2014 First Quarter

Quarterly Markets Report

Internal Market Monitor
May 9, 2014

Contents

Section 1 Executive Summary **4**

1.1 Summary of Market Outcomes and Performance *4*

Section 2 Summary of Market Outcomes and System Conditions **6**

2.1 Market Outcomes *6*

2.2 System Conditions *10*

2.3 Market Performance *12*

Tables

Table 2-1 Wholesale Market Cost Summary 6

Table 2-2 Key Statistics on Load, LMPs, and Input Fuels 7

Table 2-3 Real-Time Reserve Payments ($ and %) 8

Table 2-4 Total Submitted and Cleared Virtual Transactions, (GWh) 9

Table 2-5 Total NCPC Payments by Quarter and Category ($) 11

Table 2-6 Monthly Minimum, Maximum, and Quarterly Percentiles of Daily Supplemental Commitments for the Peak Hour, January 2014 to March 2014 (MW) 12

Section 1
Executive Summary

The Internal Market Monitor[1] has analyzed the performance in the first quarter ("Q1") of 2014 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, market prices reflected the cost of providing energy, and energy market outcomes have been competitive.[2]

1.1 Summary of Market Outcomes and Performance

- The total cost of electric energy in the Reporting Period was $5.3 billion, a 75% increase over the same period in 2013.
    - Average gas prices were the primary driver in the increase in total energy costs in the Reporting Period. Natural gas prices during the Reporting Period averaged $19.95/MMBtu. This is a 72% increase from Q1 2013.
    - Higher ancillary service costs resulted from the implementation of rule changes that increased the amount of reserves purchased in the Forward Reserve Market, the implementation of replacement reserves which effectively increased the real-time system 30-minute requirements, and rule changes that included opportunity costs in the calculation of the Regulation Clearing Price.
- Day-Ahead Energy Market prices during the Reporting Period averaged $144.99/MWh at the Hub, and Real-Time prices averaged $143.66/MWh. Day-Ahead prices were 68% higher than Q1 2013, and Real-Time prices were 77% higher than Q1 2013.
    - Higher natural gas prices in the first quarter were the primary driver for higher Day-Ahead and Real-Time prices when compared to Q1 2013.
- Total real-time reserve payments were $14.7 million in the Reporting Period, a 158% increase from Q1 2013, and Regulation payments totaled $15.8 million, an 144% increase from the fourth quarter ("Q4") 2013.

---

[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. Underlying natural gas data furnished by:

ice Global markets in clear view

- Total Net Commitment Period Compensation ("NCPC") reliability payments during the Reporting Period totaled $107.1 million, a 43% increase from Q1 2013.
    - Additional capacity was committed in January to supply energy during extremely cold days when gas prices were high. Approximately 45% of NCPC payments in the reporting period were paid on five days in late January.
- The Internal Market Monitor 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.

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 January 1, 2014 through March 31, 2014 (the "Reporting Period").

2.1 Market Outcomes

2.1.1 Total Wholesale Electricity Costs

Table 2-1 shows wholesale electricity costs (in dollars and dollars/megawatt-hour; $/MWh) by type and market in the Reporting Period compared with Q1 of 2013. Total costs increased by about 75% between Q1 2013 and the Reporting Period, and energy costs increased by about 83%.[3] Average gas prices, which increased by 72% compared to Q1 2013 contributed to the increase in total energy costs in the Reporting Period. Ancillary service costs, including NCPC payments, reserve payments, and regulation payments, increased by 90% when compared to Q1 2013. There were higher ancillary service payments in the Reporting Period due to the implementation of rule changes governing the requirements in the Forward Reserve Market in the third quarter ("Q3") of 2013 and a change in the calculation of opportunity costs in the Regulation Market relative to the Regulation Clearing Price (see Section 2.1.3.3).

Table 2-1
Wholesale Market Cost Summary

	Total Costs ($ Billions)			Average Costs ($/MWh)		
Type	Q1 2014	Q1 2013	% Change	Q1 2014	Q1 2013	% Change
Energy	4.88	2.66	83%	145.82	82.80	76%
Capacity	0.26	0.27	-6%	7.63	8.47	-10%
Ancillary Services	0.16	0.09	90%	4.91	2.70	82%
Total	5.30	3.02	75%	158.36	93.96	69%

2.1.2 Key Market Statistics

Table 2-2 shows selected key statistics for loads, Real-Time and Day-Ahead Energy Market prices, and fuel prices.

[3] The annual total cost of electric energy is approximated as the product of the annual real-time load obligation for the region and the average annual real-time locational marginal price ("LMP"). The real-time load obligation is the requirement that each market participant has for providing electric energy at each location (i.e., node, load zone or the Hub) equal to the amount of load it is serving, including external and internal bilateral transactions.

Table 2-2
Key Statistics on Load, LMPs, and Input Fuels

	Q1 2014	Q4 2013	Percent Change Q4 2013 to Q1 2014	Q1 2013	Percent Change Q1 2013 to Q1 2014
Real-Time Load (GWh)	33,474	31,651	6%	32,320	4%
Weather Normalized Real-Time Load (GWh)	32,787	31,236	5%	32,474	1%
Peak Real-Time Load (MW)	21,294	21,448	-1%	20,887	2%
Average Day-Ahead Hub LMP ($/MWh)	$144.99	$57.50	152%	$86.16	68%
Average Real-Time Hub LMP ($/MWh)	$143.66	$60.24	138%	$81.28	77%
Average Natural Gas Price ($/MMBtu)	$19.95	$7.74	158%	$11.57	72%

The following factors contributed to the market outcomes:

- Higher natural gas prices in the first quarter were the primary driver for higher day-ahead and real-time prices when compared to Q1 2013 and Q1 2013.
    - Natural gas prices during the Reporting Period increased by 72% from Q1 2013.
    - Real-Time and Day-Ahead LMPs were 77% and 68% higher than the Q1 2013 respectively.
- Net Energy for Load ("NEL") was approximately 4% higher than the Q1 2013.
- The Peak load, which occurred on January 7, 2014 during the Reporting Period, was 21,294 MW, 2% higher than the peak load observed in Q1 2013.

2.1.3 Real-Time Markets

2.1.3.1 Real-Time Energy Market

In the Reporting Period, the average real-time Hub price was $143.66/MWh, up 77% from $81.28.75 MWh in Q1 2013.[4] Price differences among the load zones stemmed primarily from marginal losses, with little congestion at the zonal level.[5] Congestion was restricted primarily to smaller, more transient load pockets that formed when transmission or generation elements were out of service. The Maine zone had lower average pricing ($130.74/MWh) than other load zones, as it is an export-constrained area with lower cost generating resources than other load zones.

In the Reporting Period, units burning natural gas were marginal for 45% of the pricing intervals, followed by coal units, which were marginal in 20% of the pricing intervals and oil units, which were marginal in 14% of the pricing intervals. Pump storage units (including pumping demand) were marginal 10% of the time. Units burning diesel, jet fuel, or wood along with traditional hydro units were marginal in the remaining pricing intervals.

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

[5] 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.

2.1.3.2 Real-Time Operating Reserves

In the Reporting Period, the total real-time reserve payments were $14.7 million; a 158% increase relative to Q1 2013's $5.7 million of payments.[6] A higher frequency of reserve pricing combined with higher average prices for all reserve products, compared with Q1 2013, increased total payments. The higher pricing frequency follows the ISO's addition of "replacement reserves" to the system thirty-minute reserve requirement. The replacement reserves effectively increase the system thirty-minute reserve requirement by approximately 20-25%.[7]

Real-time reserve payments decreased from Q4 2013. This resulted from fewer positive reserve pricing intervals, and lower average reserve prices in Q1 2014 compared to Q4 2013. This change can be observed in the difference between Q4 2013 and the Reporting Period: real-time payments for Ten-Minute Spinning Reserve ("TMSR") decreased by 18%, Ten-Minute Non-spinning Reserve ("TMNSR") decreased by 32%, and System-wide Thirty-Minute Operating Reserve ("TMOR") decreased by 7%. See Table 2-3.

Table 2-3
Real-Time Reserve Payments ($ and %)

Product	Q1 2014	Q4 2013	Percent Change Q4 2013 to Q1 2014	Q1 2013	Percent Change Q1 2013 to Q1 2014
Systemwide TMSR	4,377,902	5,334,958	-18%	1,995,906	119%
Systemwide TMNSR	7,507,427	10,983,945	-32%	2,674,528	181%
Systemwide TMOR	940,689	1,013,095	-7%	210,823	346%
SWCT TMOR	1,367,631	1,840,881	-26%	679,501	101%
CT TMOR	257,712	224,259	15%	83,499	209%
NEMA/Boston TMOR	220,386	309,993	-29%	38,930	466%
Total	14,671,747	19,707,131	-26%	5,683,187	158%

2.1.3.3 Regulation Market

Total Regulation Market payments during the Reporting Period were $15.8 million, up 144% from $6.5 million in Q4 2013, and 156% from $6.2 million in Q1 2013. The increase in regulation payments is attributable to the following:

- Real-time energy prices were higher in the Reporting Period when compared to Q4 2013. When real-time energy prices are high, the regulation service cost and the regulation opportunity cost also increase.
- The Regulation requirement in the Reporting Period was higher than Q4 2013, which increased total Regulation Capacity, Regulation Service, and the Regulation Clearing Price.
- A market rule change implemented on July 1, 2013 changed the methodology used to calculate opportunity costs in the Regulation market relative to the Regulation Clearing

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

[7] The replacement reserve requirement is 160 MW during Daylight-Savings Time periods and 180 MW during Eastern Standard Time periods, and became effective in October 2013.

Price.[8] The IMM has observed that the new new market rule has increased the Regulation Clearing Price, consistent with its design.

2.1.4 Forward Markets

2.1.4.1 Day-Ahead Energy Market

The average day-ahead Hub price in the Reporting Period was $144.99/MWh. As in real-time, this price is consistent with observed market conditions. 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.

Generators set price approximately 46% of the time in the Reporting Period in the day-ahead market. Virtual transactions set price approximately 31% of the time. In comparison, generators set price 54% of the time in the day-ahead market and virtual transactions set price 20% of the time in the Q1 2013.

In the Reporting Period, submitted virtual demand bids and virtual supply offers totaled approximately 4,452, a decline of 24% when compared with the Q1 2013. Submitted virtual transactions similarly decreased by 8% when compared to the Q4 2013. However, cleared virtual transactions increased when compared with the Q1 2013. Cleared virtual transactions totaled approximately 954 GWh in the Reporting Period, an increase of 41% compared with the Q1 2013, but an 18% decrease when compared with the Q4 2013. See Table 2-4.

Table 2-4
Total Submitted and Cleared Virtual Transactions, (GWh)

	Q1 2014	Q4 2013	Percent Change Q4 2013 to Q1 2014	Q1 2013	Percent Change Q1 2013 to Q1 2014
Total Submitted Virtual Transactions	4,452	4,860	-8%	5,889	-24%
Total Cleared Virtual Transactions	954	1,158	-18%	675	41%

2.1.4.2 Financial Transmission Rights

Three Financial Transmission Rights ("FTR") auctions were conducted during the Reporting Period for a combined total of 160,653 MW of FTR transactions. The total amount distributed as Auction Revenue Rights ("ARRs") was $5.4 million. Thirty-six bidders in January, thirty-one bidders in February and thirty-two bidders in March participated in the monthly auctions for the quarter. The level of participation was consistent with prior auctions.

2.1.4.3 Forward Capacity Market

Several monthly and annual reconfiguration auctions and bilateral contract periods were conducted during the Reporting Period.

[8] See *Regulation Market Opportunity Cost Change*, ER13-1259-000 (April 11, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/apr/er13-1259-000_4-11-2013_reg_mkt_opp_cost_chg.pdf.

Monthly reconfiguration auctions and bilateral trades for the months of March, April, and May 2014 ended during the reporting period. The reconfiguration auctions obtained pricing of $0.59, $0.25, and $1.00 per kW-month during each month, with cleared capacity in the 565 to 954 MW range. Bilateral trading exchanged MWs in the 199 to 347 MW range, with average prices for the periods ranging from $1.06/kW-month to $1.18/kW-month. The third annual reconfiguration acution and bilateral period for the 2014-2015 commitment period concluded during the Reporting Period, resulting in cleared capacity of 628 MW and 278 MW. The average prices were $1.93/kW-month and $1.74/kW-month.

The eight Forward Capacity Auction ("FCA 8") was conducted during the Reporting Period on February 3, 2014. As detailed in the ISO's FCA 8 results filing, the auction commenced with a starting price of $15.82/kW-month and concluded with a price of $14.99/kW-month when a resource submitted a bid to withdraw from the auction if the price fell lower. The auction clearing function reset the Capacity Clearing Price to $15.00/kW-month. New resources that received Capacity Supply Obligations in the Maine, Connecticut and Rest-of-Pool Capacity Zones will be paid the Capacity Clearing Price of $15.00/kW-month. Existing resources that cleared in those zones will be paid the administrative price of $7.025/kW-month. In the NEMA/Boston Capacity Zone, both new and existing resources will be paid $15.00/kW-month.[9]

2.1.4.4 Demand Resources

Demand resource payments totaled $24.7 million in the Reporting Period, which was 2.6% higher than the previous quarter's payments of $24.0 million. Payments were 14.7% higher than the same quarter last year. The Reporting Period includes payments made for the transitional Price Responsive Demand ("PRD") program, which began on June 1, 2012.

2.2 System Conditions

2.2.1 Net Commitment Period Compensation

Total Net Commitment Period Compensation ("NCPC") payments during the Reporting Period totaled $107.1 million. NCPC payments by type are shown in Table 2-5. There were no Generator Performance Audit ("GPA") NCPC payments made during the Reporting Period. The majority of the NCPC incurred during the Reporting Period was economic (also called "first contingency") NCPC. Economic NCPC 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. In the Reporting Period, additional capacity was committed in late January to supply energy during extremely cold weather days when gas prices were very high. Approximately 45% of NCPC payments in the reporting period were paid on five days in late January.

[9] See *FCA 8 Results Filing*, ER14-1409-000 (February 28, 2014), http://www.iso-ne.com/regulatory/ferc/filings/2014/feb/er14_1409-000_fca8_results_filing_2-28-2014.pdf

Table 2-5
Total NCPC Payments by Quarter and Category ($)

NCPC Category	Q1 2014	Q4 2013	Q1 2013
Economic (i.e., First Contingency) Payments	$100,105,412	$23,559,307	$49,421,679
Second Contingency Payments	$5,910,186	$2,843,280	$21,796,697
Voltage Payments	$980,917	$2,896,365	$3,156,351
Distribution Payments	$93,549	$123,898	$450,073
Total	$107,090,064	$29,422,851	$74,824,800

2.2.2 Supplemental Commitments for Capacity and Reserves

Each day after the clearing of the Day-Ahead Energy Market, the ISO performs a Reserve Adequacy Analysis and, if necessary, commits additional generators to meet capacity and reserve requirements. The ISO commits generators in the RAA whenever insufficient capacity clears in the Day-Ahead Energy Market to meet the ISO load forecast plus operating reserve requirement. The amount of capacity on line affects LMPs and NCPC costs. When too much capacity is on line and units are operating at their economic minimum levels, LMPs are likely to be lower and NCPC costs higher than what they otherwise would be. Too little capacity on line may compromise reliable operation and lead to artificially high prices.

The IMM reviews supplemental commitments each day to assess the extent to which supplemental commitments result in surplus supply. Surplus on-line capacity can arise from generation that clears in the Day-Ahead Energy Market (e.g., if the load clearing in the Day-Ahead Energy Market exceeds the real-time load), self-schedules, or the supplemental commitment performed as a result of the RAA. Thus, the market and supplemental commitments made by the ISO for reliability both contribute to the surplus.

Table 2-6 shows the minimum, maximum, and percentiles of the daily supplemental commitments for 2014 by month. The day with the highest level of supplemental commitments (3,118 MW) during the reporting period occurred on January 23, 2014. Two consecutive days of very cold weather in the region in January resulted in supplemental commitments made for system operating reserves.

Table 2-6
Monthly Minimum, Maximum, and Quarterly Percentiles of Daily Supplemental Commitments for the Peak Hour, January 2014 to March 2014 (MW)

Month-Year	Daily Supplemental Commitment MW[10]				
	Minimum	25th Percentile	50th Percentile	75th Percentile	Maximum
Jan-2014	0	0	0	448	3,118
Feb-2014	0	0	0	0	0
Mar-2014	0	0	0	0	177

2.2.3 Net Interchange

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 6,479 GWh for the Reporting Period, a 22% increase compared with the previous quarter.

2.3 Market Performance

The Internal Market Monitor calculated the following performance metrics to assess the competitiveness of the wholesale electricity market. Based on the results of the HHI and RSI metrics, the Internal Market Monitor has concluded that the energy market was competitive during 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.[11] 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.[12] The IMM calculated the HHI for the reporting period and results indicate that

[10] For this analysis, *supplemental commitments* are defined as the capacity of non-fast-start generators the ISO committed outside the day-ahead market for the peak hour, dispatched at their economic minimum.

[11] 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.

[12] 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.

the wholesale electric energy markets in New England are well within the "not concentrated" range.[13]

- 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.[14] 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 did not exist during any of the hours in the Reporting Period.

[13] 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.

[14] 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.