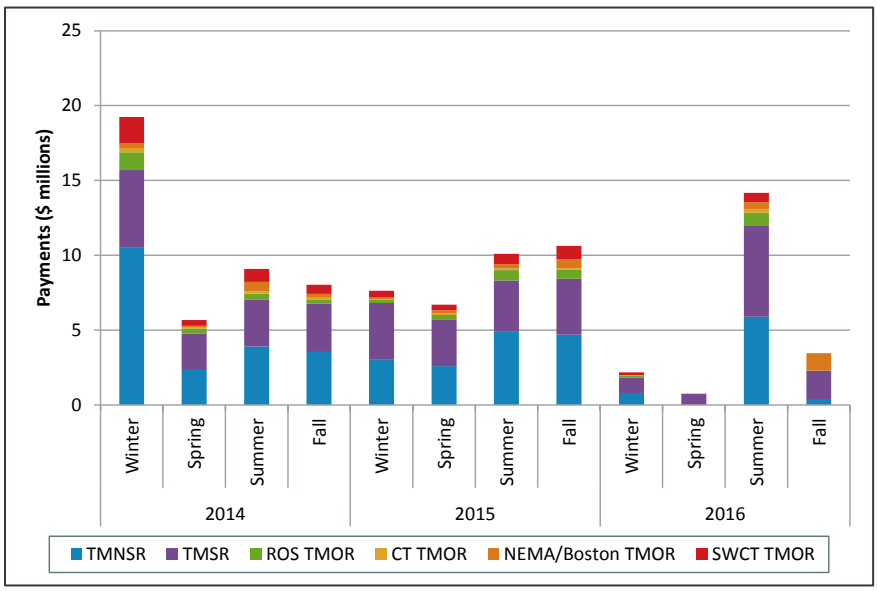
Total real-time reserve payments were $3.5 million in Fall 2016, a 67% decrease compared to Fall 2015 payments of $10.6 million.[11] The decrease in total payments compared to Fall 2015 was due to lower average prices for all reserve products, and lower frequencies of ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR) pricing, with the exception of local TMOR pricing in NEMA/Boston.

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

One third of total reserve payments in the reporting period were made to resources in the NEMA/Boston zone for local TMOR. Local transmission projects resulted in the region being frequently import-constrained, restricting the local region from accessing relatively cheaper generation from the rest of the system, thereby resulting in relatively high payments.

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

Figure 2-6: Real-Time Reserve Payments ($ millions)



As shown in Figure 2-6, real-time reserve payments were significantly lower in Fall 2016 compared to the past two fall seasons. This was due to a large reduction in the average prices of all reserve products, in all zones, compared to Fall 2015. Although average prices fell, the frequency of ten-minute spinning reserve (TMSR) prices in all zones was higher than in Fall 2015. There was non-zero TMSR pricing in 4.7% of five-minute intervals in the reporting period for all zones, with the exception of NEMA/Boston, which experienced TMSR pricing in 8.6% of five-minute intervals. For comparison, in Fall 2015, TMSR pricing frequency in each of the zones ranged from 3.4% to 3.6%. In addition to the increase in TMSR pricing frequency, the pricing frequency of all products in NEMA/Boston also increased.

The increase in the frequency of reserve pricing for all products in NEMA/Boston in Fall 2016 was due to a higher number of five-minute intervals where there was local TMOR pricing. In addition to units providing the TMOR service, TMOR prices are also received by generators providing TMNSR and TMSR. This is because generators capable of providing ten-minute reserves are also capable of delivering thirty-minute reserves and are therefore paid when there is TMOR pricing. The frequency of TMOR pricing in NEMA/Boston increased in Fall 2016 compared to Fall 2015. In Fall 2016, 4.2% of five-minute pricing intervals had positive TMOR pricing, compared to just 1.4% in Fall 2015. As mentioned earlier, this increase was due to local transmission work that resulted in the region being import-constrained.

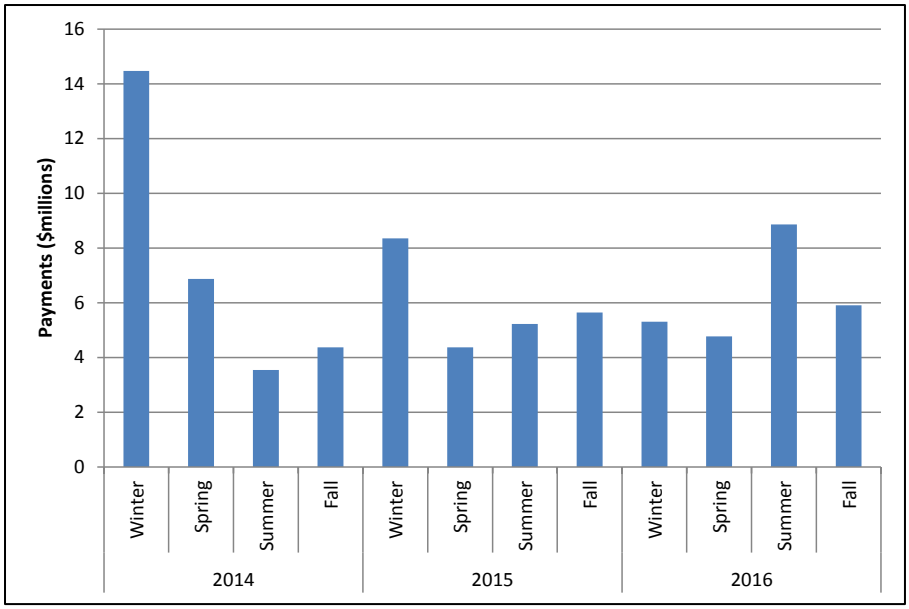
Even though the frequency of TMSR pricing and local TMOR pricing in NEMA/Boston increased in the quarter, lower reserve prices across all products more than offset the increase in frequency of

TMSR and local NEMA/Boston TMOR pricing, leading to a large decrease in reserve payments in Fall 2016 compared to Fall 2015.

2.1.3.4 Regulation Market

Total regulation market payments were $5.9 million during the reporting period, down 33% from $8.9 million in Summer 2016, and up 5% from $5.6 million in Fall 2015. Regulation payments in Fall 2016 declined primarily for two reasons. First, there were fewer intervals with high capacity prices (reflecting reduced energy market opportunity costs compared to the Summer quarter). Second, there were fewer hours in which more regulation capacity was purchased than required. The relatively small increase in regulation payments between Fall 2015 and Fall 2016 resulted mainly from increased regulation requirements.[12] Quarterly regulation payments are shown in Figure 2-7 below.[13]

Figure 2-7: Regulation Payments ($millions)



2.1.4 Forward Markets

2.1.4.1 Day-Ahead Energy Market

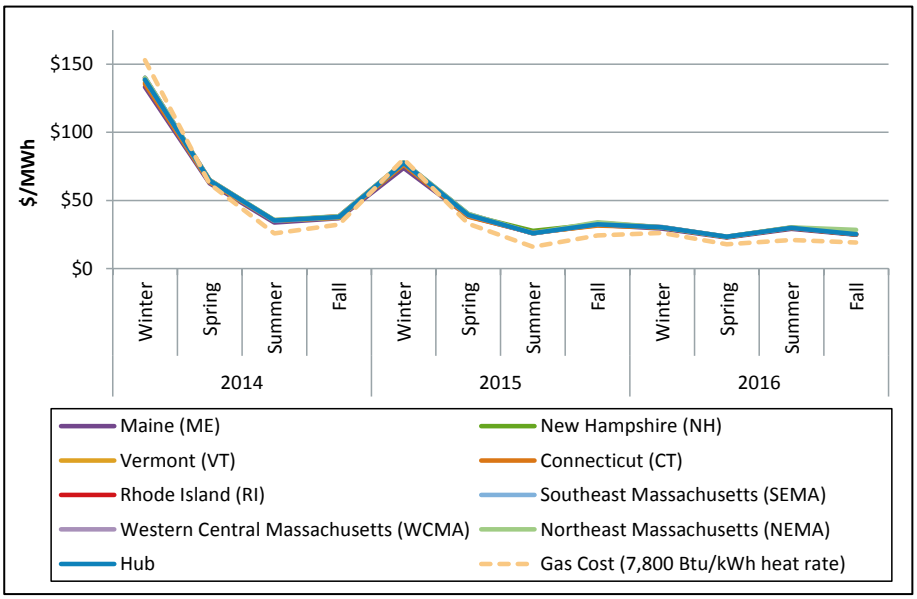
The average day-ahead Hub price for Fall 2016 was $25.16/MWh, a decrease of 16% from the Summer 2016 average of $29.83/MWh. Similar to real-time energy prices, day-ahead market prices remained correlated with natural gas prices and prices did not differ significantly among the load zones, with the exception of prices in the NEMA load zone as discussed in section 2.1.3.1 above. The average day-ahead LMP in NEMA was $28.37/MWh, which was $3.22/MWh, or 13%, above average

[12] 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.

[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.

Hub price. 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).

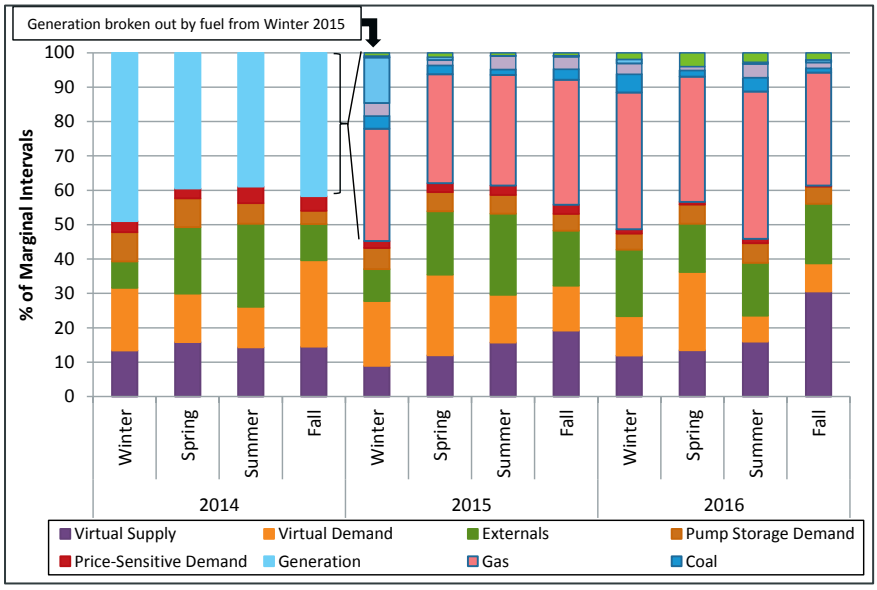
Figure 2-8: Simple Average Day-Ahead Prices and Gas Generation Costs



As shown in Figure 2-8, average day-ahead energy prices at the Hub decreased by 23% relative to the prior fall (Fall 2015) when the day-ahead price averaged $32.47/MWh. The decrease in electricity prices between these fall periods is consistent with the decrease in natural gas prices which is shown by the dashed yellow line series. During Fall 2016, the average day-ahead Hub price was 2% higher than the average real-time Hub price of $24.72/MWh.

Figure 2-9 below shows the percentage of time that each resource type set price in the day-ahead market since Winter 2014. 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. Beginning in 2015, the graph illustrates a breakdown of the generation by 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 Resource and Fuel Type

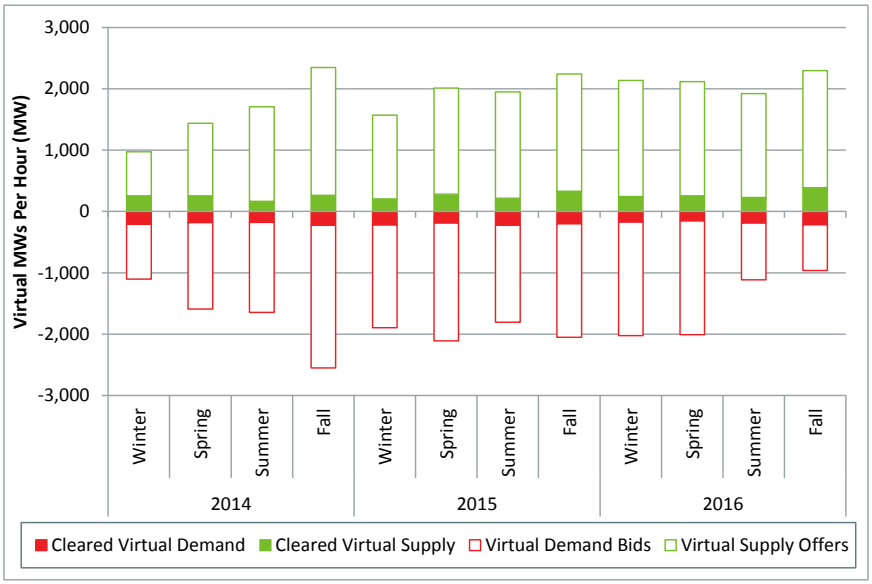


The type and frequency of resources that set price varies from one period to the next. This is due to the mix of resource types participating in both the supply and demand side of the day-ahead market. In the day-ahead market, participants may submit virtual bids and offers, and fixed and priced demand, 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, with the exception of a large increase in marginal virtual supply offers. Virtual transactions (virtual supply and demand) set price approximately 39% of the time, which represents an increase from 32% from Fall 2015. 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. Aside from virtual transactions, generators set price approximately 39% of the time, external transactions set price approximately 17% of the time and price-sensitive demand (including pump storage demand) set price in 5% of price-setting intervals.

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

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



In the reporting period, submitted virtual demand bids and virtual supply offers averaged approximately 3,256 MW per hour, a 7% increase from Summer 2016, and a 24% decrease from Fall 2015. The decrease in submitted transactions compared to last fall was due to a large decrease in submitted virtual demand bids. Despite the large reduction in submitted virtual transactions, cleared virtual transactions increased by 14% compared to Fall 2015. In the reporting period, 19% of the megawatt quantity of submitted virtual bids and offers cleared in the day-ahead market, which is a higher percentage than in preceding quarters. The percentage of cleared demand bids to submitted bids was 29% in Fall 2016, much higher than in previous reporting periods, which averaged 13% from Winter 2014 to Summer 2016. This indicates that the decrease in submitted demand bids was primarily in transactions priced very low that would typically not clear.

2.1.4.2 Financial Transmission Rights

Three Financial Transmission Rights (FTR) auctions were conducted during the reporting period for a combined total of 84,378 MW of FTR transactions. The total amount distributed as Auction Revenue Rights (ARRs) was $1.7 million, which was higher than in the previous reporting period. The increase in ARR payments is consistent with increased congestion due to planned transmission outages within the quarter. Twenty-nine bidders in September, twenty-seven bidders in October and thirty bidders in November 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.[14] 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"

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

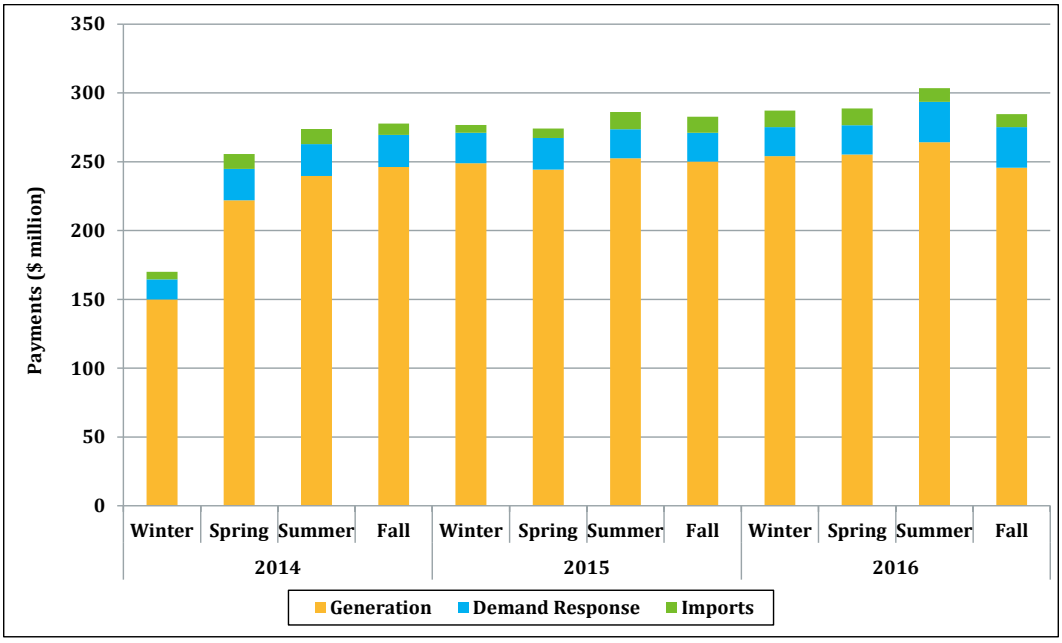
revenue and thereby induces suppliers to undertake the investments necessary for reliable electric power service.

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.[15] 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.

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 ($ millions)



The current commitment period is 2016-2017, where the NEMA/Boston zone cleared at $15.00/kW-month for new resources and $6.66/kW-month for all existing resources, and the Rest-of-Pool cleared at the floor price of $3.15/kW-month. In Fall 2016, capacity payments totaled $285 million, which accounts for adjustments to primary auction capacity supply obligations (CSOs). Adjustments include annual reconfiguration auctions, annual bilateral periods, monthly

[15] 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.

reconfiguration auctions, monthly bilateral periods, peak energy rent adjustments, performance and availability activities, and reliability payments.

The total capacity payments in Fall 2016 were roughly $19 million less than payments made in Summer 2016. The primary reason for lower FCM payments in Fall 2016 was the 290% increase (from $7 .1 million to $27.7 million) in PER adjustments from Summer 2016, which decreased net payments to resources. The peak energy rent adjustment had more of an effect on capacity payments in Fall 2016 than in previous quarters because of high real-time energy prices that occurred in August 2016.[16]

Table 2-2 provides a summary of prices and volumes associated with reconfiguration auction and bilateral trading activity during Fall 2016, 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

					Capacity Zone/Interface Prices
FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)**	Cleared MW	NEMA/Boston
FCA 7 (2016-17)	Primary	12-month	3.15	36220	15.00/6.66*
	Monthly Reconfiguration	16-Nov	0.50	495	1.00
	Monthly Bilateral	16-Nov	1.63	129	
	Monthly Reconfiguration	16-Dec	0.50	514	0.55
	Monthly Bilateral	16-Dec	2.41	191	
	Monthly Reconfiguration	17-Jan	0.50	695	1.45
	Monthly Bilateral	17-Jan	2.50	217	

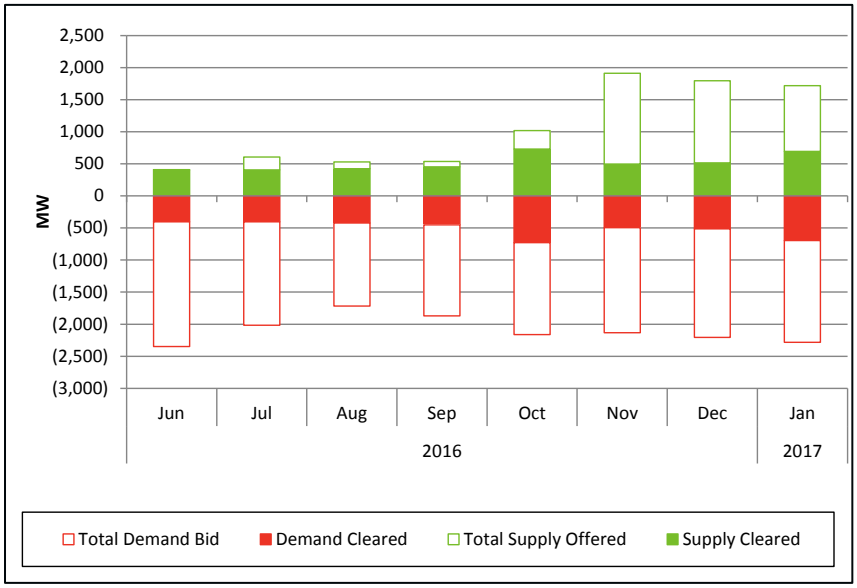
FCA 7 Commitment Period. In FCA 7 (2016-2017), there was price separation due to binding local sourcing requirements in two import-constrained capacity zones. The two zones were NEMA/Boston and Connecticut. The NEMA/Boston zone cleared at $15.00/kW-month for new resources and $6.66/kW-month for all existing 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 all other zones was the floor price of $3.15/kW-month.

Prices in Fall 2016 monthly reconfiguration auctions were lower than those during Summer 2016. In all three reconfiguration auctions, Rest-of-Pool cleared at a price of $0.50/kW-month. The NEMA/Boston zone cleared at $1.00/kW-month in November, $0.55/kW-month in December, and $1.45/kW-month in January. The cleared megawatts by auction were 495 MW, 514 MW, and 695 MW in November 2016, December 2016, and January 2017 respectively. Figure 2-12 shows supply

[16] 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 .

and demand bids in the reconfiguration auctions associated with capacity commitment period (CCP) 7.

Figure 2-12: Offers and Bids in Reconfiguration Auctions for CCP 7



Total supply offers (i.e. offers to take on a CSO) were below 600 MW up to September. For October, total supply offered ranged from approximately 1,000 MW to 1,900 MW. Throughout the monthly reconfigurations illustrated above, total demand bids ranged from approximately 1,700 MW to 2,300 MW.

Most thermal generating resources have greater capability during the winter period when ambient temperatures are colder. These resources are able to offer additional capacity (the difference between their winter and summer qualified capacity) into the winter period reconfiguration auction.[17] The additional winter capacity contributes to lower clearing prices in winter period reconfiguration auctions.

In the three bilateral periods there were 129 MW, 191 MW, and 217 MWs of approved capacity traded for the November 2016, December 2016, and January 2017 bilateral periods, respectively. The volume-weighted prices were $1.63/kW-month in November, $2.41/kW-month in December, and $2.50 /kW-month in January. Table 2-4 shows the amount of megawatts transferred and acquired by resource type.

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

Table 2-3: Bilateral Acquired and Transferred MW for Fall 2016

Month	Resource Type	Transferred MW	Acquired MW	Net MW
November 2016	Demand Response	53	23	(30)
	Generator	26	106	80
	Import	50	0	(20)
November 2016 Total		**129**	**129**	**0**
December 2016	Demand Response	36	2	(34)
	Generator	24	188	164
	Import	130	0	(130)
December 2016 Total		**191**	**191**	**0**
January 2017	Demand Response	62	2	(60)
	Generator	25	215	190
	Import	130	0	(130)
January 2017 Total		**217**	**217**	**0**

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.

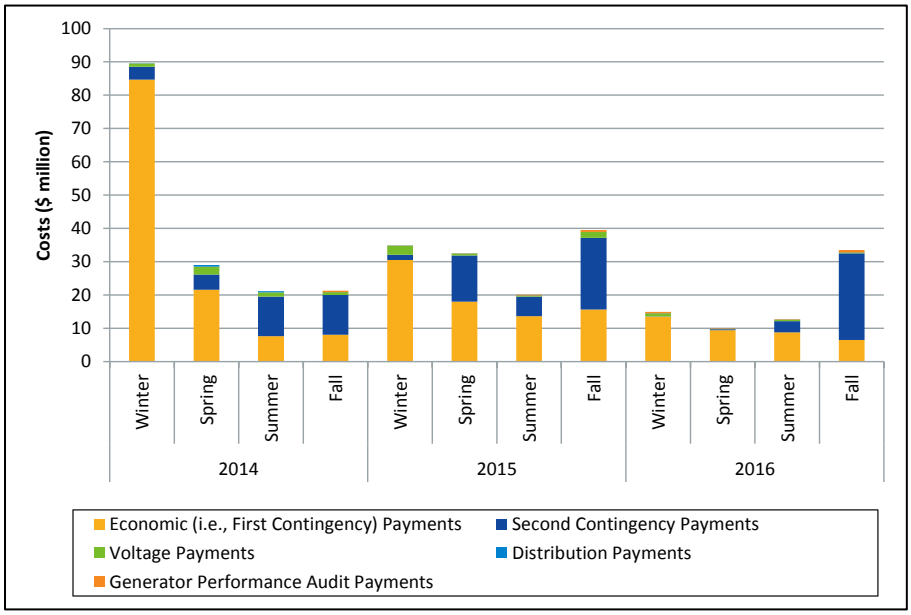
2.2.1 Net Commitment Period Compensation

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 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.[18]

In Fall 2016, NCPC payments totaled $33.5 million. This is a 15% decrease compared to the same season last year ($39.5 million) but significantly more than what was paid last quarter. NCPC payments by season and category are shown in Figure 2-13.

[18] 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*.

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



The majority of NCPC (78%) incurred during the reporting period was for second contingency protection. Approximately $28.5 million (85%) of total NCPC was paid in the day-ahead market, of which $25.4 million was for second contingency. Nearly $24.2 million (93%) of second contingency payments were made to units in NEMA/Boston. Transmission outages and upgrades limiting transfer capability within NEMA/Boston resulted in additional reliability commitments required within the load zone. 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.

The next largest category of NCPC payments was for first contingency, which totaled $6.5 million (19%) of total NCPC in the reporting period.[19] Approximately $2.8 million (44%) of first contingency NCPC payments were made in the day-ahead market. The decrease in first contingency payments in Fall 2016 compared to Fall 2015 payments of $15.6 million can be largely explained by differences in the NCPC rules between the two periods. First contingency payments in Fall 2016 of $6.5 million were 58% lower than first contingency payments made last fall. 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 $7.4 million in real-time first contingency

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

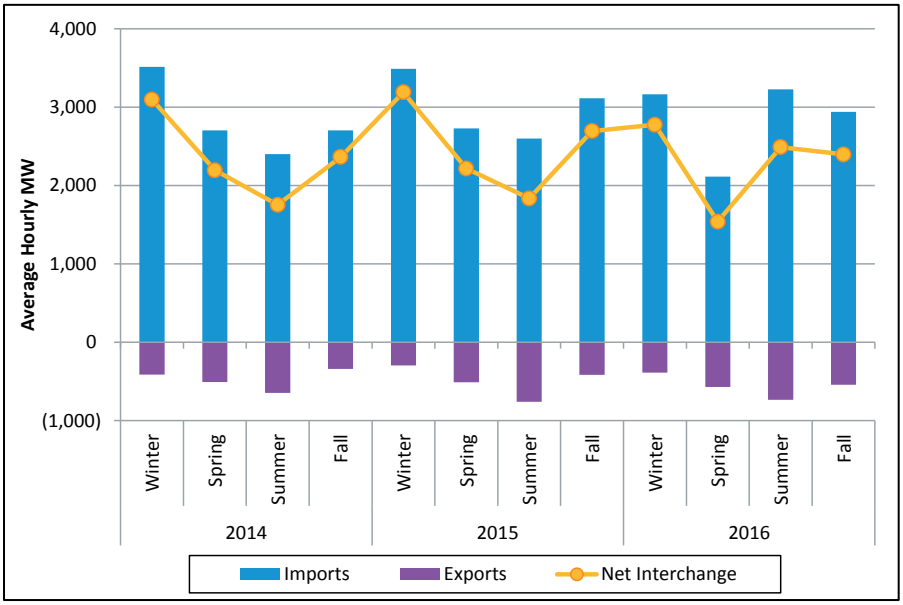
- Reliability costs paid for generation committed and dispatched to provide energy on short notice and create operating reserves that allow the system to recover from the loss of the first contingency within the specified period.
- Reliability costs paid for the commitment and dispatch of generation to provide system-wide stability or thermal support or to meet system-wide 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.

NCPC was paid last fall to eligible generators under the prior rules that were in effect in Fall 2015 and changed in Winter 2016.

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.[20] Net interchange with neighboring areas averaged 2,395 MW per hour for the reporting period. Figure 2-14 shows imports, exports, and net interchange by season.

Figure 2-14: Average Hourly Imports, Exports, and Net Interchange



The figure shows that net interchange has been seasonal in nature with the highest net imports during the winter months and the lowest during the summer or spring months. Net imported volumes in Fall 2016 were about the same as the preceding quarter (Summer 2016) when net imports averaged 2,488 MW per hour and 11% lower than the prior fall (Fall 2015) when the region imported 2,693 MW, on average, per hour. Net imports in Fall 2016 were lower primarily at New York interfaces and about the same at the Canadian interfaces compared to Fall 2015.

[20] 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 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.