ISO New England's Internal Market Monitor

Spring 2017

Quarterly Markets Report

Internal Market Monitor
August 04, 2017

Contents

Tables

Figures

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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 performance of 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 spring period from **March 1, 2017 to May 31, 2017** (the "reporting period"). The report contains our analyses and summaries of market performance. All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.[1]

Underlying natural gas data furnished by:

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media

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

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

Section 1
Executive Summary

This report covers key market outcomes and the performance of ISO New England wholesale electricity and related markets for the Spring of 2017 (March 31, 2017 through May 31, 2017).[3]

1.1 Summary of Market Outcomes and Performance for Spring 2017

- The total estimated wholesale market costs were $1.3 billion in Spring 2017, a 26% increase compared to $1.0 billion in Spring 2016.

    - Higher natural gas prices were the primary driver for the increase in total energy costs. Natural gas prices averaged $3.59/MMBtu, a 54% (or $1.26/MMBtu) increase compared to Spring 2016.
    - The majority of the year-over-year increase in natural gas prices occurred in March 2017 when gas prices were 127% higher than March 2016 due to significantly colder temperatures in the region. Spring 2016 gas prices were unusually low due to increased production, above-average storage, and low heating demand during winter 2015-16 (source: U.S. Energy Information Administration (EIA).
    - Spring 2017 natural gas prices were 18% (or $0.78/MMBtu) lower than Spring 2015 prices.

- In Spring 2017, the average hourly demand was 12,853 MW, comparable to the same season of 2016, due to similar average weather conditions. Of the three months in Spring 2017 (March, April and May), March was unseasonably cold, with higher gas demand resulting in a relatively more stressed natural gas system and higher gas (and electricity) prices compared to March 2016. April and May 2017 saw slight reductions in load compared to the same months of the prior year.

- Day-ahead and real-time energy market prices at the Hub averaged $30.78/MWh and $31.92/MWh, respectively. Day-ahead prices were 32% higher and real-time prices were 44% higher than Spring 2016 prices. Trends in energy prices continue to be closely correlated with underlying natural gas prices. The positive deviation in real-time prices for the period was driven by several days with high loads and unit outages during early April as well as the two-days from May 18th through May 19th when high temperatures resulted in loads higher than were forecasted. In addition, several units experienced forced outages.

- Energy market prices did not differ significantly among the load zones with the exception of Maine, New Hampshire, and Vermont, which had average prices lower than the Hub. This discount in real-time energy prices at all three load zones compared to the Hub was the highest, in both dollar and percentage terms, over the two and a half year period assessed in this report. The difference ranged from lower real-time prices of 6% ($1.81/MWh) in Vermont to 16% ($5.13/MWh) in Maine compared to the Hub price. In

[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).

addition to the prevalence of renewable type generators in these export-constrained areas there were also various planned and unplanned line reductions or outages during the period that further reduced the transmission capability available to export power to the rest of the system. The discount in energy prices in Maine, Vermont, and New Hampshire was less pronounced in the day-ahead market.

- Real-time reserve payments in Spring 2017 totaled $8.9 million, which was a large increase relative to the Spring 2016 total of $0.7 million and 33% above the Spring 2015 total of $6.7 million. The total payments for Spring 2017 were primarily accrued over the two-day period between May 18th and 19th when 54%, or $4.8 million, of the period credits occurred. During these two days, re-dispatch to maintain reserves was frequently required and there were many intervals when the reserve constraint penalty factors (RCPF) where triggered for ten-minute spinning reserve and thirty-minute operating reserves due to reserve deficiencies.

- Total regulation market payments were $5.8 million during the reporting period, down 26% from $7.9 million in Winter 2017, and up 22% from $4.8 million in Spring 2016. Spring regulation payments are typically lower than winter payments, as elevated winter period fuel and electricity prices contribute to higher opportunity cost for providing regulation services in the winter period. Comparing Spring 2017 to Spring 2016, higher fuel and electricity prices in Spring 2017 (relative to the earlier period) resulted in higher regulation pricing and payments.

- In Spring 2017, NCPC payments totaled $14.2 million, representing about 1.5% of total wholesale energy costs for the season, similar to Spring 2016 (1.4%). In dollar terms, this was a 42% increase compared to the same season last year ($9.9 million), but 22% less than what was paid in Winter 2017. These differences were mainly driven by changes in first contingency, second contingency, and voltage payments between the time periods.

    - The majority of NCPC (77%) incurred during the reporting period was for first contingency protection. About $1.3 million (12%) of the first contingency payments in the quarter were paid in real-time on May 18th and 19th when the system experienced an M/LCC2 event and tight conditions.
    - Similarly, payments for second contingency protection totaled nearly $1.0 million between May 17th and May 20th when system conditions necessitated reliability commitments in local areas. These payments, made to units in NEMA, SEMA, and Rhode Island, accounted for 56% of total second contingency payments made in the quarter.

- Spring 2017 coincides with the last three months of the commitment period associated with FCA 7. In FCA 7, the NEMA-Boston zone cleared at $15.00/kW-month for new resources and $6.66/kW-month for existing resources, and the Rest-of-Pool cleared at the floor price of $3.15/kW-month. In Spring 2017, capacity payments totaled $287 million and were within 1% of Spring 2016 payments. Peak energy rent adjustments remained relatively high, at $26 million, because of high real-time energy prices that occurred in August 2016. In Spring 2017.

- In April 2017, ISO New England held the forward reserve auction for the Summer 2017 delivery period (i.e., June 1st, 2017 to September 30th, 2017). Control area supply offers in the Summer 2017 auction exceeded the requirements for both TMNSR and TMOR and there were no pivotal suppliers. The clearing prices for offline thirty- and ten-minute reserves for the control area were $1,000/MW-month and $2,000/MW-month, respectively. These clearing prices were lower than Summer 2016 prices, which were $2,000/MW-month and $2,498/MW-month for ten- and thirty-minute reserve, respectively. Of the three local reserve zones, only NEMA/Boston had a different price than the control area. Because of inadequate supply (meaning all suppliers were pivotal suppliers), the thirty-minute reserve price for NEMA/Boston was set to the auction's offer price cap of $9,000/MW-month. This was the same outcome as the Summer 2016 auction.

Section 2
Summary of Market Outcomes and System Conditions

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

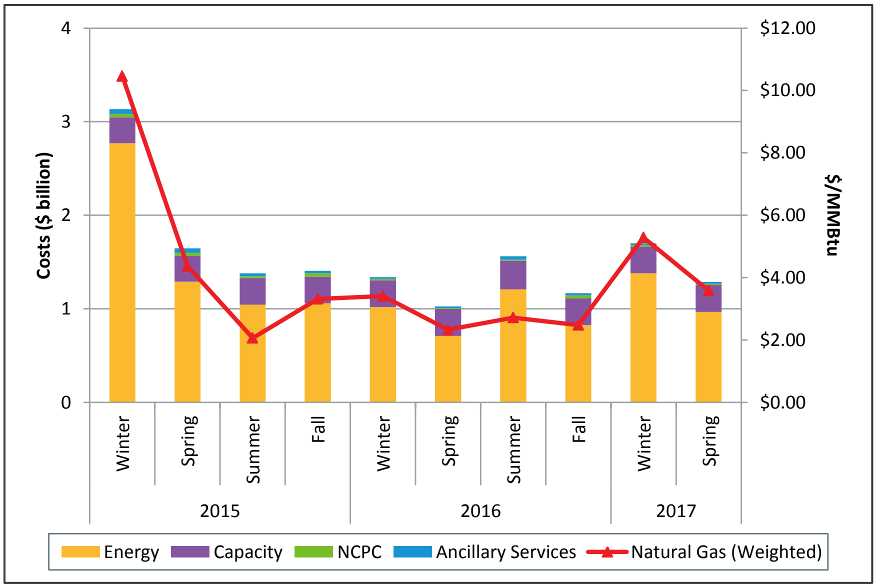
2.1 Market Outcomes

The following subsections present and discuss key trends and drivers of market outcomes from Winter 2015 through Spring 2017.

2.1.1 Total Wholesale Electricity Market Value

The estimated wholesale electricity cost for each season (in billions of dollars) by market, along with average natural gas prices (in $/MMBtu) is shown in Figure 2-1 below.[4, 5]

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



In Spring 2017, the total estimated wholesale market cost of electricity was $1.3 billion, an increase of about 26% compared to $1.0 billion in Spring 2016 and a decrease of 24% over the previous quarter (Winter 2017). Figure 2-1 illustrates how natural gas prices were a key driver behind energy costs from 2015 to 2017. The decrease in natural gas prices in Spring 2017 relative to Winter 2017 resulted in lower energy costs.

[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.

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

At $14 million, Spring 2017 Net Commitment Period Compensation (NCPC) costs represented approximately 1.5% of energy costs, which was a comparable share to the prior Spring. In dollar terms, NCPC costs were 42% higher than Spring 2016 NCPC costs, but 22% lower than Winter 2017 NCPC costs. NCPC is discussed further in Section 2.2.1 below.

Ancillary services, which include operating reserves and regulation, totaled $21 million in Spring 2017. Ancillary services costs increased by 19% and 17% when compared to Spring 2016 and Winter 2017, respectively.

2.1.2 Key Market Statistics

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

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

	Spring 2017	Winter 2017	Percent Change Spring 2017 to Winter 2017	Spring 2016	Percent Change Spring 2017 to Spring 2016
Real-Time Load (GWh)	28,366	31,012	-9%	28,272	0%
Weather-normalized Real-Time Load (GWh)	28,005	31,550	-11%	28,371	-1%
Peak Real-Time Load (MW)	20,181	19,647	3%	19,029	6%
Average Day-Ahead Hub LMP ($/MWh)	$30.78	$41.57	-26%	$23.36	32%
Average Real-Time Hub LMP ($/MWh)	$31.92	$39.89	-20%	$22.10	44%
Average Natural Gas Price ($/MMBtu)	$3.59	$5.29	-32%	$2.33	54%

The price of natural gas was the biggest contributing factor that explains the differences between Spring 2017 and Spring 2016 market outcomes. Though similar in aggregate between the two reporting periods, monthly changes in load during the reporting period contributed to differences in market outcomes between Spring 2017 and Spring 2016 (see Section 2.1.3.2 for a discussion on load).

To summarize the highlights table above:

- Higher natural gas prices were the primary driver for higher day-ahead and real-time LMPs. Natural gas prices increased by 54% compared to the prior spring, driven by a significant an increase in prices in March 2017 compared to March 2016. Prices of $4.46/MMBtu in March 2017 were notably higher (127%) than gas prices in March 2016 due to unseasonably cold weather, particularly in the middle of the month. The impact of natural gas prices on LMPs is further examined in Figure 2-2 and Figure 2-8 below.
- The total real-time load in Spring 2017 was comparable (< 1% higher) to last spring. The peak load for Spring 2017 was 6% higher than the peak load from the prior spring due to hot weather and temperatures over 90°F in mid-May. Changes in load are further discussed in Section 2.1.3.2.

2.1.3 Real-Time Markets

This section of the report covers trends in, and drivers of, energy market outcomes, as well as electricity demand (or load), and the two real-time components of the ancillary services markets; real-time reserves and regulation.

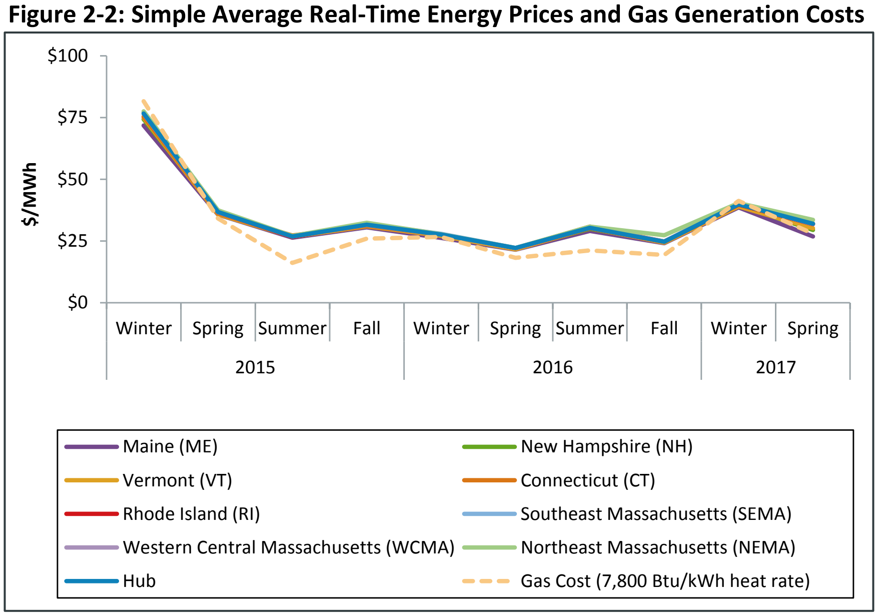
2.1.3.1 Real-Time Energy Market

Energy Prices

The average real-time Hub energy price was $31.92/MWh in Spring 2017, a 44% increase compared to the Spring 2016 average of $22.10/MWh. The increase in energy prices was consistent with the 54% increase in natural gas prices between these periods. The Maine, New Hampshire, and Vermont load zone energy prices were, on average, lower than the Hub price in real-time.[6] Renewable type generation resources located in export-constrained areas of northern New England frequently set real-time prices in these areas and transmission capability reductions contributed to the instances of price separation in these zones during the spring.

The seasonal average real-time energy prices for the Hub and each load zone are shown in Figure 2-2 below. The figure also includes the estimated cost of gas generation for each seasonal period. The cost of gas generation is estimated using a unit heat rate of 7,800 Btu/kWh and average natural gas prices each period.

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



Average real-time energy prices continue to track closely with the cost of natural gas generation in New England. As Figure 2-2 illustrates, the seasonal movements of energy prices (solid lines) are consistent with changes in natural gas generation costs (dashed yellow line). The majority of the year-over-year increase in natural gas prices occurred in March 2017 when gas prices were 127% higher than March 2016 due to significantly colder temperatures in the region ($4.46/MMBtu compared to $1.96). Gas prices were also higher during April and May this year, but to a lesser

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[6] 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.

degree. As was reported in the Spring 2016 quarterly report: the U.S. Energy Information Administration (EIA) cited increased production, above-average storage, and low heating demand during winter 2015-16 as reasons for the historically low gas prices that were observed in the spring of last year.

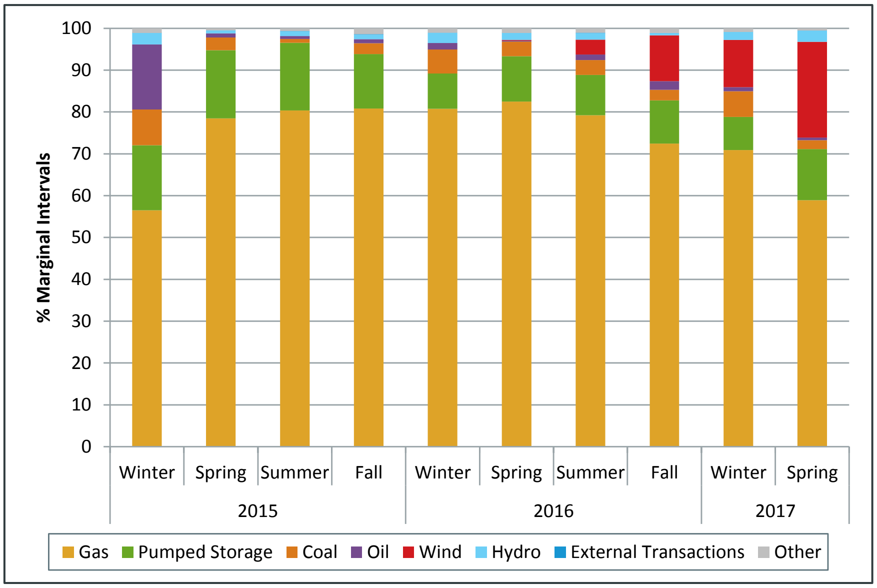
As was noted above, the average Maine, Vermont, and New Hampshire load zone prices were lower than the Hub price during Spring 2017. The average Maine price was $26.80/MWh, which was $5.13/MWh, or 16%, below the Hub average of $31.92/MWh. In the Vermont and New Hampshire zones, average energy prices were 6% and 8%, respectively, below the Hub. For the two and a half year period assessed in this report, the discount in real-time energy prices at all three load zones compared to the Hub was the highest in Spring 2017. In addition to the prevalence of renewable type generators in these export-constrained areas there were also various planned and unplanned line reductions or outages during the period that further reduced the transmission capability available to export power to the rest of the system. The discount in energy prices in Maine, Vermont, and New Hampshire was less pronounced in the day-ahead market. This is largely due to renewable generation typically clearing more in the real-time energy market compared to the day-ahead.

Real-time energy prices in the Northeast Massachusetts and Boston (NEMA) zone averaged $33.57/MWh during Spring 2017 which was $1.64/MWh, or 5%, higher than the Hub. This premium in NEMA energy prices for the period was almost entirely the result of price separation that occurred over the three days from May 17th through May 19th when there were unseasonably high temperatures and loads. System conditions during these days required using more-expensive NEMA resources to meet the Boston area's load and reserve requirements. There were also multiple intervals during this three-day period when the NEMA zone was deficient of thirty-minute operating reserves, which triggered the local reserve constraint penalty factor (RCPF) price.

Marginal Unit by Fuel

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 recent reporting periods, we have observed a reduction in the frequency of marginal gas units being offset by an increase in marginal wind units. Combined, both set price during about 80% of intervals. In Spring 2017, units burning natural gas were marginal (*i.e.*, setting the price) in 59% of the pricing intervals, followed by wind units, which were marginal in 23% of the pricing intervals. Pumped storage units were marginal in 12% of intervals.

This is the first quarterly report in which we have shown wind independent from the "other" category.[7] The higher frequency of marginal wind units is driven by the Do Not Exceed (DNE) dispatch rules which went into effect on May 25, 2016 (at the end of the Spring 2016 reporting period).[8] 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. Most of the wind units are located where the transmission system is regularly export-constrained. This means that the wind units frequently set price within their constrained region while another unit(s) set price for the rest of the system. Wind was the single marginal fuel type on the system in roughly 1% of all five-minute intervals.[9] By contrast, gas was the single marginal fuel type in about 43% of intervals.

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

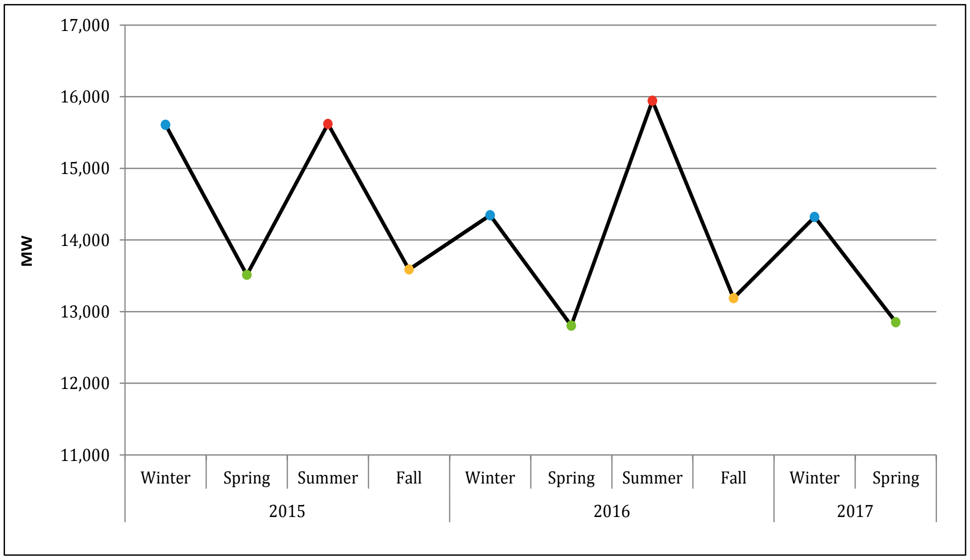
[8] *ISO New England Inc. and New England Power Pool*, Do Not Exceed ("DNE") Dispatch Changes, ER15-1509-000 (filed April 15, 2015); Order Conditionally Accepting, In Part and Rejecting, In Part, Tariff Revisions and Directing Compliance Filing, 152 FERC ¶ 61,065 (2015). In a subsequent filing, the Filing 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.

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

2.1.3.2 Load Summary

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

Figure 2-4: Average Hourly Demand

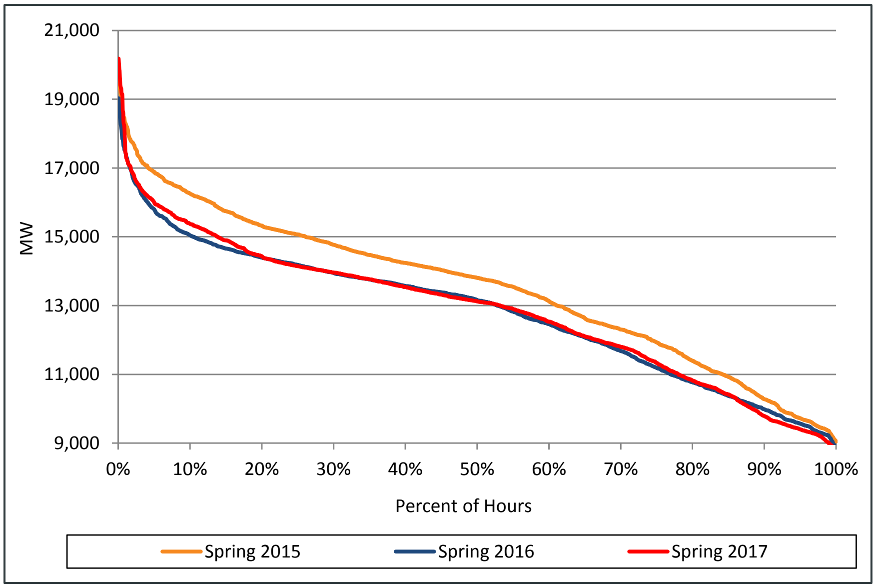


The average hourly load of 12,853 MW in Spring 2017 was comparable to Spring 2016 (12,804 MW), due to similar average weather conditions. Average load in Spring 2015 was noticeably higher at 13,513 MW. Milder temperatures during the past two spring seasons contributed to a decrease in weather-sensitive load compared to Spring 2015.

Of the three months in Spring 2017 (March, April and May), March was unseasonably cold, particularly in the middle of the month, with an average Temperature Humidity Index (THI) of 36°F, compared to 44°F in March 2016. As a result, average load in March 2017, at 13,868 MW, was 6% higher than the same month last year. Natural gas prices were also 127% higher due to a relatively more stressed natural gas system compared to March 2016. April and May 2017 saw slight reductions in load compared to the same months of the prior year, down 2% and 3%, respectively. The average THI in April 2017 was 52°F, higher by 5°F compared to April 2016. May 2017 and May 2016 had the same monthly average THI of 57°F.

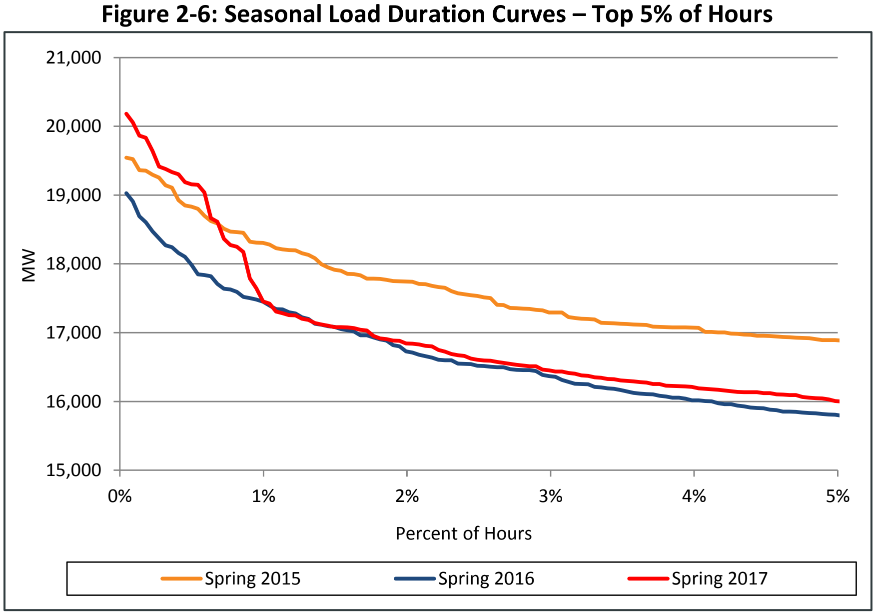
Another way to examine load is to sort all the hourly load values from highest to lowest for any given period. The resulting curve is called a load duration curve. The horizontal axes of the load duration curve are expressed as a percentage of the total number of hours in the period of interest as shown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

Figure 2-5: Seasonal Load Duration Curves



Spring 2017 and 2016 have consistently lower load levels compared to Spring 2015. The contributing factors of lower loads during Spring 2016 and 2017 were milder temperatures and growth of energy efficiency programs and behind the meter generation. To take a closer look at peak load levels, load duration curves for the highest 5% of hour are shown in Figure 2-6 below. In Spring 2017 the peak load was 20,181 MW compared to peak load of Spring 2016 value of 19,029 MW and Spring 2015 peak load value of 19,544 MW.

Figure 2-6: Seasonal Load Duration Curves – Top 5% of Hours



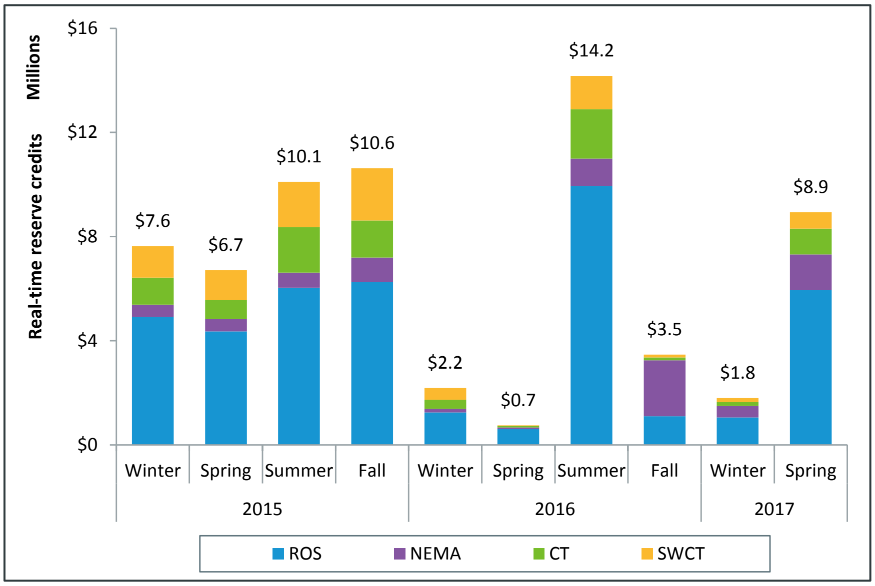
In terms of peak load levels in Spring 2017, the highest 1% of the load was significantly higher than Spring 2016 and marginally higher than Spring 2015. The largest contributing factor of higher peak loads during Spring 2017 was the heat wave of May 18th when temperatures exceeded 90°F.

2.1.3.3 Real-Time Operating Reserves

Real-time reserve payments for the Spring 2017 quarter totaled $8.9 million, which was a large increase relative to the Spring 2016 total of $0.7 million and 33% above the Spring 2015 total of $6.7 million. The total payments for Spring 2017 were primarily accrued over the two-day period of relatively high load levels between May 18th and 19th when 54%, or $4.8 million, of the period credits occurred. During these two days, re-dispatch to maintain reserves was frequently required and there were many intervals when the reserve constraint penalty factors (RCPF) where triggered for ten-minute spinning reserve and thirty-minute operating reserves due to reserve deficiencies.[10]

Total real-time reserve payments by reserve zone for the seasonal quarters from Winter 2015 through Spring 2017 are plotted in Figure 2-6 below. Note that these figures are intended to show the value of real-time reserves and therefore are the gross real-time credits for providing reserve products at the respective real-time clearing price. The netting of real-time payments for a participant's forward reserve market obligations is not accounted for in the chart totals. For reference, the total reductions for forward reserve obligations amounted to $1.6 million during Spring 2017, which resulted in total net real-time payments of $7.3 million.

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



As shown in Figure 2-6, total real-time reserve payments were higher in Spring 2017 than the preceding two spring periods. The distribution of payments among the reserve zones reflects that the majority of reserve pricing occurred for system requirements over this quarter. The frequency of non-zero reserve pricing by zone along with the average price during these intervals over the past three Spring periods are shown in Table 2-2 below. Non-zero reserve pricing means that there was an opportunity cost associated with dispatching the system in order to hold generators back for reserves or a reserve deficiency in the energy and reserve co-optimization process.

[10] The reserve constraint penalty factors are limits on the re-dispatch costs the system will incur to satisfy reserve constraints and will function as the reserve clearing price during a reserve deficiency. The penalty factors for the respective reserve products and their application are defined in Market Rule 1 Section III.2.7.A.

Table 2-2: Hours and Level of Non-Zero Reserve Pricing

Product	Zone	Spring 2017		Spring 2016		Spring 2015	
		Avg. Price $/MWh	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*	*Avg. Price $/MWh*	*Hours of Pricing*
TMSR	System	$15.85	399.7	$8.72	175.5	$26.66	130.7
TMNSR	System	$4.20	0.7	$0.00	0.0	$16.06	0.8
TMOR	System	$4.13	13.5	$0.00	0.0	$16.01	7.1
	NEMA/Boston	$11.08	30.6	$0.00	0.0	$21.86	8.8
	CT	$4.13	0.0	$0.00	0.0	$16.01	0.0
	SWCT	$4.13	0.0	$0.00	0.0	$16.01	0.0

As shown in Table 2-2, there were about 400 hours of system ten-minute spinning reserve pricing during Spring 2017. During these hours, there were 11.4 hours of reserve deficiency. The frequency of ten-minute spinning reserve pricing was much higher than the prior two spring periods. System thirty-minute operating reserve pricing occurred for a total of 13.5 hours and the replacement thirty-minute operating reserve RCPF was triggered for 45 minutes. The system thirty-minute operating reserve pricing and deficiencies occurred primarily on the two day period from May 18th through May 19th. Beginning on May 17th and through the 19th, there were almost 30 hours when the NEMA zone had localized thirty-minute operating reserve pricing, including 7 hours of reserve deficiency when the local RCPF was triggered. Otherwise, reserve pricing and credits were not localized to reserve zones during Spring 2017.

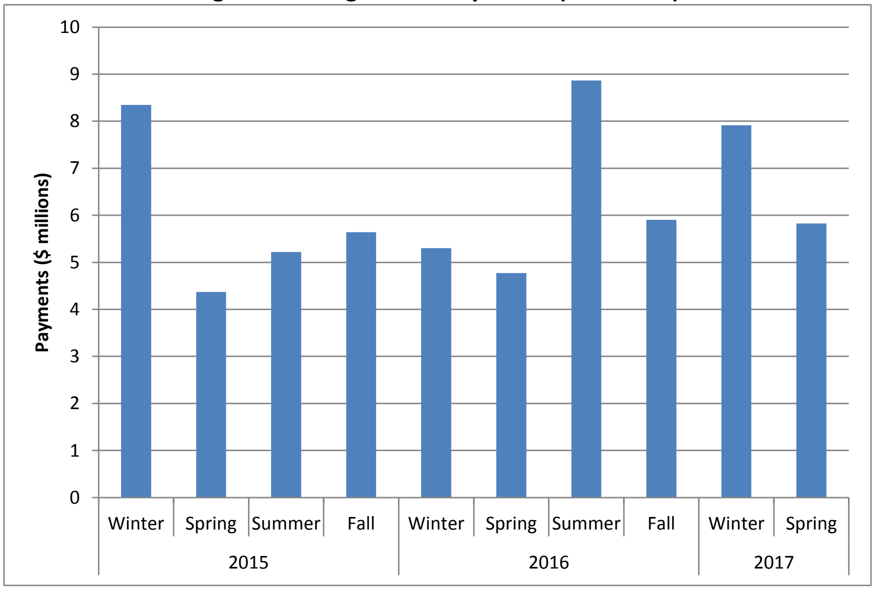
During the Spring 2017 period, overall thirty and ten-minute operating reserve margins (reserves in excess of the requirement) were down compared to Spring 2016 which is consistent with the increased frequency of reserve pricing. There were two underlying factors that led to the decreased margins compared to last spring: a higher volume of generation outages and an increase in the typical system first contingency size. The outage of the Phase II interface for upgrades reduced the system first contingency requirement for a two-month period during Spring 2016.

2.1.3.4 Regulation Market

Quarterly regulation payments are shown in Figure 2-7 below.[11]

[11] 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.

Figure 2-7: Regulation Payments ($ millions)



Total regulation market payments were $5.8 million during the reporting period, down 26% from $7.9 million in Winter 2017, and up 22% from $4.8 million in Spring 2016. Spring regulation payments are typically lower than winter payments, as elevated winter period fuel and electricity prices contribute to higher opportunity costs for providing regulation services in the winter period. Comparing Spring 2017 to Spring 2016, higher fuel and electricity prices in Spring 2017 (relative to the earlier period) similarly resulted in higher regulation pricing and payments.

2.1.4 Forward Markets

This section of the report covers activity in markets in which transactions occur prior to the actual operating day, or delivery period. As with the prior section on the real-time energy market, this section discusses trends and drivers of day-ahead energy prices. It also covers activity during the reporting period in financial transmissions rights (FTRs), the forward capacity market (FCM) and the forward reserve market (FCM).

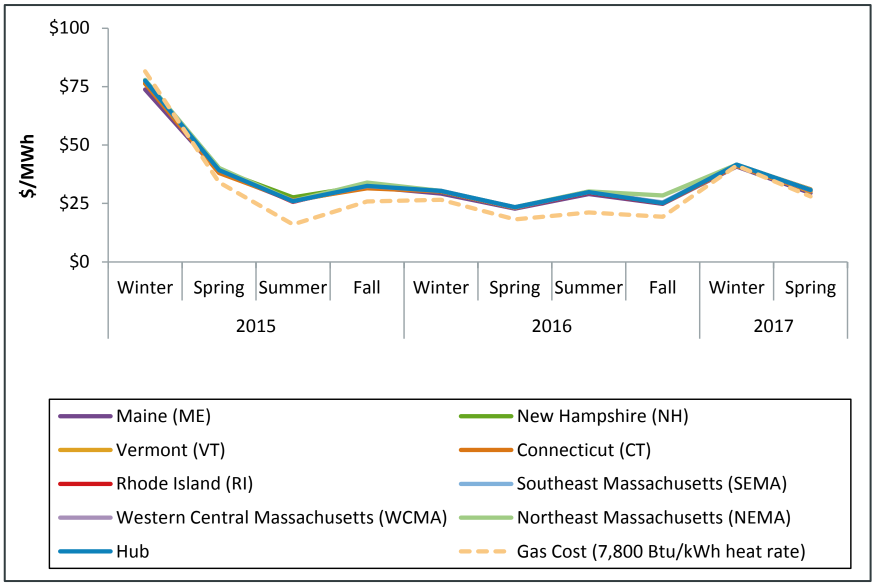
2.1.4.1 Day-Ahead Energy Market

Energy Prices

The average day-ahead Hub energy price for Spring 2017 was $30.78/MWh, which was 32% higher than the Spring 2016 average of $23.36 per MWh. Similar to real-time, day-ahead energy prices remained correlated with natural gas prices. Prices did not differ significantly among the load zones with the exception of Maine, New Hampshire, and Vermont which had average day-ahead prices lower than the Hub. Price separation in these areas was generally consistent with, although not as significant as, the price separation observed in real-time and discussed in section 2.1.3.1 above.

The seasonal average day-ahead energy prices for the Hub and each load zone are shown below in Figure 2-8 along with the estimated cost of gas generation based on average natural gas prices each season and a unit heat rate of 7,800 Btu/kWh.

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

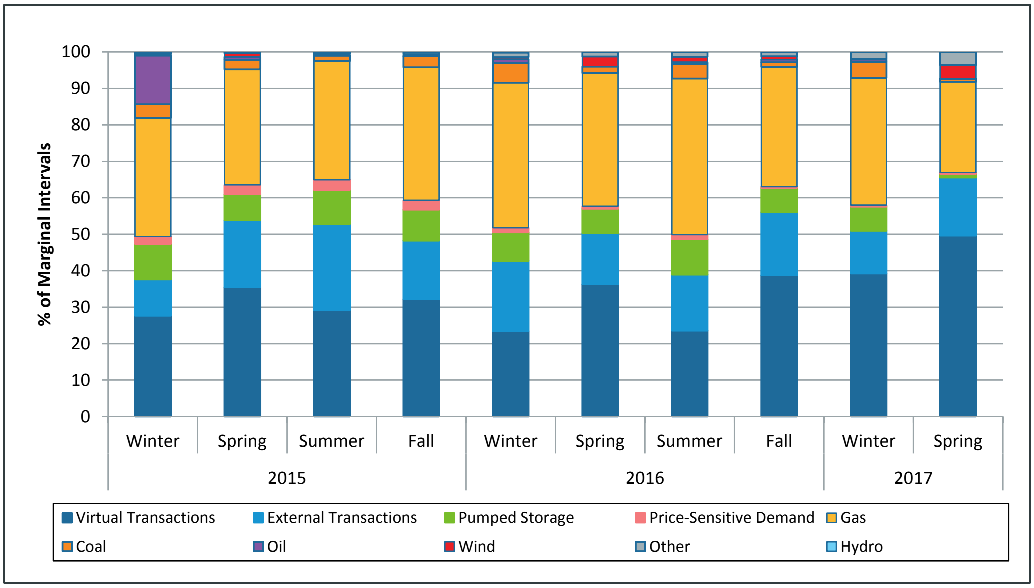


As Figure 2-8 shows, the Spring 2017 day-ahead average energy price of $30.78/MWh was higher than the Spring 2016 average of $23.36/MWh, but was below the average of $39.31/MWh observed two years prior in Spring 2015. These changes in energy prices across the past three spring periods are consistent with the fluctuations in natural gas generation costs, which are illustrated by the dashed yellow line series in Figure 2-9. For the Spring 2017 period, day-ahead Hub prices were 3.6%, or $1.14 per MWh, below the real-time Hub price, on average. The positive deviation in real-time prices for the period was driven by several days with high loads and unit outages during early April as well as the two-days from May 18th through May 19th when high temperatures resulted in loads higher than were forecasted and several units had forced outages.

Marginal Unit by Fuel and Transaction Type

The percentage of time that each resource type set price in the day-ahead market since Winter 2015 is illustrated in Figure 2-9 below. In addition to generators, there are other entities that can set price in the day-ahead market, including price-sensitive demand, priced external transactions, and virtual transactions. In the graph, marginal units are shown by category, and generators are outlined in blue and broken up by fuel type further within the generator category.

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

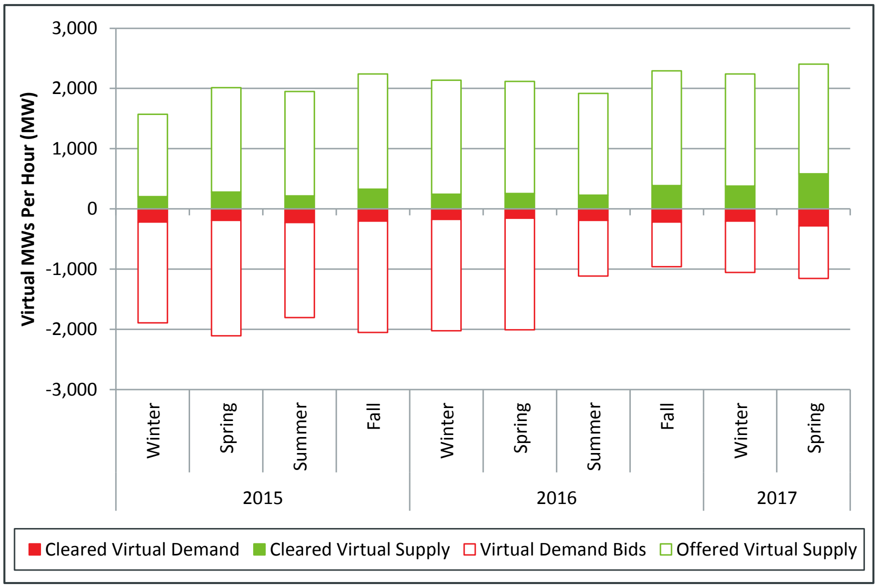


The type and frequency of resources that set price varies from one period to the next. This is due to the mix of resource types participating in both the supply and demand side of the day-ahead market. In the day-ahead market, participants may submit virtual bids and offers, and fixed and priced demand, 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 and relatively recent trends. A large increase in marginal virtual supply offers appeared in Fall 2016, and persisted into Spring 2017. Virtual transactions (virtual supply and demand) set price approximately 50% of the time, which represents an increase from 36% in Spring 2016. This increase is due to a higher frequency of virtual supply offers being marginal in export-constrained areas. In most of these intervals, virtual supply offers were not the only marginal transaction on the system and only set price for the whole system in 9% of hours in Spring 2017. Aside from virtual transactions, generators set price approximately 34% of the time, and external transactions set price approximately 16% of the time.

Virtual transaction volumes from Winter 2015 through Winter 2017 are shown in Figure 2-10 below.

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 3,560 MW per hour, an 8% increase from Winter 2017, and a 14% decrease from Spring 2016. Although submitted virtual transactions decreased from last Spring, the total volume of cleared virtual transactions in Spring 2017 was more than double last year's value. The percentage of virtual transactions that cleared was 24% in Spring 2017, much higher than the 10% that cleared in Spring 2016. Beginning in Summer 2016, the average offer prices of virtual transactions have converged towards actual LMPs, resulting in higher percentages of virtual transactions clearing. A reduction in transaction costs, in the form of NCPC, has likely contributed to this offer behavior. Beginning in February 2016, the per-MW real-time economic NCPC charge decreased substantially and has remained low. Real-time economic NCPC is charged to deviations from the day-ahead schedule, including virtual transactions. In February 2016, real-time economic NCPC payments made to generators receiving a day-ahead commitment were eliminated, reducing the total pool of real-time economic NCPC paid. More about NCPC can be found in Section 2.2.1.

2.1.4.2 Financial Transmission Rights

Three Financial Transmission Rights (FTR) auctions were conducted during the reporting period for a combined total of 89,435 MW of FTR transactions. The total amount distributed as Auction Revenue Rights (ARRs) was $2 million, which was a similar amount to the previous reporting period. Thirty-one bidders in March, twenty-nine bidders in April and twenty-nine bidders in May 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.[12] 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

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

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

During any three-month period there can be FCM activity for up to four commitment periods. The initial capacity auction occurs three years and three months before the commitment period begins.[13] Between the initial auction and the commitment period, there are six discrete opportunities to adjust annual capacity supply obligations (CSOs). Three of those are bilateral auctions where obligations are traded between resources at an agreed upon price and approved by the ISO. The other three are reconfiguration auctions run by the ISO, where participants can submit supply offers to take on obligations, or submit demand bids to shed obligations.

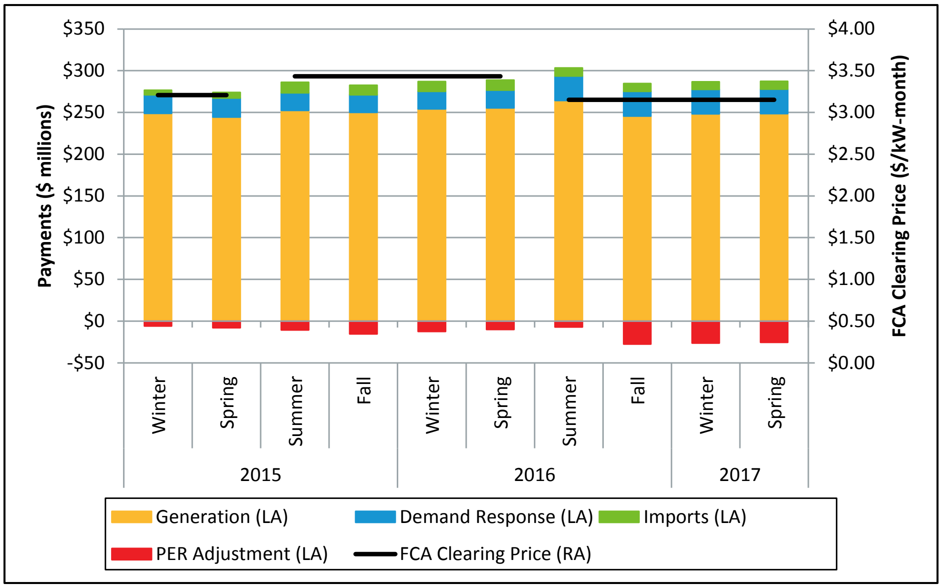
Monthly reconfiguration auctions and bilateral trading begin a month after the third annual reconfiguration auction, and occur two months before the relevant delivery month. Like the annual auctions, participants can take on obligations or shed obligations. Trading in monthly auctions adjusts the CSO position for a particular month, not the whole commitment period. The following sections summarize FCM activities during the reporting period, including total payments and trading of CSOs specific to each commitment period.

The current capacity commitment period (CCP) started on June 1st, 2016 and ended on May 31st, 2017. In the corresponding Forward Capacity Auction (FCA 7), there was price separation between the NEMA/Boston import-constrained zone and Rest-of-Pool. The price separation was due to inadequate supply in the NEMA/Boston zone. NEMA/Boston cleared at $15.00/kW-month for new resources and $6.66/kW-month for all existing resources. Existing resources were priced using administrative rules designed to protect the market from the exercise of market power. These administrative pricing provisions were used because there was insufficient competition among new resources to set a competitive price. The clearing price for the Rest-of-Pool zone was the floor price of $3.15/kW-month.

Total FCM payments as well as the existing clearing price for Winter 2015 through Spring 2017 are shown in Figure 2-11 below. The black lines (corresponding to the right axis, "RA") represent the FCA clearing prices for existing resources in the Rest-of-Pool capacity zone. The orange, blue, and green bars (corresponding to the left axis, "LA") represent payments made to generation, demand response, and import resources, respectively.

[13] 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 2-11: Total Capacity Payments ($ millions)



Total net FCM payments (top of stacked bars) have declined from the beginning of the capacity commitment period due to peak energy rent reductions. In Spring 2017, capacity payments totaled $287 million, which accounts for adjustments to primary auction CSOs.[14] The proportion of payments to each resource type has remained relatively constant over the reporting period. The negative red bar represents the reduction in payments due to Peak Energy Rent (PER) adjustments. Peak energy rent adjustments remained higher than in previous seasons because of high real-time energy prices that occurred in August 2016.[15] In Spring 2017, PER adjustments totaled $26 million.

Secondary auctions allow participants the opportunity to acquire or shed capacity after the initial auction. Table 2-3 provides a summary of prices and volumes associated with reconfiguration auction and bilateral trading activity during Spring 2017, alongside the results of the relevant primary Forward Capacity Auction (FCA).

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

[15] The incremental impacts of peak energy rent in any given month are amortized over the following twelve months as a part of the twelve-month rolling average. 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-ssets/documents/2016/11/qmr_2016_q3_summer_11_15_2016.pdf .

Table 2-3: Primary and Secondary Forward Capacity Market Prices for the Reporting Period

FCA # (Commitment Period)	Auction Type	Period	Systemwide Price ($/kW-mo)**	Cleared MW	Capacity Zone/Interface Prices		
					NEMA/Bos	New Brunswick	New York AC Ties
FCA 7 (2016-17)	Primary	12-month	3.15	36,220	15.00/6.66*		
	Monthly Reconfiguration	17-May	0.8	868	6.66		
	Monthly Bilateral	17-May	2.25	119			
FCA 8 (2017-18)	Primary	12-month	15.00/7.03*	33,712	15.00/15.00*		
	Annual Reconfiguration (3rd)	12-month	3.5	278			
	Monthly Reconfiguration	17-Jun	6.1	441		5.75	
	Monthly Bilateral	17-Jun	1.76	115			
	Monthly Reconfiguration	17-Jul	4.64	600			
	Monthly Bilateral	17-Jul	5.66	117			
FCA 10 (2019-2020)	Primary	12-month	7.03	35,567		4	6.26
	Annual Bilateral (1)	12-month	7.03	0.1			

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

Monthly Periods

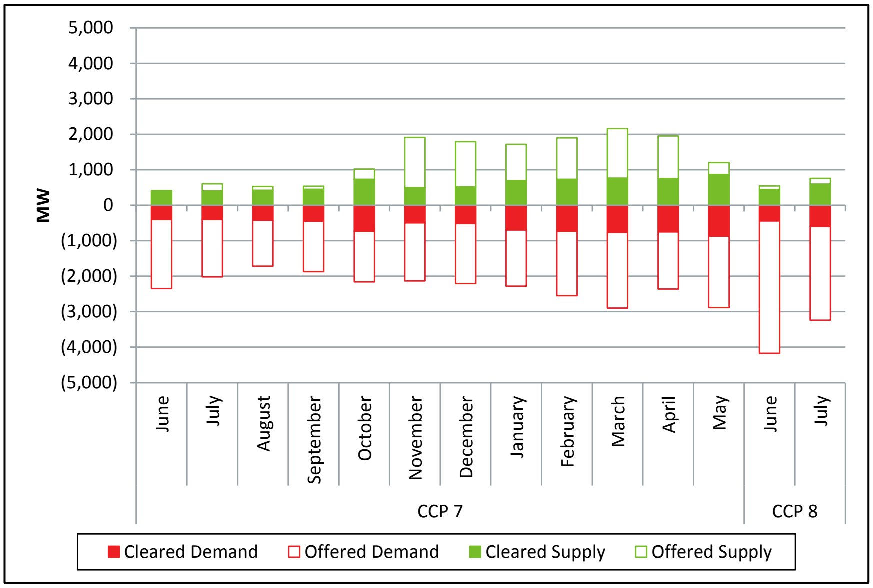
Monthly reconfiguration prices increased over the reporting period in line with higher FCA clearing prices and a lower surplus of summer qualified capacity compared to the winter qualified capacity. Two of the monthly auctions occurred for June and July 2017. These periods coincide with the beginning of CCP 8, where the system-wide clearing price was $15.00/kW-month for new resources, and $7.03/kW-month for existing resources.[16] Higher FCA prices increase the value of capacity. Therefore, we expect the higher reconfiguration clearing prices ($6.10/kW-month in June, $4.64/kW-month in July) compared to previous auctions ($0.80/kW-month in May).

Additionally, most thermal generating resources have lower capability during the summer period when ambient temperatures are higher. These resources have less uncovered capacity during summer reconfiguration auctions.[17] This has potential to limit supply in the reconfiguration auctions. Figure 2-12 shows supply and demand bids in the reconfiguration auctions associated with CCPs 7 and 8. The green bars represent total supply offers, while the red bars represent total demand bids in monthly reconfiguration auctions. The solid section of each bar illustrates total supply or demand cleared in those auctions.

[16] The period begins June 1st, 2017 and ends May 31st, 2018. The price for existing resources in NEMA/Boston was $15.00/kW-month.

[17] The summer period is different for demand response and generation/import resources. See Market Rule III.13.1.5(a) for more information.

Figure 2-12: Reconfiguration Auction Quantities in CCP 7 and 8



Average offered supply in the winter months is 1,700 MW. In comparison, summer months from CCPs 7 and 8 average 560 MW of offered supply. Along with less supply, the June auction had over 4,000 MW of demand bids (resources willing to shed their obligation).

Annual Periods

The third annual reconfiguration auction for CCP 8 took place in March 2017 and cleared 278 MW at a system-wide price of $3.50/kW-month, or roughly half of the clearing price in FCA 8 for existing resources. The ISO offered 555 MW of supply in the auction because expected system needs were lower than total capacity obligations. The driving factor of surplus capacity was the downward revisions to the Net Installed Capacity Requirement (NICR) since ARA 1. The NICR declined by roughly 900 MW between ARA 1 and ARA 3, essentially reversing the overall system short position from the primary auction and ARA 1, to a long position in ARA 3.

The first annual reconfiguration period occurred for CCP 10 (2019-2020) during Spring 2017. The first annual bilateral period closed on April 7th. There was only roughly 100 kW of capacity transferred among resources.

2.1.4.4 Forward Reserve Market Auction for Summer 2017

Twice each year, ISO New England holds forward reserve auctions. The ISO uses forward reserve auctions to enter into forward obligations with participants to provide operating reserves in the real-time energy market. These forward obligations are intended to ensure the delivery of adequate operating reserves for both the ISO New England control area and local reserve zones within the control area. On April 28th, 2017, ISO New England held the forward reserve auction for the Summer 2017 delivery period (i.e., June 1st, 2017 to September 30th, 2017).[18]

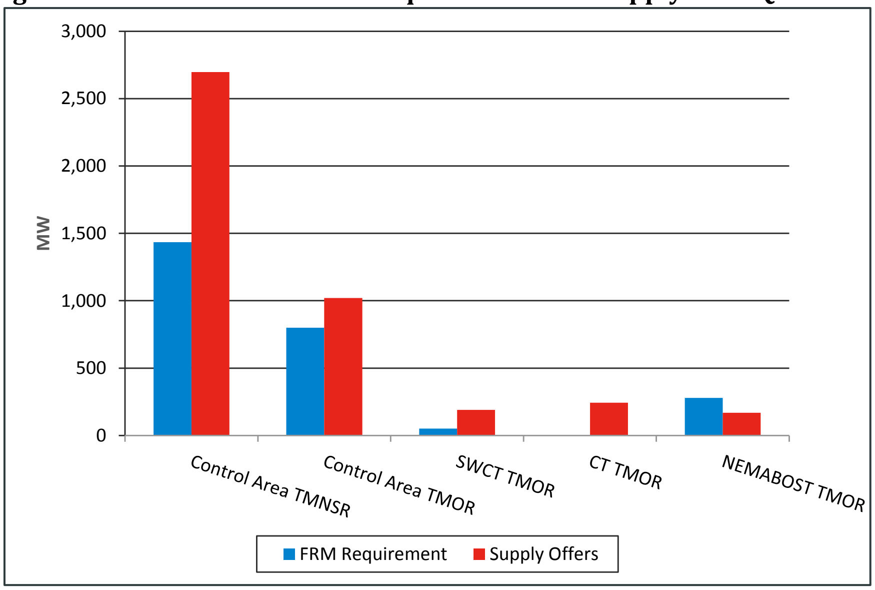
[18] The Forward Reserve Market has 2 delivery ("procurement") periods per year: Summer (June 1 to September 30) and Winter (October 1 to May 31).

Auction Reserve Requirements

Prior to each auction, the ISO establishes the amount of forward reserves, or requirements, for which it will enter into forward obligations. These requirements are set at levels intended to ensure adequate reserve availability, based on possible control area and local reserve zone contingencies (unexpected events such as the forced outage of a large generator or loss of a large transmission line).

Figure 2-13 below indicates the requirements for the Summer 2017 auction. These requirements were specified for the ISO New England control area and three local reserve zones.[19] The figure also indicates the total quantity of supply offers available in the auction to satisfy the reserve needs.[20]

Figure 2-13: Forward Reserve Requirements and Supply Offer Quantities



For the control area, requirements were set for two reserve products, ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR); the ISO bases the requirements for each product on possible system contingencies. For TMNSR, the requirement was based on the expected single contingency of the Hydro Quebec Phase II Interconnection, and was estimated as a 1,435 MW TMNSR reserve need. The control area TMOR requirement was based on the expected single contingency of the Mystic 8 and 9 generators, and was estimated as an 800 MW TMOR need.[21]

[19] The local reserve zones are Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston (NEMABOST).

[20] Because TMOR supply offers within local reserve zones also provide TMOR to the Control Area, the Control Area TMOR offers shown in the figure include the local reserve zone supply offers. Hence, the Control Area TMOR offers represent the total offers throughout the Control Area.

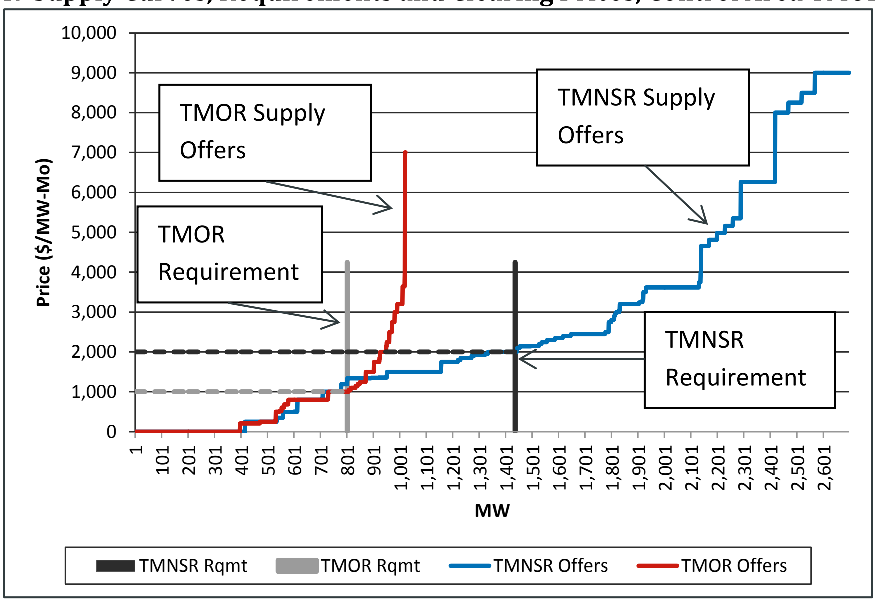
[21] ISO New England Memorandum to Market Participants (Subject: Assumptions and Other Information for the Summer 2017 Forward Reserve Auction), published March 16, 2017, indicates the control area and local reserve zone requirements.

For the local reserve zones, only a TMOR requirement is specified. The ISO bases the local requirements on local second contingencies, adjusted for the availability of transmission capacity (which also can effectively supply reserves to the local area).[22] After adjustments, the Connecticut reserve zone was found to need no local reserve requirement, as "external reserve support" (available transmission capacity) exceeded the local second contingency requirement; the Southwest Connecticut reserve zone required just 52 MW of local reserves, and NEMA/Boston needed 279 MW of local reserves.

Supply and Auction Pricing

As noted previously, control area supply offers in the Summer 2017 auction exceeded the requirements for both TMNSR and TMOR. Adequate supply ensures that the ISO can successfully obtain forward obligations to meet expected reserve needs in the auction. Figure 2-14 provides the control area supply curves for both TMNSR and TMOR, and indicates the auction clearing prices for each, given the reserve requirements.

Figure 2-14: Supply Curves, Requirements and Clearing Prices, Control Area TMOR & TMNSR



With a control area requirement of 800 MW, TMOR control area supply offers resulted in a clearing price of $1,000/MW-month (gray dashed line in the figure).[23] TMNSR supply offers led to pricing of $2,000/MW-month (black dashed line in the figure), given the reserve requirement of 1,435 MW. These clearing prices are lower than the Summer 2016 auction clearing prices for the control area TMOR and TMNSR reserve products, which were $2,000/MW-month and $2,498/MW-month (respectively).

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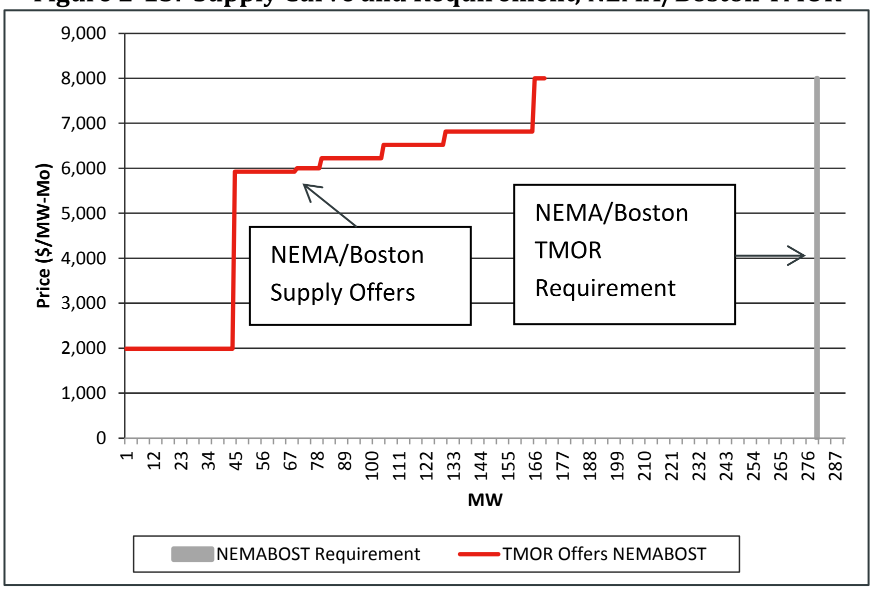
[22] See the ISO New England Manual for Forward Reserve and Real-Time Reserve for a more detailed indication of the determination of local reserve requirements (Manual M-36, Sections 2.2.3 – 2.2.5). The transmission capacity used to adjust the local requirement is referred to as "external reserve support."

[23] Because local reserve zone TMOR supply can be used to satisfy the control area requirement, local TMOR supply that was cleared to satisfy local TMOR requirements is shown as unpriced (at $0/MW-month) supply on the control area supply curve. This results from local TMOR supply being needed irrespective of the control area's reserve requirement and clearing price. The same result could be produced by using an adjusted "rest of system" requirement and supply curve that excluded the procurement of supply in local reserve zones.

For the local areas, the Southwest Connecticut reserve zone had adequate supply to clear at a price below the control area TMOR price of $1,000/MW-month. Because the local TMOR supply also counts toward meeting the system TMOR requirement, the Southwest Connecticut supply cannot receive a price that is lower than the control area TMOR price; as a result, the Southwest Connecticut TMOR supply that cleared in the auction received the control area price of $1,000/MW-month. This price is lower than the Summer 2016 auction clearing price of $2,000/MW-month.

The supply curve for the NEMA/Boston reserve zone in the Summer 2017 Auction, relative to the local reserve requirement is shown in Figure 2-15 below. As indicated in the figure, the offered TMOR supply was inadequate to satisfy the local reserve requirement.

Figure 2-15: Supply Curve and Requirement, NEMA/Boston TMOR



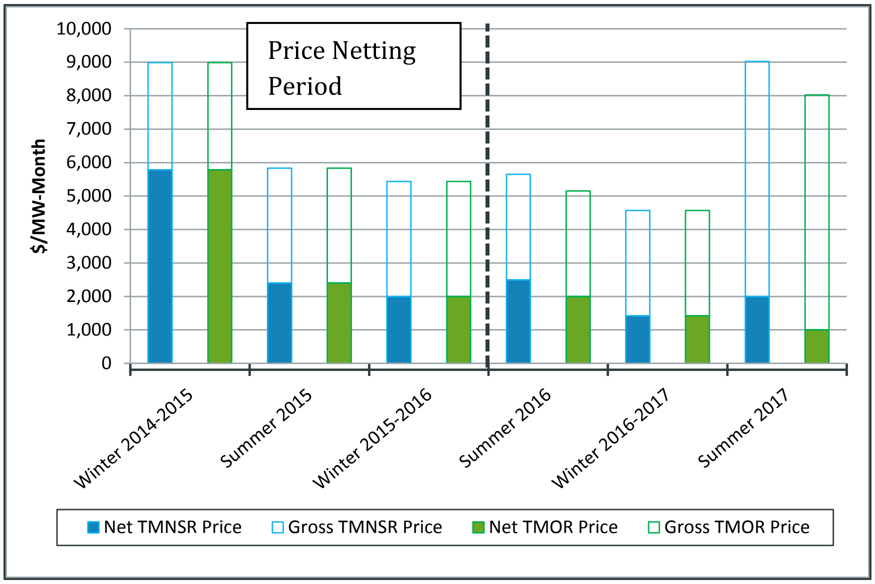
Because of inadequate supply, the TMOR price for NEMA/Boston was set to the auction's offer price cap of $9,000/MW-month.[24] Since the NEMA/Boston area also had inadequate supply to satisfy the local reserve requirement in the Summer 2016 auction, the clearing price for the 2017 auction is the same as the clearing price for the year-prior auction.

Price Summary

The gross and net forward reserve prices for system-wide TMNSR and TMOR are shown in Figure 2-16 below; for periods prior to Summer 2016, FRM auction prices were netted against Forward Capacity Market clearing prices, and the net price represents the FRM auction income for participants. Beginning with Summer 2016, FRM auction prices are no longer netted. In the figure, the gross price indicates the FRM auction income plus the FCA price (both stated as $/MW-month values), while the net price shows the FRM-only income. The net price provides the effective TMNSR and TMOR compensation rates for FRM system-wide resources for all periods in the graph. The gross price represents the FRM auction clearing price for 2015 and earlier periods. The net price represents the auction clearing price for later auctions.

[24] ISO New England's Market Rule 1 specifies: "If there is insufficient supply to meet the Forward Reserve requirements for a Reserve Zone, the Forward Reserve Clearing Price for that Reserve Zone will be set to the Forward Reserve Offer Cap."

Figure 2-16: Gross and Net Forward Reserve Market Clearing Prices for System-Wide TMNSR and TMOR



Over the review period, TMOR auction income has consistently declined at the system-wide level. TMNSR auction income has declined relative to Winter 2014-15, but has maintained more consistent pricing in subsequent auctions.

Structural Competitiveness

The competitiveness of the FRM is measured by the Residual Supply Index (RSI). RSI measures the extent to which an individual participant has market power and controls enough supply to be able to increase price above a competitive level. In other words, the RSI measures the percentage of the forward reserve requirement that can be met without the largest FRM portfolio offer. If the requirement cannot be met without the largest supplier then that supplier is pivotal. The RSI is calculated based on the FRM offer quantities.

The RSI for TMNSR is computed at a control area (or system) level based on the total quantity of TMNSR offers across all reserve zones, excluding the largest TMNSR offer quantity by a single market participant. The RSI for TMOR is computed similarly for each reserve zone with a non-zero TMOR local reserve requirement. Given that the TMNSR quantity also satisfies the TMOR requirement, the TMNSR offer quantity in a zone is included in the total TMOR offer quantity within that zone.

The heat map table – Figure 2-17 below - shows the offer RSI for TMNSR for the control area and TMOR for zones with a non-zero TMOR requirement. The colors indicate the degree to which structural market power was present, starting with low RSIs shown in red, followed by white and green colors, with the later indicating that there was still ample offered supply without the largest supplier.

Figure 2-17: Offer RSI in the FRM for TMNSR (system-wide) and TMOR (zones)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI TMOR (ROS)	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Winter 2014-15	107	186	**84**	215	N/A
Summer 2015	117	158	**69**	122	**12**
Winter 2015-16	109	154	283	382	N/A
Summer 2016	203	222	**76**	N/A	**23**
Winter 2016-17	313	308	302	N/A	N/ A
Summer 2017	240	278	183	N/A	**21**

An RSI value less than 100 (shown in red) indicates the presence of at least one pivotal supplier, which means the auction was not structurally competitive. Pivotal suppliers may be able to strategically offer reserves at uncompetitive prices. Figure 2-17 shows that there were pivotal suppliers in three instances during the prior three auctions.

Generally, the RSI values can fluctuate significantly from auction to auction. These fluctuations can be explained by the significant variation in the reserve requirement. For instance, for the SWCT zone the TMOR RSI value jumped from 76 (structurally uncompetitive levels) in Summer 2016 auction to 302 (structurally competitive level) in Winter 2016-17 period. For the same zone and time period, the TMOR local requirement went down from 250 MW to 32 MW. More suppliers were competing to fill a lower requirement.

For the Summer 2016, Winter 2016-17, and Summer 2017 procurement periods, the TMNSR RSI values were significantly greater than 100; earlier period values were competitive, but closer to the competitiveness threshold. These values suggest that the TMNSR offer quantities in these auctions were consistent with a structurally competitive level.

Similarly, the TMOR RSI values for the Rest-of-System (ROS) zone were consistent with a structurally competitive level.[25] The Southwest Connecticut (SWCT) zone was structurally competitive for the Winter 2015-16, Winter 2016-17 and Summer 2017 periods, but the offer RSI value was below a structurally competitive level for the Winter 2014-15, Summer 2015 and Summer 2016 periods. Connecticut did not have any auctions that were below the structurally competitive level. In NEMA/Boston, the RSI value for that zone was significantly below a competitive level for each of the three Summer periods. Every participant who offered forward reserves in NEMA/Boston was pivotal in those auctions because the total offered quantity was significantly below the local requirement.

2.2 System Conditions

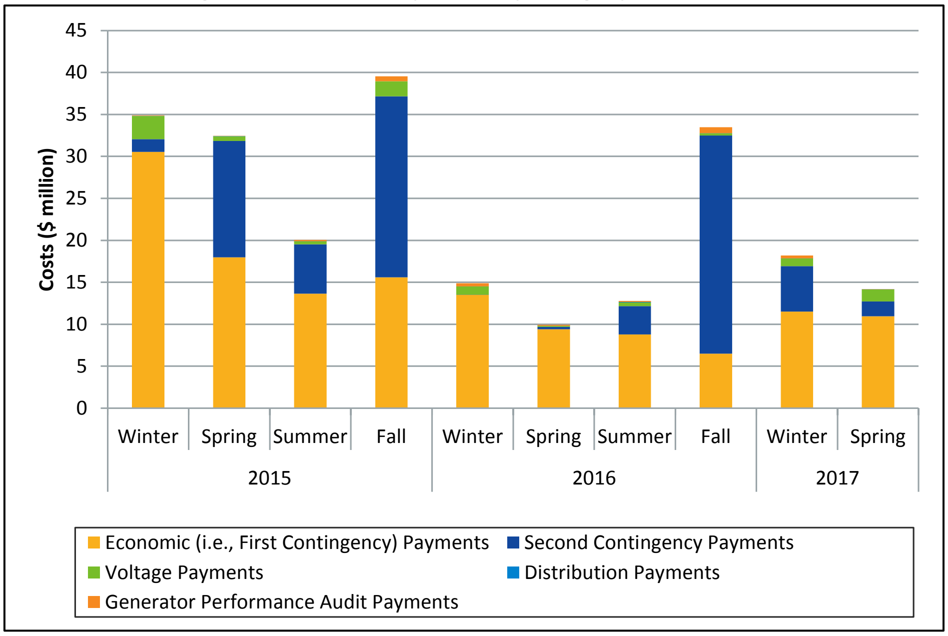
The following subsections cover recent trends and outcomes in Net Commitment Period Compensation (NCPC), or uplift payments, flows of power between New England and its neighboring control areas, and a breakdown of generation by fuel type.

[25] The "rest-of-system" zone is simply the portion of the control area that excludes the local reserve zones (CT, SWCT, and NEMABOST).

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 a number of services, including first- and second-contingency protection, voltage support, distribution system protection, and for generator performance auditing.[26] NCPC payments by season and category are illustrated in Figure 2-18.

Figure 2-18: NCPC Payments by Category ($ millions)



In Spring 2017, NCPC payments totaled $14.2 million, representing about 1.5% of total wholesale energy costs for the season, similar to Spring 2016 (1.4%). In dollar terms, this is a 42% increase compared to the same season last year ($9.9 million), but 22% less than what was paid last quarter. As shown in Figure 2-18, these differences were mainly driven by changes in first contingency, second contingency, and voltage payments between the time periods.

The majority of NCPC (77%) incurred during the reporting period was for first contingency protection.[27] First contingency payments of $11.0 million were 16% higher than payments

[26] 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*.

[27] First Contingency payments include real-time dispatch lost opportunity cost NCPC and rapid response pricing NCPC beginning in Spring 2017. Dispatch Lost-Opportunity Cost (DLOC) is an NCPC credit calculated for a resource instructed by the ISO to run at a level less than its economic dispatch point. DLOC compensates the resource for the difference between the maximum net revenue it could have earned at its economic dispatch point and the actual net revenue earned at the dispatch instruction point. Rapid-Response-Pricing Opportunity Cost (RRPOC) is an NCPC credit calculated for a resource that is postured down when a rapid-response resource is setting price. RRPOC compensates the resource for the difference between the amount it would have earned for energy and reserves absent being postured down and the

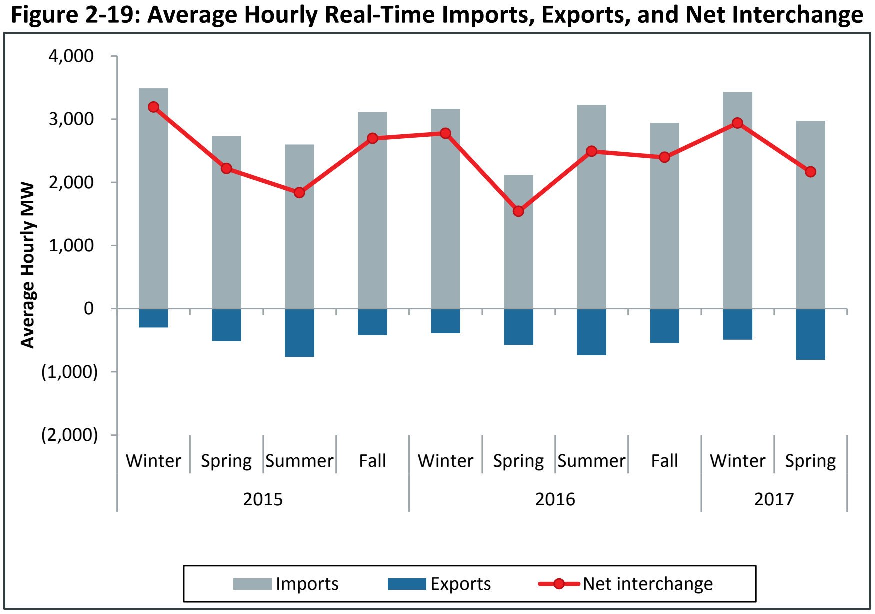
made last spring but 5% lower than payments made in Winter 2017. Of the total first contingency payments in the reporting period, $1.3 million (12%) were paid in real-time on May 18th and 19th when the system experienced an M/LCC2 event and tight conditions resulting in additional generator commitments. Many of these committed generators were subsequently paid NCPC and made whole to their offers for periods during which they were committed and didn't recover their full costs though the LMP. Similarly, payments for second contingency protection totaled nearly $1.0 million between May 17th and May 20th when system conditions necessitated reliability commitments in local areas. These payments made to units in NEMA, SEMA, and Rhode Island accounted for 56% of total second contingency payments made in the reporting period.

Lastly, voltage payments in the quarter totaled $1.4 million. Though small relative to other NCPC types, it was a significant increase compared to $0.1 million last spring and $0.9 million last quarter. The increase in payments was mainly associated with outages which required specific generator commitments for voltage support.

2.2.2 Net Interchange

New England was a net importer of 2,163 MW per hour, on average, during Spring 2017, which was 625 MW, or 41%, more than the average net interchange of 1,538 MW per hour in Spring 2016. Additional imports over the Phase II interconnection were the cause of the year-over-year increase in net imported power volumes. Last year during Spring 2016, Phase II was out of service for two months for equipment replacement and testing. The hourly average gross import and export power volumes and the net interchange amount are shown in Figure 2-19 below.

Figure 2-19: Average Hourly Real-Time Imports, Exports, and Net Interchange



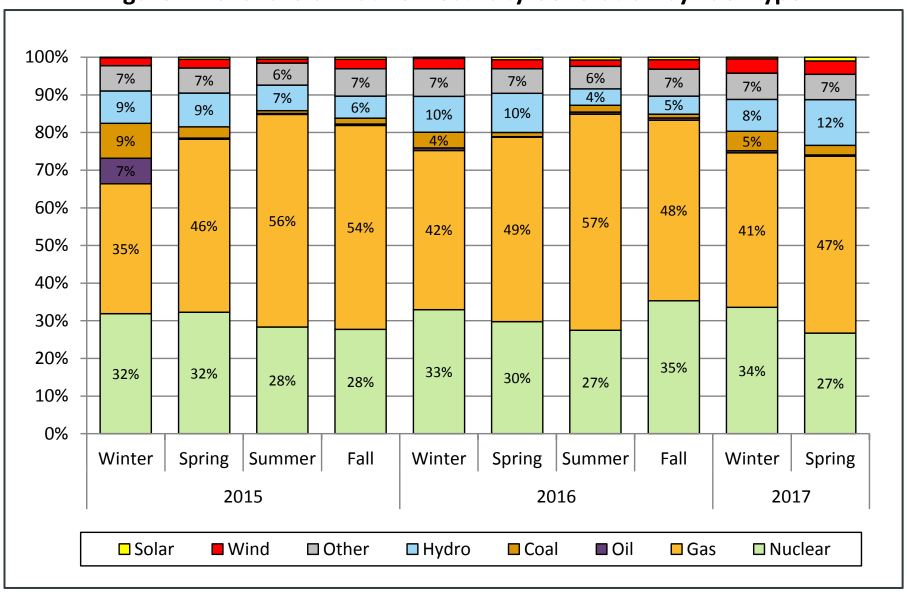
amount that it actually earned for energy and reserves in the interval. Both of these credits were implemented on March 1, 2017 with fast-start pricing rule changes. (https://www.iso-ne.com/participate/support/faq/ncpc-rmr) .

Although there is seasonal variation in the overall interchange volumes, the New England area is typically a net importer of power from the neighboring control areas in Canada and New York.[28] As Figure 2-19 illustrates, the Spring 2017 net interchange volume was higher compared to Spring 2016. However, compared for Spring 2015 two years ago, net interchange volumes were comparable. There was an increase in gross export volumes relative to the two prior springs: up 41% compared to Spring 2016 and up 58% compared to Spring 2015. The increase in exports in the current quarter occurred primarily at the New York North interface where the Coordinated Transaction Scheduling design appears to better adjust power flow as New York and New England market conditions change during the operating day.

2.2.3 Generation by Fuel Type

This subsection summarizes native generation by fuel type for the New England fleet of generators. Analyzing actual energy production (generation output in MWh) can provide useful context to overall energy market outcomes. Actual energy production by generator fuel type for Winter 2015 through Spring 2017 is illustrated in Figure 2-20 below.

Figure 2-20: Share of Native Electricity Generation by Fuel Type



Though the fuel mix varies between seasons, the majority of native generation comes from nuclear and gas-fired generation which together accounted for 74% of total native energy production in Spring 2017. Nuclear generation accounted for 27% of native energy production in Spring 2017, which is lower than Spring 2016 and Spring 2015 in which nuclear generation accounted for 30% and 32% of energy production, respectively. This reduction was mainly driven by planned refueling outages of multiple nuclear generators within the quarter.

[28] There are six external interfaces that interconnect the New England system with these neighboring areas. The interconnections with New York are the New York North interface which comprises several AC lines between the regions, the Cross Sound Cable and Northport-Norwalk Cable that run between Connecticut and Long Island. The interconnections with Canada are the Phase II and Highgate interfaces that both connect with the Hydro Québec control area, and the New Brunswick interface.