ISO New England's Internal Market Monitor

Second Quarter 2015

Quarterly Markets Report

Internal Market Monitor
October 1, 2015

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Executive Summary

The Internal Market Monitor[1] has analyzed the performance in the second quarter ("Q2") of 2015 (the "Reporting Period") of the region's wholesale electric energy, ancillary services, and capacity markets using supply offers, demand bids, fuel prices, market results, and other economic data. A summary of market conditions and outcomes are provided in this report. Overall, market prices reflected the cost of providing energy, and energy market outcomes were competitive.[2]

This report also presents the results of our analysis and recommendations relating to number of important areas of the market. The report covers the competitiveness of past Forward Reserve Market (FRM) auctions and the policy of dealing with FRM resources within the energy market mitigation rules. The report also includes recommended changes to the Forward Capacity Market (FCM) mitigation rules to address uneconomic retirements. Finally, we address the issue of generation resource ownership and control in the context of the Pivotal Supplier Test (PST) used in automated energy market mitigation and recommend enhancements to ISO systems to improve the accuracy of this test.

1.1 Summary of Market Outcomes and Performance

- The total estimated wholesale market costs in the Reporting Period were $1.12 billion, a 27% decrease compared to the same period in 2014 (Q2 2014).
    - Lower natural gas prices were the primary driver for the decrease in total energy costs in the Reporting Period. Natural gas prices during the Reporting Period averaged $2.23/MMBtu, the lowest quarterly price since 2003. This is a 47% decrease from Q2 2014.
- Day-Ahead Energy Market prices during the Reporting Period averaged $24.84/MWh at the Hub, and Real-Time prices averaged $23.89/MWh, also the lowest quarterly prices since March 2003. Day-Ahead prices were 38% lower than Q2 2014, and Real-Time prices were 37% lower than Q2 2014.
- Total real-time reserve payments were $7.9 million in the Reporting Period, a 90% increase from Q2 2014, and Regulation payments totaled $4.3 million, a 49% increase from Q2 2014.

[1] Capitalized terms used but not defined in this report are intended to have the meanings given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff ("ISO Tariff") or in ISO operating procedures. The ISO Tariff is available at www.iso-ne.com/regulatory/tariff/index.html. Market Rule 1 is Section III of the ISO Tariff.

[2] This report fulfills the requirement of Market Rule 1, Appendix A, Section III.A.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation.* Some data presented in this report are still open to resettlement, and some exhibits may be off due to rounding. Underlying natural gas data furnished by:

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- The summer 2015 locational Forward Reserve Auction cleared with a clearing price of \$5,824/MW-month for all reserve zones and products except for the Thirty-Minute Operating Reserve (TMOR) product for NEMA-Boston, which cleared at the LFRM cap of \$14,000/MW-month.

- Net Commitment Period Compensation (NCPC) payments during the Reporting Period totaled \$26.5 million, a 58% increase from Q2 2014.

- Overall, the energy market was competitive during the Reporting Period. The system-wide concentration of supply ownership remains low. Energy market prices are consistent with input costs.

1.2 Summary of Special Market Analysis and Recommendations

Structural Competitiveness in the Forward Reserve Market

The performance and structural competitiveness of the FRM was analyzed. The results indicate that the FRM auction is not reliably structurally competitive and that auction clearing prices are higher when there is less competition in the auction.

Further analysis is underway to determine if offer prices reflect a competitive basis, especially in auctions where supply was structurally uncompetitive.

Key points from the analysis are:

- The FRM clearing prices have been volatile in the study period, and even more so when considering the pure reserve price (net of the applicable Forward Capacity Market (FCM) clearing prices).
- Ten-minute Non-Spinning Reserve (TMNSR) prices are higher when there is less offer surplus (difference between total offered TMNSR and TMNSR requirement).
- The estimated Residual Supply Index (RSI) values show that there were three auctions for TMNSR in the 2012 through 2015 period when there was at least one pivotal supplier and five auctions when there was at least one pivotal supplier in one of the local reserve zones.
- The frequency of uncompetitive offer quantities, as measured by the RSI, would have been greatly reduced had all available TMNSR and TMOR available capability been offered in the auction.
- On average less than 70% of the available TMNSR and 76% of the available TMOR capability was offered in the FRM auctions.

No recommendation is made at this time, pending further analysis which is currently underway. Options for additional protections against the exercise of market power in these auctions include a must-offer obligation for generation that can provide these products and has a Capacity Supply Obligation as well as offer mitigation, triggered by a pivotal supplier test, that uses a reference level approach similar to other offer mitigation mechanisms that currently exist.

Application of Energy Market Mitigation Rules to Generation Resources with a FRM Assignment

Market Participants are required to offer resources assigned as Forward Reserve Resources in the energy market at or above a pre-established Forward Reserve Threshold Price. As this threshold price can often be greater than a resources marginal cost, the Market Participant risks having their supply offer mitigated to a reference price that is below the Forward Reserve Threshold Price, thereby incurring Failure-to-Reserve penalties. In the past, the IMM has exempted Forward Reserve Resources from energy market mitigation to reduce the Market Participant's risk of incurring a Forward Reserve Failure-to-Reserve penalty.

However, participants' ability to over-assign resources to meet their obligation and thereby avoid mitigation for capacity in excess of the obligation raises serious market power concerns. The IMM has therefore modified its practice, coincident with the start of the winter 2015-16 Forward Reserve Procurement Period, of granting energy market mitigation exemptions to all Forward Reserve resources requesting such treatment.

The IMM has issued specific conditions that must be met to warrant an exemption of FRM resources from energy market mitigations. These are listed in section 3.2.3 of this report.

Recommendation: The ISO implement an automated approach for Market Participants with FRM resources to comply with the obligation to submit supply offers for a quantity consistent with the participant's FRM Obligation, while also preserving the integrity of the automated market power mitigation mechanism in the energy market.

Uneconomic Resources Retirements and the Forward Capacity Market

The current FCM mitigation rules do not address the potential of incumbent generation companies exercising seller-side market power by retiring existing resources prematurely – at a time when they are still profitable to operate as capacity resources in the ISO New England market. Premature retirement artificially reduces the amount of capacity supply that is available in the FCM and can have a material impact on the auction clearing price.

Further, the current process for capacity resource retirement occurs after the deadline for new entry to register for the capacity auction, thereby creating an informational asymmetry between the incumbent and new entrant. This can preclude new entrants that are otherwise less inclined to enter into the next auction from choosing to do so knowing there will be less supply available due to the retirement.

Recommendation: The ISO develop a method for addressing capacity resource retirements from a market perspective including the following:

- A process for identifying resource retirements that appear to be premature with respect to their expected economic life and can be used to exercise market power in the Forward Capacity Market,
- A mitigation measure that ensures auction clearing prices are not distorted by the exercise of market power through pre-mature retirement of capacity resources,
- A more robust mechanism for existing resources to retire through competitive price discovery in the Forward Capacity Market rather than through administrative means, and

- A timeline for the retirement process that will facilitate signaling to prospective new entry the extent of potential retirement capacity prior to the show of interest deadline for new capacity resources.

The IMM has been working with the ISO to develop a process that addresses this concern. The proposed design has benefited from various communications including stakeholder input provided at several NEPOOL Markets Committee meetings this year.

Accounting for Affiliations among Lead Market Participants

Accurate accounting of a Market Participant's portfolio is an important aspect in detecting market manipulation and market power. The ability to exercise market power profitability depends on, among other things, the size of a Market Participant's portfolio relative to the product demand or requirement.

Currently, the Pivotal Supplier Test (PST) for market power mitigation in the energy market assesses market power using a portfolio construction based on the Lead Market Participant (LP) entity. There are several significantly-sized Market Participants that have generation assets in ISO New England that are registered under different LPs. In such cases, a PST evaluating market power based on portfolios defined by the LP-level entity under-identifies market power and consequently preempts the application of market power mitigation in cases where it should be applied.

Recommendation: The ISO implement the following:

- Develop and maintain a database of corporate relationships and asset control that allows for accurate portfolio construction for the purpose of identifying uncompetitive participation including the potential exercise of market power and market manipulation.
- Alter the existing Pivotal Supplier Test applied in energy market power mitigation, as set out in Section III, Market Rule 1, Appendix A of the ISO New England Inc. Transmission, Markets, and Services Tariff, to test generation portfolios based on entity control over resource participation in the energy market.

Section 2
Summary of Market Outcomes and System Conditions

This section summarizes the region's wholesale electricity market outcomes and measures of market performance and competitiveness from April 1, 2015 through June 30, 2015 (the "Reporting Period").

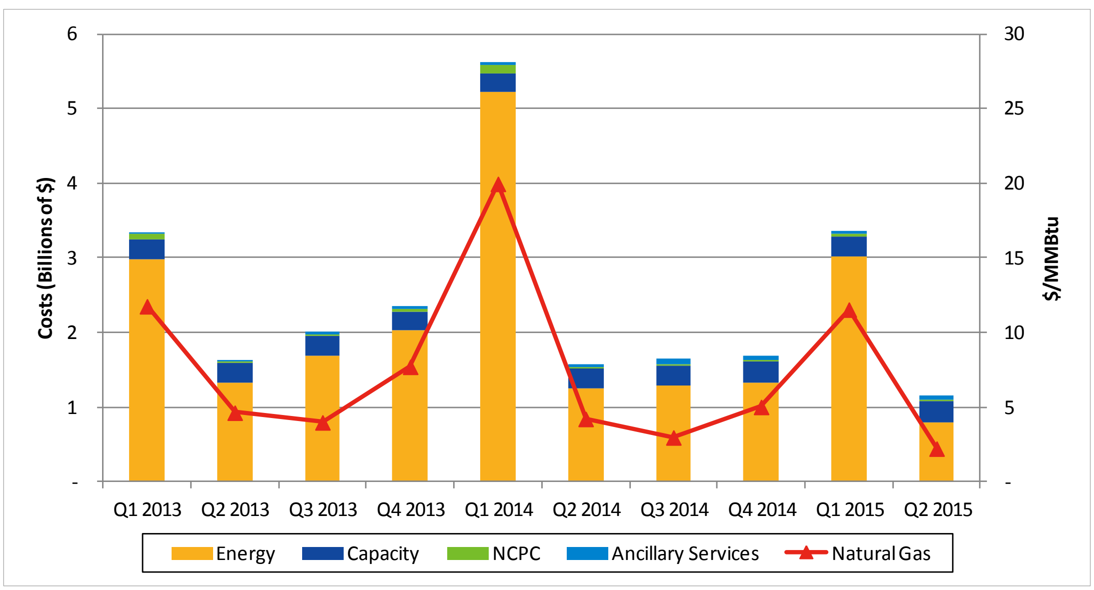
2.1 Market Outcomes

2.1.1 Total Wholesale Electricity Market Value

Figure 2-1 below shows the estimated wholesale electricity cost for each quarter (in billions of dollars) by market, along with average natural gas prices (in $/MMBtu). In Q2 2015, the total estimated market cost decreased by about 28% compared to the same quarter last year ($1.14 billion compared to $1.58 billion Q2 2014), and decreased by 66% when compared to Q1 2015 ($3.36 billion).[3] Net Commitment Period Compensation (NCPC) costs in Q2 2015, at $27 million, decreased by 27% compared to Q1 2015 but increased by 58% compared to Q2 2014. Ancillary service costs which include reserve and regulation payments totaled $43 million, a decrease of 10% when compared to both Q1 2015 and Q2 2014, respectively.

As shown in Figure 2-1, natural gas prices were the primary driver behind changes in energy costs. The large decrease in energy costs in Q2 2015 compared to Q1 2015 was the result of a large decrease in natural gas prices between the time periods as shown in Table 2-1. In addition, gas prices were much lower in Q2 2015 compared to Q2 2014, resulting in lower electricity costs.

Figure 2-1: Wholesale market costs and average natural gas prices by quarter, 2013-2015 ($ and $/MMBtu)



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[3] 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 annual wholesale costs.

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

	Q2 2015	Q1 2015	Percent Change Q2 2015 to Q1 2015	Q2 2014	Percent Change Q2 2015 to Q2 2014
Real-Time Load (GWh)	29,074	33,614	-14%	29,315	-1%
Weather Normalized Real-Time Load (GWh)	29,145	32,440	-10%	29,571	-1%
Peak Real-Time Load (MW)	20,895	20,583	2%	21,263	-2%
Average Day-Ahead Hub LMP ($/MWh)	$24.84	$84.84	-71%	$39.92	-38%
Average Real-Time Hub LMP ($/MWh)	$23.89	$81.97	-71%	$38.16	-37%
Average Natural Gas Price ($/MMBtu)	$2.23	$11.37	-80%	$4.22	-47%

The following factors contributed to market outcomes in the Reporting Period when compared to the corresponding quarter of last year:

- Lower natural gas prices in the second quarter of 2015 were the primary driver for lower day-ahead and real-time prices when compared to the same quarter last year.
  - Natural gas prices during the Reporting Period decreased by 47% from Q2 2014.
  - Oil prices were also 48% lower during the Reporting Period compared to Q2 2014.
- The Real-Time Load in Q2 2015 was 1% lower than the Real-Time load in Q2 2014.
- The peak Real-Time Load, which occurred on June 23, 2015 during the Reporting Period, was 20,895 MW, 2% lower than the peak load observed in Q2 2014.

2.1.3 LMPs and Fuel Prices

The average price for wholesale electricity in Q2 2015 was the lowest quarterly price in the past 12 years. The primary driver behind the wholesale electricity price was gas prices, which were at record lows. See Table 2-2 below, which shows the monthly and quarterly electricity and gas prices and their respective ranking relative to all monthly and quarterly prices since March 2003.[4]

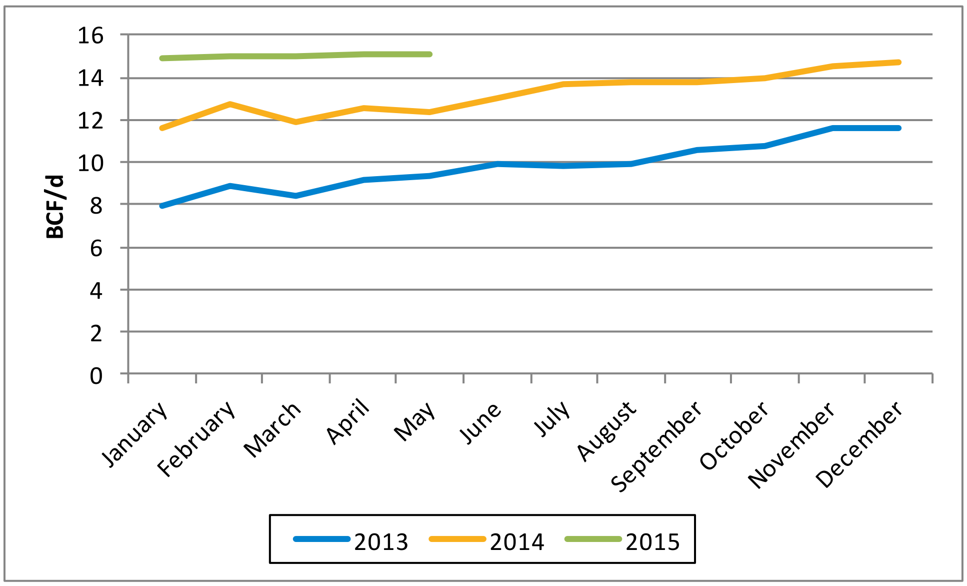
Table 2-2: Monthly and Quarterly LMPs and Algonquin Gas Prices and Ranking since March, 2003

	Day-Ahead ($/MWh)	Rank	Real-Time ($/MWh)	Rank	Algonquin ($/MMBtu)	Rank
April 2015	$28.43	6th lowest	$25.88	4th lowest	$3.18	10th lowest
May 2015	$24.92	2nd lowest	$26.12	5th lowest	$1.85	2nd lowest
June 2015	$21.16	lowest	$19.61	lowest	$1.68	lowest
Quarterly	**$24.84**	**lowest**	**$23.89**	**lowest**	**$2.23**	**lowest**

[4] March 2013 was the implementation of Standard Market Design in the New England electricity market.

Of particular interest in the Reporting Period are the record low natural gas prices. Algonquin's quarterly price of $2.23/MMBtu for the Reporting Period is 80% lower than Quarter 1 2015's price of $11.37/MMBtu, and 47% lower than Quarter 2 2014's price of $4.22/MMBtu. According to the Energy Information Administration (EIA), US dry natural gas production is at an all-time high year to date (through April 2015) of 8,884,547 MMBcf, a 9% increase over 2014, despite lower prices and reduced drilling.[5] Total U.S. production growth continues to be driven by regional shale production, concentrated in the Marcellus area in Pennsylvania, West Virginia, and Ohio.[6] Figure 2-2 below shows shale production for Marcellus from 2013 through May 2015. The figure shows that Marcellus shale gas production has increased 23% year to date compared to the first two quarters of 2014, and has increased 71% compared to the first two quarter of 2013.

Figure 2-2: Marcellus Shale Production, 2013-2015 (BCF/d)



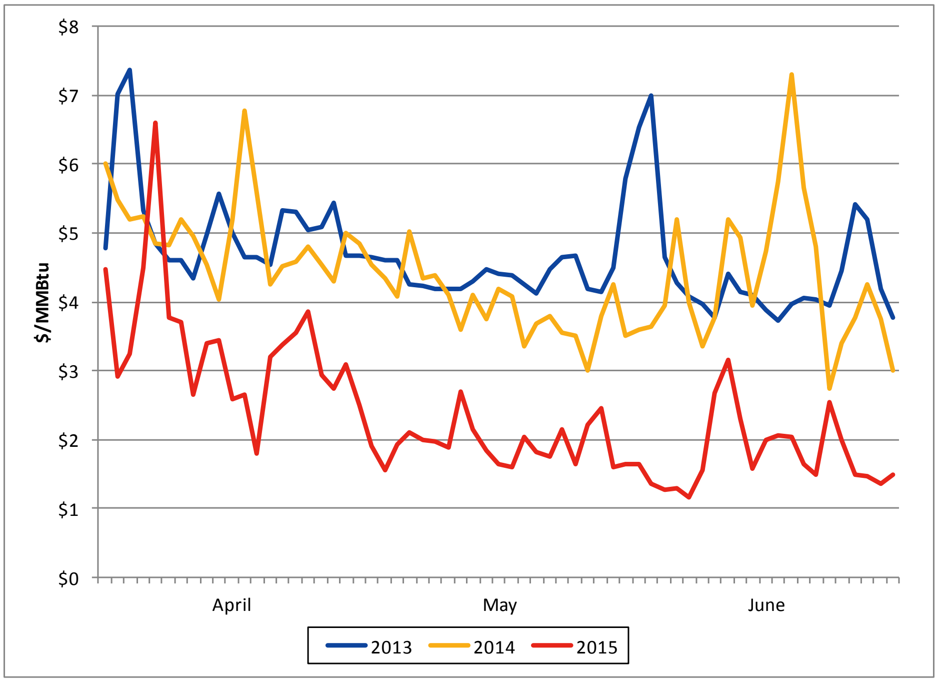
Source: U.S. Energy Information Administration (June 2015).

Figure 2-3 shows Algonquin Next-Day natural gas prices by day over the second quarter for the past three years. Each line represents a year with the median daily trade value for all Next-Day physical trades for that particular day. The low natural gas prices persisted over the quarter with only one day in early April where the daily median price in 2015 was greater than a year ago. From a monthly perspective the June 2015 median trade value was $1.62/MMBtu, 60% lower than the median trade value of June 2014. The median trade value in May 2015 was 54% lower than the May 2014 value. These low natural gas prices are the primary driver of the low wholesale electricity prices noted above.

[5] US Energy Information Administration, *US Dry Natural Gas Production 5 Year Seasonal Analysis*, http://www.eia.gov/dnav/ng/hist/n9070us2m.htm.

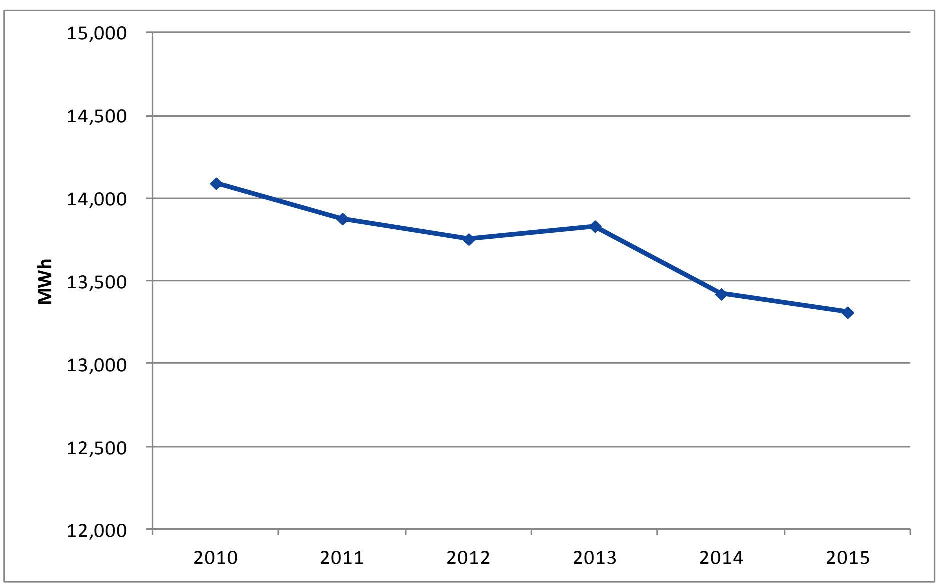
[6] US Energy Information Administration, *Natural Gas Weekly Update, July 1, 2015*, http://www.eia.gov/naturalgas/weekly/archive/2015/07_02/index.cfm.

Figure 2-3: Algonquin Next Day Median Daily Trade Prices, April, May, and June 2013-2015 ($/MMBtu)



Along with low natural gas prices, the overall demand for electricity for the quarter was also low due to mild weather. Energy consumption for the second quarter of 2015 was the lowest since the inception of Standard Market Design (SMD) with an average hourly load of 13,312 MW - see Figure 2-4 below. April 2015 energy consumption was lower than any year since the inception of SMD, while May 2015 was the third lowest and June 2015 was the second lowest.

Figure 2-4: Quarter 2 Average Hourly Demand, 2003-2015 (MW)

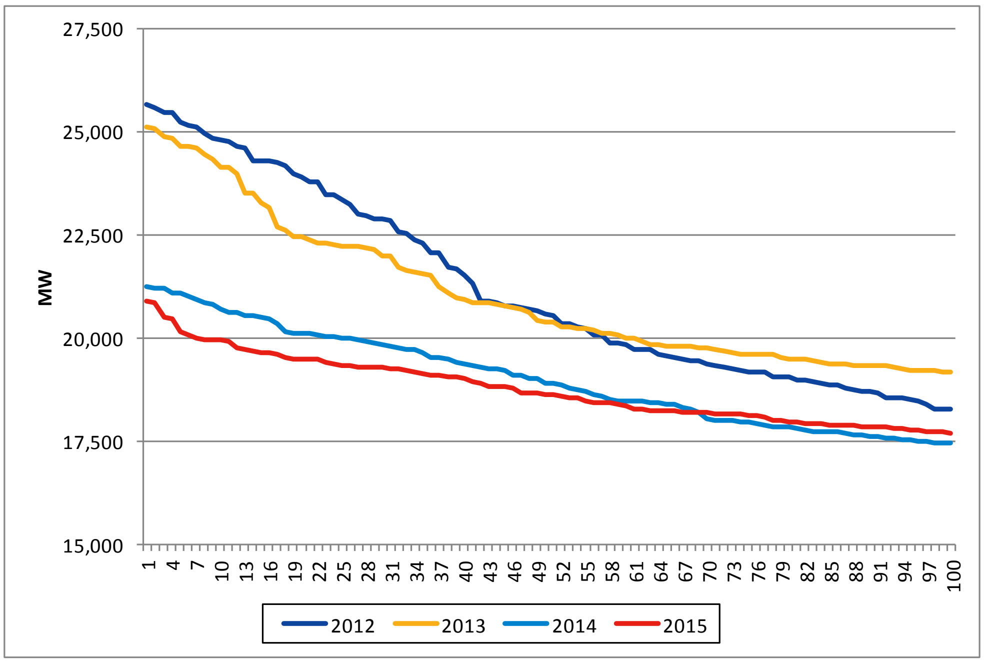


Besides low energy consumption over the quarter, hourly demand for the quarter was also quite low. Figure 2-5 shows the highest 100 hours of demand in Quarter 2 over the past four years (a load duration curve). For the quarter in 2015, there were only 6 hours where the load was greater than

20,000 MW. For comparison Q2 2014 had 24 hours where the hourly load exceeded 20,000 MW while 2012 and 2013 had 57 and 60 hours, respectively. The second quarter peak of 20,895 MW occurred on June 23 during the hour from 3:00 to 4:00 PM; the average New England temperature at the time of peak was 84 degrees. Since SMD, only 2009 had a lower second quarter system peak, where the temperature at the time of the peak hour was only 75 degrees. The typical hourly temperature at the time of the June peak for years 2003 through 2014 has been 88 degrees.

On the other end of the spectrum, hourly loads fell below 9,500 MW for 69 hours during the quarter. Years 2012, 2013 and 2014 had 28 hours, 29 hours, and 43 hours respectively when hourly loads were below 9,500 MW.

Figure 2-5: Highest 100 Hours of Hourly Demand in Quarter 2, 2012-2015 (MW)



2.1.4 Real-Time Markets

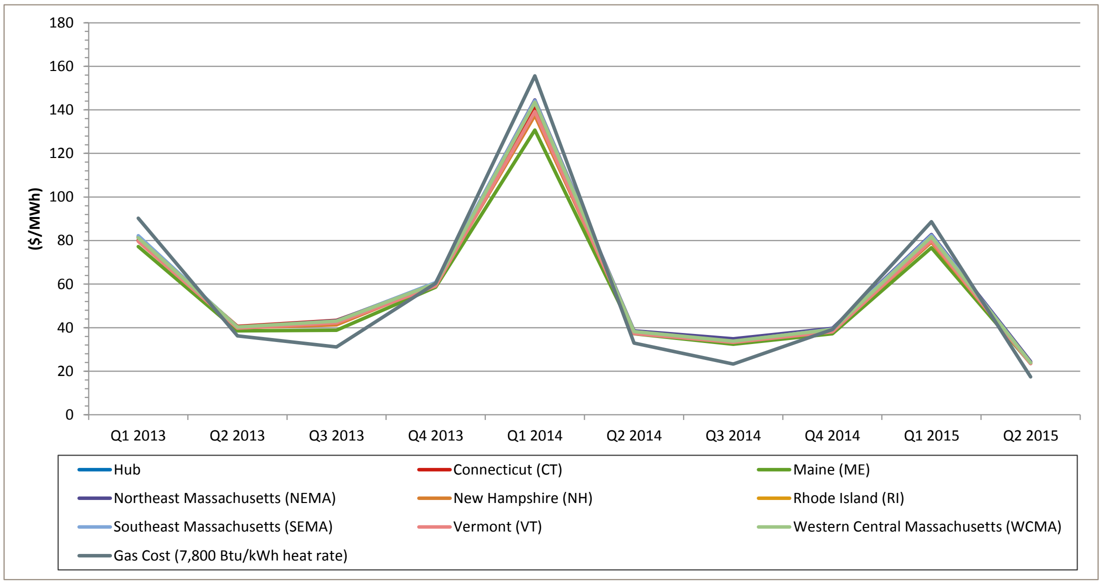
2.1.4.1 Real-Time Energy Market

In the Reporting Period, the average real-time Hub price was $23.89/MWh, down 37% from $38.16/MWh in Q2 2014.[7] The decrease in price was primarily driven by lower natural gas prices (see Figure 2-1, Table 2-1, and Section 2.1.3). Price differences between the load zones stemmed primarily from marginal losses, with little zonal congestion.[8] Congestion was restricted primarily to smaller, more transient load pockets that formed when transmission or generation elements were out of service. Figure 2-6 below shows quarterly average real-time prices for the Hub and load zones, along with the cost of gas generation (assuming a heat rate of 7,800 Btu/kWh).

[7] Throughout this report, average prices are calculated using a simple average method.

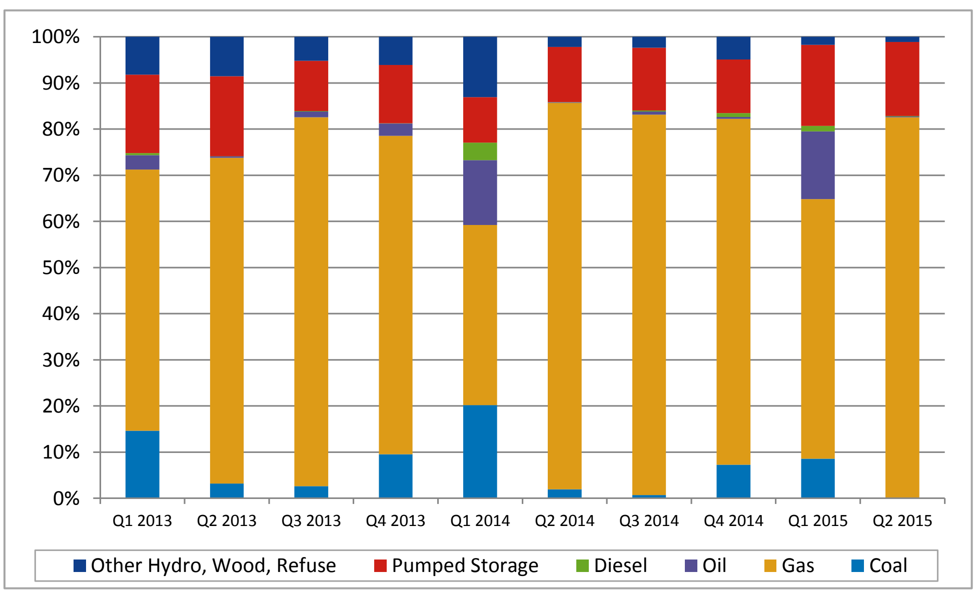
[8] A *load zone* is an aggregation of load pricing nodes (pnodes) within a specific area. The loss component of the LMP is the marginal cost of additional losses caused by supplying an increment of load at the location.

Figure 2-6: Simple Average Real-Time Hub and Load Zone Prices, 2013-2015 ($/MWh)



In the Reporting Period, units burning natural gas were marginal for 82% of the pricing intervals, followed by pump storage units (including pumping demand), which were marginal for 16% of the pricing intervals. Units burning coal, oil, diesel, jet fuel, wood, and traditional hydro units were marginal in the remaining pricing intervals. Figure 2-7 shows the percentages of marginal fuels since Q1 2013.

Figure 2-7: Real-Time Marginal units by fuel type by Quarter, 2013-2015



2.1.4.2 Real-Time Operating Reserves

In the Reporting Period, Q2 2015, total real-time reserve payments were $7.9 million; a $3.8 million increase relative to Q2 2014's $4.1 million of payments.[9] The increase in total payments compared

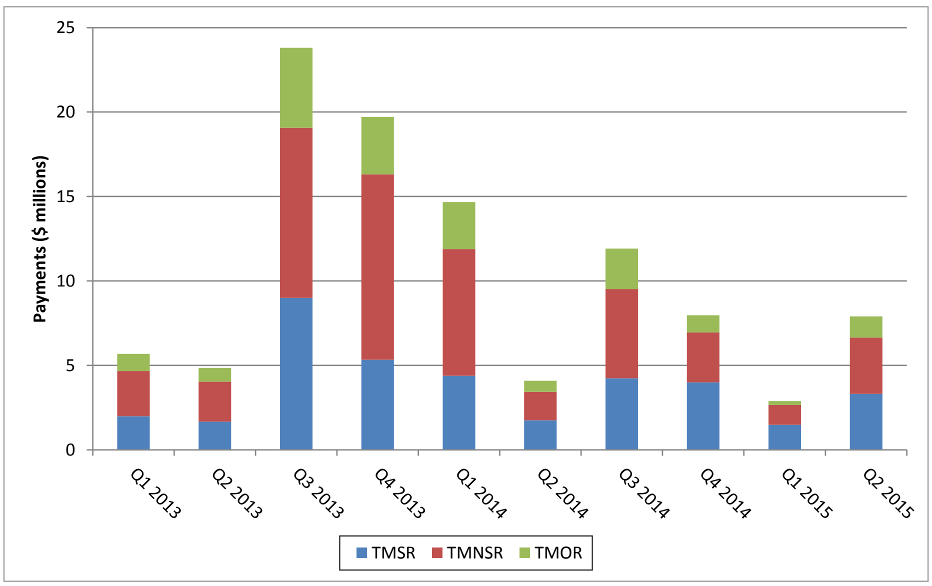
[9] Payment data represent total payments for real-time reserves, and are not net of settlement adjustments for forward reserve obligation charges.

to Q2 2014 was primarily the result of higher average reserve pricing for all reserve products. Higher average reserve pricing represents increased opportunity costs for generators that must be redirected away from providing energy to satisfy reserve requirements. With a relatively low frequency of reserve pricing, the system impact of the increased reserve payments is relatively small compared to other markets, such as the energy market.[10]

Real-time reserve payments also increased from Q1 2015 to Q2 2015, which resulted from both an increased pricing frequency for the TMOR product (from 0.13% to 0.45% frequency) and increased average reserve pricing. See Figure 2-8.

As shown in the bar chart, operating reserve payments vary significantly over time. This is the result of a variety of factors including system conditions, fuel price and real-time LMP variation, and changes to operating reserve requirement and pricing rules.

Figure 2-8: Real-Time Reserve Payments ($ millions)



2.1.4.3 Regulation Market

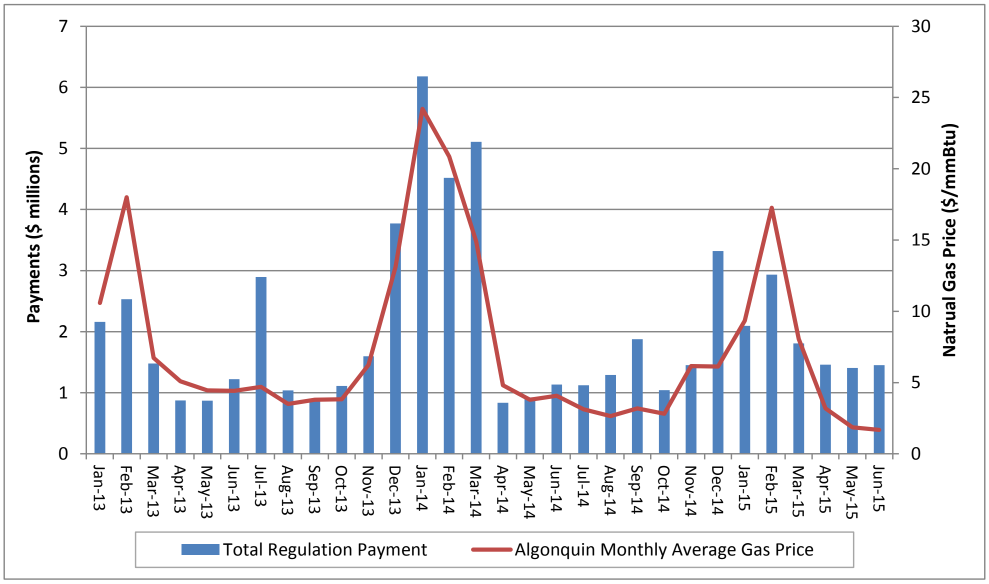
On March 31, ISO New England's redesigned regulation market went into effect. The changes were a result of FERC Order 755 requiring two-part bidding and compensation of frequency regulation resources to be based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service.

The rule changes included the introduction of a two-part methodology for offer and clearing prices. The regulation self-schedule concept was also eliminated. Resources now submit both a regulation capacity ($/MW) and service ($/MW-mile) offer price. The ISO's least cost optimization produces a corresponding clearing price for capacity, which includes the opportunity costs of the marginal unit, and a clearing price for service.

[10] Note that increased Reserve Constraint Penalty Factors (implemented just prior to Q1 2015) might also explain a small portion of the increase in payments, when comparing Q2 2014 to Q2 2015. However, only 0.06% of the total pricing intervals during the period obtained pricing in excess of prior RCPFs.

Total Regulation Market payments during the Reporting Period, coinciding with the implementation date, were $4.3 million, down 37% from $6.8 million in Q1 2015, and up 49% from $2.9 million in Q2 2014, despite a reduction in natural gas and electricity prices compared to Q2 2014. While it is difficult to draw conclusions regarding the performance of the new regulation auction design given the limited experience to date, the IMM will continue to monitor and report its observations on the new regulation market. Monthly Regulation payments along with natural gas prices are shown in Figure 2-9 below.

Figure 2-9: Regulation Payments ($millions) Compared to Natural Gas Prices ($/mmBtu)



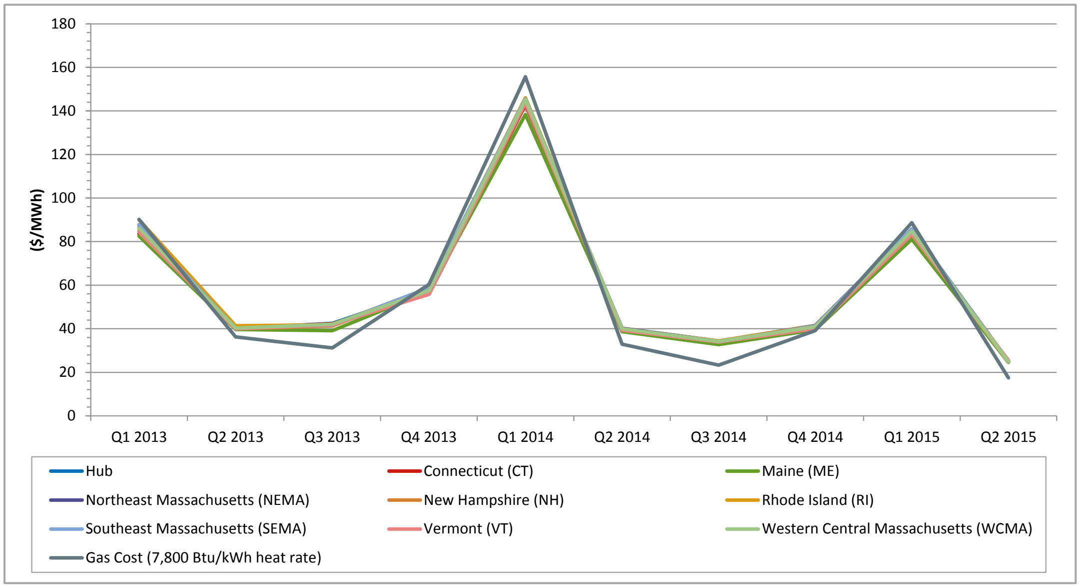
2.1.5 Forward Markets

2.1.5.1 Day-Ahead Energy Market

The average day-ahead Hub price in the Reporting Period was $24.84/MWh, down 38% from $39.92/MWh in Q2 2014. As in real-time, the decrease in price was primarily driven by lower natural gas prices (see Figure 2-1, Table 2-1, and Section 2.1.3). Price differences among the load zones stemmed primarily from marginal losses, with little congestion at the zonal level. Congestion was restricted primarily to smaller, more transient load pockets that formed when transmission or generation elements were out of service.

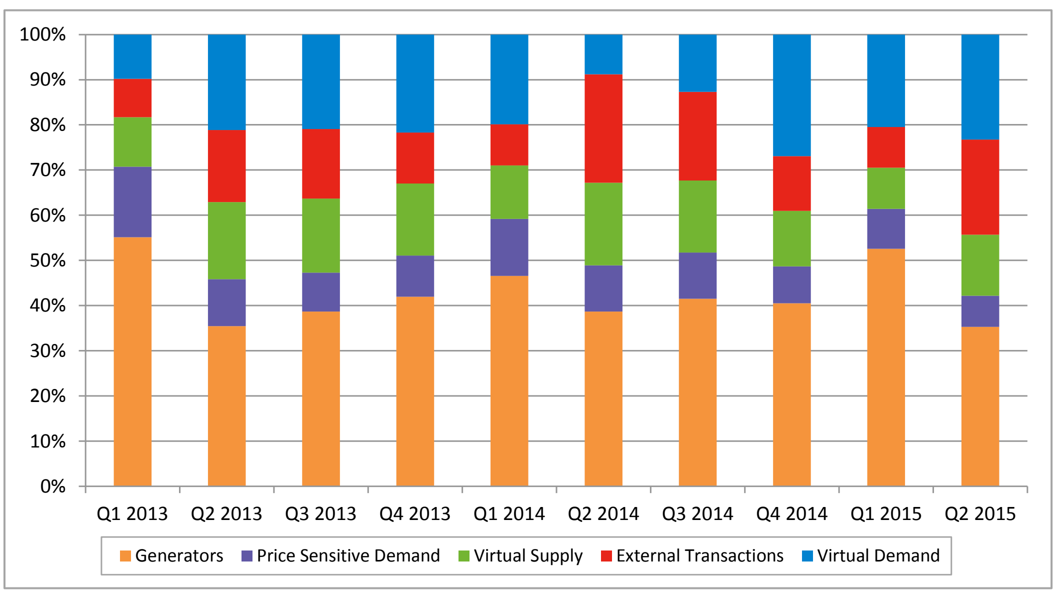
Figure 2-10 below shows quarterly average day-ahead prices for the Hub and load zones, along with the cost of gas generation (assuming a heat rate of 7,800 Btu/kWh).

Figure 2-10: Simple Average Day-Ahead Hub and Load Zone Prices, 2013-2015 ($/MWh)



As shown in Figure 2-11, generators set price approximately 35% of the time in the Reporting Period in the day-ahead market. Virtual transactions set price approximately 37% of the time, and external transactions set price approximately 21% of the time. In comparison, generators set price 39% of the time, virtual transactions set price 27% of the time, and external transactions set price 24% of the time in the day-ahead market in Q2 2014.

Figure 2-11: Day-Ahead Marginal units by type, 2013-2015



In the Reporting Period, submitted virtual demand bids and virtual supply offers totaled approximately 9,258 GWh, an increase of 26% when compared with Q1 2015 and Q2 2014. Cleared virtual transactions also increased, by 16%, compared with both Q1 2015 and Q2 2014. In the Reporting Period, 12% of submitted virtuals bids and offer cleared in the Day-Ahead market. See Table 2-3.

Table 2-3: Total Submitted and Cleared Virtual Transactions, (GWh)

	Q2 2015	Q1 2015	Percent Change Q2 2015 to Q1 2015	Q2 2014	Percent Change Q2 2015 to Q2 2014
Total Submitted Virtual Transactions	9,258	7,328	26%	7,356	26%
Total Cleared Virtual Transactions	1,057	912	16%	915	16%
Cleared as % of Submitted	11%	12%	-	12%	-

2.1.5.2 Forward Reserve Market

This section presents the results and our analysis of the competitiveness of the Summer 2015 Locational Forward Reserve Market (LFRM) auction. The Summer 2015 auction cleared with a clearing price of $5,824/MW-month for all reserve zones and products except for the TMOR product for NEMA-Boston, which cleared at the LFRM cap of $14,000/MW-month. Market conditions existed in the Summer 2015 LFRM auction to provide a competitive outcome for all reserve zones and products except for the TMOR product in Southwest Connecticut, which had the potential for Market Participants to exercise market power, and the TMOR product for NEMA-Boston, which was set at the forward reserve auction cap due to insufficient supply.

The Forward Reserve bidding period opened at midnight on Thursday, April 16, 2015 and closed at noon on Thursday, April 23, 2015. Forward reserve auction offers were submitted on a portfolio basis. Offers were submitted to reserve zones. The auction simultaneously clears offers for TMNSR and TMOR to meet the forward reserve requirements for each reserve zone. A Market Participant whose offers cleared in the forward reserve auction received a forward reserve obligation for each reserve zone equal to the amount of that Market Participant's forward reserve auction offers that cleared in the auction.

To meet their forward reserve obligations, Market Participants must assign forward reserve to their forward reserve resources on a daily basis at any time prior to the end of the re-offer period for the operating day such that the aggregate assignments are greater than or equal to their forward reserve obligations.

Requirements. The LFRM auction is designed to provide reserves to meet the reserve requirements of the zones. Some zones are constrained in terms of how much power they can import from other zones. Potentially, as observed in some of the earlier auctions, due to such restrictions, zones can have different clearing prices. As a result, instead of having a single reserve requirement for all of New England, the ISO identifies requirements at a regional level, as well as a systemwide requirement, for each reserve product procured in the auction.

The TMNSR purchase amount represented the expected single contingency of the HQ Phase II Interconnection. The TMNSR purchase amount was increased to reflect a 20% average fleet-wide historical non-performance of resources called upon after a contingency.[11] The TMOR purchase

[11]ISO New England Inc. and New England Power Pool, Docket No. ER 13-465-000, *Market Rule Revision Relating to the Procurement of Ten-Minute Non-Spinning Reserve in the Forward Reserve Market,* http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2012/nov/er13_465_000_11_27_2012_proc_ten_min_rule.pdf. This filing allowed for an additional procurement of reserve to be procured in the Forward Reserve Market to help support the availability of reserves to meet the increased real-time reserve requirements.

amount represented the expected single contingency of Seabrook. The Replacement Reserve was equal to 160 MW.

The New England control area forward reserve requirements were based on a 1st contingency of 1,664 MW and a 2nd contingency of 1,249 MW. The local forward reserve requirements for each applicable reserve zone were based on the 95th percentile value from historical requirements data for the previous two like forward reserve procurement periods for each applicable reserve zone. The forward reserve market requirements for the New England control area are based on the forecast of the first and second contingency supply losses for the next forward reserve procurement period. Local forward reserve requirements (local second contingency and external reserve support MW) for the reserve zones reflect the need for a 30-minute contingency response to provide support in import-constrained areas.[12] See Table 2-4.

Table 2-4: Forward Reserve Requirements for the Summer 2015 LFRM Auction (MW)

Reserve Zone	Reserve Category	Local 2nd Contingency MW	External Reserve Support MW	Reserve Requirement MW
New England Control Area	TMNSR	N/A	N/A	1310
New England Control Area	TMOR	N/A	N/A	785
SWCT	TMOR	503	365	138
CT	TMOR	1213	499	714
NEMA/Boston	TMOR	880	549	331

Forward Reserve Threshold Price Components. Between June 1, 2015, and September 30, 2015, Market Participants that clear in the forward reserve auction for the Summer 2015 forward reserve procurement period must offer corresponding blocks of energy at or above the daily forward reserve threshold price, which is calculated as the product of the Summer 2015 forward reserve heat rate and the daily forward reserve fuel index.

The forward reserve heat rate for the Summer 2015 forward reserve procurement period was 19,148 Btu/kWh, which was based on an analysis of historical implied heat rates. In this analysis, historic implied heat rates were calculated on an hourly basis over a five-year period. The heat rate used for a specific forward reserve procurement period is the implied heat rate value that occurs at the 97.5th percentile of the relevant five-year period and does not change during a forward reserve procurement period. The daily forward reserve fuel index is the lesser of the natural gas or heating oil price indices as available one day before the operating day.[13]

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[12] The ISO establishes the locational reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each reserve zone for like forward reserve procurement periods (winter to winter and summer to summer). The daily peak hour requirements are aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone establishes the locational requirement.

[13] These price indices are defined as:
Natural gas price index - This price index is the lowest of the day-ahead natural gas prices at three key New England hubs: Algonquin Citygates, Iroquois-Zone 2, and Tennessee-Zone 6 on the 200 lateral. For each hub, the price is the volume-weighted average price that is effective for the Operating Day.

Results. The clearing price in the LFRM auction for summer 2015 was $5,834/MW-month for TMNSR and TMOR in all locations except NEMA/Boston, which cleared at the forward reserve auction cap. See Table 2-5.

Table 2-5: Auction Clearing Price, Three-Most-Recent FRM Auctions ($/MW-month)

Location	Product	Summer 2014	Winter 2014/2015	Summer 2015
CT	TMOR	12,709	8,990	5,834
NEMA/Boston	TMOR	12,709	8,990	14,000
SWCT	TMOR	12,709	8,990	5,834
Systemwide	TMNSR	12,709	8,990	5,834
Systemwide	TMOR	12,709	8,990	5,834

The net payments to LFRM resources equals the forward reserve market auction clearing price minus the forward capacity market clearing price. Therefore, as the forward capacity market clearing price for the 2015/2016 capacity commitment period was $3,434/MW-month, the net payments to be received by reserve providers is $2,400/MW-month ($5,834/MW-month less $3,434/MW-month) for the summer 2015 auction for the TMNSR product. Since there was price separation in NEMA/Boston, the net payments to be received by NEMA/Boston reserve providers for the TMOR reserve product is $10,556/MW-month ($14,000/MW-month less $3,434/MW-month) and $2,400/MW-month in other locations.

Competitiveness. Twenty-two Market Participants participated in the auction system-wide (all products). Fourteen participants offered in the TMNSR product, and seventeen participants offered in the TMOR product. The HHI was 1,370. According to DOJ guidelines, the auction system-wide for Summer 2015 was unconcentrated.

In Southwest Connecticut, the TMOR requirement was 138 MW. Four participants participated in the auction, with the participant with highest market share at 44%. The HHI in Southwest Connecticut for TMOR was 3,290, highly concentrated according to DOJ guidelines. The total MW offered into the auction for TMOR was 218 MW, so there was adequate supply to meet the requirement for the TMOR product. The auction cleared 190.7 MW economically (below the system clearing price of $5,834/MW-Month). Even though the TMOR product within Southwest Connecticut cleared at the system clearing price, we conclude that the potential existed for Market Participants to exercise market power due to the high HHI and the presence of pivotal suppliers in the reserve zone.

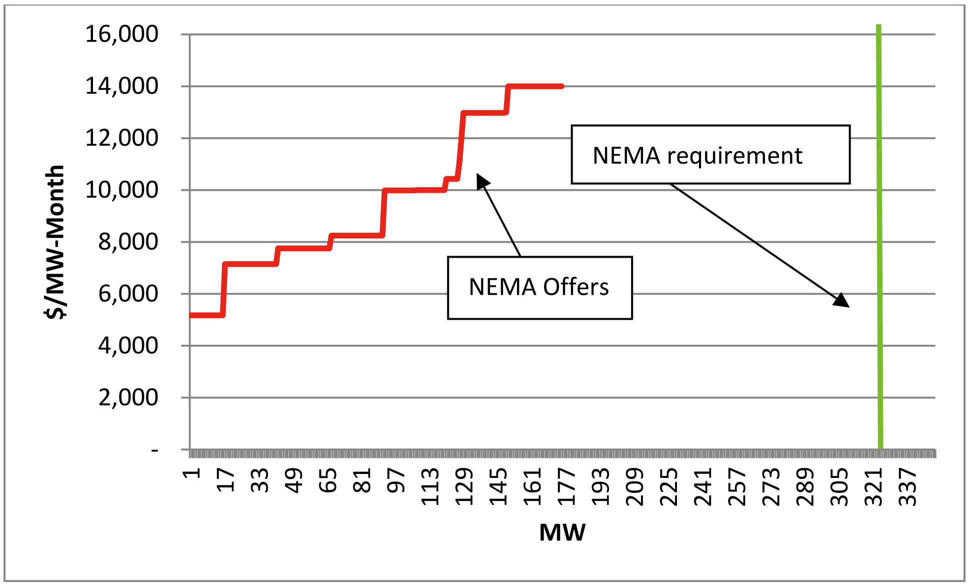
The requirements for the Connecticut reserve zone can be partially fulfilled by the requirements for Southwest Connecticut. In Connecticut, the total MW offered into the auction was 1,188 MW for all products, and the total requirement was 852 MW. Twelve Market Participants submitted offers in the Connecticut area auction. The largest supplier had a 30% market share. The HHI was 1,610 (moderately concentrated according to DOJ guidelines).

Heating oil price index - This price index is the simple average of the *buy* and *sell* prices of the Argus Diesel 15ppm NYH Barge Prompt index as published in the most recently available "Argus US Products" report. The price is then increased by an additional seven percent to account for transportation costs.

The results in NEMA Boston for TMOR tell a different story. Four participants participated in the auction for TMOR in NEMA, and one single participant had the highest market share at 77%. The HHI in NEMA for the Summer 2015 auction was 6,152 –highly concentrated according to DOJ guidelines.

The total requirement in NEMA was 331 MW, only 175 MW of supply were offered into the market and all offers were accepted. All participants were pivotal. See Figure 2-12. Based on these results, market conditions did not exist to ensure a competitive outcome for the Summer LFRM auction for TMOR in NEMA.

Figure 2-12: Supply and Demand for the TMOR Product in NEMA Boston (MW and $/MW-Month)



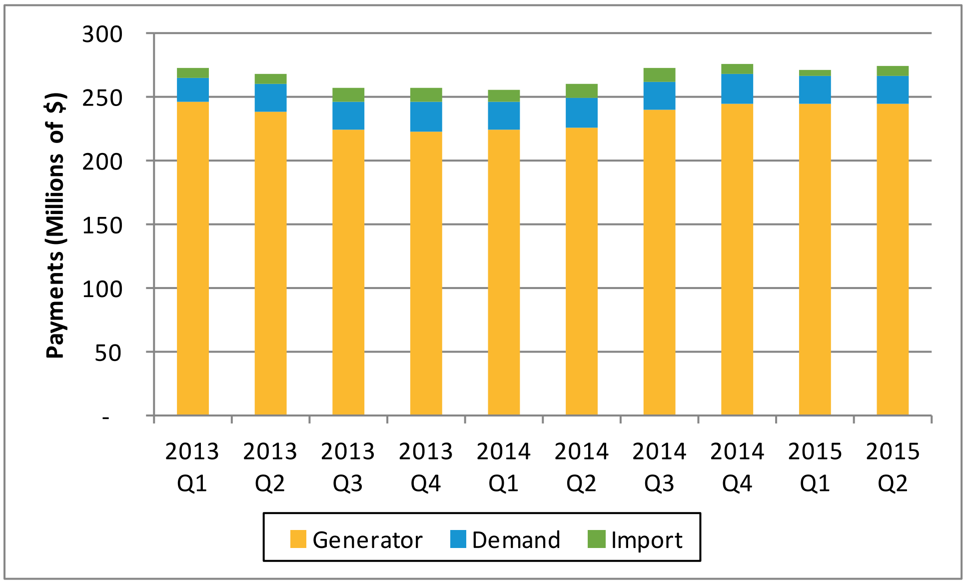
2.1.5.3 Financial Transmission Rights

Three Financial Transmission Rights (FTR) auctions were conducted during the Reporting Period for a combined total of 105,841 MW of FTR transactions. The total amount distributed as Auction Revenue Rights (ARRs) was $2.0 million. Thirty-two bidders in April, thirty bidders in May and thirty bidders in June participated in the monthly auctions for the quarter. The level of participation was consistent with prior auctions.

2.1.5.4 Forward Capacity Market

Payments. Figure 2-13 below shows the total FCM payments by resource type from Q1 2013 through the end of the reporting period. Capacity payments in the reporting period totaled $275.1 million. Within the reporting period, April 2015 and May 2015's FCA initial supply credit was based off of a clearing price of $3.21/kW-month, while June 2015's FCA initial supply credit was based off of a clearing price of $3.43/kW-month. The supply credit paid for the CSO can be adjusted based upon bilateral and reconfiguration auction activity, computed values for Peak Energy Rent (PER), the participation of the ISO in reconfiguration auctions, and actual resource performance, which are accounted for in the data below.

Figure 2-13: Total Capacity Payments, April 2014-June 2015 (millions of $)



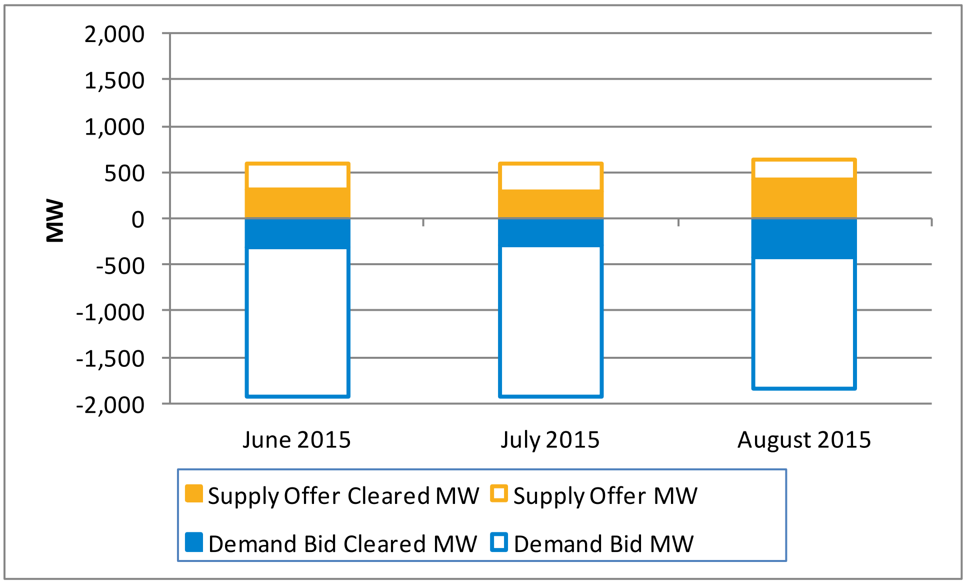
Auctions. Several annual reconfiguration and monthly reconfiguration auctions were conducted and contracts were bilaterally traded during the Reporting Period. Monthly reconfiguration auctions and bilateral trades for the months of June 2015, July 2015, and August 2015 took place during the Reporting Period.

Annual reconfiguration auctions. Three annual reconfiguration auctions were conducted in the Reporting Period.

- The first annual reconfiguration auction Bilateral Period for the 2017-2018 commitment period exchanged 10 MW in capacity.
- The second annual reconfiguration auction Bilateral Period for the 2016-2017 commitment period exchanged 224 MW in capacity.
- The first annual reconfiguration auction for the 2017-2018 commitment period cleared 316 MW in capacity with a price of $15.82/kW-month, the result of mandatory demand bids placed in the auction at the cap by the ISO. This was $0.82/kW-month greater than the clearing price in the primary auction for that commitment period.

Monthly reconfiguration auctions. Figure 2-14 below shows bid/offered and cleared MWs by monthly auction. The reconfiguration auctions cleared at $3.10, $3.35, and $3.10 per kW-month during each month, with cleared capacity in each auction being 306 MW, 295 MW, and 429 MW for June 2015, July 2015, and August 2015, respectively.

Figure 2-14: Bid/Offered and Cleared MW, June-August 2015 Monthly Reconfiguration Auctions



Bilateral contract periods. Table 2-6 below shows acquired and transferred MW by resource type for the three bilateral trading periods in the Reporting Period. Exchanged MWs in the bilateral trading periods ranged from 110 to 117 MW. Average prices for the bilateral trading periods ranged from $1.63/kW-month to $2.64/kW-month. This compares to a clearing price in the primary FCA of $3.43/kW-month.

Table 2-6: Acquired and Transferred MW for the June-August 2015 Bilateral Contract Periods[14]

Month	Resource Type	Acquired MW	Transferred MW	Net MW
June 2015	Demand Response	13	39	(26)
	Generator	105	8	96
	Import	-	70	(70)
June 2015 Total		117	117	-
July 2015	Demand Response	10	36	(26)
	Generator	104	7	96
	Import	-	70	(70)
July 2015 Total		114	114	-
August 2015	Demand Response	6	32	(26)
	Generator	105	8	96
	Import	-	70	(70)
August 2015 Total		110	110	-
Total Q2 2015		342	342	-

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

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 prices 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 voltage support and control as well as distribution system protection in either the Day-Ahead or Real-Time Energy Markets.[15] Total NCPC payments during the Reporting Period totaled $26.5 million. There were no Generator Performance Audit (GPA) NCPC payments made during the quarter.

Total NCPC payments decreased by 27% when compared to last quarter but increased by 58% when compared to Q2 2014. The majority of NCPC incurred during the Reporting Period was for first contingency.[16] The increase in Economic NCPC payments compared to Q2 2014 was due to lower real-time prices and posturing of limited energy generating resources. There was also a notable change in NCPC payments for Local Second Contingency Protection (LSCPR), which increased by 103% compared to last quarter and 147% compared to the same quarter last year. This increase was attributable to an increase in payments to units providing local reliability protection in the NEMA Boston load zone. When expressed as a percentage of total energy, NCPC payments were 3.4%, 1.2%, and 1.4% for Q2 2015, Q1 2015, and Q2 2014, respectively.

[15] NCPC payments include economic/first contingency 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), and *distribution reliability NCPC payments* (reliability costs paid to generating units that are operating to support local distribution networks).

[16] *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 hours
- Reliability costs incurred for generation committed for peak hours but are still on line after the peak hours to satisfy minimum run-time requirements

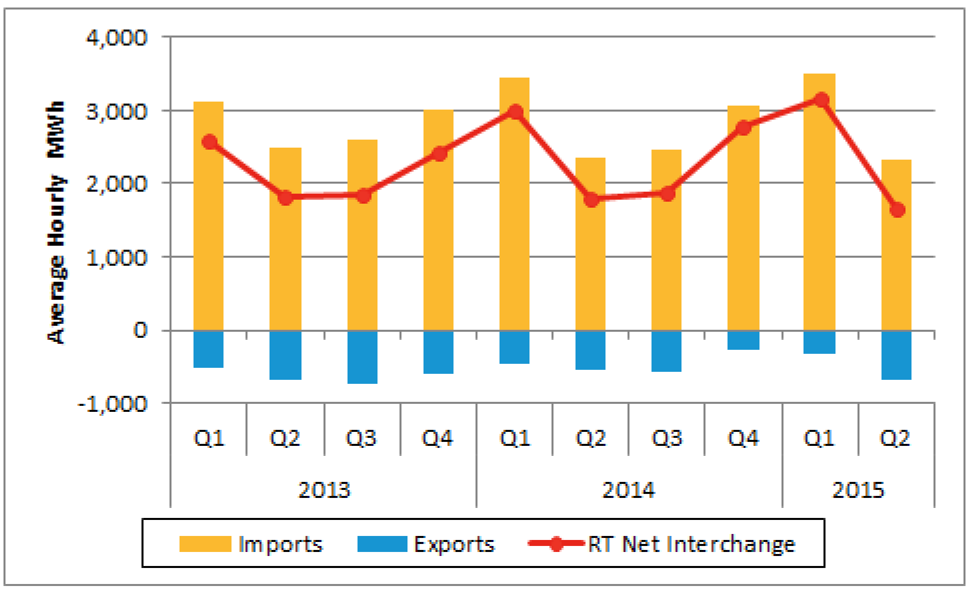
Table 2-7: NCPC Payments by Quarter and Category ($)

	Q2 2015	Q1 2015	Q2 2014
Economic (i.e., First Contingency) Payments	$13,409,171	$27,170,420	$8,725,181
Second Contingency Payments	$12,811,332	$6,300,736	$5,189,803
Voltage Payments	$256,094	$2,580,235	$2,422,387
Distribution Payments	$17,879	$22,317	$459,252
Total	**$26,494,476**	**$36,073,708**	**$16,796,623**

2.2.2 Net Interchange

In the Reporting Period, New England was a net importer of power. Net imports from Canada exceeded net exports to New York. Net interchange with neighboring balancing authority areas totaled 3,614 GWh for the Reporting Period, a 48% decrease compared with Quarter 1 2015 and an 8% decrease when compared to Quarter 2 2014. As shown in Figure 2-15 below, net interchange has been seasonal in nature, with higher imports occurring during the winter months over the past few years. The increase in net real-time net imports in Q4 2014 and Q1 2015 was partially due to the loss of a transmission facility between New England and New York that is predominantly a net exporter of power to New York.

Figure 2-15: Imports, Exports, and Net Interchange, by Quarter, 2013-2015 (Average hourly MWh)



2.3 Market Competitiveness

The Internal Market Monitor calculated the following performance metrics to assess the competitiveness of the wholesale electricity market.[17] Based on the results of the HHI and RSI metrics, the Internal Market Monitor has concluded that the energy market was competitive during

[17] The HHI and RSI results shown here do not account for affiliations between Lead Market Participants. This issue is addressed in more detail section 3.4 of the report. Enhancements to these competitiveness measures, that take account of affiliations, are being developed and will be included in future reports.

the Reporting Period. System-wide concentration remains low. Energy market prices are consistent with costs.

The *Herfindahl-Hirschman Index* (HHI) is a commonly used measure of market concentration. The HHI is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers.[18] The HHI takes into account the relative size distribution of the firms in a market. It approaches zero when a market is occupied by a large number of firms of relatively equal size and reaches its maximum of 10,000 points when a market is controlled by a single firm. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases.[19] The IMM calculated the HHI for the reporting period and results indicate that the wholesale electric energy markets in New England are well within the "not concentrated" range.[20]

Table 2-8 summarizes the results of the HHI analysis. The median HHI calculated using the value corresponding to each day's peak hour is 694 and the median HHI calculated using the value corresponding to each day's lowest load hour is 821. Using the DOJ's *Horizontal Merger Guidelines*, the Real-Time Energy Market in New England is not concentrated. In general, the HHI is higher in low-load hours than peak hours. During low-load hours, large baseload units meet much of the demand. These baseload units are owned by a few participants, which increases the market concentration. During peak load hours, more resources owned by additional participants enter the market, lowering the market share of the participants that control the majority of baseload resources, as well as the overall market concentration. This was evident in Q2 2015, when the top-four participants (by market share) comprised 49% of the market in the hours with the lowest load, compared with 42% for the peak hours.

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[18] The HHI is calculated as follows:

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

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

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

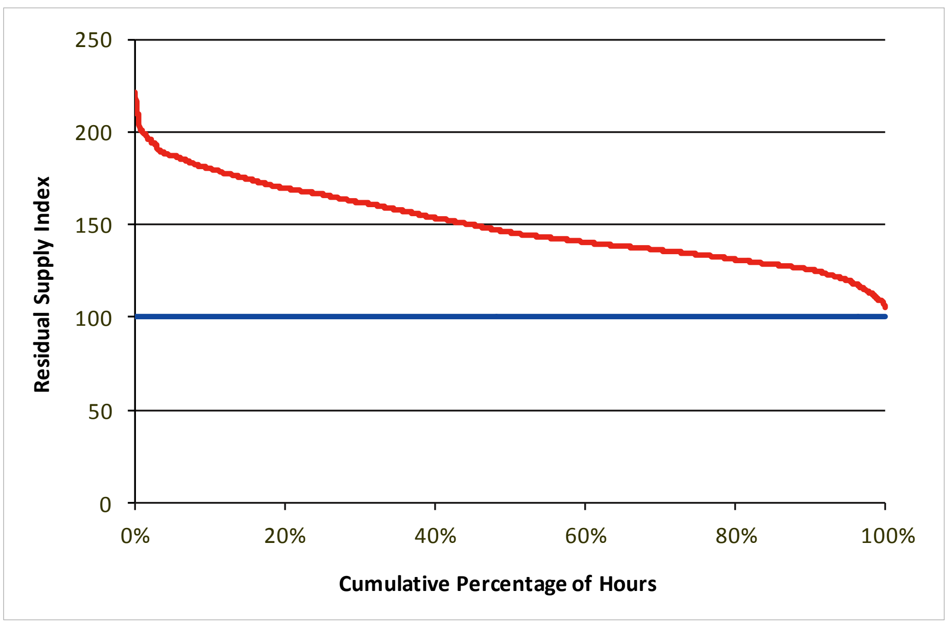
[20] HHI ignores transmission constraints and contractual entitlements to generator output, which would have the effect of increasing and decreasing concentration, respectively. The net effect has not been measured; however, given the low level of overall concentration even if these effects produced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

Table 2-8: Median and Maximum HHI, Median Hourly Load, Number of Participants, and Share of Top Participants (by Market Share) for Each Day's Peak-Load and Lowest-Load Hours in Q2 2015

	Median HHI	Max HHI	Median Share of Top *N* Participants				Median Number of Participants	Median Load (MW)
			N = 1	***N = 4***	***N = 8***	***N = 16***		
Peak hour	694	854	*15%*	*42%*	*68%*	*85%*	122	15,712
Lowest-load hour	821	1,049	*18%*	*49%*	*71%*	*86%*	118	11,157

The systemwide *Residual Supply Index* (RSI) measures the percentage of demand in a given hour (in megawatt-hours) that can be met without any capacity from the largest supplier. The RSI also measures the number of hours in which one or more suppliers is pivotal, or can price above the competitive level, subject only to offer caps, mitigation measures, and the price elasticity of demand.[21] The system level analysis shows that there were no pivotal suppliers in any of the hours in the Reporting Period, as shown in Figure 2-16 below.[22]

Figure 2-16: Systemwide Residual Supply Index duration curve, all hours, Q2 2015



[21] When the RSI exceeds 100%, the system has sufficient capacity from other suppliers to meet demand without any capacity from the largest supplier. When the RSI is below 100%, a portion of the largest supplier's capacity is required to meet market demand, and the supplier is pivotal. As RSIs rise, the ability of Market Participants to unilaterally set prices above competitive levels decreases. RSIs generally are lowest during periods of high demand, indicating a drop in the level of competition as the system approaches its capacity limit.

[22] The RSI results presented in this report are based on a methodology that assumes available generation in any given hour includes all capacity that is not on outage. The IMM is currently refining this methodology to include only the potential energy a generator resource can provide during a given interval and given its operating status and other physical limitations such as ramp rate. The IMM will include the revised calculation in a future report.

Section 3
Market Analysis and IMM Recommendations

This section includes the details of our market analyses and a number of recommendations to address current deficiencies and potential future enhancements aimed at improving the efficiency of various aspects of the market. The topics in this section relate to the competitiveness of the Forward Reserve Market (FRM) and the market power mitigation framework in both the capacity and energy markets.

3.1 Forward Reserve Market Performance Analysis

3.1.1 Introduction

This section presents an analysis of the competitiveness of supply offered into the Forward Reserve Market (FRM) auctions conducted between years 2012 and 2015. The objective of this analysis is to examine the performance and structural competitiveness of the FRM. Key points from the analysis are:

- The FRM clearing prices have been volatile in the study period, and even more so when considering the pure reserve price (net of the applicable Forward Capacity Market (FCM) clearing prices).
- Ten-minute Non-Spinning Reserve (TMNSR) prices are negatively correlated with the TMNSR offer surplus (difference between total offered TMNSR and TMNSR requirement).
- The estimated Residual Supply Index (RSI) values show that there were three auctions for TMNSR in the 2012 through 2015 period when there was at least one pivotal supplier and five auctions when there was at least one pivotal supplier in one of the local reserve zones.
- The frequency of uncompetitive offer quantities, as measured by the RSI, would have been greatly reduced had all available TMNSR and TMOR available capability been offered in the auction.
- On average less than 70% of the available TMNSR and 76% of the available TMOR capability was offered in the FRM auctions.

The results of this analysis indicate the FRM auction is not reliably structurally competitive and that auction clearing prices are higher when there is less competition in the auction. There currently are no market power mitigation measures applied in this auction, beyond a damage control offer cap,[23] to ensure available reserve capability is offered into the auction and that offer prices reflect competitive values. Further analysis is required to determine if higher auction clearing prices in auctions with less competition are the result of offer prices that were higher than expected. No recommendation regarding additional mitigation measures is made at this time, pending further analysis of the competitiveness of submitted offer prices.

[23] A global offer cap is often applied that serves the purpose of limiting the extent to which uncompetitive conditions can result in unwarranted excess cost due to the exercise of market power. However, they are set sufficiently high that they serve a damage control function and do not force offers at competitive prices (for example, based on variable cost, opportunity cost, risk of loss, etc.). Similar offer caps currently exist in the energy, real-time ancillary services, and forward reserve markets.

3.1.2 Overview

The FRM is designed to compensate generation portfolios for committing to provide off-line reserves in the Real-Time energy market to meet the system-wide and local reserve requirements. Participants with the FRM obligation are required to offer generating resources at prices which would make them likely to be unloaded and thus available to provide energy within 10 or 30 minutes. The FRM procures resources needed to satisfy off-line reserve requirements, namely TMNSR and TMOR. Spinning reserves are not procured in the forward market.

The ISO conducts two FRM auctions each year, one each for the summer and winter reserve periods (June through September and October through May, respectively). FRM auctions are conducted to acquire obligations to provide pre-specified quantities of each reserve product. FRM offers are not resource-specific. Participants may offer up-to twenty price-quantity pairs for each product and each reserve zone. Forward reserve auction clearing prices are calculated for each reserve product in each active reserve zone. When supply offers for forward reserves are not adequate to meet a requirement, the clearing price for that product is set to the price cap. When enough supply is offered under the price cap to meet the requirement for a product in a particular zone, the auction clearing price for that product is set equal to the price of the marginal supply offer.

To maintain resources to provide reserves instead of energy, the FRM requires participants with FRM obligations to designate forward reserve resources and to offer the FRM obligation quantity of these resources at or above a threshold price. Participants would not be expected to designate resources that normally are in merit with variable costs below the threshold price because they would forego any energy revenue from operating. Conversely, designating a high incremental cost peaking resources does not create an opportunity cost, because the ISO would not dispatch such resources to provide energy under normal circumstances.

Prior to the close of the Re-Offer Period for each operating day of the forward reserve procurement period, Market Participants must convert their forward reserve obligations into resource-specific obligations by assigning forward reserve MWs to specific eligible forward reserve resources. Failure to assign the FRM obligation quantity results in the assessment of a "Failure-to-Reserve" penalty. Bilateral transactions, as well as any reserve capable resource in the participant's portfolio, can meet the reserve obligations incurred in the auction. If a forward reserve resource is called on by the ISO to generate for energy, the resource is expected to ramp up at least at the speed of claimed capability. A forward reserve "Failure-to-Activate" penalty is applied if a resource fails to activate in response to a dispatch instruction as part of the Real-Time Contingency Dispatch algorithm.

Payment for forward reserve is based on a Market Participant's final forward reserve obligation and the applicable forward reserve clearing prices. To avoid compensating the same resource megawatt as both general capacity (from the Forward Capacity Market) and forward reserve, actual FRM payments to participants are reduced by the FCA clearing price. Since the forward reserve resource is being paid to provide reserve capacity via the FRM clearing price, it is not qualified to collect a real-time reserve payment.

3.1.3 Summary of Price Outcomes

Table 3-1 below shows FRM clearing prices for each auction from Summer 2012 through Winter 2015-16. The auction price is expressed as $/MW-hour of reserves. The FRM clearing price net of the capacity clearing price is also shown. In this section, only the TMNSR clearing prices are discussed as there was only one instance when a price separation was observed between TMNSR and TMOR prices. Also, there was only one instance when TMOR price separation was observed within reserve zones. These two instances are discussed separately.

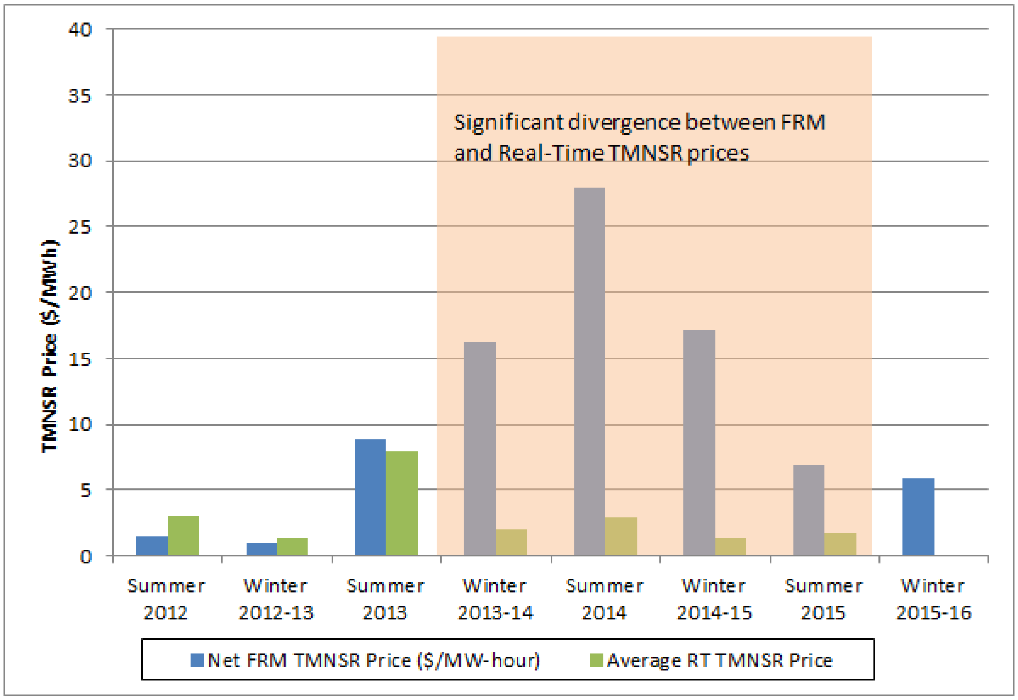
Table 3-1 TMNSR and FCM Clearing Prices

Procurement Period	Procurement Hours	TMNSR Clearing Price ($/MW-hour)	FCM Clearing Price ($/MW-hour)	Net TMNSR Price ($/MW-hour)
Summer 2012	1,344	10.27	8.78	1.49
Winter 2012-13	2,736	9.65	8.63	1.02
Summer 2013	1,344	17.70	8.78	8.91
Winter 2013-14	2,720	24.86	8.68	16.18
Summer 2014	1,360	37.38	9.44	27.94
Winter 2014-15	2,704	26.60	9.49	17.10
Summer 2015	1,392	16.76	9.87	6.90
Winter 2015-16	2,720	15.98	10.10	5.88

The highest TMNSR clearing price is roughly 287% higher than the lowest clearing price and 111% higher than the median clearing price. The Net TMNSR price shows an even higher degree of variability. The highest price is roughly 2600% and 200% higher than the lowest and median net prices respectively. The TMNSR prices increased significantly after the Winter 2012-13 auction. Figure 3-1 shows the Real-Time TMNSR price for peak hours along with the TMNSR clearing prices in FRM for each procurement period. The net FRM clearing price is a reflection of the opportunity costs[24] and risk premium associated with the Failure-to-Reserve and Failure-to-Activate penalty.

[24] Lost opportunity cost for a forward reserve product is primarily comprised of expected margin on real-time energy sales and expected revenue on real-time operating reserve sales.

Figure 3-1: Average Hourly Peak Real-Time TMNSR Price and Net FRM TMNSR Clearing Price[25]



The Real-Time TMNSR price moved in the same direction as the FRM clearing price in five procurement periods. Notably, for the first three procurement periods the Real-Time and FRM TMNSR prices are comparable. After those periods the FRM price is significantly higher than the Real-Time TMNSR price. The change in penalty rates for Failure-to-Reserve and Failure-to-Activate penalties in the Summer 2013 procurement period may have contributed to the increase in FRM TMNSR price and the resulting divergence between the Real-Time and FRM TMNSR prices. The penalty rate prior to the Summer 2014 period was based on the auction clearing price, which created an incentive for participants to deviate from their FRM obligations when the energy price was relatively higher than the FRM clearing price.[26] The current Failure-to-Reserve Penalty Rate is based on the real-time reserve clearing price. Prior to this change a participant with a FRM obligation had an incentive to deviate from their forward reserve obligation. If the real-time reserve prices are high real-time LMP spikes due to cascading. Basing the penalty on the real-time reserve prices removes the incentive for an FRM resource to deviate from its forward reserve obligation when real-time LMPs spike as result of real-time reserve prices. The change in the penalty rate may have also added to the risk premium associated with acquiring a FRM obligation, resulting in higher FRM offer prices.

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[25] The Real-Time TMNSR prices are not yet available for the Winter 2015-16 procurement period. Also, available real-time prices for the Summer 2015 are used as the procurement period was not over at the time of this analysis.

[26] Prior to Summer 2014 procurement period, the Failure-to-Reserve penalty rate was equal to 1.5 times the forward reserve payment rate. The forward reserve payment rate is equal to the forward reserve clearing price (net of the capacity clearing price) divided by the number of procurement hours in the month. Current Failure-to-Reserve penalty rate equals 1.5 times the maximum of (i) forward reserve payment rate (ii) Real-Time reserve clearing price minus forward reserve payment rate.

3.1.4 Price Separation within Zones and Products

The FRM procures the required quantity of reserves for each of the individual Reserve Zones. Currently there are four reserves zones: CT, SWCT, NEMA/Boston (NEMA) and the Rest of the System (ROS). Figure 3-2 shows the TMNSR and TMOR clearing prices by Reserve Zone for each auction from summer 2012. The auction price is expressed as $/MW-hour of reserves.

Figure 3-2: Zonal Forward Reserve Auction Clearing Prices by Procurement Period

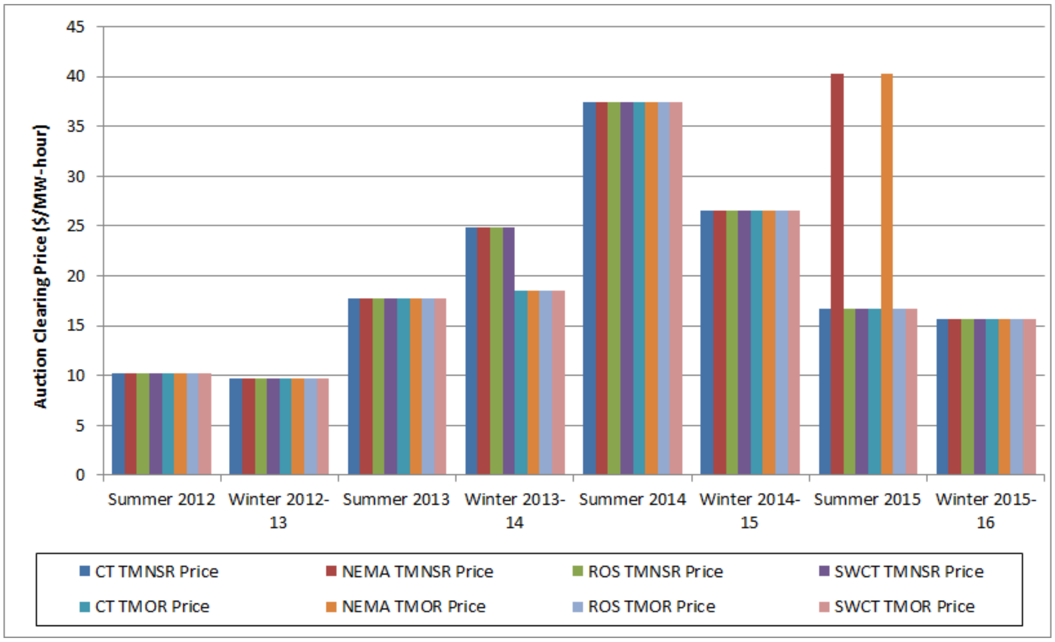


Figure 3-2 shows that there have been only two instances when price separation was observed in the FRM. In the Winter 2013-14 Procurement Period, price separation between the two reserve products was observed. In that period, the TMNSR clearing price was nearly 34% higher than the TMOR clearing price. The increase in TMNSR requirement to 1,532 MW from 820 MW in Winter 2012-13 partly contributed to the higher TMNSR clearing price. See Table 3-2 below. The second incident of price separation was observed in the Summer 2015 auction. The forward reserve auction clearing prices in NEMA hit the auction price cap, resulting in the $40/MW-hour price for TMNSR and TMOR. This zonal price separation was a direct result of an inadequate total quantity of supply offered to meet the TMOR requirement in the NEMA zone.

3.1.5 Reserve Requirement and Available Supply

We evaluated changes in the demand (reserve requirement) and supply (offered reserves in the FRM) quantities over different procurement periods to determine potential drivers of changes in the FRM clearing prices. The local Forward Reserve requirements for each applicable Reserve Zone are based on the 95th percentile value from historical requirements data for the previous two like Forward Reserve Procurement Periods for each applicable Reserve Zone. The historical requirements in turn are based on the local second contingency capacity requirements. Through external reserve support, resources within a local region as well as operating reserves available in other locations, if needed, can satisfy second contingency capacity requirements. External reserve support is then subtracted from the local reserve requirement. Table 3-2 shows the local TMOR requirements by reserve zone.

Table 3-2: TMOR Requirement (MW) by Reserve Zone

Procurement Period	ROS	SWCT	CT	NEMA
Summer 2012	750	0	765	0
Winter 2012-13	775	50	837	0
Summer 2013	723	0	747	0
Winter 2013-14	915	155	578	0
Summer 2014	891	94	900	0
Winter 2014-15	831	87	363	0
Summer 2015	785	138	714	331
Winter 2015-16	805	36	152	0

The TMNSR Reserve requirements are based on expected system operating conditions. The Forward Reserve Auction simultaneously clears offers for TMNSR and TMOR to meet the Forward Reserve Requirements for each Reserve Zone. FRM offers are submitted on a portfolio basis and are not resource specific. Table 3-3 shows the TMNSR requirement, total TMNSR offered and available TMNSR in the FRM auction from the Summer 2012 to Winter 2015-16 auction.

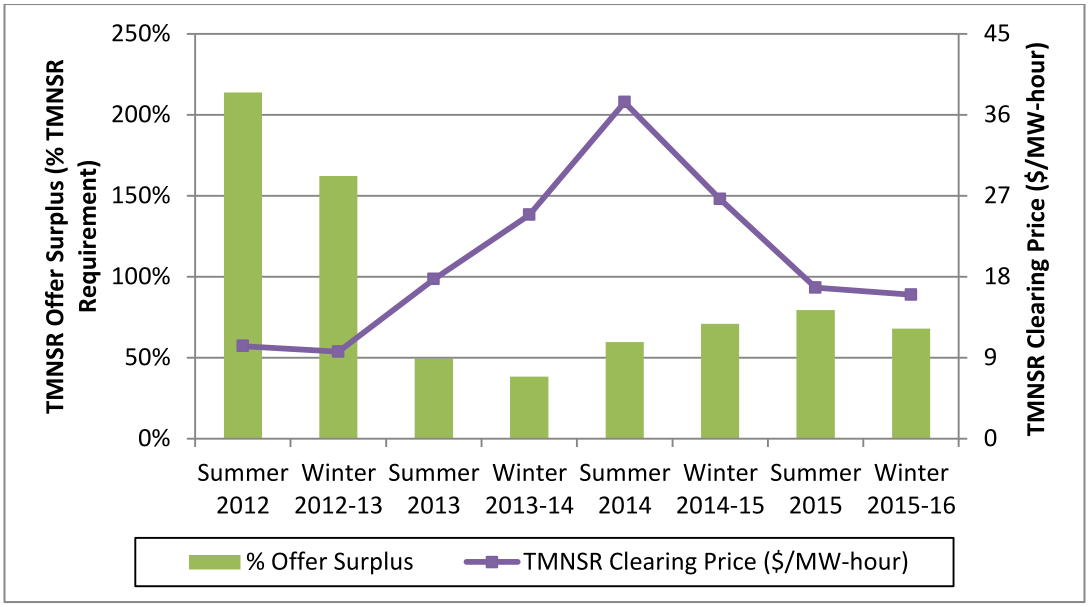
Table 3-3 FRM Available Supply and Requirement

Procurement Period	TMNSR Requirement (MW)	Total Offered TMNSR (MW)	Total TMNSR Capacity Cleared (MW)
Summer 2012	815	2,557	1,118
Winter 2012-13	820	2,150	1,122
Summer 2013	1,349	2,013	1,406
Winter 2013-14	1,532	2,119	1,532
Summer 2014	1,573	2,509	1,768
Winter 2014-15	1,562	2,669	1,608
Summer 2015	1,310	2,349	1,457
Winter 2015-16	1,270	2,133	1,431

Table 3-3 shows a significant increase in the TMNSR requirement in the Summer 2013 procurement period. The TMNSR requirement went up by 529 MW in Summer 2013 compared to Winter 2012-13. This increase in TMNSR requirement was due in part to the increase in the share of TMNSR relative to TMSR (TMNSR bias) in the ten-minute reserve requirement. The share of TMNSR in the ten-minute reserve requirement was further increased in the Winter 2013-14 auction which contributed to the 183 MW increase in TMNSR requirement relative to Summer 2013 auction. The total TMNSR offered quantity declined sharply in Winter 2012-13 relative to the Summer 2012 FRM auction and stayed at a lower level before recovering back to Summer 2012 levels in Summer 2014 auction.

In each of the FRM auctions, the amount of offered TMNSR capability has been greater than the requirement. Figure 3-3 shows the relationship between the percent of surplus offer TMNSR quantity relative to the requirement and the FRM TMNSR clearing prices. The decline in surplus in the Summer 2013 auction coincided with an increase in the TMNSR clearing price. Generally, a negative relationship between the surplus and the clearing prices is expected.

Figure 3-3: Zonal Forward Reserve Auction Clearing Prices by Procurement Period



3.1.6 FRM Supply Offers and Observed Real-Time Reserve Capability

The FRM does not require participants to back their forward reserve offers with physical generating resources. It also does not require participants to offer the full reserve capability of their generating resources. Generally, reserve-capable resources which have a cost lower than the FRM cap price are expected for economic reasons to offer in the FRM auction.[27] Table 3-4 below shows the total amount of qualified reserve capability, the observed Real-Time reserve capability and the total offered TMNSR and TMOR quantities in the FRM at the system level.[28]

[27] The cost with respect to forward reserves is the lost opportunity cost of earning energy and real-time reserve revenues plus a risk premium associated with penalties.

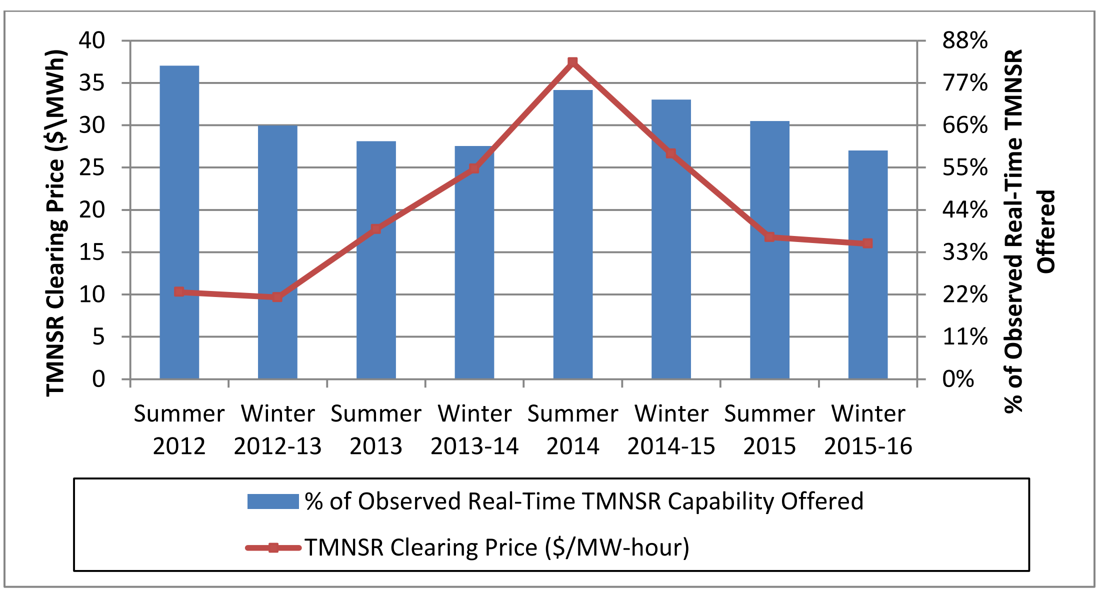
[28] The observed real-time reserve capability is an hourly average of available 10-minute and 30-minute claimed capability in Real-Time for the peak hours in the procurement period.

Table 3-4: Qualified Reserve Capability, Observed Real-Time Reserve Capability and Offered Reserves in FRM

Procurement Period	Qualified TMNSR Capability (MW)	Observed Real-Time TMNSR Capability (MW)	Total TMNSR Offer Quantity (MW)	Qualified TMNSR and TMOR Capability (MW)	Observed Real-Time TMNSR and TMOR Capability (MW)	Offered TMOR and TMNSR Quantity (MW)
Summer 2012	3,301	3,138	2,557	4,293	4,082	3,351
Winter 2012-13	3,316	3,263	2,150	4,283	4,178	3,071
Summer 2013	3,671	3,257	2,013	4,234	4,074	2,811
Winter 2013-14	4,235	3,499	2,119	4,781	4,505	3,162
Summer 2014	3,756	3,338	2,509	4,303	4,123	3,220
Winter 2014-15	4,463	3,672	2,669	5,024	4,666	3,629
Summer 2015	4,027	3,504	2,349	4,607	4,326	3,415
Winter 2015-16	N/A	N/A	2,133	N/A	N/A	3,125

Table 3-4 shows that the quantity offered into the FRM is lower than the observed reserve capability for both 10 and 30 minute products. Also, compared with the changes in the reserve capability, the FRM offered MW have changed at a much more moderate rate. For instance, the observed TMNSR capability increased by almost 304 MW during the Winter 2014-15 period; yet the offered TMNSR MW increased only by 160 MW in the Winter 2014-15 FRM auction. On average, 69% of the observed 10-minute reserve capability and 76% of the observed 10 and 30-minute reserve capability are offered in the FRM auction during the study period. Figure 3-4 shows the percentage of observed 10-minute reserve capability offered in the FRM auction and the TMNSR clearing prices.

Figure 3-4: Percent of Observed Real-Time TMNSR capability Offered in the FRM and the TMNSR Clearing Prices



3.1.7 Structural Competitiveness

This portion of the analysis focuses on structural competitiveness. Participants may be able to strategically offer reserves into the FRM at uncompetitive prices if there is a presence of market power in the FRM. The analysis leverages the Residual Supply Index (RSI) to evaluate whether a competitive level of supply offered into the FRM exists. The RSI is calculated based on both the FRM offers and observed real-time reserve capability.

The offer-based RSI measures the percentage of forward reserve requirement that can be met without the largest FRM portfolio offer. The offer RSI for TMNSR is calculated at a system-level, based on the total quantity of TMNSR offers across all reserve zones excluding the largest TMNSR offer quantity by a single participant. The offer-based RSI for TMOR is calculated similarly for each reserve zone with a non-zero TMOR Local Reserve Requirement[29]. Given that the TMNSR quantity also satisfies the TMOR requirement, the TMNSR offer quantity in a zone is included in the total TMOR offer quantity within the zone. Table 3-5 shows the offer RSI for TMNSR at a system level and TMOR for zones with non-zero TMOR requirement.

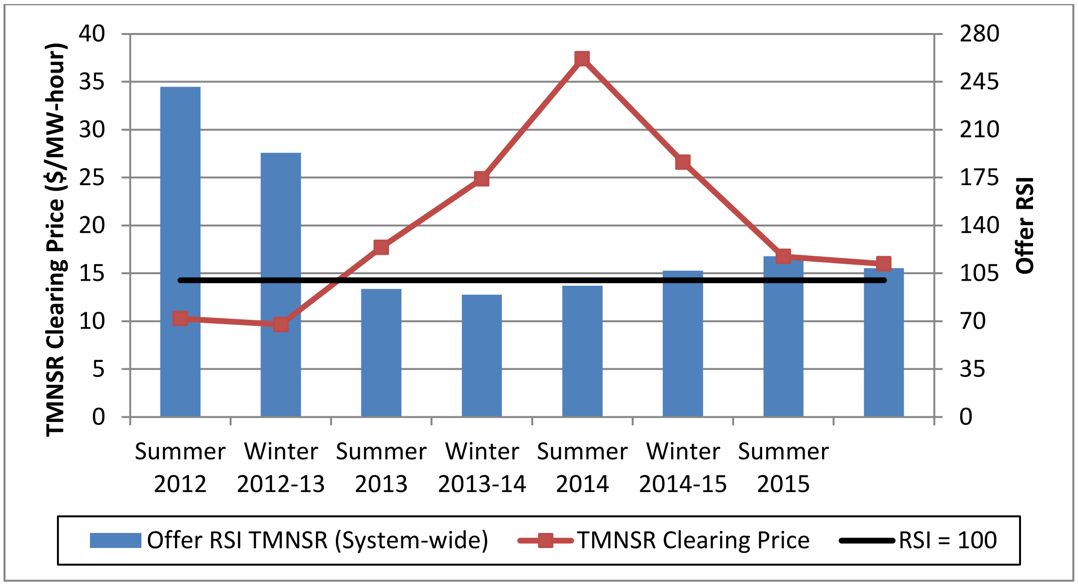
Table 3-5: Offer RSI in the FRM for TMNSR (system-wide) and TMOR (zones)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI TMOR (ROS)	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Summer 2012	241	189	N/A	114	N/A
Winter 2012-13	193	132	244	134	N/A
Summer 2013	94	138	N/A	99	N/A
Winter 2013-14	89	136	58	123	N/A
Summer 2014	96	124	85	87	N/A
Winter 2014-15	107	186	84	215	N/A
Summer 2015	117	158	69	122	12
Winter 2015-16	109	154	283	382	N/A

A RSI value less than 100 (shown in red) implies there is at least one pivotal supplier and that the auction is not structurally competitive. Table 3-5 illustrates that there was the presence of a pivotal supplier in 3 out of the 7 FRM auctions in case of TMNSR. Also, there was the presence of a pivotal supplier in 5 out of the 7 auctions in at least one zone. The Southwest Connecticut (SWCT) zone had an RSI less than 100 for four consecutive auctions. The lowest RSI value of 12 was observed in NEMA/Boston in the Summer 2015 auction. Figure 3-5 shows the relationship between offer RSI and TMNSR clearing prices. Notably, the auctions with pivotal suppliers (Summer 2013, Winter 2013-14, and Summer 2014) had the highest clearing prices. The highest clearing price in Summer 2014 FRM auction corresponds with the change in penalty calculation; however, the clearing price was considerably high two auctions before the change in penalty rate, during periods of low RSI, indicating low or uncompetitive supply.

[29] The TMOR requirement for a zone is the maximum of difference between the Local 2nd Contingency MW minus the External Reserve Support MW and zero.

Figure 3-5: TMNSR Offer RSI and the TMNSR Clearing Price



The RSI values for TMOR and TMNSR are also computed based on the observed TMNSR and TMOR reserve capability available in Real-Time.[30] The availability-based RSI measures the degree of structural competitiveness if all the reserve capable generation quantity is offered in the FRM.

Table 3-6: RSI based on the Observed Real-Time Available TMNSR (system-wide) and TMOR (zones)[31]

Procurement Period	RSI: Observed Real-Time Available TMNSR (System-wide)	RSI: Observed Real-Time Available TMOR (ROS)	RSI: Observed Real-Time Available TMOR (SWCT)	RSI: Real-Time Available TMOR (CT)	RSI: Real-Time Available TMOR (NEMA)
Summer 2012	242	536	N/A	107	N/A
Winter 2012-13	254	375	1,988	100	N/A
Summer 2013	155	527	N/A	92	N/A
Winter 2013-14	151	291	733	134	N/A
Summer 2014	138	255	1,149	83	N/A
Winter 2014-15	158	342	1,366	229	N/A
Summer 2015	173	331	764	106	32

If all the available reserve capability was offered in the FRM, there would not have been a pivotal supplier in any of the auctions for TMNSR and the auctions would have been structurally

[30] See Footnote 24.

[31] The real-time data for the Winter 2015-16 procurement period was not available at the time of this analysis and is excluded from the availability-based RSI calculation.

competitive.[32] The same would have been true in the case of TMOR for the SWCT zone. Generally, comparison between RSI values based on the FRM offers and the estimated amount of available reserves suggests that the FRM auction would have been structurally competitive if all the available reserve capability was offered into the FRM auction.

The focus of this analysis is to examine structural competitiveness of FRM both in terms of total observed offers and the potential for greater offered reserve capability. Additional analysis, specifically focused on the competitiveness of offer prices observed in the FRM auction, is required to determine if instances of structural competitiveness have resulted in clearing prices that may reflect the exercise of market power. No recommendation regarding additional market power mitigation measures is offered at this time. Additional analysis of the competitiveness of offer prices and resulting auction clearing prices is under way and the results, along with a recommendation if warranted, will be included in a subsequent report.

3.2 Application of Energy Market Mitigation Rules to Generation Resources with a FRM Assignment

3.2.1 Background

As described in section 3.1, a Market Participant with a Forward Reserve Obligation is required to submit energy market offers for resources that are assigned to meet that obligation at a price that is at or above a pre-established Forward Reserve Threshold Price.[33] The Forward Reserve Threshold Price is designed to be sufficiently high as to keep the resource from being economically dispatched, such that the resource is not providing energy and is available as reserves.

In some cases, the Forward Reserve Threshold Price is greater than the Forward Reserve Resource's marginal cost of producing electricity. The resource's marginal cost is often the basis for establishing a reference price to energy market mitigation purposes. If the Forward Reserve Threshold Price (and the Market Participant's supply offer) is significantly greater than the Forward Reserve Resource's reference price, the Market Participant risks having their supply offer mitigated to a reference price that is below the Forward Reserve Threshold Price. If this happens, the Market Participant may be subject to a Forward Reserve Failure-to-Reserve penalty.[34] For this reason, Section III.A.13.4 requires the IMM to consider the impact energy market mitigation may have on a Market Participant's ability to satisfy its Forward Reserve Obligation before imposing energy market mitigation. In the past, the IMM has exempted Forward Reserve Resources from energy market mitigation to reduce the Market Participant's risk of incurring a Forward Reserve Failure-to-Reserve penalty.

[32] Some participants may choose, as a matter of practice, to physically hedge their exposure to Failure-to-Reserve penalties with a portion of their resource capacity. This results in a quantity of reserve assigned in real-time that is in excess of the participant's obligation. Therefore, we would not expect all available reserve capacity to be offered into the FRM since some would naturally be held to be used as a physical hedge.

[33] The LFRM Threshold Price is the variable cost for a natural gas or oil resource with a heat rate of 19,500 MMBtu/MWh. It is calculated daily, reflecting changes in the natural gas and oil prices. The resulting threshold price is sufficiently high that it should preclude dispatch for energy except under conditions where electric generation is relatively scarce, thereby holding these resources in reserve.

[34] As described in Section III.9.7.1 of the Tariff, a Real-Time Forward Reserve Failure-to-Reserve occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

3.2.2 Market Power Concerns

The IMM has observed that some Market Participants with a Forward Reserve Obligation have assigned multiple resources, representing capacity in excess of the Market Participant's obligation, as available to support the obligation. If the IMM exempts the assigned resources from energy market mitigation, then the Market Participant is able to have much of their portfolio exempted from energy market mitigation, even though only a portion of the portfolio is effectively meeting the participant's Forward Reserve Obligation. There are two primary factors that limit the ability to exempt the correct amount of capacity from energy market mitigation:

- The ISO Tariff and market software systems do not accommodate exempting a portion of a resource's offer curve from energy market mitigation. This results in an over-exemption from mitigation in cases where a resource is assigned an FRM quantity that is less than the entire resource's offered output.
- Participants can assign, and request exemption from mitigation, a quantity (on a single resource or across resources) well in excess of their FRM Obligation. Applying exemption from mitigation to resources assigned to meet the FRM Obligation in this circumstance can also result in an over-exemption from energy market mitigation when uncompetitive circumstances are triggered.

This potentially raises significant market power concerns.

For example, under the current Forward Reserve Market structure, a participant can assign only a portion of its resource to satisfy a Forward Reserve Obligation. However, energy market mitigation is applied (or not applied) to the resource's entire offer curve, creating the opportunity for a participant to limit Forward Reserve assignments to only portions of a resource while avoiding mitigation for the entire resource. It is not possible within the ISO systems or allowed under the ISO tariff to separate, for mitigation purposes, the energy offer segments that support a Forward Reserve Obligation from the energy offer segments that are not supporting an obligation. This problem is exacerbated as participants with a Forward Reserve Obligation have the ability to designate multiple resources as available to support the obligation, thereby allowing the participant to avoid energy market mitigation for a broad range of resources. Furthermore, participants in the Forward Reserve Market are not restricted to submitting energy market offers at the Forward Reserve Threshold Price, but are free to offer at prices up to the $1,000/MWh supply offer cap.

3.2.3 Limited Exemption for the Winter 2015-16 Forward Reserve Procurement Period

Consistent with its tariff authority under Section III.A.13.4, the IMM determined that it would no longer exempt all Forward Reserve Resources from mitigation because of the market power concerns.[35] The IMM will modify its practice coincident with the start of the winter 2015-16 Forward Reserve Procurement Period.

The IMM has determined that, under the following specific conditions, it is appropriate <u>not</u> to apply energy market mitigation to Forward Reserve Resources if mitigation is otherwise warranted pursuant to Section III.A.5 of the tariff. All six of the conditions must be satisfied for mitigation not to apply.

[35] The IMM issued a memo on July 28, 2015, highlighting the issue and notifying Market Participants of changes in how these resources would be treated with respect to mitigation and a second memo on August 27, 2015, clarifying specific circumstances under which exemption from mitigation would still be allowed. The July 28 memo can be found at http://www.iso-ne.com/static-assets/documents/2015/07/20150728_mitigation_frm_resources_final.pdf and the August 27 memo can be found at http://www.iso-ne.com/static-assets/documents/2015/08/mitigation_frm_resources_08_27_2015.pdf

1. The Forward Reserve Resource's full Claim 10 or Claim 30 capability is greater than or equal to 75% of the resource's Economic Max capability offered in the Real-Time Energy Market in any hour of the operating day. [36]

2. The Market Participant assigns 100% of the resource's Claim 10 or Claim 30 capability toward meeting its Forward Reserve Obligation.

3. The Market Participant requests a cost-based Reference Level, for the entire winter 2015-16 Forward Reserve Procurement Period, for any Forward Reserve Resource for which it requests mitigation exemption.

4. The Forward Reserve Resource's cost-based Reference Level is less than the Forward Reserve Threshold Price.

5. At any time during the operating day, the total Claim 10 and Claim 30 capability of the Market Participant's Forward Reserve Resources exempted from mitigation for the operating day does not exceed 110% of the Market Participant's Forward Reserve Obligation, adjusted for bilateral transactions, for the operating day and the Market Participant cannot satisfy its Forward Reserve Obligation without designating these resources as a Forward Reserve Resource.

6. No offer block price of the Forward Reserve Resource's Supply Offer exceeds 110% of the Forward Reserve Threshold Price and the resource's start-up and no-load costs are offered at the cost-based Reference Level.

The IMM has determined that Forward Reserve Resources satisfying these conditions do not have the same material opportunity for the exercise of market power as other Forward Reserve Resources. Therefore, Market Participants with Forward Reserve Resources satisfying all the conditions described above can request that the IMM consider not applying energy market mitigation to their resources.

The IMM will be monitoring compliance with the criteria after the fact for resources that are exempted from energy market mitigation. The cursory review of the application for exemption, the application of the mitigation exemption, and the ex post monitoring of compliance with the conditions for exemptions are manual processes. Compliance with criteria like these is best performed by automated systems. An automated system approach reduces the risk of improper application of exemption from mitigation, improves rigor and consistency in how the exemption is applied, and reduces the risk of omission and subsequent settlement correction due to anticipated human error associated with manual processes.

Market Participants with Forward Reserve Resources that do not satisfy all the conditions described above are expected to factor into the Market Participant's Forward Reserve Auction offer the risk of a Failure-to-Reserve penalty resulting from mitigation. The risk of incurring a Forward Reserve Failure-to-Reserve penalty due to energy market mitigation is similar to the risk of incurring a Forward Reserve Failure-to-Reserve penalty due to non-energy market mitigation factors, such as a Forward Reserve Resource becoming unavailable in real-time. Monetizing the risk of incurring a Forward Reserve Failure-to-Reserve penalty, whether due to mitigation or non-mitigation (e.g. availability) of the resource, in a Forward Reserve Auction Offer can be approached in a similar fashion.

[36] Pursuant to Section III.13.6.1.1.1, a resource with a Capacity Supply Obligation must be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available.

3.2.4 Recommendation

It is recommended that the ISO implement an automated approach for Market Participants with FRM resources to comply with the obligation to submit supply offers for a quantity consistent with the participant's FRM obligation, while also preserving the integrity of the automated market power mitigation mechanism in the energy market given the concerns outlined above.

The ISO has committed to work with the IMM over the coming months to evaluate alternative approaches to addressing the market power concerns, including the feasibility of modifying the existing automated mitigation systems to accommodate exempting, when appropriate, all or a portion of a Forward Reserve Resource's energy supply offer.

3.3 Uneconomic Resources Retirements and the Forward Capacity Market

3.3.1 Introduction

The Forward Capacity Market (FCM) is designed to procure an amount of capacity that will allow the ISO to maintain reliable system operation. Capacity is procured more than three years in advance of the delivery period in order to provide revenue assurance to developers of new resources with sufficient time such that, if awarded a Capacity Supply Obligation (CSO) in the auction, the new capacity can be built and brought online in time for the delivery period. The FCM also provides price signals that can result in the retirement of higher-cost resources.

3.3.2 Issue

Ownership concentration, relatively small capacity margins, and limited new entry can result in instances where there is insufficient competition among suppliers and some or all capacity suppliers can possess market power. There are existing market power mitigation provisions for the FCM that address the exercise of seller-side market power via existing capacity resources and buyer-side market power via new capacity resources. Incumbent suppliers can exercise seller-side market power by retiring existing resources prematurely – at a time when they are still profitable to operate as capacity resources in the ISO New England market. Doing so artificially reduces the amount of capacity supply that is available in the FCM and can have a material impact on the auction clearing price. The balance of a supplier's existing generation portfolio can benefit from the resulting higher auction clearing price in excess of the foregone revenue from the generation resource that was retired prematurely. In such cases, the inflated capacity auction clearing price and resulting cost paid by load cannot be considered an outcome of a competitive market.

The existing process for evaluating retirement of capacity resources is centered on a review of potential reliability issues brought on by the retirement. Current ISO process does not provide for an economic evaluation of retirements to determine if the retirement is consistent with competitive conduct and there is no provision for remedy should it be determined that the retirement of a capacity resource appears to be an exercise of market power.

Further, the current process for capacity resource retirement occurs after the deadline for new entry to register for the instant capacity auction. This limits the potential for new entry that is uncertain about participating in the instant auction or a subsequent auction to contest the retirement. This creates an informational asymmetry between the incumbent and new entrant. The incumbent can retire a resource unilaterally after all the entry decisions have been made, and the new entrant does not have information about unanticipated retirements and supply of existing capacity. This may lead to an insufficient or uncompetitive level of new capacity to competitively contest the retirement.

A recommendation is provided below to address these issues, and the External Market Monitor has also recommended that the ISO address the potential exercise of market power through pre-mature retirement of capacity resources.[37]

3.3.3 Recommendation

It is recommended that the ISO develop and implement the following:

- A process for identifying resource retirements that appear to be pre-mature with respect to their expected economic life and can be used to exercise market power in the Forward Capacity Market,
- A mitigation measure that ensures auction clearing prices are not distorted by the exercise of market power through pre-mature retirement of capacity resources,
- A more robust mechanism for existing resources to retire through competitive price discovery in the Forward Capacity Market rather than through administrative means, and
- A timeline for the retirement process that will facilitate signaling to prospective new entry the extent of potential retirement capacity prior to the show of interest deadline for new capacity resources.

The IMM has been working with the ISO to develop a process that addresses this concern. The proposed design has benefited from various communications including stakeholder input provided at several NEPOOL Markets Committee meetings this year.

3.4 Accounting for Affiliations among Lead Market Participants

3.4.1 Introduction

Accurate accounting of a Market Participant's portfolio is an important aspect in detecting market manipulation and market power. The ability to exercise market power profitability depends on, among other things, the size of a Market Participant's portfolio relative to the product demand or requirement. The ability to manipulate a market price profitably in a two-product manipulation scheme depends, in part, on the relative size of holdings of both products in the Market Participant's portfolio. Currently, the Pivotal Supplier Test (PST) for market power mitigation in the energy market assesses market power using a portfolio construction based on the Lead Market Participant (LP) entity. There are several significantly-sized Market Participants that have generation assets in ISO New England that are registered under different LPs. In such cases, a PST that evaluates market power based on portfolios defined by the LP-level entity will result in under-identification of market power and consequently will preempt the application of market power mitigation in cases where it should be applied. Constructing portfolios for the PST in a manner that recognizes common corporate relationships among LPs and the asset control that these relationships reflect is a more accurate means to identifying market power under the PST.

[37] See External Market Monitor report "2014 Assessment of the ISO New England Electricity Markets", Section C.2.D, http://iso-ne.com/static-assets/documents/2015/06/isone_2014_emm_report_6_16_2015_final.pdf.

At the end of this section we present recommendations on altering the PST to more accurately account for generation portfolios and data needed to support that accounting.

3.4.2 Challenges in Measuring Competitiveness of Market Structure

The current process for applying the Pivotal Supplier Test for General Threshold Mitigation constructs generation portfolios based on individual Lead Market Participants. There are several significantly-sized companies, referred to here as Ultimate Parent Companies (UPCs), that control a number of different LPs. In effect, the portfolio of generation assets for these UPCs are divided among different "child" companies that are represented in the ISO system as LPs. The relationship between UPCs and LPs is referred to here as an affiliation.

An illustration of this is presented in Figure 3-6 below. The generation portfolio for a UPC that creates a single LP for all of its assets is accurately represented in the PST. In this example, UPC 1 has a 100 MW portfolio, all of which are represented by LP 1. UPC 2 has a 200 MW portfolio, but in the existing framework this 200 MW portfolio is treated as two separate 100 MW portfolios, those of LP 2 and LP 3. In this simple example, if these three assets represented the total system generation, and required energy and reserves totaled 150 MW, none of the three LPs would be necessary to meet system requirements individually. Therefore, no LPs would be detected as a pivotal supplier. However, because UPC 2 controls both LP 1 and LP 2, its resources would be needed to meet the system requirement and UPC 2 is in fact pivotal (i.e. has market power). Assessing the market power of portfolios at the LP level instead of the UPC level understates the size of the portfolios when there are parent-child corporate relationships as is the case in ISO-NE. This results in under-identification of market power and preempts the application of market power mitigation where its application is appropriate.

Figure 3-6: Simple Example of UPC and LP Relationships

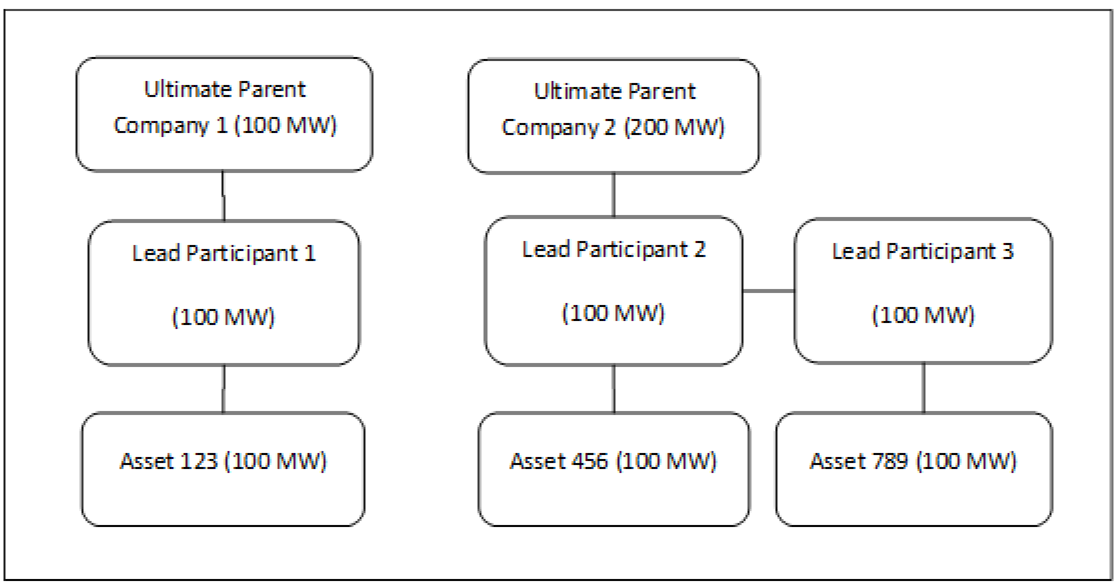
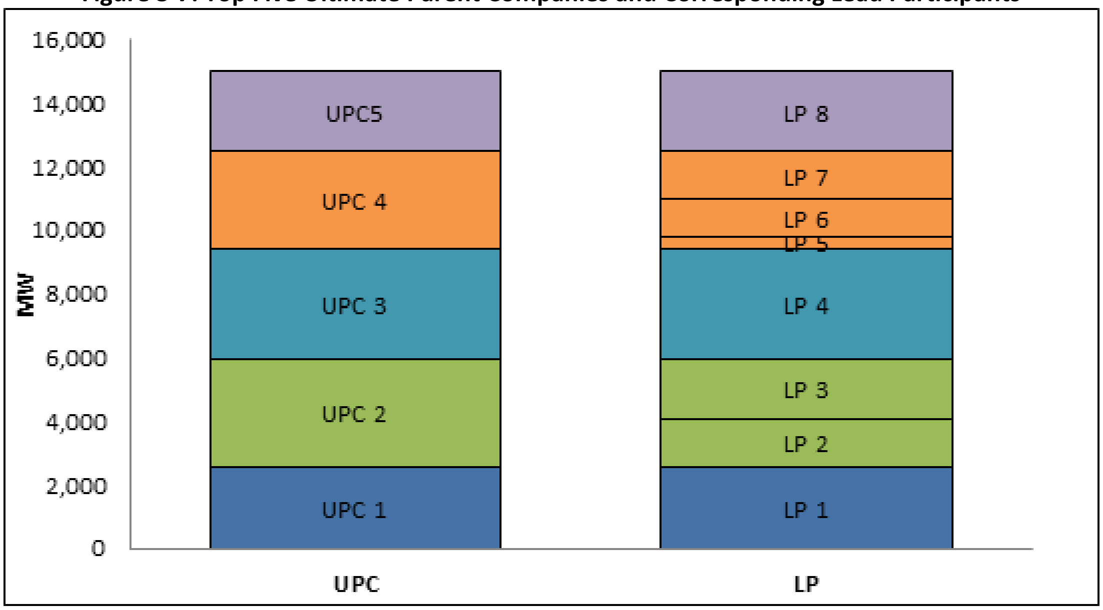


Figure 3-7 below shows how the five largest UPCs, in terms of claimed MW capability, are divided among various LPs. Three of the largest five UPCs are represented completely by a corresponding LP and would be treated appropriately in the pivotal suppler test. The other two UPCs are comprised of two and three LPs each. The existing PST for General Threshold Mitigation in the energy market will evaluate each of the LPs associated with UPC 2 and UPC 4 separately for market power.

Figure 3-7 highlights the inaccuracy in portfolio size that can arise from constructing portfolios on the basis of LP without recognizing common corporate relationships that are captured by an affiliate company construct. This error will also impact other measures such as market concentration metrics.

Figure 3-7: Top Five Ultimate Parent Companies and Corresponding Lead Participants



Accounting for affiliations between UPCs and LPs in monitoring and mitigation is common practice in other ISOs. These processes require participants to disclose affiliations and maintain the accuracy of the disclosed data in the event relationships change over time.[38] Within ISO-NE, affiliation data are maintained by participants via the Customer Asset Management System. However, there are issues that must be remedied in order to use existing UPC data within the system for purposes of testing for market power, detecting market manipulation, and related monitoring activities:

- The data do not account for affiliations due to agreements or swaps. The omission of these relationships may result an underrepresentation of the true size of some companies' portfolios; and

- Any company that has some ownership of an LP is treated as a UPC related to that LP. In these cases, the entire capacity from a single generation asset is mapped to multiple UPCs. The actual ownership share is not recorded in existing ISO data. This may lead to

[38] PJM Open Access Transmission Tariff, Attachment Q, I.B.5; CAISO Tariff, 4.14.2.1, 4.14.2.2; NY ISO Market Administration and Control Area Services Tariff 9.2.

overestimation of some companies' portfolios if a company owns a portion of a resource but scheduling control rests with one of the other owners.

3.4.3 Recommendation

In the interest of improving the accuracy of measuring market competitiveness and the ability to detect market power and manipulation, the IMM recommends that the ISO implement the following:

- Develop and maintain a database of corporate relationships and asset control that allows for accurate portfolio construction for the purpose of identifying uncompetitive participation including the potential exercise of market power and market manipulation.[39]
- Alter the existing Pivotal Supplier Test applied in energy market power mitigation, as set out in Section III, Market Rule 1, Appendix A of the ISO New England Inc. Transmission, Markets, and Services Tariff, to test generation portfolios based on the corporate entities that reflect the corporate and control relationships among groups of Lead Market Participants and their role in resource participation in the energy market.

[39] On September 17, 2015, the Federal Energy Regulatory Commission issued a Notice of Proposed Rulemaking to address the collection of connected entity data from RTOs and ISOs. *See* Notice of Proposed Rulemaking, *Collection of Connected Entity Data from Regional Transmission Organizations and Independent System Operators*, 152 FERC ¶ 61,219 (2015). The IMM is evaluating the NOPR to determine whether the Commission's connected entity data collection proposal will meet the IMM's needs for purposes of the PST.