2012 Fourth Quarter

Quarterly Markets Report

Internal Market Monitor
February 15, 2013

Preface

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

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

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

This report covers the period from October 1, 2012 to December 31, 2012 (the "Reporting Period"). The report contains the IMM analyses and summaries of market performance. All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.

For background on, and an in-depth explanation of the Day-Ahead Energy Market and Real-Time Energy Market in New England, refer to the IMMs *Overview of New England's Wholesale Electricity Markets and Market Oversight* posted on the ISO New England website.[1,2]

Underlying natural gas data furnished by:

---

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

[2] *Available at* http://www.iso-ne.com/pubs/spcl_rpts/2012/markets_overview_final_051512.pdf.

ICE Global markets in clear view[3]

Oil prices are provided by Argus Media.

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

Contents

Figures

Tables

Section 1
Executive Summary

The Internal Market Monitor has analyzed fourth quarter performance of the region's wholesale electric energy, reserve and capacity markets using supply offers, demand bids, fuel prices, market results, and other economic data. Overall, the markets have performed well, outcomes have been competitive, and results are within normal ranges.

1.1 Summary of Market Outcomes

- The Internal Market Monitor has concluded that 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 (see Section 2.1.2).

- Day-Ahead Energy Market prices during the Reporting Period averaged $45.41/MWh at the Hub, and Real-Time prices averaged $44.75/MWh (see Section 2.1.1.2). The total energy value in the Reporting Period was $1.38 billion.[4]

- Natural gas prices during the Reporting Period averaged $5.74/MMBtu (see Section 2.1.3.2). The implied heat rate for converting natural gas to electricity was 7,800 Btu/kWh, a 16% decrease from Q4 2011.

- Net energy for load ("NEL") was 30,776 GWh. Peak load during the Reporting Period was 19,119 MW, and occurred on December 17, 2012 (see Section 2.1.3.3).[5]

- Total real-time reserve payments were $8.4 million in the Reporting Period (see Section 2.2). Overall, reserve payments increased by approximately 433% when compared to the fourth quarter of 2011. In addition to the impact of the increased reserve constraint penalty factor, the IMM is looking into other reserve product interdependencies, the frequency of reserve pricing, and the impact that system conditions have had on reserve payments over the past year.

- Total Net Commitment Period Compensation ("NCPC") payments during the Reporting Period totaled $31.5 million; compared to $22.7 million in Q3 2012 (see Section 2.4.1). $4.7 million NCPC payments were directly associated with generator commitments for Superstorm Sandy from October 29 through November 3. Voltage payments continued to increase

[4] The total energy value is the Real-Time Hub LMP times the net energy for load.

[5] Net energy for load is calculated as total generation (not including the generation used to support pumping at pumped-storage hydro generators), plus net imports.

due to the frequent commitment of a unit needed to maintain voltage in a local area.

- The net payments to resources with a Capacity Supply Obligation ("CSO") totaled approximately $273.1 million in the Reporting Period; compared to $271.6 million in Q3 2012, a 1% increase (see Section 3.4.1). This is consistent with the observed 1% increase in total Capacity Supply Obligations from Q3 2012 (98,451 MW) to Q4 2012 (98,966 MW).

- There were 67 mitigation events during the Reporting Period compared to 114 mitigation events in Q3 2012 (see Section 4.1.2.1).

- The IMM made one new non-public referral to FERC in the Reporting Period. Two referrals were closed in the Reporting Period. As of the end of the Reporting Period, there were eight open referrals made by the IMM before FERC (see Section 4.1.2.1).

Section 2
Real-Time Markets

ISO New England's ("ISO") real-time markets include the Real-Time Energy Market, real-time reserves, and the Regulation Market. This section describes the real-time market outcomes in the Reporting Period.

2.1 Real-Time Energy Market

2.1.1 Prices

2.1.1.1 Real-Time Prices

In the Reporting Period, the average real-time Hub price was $44.75/MWh, up from $37.28/MWh during the fourth quarter of 2011.[6] The Reporting Period price is consistent with observed market conditions including natural gas prices, loads, and available supply. The price differences between the various load zones was caused by from marginal losses, not congestion, at the zonal level.[7, 8] Congestion was generally limited to small, transient load pockets that formed when transmission or generation elements were out of service. See Table 2-1.

---

6 Throughout this report, average prices are calculated using a simple average method.

7 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.

8 For example, the price in Maine is lower than the price in the Hub because of the transmission losses that occur in sending power from Maine to the Hub.

Table 2-1
Simple Average Real-Time Hub and Zone Prices, ($/MWh)

Location/Load Zone	Q4 2012	Q3 2012	Q4 2011
Hub	$44.75	$39.51	$37.28
Maine (ME)	$43.86	$38.19	$35.78
New Hampshire (NH)	$44.60	$39.55	$36.84
Vermont (VT)	$44.73	$39.93	$36.96
Connecticut (CT)	$44.57	$40.73	$37.78
Rhode Island (RI)	$44.50	$39.10	$36.77
Southeast Massachusetts (SEMA)	$44.92	$39.47	$37.05
Western Central Massachusetts (WCMA)	$44.94	$40.26	$37.40
Northeast Massachusetts (NEMA)	$44.90	$39.51	$37.24

2.1.1.2 Day-Ahead and Real-Time Price Comparison

The average Day-Ahead energy price at the Hub for the Reporting Period was $45.41/MWh, 19.4% above the fourth quarter 2011 level. The average Real-Time energy price at the Hub was $44.75/MWh, 20.1% above the fourth quarter 2011 level. Changes in Locational Marginal Prices ("LMPs") at the Hub compared to previous periods are consistent with changes in input fuel prices and are within normal ranges.

In the Reporting Period, the difference between the average Day-Ahead and Real-Time prices was $0.66. The average daily difference between Day-Ahead and Real-Time prices in the Reporting Period generally trend together and there have been no unexpected deviations. Observed price differences reflect market fundamentals and changes in system conditions. See Figure 2-1, which shows daily average Day-Ahead and Real-Time Hub LMPs.

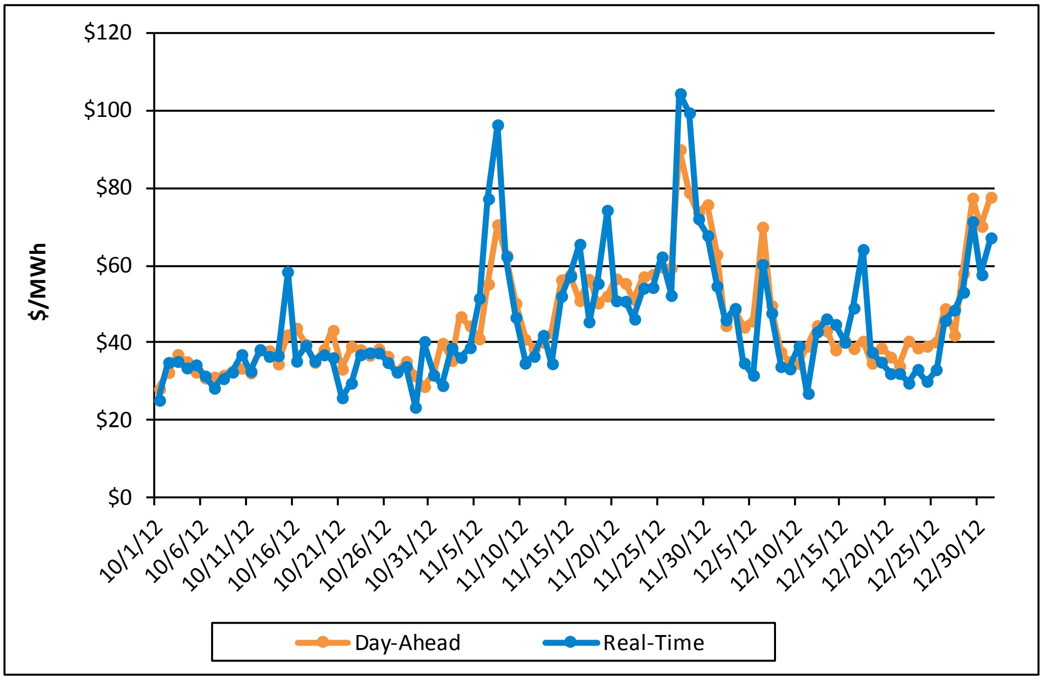

Figure 2-1: Average daily Day-Ahead and Real-Time hub prices, LMPs, Q4 2012.

2.1.2 Market Structure

This section presents the results of the IMM's analysis of market structure.

A core function of the IMM is to monitor market participant behavior and detect deviations from competitive behavior. The exercise of market power is more likely when there are fewer competitors (*i.e*, less competition) in the market. Thus, the number of competitors, and the frequency with which suppliers are *pivotal* (are necessary to meet demand and therefore can unilaterally set prices) affects the ability of participants to raise prices above competitive levels. The IMM calculated and reviewed the following statistics as measures of market competitiveness:

- Market concentration as measured by the Herfindahl-Hirschman Index ("HHI")
- The number of hours in which participant portfolios were pivotal as measured by the system-wide Residual Supply Index ("RSI")

2.1.2.1 Structural Measure of the Real-Time Energy Market

The HHI, a commonly used measure of market concentration, is calculated by summing the squares of each participant's market share.[9] The HHI gives proportionately greater weight to

[9] The HHI is calculated as follows:

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

the market shares of the larger firms, consistent with their greater importance in competitive interactions.

Monthly system-wide HHIs for New England internal resources, based on summer capabilities and the resources' Lead Market Participants, averaged 628 in the Reporting Period. This value has changed little over the past three years and is consistent with a competitive market.[10] It is well below the 1,500 level that the US Department of Justice (DOJ) uses as a threshold measure of an unconcentrated market.[11]

2.1.2.2 Residual Supply Index

The systemwide RSI measures the percentage of demand in a given hour (in megawatt-hours) that can be met with no capacity from the largest supplier. When the RSI exceeds 100%, the system has sufficient capacity 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, the supplier is defined as pivotal and able to raise prices above the competitive level. As the RSI rises, the ability of market participants to unilaterally set prices above competitive levels decreases. RSIs are generally lowest during periods of high demand, indicating reduced competition as the system approaches its capacity limit.

Overall, the RSI analysis for the Reporting Period suggests that suppliers at the system level had limited ability to exercise market power. The system-level analysis shows that pivotal suppliers existed during 3 hours in the Reporting Period, approximately 0.1% of all hours and the result is within normal ranges. See Figure 2-2.

---

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.

[10] 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.

[11] 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.

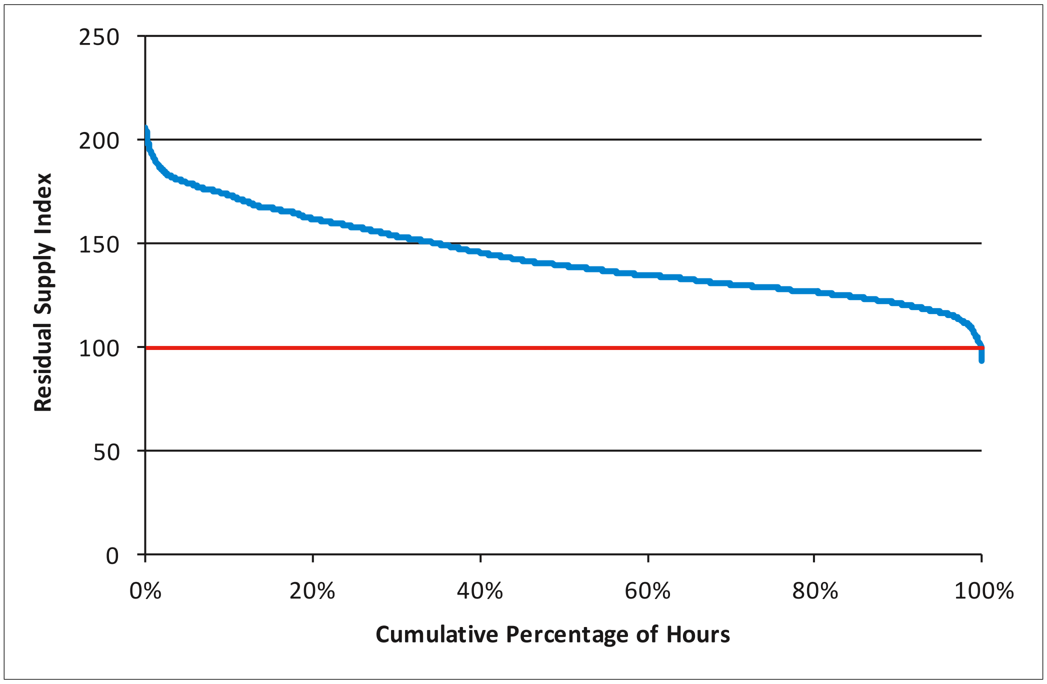

Figure 2-2: Systemwide Residual Supply Index duration curve, all hours, Q4 2012.

2.1.3 Factors Influencing Real-Time Energy Prices

This section describes the factors influencing real-time electric energy prices, including fuel prices and load levels.

2.1.3.1 Energy Prices and Marginal Units

The LMP is set by the cost of the megawatt dispatched to meet the next increment of load. The resource that sets price is called the marginal unit. Because the price of electricity changes as the price of the marginal fuel changes, examining marginal units by fuel type helps to explain changes in electricity prices. During each pricing interval, the system has at least one marginal unit associated with meeting the energy requirements on the system. If transmission is not constrained, the marginal unit is classified as the *unconstrained* marginal unit. In intervals with binding transmission constraints, an additional marginal unit is associated with each binding constraint.

In the Reporting Period, units burning natural gas were marginal for 76% of the pricing intervals, followed by pumped storage units, which were marginal in 15% of the pricing intervals. Generating resources burning coal were marginal 3% of the time, and hydro and wood were marginal 2% of the time. See Figure 2-3.

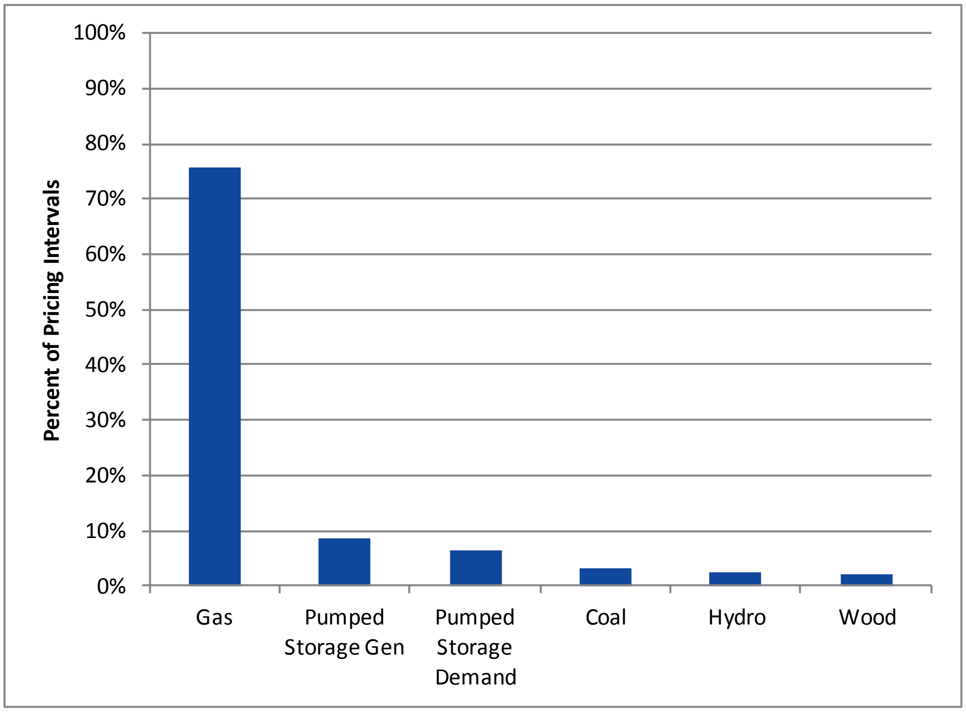

Figure 2-3: Marginal fuel-mix percentages of unconstrained pricing intervals, Q4 2012.

2.1.3.2 Energy Prices and Natural Gas Prices

The cost of natural gas increased by 43% in the Reporting Period, from $4.02/MMBtu in the fourth quarter of 2011 to $5.74/MMBtu in the fourth quarter of 2012. Real-Time electricity prices increased from $37.28/MWh in the fourth quarter 2011 to $44.75/MWh in the Reporting Period, a 20% rise. Wholesale electricity prices continue to track natural gas prices, which is expected in a competitive market. See Figure 2-4.

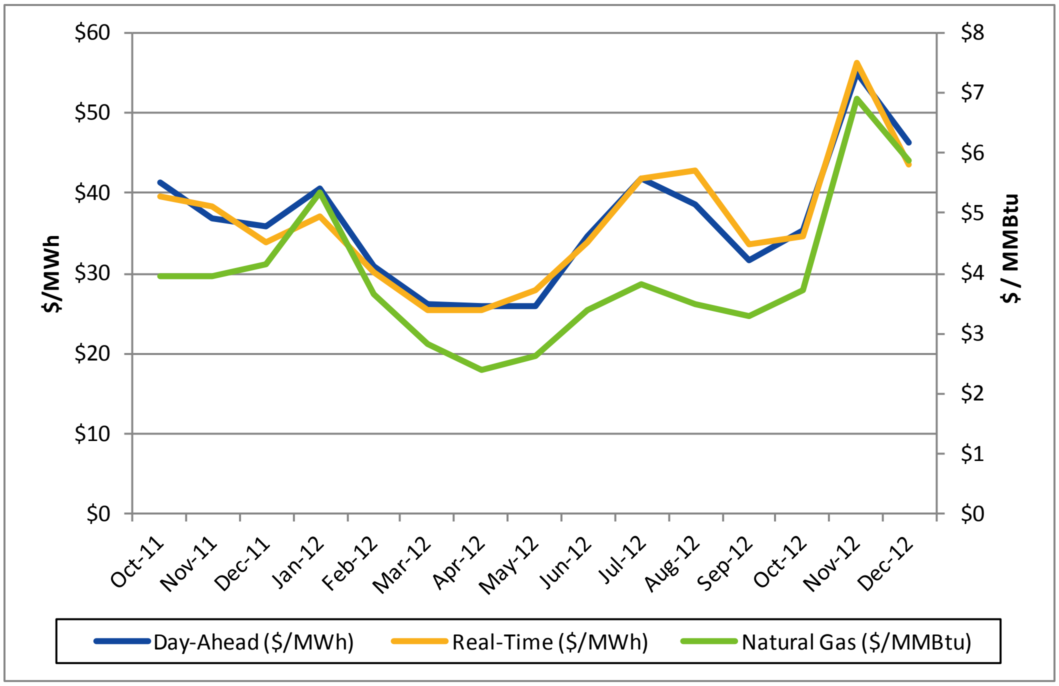

Figure 2-4: Monthly Average Day-Ahead and Real-Time Hub and Natural Gas Prices, October 2011-December 2012.

Over time, the IMM has observed that the relationship between the changes in LMPs and natural gas prices tracks together, but is not linear (*i.e.*, one-to-one). The relationship between LMPs and natural gas prices is a function of many different variables, including a generators heat rate, the fuel source of the marginal resource, load levels, outages, and other system conditions. The IMM also observed that system load levels and the percent of time that gas units set price in the Reporting Period were similar to that in Q4 2011. However, the IMM observed that the *implied heat rate* for a typical gas unit fell from 9,273 Btu/kWh in Q4 2011 to 7,797 Btu/kWh in Q4 2012, a 16% decrease.[12] This suggests that cheaper, more efficient gas units were setting the price in the Reporting Period, consistent with a smaller percent increase in electricity prices than natural gas prices. See Table 2-2.

[12] A generator's heat rate is the rate at which it converts gas (MMBtu) to electricity (MWh) and measures the thermal efficiency of the conversion process. The implied heat rate for any day can be calculated as the ratio of power and gas prices for that day, which approximates the thermal efficiency that would be required to break even on the conversion of fuel to electricity. VOM and emissions are not considered.

Table 2-2
Hub Prices, Gas Prices, and Implied Heat Rates, Q4 2011-Q4 2012

Quarter	Average Real-Time Hub LMP ($/MWh)	Average Gas Price ($/MMBtu)	Implied Heat Rate (Btu/kWh)
Q4 2011	37.28	4.02	9,273
Q1 2012	30.90	3.90	7,925
Q2 2012	29.06	2.76	10,544
Q3 2012	39.51	3.62	10,907
Q4 2012	44.75	5.74	7,797

The natural gas *spark spread* quantifies the relationship between real-time electric energy prices and the cost of producing that energy using natural gas. Figure 2-5 presents monthly estimated natural gas spark spreads for on peak hours.[13] The results suggest show that day-ahead and real-time spark spreads averaged $7.48/MWh (Day-Ahead Market) and $8.18/MWh (Real-Time Market), respectively, in the Reporting Period.[14]

[13] A spark spread is a measure of the gross margin (energy revenues minus fuel costs) from converting fuel to electricity based on the wholesale price of electricity and the cost of producing electricity with a given fuel and technology. The calculation is based on the unweighted monthly average day-ahead and real-time Hub price for on-peak hours (in $/MWh) from October 2011 through December 2012, and the estimated cost of a combined cycle gas turbine ("CCGT") unit. Fuel costs approximate those of a typical CCGT in New England, assuming the Algonquin gas price, a 7,800 Btu/kWh heat rate, and 100% availability.

[14] This is an idealized representation of the gross margins to a combined cycle unit. An evaluation of revenues earned by any particular resource should take into account all unit-specific operating characteristics (e.g., availability, minimum run time, ramp rates, economic minimum, and heat rate).

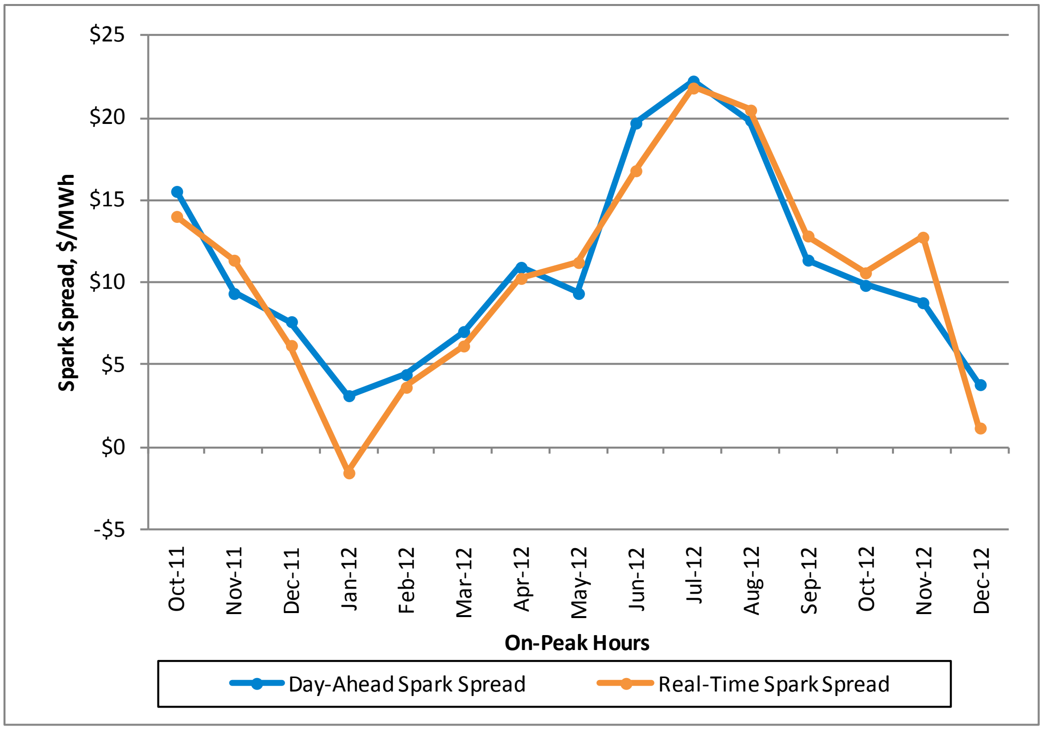

Figure 2-5: Estimated Spark Spreads, October 2011-December 2012.

2.1.3.3 Energy Prices and Real-Time Demand

The demand for electricity in New England, defined as *net energy for load* ("NEL"), was 30,776 gigawatt-hours ("GWh") in the Reporting Period.[15] This is a 1% increase from the recorded NEL of 30,528 GWh in the fourth quarter of 2011. The peak demand in the Reporting Period was 19,119 MW and occurred on December 17, 2012. This is a 1% decrease from the recorded peak demand in the fourth quarter 2011 of 19,357 MW, which occurred on December 19, 2011. See Table 2-3.

Table 2-3
Net Energy for Load

	(GWh)			
	Q4 2012	**Q4 2011**	**Diff.**	**%Chg.**
Recorded NEL (GWh)	30,776	30,528	248	1%
Normalized NEL (GWh)[(a)]	30,955	31,087	-132	0%
Recorded peak demand (MW)	19,119	19,357	-238	-1%

(a) *Weather-normalized* results are those that would have been observed if weather were the same as the long-term average weather.

[15] *Net energy for load* (NEL) is calculated as total generation (not including the generation used to support pumping at pumped-storage hydro generators), plus net imports.

2.1.3.4 Energy Prices and External Transactions

In the Reporting Period, New England was a net importer of power. Net imports from Canada exceeded net exports to New York ("NY"). Net interchange with neighboring balancing authority areas totaled 4,245 GWh imported for the Reporting Period, a 53% increase compared with the previous quarter. See Figure 2-6, which shows total interregional power flows by quarter from the fourth quarter of 2011 through the fourth quarter of 2012.

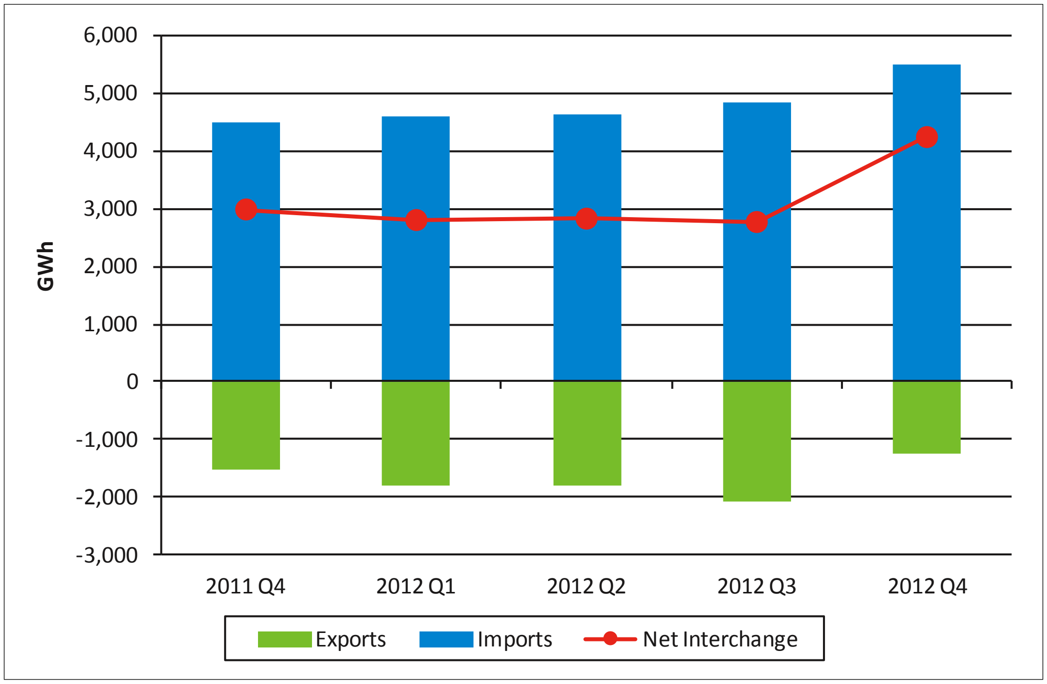

Figure 2-6: Quarterly New England Imports, Exports and Net Interchange, Q4 2011-Q4 2012.

2.2 Real-Time Reserves

This section summarizes the performance of the real-time reserves market.

On June 1, 2012, the reserve constraint penalty factor for Thirty Minute Operating Reserve ("TMOR") increased from $100/MWh to $500/MWh.[16] In the Reporting Period, the total real-time reserve payments were $8.4 million. In the fourth quarter of 2011, real-time reserve payments totaled $1.6 million. Comparing fourth quarter 2011 with fourth quarter 2012, real-time payments for ten-minute spinning reserve ("TMSR") increased by 168%, ten-minute non-spinning reserve ("TMNSR") increased by 1055%, and system TMOR increased by 1443%.[17] Overall, reserve payments increased by approximately 433% when compared to the fourth quarter of 2011. Reserve payments decreased by a 56% between the third quarter of 2012 and the Reporting Period. See Table 2-4.

[16] See *RCPF Value Change,* ER-12-1314-000, filed March 22, 2012, *available at* http://www.iso-ne.com/regulatory/ferc/filings/2012/mar/er12-1314-000_rcpf_value_chg_3-22-2012.pdf.

[17] This is on a weighted-average basis, given the reductions in Southwest Connecticut and Connecticut.

Table 2-4
Real-Time Reserve Payments ($ and %)

Product	Q4 2012 ($)	Q3 2012 ($)	% Change (Q3 2012 to Q4 2012)	Q4 2011 ($)	% Change (Q4 2011 to Q4 2012)
System-Wide TMSR	3,030,311	6,632,044	-54%	1,132,616	168%
System-Wide TMNSR	3,544,780	8,386,002	-58%	307,020	1055%
System-Wide TMOR	374,894	950,635	-61%	24,294	1443%
SWCT TMOR	1,087,365	2,077,407	-48%	80,317	1254%
CT TMOR	292,659	894,404	-67%	25,492	1048%
NEMA/Boston TMOR	111,198	289,213	-62%	14,117	688%
Total	8,441,207	19,229,705	-56%	1,583,856	433%

The IMM is currently analyzing the factors effecting reserve payments to understand the root causes of the increases observed beginning in Q3 2012. In addition to the impact of the increased reserve constraint penalty factor, the IMM is looking into other reserve product interdependencies (i.e., higher-quality reserve products which can be substituted for lower-quality reserves), the frequency of reserve pricing, and the impact that system conditions have had on reserve payments over the past year.

The IMM plans to publish its findings in a future quarterly report or the *2012 Annual Markets Report* when the analysis is complete.

2.3 Regulation Market

This section summarizes the outcomes of the Regulation Market during the Reporting Period.

2.3.1 Regulation Pricing and Payments

The average regulation price in the Reporting Period was $7.21/MWh. Total Regulation Market payments during the Reporting Period were nearly $3.5 million. See Table 2-5. The increase in regulation payments in the Reporting Period from the third quarter is attributable to higher natural gas prices.

Table 2-5
Regulation Market Outcomes ($ and %)

	Q4 2012 ($)	Q3 2012 ($)	% Change (Q3 2012 to Q4 2012)	Q4 2011 ($)	% Change (Q4 2011 to Q4 2012)
Capacity Credit	1,095,500	887,339	23.5%	905,161	21.0%
Opportunity Cost	1,315,544	1,248,234	5.4%	940,034	39.9%
Service Credit	1,043,886	841,564	24.0%	938,879	11.2%
Total Regulation Payments	3,454,930	2,977,137	16.0%	2,784,074	24.1%

2.3.2 Requirements and Performance

New England's hourly regulation requirement has been steadily decreasing from an average requirement of 181 MW in 2002, to 60 MW in 2011. The average hourly requirement in the Reporting Period was approximately 60 MW. The regulation requirement in New England typically is highest in the early morning and the late evening. The higher regulation requirement during these hours is the result of load variability and supply uncertainty.

Over time, the ISO has been able to reduce the regulation requirement because of increased performance of the resources providing regulation. One of the contributing factors to the increase in performance is the incentive structure that compensates faster-responding units for their higher contribution to regulation service through the service payment.

2.4 Reliability Assessment

This section discusses actions taken by the ISO to ensure real-time reliability. It includes a review of *Net Commitment-Period Compensation* ("NCPC"), "make-whole" payments made to resource owners that do not recover their full as-bid cost from the energy markets.

2.4.1 Daily Reliability Payments

Total NCPC payments during the Reporting Period totaled $31.5 million, as shown in Table 2-6. Outcomes are within normal ranges. The majority of the NCPC incurred during the reporting period was economic (also called "first contingency") NCPC. Economic NCPC paid to a resource is the difference between

- the cost of committing and operating a generating resource to meet capacity and energy needs in the day-ahead and real-time markets; and,
- the energy revenues the resource realizes during the market day.

Most economic NCPC is associated with generating resources committed in real-time for 1st contingency coverage. The NCPC is created because the Resources must remain in operation at Economic Minimum beyond those hours of need due to their minimum run time limitations.

In the Reporting Period, $4.7 million of economic NCPC payments were directly associated with generator commitments for Superstorm Sandy from October 29 through November 3. These units were committed to maintain system reliability and transmission security in anticipation of potential transmission and generation outages due to the storm. Voltage payments continued to increase due to the frequent commitment of a unit needed to maintain voltage in a local area.

Table 2-6
Total NCPC Payments by Quarter and Category

NCPC Category	Q4 2012 ($)	Q3 2012 ($)	Q4 2011 ($)
Economic and First Contingency Payments	22,312,923	13,280,561	9,204,440
Second Contingency Payments	2,834,419	1,705,640	2,894,871
Voltage Payments	6,371,217	4,493,466	1,957,925
Distribution Payments	1,293	3,236,861	258,175
Total	31,519,852	22,716,527	14,315,410

2.4.2 Supplemental Commitments

Each day after the clearing of the Day Ahead Energy Market, ISO New England performs a Reserve Adequacy Analysis ("RAA"). The results of the RAA are used to make operational decisions to commit additional generators if insufficient capacity clears in the Day-Ahead Energy Market to meet the ISO peak load forecast plus operating reserve requirement. The amount of capacity on line affects LMPs and NCPC costs. If excess capacity is on line, then LMPs can be supressed and NCPC costs inflated. On the other hand, if the amount of committed capacity is less than the ISO peak load forecast plus operating reserve requirement, then reliable operation may be compromised.

On most days in the Reporting Period, no generators were committed supplementally. As a result, the minimum for each month is zero. Figure 2-7 below illustrates the minimum, maximum and average supplemental commitments for October 2011 through December 2012. For each month, the orange dashed line represents the range of values in the month with the maximum value at the top, the minimum at the bottom and the blue line representing the average.

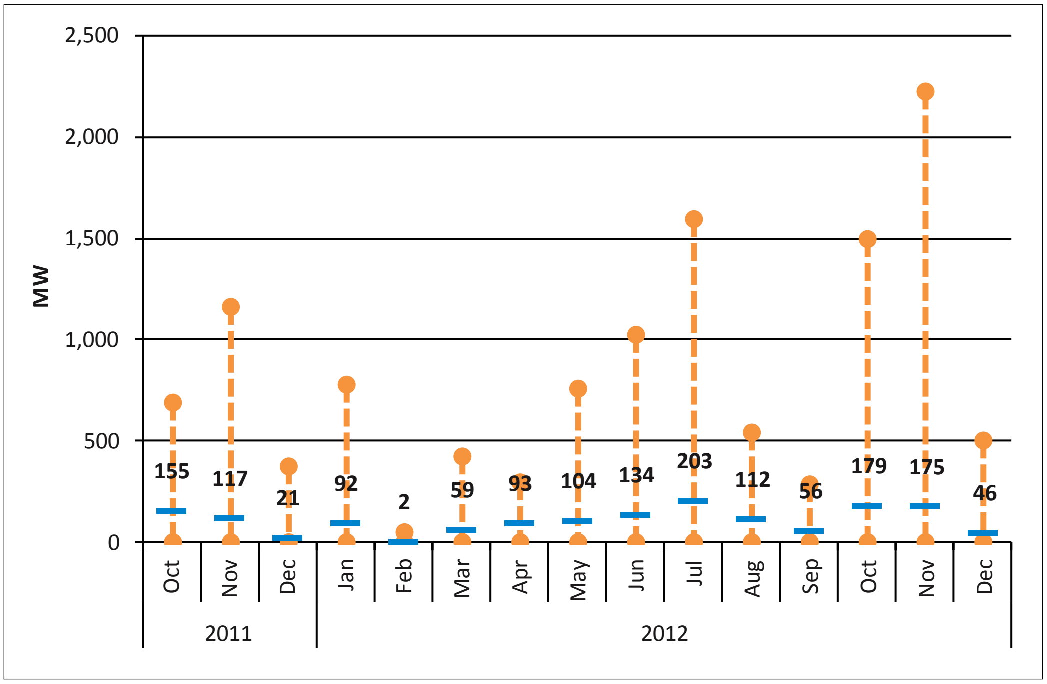

Figure 2-7: Monthly average, maximum, and minimum of daily supplemental commitments, October 2011 to December 2012 (MW).

Section 3
Forward Markets

This section describes the Reporting Period outcomes of the ISO's forward markets, including the Day-Ahead Energy Market, the Forward Reserve Market, and the Forward Capacity Market. The outcomes for Financial Transmission Rights and demand resources are also discussed.

3.1 Day-Ahead Energy Market

3.1.1 Day-Ahead Pricing

The average day-ahead Hub price in the Reporting Period was $45.41/MWh. As in real-time, this price is consistent with observed market conditions, including natural gas prices, loads, and available supply. This price is consistent with observed market conditions including natural gas prices, loads, and available supply. The price differences between the various load zones were caused by marginal losses, not congestion, at the zonal level. Congestion was generally limited to small, transient load pockets that formed when transmission or generation elements were out of service. See Table 3-1.

Table 3-1
Simple Average Day-Ahead Hub and Zone Prices ($/MWh)

Location/Load Zone	Q4 2012	Q3 2012	Q4 2011
Hub	$45.41	$37.38	$38.04
Maine (ME)	$44.55	$37.52	$36.99
New Hampshire (NH)	$45.40	$37.40	$37.66
Vermont (VT)	$45.79	$37.83	$38.24
Connecticut (CT)	$45.14	$38.62	$38.79
Rhode Island (RI)	$45.48	$37.19	$37.47
Southeast Massachusetts (SEMA)	$45.56	$37.29	$37.70
Western Central Massachusetts (WCMA)	$45.74	$38.52	$38.57
Northeast Massachusetts (NEMA)	$45.61	$37.80	$37.94

3.1.2 Influences on Day-Ahead Energy Prices

This section describes the relationships between day-ahead electric energy prices and other market factors.

3.1.2.1 Price Setting in the Day-Ahead Market

In the day-ahead market, generators set price approximately 46% of the time in the Reporting Period, and virtual transactions set price approximately 30% of the time. External transactions and priced demand set price for the remaining 24% of the time. See Figure 3-1.

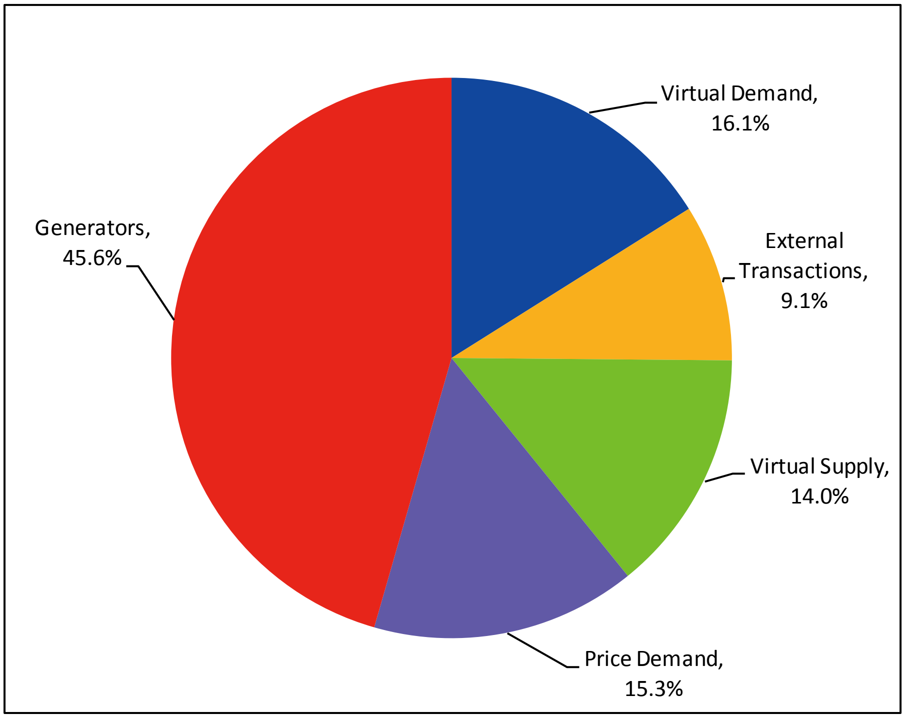

Figure 3-1: Percentage of price setting in the day-ahead market, Q4 2012.

3.1.2.2 Day-Ahead Demand Compared with Real-Time Demand

The day-ahead cleared demand as a percentage of real-time load is the most important factor determining the supplemental commitments needed in the real-time energy market.[18] The higher this percentage, the lower the amount of supplemental commitment. This percentage has been fairly stable over time, generally in the 92% - 95% range. The percentage of day-ahead demand cleared in the Reporting Period was 93.5%, compared to the previous quarter's percentage of 94.4%.[19]

[18] Supplemental commitments are made through the Reserve Adequacy Analysis process (see Section 2.4.2).

[19] The metric is the energy purchased in the day-ahead market as a percentage of actual energy consumption in New England and is calculated as follows:

> Day-Ahead Demand Cleared as a Percentage of Real-Time Load = (Cleared Fixed Demand Bids + Cleared Price-Sensitive Demand Bids + Cleared Virtual Demand Bids – Cleared Virtual Supply Offers)/(Net Energy for Load).

3.1.2.3 Virtual Transactions

In the fourth quarter of 2012, submitted and cleared virtual transactions continued the year over year declining trend reported in the 2011 *Annual Markets Report*. Submitted virtual demand bids and virtual supply offers totaled approximately 7,310 GWh in the Reporting Period, a decline of 4% when compared with the fourth quarter of 2011, and a decline of 18% compared with the fourth quarter of 2010. Cleared virtual transactions totaled approximately 1,193 GWh in the Reporting Period, a 22% decline compared with the fourth quarter 2011, and a 44% decline compared with the fourth quarter of 2010. However, there were slight increases compared with the previous quarter, likely driven by higher energy prices. In the Reporting Period, submitted virtual transactions were 14% higher than the third quarter of 2012, while cleared transactions increased 13% when compared to the third quarter of 2012. See Table 3-2.

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

	Q4 2012	Q3 2012	% Change (Q3 2012 to Q4 2012)	Q4 2011	% Change (Q4 2011 to Q4 2012)	Q4 2010	% Change (Q4 2010 to Q4 2012)
Total Submitted Virtual Transactions	7,310	6,401	14%	7,649	-4%	8,868	-18%
Total Cleared Virtual Transactions	1,193	1,053	13%	1,526	-22%	2,140	-44%

3.2 Financial Transmission Rights

During the Reporting Period, 39 bidders participated in the October monthly auction, 32 bidders participated in the November auction, and 34 bidders participated in the December auction. This is consistent with levels of participation in prior auctions. The three auctions combined totaled 95,608 MW of FTR transactions. The amount distributed as Auction Revenue Rights ("ARRs") was $2.09 million, compared to $1.96 million in Q3 2012.

3.3 Demand Resources

3.3.1 Demand Resources in the Forward Capacity Market

The capacity supply obligation of all demand resources participating in the FCM decreased by 9.2% (175 MW) in the Reporting Period compared to the previous quarter. The capacity supply obligations of active demand resources decreased by 19.5% (181 MW), while passive demand resources increased by 0.6% (6 MW).[20] The change in CSOs between the end of Q3 and the end Q4 is most likely attributed to transfers in capacity supply obligations through bilateral transactions or reconfigurations auctions, as well as the seasonal variations in the capacity supply obligations of some demand resources. See Table 3-3.

[20] Values are based on the resources' capacity supply obligations as of September 1, 2012 and December 1, 2012.

Table 3-3
Capacity Supply Obligation by Demand-Resource Type (MW), Q3 and Q4 2012

	Active Demand Resources			Passive Demand Resources			Total All Demand Resources
	Real-Time Demand-Response Resource	Real-Time Emergency Generation Resource	Total Active Demand Resources	On-Peak Demand Resource	Seasonal-Peak Demand Resource	Total Passive Demand Resources	
Q3 End of Quarter	562.7	363.5	926.2	726.8	246.4	973.3	1,899.5
Q4 End of Quarter	446.2	299.1	745.3	723.1	255.7	978.8	1,724.1
% change Q3 to Q4	-20.7%	-17.7%	-19.5%	-0.5%	3.8%	0.6%	-9.2%

3.3.2 Demand Resource Payments

Demand response payments totaled $21.3 million in the Reporting Period, which was 3.6% lower than the previous quarter's payments of $22.1 million. Of the total payments made to demand resources in the Reporting Period, 97.2% were capacity payments. The previous quarter's capacity payments were 96.4% of total payments.

The transitional Price Responsive Demand program ("PRD") program that went into effect on June 1, 2012 replaced the Day Ahead Load Response Program ("DALRP") and the Real-Time Price-Response ("RTPR") programs, which retired on May 31, 2012. With the introduction of the new PRD program design, there has been a 4.4% decrease in payments to demand resources for price responsive load reductions in Q4 2012 as compared to Q4 2011. See Table 3-4.

Table 3-4
Total Payments to Demand-Response Resources ($)

Period	Capacity Payments ($)	DALRP Payments ($) (ended 5/31/2012)	RTPR Payments ($) (ended 5/31/2012)	Price Responsive Demand Payments ($) (began 6/1/12)	Total Payments ($)
Q4 2012	20,735,810	0	$0	603,905	21,339,715
Q3 2012	21,332,489	0	$0	796,774	22,129,263
Q4 2011	24,313,744	607,006	$24,752	$0	24,945,502
Difference Q4-Q3 2012	-596,680	0	0	-192,869	-789,549
Difference (%) Q3 to Q4 2012	-2.8%	0%	0%	24.2%	-3.6%

3.4 Forward Capacity Market

3.4.1 Capacity Market Outcomes

The net payments to resources with a Capacity Supply Obligation ("CSO") totaled approximately $273.1 million in the Reporting Period, compared with $271.6 million in Q3 2012, a 1% increase. See Table 3-5. This is consistent with the observed 1% increase in total Capacity Supply Obligations from Q3 2012 (98,451 MW) to Q4 2012 (98,966 MW).

The total net payment is the sum of the following:

- Supply Credit: The capacity payment rate times the total amount of Capacity Supply Obligations in the month
- Peak Energy Rent ("PER") Adjustment: The PER rate multiplied by the total amount of Capacity Supply Obligations subject to PER in the month
- Excess Demand Response ("DR") Penalties: The total unallocated DR Penalties in the month
- Reliability Credit: Payments to resources retained for reliability.

Table 3-5
FCM Payments and Charges, Q4 2012

Month	Capacity Zone	CSO MW	Supply Credit ($)	PER Adjustment ($)	Excess DR Penalties ($)	Reliability Credit ($)	Total Payment ($)
12-Oct	Rest-of-Pool	29,336	79,770,840	0	0	1,623,350	81,394,190
12-Oct	Maine	3,647	9,672,908	0	(49,496)	0	9,623,411
12-Nov	Rest-of-Pool	29,282	79,755,703	0	0	1,623,350	81,379,053
12-Nov	Maine	3,702	9,688,045	0	(49,804)	0	9,638,241
12-Dec	Rest-of-Pool	29,362	79,806,818	0	0	1,623,350	81,430,168
12-Dec	Maine	3,637	9,675,264	0	0	0	9,675,264

3.4.2 Resource Performance

All capacity resources with a CSO are subject to performance evaluation during each obligation month of a commitment period. The performance of generation and import resources is evaluated during shortage events. There were no shortage events during the Reporting Period. The performance of active demand resources, such as Real-Time Demand Response Resources, is determined based on the amount of load reduction achieved when the resource is dispatched during emergency actions (*i.e.*, OP4) or audited. During the Reporting Period, there were no OP4 dispatch events and 22 audits. The performance of passive demand resources, such as On-Peak Demand Resources, is determined each month based on the amount of load reduction achieved in the month.[21]

[21] A system wide summary of demand resource performance by type is available at ISO New England's external web at http://www.iso-ne.com/markets/mkt_anlys_rpts/index.html under Monthly Market Reports.

3.4.3 Reconfiguration Auctions and Bilateral Transactions

Participants can transfer and acquire capacity supply obligations through bilateral transactions and reconfiguration auctions. Bilateral transactions and auction trades can be for either one month or the entire one-year capacity commitment period, and volumes exchanged in monthly bilateral trades and the monthly reconfiguration auctions vary from month to month. Table 3-6 summarizes the results of bilateral trades for the capacity commitment period of 2013-2014.

Table 3-6
Bilateral Trades, Capacity Commitment Period 2013-2014

Auction	Bilateral Transactions	
	Trades (MW)	Average Trade Price ($/kW-Month)
ARA 2 Bilateral Period 2 (CP 2013-14)**	1,004	$0.86

* The clearing price reflects rest-of pool clearing price.
** "CP" refers to capacity commitment period.

Additionally, during the Reporting Period, monthly Forward Capacity Market bilateral transactions and reconfigurations auctions took place for the 2012-13 CCP. Monthly CSO bilateral and reconfiguration activity took place in October, November, and December (the Reporting Period) for the obligation months December 2012, January 2013, and February 2013, respectively. Table 3-7 shows the results of monthly reconfiguration auctions and bilateral transactions that occurred during the Reporting Period, for the obligation months indicated in the table.

Table 3-7
Monthly Reconfiguration Auctions and Bilateral Trades

Obligation Month	Monthly Reconfiguration Auctions		Bilateral Transactions	
	Cleared CSO MW	Auction Clearing Price ($/kW-Month)	Traded CSO MW	Average Trade Price ($/kW-Month)
December-12	131	$0.32	385	$1.34
January-13	178	$0.33	799	$1.12
February-13	161	$0.43	704	$1.01

Section 4
Data Appendix

This appendix contains details on the energy, forward capacity, locational forward reserve, and regulation markets. It also contains information about Mitigation and Investigation activities.

4.1 Real-Time Energy Markets

4.1.1 Real-Time Market

4.1.1.1 Pricing

The average day-ahead premium for the Hub and eight load zones is shown in Table 4-1.

Table 4-1
Average Day-Ahead Premium, ($/MWh)

Location/Load Zone	Q4 2012	Q3 2012	Q4 2011
Hub	$0.66	$-2.13	$0.77
Maine (ME)	$0.69	$-0.67	$1.20
New Hampshire (NH)	$0.80	$-2.15	$0.82
Vermont (VT)	$1.06	$-2.10	$1.28
Connecticut (CT)	$0.57	$-2.11	$1.01
Rhode Island (RI)	$0.97	$-1.90	$0.70
Southeast Massachusetts (SEMA)	$0.64	$-2.18	$0.65
Western Central Massachusetts (WCMA)	$0.71	$-1.71	$0.70
Northeast Massachusetts (NEMA)	$0.80	$-1.74	$1.16

4.1.1.2 Relationships to Pricing and Other Factors

Table 4-2 shows average prices for selected fuels.

Table 4-2
Fuel Prices

Fuel Type	Q4 2012 ($/MMBtu)	Q3 2012 ($/MMBtu)	% Change (Q3 2012 to Q4 2012)	Q4 2011 ($/MMBtu)	% Change (Q4 2011 to Q4 2012)
Natural Gas	5.74	3.61	59.1%	4.02	42.9%
No. 6 Oil 1%	16.29	16.92	-3.7%	16.05	1.5%
No.2 Oil	21.99	21.58	1.9%	21.34	3.1%
Low Sulfur Coal	2.69	2.55	5.7%	3.00	-10.2%
High Sulfur Coal	2.53	2.44	3.8%	2.85	-11.4%

Figure 4-1 compares generation by fuel type as a percentage of total generation for Q4 2011 and Q4 2012.

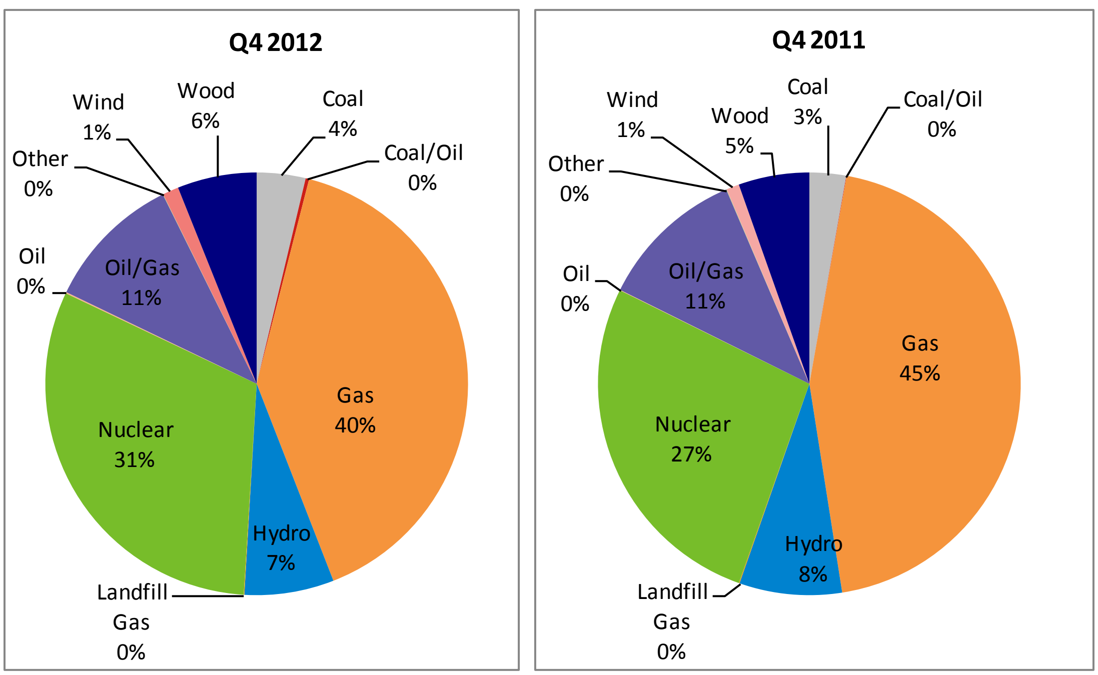

Figure 4-1: Percent of Generation by Fuel Type, Q4 2012 and Q4 2011.

Table 4-3 shows the difference between day-ahead and real-time self-scheduled generation.

Table 4-3
Day-Ahead, Real-Time, and
Real-Time Supplemental Self-Schedules (GWh)

Month	Day-Ahead Self-Schedule (GWh)	Real-Time Self-Schedule (GWh)	Real-Time Supplemental Self-Schedule (GWh)	Percentage (Day Ahead/ Real Time)
Jan 2012	6,720	7,719	999	87%
Feb 2012	6,218	7,037	818	88%
Mar 2012	6,175	7,200	1,025	86%
Apr 2012	5,691	6,589	898	86%
May 2012	6,367	7,347	980	87%
Jun 2012	6,467	7,509	1,043	86%
Jul 2012	7,455	8,679	1,224	86%
Aug 2012	6,760	7,440	680	91%
Sep 2012	5,715	6,383	669	90%
Oct 2012	5,055	5,737	683	88%
Nov 2012	5,589	6,362	773	88%
Dec 2012	6,160	7,213	1,052	85%

Table 4-4 shows the net interchange by interface.

Table 4-4
Net Interchange by Interface (GWh)

External Interface	Q4 2012	Q3 2012	Q4 2011
Hydro Quebec Highgate	242	400	356
Hydro Quebec Phase I/II	2,969	2,978	2,472
New Brunswick	332	141	119
NY-NNC (Northport)	-141	-308	-247
NY-AC (Roseton)	1,228	229	865
NY-Cross-Sound Cable (Shoreham)	-384	-670	-575

Note: positive values denote net imports and negative values denote net exports.

Figure 4-2 shows a summary of Reporting Period net interchange by interface.

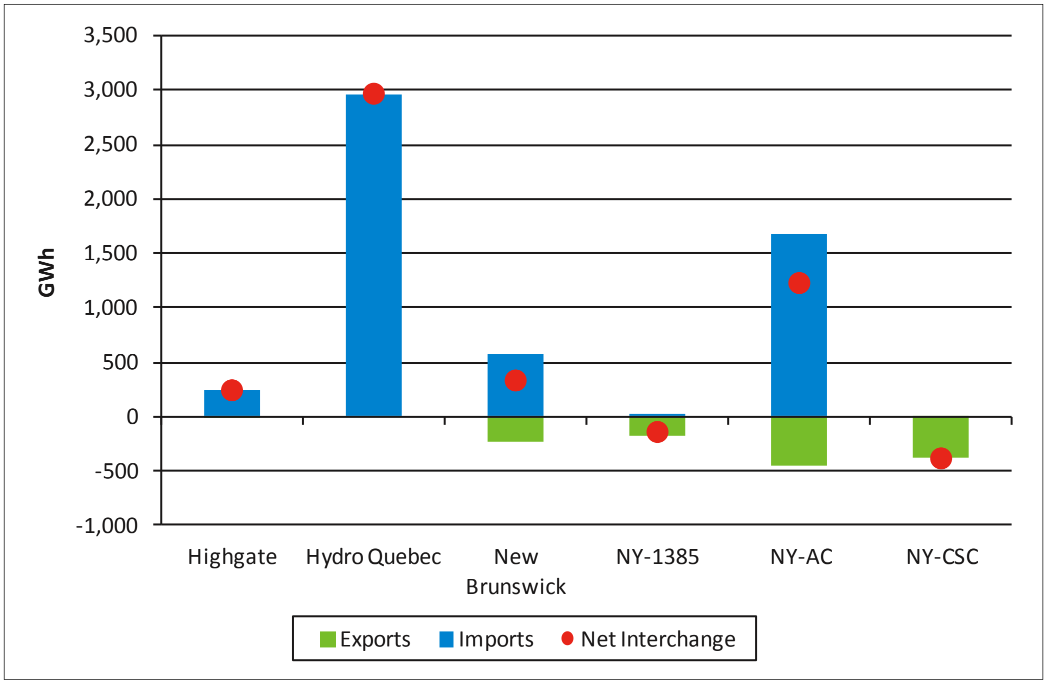

Figure 4-2: New England Imports and Exports by Interface, Q4 2012.

Figure 4-3 shows statewide ranks for temperature for the Reporting Period, obtained from the National Oceanographic and Atmospheric Administration ("NOAA").[22]

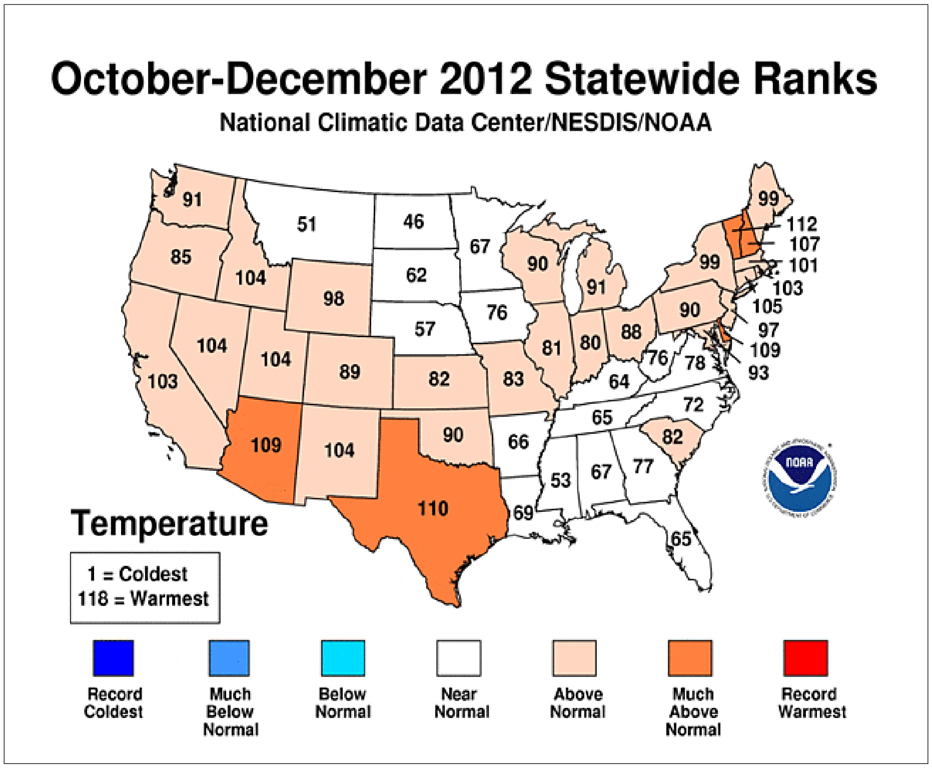

Figure 4-3: Statewide Ranks for Temperature, Q4 2012.

(**Source:** NOAA)

4.1.2 Mitigation, Investigation, and Price Corrections Appendix

This section includes information on IMM mitigation and investigation activities, and administrative price corrections for the Reporting Period.

4.1.2.1 IMM Mitigation and Investigation Activities

Mitigation Activities. On April 17, 2012, the IMM implemented automated mitigation.[23] Table 4-5 shows the mitigations imposed by the IMM for 2012.

[22] http://www.ncdc.noaa.gov/sotc/service/national/Statewidetrank/201210-201212.gif

[23] See *Market Rule 1 Revisions Relating to Real-Time Automated Mitigation of Supply Offers*, ER11-4540-000, filed September 15, 2011, *available at* http://www.iso-ne.com/regulatory/ferc/filings/2011/sep/er11_4540_000_9-15-11_rev_auto_mitigation.pdf.

Table 4-5
2012 Mitigations

Month	Reliability Commitment Mitigation	General (Unconstrained) Commitment Mitigation	Constrained Area Commitment Mitigation	General (Unconstrained) Energy Mitigation	Constrained Area Energy Mitigation	Dual Fuel Corrections
Jan 12	15	0	0	0	0	0
Feb 12	1	0	0	0	0	0
Mar 12	3	0	0	0	1	0
Apr 12	8	17	0	0	2	0
May 12	23	13	20	8	8	0
Jun 12	2	5	0	5	9	1
Jul 12	2	3	0	37	5	7
Aug 12	2	6	5	7	1	3
Sep 12	19	3	2	0	12	0
Oct 12	5	9	0	0	4	1
Nov 12	7	1	0	4	18	0
Dec 12	1	7	0	9	1	0
Total	**88**	**68**	**27**	**63**	**61**	**12**

The types of mitigation are:

- **Reliability Commitment Mitigation** occurs when a market participant submits a supply offer for a resource committed for reliability and the resource's supply offer exceeds the reliability commitment offer thresholds. When the conditions are met, mitigation is applied *ex ante* at the time the decision to commit the resource is made.
- **General (Unconstrained) Commitment Mitigation** occurs when a market participant, determined to be a pivotal supplier, submits a supply offer and the resource's start-up or no-load offers parameters exceed specified conduct offer thresholds. When the conditions are met, mitigation is applied *ex ant*e at the time the decision to commit the resource is made.
- **Constrained Area Commitment Mitigation** occurs when a market participant submits a supply offer for a resource located and committed in a constrained area in the Real-Time energy market and the resource's start-up or no-load offers parameters exceed specified conduct offer thresholds. When the conditions are met, mitigation is applied *ex ant*e at the time the decision to commit the resource is made.
- **General (Unconstrained) Energy Mitigation** occurs when a market participant, determined to be a pivotal supplier, submits a supply offer that exceeds specified offer and market impact thresholds. When the conditions are met, mitigation is automatically applied *ex ante* in the energy market.
- **Constrained Energy Mitigation** occurs when a market participant submits a supply offer for a resource located within a constrained area and the resource's supply offer exceeds specified offer and market impact thresholds. When the conditions are met, mitigation is automatically applied *ex ant*e in the energy market.
- **Dual Fuel Corrections** are *ex post* corrections to dual fuel override requests.

FTR Capping. No participants had their FTR revenues reduced pursuant to the FTR revenue-capping provisions of *Market Rule 1*.[24]

Investigations and Referrals to FERC. Prior to the Reporting Period the IMM had nine open referrals before FERC. In the Reporting Period, the IMM made one additional nonpublic referral, and FERC closed two with action, bringing the quarter-end total of open referrals made by the IMM before FERC to eight.

4.1.2.2 Administrative Price Corrections

Table 4-6 shows the ISO's administrative price corrections for the Reporting Period.

Table 4-6
Administrative Price Corrections, Q4 2012

Location/Load Zone	Number of Occurrences
Data error	2
Hardware/software outage, scheduled	0
Hardware/software outage, unscheduled	0
Software limitation	4
Software error	0
Dead-bus logic	14

[24] See *Market Rule 1*, Section III.A.8.4, Appendix A, "Cap on FTR Revenues."

4.2 Forward Markets

4.2.1 Virtual Transactions

Figure 4-4 below shows submitted and cleared virtual supply offer volumes.

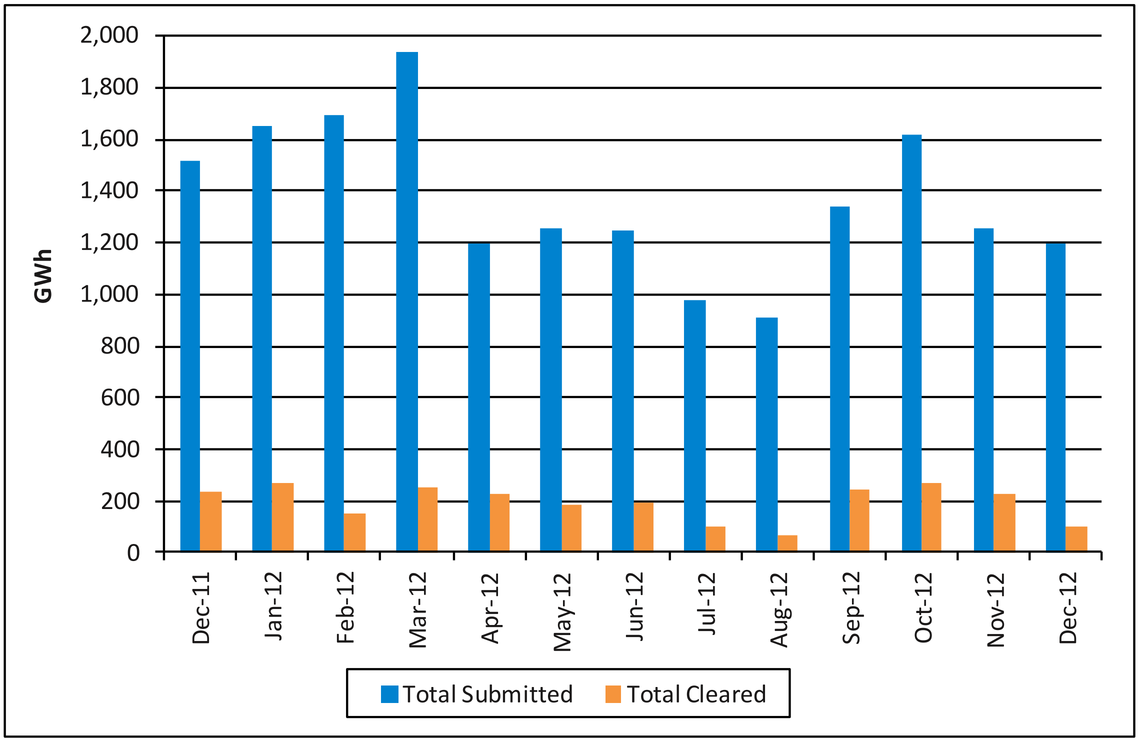

Figure 4-4: Submitted and Cleared Virtual Supply Offer Volumes, December 2011 – December 2012.

Figure 4-5 below presents submitted and cleared virtual demand bids.

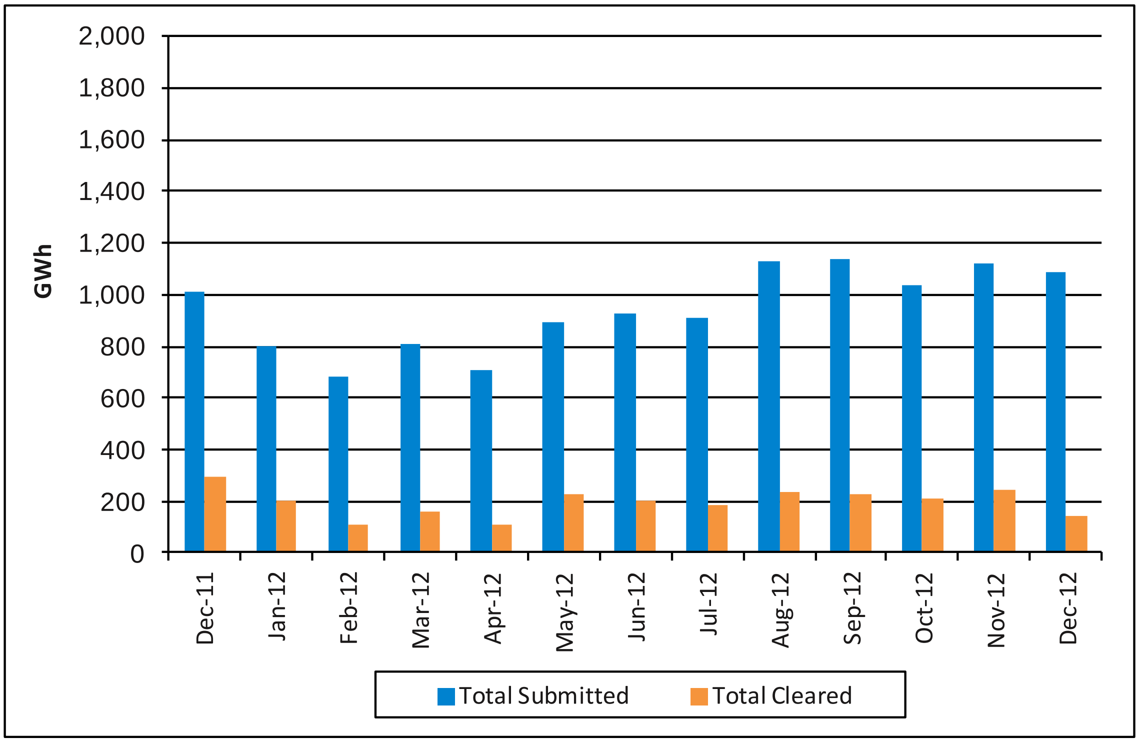

Figure 4-5: Submitted and Cleared Virtual Demand Bids, December 2011 – December 2012.

Table 4-7 shows quarterly trends in virtual trading at the Hub, load zones, internal network nodes, and the external interface nodes (the "node categories") for 2010 through 2012 by quarter.[25]

[25] The Hub, load zones and internal network nodes are points on the New England Transmission System at which LMPs are calculated. Internal nodes are individual pricing points on the system. Load zones are aggregations of internal nodes within specific geographic areas. An external interface node is a proxy location used for establishing a LMP for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area. The Hub is a collection of internal nodes that represents an uncongested price.

Table 4-7
Total Cleared Virtual Transactions by Node Category, (GWh)

	Q4 2012	Q3 2012	% Change (Q3 2012 to Q4 2012)	Q4 2011	% Change (Q4 2011 to Q4 2012)	Q4 2010	% Change (Q4 2010 to Q4 2012)
Hub	494	301	64%	478	3%	625	-21%
Load Zone	495	481	3%	525	-6%	421	18%
Network Node - External	28	36	-23%	42	-34%	537	-95%
Network Node - Internal	177	235	-25%	481	-63%	557	-68%
Total	1,193	1,053	13%	1,526	-22%	2,140	-44%

Two types of participants engage in virtual trading:[26]

- "Hedgers"-those who have physical load or generation within New England and participate in virtual trading to hedge the risks associated with the unanticipated changes in real-time energy markets. Typically, these participants hedge a portion of their physical position through virtual trades.
- "Arbitragers"-those who assume virtual positions to arbitrage price differences in the Day-Ahead and Real-Time Energy Markets.

Table 4-8 shows virtual trading composition by participant type.

Table 4-8
Virtual Trading Participant Composition

Participant Type	Q4 2012	Q3 2012	Q4 2011	Q4 2010
Hedgers	8	11	11	14
Arbitragers	26	27	27	41
Total Participants	34	38	38	55

Table 4-9 shows cleared virtual volumes by participant type.

[26] For this analysis, if a participant's average cleared virtual position (virtual demand bids + virtual supply offers) is less than 20% of the sum of load and generation (measured as maximum of summer claimed capability and winter claimed capability), the participant is defined as a "hedger." If a participant's cleared virtual position exceeds 20% of the sum of load and generation, the participant is defined as an "arbitrager." A participant with no physical load or generation is defined as an "arbitrager."

Table 4-9
Total Cleared Virtual Volumes by Participant Type, (GWh)

	Q4 2012	Q3 2012	% Change (Q3-Q4 2012)	Q4 2011	% Change (Q4 2011-2012)	Q2 2010	% Change (Q4 2010-2012)
Hedgers	106	269	-61%	707	-85%	250	-58%
Arbitragers	1,087	784	39%	818	33%	1,890	-42%
Total Participants	1,193	1,053	13%	1,526	-22%	2,140	-44%