ISO New England's Internal Market Monitor

Spring 2016

Quarterly Markets Report

Internal Market Monitor
August 26, 2016

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Preface

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

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

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

This report covers the spring period from **March 1, 2016 to May 31, 2016** (the "reporting period"). The report contains our analyses and summaries of market performance. All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.[1]

Underlying natural gas data furnished by:

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

ICE Global markets in clear view[2]

Oil prices are provided by Argus Media.

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

Section 1
Executive Summary

This report presents metrics and analysis of the performance of ISO New England wholesale electricity and related markets for the Spring of 2016 (March 2016 through May 2016).[3]

1.1 Summary of Market Outcomes and Performance for Spring 2016

- The total estimated wholesale market costs were $1.02 billion in the reporting period, a 38% decrease compared to the same period in 2015 (Spring 2015).
  - Lower natural gas prices were the primary driver for the decrease in total energy costs. Natural gas prices averaged $2.29/MMBtu. This is a 32% decrease from Winter 2015 and a 45% decrease compared to Spring 2015.
- In Spring 2016, the average hourly demand was 12,783 MW, compared to 13,513 MW in the same season of 2015, a decrease of 5%. This decrease is explained by milder weather, particularly in the month of March. The peak real-time load, which occurred on May 31, 2016 during the reporting period, was 19,008 MW, 3% lower than the peak load observed in Spring 2015.
- Day-ahead and real-time energy market prices at the Hub averaged $23.36/MWh and $22.10/MWh, respectively. Day-ahead prices were 41% lower and real-time prices were 40% lower than Spring 2015 prices. These outcomes were driven by lower demand and natural gas prices.
- Total real-time reserve payments were $0.7 million, an 89% decrease from $6.7 million in Spring 2015. The decrease in total real-time reserve payments compared to Spring 2015 was due to mild temperatures, lower loads and higher reserve surplus throughout the reporting period, which contributed to the lower reserve prices and pricing frequencies.
- Regulation payments totaled $4.8 million, a 9% increase from $4.4 million in Spring 2015. Regulation payments increased from Spring 2015 levels as the ISO procured 22% more regulation capacity in Spring 2016 compared to Spring 2015.
- Net Commitment Period Compensation (NCPC) payments in the quarter totaled $10.2 million, a 68% decrease from Spring 2015. The decrease in NCPC payments in Spring 2016 was attributable to a number of factors, including changes to market rules, milder weather and lower loads, lower natural gas prices and fewer reliability commitments compared to last Spring.

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

- Spring 2016 coincides with the end of the commitment period associated with FCA 6, which had system-wide clearing price of $3.43/kW-month .Payments to generation, demand response, and import resources totaled $268 million.

1.2 Summary of Coordinated Transaction Scheduling Analysis

The Coordinated Transaction Scheduling (CTS) design is intended to improve the efficiency of wholesale electricity trades that occur between New England and New York. CTS was implemented on December 15, 2015.

Section 3 of this report presents an assessment of the performance of CTS since its implementation. The CTS design depends on reasonably accurate price forecasts and robust participant bidding to schedule power flows efficiently as market conditions change. Therefore, to help explain the performance measures we also evaluated the two primary inputs to CTS: the price forecasts developed by each ISO and the participant bids. Our findings indicate that in the early period of CTS operation:

- New England is a net importer of power the vast majority of the time. However, very often when New England is importing the New York price is higher at the margin. Therefore, *reducing* net imports would be more efficient. With CTS there has been a decrease in the amount of this counterintuitive power flow.
- Each ISO's price forecast accuracy varies over the hours of the day and tends to err in the opposite directions – with ISO-NE forecasting its price too high, on average, and the NYISO forecasting its price too low. Combined the errors create forecasted market price spreads that are higher than actual, on average.
- There is an abundance of price-*insensitive* bids to import power into New England, which exacerbates counterintuitive power flows, but increased export bid participation could counteract this provided the ISOs' price forecast biases don't inhibit economic scheduling.

1.3 Summary of Regulation Market Analysis

Over the past several years the ISO has implemented two significant sets of revisions to the regulation market offer and pricing rules. First, in July 2013 the pricing rules were changed to include the opportunity cost of providing regulation and the payment was changed to include a make-whole component to account for costs that were not recovered through the clearing price. Second, in March 2015, to comply with FERC Order 755, the single-part offer and single clearing price were replaced by three-part offers and two-part clearing prices, for capacity and mileage. During this time, the New England region also experienced winter periods with unusually high fuel and electricity prices.

Section 4 of this report presents an analysis of how both factors (market changes and winter season market factors) contributed to the increase in regulation market payments, from a low of $11 million in 2012 to a high of $29 million in 2014. Our findings indicate that:

- Winter regulation payments were approximately one-third of total annual regulation payments in 2011, 2013, and 2015, with Winter payments accounting for approximately one-half of all regulation payments in 2014. During winter seasons energy market opportunity costs have made a significant contribution to higher regulation market prices and payments, compared to the remainder of the year. Offers of selected resources also are higher in winter months, likely reflecting the impact of high and volatile fuel market prices on fuel management risks for resources providing regulation. The average addition to offer pricing from opportunity costs in Winter is 80%, compared to a 44% increase in other quarters. The increase in participant regulation offers in Winter compared to other quarters is 72%.

- For non-winter seasons, offer behavior does not explain the increase in regulation payments; capacity offer price data exhibit a reasonably stable pattern, while mileage offers were effectively lowered since March 2015.
- Overall, the impact of the pricing changes appears to have been smaller than winter impacts, increasing non-winter quarterly payments by approximately 25% and winter payments by 20%.

Section 2
Summary of Market Outcomes and System Conditions

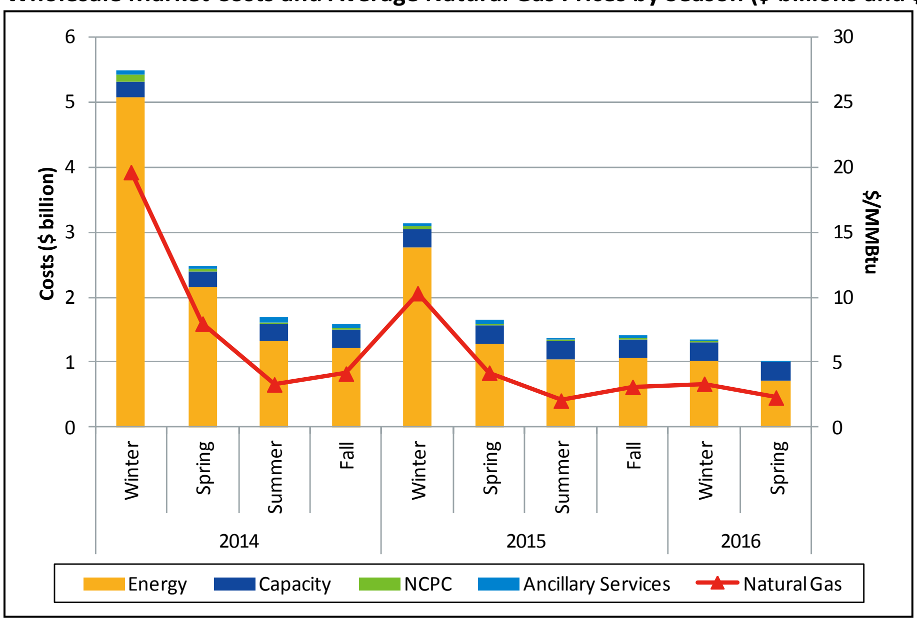
This section summarizes the region's wholesale electricity market outcomes and measures of market performance.

2.1 Market Outcomes

2.1.1 Total Wholesale Electricity Market Value

In Spring 2016, the total estimated market cost decreased by about 38% compared to the same season last year ($1.02 billion compared to $1.64 billion), and decreased by 23% when compared to Winter 2016 ($1.34 billion).[4] Spring 2016 Net Commitment Period Compensation (NCPC) costs of $10 million were 68% lower than Spring 2015 NCPC costs and 31% lower than Winter 2016 NCPC costs. Ancillary service costs, which include reserve and regulation payments, totaled $17 million in Spring 2016, a decrease of 65% when compared to Spring 2015 and a decrease of 9% when compared to Winter 2016, respectively. Figure 2-1 shows the estimated wholesale electricity cost for each season (in billions of dollars) by market, along with average natural gas prices (in $/MMBtu).[5]

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



[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] 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.

As illustrated in Figure 2-1, natural gas prices are a key driver behind changes in energy costs in New England. The decrease in natural gas prices between Spring 2015 and Spring 2016 resulted in lower energy costs in this most recent quarter. Additionally, lower natural gas prices in this most recent quarter compared to the Winter also resulted in a decrease in energy costs in Spring 2016 compared to Winter 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

	Spring 2016	Winter 2016	Percent Change Spring 2016 to Winter 2015	Spring 2015	Percent Change Spring 2016 to Spring 2015
Real-Time Load (GWh)	28,226	31,270	-10%	29,837	-5%
Weather Normalized Real-Time Load (GWh)	28,371	31,948	-11%	29,283	-3%
Peak Real-Time Load (MW)	19,008	19,524	-3%	19,544	-3%
Average Day-Ahead Hub LMP ($/MWh)	23.36	30.32	-23%	39.31	-41%
Average Real-Time Hub LMP ($/MWh)	22.10	27.58	-20%	36.75	-40%
Average Natural Gas Price ($/MMBtu)	2.29	3.35	-32%	4.20	-45%

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

- Lower natural gas prices in Spring 2016 were the primary driver for lower day-ahead and real-time prices when compared to the same season last year.
    - Natural gas prices during the reporting period decreased by 45% from Spring 2015.
    - Oil prices were also 38% lower during the reporting period compared to Spring 2015.
- The real-time load in Spring 2016 was 5% lower than the real-time load in Spring 2015.

2.1.3 Real-Time Markets

2.1.3.1 Real-Time Energy Market

The average real-time Hub energy price was $22.10/MWh in the reporting period. Real-time energy prices in Spring 2016 were lower than the two preceding springs, down 40% compared to Spring 2015 and 66% compared to Spring 2014. Real-time prices continue to follow the cost of natural gas generation. Energy prices did not differ significantly among the load zones.[6] Figure 2-2 shows the

[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.

seasonal average real-time energy prices and the estimated cost of gas generation based on a unit heat rate of 7,800 Btu/kWh and the Tennessee Gas Pipeline Zone 6 index price.

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

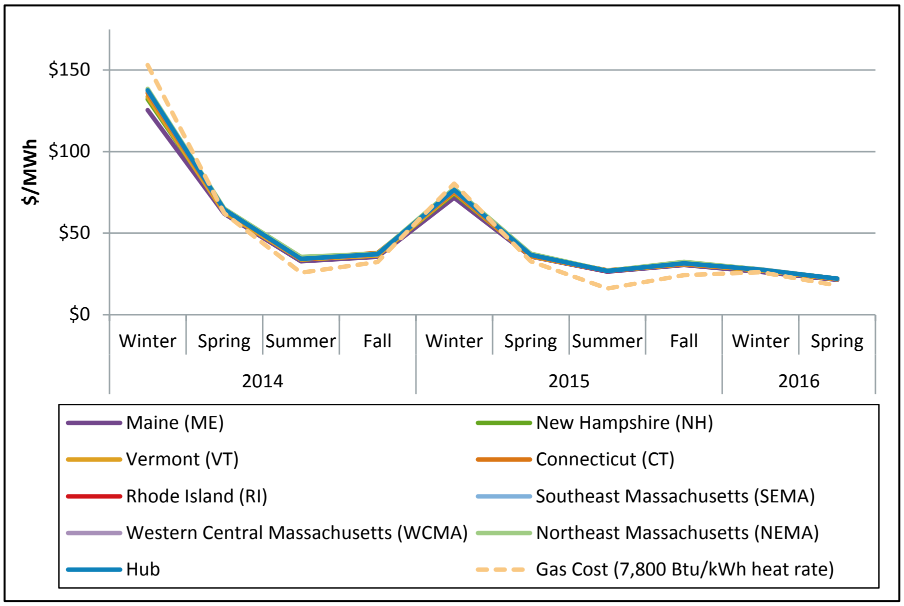
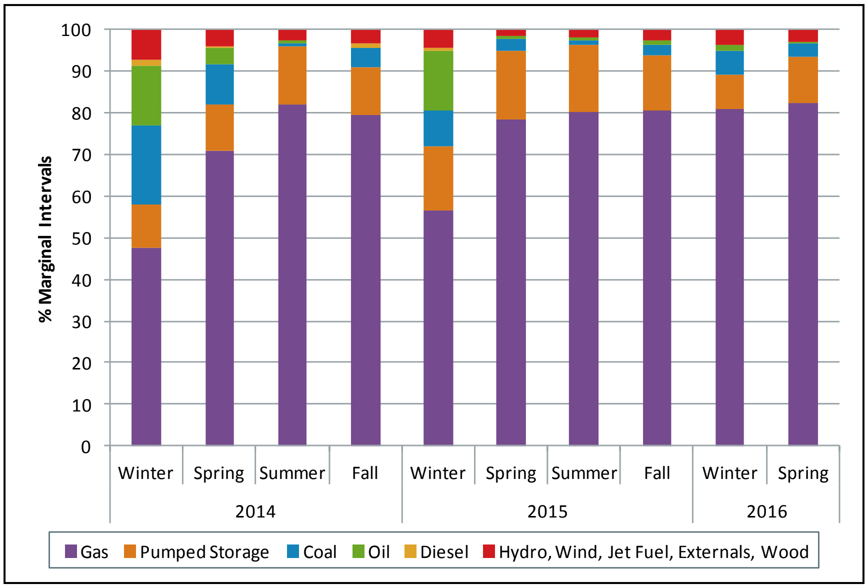


Figure 2-2 illustrates that average real-time energy prices tend to track closely with the cost of natural gas. This is shown by the movement in the zonal energy price trend lines and the natural gas cost trend line. The decline in spring season energy prices compared to prior periods tracks closely with the decline in natural gas prices over the same period. Spring 2016 natural gas prices dropped significantly compared to both the Spring 2015 and Spring 2014 seasons (*i.e.*, 45% and 71%, respectively). According to the U.S. Energy Information Administration (EIA), increases in domestic natural gas production, above-average storage inventories, and lower heating demand during the 2015-16 season contributed to gas prices falling well below recent historical prices.[7]

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

[7] US Energy Information Administration. Short Term Energy Outlook June 2016. Washington, DC: US Department of Energy, June 2016. https://www.eia.gov/forecasts/steo/archives/Jun16.pdf. Pages 9 – 10.

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



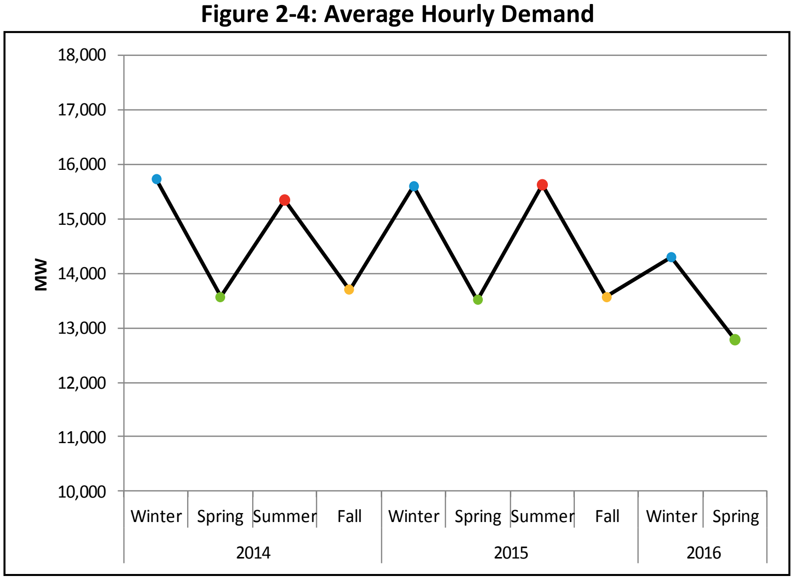
In the reporting period, units burning natural gas were marginal (*i.e.*, setting the price) during 83% of the pricing intervals, followed by pump storage units (including pumping demand), which were marginal in 11% of the pricing intervals. Units burning coal, oil, diesel, jet fuel, wood, traditional hydro units, and external transactions were marginal in the remaining pricing intervals.

As seen in the figure above, the composition of marginal units in Spring 2016 was similar to Spring 2015, although marginal gas units did displace a small portion of pumped storage and other units. Spring 2016 had a lower share of marginal coal and oil units than Spring 2014, due to high gas prices (particularly in March) compared to coal and oil in Spring 2014.

2.1.3.2 Load Summary

Figure 2-4 illustrates average hourly load by seasonal quarter. The blue dots represent winter, the green dots represent spring, the red dots represent summer, and the yellow dots represent fall.

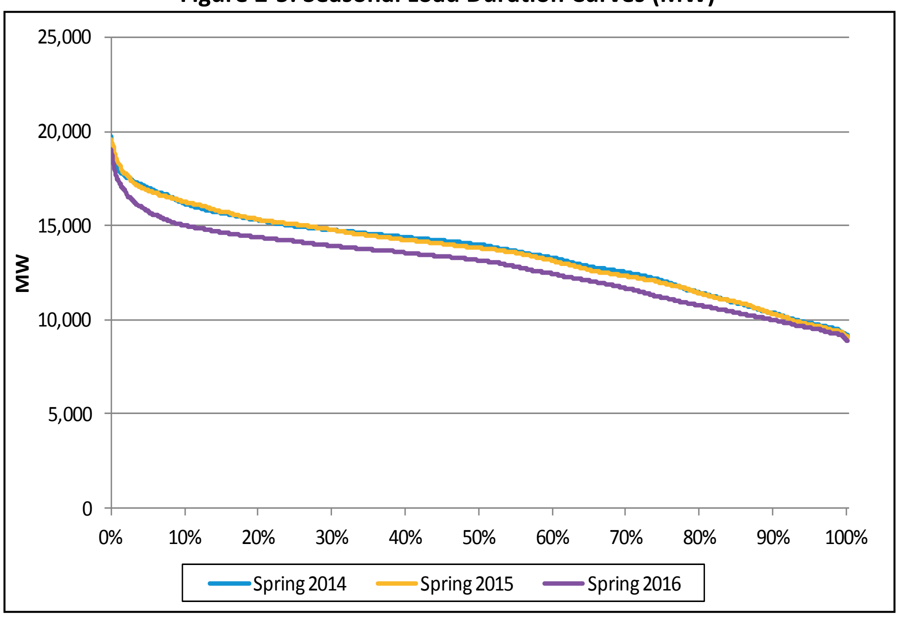
Figure 2-4: Average Hourly Demand



In Spring 2016, the average hourly load was 12,783 MW, a 5% decrease compared to the Spring 2015 value of 13,513 MW.[8] As shown in Figure 2-4, average hourly load in the reporting period was lower than average hourly load levels in the past two spring seasons. Milder weather in Spring 2016 helps explain why the average hourly load was lower compared to the past two spring seasons. Of the three months in the quarter (March, April, and May), March 2016 was particularly warmer, on average, than March 2014 and March 2015. The average temperature in March 2016 was 41°F, a large increase compared to the March 2015 average temperature of 32°F and the March 2014 average temperature of 31°F. The low loads resulting from warmer than average temperatures in March 2016 helps explain why the average hourly load for the quarter was lower than the two previous Spring seasons.

Another way to examine load is to sort all the hourly load values (i.e. 2,208 hourly values in the reporting period) from highest to lowest for any given period. The resulting curve is called a *load duration curve.* By plotting several seasonal load duration curves, one can easily observe differences between periods. Also, since the load duration curves have the same number of observations (hours), the horizontal axis can be expressed as a percentage of the total number of hours in the period of interest as shown in Figure 2-5. The percent axis allows one to quickly view what percentage of hours are above or below a particular load level.

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



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

The peak hourly demand in the reporting period occurred on May 31 at 6:00 PM and was 19,008 MW. This was lower than the Spring 2015 peak of 19,544 MW. The lowest hourly demand in the reporting period was 8,850 MW, which was the lowest load hour since October 2012. There were 229 hours (approximately 10%) in which actual loads were below 10,000 MW. Last Spring, loads dropped below 10,000 MW in 172 hours and in Spring 2014, loads dropped below 10,000 MW in

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

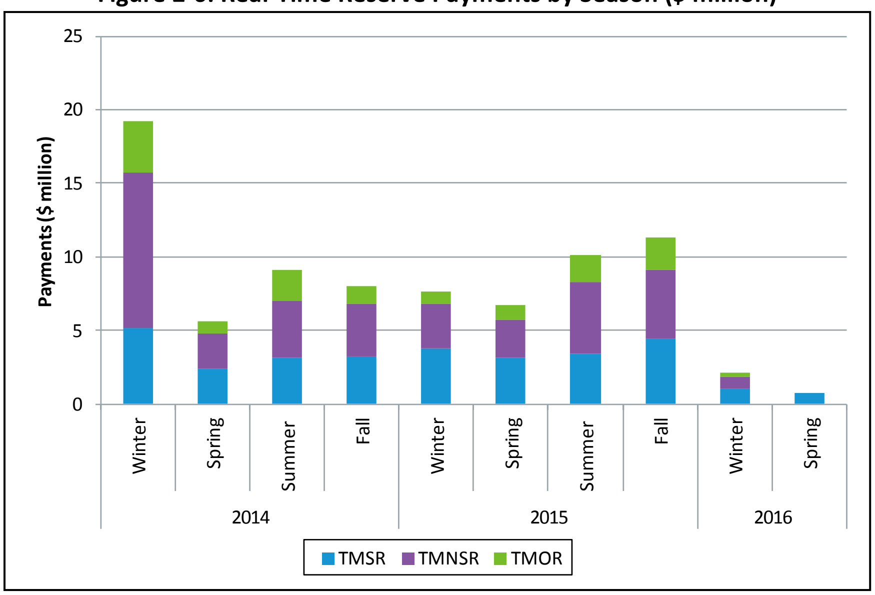
161 hours. When loads drop to relatively low levels like these, the system is more likely to experience low (or negative) prices due to higher supply margins and a high amount of fixed supply.

2.1.3.3 Real-Time Operating Reserves

Total real-time reserve payments were $0.7 million in Spring 2016, an 89% decrease compared to Spring 2015 payments of $6.7 million.[9] The decrease in total payments compared to Spring 2015 was primarily the result of lower prices and pricing frequencies for almost all reserve products. The frequency of ten minute spinning reserve (TMSR) pricing increased slightly from 6.2% to 7.9%, however, the frequency of ten minute non-spinning reserve (TMNSR) pricing and thirty minute operating reserve (TMOR) pricing both decreased from 0.3% to 0% as there were no instances of either TMNSR or TMOR pricing in the quarter. Average non-zero TMSR prices decreased from $28.41/MWh to $8.72/MWh, average non-zero TMNSR prices decreased from $313.04/MWh to $0/MWh, and average non-zero TMOR prices decreased from $326.76/MWh to $0/MWh. Real-Time reserve payments also decreased by 66% compared to Winter 2016 payments of $2.2 million for similar reasons.

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

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



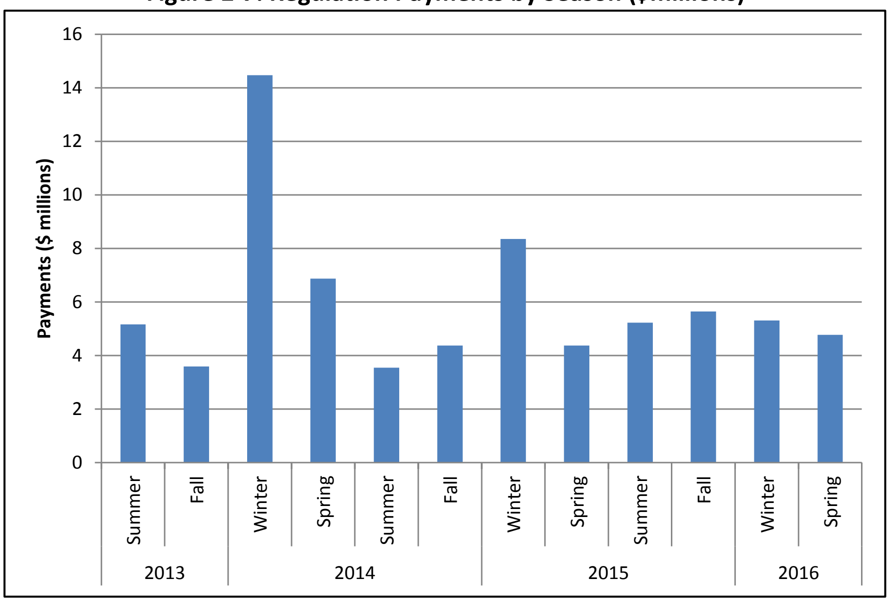
As shown in Figure 2-6, real-time reserve payments were significantly lower in Spring 2016 compared to the past two years. This was due to mild temperatures, lower loads and a higher reserve surplus throughout the reporting period, which contributed to the lower reserve prices and pricing frequencies.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

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

2.1.3.4 Regulation Market

Total regulation market payments were $4.8 million during the reporting period, down 10% from $5.3 million in Winter 2016, and up 9% from $4.4 million in Spring 2015. While the volume of regulation capacity procured by the ISO increased by 7% in Spring 2016 compared to Winter 2016, the Spring capacity was procured at a 16% cheaper cost than capacity for the Winter, leading to an overall 10% reduction in payments. Additionally, although regulation procurement costs for Spring 2016 were lower than procurement costs for Spring 2015, the regulation capacity procured by the ISO averaged 22% higher in Spring 2016 than for the 2015 period, leading to an overall increase in regulation payments when comparing the two periods. 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. Quarterly regulation payments are shown in Figure 2-7 below.

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

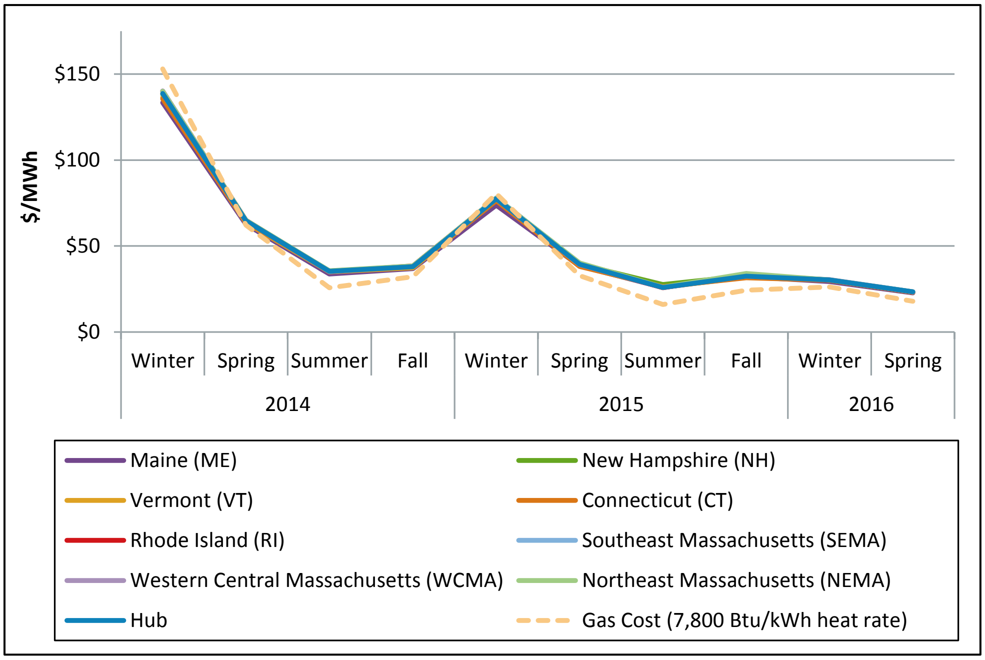


2.1.4 Forward Markets

2.1.4.1 Day-Ahead Energy Market

The average day-ahead Hub price for Spring 2016 was $23.36/MWh, a decrease of 23% from the Winter 2016 average of $30.32/MWh. Day-ahead energy prices remained correlated with natural gas prices and were lower than preceding spring seasons by similar magnitudes as those discussed for real-time prices in Section 2.1.3.1. Prices did not differ significantly among the load zones. Figure 2-8 below depicts seasonal quarterly average day-ahead energy prices and estimated cost of gas generation (assuming a unit heat rate of 7,800 Btu/kWh and the Tennessee Gas Pipeline Zone 6 index price).

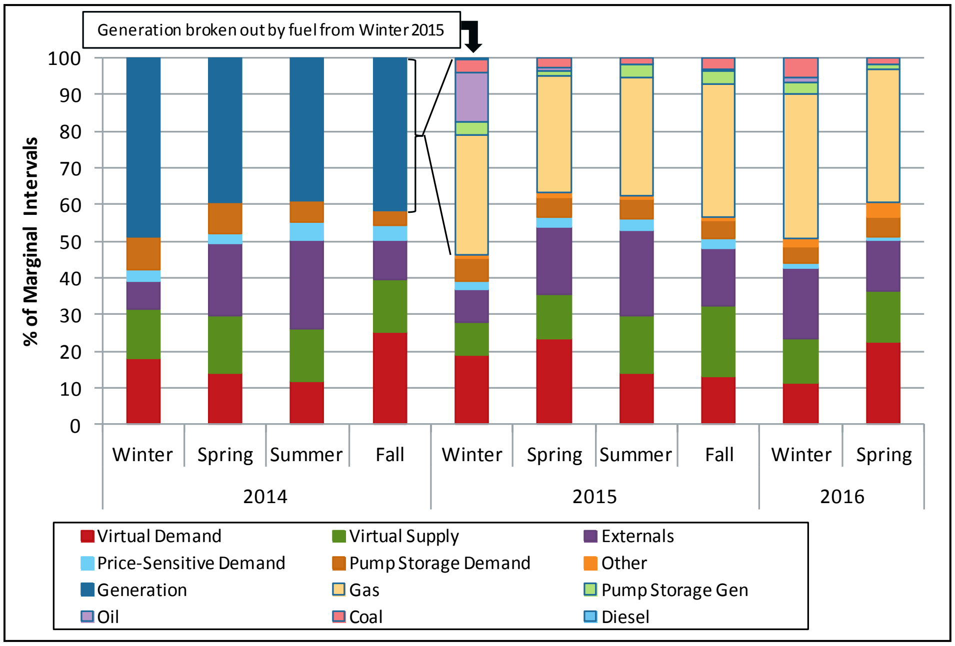
Figure 2-8: Simple Average Day-Ahead Prices and Gas Generation Costs by Season



As shown in Figure 2-8, average day-ahead energy prices decreased relative to Winter 2016 prices and were also down relative to prices in the two preceding spring periods. Day-ahead energy prices in this most recent spring were 41% lower compared to Spring 2015 and 64% lower compared to Spring 2014. As discussed in Section 2.1.3.1, the downward trend in energy prices tends to track very closely with trends in natural gas prices as domestic gas production has continued to outpace demand. The average day-ahead Hub price was roughly 6% higher than the average real-time Hub price of $22.10/MWh (Section 2.1.3.1) – a day-ahead premium of $1.25/MWh relative to real-time prices for the period.

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 generators category (large blue bar, years 2011-2014) by generator fuel type (bars outlined in blue). With the introduction of Energy Market Offer Flexibility (EMOF) in December 2014, generators submit information regarding fuel in their supply offer. This provides better information on the fuel underlying the marginal unit than existed prior to EMOF. The metric has been adjusted accordingly starting with Winter 2015.

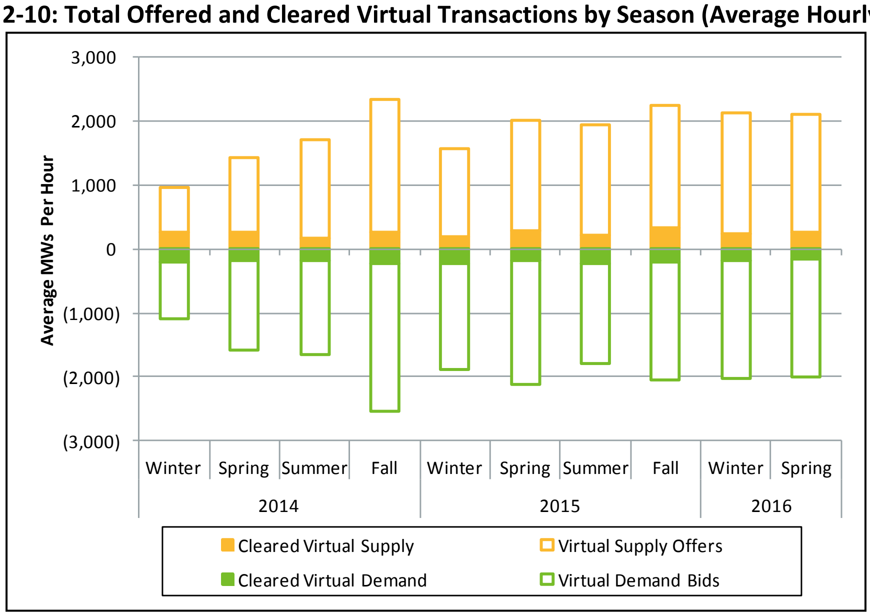
Figure 2-9: Day-Ahead Marginal Units by Fuel Type by Season



Similar to the real-time market, Spring 2016 marginal fuel mix outcomes are comparable to Spring 2015 outcomes. During the reporting period, generators set price approximately 43% of the time in the day-ahead market. Virtual transactions (virtual supply and demand) set price approximately 36% of the time, and external transactions set price approximately 14% of the time. Price-sensitive demand (including pump storage demand) was marginal in the remainder of the price-setting intervals at 6%.

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

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



In the reporting period, submitted virtual demand bids and virtual supply offers averaged approximately 4,124 MW per hour, a 1% decrease when compared with Winter 2016, and a negligible change from Spring 2015 (less than 0.1%). Cleared virtual transactions decreased by 1% compared with Winter 2016 and decreased by 12% when compared with Spring 2015. In the reporting period, 10% of the megawatt quantity of virtuals bids and offers cleared in the day-ahead market.

2.1.4.2 Financial Transmission Rights

Three Financial Transmission Rights (FTR) auctions were conducted during the reporting period for a combined total of 89,636 MW of FTR transactions. The total amount distributed as Auction Revenue Rights (ARRs) was $1.3 million. The reduction in auction value from $1.7 million in the previous reporting period reflects the reduction in congestion during the shoulder months. Thirty-four bidders in March, thirty-one bidders in April and thirty-five 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 systemwide resource adequacy requirements. The FCM is designed to procure and price capacity before the system will need it. The region developed the FCM in recognition of the fact that the energy market alone does not provide sufficient revenue to facilitate new investment or, in many cases, cover the cost of maintaining and operating existing resources. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue and thereby induces suppliers to undertake the investments necessary for reliable electric power service.

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.[10] 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 supply obligation 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.

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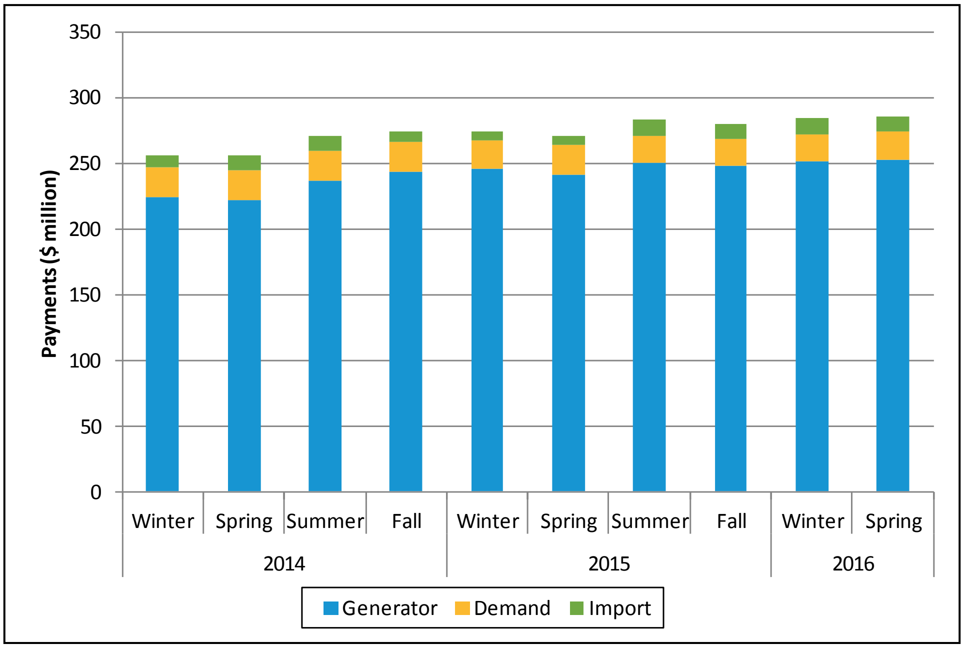
[10] Each capacity commitment period is a twelve-month period starting on June 1 of a year and ending on May 31 of the following year.

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



Spring 2016 coincides with the end of the commitment period associated with FCA 6, which had system-wide clearing price of $3.43/kW-month. In Spring 2016, capacity payments totaled $286 million, which accounts for adjustments to primary auction capacity supply obligations (CSOs). This includes adjustments based upon bilateral and reconfiguration auction activity, computed values for Peak Energy Rent (PER), the participation of the ISO in reconfiguration auctions, and actual resource performance.

FCM Reconfiguration Auction and Bilateral Trading Activity. Table 2-2 provides a summary of prices and volumes from the reconfiguration and bilateral trading of CSOs that occurred during Spring 2015, alongside the results of the relevant primary forward capacity auction.

Table 2-2: 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	SEMA/RI	HQ Highgate
FCA 6 (2015-16)	Primary	12-month	3.43	36,309			
	Monthly Reconfiguration	May-16	1.25	693			
	Monthly Bilateral	May-16	3.22	130			
FCA 7 (2016-17)	Primary	12-month	3.15	36,220	15.00/6.66*		
	Annual Reconfiguration (3)	12-month	0.99	632	12.11		
	Monthly Reconfiguration	Jun-16	3.05	405	15.00		0.25
	Monthly Bilateral	Jun-16	1.74	35			
	Monthly Bilateral	Jul-16	2.60	114			
FCA 8 (2017-18)	Primary	12-month	15.00/7.03*	33,712	15.00/15.00*		
	Annual Bilateral (2)	12-month	1.32	87			
FCA 9 (2018-19)	Primary	12-month	9.55	34,695		17.73/11.08*	
	Annual Bilateral (1)	12-month	9.55	16			

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

FCA 6 Commitment Period. The May 2016 reconfiguration auction cleared below the annual price of $3.43/kW-month from the primary auction. The clearing price for the May 2016 auction was $1.25/kW-month, with 693 MW of cleared capacity. For most auctions, the reconfiguration prices have been lower than the FCA price. In FCA 1 through FCA 7, there was an abundance of capacity and many FCA prices cleared at the floor. In the reconfiguration auctions, however, there is no floor price and in some cases the monthly price cleared close to $0/kW-month. The floor price was eliminated in the primary auction starting with FCA 8.

There was 130 MW of cleared capacity in the May 2016 bilateral period. Since there is no single clearing price, a volume- weighted price is used to represent the trading price during the month. The volume-weighted price was $3.22/kW-month in May 2016. Table 2-2 shows the amount of megawatts transferred and acquired by resource type.

Table 2-3: Acquired and Transferred MW for FCA Commitment Period 6

Month	Resource Type	Acquired MW	Transferred MW	Net MW
May 2016	Demand Response	32	59	(27)
	Generator	98	1	97
	Import	0	70	(70)

FCA 7 Commitment Period. In FCA 7 (2016-2017), the ISO modeled import constrained capacity zones, specifically the Northeastern Massachusetts - Boston (NEMA - Boston) and the Connecticut zones for the first time. The NEMA – Boston zone cleared at $15.00/kW-month for new resources and $6.66/kW-month for all existing resources. The pricing for existing resources was determined

using administrative pricing 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.

The third and final annual reconfiguration auction occurred in March for the FCA 7 (2016-2017) commitment period, and cleared 632 MW. The clearing price for capacity outside the NEMA-Boston zone was $0.99/kW-month, while capacity inside the NEMA-Boston zone cleared at $12.11/kW-month. The first monthly reconfiguration auction for FCA 7 occurred in June 2016, resulting in three clearing prices. The prices were $0.25/kW-month for the Hydro-Quebec Highgate interface, $15.00/kW-month for NEMA-Boston, and $3.05/kW-month for all other zones. The total cleared capacity was 405 MW. In the July 2016 monthly reconfiguration auction, the clearing prices were $1.00/kW-month for Phase I/II HQ interface, $6.66/kW-month for NEMA-Boston, and $2.00/kW-month for all other zones. The July 2016 reconfiguration auction also cleared 405 MW of capacity.

There were 35 and 114 MWs of cleared capacity traded in the June and July 2016 bilateral periods, respectively. The volume-weighted prices were $1.74/kW-month in June and $2.60/kW-month in July. Table 2-4 shows the amount of megawatts transferred and acquired by resource type.

Table 2-4: Acquired and Transferred MW for FCA Commitment Period 7

Month	Resource Type	Acquired MW	Transferred MW	Net MW
June 2016	Demand Response	2	32	(30)
	Generator	33	3	30
	Import	0	0	0
June 2016 Total		35	35	0
July 2016	Demand Response	2	52	(50)
	Generator	112	7	105
	Import	0	55	(55)
July 2016 Total		114	114	0

FCA 8 Commitment Period. The second annual bilateral trading period for the 2017-2018 commitment period took place in May 2016 and exchanged 87 MW of capacity at a capacity weighted price of $1.32/kW-month.

FCA 9 Commitment Period. The first annual bilateral trading period for the 2018-2019 commitment period took place in April 2016 and exchanged 16 MW of capacity at a volume-weighted price of $9.55/kW-month.

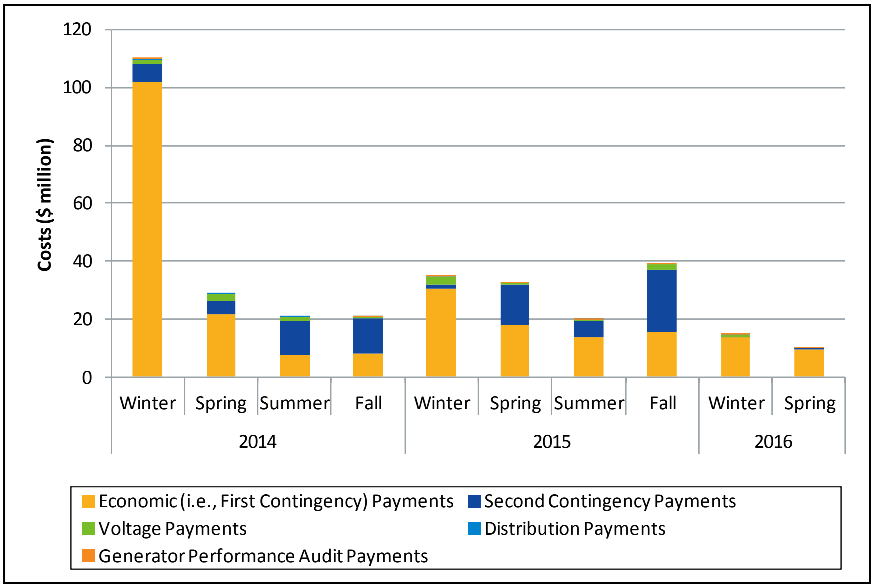
2.2 System Conditions

2.2.1 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) is a method of providing a make-whole payment to resources when market payments are insufficient to cover production costs. Resources committed and dispatched economically (in-merit), as well as resources dispatched out of economic-merit order for reliability purposes, may require make-whole payments. NCPC is paid to resources for providing first- and second-contingency protection, voltage support and control, and distribution system protection in either the day-ahead or real-time energy markets, and for generator performance auditing.[11]

In Spring 2016, NCPC payments totaled $10.2 million. This is a 68% decrease compared to the same season last year ($32.4 million) and a 31% decrease compared to Winter 2016 ($14.9 million). NCPC payments by season and category are shown in Figure 2-12.

Figure 2-12: NCPC Payments by Season and Category ($ millions)



The majority of NCPC (95%) incurred during the reporting period was for first contingency protection. Approximately $5.4 million of total NCPC was paid in the real-time market, of which $5.2 million was for first contingency.[12] Approximately $4.8 million of total NCPC was in the day-ahead market, of which $4.5 million was for first contingency.

First contingency payments of $9.7 million in Spring 2016 were significantly lower than Winter 2016 and Spring of last year, down 28% and 46%, respectively. The trend of very low second contingency payments from Winter 2016 continued into the Spring, with Spring 2016 payments of less than $0.25 million, representing a 98% decline compared to Spring 2015.

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[11] 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*.

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

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

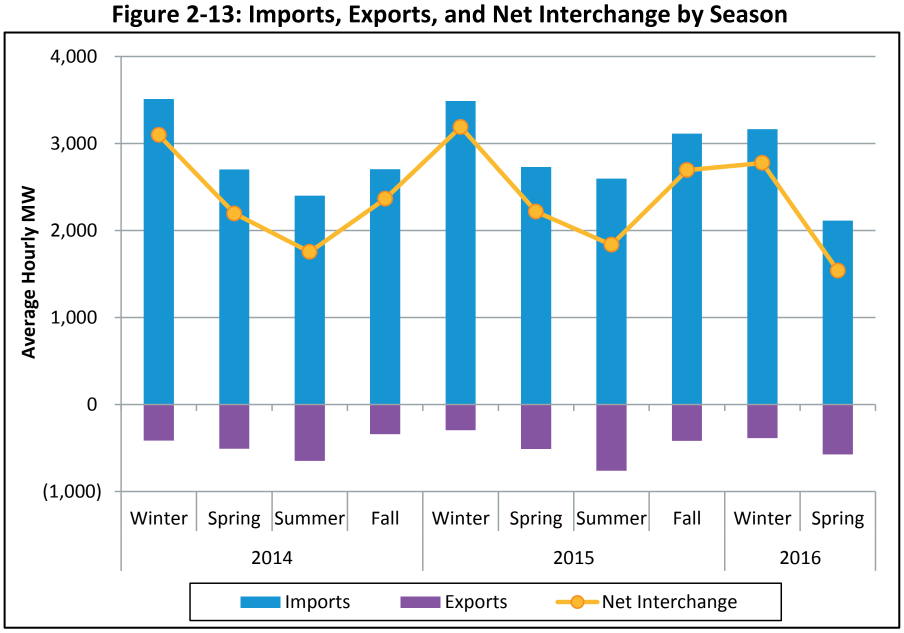
Milder weather, lower loads, and lower natural gas prices resulted in lower operating costs for generators and fewer reliability commitments during Spring 2015. On an hourly average basis, less than 10 MW was committed for reliability in Spring 2016, compared to about 100 MW in Spring 2015. In particular, in Spring 2015 generators were needed to provide local reliability protection in the NEMA/Boston load zone on several days, a need which did not materialize in Spring 2016.

In addition, 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 $17 million in real-time NCPC was paid to eligible generators under the prior rules that were in effect in Spring 2015 and phased out 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.[13] Net interchange with neighboring areas averaged 1,538 MW per hour for the reporting period, a 45% decrease compared with Winter 2016 and a 31% decrease when compared to Spring 2015. This was primarily due to a decrease in imports from the Phase II (Quebec) location. Figure 2-13 shows imports, exports, and net interchange by season.

Figure 2-13: Imports, Exports, and Net Interchange by Season



[13] 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.

The figure shows that net interchange has been seasonal in nature, with more imports occurring during the winter months when New England energy prices have been at their highest over the past few years. The larger than normal decrease in net imports in Spring 2016 was primarily driven by the planned outage of the Phase II interconnection to replace and test interface protection and control equipment. In Spring of 2015, average hourly net imports from Phase II were 1,271 MW. The Phase II path was out of service from April 1st through May 30th – two of the three months in the reporting period. Relative to Winter 2016, Phase II net imports were lower by 65% during Spring 2016.

Section 3
Coordinated Transaction Scheduling

This special section of the quarterly markets report provides an assessment of the energy market impacts of Coordinated Transaction Scheduling (CTS). The CTS design is intended to improve the efficiency of wholesale electricity trades that occur between New England and New York on interfaces for which CTS has been implemented by ISO New England (ISO-NE) and the New York Independent System Operator (NYISO). Our findings indicate in the early period of CTS operation that:

- New England is a net importer of power the vast majority of the time. However, very often when New England is importing the New York price is higher at the margin. Therefore, *reducing* net imports would be more efficient. With CTS there has been a decrease in the amount of this counterintuitive power flow.
- Each ISO's price forecast accuracy varies over the hours of the day and the forecasts tend to err in the opposite directions – with ISO-NE forecasting its price too high, on average, and the NYISO forecasting its price too low. Combined the errors create forecasted market price spreads that are higher than actual, on average.
- There is an abundance of price-*insensitive* bids to import power into New England, which exacerbates counterintuitive power flows, but increased export bid participation could counteract this provided the ISOs' price forecast biases don't inhibit economic scheduling.

The analysis of the CTS design performance presented here focuses on measures of the frequency and magnitude of intuitive power flows (*i.e.*, from the lower- to higher-priced region), and those of counterintuitive flows (*i.e.*, when too much power is scheduled such that the market price differences invert at the margin). The CTS design depends on reasonably accurate price forecasts and robust participant bidding to schedule power flows efficiently as market conditions change. Therefore, to help explain the performance measures we also evaluated the two primary inputs to CTS - the price forecasts developed by each ISO and the participant bids – to understand the extent to which either will impact the performance of CTS.

3.1 Background

The CTS design modified the bidding and scheduling mechanics for real-time energy trades (or "external transactions") between the ISO-NE and NYISO markets. At a high level, the design changes unified the bid submission and clearing process, decreased the schedule duration from one hour to 15 minute intervals, moved bid submittal and clearing timelines closer to the interval when power flows, and eliminated fees on transactions. The CTS design mechanics are focused on improving the frequency with which power moves from the lower- to higher-cost region and increasing the utilization of the interface transfer capability to converge prices between the regions. If effective, CTS is anticipated to reduce wholesale electricity costs in both regions by offsetting the need for higher cost native generation with lower cost imported power.[14]

[14] The design basis documents, FERC filing materials, and implementation documentation describing the CTS design in detail can be found on the ISO-NE key project webpage: http://www.iso-ne.com/committees/key-projects/implemented/coordinated-transaction-scheduling/

The CTS implementation occurred on December 15, 2015 and enabled coordinated scheduling over the New York North (NYN) interface, which is also known as "Roseton" or the "NYISO-ISONE" interface in New York. This interface is the primary pricing location for power flow between the two regions, with the capability to flow 1,200 MW of power to New York and 1,400 MW to New England at typical ratings.

The prices used in this analysis are each ISO's energy prices at their respective pricing nodes that correspond to the NYN interface.[15] The period referred to as "before CTS" in the context of this analysis is the period from December 15, 2014, through June 30, 2015. The period "after CTS" refers to the period from December 15, 2015, when CTS was implemented, through June 30, 2016. Future analysis on this topic will benefit from using additional observations to compare like-periods.

3.2 Energy Market Impacts

We assessed the relative performance of CTS using the actual real-time scheduled flows and prices when one ISO is producing electricity at higher cost and the interface is unconstrained.[16] Figure 3-1 below segments the actual real-time scheduled flow and price difference occurrences between regions into each of four possible states. The first two states are the intuitive outcomes based on real-time prices: (1) when the New England price is higher and net tie flow is toward New England (the top right quadrant), and (2) when the New York price is higher and net tie flow is toward New York (the bottom left quadrant). These intuitive quadrants are highlighted green. These instances *appear* intuitive because the importing region has a higher native generation cost. However, the large price differences between the regions during unconstrained intervals indicate that the amount of power delivered to the importing ISO should be further increased to achieve a more efficient tie schedule. That is, the interface would be utilized to deliver more lower cost power from the exporting region and the importing region would back down its more expensive generation, up to the point that the market prices are equal.

The other two states are counterintuitive outcomes where the exporting ISO has a higher cost of energy at the margin than the importing ISO. These outcomes are: (3) when the New England price is higher and the net tie flow is toward New York (the bottom right quadrant), and (4) when the New York price is higher and net power flow is toward New England (the top left quadrant). In these instances it would be more efficient to reduce the tie flow (toward zero), backing down higher cost generation in exporting region and dispatching up lower cost generation in the importing region up to the point that the market prices are equal.

Within each quadrant of Figure 3-1, the following measures are presented for the periods before CTS (blue) and after CTS (yellow): the average tie flow[17] on the top line (the bubbles are sized

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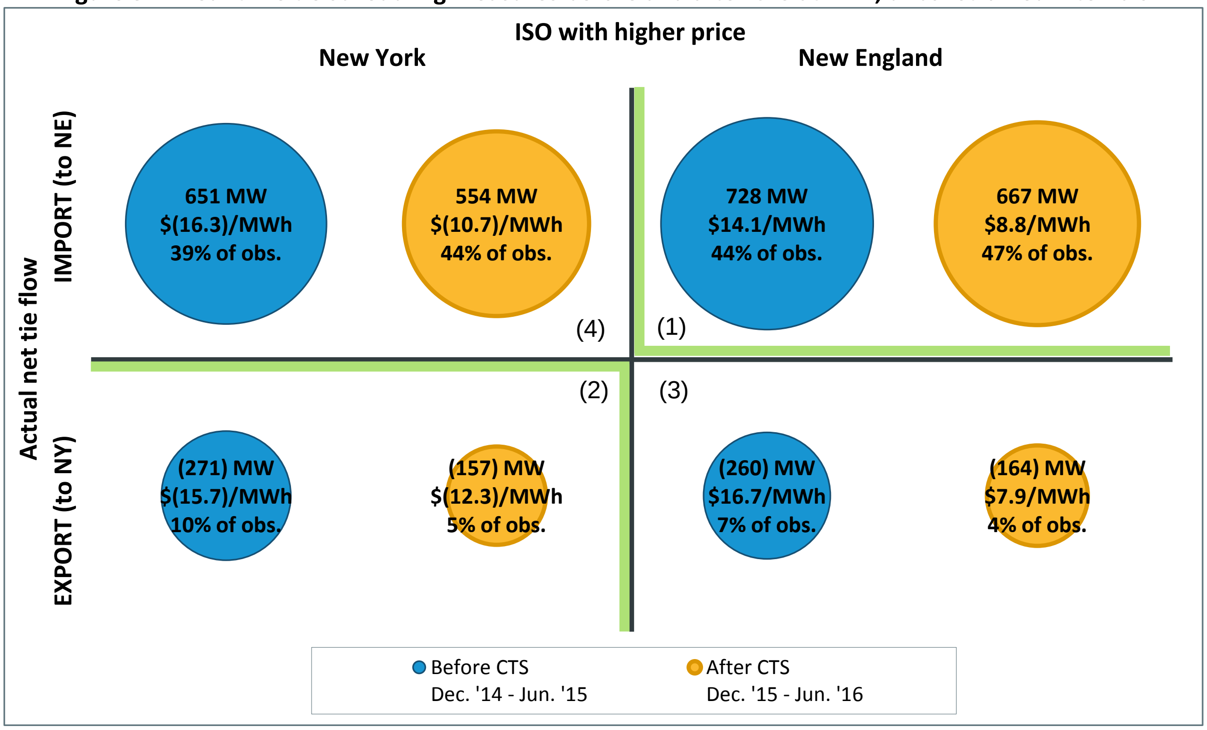
[15] Specifically, these are the NYISO "N.E._GEN_SANDY PD" location and ISO-NE "I.ROSETON 345 1" location. More than two hundred 15 minute scheduling intervals were excluded for the period after CTS because the price data available contained errors. The excluded observations would unlikely change the overall result, but inaccuracies or omissions of data will impact the values presented.

[16] For this analysis, the interface was characterized as constrained in the period before CTS if the scheduled power flow was within 2% of the total transfer capability (TTC) applicable for the hour. The interface was constrained for 24% of observations in the before CTS period, predominately when scheduled flows were in the direction of New England at or near the TTC. For the period after CTS, the interface schedule is identified as constrained if a reliability limit (*e.g.*, TTC, interface ramp limit, system reserve requirement) was binding for the 15-minute scheduling interval; this occurred during 17% of observations.

[17] A positive value of average tie flow indicates a net import of power to New England and a negative value indicates a net export of power to New York.

according to this value); the average real-time price difference on the middle line (calculated as the ISO-NE price minus the NYISO price[18]); and the frequency that each condition occurred before or after CTS as the percent of observations ("obs.") on the bottom line. As an example of how to read the chart, consider the top right quadrant where the New England price is higher and the direction of tie flow is an import to New England. Here we observe that, on average, 728 MW were delivered to New England before CTS whereas 667 MW went to New England after CTS; the New England price was higher by $14.1/MWh before CTS and higher by $8.8/MWh after CTS; and that this scenario (New England having the higher price and net tie flow being to New England) was observed 44% of the time before CTS and 47% of the time in the period after CTS.

Figure 3-1: Real-time tie scheduling measures before and after CTS at NYN, unconstrained intervals



The results presented in Figure 3-1 indicate a mixed change in performance measures after the CTS implementation. In the intuitive condition when the New England price is higher and power is flowing to New England (top right quadrant), there was an increase in the frequency of observations (from 44% to 47%) although less power is being imported – on average only 667 MW after CTS compared to 728 MW before CTS. However, compared to the period before CTS the average price difference decreased to $8.8/MWh from $14.1/MWh.[19] Nevertheless, there is ample capability to increase flows to New England, on average, and price differences are nearly $9/MWh. More of the lower cost New York power could be used to offset higher cost New England power in these instances.

[18] A positive value of average price difference indicates the ISO-NE price is higher and a negative value indicates the NYISO price is higher.

[19] As noted throughout this section, real-time price differences between New York and New England have been lower in the period after CTS was implemented compared to the period before CTS. The narrowed regional price spreads are likely driven by the lower natural gas and electricity prices in both regions that occurred coincident with the period after CTS.

In the other intuitive condition when the New York price is higher and net power flow is an export to New York (the bottom left quadrant in Figure 3-1), the results indicate worse scheduling performance. The frequency of observations decreased from 10% before CTS to 5% after CTS and the volume of power being exported decreased by about half from 271 MW exported before CTS to 157 MW after CTS. Here the price difference is also lower between the two regions after CTS, but not of a magnitude that appears to explain the reduction in economic power flow to New York.

Taken together, the results in the two intuitive conditions reveal that power flow is in the economically efficient direction 52% of the time (47% + 5%) in the period after CTS, which is slightly *less* often than 54% before CTS (44% + 10%). The large price differences between the regions indicate the tie is on average under-utilized during unconstrained intervals. Too little power is flowing in the intuitive direction. In short, the importing ISO is operating higher cost generation at the margin that could otherwise be offset by importing more power across the interface.

For the counterintuitive scenarios, the results with CTS show improvement. The counterintuitive observations are when the exporting region is using higher cost generation to deliver power to the lower cost region, which has native generation that is less expensive at the margin. Again looking at Figure 3-1, when the New York real-time price is higher, but net power flow is to New England (the top left quadrant), the average flow has decreased from 651 MW before CTS to 554 MW after CTS, and the premium paid for NYISO power at the margin decreased from $16.3/MWh to $10.7/MWh. However, the market price differences are still far apart and New England is importing too much New York power in 44% of intervals after CTS implementation, compared to 39% of the time before CTS. When the New England real-time price is higher but net power flow is to New York (the bottom right quadrant in Figure 3-1) the results are overall more positive: average flow decreased (from 260 MW before CTS to 164 MW after CTS), the frequency of occurrences dropped by 3%, and the premium for New England power delivered to New York at the margin decreased from $16.7/MWh before CTS to $7.9/MWh after CTS implementation.

The measures presented above are intended to provide insight into the relative performance of CTS compared with the prior transaction scheduling system. However, the above analysis is has its limitations. To thoroughly evaluate the cost of under-utilization and counterintuitive flows would require analyzing each ISO's supply curve and the interface bids to determine the optimal tie schedules ex-post. The NYISO internal supply curve data is not currently provided to ISO-NE. ISO-NE should acquire the additional data necessary to perform a more detailed assessment of the CTS scheduling solution and sources of deviation between actual flows and optimal flows.

In the next two sections, we discuss how the primary inputs to the CTS clearing (*i.e.*, each ISO's price forecast and market participant bids) affect CTS performance.

3.3 ISO Price Forecasts

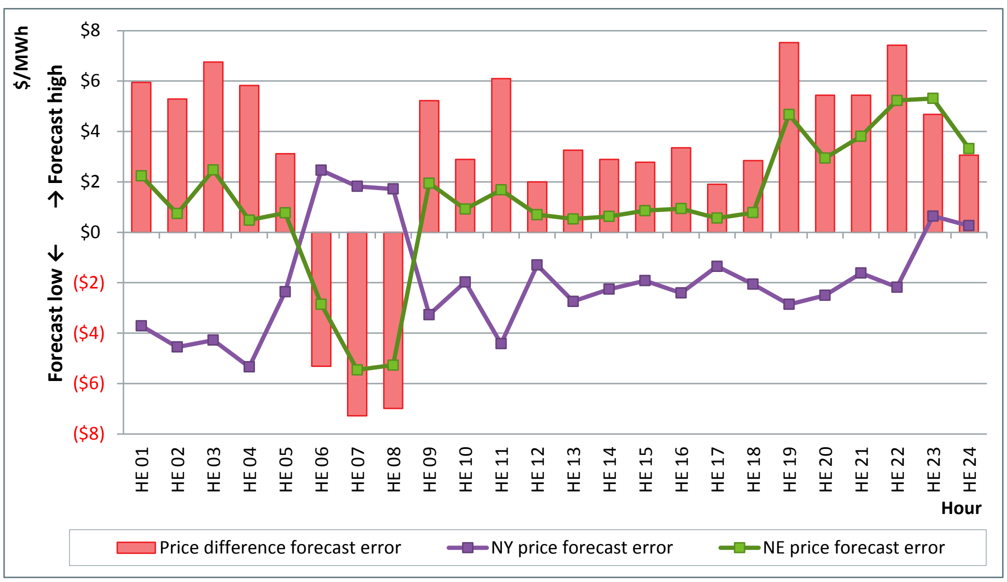
The price forecasts developed by each ISO are an important input to the CTS clearing engine. Price forecasts are calculated for each 15 minute interval and are used to determine the direction of price differences between the regions, which participant bids clear and the interface flow. Generally, interface bids are cleared if the offer price is below the forecasted price difference. ISO-NE creates its supply curve data that is the basis of its CTS price forecast using current offers and system conditions at about 45 minutes ahead of the scheduling interval. The NYISO forecast of its price is determined at about 30 minutes ahead of the scheduling interval.

There are two notable observations with respect to the ISO price forecasts. First, in absolute terms, each ISO tends to err in its forecast by a similar magnitude, on average, of between $1 and $2/MWh. However, the errors for the two ISOs are generally in *opposite directions*, which will overestimate the actual price difference between the regions. Second, forecast performance is not consistent for either ISO across the hours of the day. The ISOs' forecast errors tend to be higher in some hours of the day than in other hours, and the hours with the higher errors are not the same for each ISO.

The NYISO forecast is lower than its actual settlement price by ($1.93)/MWh, on average,[20] while the ISO-NE forecast is higher, on average, than its actual price by $1.17/MWh. Because each ISO's forecast error tends to occur in the opposite direction, the forecasted price *difference* between the two markets is higher than actually materializes by $3.10/MWh, on average.[21]

Figure 3-2 below shows the simple average of forecast errors calculated by hour of the day. The tendencies for New England to forecast too high and for New York to forecast too low are evident in most hours. On average, errors in the New England price forecast are largest during typical system ramp periods; *i.e.*, before the morning peak and after the evening peak. New York forecast errors are most apparent in the early morning hours. There is a reversal in the forecast errors of both ISOs during the morning load ramp hours between 5:00 a.m. to 8:00 a.m. (HE 06 – HE 08). The cause of this shift in error tendencies during the morning hours is not yet known.

Figure 3-2: Average real-time ISO price forecast errors (forecast minus actual), by hour



In Figure 3-2 above, a positive observation indicates the forecast is higher than the actual price and a negative observation indicates the forecast is lower than actual price. The purple line series represents the average error in the NYISO price forecast for each hour and the green line series represents the average error in the ISO-NE price forecast each hour. The red bar series is the

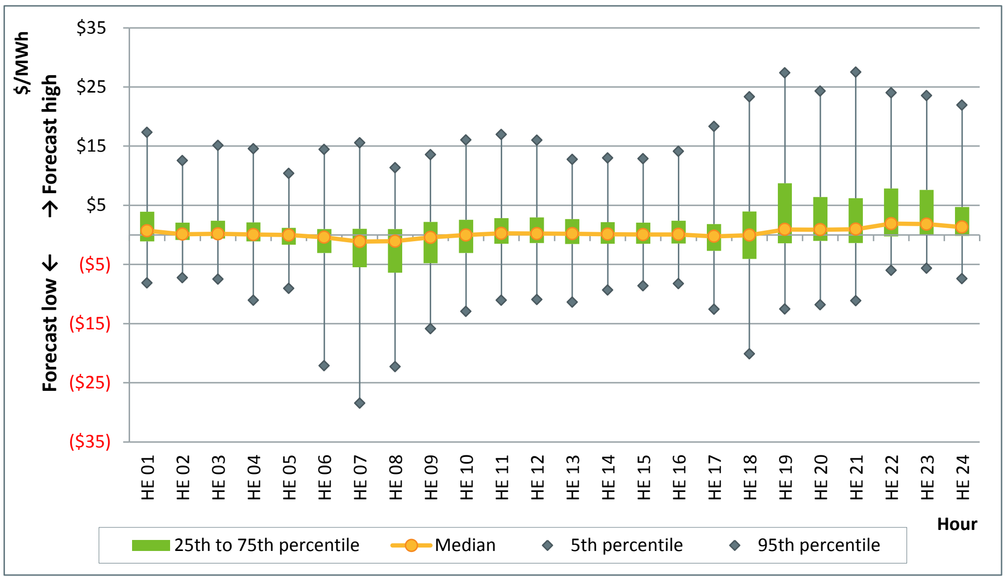
[20] The sign of the New York price forecast error value is negative under the convention of calculating the errors as: Forecast minus Actual.

[21] The error in forecasted price differences is calculated as: (Forecast $_{\text{New England}}$ – Forecast $_{\text{New York}}$) – (Actual $_{\text{New England}}$ – Actual $_{\text{New York}}$).

average error in forecasting the price difference between the markets.[22] For example, in the first hour of the day (HE 01) ISO-NE produces a forecast higher than its actual price by about $2/MWh and NYISO forecasts lower than its actual price by $4/MWh, on average. Therefore, the average error in the forecast of price difference between the markets is about $6/MWh higher than the difference in actual prices.

The following two charts illustrate the inconsistency in forecast performance for each ISO using simple distribution statistics. The results for ISO-NE are shown in Figure 3-3, and those for the NYISO are shown in Figure 3-4. The distribution measures highlight that certain hours in the morning and late evening have very wide variability in forecast accuracy.

Figure 3-3: New England real-time price forecast errors, by hour



As shown in Figure 3-3 above, the variability in the ISO-NE price forecast error occurs primarily in the morning ramp hours (HE06 – HE08) as well as through the evening peak and ramp down (HE19 – HE 23) where the median error is furthest away from zero. As noted above, ISO-NE creates its supply curve data that is the basis of the its CTS price forecast using current offers and system conditions at about 45 minutes ahead of the scheduling interval.

[22] See footnote 21 for the calculation of the price difference error.

Figure 3-4: New York real-time price forecast errors, by hour

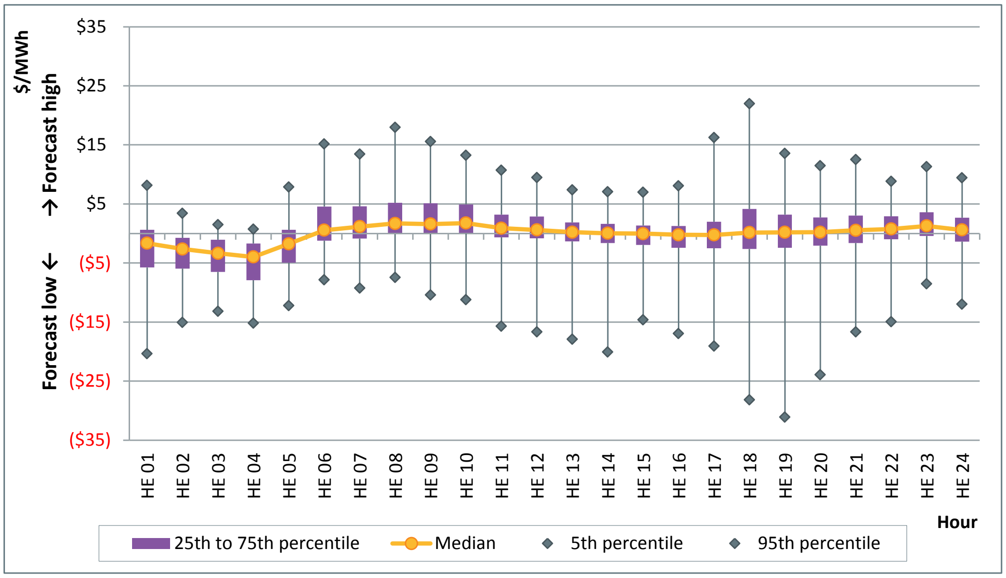


Figure 3-4 above demonstrates a consistent occurrence of NYISO forecast errors in the early morning hours (HE01 – HE05), with the median below zero despite the relative tight distributions of errors in these hours. Over the morning ramp hours (HE06 – HE 10) the median error shifts to a positive value as observed in Figure 3-2, which plots the average errors. The NYISO forecast errors have wider distributions over the evening peak hours (HE17 – HE20) even though the distributions are centered near zero. As noted above, the NYISO forecast of its price is determined at about 30 minutes ahead of the scheduling interval.

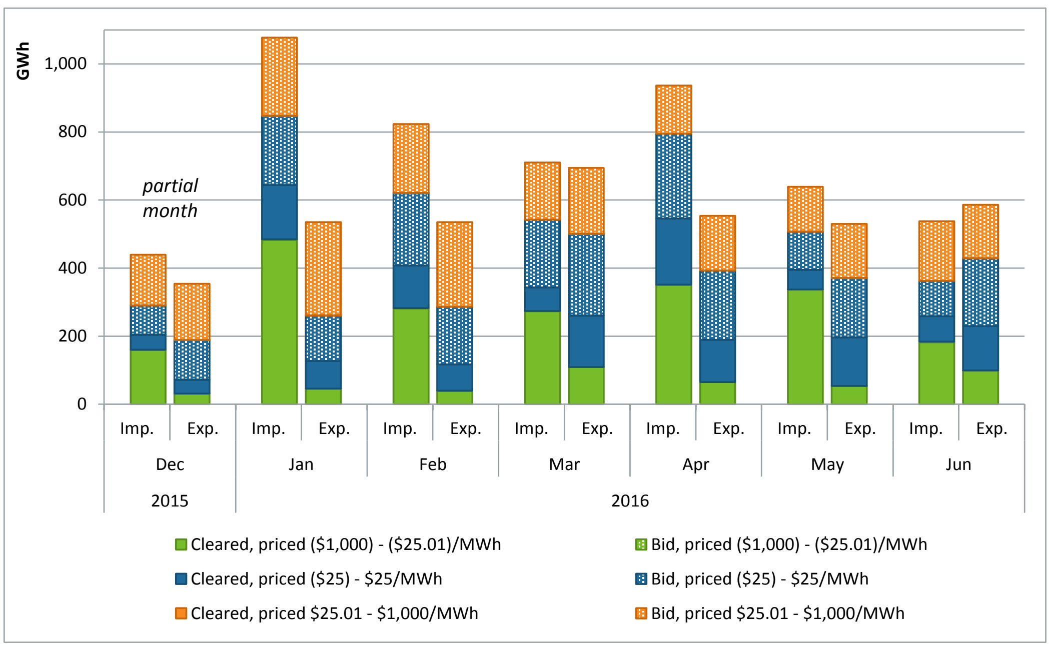
The ISOs' forecast biases being in opposite directions may consistently produce inefficient tie schedules. When forecasted price differences are under-estimated, too few interface bids may clear and the interface may be underutilized delivering power to the higher cost region. When the forecasted price difference is over estimated, more higher-priced interface bids can clear than will actually be in rate and the tie schedule can exceed the economically efficient level. The risk of ISO price forecast error is born by the participants because there is no make-whole compensation for cleared interface bids. The causes of bias in the price forecasts should be investigated and addressed by the ISOs.

3.4 Market Participant Bids

The ability to schedule real-time power in the economically efficient direction under the CTS design is also dependent on the bids submitted by market participants. The CTS implementation requires participants to submit interface bids to schedule power. CTS can only schedule import and export volumes up to the amount of the bid MW volumes submitted at prices below the forecasted price spread between the two markets. An interface bid specifies the bid quantity (MW), the direction of flow (to New York, or to New England), and the minimum expected price spread that the participant is willing to accept. Bid prices can be positive, negative, or zero. A positive bid price indicates the participant is willing to trade power when, as forecasted, the price in the source market is lower than the price in the destination market (buy low and sell high) by at least the amount of the bid price.[23] A negative bid price indicates a willingness to *counterintuitively* buy high and sell low; *i.e.*, to trade power when the energy price is expected to be higher at the source than the destination, up to the negative bid price.[24]

A total of 8,949 GWh of CTS interface bid transactions have been submitted by participants and 3,986 GWh (45%) of these have been cleared. Transactions to send power to New England ("imports" by New England conventions) made up 58% of the submitted volumes and 70% of the cleared energy. Export bids to send power to New York were 42% of submitted bid volumes and 30% of the cleared energy. With respect to bid prices, 46% of imports and 29% of exports were offered at negative prices, but a notable 83% of cleared imports and 82% of cleared exports were negative priced. The other 17% of cleared imports and 18% of cleared exports were offered at prices greater than or equal to zero. The predominance of price-insensitive import bids (those at very low negative prices) suggests many participants are structuring their real-time interface bids to cover their day-ahead cleared awards. In Figure 3-5 below, the total energy volumes (GWh) of submitted and cleared interface bids are shown in three ranges of bid price: the price-insensitive bids offered at prices between ($1,000)/MWh and ($25.01)/MWh, a plausible range of competitive offers between ($25)/MWh and $25/MWh, and an opportunistic range of offers between $25.01/MWh and $1,000/MWh.

Figure 3-5: Interface bid and cleared volumes (GWh) in price ranges, by month



The monthly totals of submitted and cleared interface bids in Figure 3-5 shows the predominance of price-insensitive bids (green bars) contributing to cleared transaction volumes. Over the entire

[23] For example, an interface bid priced at positive $5/MWh and in the direction to New England indicates the participant is willing to buy power from New York and sell to New England if the New England forecasted price is at least $5/MWh higher than the forecasted New York price.

[24] For example, an interface bid priced at negative $5/MWh and in the direction to New England indicates the participant is willing to buy power from New York and sell to New England if the New England forecasted price is not more than $5/MWh lower than the forecasted New York price.

period, the largest share of scheduled power comes from negative priced import bids (to New England). Less than half the competitive bids between ($25)/MWh and $25/MWh (blue bars) are being cleared in either direction. Less than 1% of the cleared energy is from offers between $25.01/MWh and $1,000/MWh (orange bars), although these are more than a quarter of bid import and export volumes. The overall lower submitted volumes of export bids (to New York) mean there is less flexibility for the CTS solution to schedule power flow to New York. Ideally, the CTS software would have large volumes of bids offered to flow in each direction and at prices closer to zero in order to adjust the power flow between the regions as market conditions change. In May and June, as well as March, the overall volumes of bid exports did nearly match imports, although price-insensitive imports were the majority cleared. Notable in June as well is the nearly equal volumes of cleared import and export bids and the relatively large share of price-sensitive export bids contributing to the CTS schedule solution.

Overall, our measures indicate the CTS scheduling system has helped to improve the efficiency of real-time power flows to the extent it has reduced counterintuitive flows. However, improved price forecasting and an increase in price sensitive bidding could enhance the effectiveness of CTS. To date, as discussed, forecast biases have been in opposite directions, which may consistently produce inefficient tie schedules. In addition, a significant volume of price-*insensitive* bids have been submitted and cleared to import power to New England, suggesting participants submit transactions to fulfill contractual positions outside the wholesale markets or are unwilling to deviate from their day-ahead cleared awards for other reasons. More participation from companies willing to make additional power transactions at spot prices would add to the bid liquidity necessary for CTS clearing to shift real-time power flows in the economically efficient direction, more fully utilize the tie transfer capability during unconstrained intervals, and further converge market prices.

Section 4
Regulation Market

This special section of the quarterly markets report reviews regulation market payments between 2011 and 2015.[25] During that time period, regulation market payments have increased significantly, going from a low of $11 million in 2012 to a high of $29 million in 2014 (See Figure 4-1 below).[26] Over the same period, the ISO has implemented two revisions to the regulation offer and pricing rules, and the New England region also has experienced winter periods with unusually high fuel and electricity prices. Both of these factors explain the increase in regulation payments during the review period.

4.1 Regulation Overview

Regulation is an essential reliability service provided by generators and other resources[27] in the real-time energy market. Generators providing regulation allow the ISO to use a portion of their capacity to match supply and demand (and to regulate frequency) over short time intervals. The ISO sends instructions to regulation resources to increase and decrease energy output on a second-to-second basis. The up and down movement by the generators is called regulation "mileage" and is measured as the absolute MW variation in output per hour.

Both regulation mileage and the potential withdrawal of capacity available for use in the energy market represent costs for generators providing regulation. The mileage component represents the direct cost of providing the regulation service. These direct costs may include increased variable operating and maintenance ("O&M") costs, as well as incremental fuel costs resulting from the generator operating less efficiently (heat rate degradation) while providing regulation service.

The capacity component may represent several factors. These include (1) the expected value of lost energy market opportunities when the capacity is used to provide regulation service, (2) elements of fixed costs such as incremental maintenance to ensure a generator's continuing performance when providing regulation, and (3) fuel market or other risks associated with providing

[25] The regulation market in New England is a very small component of the overall energy market; in terms of energy market payments over the review period, it accounted for only 0.3 percent on average. Energy market payments include direct energy market compensation via locational marginal prices (LMPs), uplift payments (net commitment period compensation), and ancillary market payments.

[26] Note that the annual values conform to "reporting quarter" definitions; since the first quarter of each year (the winter season) begins in December of the preceding year, the reporting year spans December of the preceding year to November of the reporting year: for example, reporting year 2012 begins in December 2011 and concludes with November 2012.

[27] Examples of other resources include flywheel storage, plug-in vehicle load response, plug-in vehicle distributed storage/generation that can discharge energy back onto the grid, residential heating demand response, real-time commercial-scale load management, and nano-phosphate battery storage. ISO New England Filing at the Federal Energy Regulatory Commission, December 19, 2012, Re: *ISO New England Inc. and New England Power Pool*, Docket No. ER08-54-014; Report of ISO New England Inc. Regarding the Implementation of Market Rule Changes to Permit Non-Generating Resources to Participate in the Regulation Market. There are currently no such resource participating in the regulation market.

regulation.[28] The regulation market provides compensation for these costs to the resources selected to provide regulation each hour.[29]

Because of the particular pricing and compensation structure for regulation within ISO New England (discussed in the next section), it should be expected that regulation offers would include no, or minimal, compensation for lost energy market opportunities. The ISO's regulation market pricing and compensation have effectively eliminated the need for generators to estimate and include such costs in their offers.[30]

4.2 ISO Changes to Regulation Pricing and Compensation

The ISO has revised regulation pricing and compensation on two occasions over the review period. An overview of the key components of the regulation offer, pricing and payment rules in place during the review period is presented in Table 4-1 below.

Table 4-1: Overview of Key Regulation Market Changes

Components of:	Pre-July 2013	July 2013 through March 2015	From March 2015 to Present
Offer	**Single-part Offer** combined capacity and mileage cost [31]	**Single-part Offer** combined capacity and mileage cost	**Three-part Offer** capacity, mileage and inter-temporal capacity offers
Price	**Single Clearing Price** based on marginal Offer	**Single Clearing Price based on *adjusted* marginal Offer** Offers adjusted to reflect resources' estimated opportunity cost	**Two Clearing Prices** capacity and mileage - capacity offers adjusted to reflect opportunity costs and incremental cost savings
Payment	**Capacity** Clearing Price x Capacity **Mileage** Clearing Price x 10% x Actual Mileage **Opportunity Cost** *Resource-specific* opportunity cost estimate	**Capacity** Clearing Price x Capacity **Mileage** Clearing Price x 10% x Actual Mileage **Make-whole payment** Unrecovered as bid-costs and actual opportunity costs	**Capacity** Clearing Price x Capacity **Mileage** Mileage Clearing Prices x Actual Mileage **Make-whole payment** Unrecovered as bid-costs, including opportunity costs and incremental cost savings

[28] Anecdotally, participants have indicated that providing regulation can both increase and decrease fuel market and other operational risks, and regulation offers will be revised to reflect those changes in risk.

[29] Generators providing regulation also receive energy market payments for their energy output.

[30] Based on a number of conversations with participants, energy market opportunity costs do not appear to be a significant component of these offers.

[31] The ISO adjusted these offers to include estimates of energy market opportunity costs, when selecting regulation resources. However, the opportunity cost estimates were not included in regulation market pricing: these opportunity costs were compensated via a resource-specific opportunity cost payment.

Prior to the first revision (implemented by the ISO in July 2013), generators indicated a willingness to provide regulation via a single-part regulation offer (i.e., a single offer price indicating the generator's expected cost for regulation mileage and capacity).

The ISO used these regulation offers to derive a regulation market clearing price.[32] This price was then used to compensate generators separately for providing regulation capacity and mileage. Capacity was compensated at the clearing price times the amount of regulation capacity provided by the generator; regulation mileage was compensated at a rate of 10% of the regulation clearing price times the actual mileage provided by the generator. Additionally, the ISO provided resource-specific payments to regulation resources, based on the ISO's estimates of energy market opportunity costs. These opportunity cost payments were in addition to ISO payments for regulation capacity and mileage.

On July 1, 2013, the ISO implemented revisions to regulation pricing and compensation. Specifically, it revised the regulation clearing price to explicitly include an *ex ante* estimate of energy market opportunity costs; it accomplished this by using adjusted generator offers that included the resource-specific opportunity costs, and basing the clearing price on the highest adjusted offer price among the selected regulation resources. The ISO also eliminated the resource-specific opportunity cost payments, but added a more generic regulation uplift payment for generators, to ensure that generators would suffer no losses when providing regulation.[33] This make-whole payment provides uplift when regulation market revenue is insufficient to cover a generator's as-bid cost, plus a generator's actual (*ex post*) energy market opportunity costs (based on final energy market prices).

Finally, on March 31, 2015, the ISO implemented additional changes to generator regulation offers and pricing to comply with FERC Order 755. These changes resulted in the creation of separate market clearing prices for regulation mileage and capacity; the ISO also created a three-part offer for regulation, giving resources the opportunity to state separate offer costs for mileage, capacity and "inter-temporal" costs.[34] The regulation market clearing price for mileage represents the highest as-bid cost from selected regulation resources; the capacity clearing price is the highest capacity price for the selected resources, as adjusted to reflect both energy market opportunity costs and "incremental cost savings.[35] The make-whole payment, to ensure that regulation resources incur no losses when providing regulation, was continued.[36]

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[32] The ISO's process for selecting generators to provide regulation minimized the overall cost of obtaining that service and included the ISO's *ex ante* estimate of resource-specific energy market opportunity costs. The market clearing price for regulation, however, was set using the as-offered cost of the most expensive generator within the selected set of regulation resources: the regulation market clearing price did not include the ISO's energy market opportunity cost estimate.

[33] See, for example, Jonathan B. Lowell's testimony, filed at the Federal Energy Regulatory Commission on 4/11/2013, for an explanation of the changes to regulation pricing and payments. ISO New England Filing to the Federal Energy Regulatory Commission, Re: ISO New England Inc. and New England Power Pool, Docket No. ER13-___-000 Regulation Market Opportunity Cost Change.

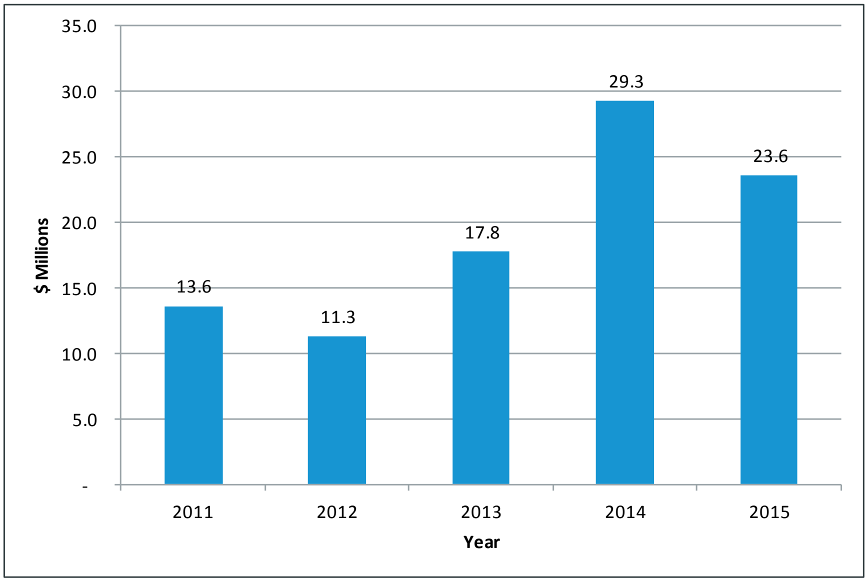
[34] FERC Order 755 describes these costs as: "An inter-temporal opportunity cost represents the foregone value when a resource must operate at one time, and therefore must either forego a profit from selling energy at a later time or incur costs due to consuming at a later time."

[35] Incremental cost saving represents the reduction in total system cost provided by a specific regulation offer, when compared to the next most expensive offer. This compensation replicates a "Vickery" approach to compensating lumpy "supply," and is intended to provide regulation resources with payments approximating the system opportunity cost of obtaining regulation. See Peter Cramton's testimony (April 26, 2012) to the Federal Energy Regulatory Commission, Re:

4.3 Regulation Market Payments, 2011-2015

Figure 4-1 shows regulation payments by year; the table, just below that graph, indicates the regulation volumes procured over the period: both regulation capacity and mileage.

Figure 4-1: Regulation Payments and Volumes



	2011	2012	2013	2014	2015
Hourly Avg Reg Capacity	62	60	60	60	63
Hourly Avg Reg Mileage	623	575	542	522	555

As noted earlier, regulation payments have increased significantly over the review period. These increases are particularly pronounced beginning in 2013, with a 57% increase in payments over 2012 levels and a 30% increase over 2011 levels. The trend of increasing regulation payments continues in 2014, with a 65% increase over 2013 levels. Payments in 2015 declined somewhat relative to 2014 (19%), but continued at elevated levels compared to earlier periods.

The annual average volume data over this period do not explain the increase in payments, as the volume changes are either uncorrelated or negatively correlated with payments; the annual change in volumes does help to explain part of the decrease in payments in 2012 compared to 2011 (when coupled with a decline in regulation offer prices and energy market opportunity costs).

The IMM has examined several factors to understand the change in payments: seasonal variation, changes in regulation offers, and ISO-initiated changes to regulation pricing.

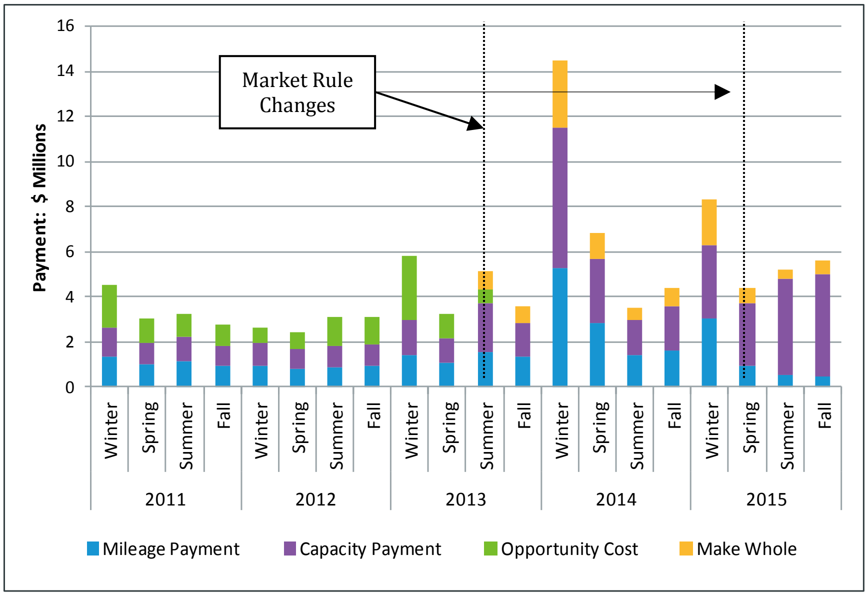
Docket Nos. RM11-7-000 and AD10-11-000; Order No. 755, Frequency Regulation Compensation in the Organized Wholesale Power Markets.

[36] A performance scoring mechanism was also implemented; payments are adjusted to reflect the performance of individual resources.

4.3.1 Winter Impact on Regulation Payments

As illustrated in Figure 4-2, a large portion of regulation payments has occurred in the winter season (Quarter 1). Although not directly observable from the graph, Winter regulation payments were approximately one-third of total annual regulation payments in 2011, 2013, and 2015, with Winter payments accounting for approximately one-half of all regulation payments in 2014. Winter payments in 2012 were an outlier over this period with just 23 percent of total payments occurring during that period.

Figure 4-2: Regulation Payments by Payment Type and Quarter



In 2011 and 2013, the Winter quarter is particularly noteworthy because the increase in payments can be attributed primarily to an increase in resource-specific side-payments for energy market opportunity costs; overall, energy market opportunity costs averaged 72% higher in the Winter quarters for 2011 to 2013 than for other quarters in those years. Other components of regulation payments averaged 29% higher in the Winter quarter, compared to other quarters.

In Winter 2014, opportunity cost compensation is no longer directly observable as a side payment, because the ISO eliminated the side payment and began including energy market opportunity costs in the regulation price starting in July 2013.[37] A precise estimate of the impact of opportunity cost on payments is not feasible as it would require re-running the regulation market clearing software to observe the change in pricing and payments both with and without the inclusion of those costs. However, examining the composition of offers for generators selected to provide regulation can provide a rough indication of that impact and how it changes over time.

[37] The make-whole payment may include some energy market opportunity costs to the extent that the *ex ante* estimate of opportunity costs included in the market clearing price under-estimated actual (*ex post*) energy market opportunity costs.

Figure 4-3: Offer Components for Generators Selected to Provide Regulation

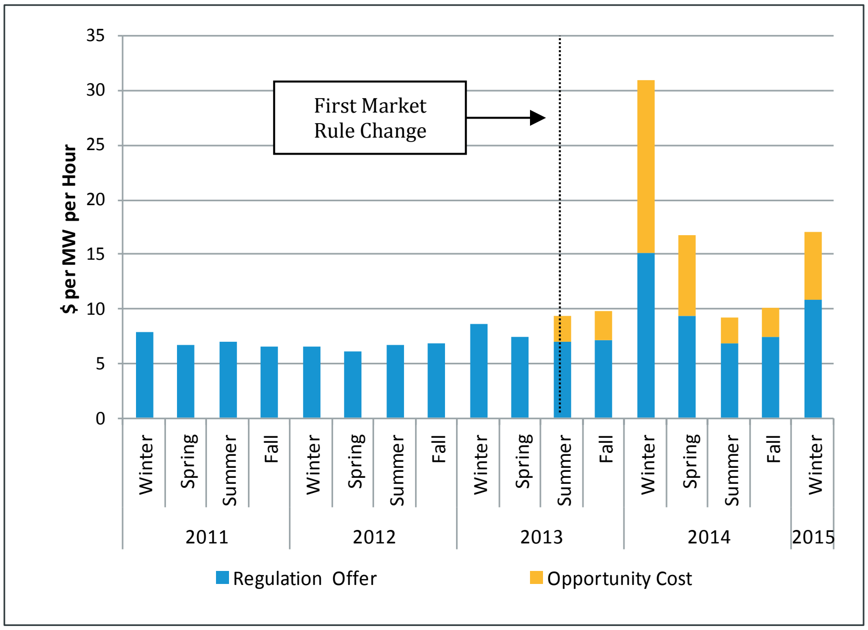


Figure 4-3 shows capacity-weighted average offers for generators selected to provide regulation between 2011 and Winter 2015. (The graph excludes offer data after Winter 2015, because of the change from single-part offers to three-part offers.) The offer data confirm that energy market opportunity costs have made a significant contribution to higher regulation market prices and payments in the Winter quarter, compared to other quarters. Additionally, it illustrates that selected participant offers – aside from the ISO's opportunity cost adjustment – also are higher in Winter, compared to other quarters. The average addition to offer pricing from opportunity costs in Winter is 80%, compared to a 44% increase in other quarters. The increase in participant regulation offers in Winter compared to other quarters is 72%.

Higher fuel costs and electricity prices during winter months also influence regulation market prices and payments during the winter. High fuel and electricity costs can affect regulation market payments in at least three ways. First, high real-time energy market LMPs directly impact the energy market opportunity costs for generators that would be dispatched away from their optimal energy market dispatch points, when providing regulation; these energy market opportunity costs represent the lost revenue (energy market LMP less a resource's as-offered energy costs) times the MW deviation of the resource's regulation dispatch relative to its in-merit-order energy dispatch.[38] As noted earlier, these costs were directly observable prior to July 2013, and since may be observed indirectly through the adjustments to regulation offers.

Second, high fuel costs can affect the direct cost of providing regulation; heat rate degradation from the up and down movement of providing regulation can lead to increased fuel consumption. Third, high and volatile fuel market prices can lead to fuel management risks for resources providing regulation. These factors are likely to influence participant offers.

[38] See, for example, the ISO's Market Rule 1 at Section III.14.8(b)(ii).

Figure 4-4: Regulation Payments Compared to Real-Time Energy Market LMPs

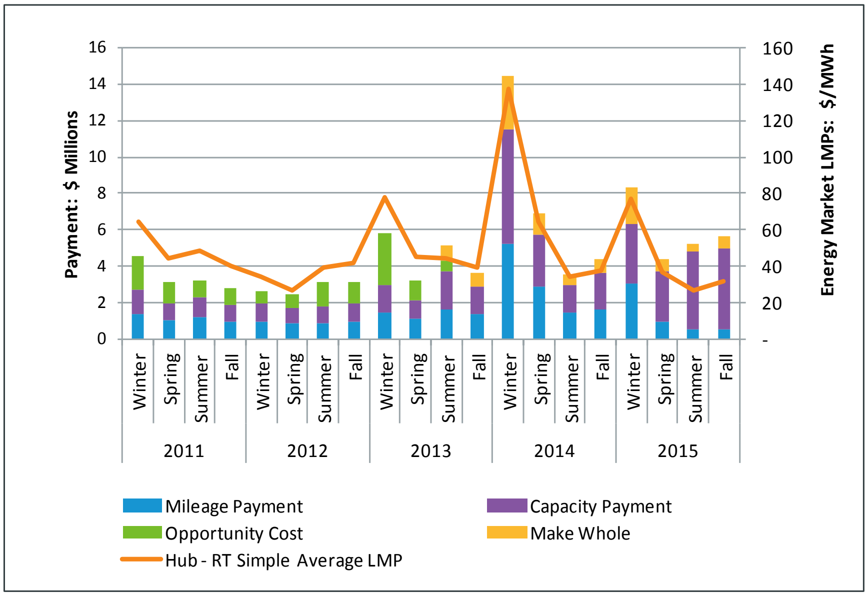


Figure 4-4 indicates the correspondence of real-time energy market LMPs at the Hub and regulation payments, and further illustrates a reasonably close relationship between electricity market prices and regulation market pricing and payments in winter months, with winter months tending to have the highest real-time energy market LMPs of the year. Winter 2014 is noteworthy for having been a winter season with unusually high natural gas and electricity market LMPs, both reflecting fuel supply and supply volatility issues in natural gas markets in New England. These issues carried over into Spring 2014 (which begins with March), as represented by the high energy market LMPs and regulation payments in that quarter.

Based on the opportunity cost data, it is reasonable to expect that the especially high energy market opportunity costs and resulting payments in Winter of 2013, 2014, and 2015 explain a significant portion of the increase in annual payments. The final section of this article provides a rough estimate of both winter impacts on payments and the impact of changes to regulation payment and pricing implemented in July 2013 and March 2015.

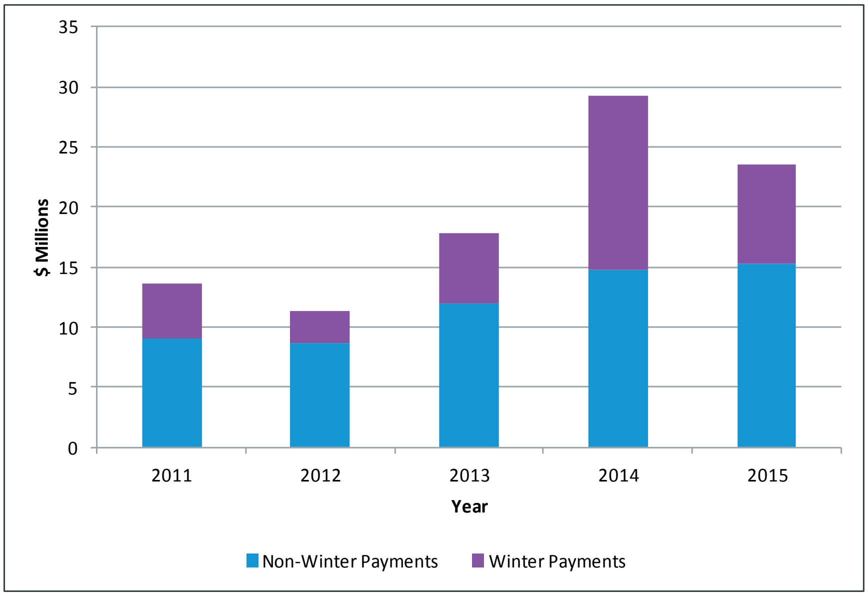
4.3.2 Other Impacts on Regulation Payments

In addition to the winter impacts on regulation payments,

Figure 4-5 indicates that regulation payments in other quarters have increased significantly over the 2011 to 2015 period. This change began in 2013, with non-winter payments (i.e., for the Quarters of Spring, Summer, and Fall) increasing to $12 million from $9 million in 2011-12, and continued into 2014-15, with payments levels at $15 million.[39] Earlier-presented quarterly payment data suggest that the increase in non-winter payments began approximately at mid-year of 2013, when the ISO implemented regulation pricing changes in July 2013.

[39] Some year-to-year variation in payments is expected, as the amount of regulation procured each year may vary and as opportunity costs fluctuate with energy market conditions.

Figure 4-5: Winter and Non-Winter Regulation Payments, by Year



To understand the likely cause for the non-winter component of the payment increase, both participant offers and changes in market rules have been reviewed. The ISO implemented revisions to regulation market pricing and offers in both 2013 and 2015.

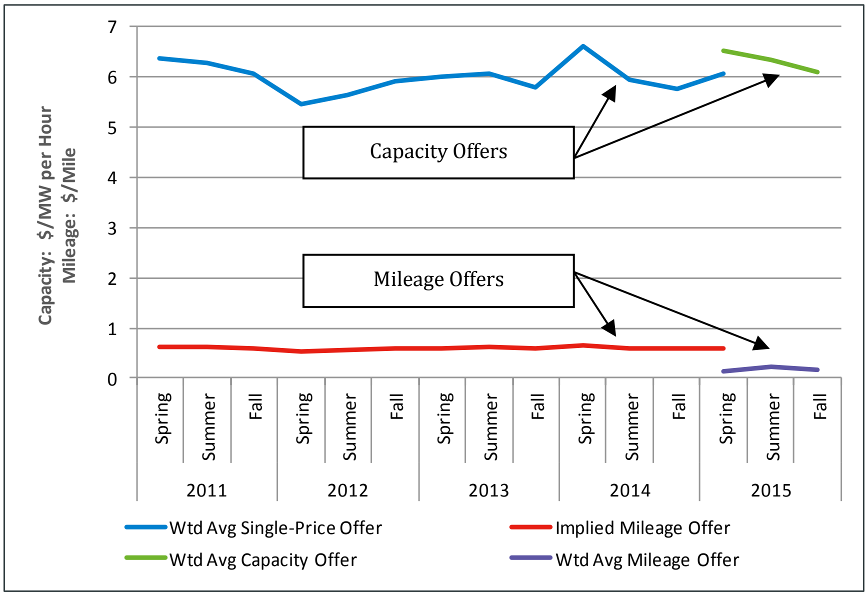
4.3.3 Participant Offers

As described below, we find that offer behavior does not explain the increase in regulation payments.

Figure 4-6 shows participant offer levels for the review period. These data differ from the earlier offer data, which represented weighted average offers for generators that had been selected for regulation; these data summarize a broader set of offers.[40]

[40] Only a "relevant" range of the supply curve was reviewed. The range was six times the hourly requirement. Because the construction of the regulation market supply curve used to select resources to provide regulation and to determine the market price is quite complicated (taking into account the amount of capacity offered by each resource, energy market opportunity costs and incremental cost savings), the "relevant" range was chosen to capture resources that might be selected for regulation, while excluding high, outlier offers that are less likely to be chosen to provide regulation.

Figure 4-6: Regulation Offers



The data represent weighted-average offers by quarter. The time-series data for 2011 to Spring 2015 are the single-offer price data, with the "implied mileage offer" representing ten percent of the single offer price (i.e., the mileage compensation provided by the market rules).[41] The time-series data that begin in Spring 2015, indicate the average offer values for the three-part offer prices.[42] The capacity and inter-temporal components have been combined and are reflected in the capacity price data.

Two aspects of the offer data are interesting. First, the capacity offer price data exhibit a reasonably stable pattern over the period, fluctuating around the long-run average of $6 per MW per hour, and would not explain the significant increase in regulation payments beginning in 2013. Mileage offer prices are significantly lower than the implied mileage prices under single-part offers. This suggests that participants have effectively lowered offer prices for providing regulation.

To illustrate the impact of the reduced mileage offer prices on regulation compensation, the offer prices have been converted to payment rates. The payment rates assume that 9.1 miles of regulation service would be provided for every megawatt of regulation capacity (the average mileage over the review period). The payment rates indicate the amount of compensation, in dollars per MW per hour, that a participant would expect given an "average" offer.[43]

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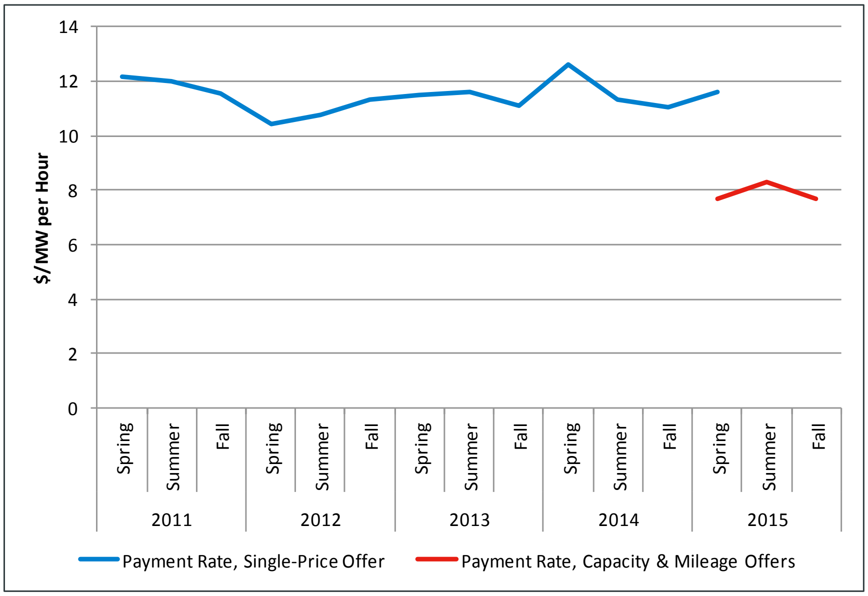
[41] The change from single-part offers to three-part offers occurred at the end of the first month of Quarter 2 2015. As a result, the quarterly data overlap.

[42] The averages for the three-part offers are based on a sorted supply curve (least cost to highest cost) using each offer's combined cost of providing capacity (which includes inter-temporal costs) and service (assuming 9.1 miles of service).

[43] Payment rates are calculated in the following manner. For single-part offers: Offer price x 1 MW of capacity + offer price x .1 x 9.1 miles of service; for three-part offers, 1 MW times the capacity offer price + 9.1 x the service offer price. The payment rate is the dollar compensation per regulation MW per hour that an "average" offer would expect to obtain.

Figure 4-7: Offers Stated as Expected Payment Rate



As indicated in Figure 4-7, an "average" generator, prior to three-part offers, requested payments equivalent to approximately $10 to $12 per MW of regulation capacity to cover the cost of providing both regulation capacity and mileage; with three-part offer pricing, a payment of $7 to $8 per MW of capacity is now being requested to provide regulation capacity and mileage.

The offer pricing and payment rate data suggest that changes in participant behavior, through offer pricing, do not explain the significant increase in regulation payments that began in 2013. The single-part offers were relatively stable throughout the 2011 – Spring 2015 period. Offers and payment rates have declined since the implementation of three-part offers.

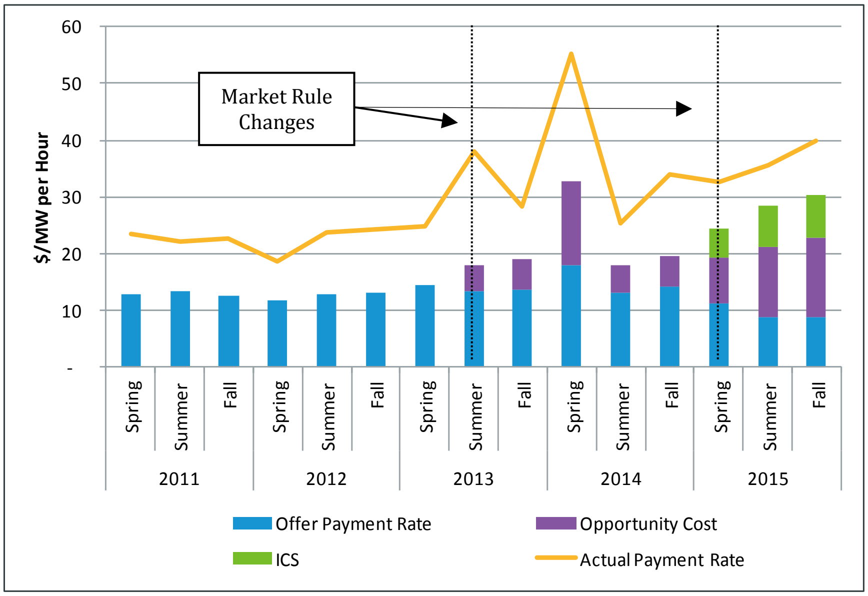
4.3.4 Change in Regulation Market Rules

As explained earlier, the market rules governing regulation market offers and pricing changed on two occasions during the review period: Beginning in July 2013, the market clearing price for regulation began including the ISO's estimate of energy market opportunity costs; in March 2015, offers were adjusted to also include incremental costs savings.[44]

Figure 4-8 illustrates the impact on regulation offers of the inclusion of opportunity costs and incremental cost savings, for the non-winter periods of 2013 to 2015. (Note that, prior to July 2013, the opportunity cost estimates were used to determine the least-cost set of regulation offers, but were not included in the offer prices used to set the regulation clearing price.) The average offer data in the graph provide a rough indication of the impact of ISO offer adjustments on regulation market pricing. The regulation payment rate data, which show the average compensation levels inclusive of all payment types, provide an indication of how pricing adjustments have influenced payment rates.

[44] The opportunity costs and incremental cost savings are included by adjusting participant offers and clearing the market based on the adjusted offers.

Figure 4-8: Regulation Offers by Component



Setting aside Spring 2014 (which reflects unusual energy market conditions), the offer data and the payment rate data in the graph suggest that payment rates have risen with the regulation market pricing changes in 2013 and 2015. The inclusion of incremental cost savings, and increased opportunity costs, since the March 2015 pricing changes have more than offset the reduction in participant offers.

4.4 Conclusion: Contribution of Seasonal Variation and Changes in Regulation Pricing to Regulation Payments

A rough estimate of the impact of seasonal variation and changes in regulation pricing has been prepared.[45] The estimate assumes a payment structure analogous to the pre-July 2013 structure, and chooses the highest offer cost from the resources selected for regulation to estimate the regulation payment rate. Each selected resource is paid for providing regulation at that rate, plus the individual resources are paid for opportunity costs at the ISO's *ex ante* estimate of those costs.[46] The estimates for service and capacity payments using this approach track reasonably well with the actual payments in the regulation market for the pre-July 2013 period.

[45] These estimates assume that the selection of resources for providing regulation would have been the same, with or without the changes to pricing implemented in July 2013 and March 2015. Since the inclusion of incremental cost savings in the regulation price beginning in March 2015 could change the selection of resources, the estimates for the March 2015 pricing changes are imprecise. The July 2013 change in regulation pricing would not be expected to change the selection of regulation resources; those estimates should be more precise than for the later period.

[46] The alternative prices that exclude the July 2013 and March 2015 pricing changes were calculated in the following manner. For the July 2013 to March 2015 period, the highest offer from the resources originally selected to provide regulation was utilized as the alternative regulation price. For the March 2015 to December 2015 period, the highest capacity price from the resources originally selected to provide regulation was utilized as the alternative capacity price; since the original mileage price determined by the ISO is not directly adjusted for opportunity costs or incremental cost savings, the original mileage price has been used.

Table 4-2 compares winter and non-winter period payment estimates; these estimates exclude the regulation pricing changes that occurred in July 2013 and March 2015, and are based on the pre-July 2013 pricing and payment structure.

Table 4-2: Comparison of Winter and Non-Winter Payments ($ Millions)

Year	Winter Quarter (Q1)	Non-Winter Quarter Average (Q2-Q4)
2011	4.5	3.0
2012	2.6	2.9
2013	5.8	3.5
2014	11.9	4.1
2015	7.0	3.9

The payment estimates suggest that winter payments would have been much higher than for other quarters, irrespective of the pricing changes. These higher payments reflect the increased costs (direct and opportunity costs) that regulation resources incur during higher fuel cost and energy market LMP periods. Over the review period, Winter quarter payments averaged 84 percent higher than payments during non-winter quarters.

Figure 4-9 indicates the impact of the regulation pricing changes that occurred in July 2013 and March 2015. In general, the impact of the pricing changes appears to have been smaller than winter impacts, increasing non-winter quarterly payments by approximately 25% and winter payments by 20%. These estimates assume that resource-specific opportunity cost payments would have been provided, absent the changes in the regulation pricing mechanism. Hence, the below payment estimates are highlighting the incremental addition to payments that result from including opportunity costs and incremental cost savings in the clearing price.

Figure 4-9: Regulation Market Payments, Impact of Regulation Pricing Changes