ISO New England's Internal Market Monitor

2014 Annual Markets Report

Internal Market Monitor
May 20, 2015

Preface

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO.[1] The *2014 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2014. 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*, Section III.A.17.2.4, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*:

> *The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, Net Commitment-Period Compensation costs and the performance of the Forward Capacity Market and Financial Transmission Rights Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.*[2]

This report is being submitted simultaneously to the ISO and the US Federal Energy Regulatory Commission (FERC) per FERC order:

> *The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of a Regional Transmission Organization's market monitor at the same time they are submitted to the RTO.*[3]

The External Market Monitor (EMM) also publishes an annual assessment of the ISO New England wholesale electricity markets. The EMM is external to the ISO and reports directly to ISO New England's board of directors. Like the IMM's report, the External Market Monitor's report assesses the design and operation of the markets and the competitive conduct of the market participants.

This report presents the most important findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2014. Section 1 summarizes the

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[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] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III.A.17.2.4, *Market Rule 1*, Appendix A, "Market Monitoring, Reporting, and Market Power Mitigation" (December 3, 2014), http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

[3] FERC, PJM Interconnection, L.L.C. et al., *Order Provisionally Granting RTO Status*, Docket No. RT01-2-000, 96 FERC ¶ 61, 061 (July 12, 2001).

region's wholesale electricity market outcomes for 2014, the important market issues and our recommendations for addressing these issues, the overall competitiveness of the markets, and market mitigation and market reform activities. Section 2 and Section 3 include more detailed discussions of each of the markets, market results, analysis and recommendations. Section 4 provides information on audits conducted to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders. A list of acronyms and abbreviations also is included. Key terms are italicized and defined within the text and footnotes.

All information and data presented are the most recent as of the time of publication. Some data presented in this report are subject to resettlement. Underlying natural gas data is furnished by the Intercontinental Exchange (ICE):

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Section 1
Executive Summary

The *2014 Annual Markets Report* addresses the development, operation, and performance of the wholesale electricity markets administered by ISO New England (ISO) and presents an assessment of each market based on market data and performance criteria. In addition to buying and selling wholesale electric energy in the day ahead and in real time, the participants in the ISO-administered forward and real-time markets buy and sell operating reserve products, regulation service, Financial Transmission Rights (FTRs), and capacity. These markets ensure the competitive and efficient supply of electricity to meet the energy needs of the New England region and secure adequate resources required for the reliable operation of the power system.

This section summarizes the region's wholesale electricity market outcomes for 2014, the important market issues and recommendations for addressing these issues, the overall competitiveness of the markets, and market mitigation and market reform activities. Section 2 and Section 3 contain a more detailed discussion of the performance of the real-time and forward markets, respectively. A list of abbreviations and acronyms is included at the end of the report. Key terms are italicized and defined within the text and footnotes.

1.1 Summary of Market Outcomes

Over the long run, competitive and efficient wholesale electricity and capacity markets provide the incentives to maintain an adequate supply of electric energy at prices consistent with the cost of providing it. The core responsibilities of the ISO New England Internal Market Monitor include reviewing the competitiveness of the wholesale electricity markets, reporting on the performance of the markets, and recommending improvements to the market design. In this report market outcomes and associated information for 2014 are reviewed, and we conclude that the wholesale electric markets operated competitively in 2014. Energy prices remain at levels consistent with short-run marginal production costs. Market concentration, based on the number of companies selling electricity in the market and their respective shares of the total production, remained at a competitive level. The weather in 2014 was milder compared with 2013; however, the region experienced significant increases in fuel prices in the first quarter of 2014, which was the primary driver of an increase in energy prices from 2013 to 2014. See Table 1-1.

Table 1-1
Key Statistics on Load, Locational Marginal Prices (LMPs), and Input Fuels

Statistic[(a)]	2013	2014	% Change 2013 to 2014
Real-time Load (GWh)	129,377	127,138	-2%
Weather-normalized real-time load (GWh)	127,754	127,114	-1%
Peak real-time load (MW)	27,379	24,443	-11%
Average day-ahead Hub LMP ($/MWh)	56.42	64.56	14%
Average real-time Hub LMP ($/MWh)	56.06	63.32	13%
Average natural gas price ($/MMBtu)	6.97	7.99	15%

(a) GWh and MWh stand for *gigawatt-hours* and *megawatt-hours*, respectively; MW stands for *megawatts*; and MMBtu stands for *million British thermal units*. The *Hub* is a collection of energy pricing locations that has a price intended to represent an uncongested price for electric energy, facilitate energy trading, and enhance transparency and liquidity in the marketplace. *Weather-normalized* results are those that would have been observed if the weather were the same as the long-term average.

Table 1-2 shows estimated wholesale electricity costs (in dollars and dollars per megawatt-hour; $/MWh) broken down by market product (i.e., energy, capacity, etc.) in 2014 compared with 2013. Total costs of wholesale electricity increased by about 12%.[4] Some of the factors contributing to the 12% increase are as follows:

- Prices for natural gas, the predominant fuel used to produce electricity in New England, increased in 2014, causing overall energy prices to increase compared with the prior year. Section 1.1.1 and Section 2.1.3.3 contain more information on the relationship between natural gas and electricity prices and the challenges resulting from New England's dependency on natural gas.

- The costs of procuring systemwide operating reserves through the Forward Reserve Market (FRM) increased in 2014 due, in part, to increased operating reserve requirements. More information on the FRM, the types of operating reserve products, and FRM requirements is included in Section 3.3.

- Additional "make-whole" payments to suppliers for costs that could not be recovered through energy market payments, also known as Net Commitment-Period Compensation (NCPC), increased in 2014. The increase resulted from the operation of expensive generation during extreme cold weather in the first quarter of 2014 (see Section 2.1.4).

[4] 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 LMP. The real-time load obligation is the requirement that each market participant has for providing electric energy at each location (i.e., pricing node, load zone, or the Hub) equal to the amount of load it is serving, including external and internal bilateral transactions. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of annual wholesale costs.

- Payments to suppliers providing regulation services increased in 2014 compared with 2013. The increase was the result of increased natural gas prices, as well as changes in regulation services rules implemented in July 2013 (see Section 2.3).

Table 1-2
Wholesale Market Cost Summary

Type	Annual Costs ($ Billions)			Average Costs ($/MWh)[5]		
	2013	2014	% Change	2013	2014	% Change
Energy	7.49	8.42	12%	58.14	66.25	14%
Capacity	1.06	1.06	1%	8.20	8.36	2%
Ancillary Services[6]	0.27	0.41	50%	2.12	3.23	52%
Total	**8.82**	**9.90**	**12%**	**68.47**	**77.84**	**14%**

1.1.1 Natural Gas Dependency and Energy Market Enhancements

New England's wholesale electricity market is highly dependent on the availability of natural gas and fuel oil. A number of market forces influence the relationship of the New England electricity market and the natural gas market, including the following:

- An influx of natural gas-fired generating capacity over the past 15 years[7]
- An aging and declining fleet of oil- and coal-fired generators, many of which were constructed during the 1960s and 1970s, and the retirement of the Vermont Yankee nuclear station. These generators are increasingly being displaced by more efficient gas-fired generators
- Lower natural gas prices resulting from increased production of domestic shale gas from the Marcellus Shale region of the country
- Relatively static gas pipeline capacity in New England that has had to accommodate a 37% increase in overall natural gas consumption in New England from 1999 through 2013; three-fourths of this 37% increase was for gas generation.[8]

[5] The annual cost is divided by the real-time load obligation to obtain the average total price.

[6] Ancillary services include operating reserves, regulation, and NCPC payments.

[7] During the 1990s, the region's electricity was produced primarily by oil, coal, and nuclear generating plants, with very little gas-fired generation. In 1990, oil and nuclear generating plants each produced approximately 35% of the electricity consumed in New England, whereas gas-fired plants accounted for approximately 5%. Coal plants produced about 18% of New England's electricity. In contrast, by 2011, oil-fired plants produced 0.6% of electricity consumed in New England, and approximately 51% was produced by gas-fired generation. Coal production also fell by about two-thirds. ISO New England, *Addressing Gas Dependence* (July 2012), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/natural_gas_white_paper_draft_july_2012.pdf.

[8] Approximately 12,000 of 14,000 MW of new capacity have come from gas-fired, combined-cycle generators. *ISO New England 2013 Regional Electricity Outlook*, p. 15 (2014), http://www.iso-ne.com/aboutiso/fin/annl_reports/2000/2014_reo.pdf. Total consumption in New England increased by 37%; total deliveries to electric power consumers increased by 99%; and total consumption by residential, commercial, industrial, and vehicle fuel end uses increased by 1,394%. Note that these data have not been weather normalized.

One of the most pressing challenges identified in the ISO's Strategic Planning Initiative has been the region's reliance on generators fueled by natural gas.[9] In the *2013 Annual Markets Report* 29 instances were identified when generators fueled by natural gas were not available to produce electricity because natural gas was not available due to a constraint or limitation on the natural gas pipeline. In tandem, the ISO undertook a number of projects aimed at improving the reliability of generators fueled by oil and natural gas through improved market incentives and market design, and supplemental payments to improve fuel diversity.

For example, the 2013/2014 Winter Reliability Program provided financial incentives to oil-fired generators to maintain on-site inventories. The program also provided incentives to dual-fuel generators capable of burning oil or natural gas to test and maintain their dual-fuel capability. The 2014/2015 Winter Reliability Program, built on the prior winter program, also provided incentives for resources to enter into contracts for liquefied natural gas (LNG) and included additional market monitoring changes designed to provide greater flexibility to dual-fuel resources. By ensuring that oil- and dual-fuel-fired generators had sufficient on-site fuel inventory, and that participating gas generators contracted for liquefied natural gas, the winter reliability programs helped mitigate concerns about the reliance of generators fueled by natural gas on pipeline deliveries of fuel during periods of high natural gas demand and stress on the pipeline system.

The number of reductions in generation availability associated with the availability of natural gas declined in 2014 compared to 2013. This decrease is coincident with the Federal Energy Regulatory Commission's (FERC's) August 2013 order clarifying the obligations of resources to procure fuel, the changes in the Day-Ahead Energy Market supply-offer timeline that went into effect in mid-2013, and the implementation of Energy Market Offer Flexibility (EMOF) that went into effect in December 2014.[10]

The combination of market fundamentals such as the increased supply of LNG in New England in late 2014, lower oil prices, a mild summer, along with the implementation of a number of ISO initiatives had the expected outcome of increasing reliability during 2014 and lowering electric energy prices after the first quarter of 2014.

1.1.2 Dual-Fuel Generator Exemption from Certain Requirements to Provide Documentation

As part of the winter reliability program package,[11] FERC approved an IMM proposal that dual-fuel generators be exempt from the requirement to justify and verify the use of the higher-priced fuel when oil and natural gas index prices converge—specifically, when the ratio of the

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US Energy Information Administration (EIA), "Natural Gas Consumption by End Use," webpage (data for state-level and end-user natural gas consumption, 1999–2013) (March 30, 2015), http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCT_a.htm.

[9] More information about the ISO's Strategic Planning Initiative is available at http://www.iso-ne.com/committees/key-projects/strategic-planning-initiative.

[10] FERC, *Order on Complaint, New England Power Generators Association v. ISO New England*, Docket No. EL13- 66 - 000 (August 27, 2013),http://www.iso-ne.com/regulatory/ferc/orders/2013/aug/el13-66_8-7-13_order_nepga_complaint.pdf.

[11] ISO New England Inc. and New England Power Pool, *ISO New England Inc., Docket No. ER14-___-000 Winter 2014-15 Reliability Program (Part 1 of 2)* (July 11, 2014), http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14_2407_000_win_rel_pro_7_11_2014.pdf.

generator's higher-priced fuel index price to its lower-priced fuel index price is less than or equal to 1.75.[12]

FERC required that the appropriateness of the ratio be reviewed and that the analysis and recommendations be provided as part of the Annual Markets Report. The analysis described in Section 2.1.4.4 shows that, notwithstanding the reduction in natural gas price volatility during winter 2014/2015, the 1.75 ratio continues to be a reasonable and appropriate indicator of oil and natural gas price convergence and consequently should remain as the exemption threshold.

1.1.3 Forward Capacity Market

The ISO held the eighth Forward Capacity Auction (FCA #8) on February 3, 2014. Unlike the seven previous auctions, FCA #8 was the first auction conducted without a "floor price." With one limited exception, the seven previous auctions all cleared at the administratively set floor prices with excess capacity.[13]

Before FCA #8 was conducted, 3,135 MW of existing resources announced plans to retire. This resulted in an insufficient number of resources participating in the auction to ensure a competitive outcome. The insufficient competition triggered the FCM's administrative pricing rules designed to mitigate any market power, which could inappropriately raise prices, while still providing incentives to attract and retain resources. The Carry Forward rule also applied in NEMA/Boston Carry Forward due to excess procurement in the prior auction.

FCA #8 resulted in the acquisition of 33,712 MW of capacity supply obligations in 2017/2018, which was 143 MW short of the 33,855 MW procurement target. Under the administrative pricing rules, the capacity clearing price of $15.00/kilowatt (kW)-month will be paid in 2017/2018 to about 1,380 MW of new capacity resources outside the Northeast Massachusetts/Boston (NEMA/Boston) zone. About 24,885 MW of existing resources will be paid $7.025/kW-month. Self-supply resources, totaling 3,330 MW, will not receive any payment through the FCM.

Another 357 MW of existing resources with multiyear supply obligations will be paid at rates set in previous auctions, ranging from $2.52/kW-month to $3.43/kW-month. In NEMA/Boston, 3,085 MW of both new and existing resources will be paid $15.00/kW-month based on administrative pricing rules, while 674 MW of existing capacity that opted for a multiyear price commitment in a previous auction will be paid $14.99/kW-month.

While the auction closed with slightly less capacity than expected to be needed in 2017/2018, the FCM design provides a mechanism for such gaps to be closed through annual and monthly reconfiguration auctions held over the three years before the capacity commitment period.

In its review of FCA #8, FERC determined that the current FCM rules may create an opportunity for suppliers importing capacity from outside New England to exercise market power and may result in preferential or unduly discriminatory treatment favoring importers over other capacity resources. As a result, FERC required the ISO to revise the FCM rules to require the

[12] For example, if the day-ahead index price of natural gas is $5/MMBtu and the day-ahead index price of No. 2 oil is $20/MMBtu the ratio would be calculated as $20 divided by $5, or 4.0. On the other hand, if the day-ahead index price of natural gas is $30/MMBtu and the day-ahead index price of No. 2 oil is $20/MMBtu, the ratio would be calculated as $30 divided by $20 or 1.5.

[13] One zone in the FCA #7 cleared above the floor price.

IMM to review importer capacity offers before each FCA and to treat them in a manner similar to other existing capacity resources for mitigating the exercise of market power. These rules were implemented in time for their use in FCA #9.

1.1.4 Ancillary Service Markets

Real-time operating reserve payments declined from $54.0 million in 2013 to $38.6 million in 2014. Except for payments to some resources in NEMA/Boston (which only increased modestly), operating reserve payments decreased across all products and regions. Payments to resources providing regulation service totaled $28.8 million in 2014, a 41% increase from 2013. Changes to the methodology for calculating regulation service payments, required under FERC Order No. 755, and increased natural gas prices, contributed to the increased cost of regulation service.[14]

1.2 Market Design Changes

The following is a summary of the major revisions to the market design implemented in 2014 and planned for in future years:

1.2.1 Major Design Changes Implemented in 2014

Three major changes to the market design have been implemented in 2014.

1.2.1.1 Energy Market Offer Flexibility

The ISO implemented Energy Market Offer Flexibility changes on December 3, 2014.[15] The changes are designed to improve a market participant's ability to reflect expected fuel costs in its energy market supply offers, and to update its offers as expected fuel costs change during the operating day. Offers that more accurately reflect expected fuel costs improve energy market price signals.

The EMOF changes provide market participants with the following flexibility:

- The ability to change their supply offers during the operating day to reflect the costs of purchasing intraday fuel. This is a significant improvement for the owners of generators fueled by natural gas because it allows them to reflect expected natural gas price volatility in their supply offers
- The ability to submit certain supply offer parameters that vary by hour, rather than requiring the parameters to be the same for all hours of an operating day
- The ability to submit a negative supply offer as low as negative $150/MWh

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[14] ISO New England Inc. and New England Power Pool, *Regulation Market Opportunity Cost Change*, Docket No. ER13-1259-000, FERC filing (filed 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. FERC, letter order accepting the opportunity cost changes (June 27, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/jun/er13-1259-000_6-17-13_ltr_order_accept_reg_mrkt_rev.pdf.

[15] ISO New England Inc. and NEPOOL, *Energy Market Offer Flexibility Changes*, Docket No. ER13-1877-000, FERC filing, (July 1, 2013), http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jul/er13_1877_000_mkt_offer_flex_7_1_2013.pdf. FERC, *Order Conditionally Accepting Tariff Revisions*, Docket No. ER13-1877-000 (October 3, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/oct/er13-1877-000_10-3-13_order_condition_accept_flex_rev.pdf.

1.2.1.2 Increasing (Operating) Reserve Constraint Penalty Factors

In response to a FERC order, the ISO increased the Reserve Constraint Penalty Factors (RCPFs).[16] The RCPFs are administratively set limits on redispatch costs ($/MWh) that the system will incur to meet operating reserve constraints and that will become the reserve price when operating reserves are scarce. The RCPFs for 30-minute operating reserves increased from $500/MWh to $1,000/MWh, and 10-minute non-spinning reserves increased from $850/MWh to $1,500/MWh. This change was implemented on December 3, 2014.

1.2.1.3 Review and Mitigation of New Import Capacity Resources in the FCM

Under the previous market rule, most new import capacity resources were not subject to a cost review for market power. Consequently, a supplier with a new import capacity resource was free to remain in the auction at any price above zero and was thereby exempt from buyer-side market power mitigation.[17] Further, even though most new import capacity resources were sponsored by suppliers who are essentially renewing their import contracts year after year, these resources were not subject to the same type of seller-side market power mitigation as existing capacity resources. Therefore, a supplier with a new import capacity resource was free to exit the auction at any price. The supplier with a new import capacity resource could exercise either buyer-side or seller-side market power by taking uneconomic actions during the auction.

In an October 16, 2014 filing, rule revisions were filed to provide for the review and potential mitigation of importers' supply offers before each annual Forward Capacity Auction.[18] The rule revisions determine which import suppliers have market power (that is, which are "pivotal") and apply mitigation to those suppliers in a manner consistent with the mitigation applied to existing resources located within New England.

1.2.1.4 FCM Pay-for-Performance Market Design

The pay-for-performance (PFP) design is based on the two-settlement logic generally used in forward markets. It entails two key elements. The first element is a forward position in which a quantity of capacity is obligated, or sold, in the capacity auction. Each megawatt is paid at the auction clearing price, and the sale creates a resource-specific physical obligation and forward financial position in the capacity market. A resource's forward financial position is a share of the system's energy and reserve requirements during operating reserve deficiencies.

The second element includes a settlement for deviations. A resource that delivers more than its share of the system's requirements during an operating reserve deficiency (i.e., an over-performer) will be paid for that incremental production. If it delivers less than its share (i.e., it underperforms), it will "buy out" of its position by paying other resources that did deliver. Positive and negative deviations are paid or charged at the same rate specified in the tariff.

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[16] FERC, *Order on Compliance Filing* (October 2, 2014), http://www.iso-ne.com/static-assets/documents/2014/10/er14-2419-000_-001_10-2-14_pay_for_performance_compliance_order.pdf.

[17] In the context of this discussion, buyer-side market power is exercised through a participant offering supply at a price below cost to lower the auction price and benefit the participant's net buy position. Conversely, seller-side market power can be exercised by a participant offering supply at a price above cost to increase the auction price and benefit the participant's net sell position.

[18] *ISO New England, Inc., Docket EL14-99-000, Response to Order to Show Cause*, , FERC filing (October 16, 2014), http://www.iso-ne.com/static-assets/documents/2014/10/er15-117-000_show_cause_10-16-2014.pdf.

The two-settlement approach is standard in forward contracts, both for electricity and commodities, ranging from oil to agricultural goods to metals. In fact, the two-settlement design underlies the design of New England's day-ahead and real-time electricity markets (in which deviations are settled at the real-time price) and is well understood by stakeholders.

Under PFP, buyers will pay the auction-clearing price to all resources that clear in the Forward Capacity Auction. Because over-performers will be paid by the under-performers, buyers will not bear the short-run risk of covering any unexpectedly high performance payments. This will continue to provide buyers with a predictable capacity price three years after the close of each Forward Capacity Auction. Having under-performers pay over-performers will also provide strong incentives for each resource to perform as needed and for over-performers to benefit by helping meet the system's needs. These incentives will place performance risk on all FCM resources, and each resource will need to price this risk in its future capacity auction bids. The first element of the PFP two-settlement contract was implemented with the ninth FCA in February, 2015, and the second element of the two-settlement construct will become fully effective during the associated capacity commitment period beginning June 1, 2018.

1.2.1.5 FCM Sloped Demand Curve

In its May 30, 2014 Order, the FERC accepted the ISO's proposal to implement a system-wide sloped demand curve for the FCM.[19] The ISO implemented the sloped demand curve at the system level for the ninth FCA. Continuing issues regarding the potential for market power to be exercised within capacity zones have been identified, specifically within import-constrained capacity zones, and we are addressing these issues with the ISO and stakeholders in conjunction with the development of zonal demand curves.[20]

1.2.2 Major Design Changes Proposed for Future Years

The following major design changes to the market design have been proposed for future delivery years.

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[19] FERC, *ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Tariff Revisions*, Docket No. ER14-1639-000, 147 FERC ¶ 61,173 (2014) (the "May 30, 2014, Order"), http://www.iso-ne.com/static-assets/documents/regulatory/ferc/orders/2014/may/er14_1639_000_5_30_14_sloped_demand_curve_order.pdf.

[20] Four capacity zones were modeled in FCA #9. Three are import-constrained, and the fourth is the "Rest of Pool" zone that represents the balance of the system requirements beyond those reflected in the three import-constrained zones.

1.2.2.1 Uneconomic Retirements

The owners of existing generators can potentially exercise market power in an import-constrained zone through the uneconomic retirement of an existing resource.[21] When existing and new supply are not abundant in a capacity zone, an incumbent supplier can seek to retire an existing resource to reduce available supply. This action will have a price-increasing effect within that capacity zone, which will benefit the remainder of the supplier's portfolio in that capacity zone. In cases where capacity zones are sufficiently small, the retirement of even a single resource of moderate size can have a significant price impact even with sloped zonal demand curves.

Market rule changes are being recommended that will provide a process for reviewing options for capacity market participation or retirement, and market power mitigation measures in the capacity auction. The proposed process, with these components, eliminates the potential that a capacity auction will be executed with known market power resident through early resource retirement. It will also provide a means for resources to retire through the market, as opposed to administratively as is now the case, and potentially be replaced by new generation in that same capacity auction. The External Market Monitor has also recommended that the ISO adopt a measure that addresses the potential for retirement delist bids to be used to increase FCA prices above competitive levels.[22]

1.2.2.2 Accuracy of Static Delist Bids

The ability to modify or withdraw Static De-List Bids after the IMM's review of the bid is complete is contrary to the original intent to allow suppliers the opportunity to "fine tune" bids. The flexibility to modify or withdraw Static De-List Bids can be used more as an instrument to increase the range of acceptable bids. This permits the unintended consequence of static delist bids being submitted at prices notably higher than those representative of the resource's costs and reasonable levels of expected performance. The ability to convert a delist bid into a nonprice retirement request may also cause abrupt shifts in the supply curve at a time in the FCM annual process when no competitive market response can occur.

On May 1, 2015, market rule changes that address the potential exercise of market power in the Forward Capacity Market were filed at FERC. The first two parts of the market rule changes address with the treatment of de-list bids. First, we proposed to increase the Dynamic De-List Bid Threshold from $3.94 to $5.50/kW-month. This change was intended to avoid the review of de-list bid information at prices below the competitive offer price of higher cost existing resources that are expected to set the price if no new entry is needed. Second, it was proposed to limit the amount of flexibility that currently is afforded to capacity suppliers to modify Static De-List Bids after those bids have been submitted and reviewed by the IMM and also to eliminate the option to replace a Static De-List Bid with a Non-Price Retirement Request in certain instances.

These changes are intended to encourage the submission of Static De-List Bids that are closer to actual cost and remove any incentive for capacity suppliers to use the Static De-List Bid process

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[21] Uneconomic retirement is the premature withdrawal of a generation resource's capacity from the capacity market if expectations over its remaining life indicate that continued operation of the resource would be economically viable.

[22] Potomac Economics, *2013 Assessment of the ISO New England Electricity Markets*, June 25, 2014, http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf.

to explore whether the IMM will allow bid prices that substantially exceed costs. Together, these two changes are motivated by the desire to maintain the continued integrity of the market power mitigation structure in the capacity market and to focus more closely on those bids that actually raise significant market power concerns.

1.2.2.3 Improved Competitiveness Test for Existing Resources in the FCM

The May 1, 2015 filing also included changes to improve the accuracy of the competitiveness test, or pivotal supplier test that is administered prior to the auction to determine if a capacity supplier has the potential to exercise market power. The proposed market rule establishes a single pivotal supplier test that applies to both capacity imports and existing resources. The improvements include a consistent treatment of interface constraints for purposes of determining whether a supplier is pivotal, moving the performance of the test closer to the time of the auction and a new definition of "control" that will more accurately account for resources should to be included in the assessment of a supplier's overall capacity portfolio.

Along with the changes to the pivotal supplier test, the ISO also filed changes to improve the rules governing the treatment of import capacity resources in the Forward Capacity Auction. The proposed changes will ensure that capacity imports that are more akin to existing resources receive the same mitigation treatment in the Forward Capacity Auction as existing resources. The changes also will ensure that capacity imports that are akin to new resources receive the same treatment as other new resources during the conduct of the auction.

1.3 Recommendation

The following recommendation for improving the market design is as follows. The recommendation is based on observations of participant behavior and market outcomes in 2014 and the analysis described in the following sections of this report:

> The overall decline of cleared virtual transactions in the long run continues to imply that the effects of high and uncertain transaction costs observed continue to persist, as documented in past Annual Markets Reports.[23] The ISO should revise the market rules so that real-time NCPC charges do not prevent virtual transactions from improving the liquidity in the day-ahead market.

In 2014, the ISO proposed market rule changes to strengthen the incentive for load serving entities, exporters and virtual demand bidders to buy energy in the day-ahead energy market. The proposed rule changes would have excluded positive load deviations from real-time first contingency NCPC charges. However, stakeholders did not support the proposed change and the ISO opted not to file the proposed change with FERC. Had the proposal been implemented, it would have addressed only *half* of the recommendation by exempting virtual demand bids from real-time NCPC charges. The proposal would not have addressed the recommendation for virtual supply offers. As noted below, the ISO plans to commence a stakeholder process in 2015 to address the NCPC cost allocation issues in general including the method used to allocate first-contingency NCPC charges to both virtual demand and supply deviations (See Section 3.1.4.).

[23] A decrement bid is a bid to purchase energy at a specified location in the Day-Ahead Energy Market that is not associated with a physical load. An accepted decrement bid results in scheduled load at the specified location in the Day-Ahead Energy Market.

1.4 Status of IMM Recommendations from the *2013 Annual Markets Report*

The status of the IMM recommendations from the *2013 Annual Markets Report* is shown in Table 1-3.

Table 1-3
Status of Key Recommendations from the *2013 Annual Markets Report*

2013 Recommendations	Status as of the AMR14 Publication Date
Recommendation to modify the market rules as necessary when EMOF is introduced to ensure that the use of the limited-energy generator (LEG) provisions in both the day-ahead and real-time markets are restricted to instances when the availability of fuel is physically limited.	The ISO is currently assessing this issue
Recommendation that the ISO discontinue or replace the locational marginal price calculator for calculating real-time prices.	Tariff revisions filed mid-March for implementation by June 1
Recommendation that the ISO revise the market rules so that real-time NCPC charges do not prevent virtual transactions from improving the liquidity in the day-ahead market.	Stakeholder process expected to start at the end of 2015
Recommendation that, as part of the market development plan, the ISO study, develop, and implement a market-based reliability commitment method to improve incentives for meeting reliability objectives and the efficiency of the Day-Ahead Energy Market and Real-Time Energy Market.	The ISO is currently assessing this issue

Section 2
Real-Time Markets

The ISO New England's (ISO's) real-time markets include the Real-Time Energy Market, the Regulation Market, and real-time operating reserves. This section describes the 2014 outcomes of the real-time markets. The section also summarizes the ISO's actions to ensure real-time reliability and includes an assessment of ISO operations.

2.1 Real-Time Energy Market

This section describes the outcomes, structure, and competitiveness of the Real-Time Energy Market. The review of market outcomes shows that the Real-Time Energy Market was competitive in 2014.

The Real-Time Energy Market is the physical market in which generators sell, and load-serving entities (LSEs) purchase, electricity. The ISO coordinates the production of electricity to ensure that the amount produced moment to moment equals the amount consumed, while respecting transmission constraints. The ISO publishes locational marginal prices (LMPs) every five minutes for each location on the transmission system at which power is either withdrawn or injected.[24] The prices for each location reflect the cost of the resource needed to meet the next increment of load at that location.

The Real-Time Energy Market settles the difference between positions cleared in the Day-Ahead Energy Market (discussed in Section 3.1) and actual production or consumption in the Real-Time Energy Market. Participants that consume more or provide less than their day-ahead schedule pay the real-time LMP, and participants that consume less or provide more than their day-ahead schedule are paid the real-time LMP. Because of the dependencies between the Real-Time Energy Market, the Day-Ahead Energy Market, and other forward markets, this section contains information on forward markets where relevant.

2.1.1 Prices

Real-time price data for 2014 and comparisons of real-time prices and day-ahead prices are presented below (see Section 3.1.1 for a full discussion of day-ahead pricing).

2.1.1.1 Real-Time Prices

In 2014, the average real-time Hub price was $63.32/MWh, up approximately 13% from $56.06/MWh in 2013.[25] This price is consistent with observed market conditions, including those for input fuel costs, loads, and generating resource operations. Price differences between the load zones primarily were due to marginal losses.[26] Congestion between zones can also

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[24] 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 (*pnodes*) on the system. *Load zones* are aggregations of internal nodes within specific geographic areas. The *Hub* is a collection of internal nodes not typically congested. An *external interface node* is a proxy location used for establishing an LMP for electric energy received by market participants from, or delivered by market participants to, a neighboring balancing authority area.

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

[26] The loss component of the LMP is the marginal cost of additional losses resulting from supplying an increment of load at the location. New England is divided into the following eight load zones used for wholesale market billing:

result in price differences, although there was little congestion between zones. Most of the congestion was the result of sub-zonal transient load pockets caused by transmission or generation elements being out of service.[27]

The Maine (ME) load zone continues to have the lowest average prices in the region, while the Southeastern Massachusetts (SEMA) load zone had the highest. The average LMPs in the Maine load zone were $4.28/MWh lower than the Hub price, explained by both the marginal loss and congestion components of Maine's average LMPs. The higher NEMA prices are attributable to local area constraints within the zone. The average LMPs in the NEMA load zone were $0.71/MWh greater than the average Hub price, again explained by both marginal loss and congestion within the NEMA zone. See Table 2-1.

Table 2-1
Simple Average Real-Time Hub and Load Zone Prices for 2013 and 2014 ($/MWh)

Location/Load Zone	2013	2014
Hub	56.06	63.32
Maine (ME)	53.23	59.04
New Hampshire (NH)	55.15	61.47
Vermont (VT)	55.08	61.60
Connecticut (CT)	55.89	63.11
Rhode Island (RI)	56.10	63.33
Southeast Massachusetts (SEMA)	56.43	63.44
Western Central Massachusetts (WCMA)	56.12	63.29
Northeast Massachusetts (NEMA)	56.31	64.03

2.1.1.2 Day-Ahead and Real-Time Price Comparison

In 2014, average day-ahead prices at the Hub ($64.57/MWh) were 2% more than average real-time energy prices at the Hub ($63.32/MWh). See Table 2-2.

Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).

[27] *Load pockets* are areas of the system that require local generation to meet demand because the transfer capability of the transmission system is insufficient to serve the load in the area.

Table 2-2
2014 Annual and Quarterly
Day-Ahead and Real-Time Hub Prices ($/MWh)

	Annual	Q1	Q2	Q3	Q4
Day-ahead	64.57	144.99	39.92	33.98	40.90
Real-time	63.32	143.66	38.16	33.70	39.27

In 2014, hourly real-time and day-ahead prices at the Hub correlated positively (0.85). Hourly real-time LMPs at the Hub for 2014 had a standard deviation of $72/MWh, while hourly day-ahead LMPs at the Hub for 2014 had a standard deviation of $63.64. Some factors not present in the day-ahead market affect real-time prices. Examples include contingencies or forced outages, Minimum Generation (Min Gen) Emergencies, operating reserve-shortage pricing, and ramping constraints associated with a five-minute dispatch in real time as opposed to an hourly dispatch in the day-ahead.[28] These factors can create additional variability in real-time prices compared with those in the day-ahead market.[29] See Figure 2-1.

[28] The declaration of a *Minimum Generation Emergency* is called when the on-line generation plus net imports comes close to exceeding system load and all generators are operating at *economic minimum* (ecomin) (i.e., the minimum amount of electric energy available from a generating resource for economic dispatch.) A Min Gen Emergency resets the economic minimums of resources down to their emergency minimums (if available) to gain additional dispatchable range. Before the Energy Market Offer Flexibility (EMOF) rules went into effect (see Section 2.1.2.4), the ecomin LMPs were administratively set to zero. With EMOF in effect, the ecomin LMPs will be set to −$150.

[29] A *forced* outage is a type of unplanned outage that involves the unexpected removal from service of a generating unit, transmission facility, or other facility or portion of a facility because of an emergency failure or the discovery of a problem. A *planned* outage is the planned inoperability of a generator or transmission facility, generally to perform maintenance.

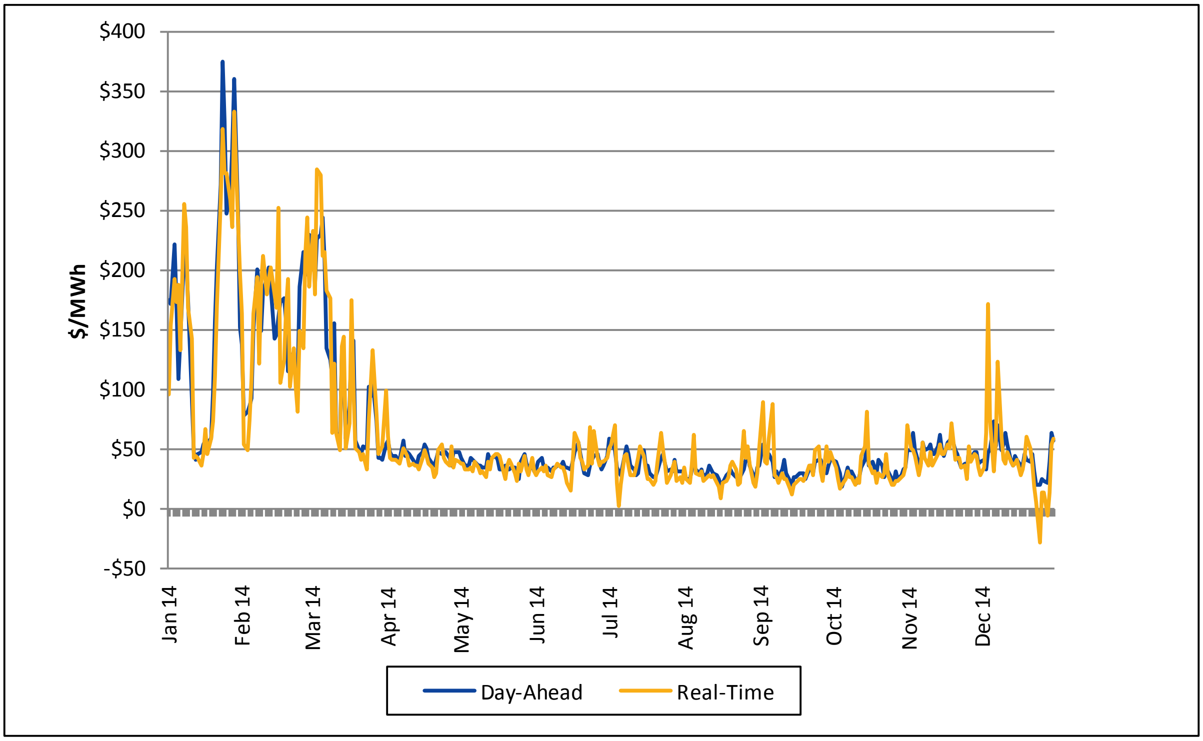

Figure 2-1: Average daily day-ahead and real-time Hub prices, 2014 ($/MWh).

2.1.2 Market Structure, Competitiveness, and Mitigation

This section presents the results of the analysis of market structure (Section 3.1.7 examines conduct and performance) and presents the results of mitigation activities.

A core function of the IMM is to monitor market participant behavior and detect deviations from competitive behavior. The competitive structure of the market is determined by the number of competitors and the frequency with which suppliers are pivotal. A *pivotal* supplier has the ability to exercise market power because it is needed for meeting demand and can therefore offer energy and set prices above competitive levels, subject to offer caps and mitigation measures. Thus, market structure affects the ability of a participant to raise price above its marginal cost and sustain profits above the competitive level. The fewer competitors in the market, the easier it is for a participant to exercise market power.

Two measures of market concentration are being presented in this section. The first is a measure of market concentration focusing on the four largest competitors relative to the market as a whole. This measure is called C4 and is the percentage of the market controlled by the four largest competitors, or the simple sum of the market shares of the top-four firms. A C4 value of 100% means that the top-four firms supply all the market demand. However, this measure does not distinguish between a near-monopoly condition where one firm supplies 97% of the market with the other three supplying 1% each and a more competitive situation where each firm supplies 25% of the market.

The second measure of market concentration, the Herfindahl-Hirschman Index (HHI), provides more detail on market structures than C4.[30] The HHI would identify the example of a firm with

[30] The HHI is calculated as follows:

97% of the market share as virtually indistinguishable from a monopoly and the example of four equal market shares of 25% as more competitive. The HHI is calculated as the sum of the squared market shares of the firms in the market. The example of a firm with 97% market share would yield a value of 9,412 out of a maximum value of 10,000 for a pure monopoly. The more competitive example of four equal market shares of 25% would yield a value of 2,500. This value of 2,500 is close to the threshold used by the United States (US) Department of Justice (DOJ) to separate unconcentrated markets from concentrated markets—no such commonly used thresholds exist for C4.[31]

The number of hours in which a given participant's portfolio was pivotal was calculated, as measured by the Residual Supplier Index (RSI), described in Section 2.1.2.3.

The conclusions are as follows:

- The amount of generation and load held by the four largest suppliers or load-serving entities is not large enough to raise concerns about the exercise of market power at the system level.
- From the HHI analysis, the Real-Time Energy Market in New England is not concentrated at the system level.
- From the RSI analysis, the 2014 result is consistent with a structurally competitive market at the system level.

The conclusions regarding competitiveness are with respect to meeting system-wide load and operating reserve requirements. As noted above, there is little congestion that creates price separation within the ISO New England control area. If there were more frequent congestion that created price separation within the control area, structural measures of competitiveness for regions within the control area would be appropriate.

2.1.2.1 Market Share Controlled by the Four Largest Competitors for the 2014 Peak Hour

In 2014, the four largest generating companies and the four largest LSEs controlled more than 40% of the supply and load in the region, with two of the largest suppliers also serving a large percentage of the load.

For the 2014 peak load hour—July 2, 2014, hour ending (HE) 3:00 p.m.—generators and imports produced 25,590 megawatts (MW) of electricity.[32] The four largest generation suppliers provided 40% of the total electricity produced in New England in that hour, while all

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

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 percentages are used as whole numbers, as in 75 instead of 0.75, the index can range up to 100^2, or 10,000.

[31] 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.

[32] *Hour ending* denotes the preceding hourly period. For example, 12:01 a.m. to 1:00 a.m. is hour ending 1:00 a.m. Hour ending 6:00 p.m. is the period from 5:01 p.m. to 6:00 p.m.

other market participants provided 60% of the electricity generated in that hour. The participant that supplied the most generation to the system during the peak hour was Exelon Generation Company, which supplied 3,812 MW (14.9%) of the total electricity generated. Dominion Energy Marketing provided 2,414 MW (9.4%); GDF Suez Energy Marketing, 2,202 MW (8.6%); and Entergy Nuclear Power Marketing provided 1,797 MW (7.0%) of total supply during the peak load hour of 2014. See Figure 2-2.

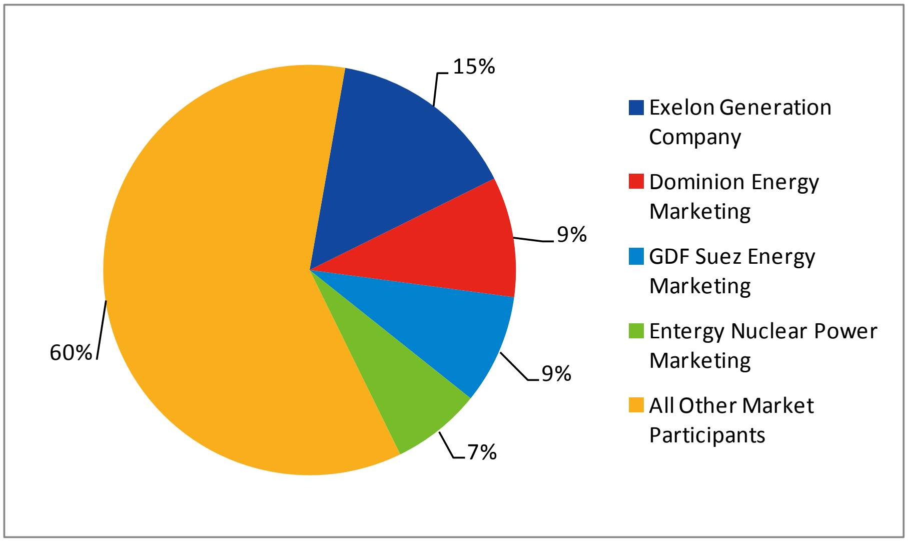

Figure 2-2: Market share of generation by participant, peak load hour, 2014 (July 2, hour ending 3:00 p.m.).

For the 2014 peak load hour, the total amount of electricity purchased, or *real-time load obligation* (RTLO), was 25,369 MW.[33] Overall, as shown in Figure 2-3, the four largest load-serving participants served 35% of the total system load for the 2014 peak load hour, while all other market participants served 65% of the total system load in that hour. Exelon had the largest real-time load obligation, serving 3,216 MW (13%) of total system peak load. Direct Energy Business Marketing served 2,124 MW of total system peak load in that hour (8%); TransCanada Power Marketing, 2,078 MW (8%); and NextEra Energy Marketing, 1,607 MW (6%).

[33] Losses account for the difference between the 25,590 MW of sold generation and the 25,369 MW of bought generation. This value includes exports.

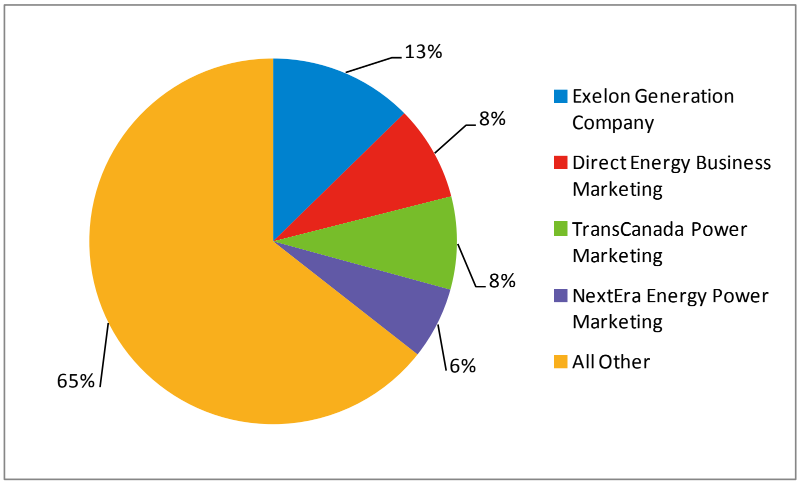

Figure 2-3: Real-time load obligation by participant, peak load hour, 2014 (July 2, hour ending 3:00 p.m.).

Figure 2-2 and Figure 2-3 show that Exelon is in the top-four participant list for both load served and generation provided in the peak load hour of 2014. Participants with both load and generation generally have less incentive to exercise market power. Actions that would tend to raise prices for generation would come at a cost to load, and any actions that would suppress prices would come at a cost to generation. Consequently, a participant's net position and the conditions under which unilateral action might become profitable are of highest concern. The amount of generation and load held by the four largest suppliers or load-serving entities is not large enough to raise concerns about the exercise of market power.

2.1.2.2 Herfindahl-Hirschman Index

Market shares of each market participant and HHIs in the Real-Time Energy Market were calculated using cleared megawatts for each real-time pricing interval. Market shares or HHIs for load zones or other subregional areas were not calculated because of the lack of transmission congestion on the system that would create separate pricing zones where lack of competition may be more of an issue.

The HHI calculation is conservative because it uses the gross generation of each participant rather than its *net generation* (i.e., a participant's generation minus its load obligation). HHIs based on estimates of market share that accounted for each participant's net generation and load position would be lower than or equal to those calculated and presented herein.

Table 2-3 summarizes the results of the HHI analysis. The median HHI calculated using the value corresponding to each day's peak hour is 638 and the median HHI calculated using the value corresponding to each day's lowest load hour is 766.[34] Using the DOJ's *Horizontal Merger Guidelines*, the Real-Time Energy Market in New England is not concentrated.[35]

[34] This analysis was based on lead participant by generator. Conducting the analysis by affiliate would produce a moderately different result. The IMM has estimated this difference in the range of 5% to 10%, which does not change the conclusion that the energy market is competitive.

[35] The Department of Justice defines markets with an HHI below 1,500 points to be unconcentrated.

Table 2-3
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 2014

	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	638	937	*13%*	*41%*	*65%*	*82%*	123	17,277
Lowest-load hour	766	1,066	*15%*	*47%*	*69%*	*85%*	118	11,998

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 2014, when the top-four participants (by market share) comprised 47% of the market in the hours with the lowest load, compared with 41% for the peak hours.

2.1.2.3 Residual Supply Index

The systemwide Residual Supply Index measures the percentage of real-time demand in a given hour that can be met without any capacity from the largest supplier.[36] The RSI also measures the number of hours in which at least one supplier is pivotal and able to exercise market power. 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, and the supplier is pivotal. As the RSI increases, the ability of market participants to set prices above competitive levels decreases. In general, the RSI is lowest during periods of high demand.

Overall, the analysis of RSI figures for 2014 suggests that the suppliers' ability to exercise market power at the system level was limited. The system-level analysis shows that pivotal suppliers existed during 37 hours in 2014, approximately 0.4% of all hours. This is a decline from 2013, when suppliers were pivotal in 123 hours. Overall, the 2014 result is consistent with a structurally competitive market. See Figure 2-4.

[36] For the period before the implementation of Energy Market Offer Flexibility (EMOF; also commonly known as "hourly markets"), the calculation recognizes that participants submit a single supply offer that covers the 24-hour period of the market day and that their ability to alter that offer during the course of the day is limited. As a result, the RSI calculation uses the total quantity offered from generating resources during the reoffer period.

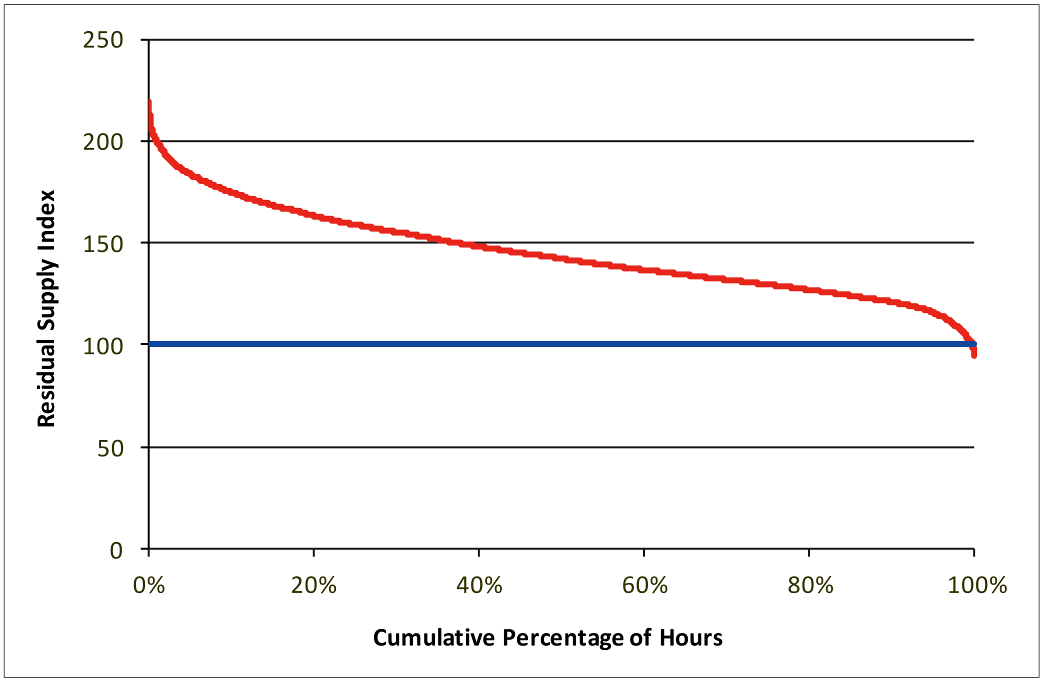

Figure 2-4: Systemwide Residual Supply Index duration curve, all hours, 2014.

2.1.2.4 Mitigation

Mitigation is an automated process that prevents noncompetitive supply offers from affecting the market price. The market rules governing the mitigation process use three tests: structure, conduct, and impact. The process comprises the following:

- An evaluation of the *structure* of the competition the generator faces (e.g., the generator is part of a lead market participant's portfolio that is pivotal, systemwide, or the generator is in an import-constrained area of the system and faces less competition)
- An evaluation of the generator's *offer* (i.e., its conduct) against a reference level prepared by the IMM[37]
- After the evaluations, an estimation of the *impact* the generator's supply offer will have on market outcomes

The tariff requirement for determining energy market mitigation is to evaluate supply offers for all generating resources across the system that exceed the applicable reference level plus the appropriate threshold. Generator supply offers are mitigated only when they exceed the applicable reference level plus the appropriate threshold (conduct) and the supply offer raises the market price (e.g., the LMP) by a specific (impact) threshold.

Another set of mitigation rules applies to generation resources' commitment costs, and evaluates the supply offer in comparison with the resource's reference level plus an applicable threshold value. This commitment evaluation applies start-up, no-load, and energy costs at the

[37] A reference level generally reflects either the actual cost to the resource of generating electricity or, most frequently, in the case of hydroelectric units, the opportunity cost of producing electricity now compared with storing it and generating electricity later.

economic minimum limit (also known as a generator's "low-load cost"). Mitigation rules that apply to generators committed for reliability have smaller thresholds because units committed for reliability often face no competition and could offer significantly above their costs.

The EMOF changes implemented in late 2014 now provide market participants with the opportunity to submit offers that vary by hour and to change offers very near real time.[38] These changes, which went into effect on December 3, 2014, required modifications to the mitigation rules, which included the following provisions:

- Developing hourly reference levels rather than reference levels that are fixed for an operating day
- Modifying commitment mitigation conduct tests so that they account for the low load cost over the commitment period
- Modifying the duration of mitigation such that commitment mitigation is in effect for the duration of the commitment period and energy mitigation is in effect until structural market power or market impact are no longer detected. Under the pre-EMOF rules mitigation remained in effect until at least the end of the operating day.
- Introduction of limits based on fuel prices, to the amount that start-up fees and no-load fees may be increased in real time
- Implementation of mechanisms to permit Market Participants to enter fuel price adjustments to resource reference levels to reflect hourly changes in fuel costs
- Elimination of the requirement that Market Participants with dual fuel resources submit offers based on the resource's least cost fuel under certain conditions

Table 2-4 shows all the mitigations by occurrence for 2014. Some variation in mitigations over time is consistent with changes in system conditions.

- In January 2014, most of the mitigations were for constrained area energy, and most of the mitigations occurred on January 7, January 23, and January 28. On these days (and for the month in general), the constrained energy mitigation threshold of $25/MWh was relatively tight in terms of the percentage of the generator offer for some units.[39] For example, assuming an average heat rate of 10,000 British thermal units/kilowatt-hour (Btu/kWh) and an average January 2014 gas price of almost $24/million Btu (MMBtu), $25/MWh represents a conduct test threshold of just over 10% of costs.
- In December 2014, the number of commitment mitigations increased due to the increased commitment flexibility under EMOF.[40] A greater number of commitment mitigations is expected because under EMOF the duration of mitigation is shorter. Under EMOF, a generator is subject to mitigation for the duration of the commitment only. Before EMOF was implemented, offers were subject to mitigation until at least the

[38] ISO New England Inc. and New England Power Pool, Docket No. ER 13-1877-000, *Energy Market Offer Flexibility Changes* (July 1, 2013) http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jul/er13_1877_000_mkt_offer_flex_7_1_2013.pdf.

[39] The constrained area energy threshold is the minimum of the reference level times 1.5 and the reference level plus $25/MWh.

[40] Commitment mitigation can occur when an operator takes no action to shut down a unit beyond its initial commitment, and thus remains online beyond its scheduled commitment.

end of the operating day. To put this into context, the average duration of mitigation in December 2014 was approximately two hours. In December 2013, the average duration of a mitigation event was over 23 hours.

Table 2-4
2014 Day-Ahead and Real-Time Mitigations

Month	Commitment Mitigations	Energy Mitigations	Total
Jan	34	128	162
Feb	3	2	5
Mar	7	12	19
Apr	14	0	14
May	7	0	7
Jun	1	0	1
Jul	17	2	19
Aug	9	0	9
Sep	8	3	11
Oct	3	8	11
Nov	18	3	21
Dec[41]	149	4	153
Total	270	162	432

2.1.3 Factors that Affect Energy Prices

This section examines the relationships between real-time electric energy prices, fuel prices, and other market factors. Day-ahead market outcomes are also referenced where appropriate. Price spikes typically are explained by sudden changes in weather, fuel prices, and unplanned generator or transmission outages.

2.1.3.1 Energy Prices and Real-Time Demand

The demand for electricity in New England, defined as *net energy for load* (NEL), is weather sensitive and contributes to the seasonal variation in energy prices.[42] As shown in Table 2-5, the NEL was highest in the third quarter of 2014, at 33,697 gigawatt-hours (GWh). The annual peak demand of 24,443 MW also occurred in the third quarter, on July 2. The weather in 2014 was milder than that in 2013. The peak load of 27,379 MW in 2013 occurred on July 19 during a five-day heat wave. The major factor behind the reduced level of demand year over year was weather related. The temperature at the time of the peak in 2014 was 88 degrees versus 95 degrees in 2013. The first quarter had the second-highest demand for electricity in 2014, at 33,528 GWh of electricity consumption, which is consistent with historical observations and is driven by the higher electrical heating demand on the system during the peak winter months. The second and fourth quarters of 2014, with more mild temperatures, had the lowest demand for electricity.

[41] Post-EMOF mitigations are counted in unit days.

[42] *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.

Table 2-5
Energy Statistics, 2013 and 2014

	2013 Annual	2014 Annual	Q1 2014	Q2 2014	Q3 2014	Q4 2014
NEL (GWh)	129,377	127,138	33,528	29,315	33,697	30,569
Weather-normalized NEL (GWh)[(a)]	127,754	127,114	32,804	29,571	34,075	30,664
Recorded peak demand (MW)	27,379	24,443	21,334	21,263	24,443	19,812

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

Figure 2-5 shows real-time monthly LMPs and illustrates the effect that increased natural gas prices over the winter months in the past two years (2013/2014 and 2014/2015) had on energy prices. Of particular note is the fact that winter electricity prices, driven by high natural gas prices, exceeded electricity prices during the summer months even though the summer electrical demand exceeds the winter electrical demand (see Table 2-5). This can be seen to a large extent in January, February, and March 2014, when average prices exceeded $100/MWh, while the average prices in July 2014, the month with the annual peak load, were slightly below $40/MWh.

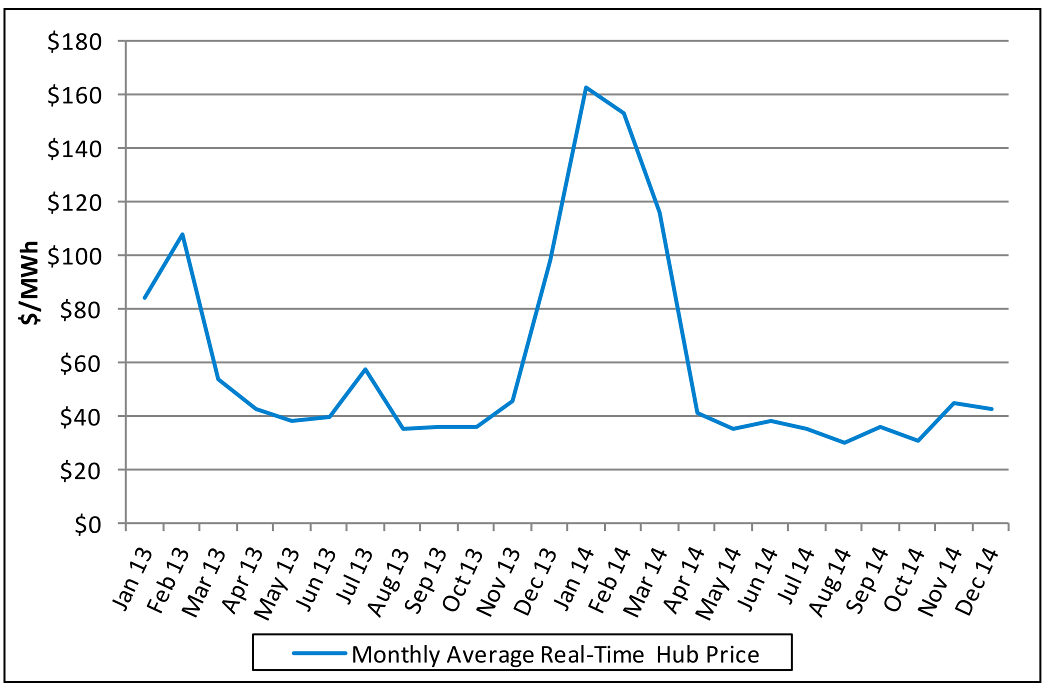

Figure 2-5: Monthly average real-time Hub prices, 2013 to 2014 ($/MWh).

2.1.3.2 Energy Prices and Weather

This section provides an overview of how weather affected LMPs in 2014. Very cold weather throughout the first quarter (January to March) of 2014 resulted in a high demand for natural gas, which led to high natural gas prices. Natural gas was sufficiently scarce and its price was sufficiently high during this period that, at times, other fuel types were more economic. This resulted in fuel switching among resources and high LMPs. In the first quarter of 2014, the high

LMPs were the primary driver behind a higher annual average LMP for 2014 ($63.52/MWh) compared with the annual 2013 LMP ($56.06/MWh).

The following are highlights from the winter months in 2013/2014:

- The ISO reported that during a number of periods from December 2013 through February 2014, daily average temperatures were well below the 20-year historical average.[43] In March 2014, the average temperature in Boston was 6.3 degrees F (°F) below average.[44]
- January 2014 started with a three-day cold spell, from January 2 to January 4, with very cold temperatures (6.8°F at the peak hour).
- On Tuesday, January 7, a polar vortex that brought subzero temperatures throughout the Midwest pushed into New England, with temperatures falling into the low teens.[45] The peak load on January 7 was 21,334 MW. Most of the area's pipelines were operating at or near capacity, with some recording record throughputs. Much of the ISO's gas fleet was either off line due to economics or burning an alternate fuel. Temperatures began to return to normal on January 9, approaching 30°F.
- Also on January 7, a gas compressor failed on the Texas Eastern system at Delmont, PA, with a subsequent *force majeure* declaration. Gas nominations were reduced by 575,000 MMBtus, and the lateral pipeline on the Algonquin system that feeds Rhode Island and southeastern Massachusetts was physically sealed.[46] Six generators fueled by natural gas reported to the ISO that they could not affirm whether they would be able to procure fuel when called intraday. Many of the resources that could not provide certainty on gas procurement during this time later informed the ISO that they were available once the situation on the gas system had improved. Upon further review, these generators had gas nominations cut because of the *force majeure*, or were located on portions of the gas system where the laterals had been physically sealed.

Comparison with 2013 Winter. New England experienced two extreme weather events in winter 2013 (first quarter 2013). The first event, from January 21 through January 28, had been New England's coldest multiple-day stretch since 2009. The second event, occurring two weeks later in February, was a weekend blizzard that left record snowfall across the region.[47] The rest of the 2013 winter was relatively mild.

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[43] The periods are December 10–17, 2013; January 1–10, 2014; January 21–30, 2014; February 6–12, 2014; February 16–19, 2014; and February 25–28, 2014. See *NEPOOL Participants Report, March 2014*, (March 7, 2014), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/mar72014/coo_report_mar_2014.pdf.

[44] See *NEPOOL Participants Report, April 2014* (April 4, 2014), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/apr42014/coo_report_apr_2014.pdf.

[45] See the ISO's *January 2014 FERC Data Request* (Preliminary) (January 10, 2014), http://www.iso-ne.com/static-assets/documents/pubs/spcl_rpts/2014/iso_ne_response_ferc_data_request_january_2014.pdf.

[46] The Algonquin Gas Transmission is a regional interstate natural gas pipeline system that transports natural gas from pipeline interconnects in New Jersey and southeastern New England to major markets in New England.

[47] See *2013 Annual Markets Report* (May 6, 2014), http://www.iso-ne.com/static-assets/documents/markets/mkt_anlys_rpts/annl_mkt_rpts/2013/2013_amr_final_050614.pdf.

Market Fundamentals in the Remainder of 2014. Temperatures during the summer and through December 2014 were milder than in 2013. Lower oil and natural gas prices, combined with the mild summer weather brought generally lower wholesale electricity prices during the rest of the year.

2.1.3.3 Electricity Prices and Natural Gas Prices

New England's wholesale electricity market is highly dependent on the availability of natural gas and fuel oil. A number of market forces influence the relationship between New England's natural gas and electricity markets, including the following:

- An influx of natural gas-fired generating capacity over the past 15 years[48]
- An aging and declining fleet of oil- and coal-fired generators, many of which were constructed during the 1960s and 1970s, and the retirement of the Vermont Yankee nuclear station. These generators would have been displaced by more efficient gas-fired generators in recent years
- Lower natural gas prices resulting from the increased production of domestic shale gas from the Marcellus Shale region of the country
- Relatively static gas pipeline capacity in New England[49] that has had to accommodate a 37% increase in overall natural gas consumption in New England since 1999; 95% of which was for power generation by natural gas facilities.[50]

The confluence of these forces has resulted in a much higher proportion of electricity being generated by gas-fired generators in New England, while pushing gas pipeline capacity to its limits during periods of peak gas demand. As a consequence, the reliability of New England's wholesale electricity grid is dependent, in part, on the owners and operators of natural gas-fired generators effectively managing natural gas deliveries during contemporaneous periods of high gas and electric power demand. Reliability is also increasingly dependent on the region's oil fleet having sufficient oil on hand to operate when the gas network is highly constrained and gas prices rise to levels that exceed the price of oil. When this occurs, oil units are dispatched more frequently.

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[48] During the 1990s, the region's electricity was produced primarily by oil, coal, and nuclear generating plants, with very little gas-fired generation. In 1990, oil and nuclear generating plants each produced approximately 35% of the electricity consumed in New England, whereas gas-fired plants accounted for approximately 5%. Coal plants produced about 18% of New England's electricity. In contrast, by 2011, oil-fired plants produced 0.6% of electricity consumed in New England, and approximately 51% was produced by gas-fired generation. Coal production also fell by about two-thirds. ISO New England, *Addressing Gas Dependence* (July 2012), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/natural_gas_white_paper_draft_july_2012.pdf.

[49] There has been no capacity change since the Maritimes and Northeast Pipeline went commercial in 1999.

[50] Approximately 12,000 of 14,000 MW of new capacity have come from gas-fired, combined-cycle generators. *ISO New England 2013 Regional Electricity Outlook*, p. 15 (2014), http://www.iso-ne.com/aboutiso/fin/annl_reports/2000/2014_reo.pdf. US Energy Information Administration (EIA), "Natural Gas Consumption by End Use," webpage (data for state-level and end-user natural gas consumption, 1999–2012) (March 31, 2014), http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCT_a.htm. Total consumption in New England increased by 37%; total deliveries to electric power consumers increased by 99%; and total consumption by residential, industrial, and vehicle fuels increased by 1,394%. Note that these data have not been weather normalized.

One of the most pressing challenges identified in the ISO's Strategic Planning Initiative was the region's reliance on generators fueled by natural gas. The ISO has undertaken a number of projects aimed at improving reliability through better generator performance and fuel assurance and has been, or is addressing the problem through the following initiatives:

- Increasing ten-minute non-spinning reserve to be procured in the Forward Reserve Market
- Modifying generation resource auditing requirements and procedures
- Allowing the ISO to share information concerning the scheduled output of natural gas-fired generation resources with the operating personnel of the interstate natural gas pipeline companies serving New England
- Accelerating the closing time of the day-ahead energy market
- Considering procurement of additional intra-day operating reserve capability
- Allowing intra-day reoffers
- Redesigning Forward Capacity Market performance penalties with the pay-for-performance (PFP) capacity market design and
- the Winter Reliability Programs, which will be needed until PFP become fully effective in 2018 (see Section 3.4).

Spark Spreads. The *spark spread* measures the relationship between real-time electricity prices and natural gas prices. Spark spread measures the gross margin (electricity revenues minus fuel costs) from converting natural gas to electricity for a typical power plant fueled by natural gas. The data required to calculate the spark spread includes the wholesale price of electricity, the cost of natural gas (measured by a natural gas price index), and the efficiency of the generation technology in converting fuel input to electricity (i.e., the plant's *heat rate*). The spark spread for a combined-cycle gas-turbine unit (CCGT) was calculated with a heat rate of 7,800 Btu/kWh.[51]

Figure 2-6 presents the quarterly estimated spark spreads for natural gas based on the following:

- The simple average of the quarterly real-time Hub price for on-peak hours from January 2012 through December 2014[52]
- The fuel costs of a representative CCGT in New England, using the Algonquin gas price index
- A 7,800 Btu/kWh heat rate
- 100% availability

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[51] The heat rate (Btu/kWh) for a power plant is equal to its fuel consumption divided by its generation. A unit's heat rate depends on the individual plant design, its operating conditions, and its level of electrical power output. Plants with lower heat rates are more efficient than plants with higher rates.

[52] For this analysis, "on peak hours" is defined as 7:00 a.m. (HE 8:00 a.m.) through 11:00 p.m. (HE 11:00 p.m.) on all nonholiday weekdays.

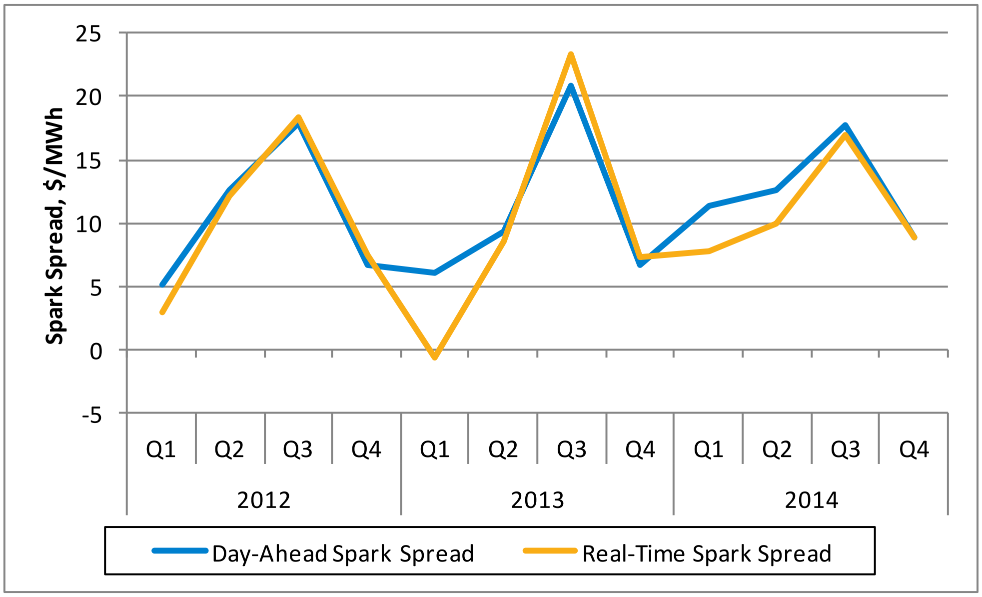

Figure 2-6: Quarterly estimated spark spreads for on-peak hours, 2012 to 2014 ($/MWh).

The results show that, on average, the representative gas unit earned a positive gross margin in 2014. The annual average spark spreads were approximately $12.90/MWh in day ahead and $11.19/MWh in real time, an increase from 2013 day-ahead and real-time spark spreads of $10.81/MWh and $9.76/MWh, respectively.[53] Spark spreads for natural gas increased in the summer months when high loads called for less efficient gas-fired and oil-fired units to operate and set price. This increased the margin reflected in the spark spread, which is based on a more efficient resource with a 7,800 Btu/kWh heat rate. Real-time spark spreads decreased in the winter months (Q1) of 2013. This decrease in the spark spread was primarily due to high natural gas prices exceeding the price of oil for most days in January and February. In these cases, resources fueled by natural gas are displaced by oil-fired resources that set price below a level that would support a gas-fired resource, resulting in a negative calculated spark spread for the gas resources. Generally, spark spreads can be lower in the winter months because constraints on the natural gas pipelines raise the cost of natural gas, sometimes to levels that exceed the price of oil.

Fuel Prices and LMPs. Figure 2-7 shows, by quarter, average day-ahead and real-time LMPs and the Algonquin gas price for 2013 and 2014. The Algonquin gas price in quarter 1 2014 averaged $19.96/MMBtu, 72% higher than the quarter 1 2013 price. In addition, in four days in January 2014, gas prices exceeded $40.00/MMBtu. The figure also shows the corresponding increase in day-ahead and real-time LMPs.

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

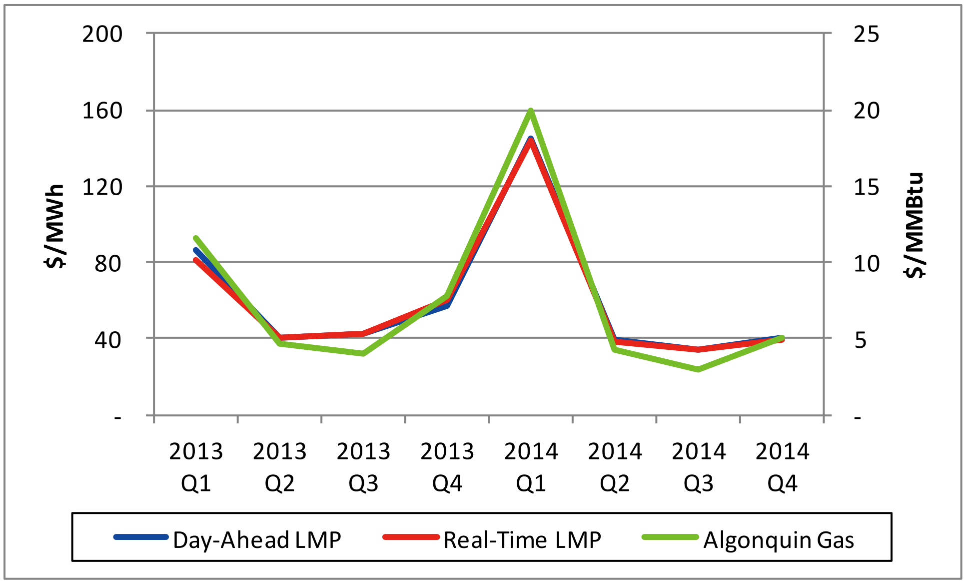

Figure 2-7: Day-Ahead LMPs, real-time LMPs, and Algonquin average prices by quarter, 2013 to 2014.

Figure 2-7 also shows a decrease in natural gas prices and subsequent LMPs in the second to fourth quarters in 2014 compared with the same quarters in 2013. If Quarter 1 prices are excluded, 2014 day-ahead and real-time prices fell by 18% and 23% compared with 2013 prices. See Figure 2-8.

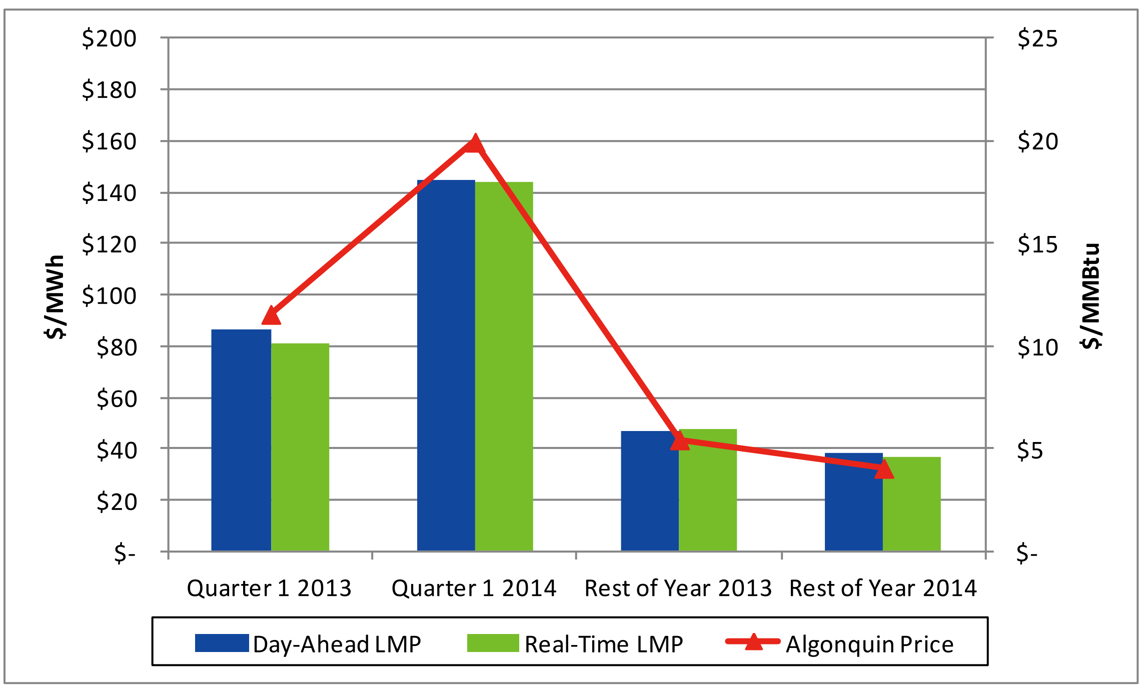

Figure 2-8: Average LMPs ($/MWh) and Algonquin price ($/MMBtu), Quarter 1 and rest of year, 2013 to 2014.

A number of factors contributed to lower LMPs from April to December 2014. As mentioned above, relatively mild weather contributed to lower loads during the summer, with a decrease in peak load of 1.8% from 2013 to 2014.

Oil prices decreased in 2014, the result of increases in US production and weaker-than-expected non-US global demand. Libyan oil production returned to the market, and the outlook for global oil demand was weak. These factors put lower price pressure on natural gas prices, given that oil is a substitute for natural gas.[54] On some days in late 2014, oil prices were less expensive than gas.[55]

Figure 2-9 presents representative generator costs for natural gas and oil units from January 1, 2014 through February 28, 2015. For 13 days in January and February 2014, generator costs for oil units were cheaper than natural gas units. It also shows that in December 2014, oil costs closed the gap with natural gas costs. For 15 days in February 2015, oil units were cheaper than natural gas units.

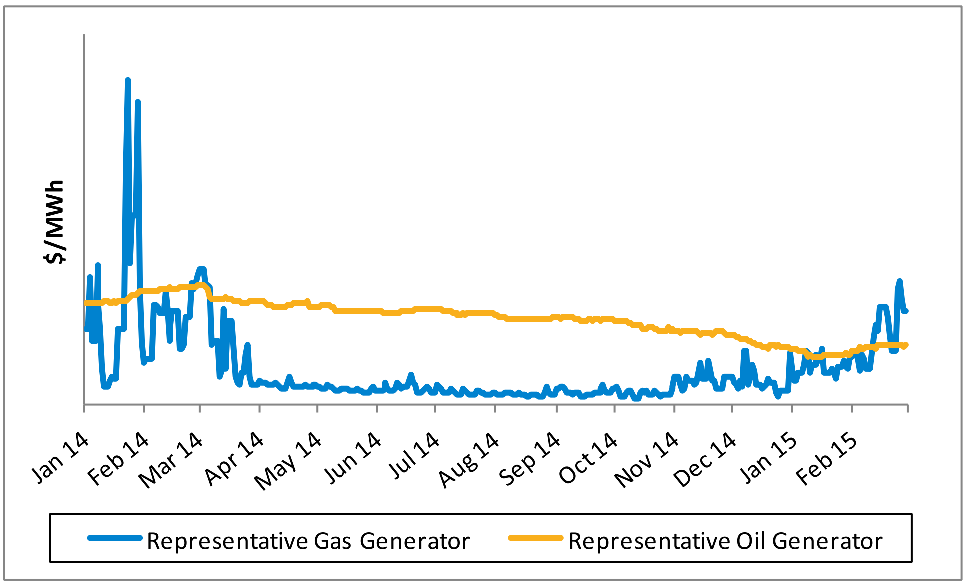

Figure 2-9: Representative generation prices for oil and natural gas, January 2014 to February 2015 ($/MWh).

Gas prices have been less volatile in winter 2014/2015 compared with the past two winters. Figure 2-10 displays the median daily trade prices for Algonquin next-day trades compared with the average daily temperature for the past three winters. For example, if on a given day, there were 25 trades for the Algonquin next-day product, the price displayed for that day would be the median trade value of the 25 trades. The median daily trade prices for winter 2014/2015 (black dots), given similar temperatures, are lower than in the past two winters. Winter 2013/2014, in particular, experienced high and volatile fuel prices.

[54] EIA, *This Week in Petroleum* (September 24, 2014), http://www.eia.gov/petroleum/weekly/archive/2014/140924/includes/analysis_print.cfm.

[55] This does not necessarily mean that all the ISO's oil fleet generated on those days. Oil units generally have different price points, higher heat rates, and longer minimum run times.

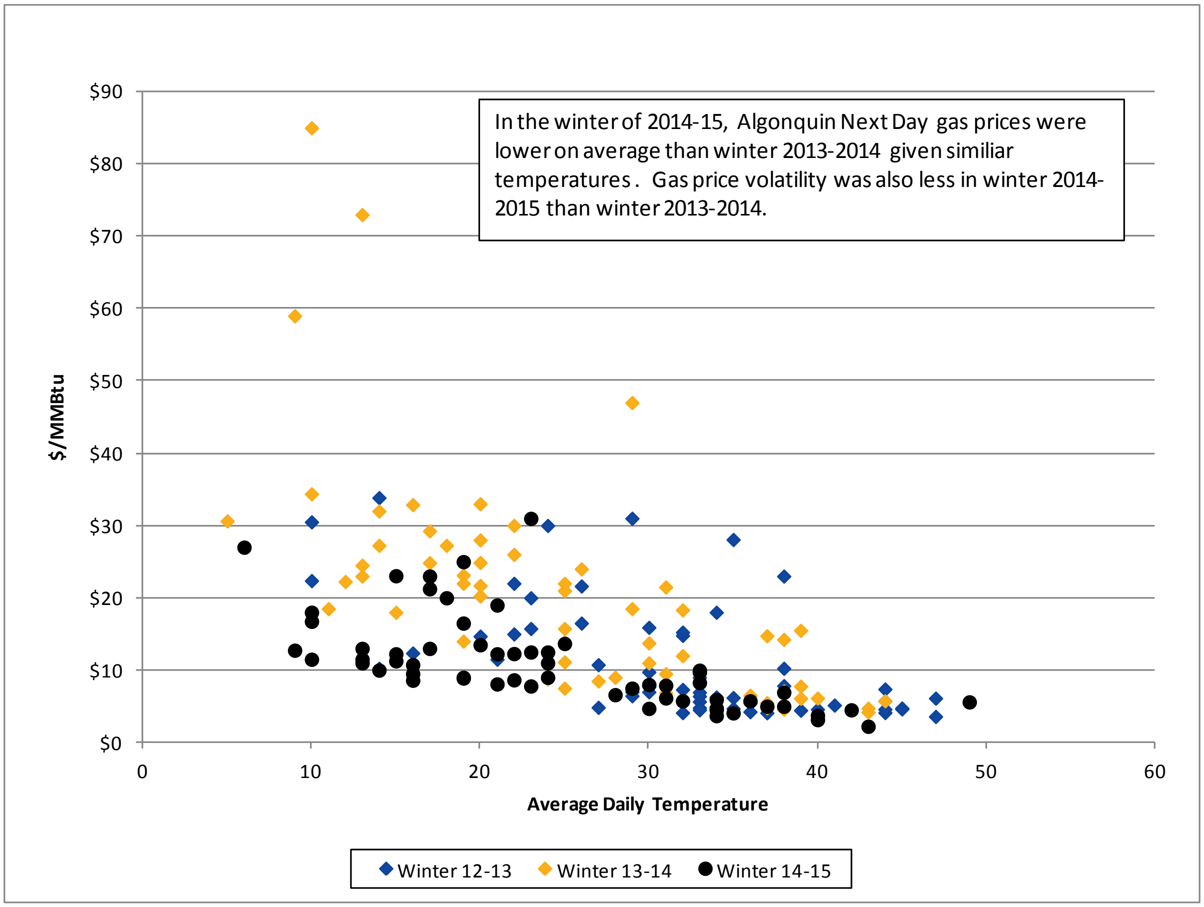

Figure 2-10: Algonquin next-day trades (median daily price), winter 2012 to 2013, winter 2013 to 2014, and winter 2014 to 2015 (December 1 through February 28).

Finally, the natural gas supplied to New England has increased over the course of winter 2014/2015. The increased natural gas supplies come from two different sources, including LNG converted back to gas form and sent out from the importing terminal and pipeline imports from Canada:[56]

- In the first three weeks of January 2015, cumulative LNG sendout from the Northeast Gateway floating LNG facility and the Everett terminal, both in Massachusetts, and the Cove Point facility in Maryland totaled 10 Bcf, which is more than 3.5 times the LNG sendout during the same period in 2014, and 30% more than the LNG sendout for the entire 2013/2014 heating season (November through March).
- Cumulative imports of natural gas from Canada in the first three weeks of January 2015 totaled 28 Bcf, a 5% increase over the same period in 2014.

Also, during winter 2014/2015, natural gas from LNG facilities injected into the interstate pipeline system in New England increased more than 97%, or more than a 15.5 bcf, compared to winter 2013/2014. To put this increase in supply into context, this is enough gas to run a 500 MW CCGT with a heat rate of 8,000 Btu/kWh for approximately 162 days at full load.

[56] EIA, *Natural Gas Weekly Update, January 21, 2015* (January 22, 2015), http://www.eia.gov/naturalgas/weekly/archive/2015/01_22/index.cfm.

The increase in LNG has come from several pipeline receipt points in New England, including Distrigas (Distrigas Receipt), Everett Interconnect, (Middlesex, MA), Excelerate Energy LP (Essex, MA), and Canaport (Maritimes/Brunswick Pipeline), with the largest increase in capacity coming from Everett Interconnect. In addition, Excelerate Energy LP supplied LNG during the winter 2014/2015, compared with winter 2013/2014 when they did not supply any LNG. See Table 2-6.

Table 2-6
LNG Scheduled Capacity Data, Dec. 1 to Feb. 28 (MMBtu)

Receipt Points	Winter 2013/2014	Winter 2014/2015	Change
Distrigas Receipt	212,585	2,672,611	**2,460,026**
Everett Interconnect (Middlesex, MA)	2,548,528	8,119,397	**5,570,869**
Excelerate Energy LP (Essex, MA)	0	2,675,821	**2,675,821**
Maritimes/Brunswick Pipeline	13,266,225	18,129,567	**4,863,342**
Total	**16,027,338**	**31,597,396**	**15,570,058**

Source: Genscape

With flexible LNG supply competing against natural gas and oil as a source in the production of electricity, the price that LNG has been able to receive in the spot market has been capped at a much lower value than in 2013. This was due to the large decrease in natural gas and oil prices in winter 2014/2015 compared with winter 2013/2014 (for both heavy and light fuel oils).

2014 Observations on Fuel Availability from the 2013 Annual Markets Report. The *2013 Annual Markets Report* reviewed the instances when gas-fired generators were not physically available. This occurred when gas-fired generators either lacked the physical access to natural gas or failed to procure natural gas. This can increase both price and quantity risks for gas-fired generators. The report addressed the following topics:

- Gas-fired generators' use of the limited-energy generation feature
- Real-time limited-energy generation
- Generator reductions resulting from gas-availability issues

The limited-energy generator feature permitted generators to manage fuel limitations before the implementation of EMOF. The *2013 Annual Markets Report* concluded that the use of the limited-energy generation provisions in both the day-ahead and real-time markets should be restricted to instances when the availability of fuel is physically limited, and that reductions in availability for economic considerations, such as simply choosing not to purchase sufficient fuel to follow dispatch signals, is incompatible with the requirements of the tariff. With the implementation of EMOF, the use of the limited-energy generation feature has dropped significantly, and when employed, it appears to have been limited to managing actual limitations on availability.

A decrease in generation reductions resulting from gas availability issues has also been observed. This decrease is coincident with the FERC orders clarifying the obligations of resources to procure fuel, the increase in gas supply, the change in the day-ahead market timeline, and the implementation of EMOF.

2.1.3.4 System Events and Energy Prices

System events affected prices on two days in 2014. This section provides an overview of these events.

Operating Procedure No. 4 (OP 4) on September 28, 2014.[57] The following is a summary of the main system and market observations from the event:

- Loads running over forecast in the late afternoon and evening, along with limited generation, resulted in a brief capacity and operating reserve shortage.
- The ISO implemented Action 1 of OP 4 to inform resources that a capacity shortage existed and to begin to allow the depletion of 30-minute operating reserves.
- Demand response was not dispatched during the OP 4 event.
- Operating reserve levels recovered to sufficient levels after the evening peak occurred, which allowed for the cancellation of OP 4 at 8:30 p.m.

<u>Price analysis.</u> On September 28, 2014, real-time hub LMPs rose in HE 7:00 p.m. to 9:00 p.m. due to an operating reserve deficiency. The deficiency resulted in positive operating reserve pricing in HE 7:00 p.m. through HE 11:00 p.m. The hourly 10-minute spinning reserve (TMSR) price (see Section 2.2.1) peaked at $426.27/MWh in HE 8:00 p.m. The positive operating reserve pricing resulted in a peak real-time hub LMP for the day of $507.17/MWh in HE 8:00 p.m. See Figure 2-11.

[57] ISO New England Operating Procedure No. 4, *Action during a Capacity Deficiency* (August 12, 2014), http://www.iso-ne.com/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

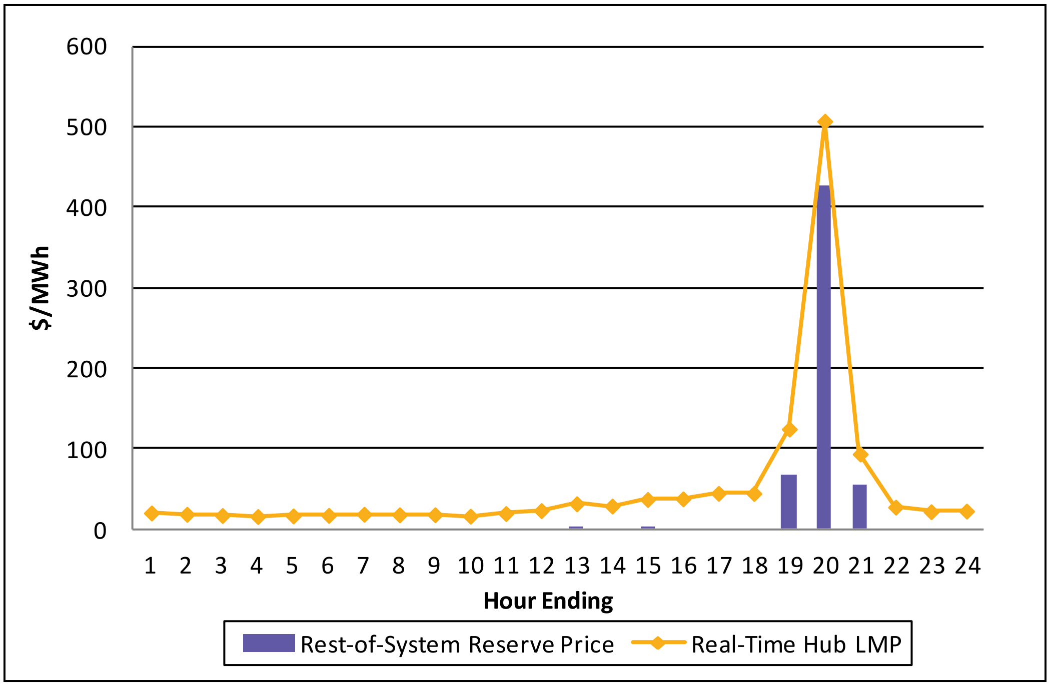

Figure 2-11: Real-time Hub LMP and 10-minute spinning reserve price, September 28, 2014.

Operational analysis. On the evening of Sunday, September 28, 2014, the New England region experienced tight capacity conditions due to loads that were slightly over the forecast and generating unit reductions.[58] At approximately 6:10 p.m., a large generating unit rated at approximately 600 MW was forced off line due to a mechanical problem. These two contributing factors resulted in the ISO declaring Master/Local Control Center 2 (M/LCC2) (Abnormal Conditions Alert) for all New England at 6:50 p.m. At 7:00 p.m., the ISO declared OP4 Action 1 due to a deficiency in 30-minute operating reserves (see Section 2.2.1). After the evening peak, the decrease in the New England load allowed for the cancellation of OP 4 Action 1 at 8:30 p.m. and the cancellation of M/LCC2 at 10:00 p.m. Figure 2-12 illustrates the time at which OP 4 Action 1 was declared and cancelled, alongside the actual and required operating reserves throughout the OP 4 event and evening hours.

[58] Loads were approximately 290 MW over the forecasted load in the peak hour, HE 8:00 p.m.

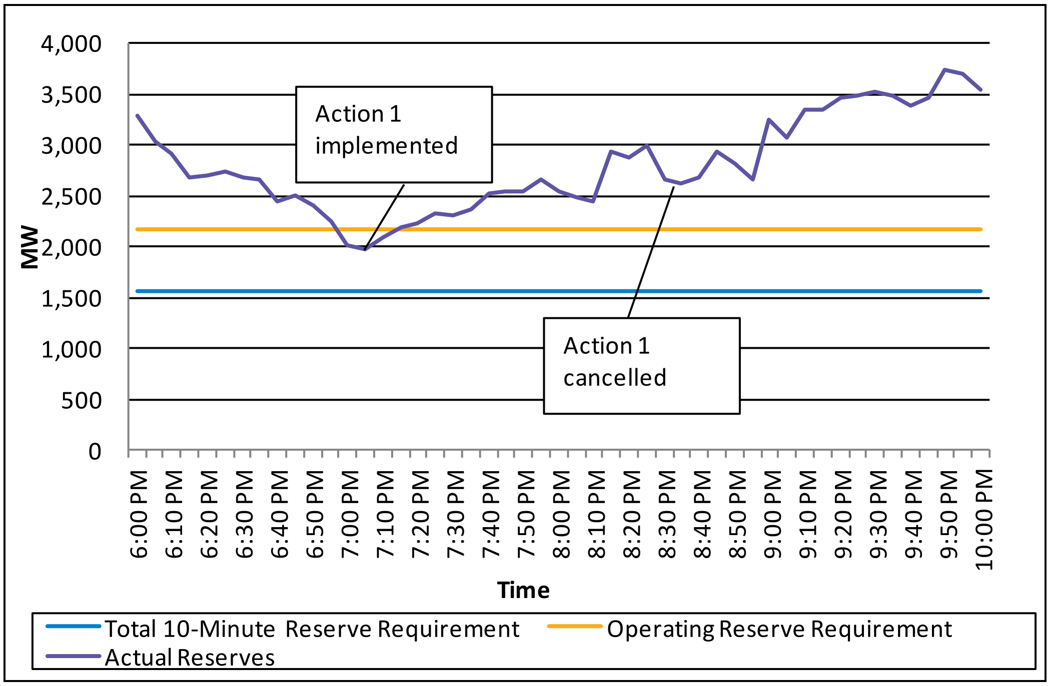

Figure 2-12: Operating reserves and requirements during OP 4 event, September 28, 2014.

OP 4 on December 4, 2014. The following is a summary of the main system and market observations:

- The curtailment of nearly 2,000 MW from Hydro-Québec TransÉnergie (HQ) into New England resulted in a brief capacity and operating reserve shortage.
- The ISO implemented Action 1 of OP 4 to inform resources that a capacity shortage existed and to begin to allow the depletion of 30-minute operating reserves.
- Demand response was not dispatched during the OP 4 event.
- Sufficient operating reserves were available after the evening peak occurred, which allowed for the cancellation of OP 4 at 8:45 p.m.

Price analysis. On December 4, 2014, real-time hub LMPs rose in HE 5:00 p.m. to 8:00 p.m. due to an operating reserve deficiency. The deficiency resulted in positive operating reserve pricing from HE 5:00 p.m. through HE 8:00 p.m. The hourly TMSR price peaked at $1,000/MWh in HE 8:00 p.m. The positive operating reserve pricing resulted in a peak real-time hub LMP for the day of $1,113.42/MWh in HE 6:00 p.m. See Figure 2-13.

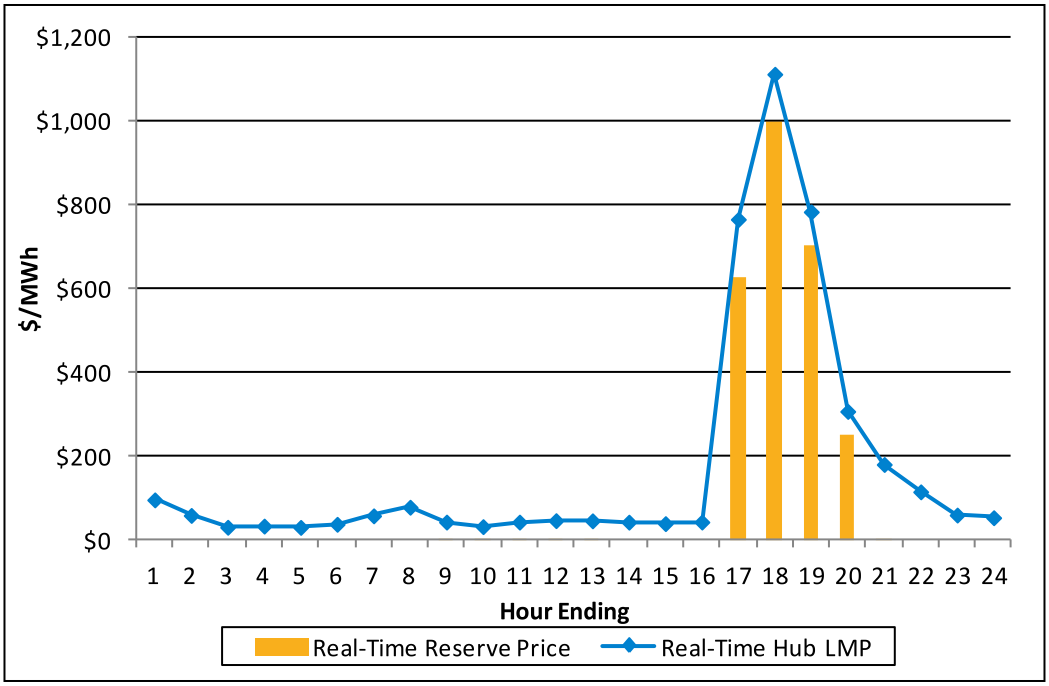

Figure 2-13: Real-time Hub LMP and 10-minute spinning reserve price, December 4, 2014.

Operational analysis. On the afternoon of Thursday, December 4, 2014, the New England region experienced tight capacity conditions due to the curtailment of approximately 2,005 MW from Hydro-Québec TransÉnergie into New England due to the loss of two major 735 kV transmission lines in Québec. At 4:00 p.m., M/LCC 2 was declared for all New England. At 4:15 p.m., OP 4 Action 1 was implemented to manage the deficiency in 30-minute operating reserve. Figure 2-14 illustrates the time at which OP 4 Action 1 was declared, alongside the actual and required operating reserves throughout the OP 4 event and evening hours.

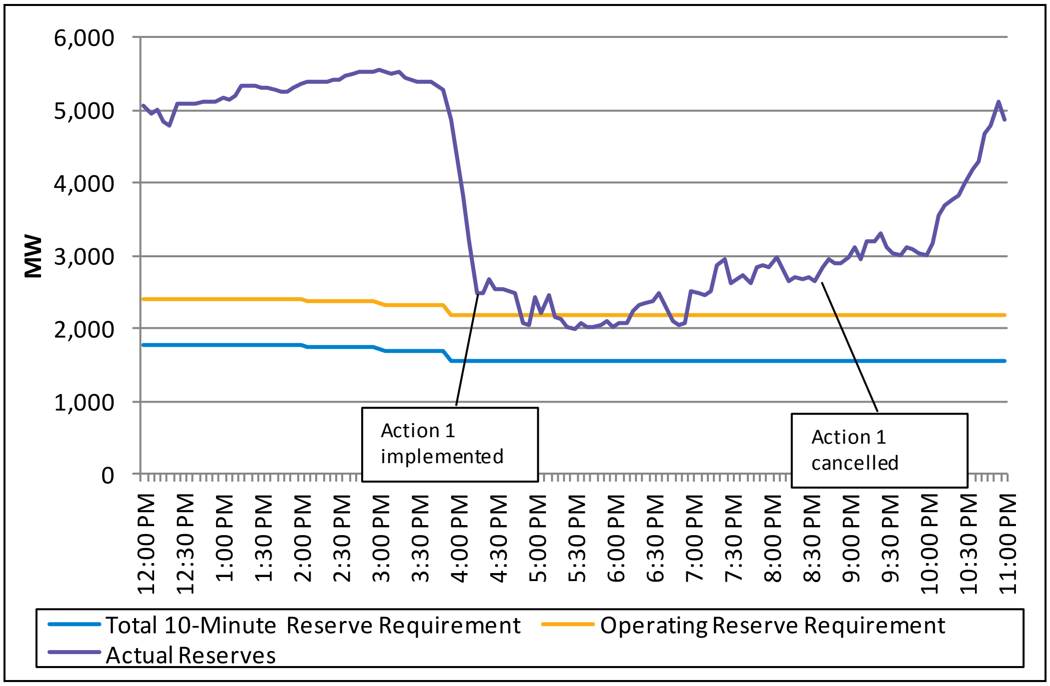

Figure 2-14: Operating reserves and requirements during OP 4 event, December 4, 2014.

In addition to the emergency energy provided to HQ from New England, HQ provided up to 500 MW of capacity-backed emergency energy to New Brunswick, which was "wheeled through" New England and returned to HQ through Phase II.[59] Figure 2-15 illustrates the flow of energy between New England and Hydro-Québec before the trip of the lines in Québec and during the OP 4 event. Negative values in the figure indicate that the New England region was importing energy, and positive values indicate that New England was exporting energy.

[59] *Wheel through* refers to the transmission of electric power from one system to another over a third party's transmission lines. *Phase II* refers to the DC interconnection ISO New England has with Hydro-Québec.

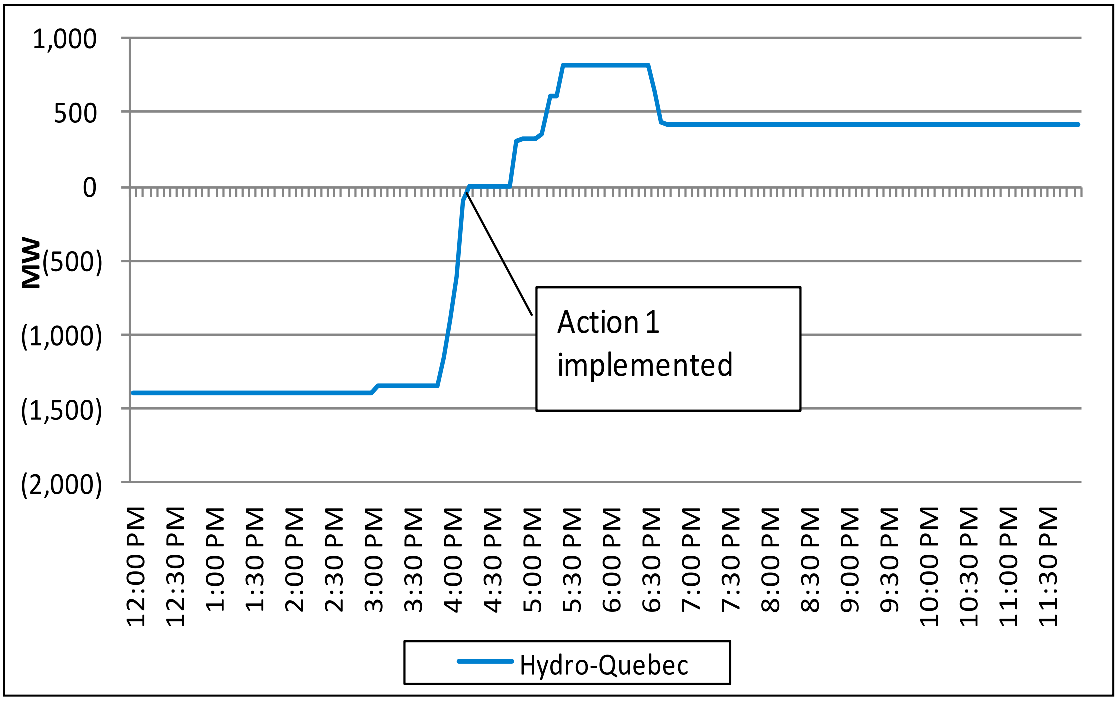

Figure 2-15: External flow between Hydro-Québec and New England during OP 4 event, December 4, 2014.

Note: Negative values in the figure indicate that the New England region was importing energy, and positive values indicate that New England was exporting energy.

After the evening peak, at 8:45 p.m., the ISO cancelled OP 4 Action 1. The M/LCC2 was cancelled on the following day, Friday, December 5, at 6:00 p.m.

2.1.3.5 Energy Prices and External Transactions

In 2014, New England was a net importer of power. Net imports from Canada exceeded net exports to New York (NY). The net interchange with neighboring balancing authority areas totaled 20,677 GWh for 2014, a 9% increase compared with the previous year. The increase in the net interchange is the result of both fewer exports and slightly greater imports in 2014 compared with 2013. The reduction in exports 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. See Figure 2-16.

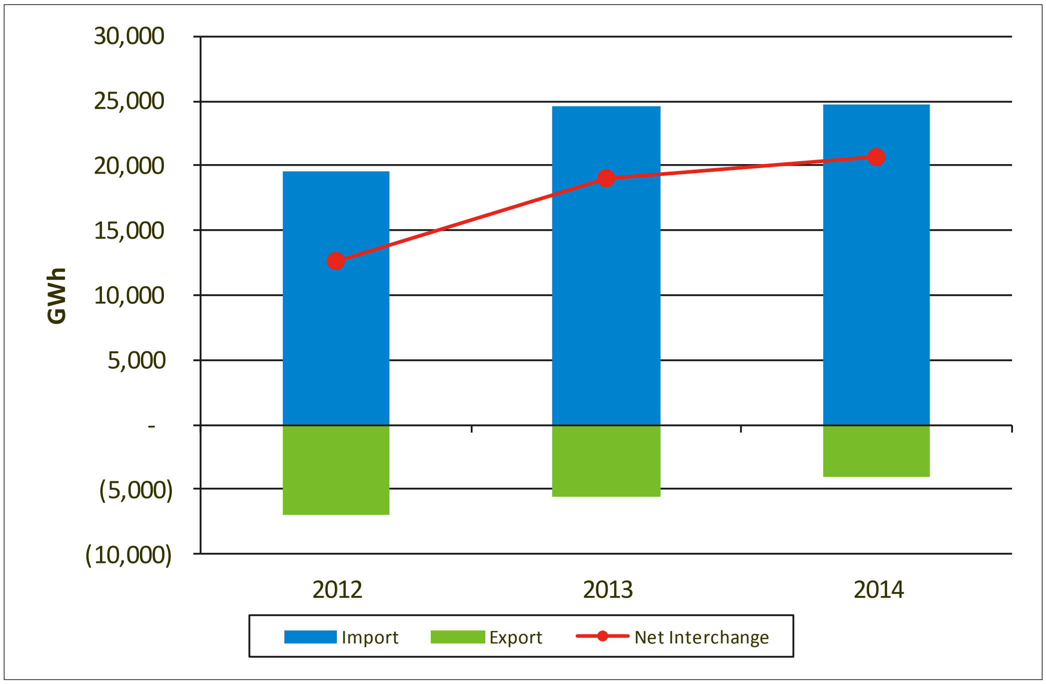

Figure 2-16: Scheduled imports and exports and net external energy flow, 2012 to 2014 (GWh).

The lower levels of New England exports are not directly attributable to a price differential between New England and New York. The current rules and systems that govern the interchange between New York and New England do not allow all possible gains to be realized from trade between the regions. Ideally, power should flow from the region with lower costs to the region with higher costs. However, the current scheduling system does not allow market participants to modify their bids and offers during the day, nor does it allow the ISO to optimize tie flows with sufficient frequency to ensure the efficient scheduling of the ties under all conditions. As a result, on the northern alternating-current (AC) ties between the New York Independent System Operator (NYISO) and ISO New England, power only flows in the apparent "right" direction about half the time, that is, in the direction expected based on observable price differences between the Roseton and the Sandy Pond pricing locations.[60] See Table 2-7.

Table 2-7
Percentage of Time Transactions Are Scheduled in the Direction of the Higher Price on the Roseton Interface, 2012 to 2014

Year	Real-Time (%)	Day-Ahead (%)
2012	52	57
2013	52	55
2014	56	49

In addition, production costs would be lower if the existing transmission interconnections were scheduled more efficiently, that is, scheduled in the prevailing direction of price up to the available total transfer capability (TTC). The data indicate that during many hours of the year,

[60] *Roseton* and *Sandy Pond* are the "border," or proxy bus, pricing nodes for real-time, hourly integrated LMPs for NYISO and ISO New England.

ample transmission capacity is available to move additional power from the lower-cost region to the higher-cost region.

On January 20, 2012, stakeholders agreed to investigate coordinated transaction scheduling (CTS), which employs higher-frequency scheduling and eliminates charges and credits on external transactions that deter trade. FERC accepted CTS on April 19, 2012.[61] The ISO anticipates that CTS will be implemented at certain locations between New England and New York in 2015. The IMM supports the ongoing efforts to implement CTS.

2.1.3.6 Energy Prices and Marginal Units

The LMP is set by the cost of the next megawatt that would have to be dispatched to meet an incremental change in load at the pricing location. The resource that sets price is called the marginal unit. Because the price of electricity changes as the price of the marginal unit changes, and the price of the marginal unit is largely determined by its fuel type, examining marginal units by fuel type helps understand changes in electricity prices. The system has at least one marginal unit associated with meeting the energy requirements on the system during each pricing interval. 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 exists for each binding constraint.

In 2014, unconstrained pricing intervals accounted for approximately 88% of all pricing intervals. When considering both unconstrained and constrained intervals, natural gas was the marginal fuel during 70% of all pricing intervals, followed by coal and pumped-storage generation, which were marginal in 8% and 7% of all pricing intervals, respectively. These percentages are comparable with data from the past few years, with the exception of 2012, when coal prices (and associated transportation costs) converged with the natural gas prices. The percentage of time natural gas set the price has been high, compared with other fuel types, and further illustrates New England's reliance on natural gas. See Figure 2-17.

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[61] FERC, *Order Accepting Tariff Revisions, Subject to a Compliance Filing*, Docket No. ER12-1155-000 (April 19, 2012), http://www.iso-ne.com/regulatory/ferc/orders/2012/apr/er12-1155-000_4-19-12_order_accept_cts.pdf.

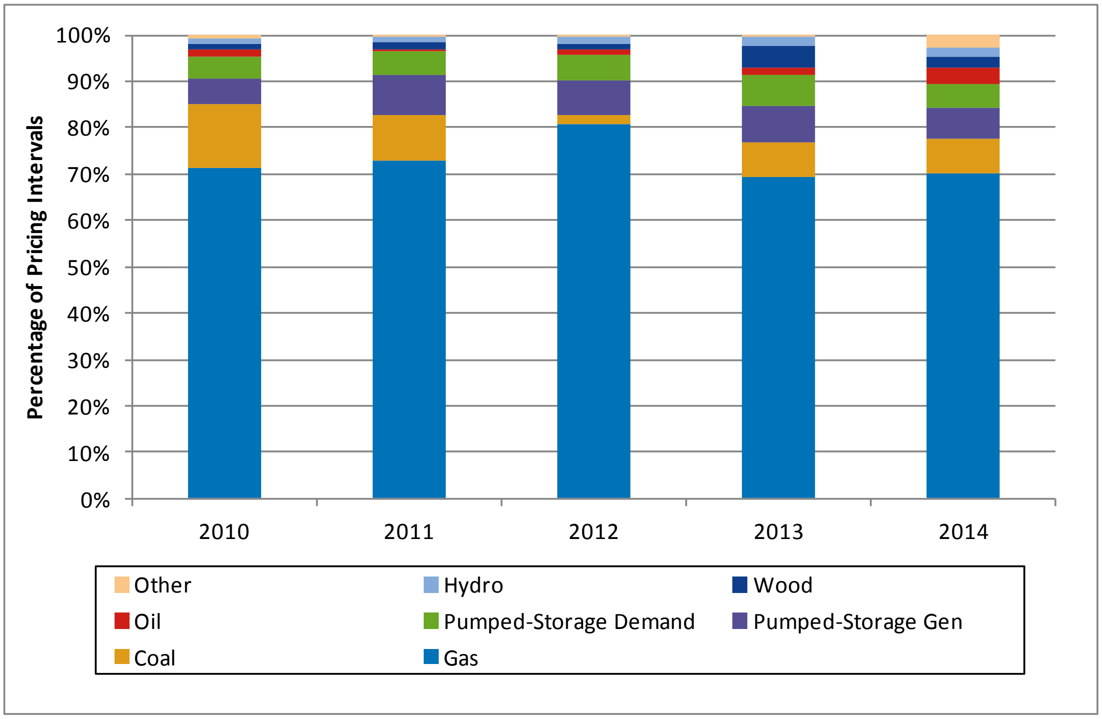

Figure 2-17: Marginal fuel-mix percentages of all pricing intervals, 2014.

2.1.4 Reliability and Operations Assessment

This section discusses ISO actions to ensure real-time reliability and an assessment of ISO operations. It includes a review of Net Commitment-Period Compensation (NCPC) payments to suppliers.

Total NCPC payments in 2014 totaled $174.1 million. This total includes both daily-reliability NCPC payments and generator performance audit (GPA) NCPC payments. Details of the payments made in 2014 are described below.

2.1.4.1 Daily Reliability NCPC Payments

The ISO is required to operate New England's wholesale power system to the reliability standards developed by North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the ISO through open stakeholder processes.[62] To meet these requirements and maintain daily system reliability, the ISO may commit resources, in addition to those cleared in the Day-Ahead Energy Market, to ensure capacity adequacy in real-time. Resources that operate at the ISO's instruction but do not recover their as-bid costs through energy market revenues are paid one of the following types of compensation, depending on the reason for the commitment:[63]

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[62] These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures. For more information on NERC standards, see http://www.nerc.com/pa/stand/Pages/default.aspx. For more information on NPCC standards, see https://www.npcc.org/Standards/default.aspx. The ISO's system operating procedures are available at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

[63] A system's *first contingency* (N-1) is when the power element (facility) with the largest impact on system reliability is lost. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that time has the largest impact on the system.

- Economic/first-contingency NCPC
    - 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
- Local second-contingency NCPC
    - Reliability costs paid to generating units providing capacity in constrained areas
- Voltage reliability NCPC
    - Reliability costs paid to generating units dispatched by the ISO to provide reactive power for voltage control or support
- Distribution reliability NCPC
    - Reliability costs paid to generating units that are operating to support local distribution networks

Daily Reliability Payments for 2014. As shown in Table 2-8, daily reliability payments totaled $173.7 million in 2014, or about 2.1% of the total wholesale cost of electricity.

Table 2-8
Total Daily Reliability Payments by Quarter, 2014 ($ Millions)

	2014	Q1	Q2	Q3	Q4
Total Daily Reliability Payments	173.7	107.7	16.8	21.5	27.8

As shown in Table 2-9, daily reliability payments in 2014 increased by $15.7 million (10%) from 2013, and first-contingency NCPC payments increased by $36.2 million (37%) from 2013. Generators fueled by natural gas were committed in late January 2014 to supply energy during extremely cold weather days when gas prices were very high. These resources were economically displaced by less expensive oil-fired resources that set the market price. The market price was insufficient to cover the cost of the higher-cost of generators fueled by natural gas because the price was set by the lower-cost oil-fired resources. The resulting revenue deficiency was paid through NCPC. Overall, 62% of all NCPC payments were paid in the first quarter of 2014, which was a period of cold weather that resulted in high natural gas prices, fuel switching, and high LMPs (see Section 2.1.3.2). Second-contingency payments decreased by $5.6 million (15%) compared with 2013, and local distribution payments decreased by 83%. Additional local capacity was committed in January and February 2013 during a cold snap and a blizzard. Voltage payments decreased by 63%, the result of variations in loads, generation, and transmission mix.

Table 2-9
Total Daily Reliability Payments, 2013 and 2014 ($ Millions)

Payment Type	2013	2014	Difference	% Change
Economic and first-contingency payments	98.2	134.3	36.2	37%
Second-contingency reliability payments	38.0	32.4	(5.7)	-15%
Distribution	5.2	0.9	(4.4)	-83%
Voltage	16.6	6.2	(10.4)	-63%
Total	**158.0**	**173.7**	**15.8**	**10%**

Table 2-10 shows that approximately 42% of all reliability payments in 2014 were made in January. Additional results are as follows:

- In January, February, and March 2014, New England experienced extended periods of very cold weather.
- In December 2014, NCPC was paid to a number of generators in real time as a result of hours with low or negative LMPs.

Table 2-10
Daily Reliability Payments by Month, 2014 ($ Millions)

Month	Total Reliability Payment
Jan	73.3
Feb	16.3
Mar	18.1
Apr	7.0
May	3.9
Jun	5.9
Jul	9.7
Aug	5.5
Sep	6.3
Oct	7.8
Nov	6.4
Dec	13.5

2.1.4.2 Generator Performance Audit NCPC Payments

NCPC payments for generator performance audits became effective on June 1, 2013.[64] NCPC payments to participants for this category are incurred for the following:

- Performance audits of on-line and off-line operating reserves and for seasonal claimed capability audits initiated by the ISO rather than the participant
- Dual-fuel testing services as part of the 2014/2015 Winter Reliability Program.[65]

Table 2-11 shows the total GPA NCPC payments made to generators during the reporting period by month.

Table 2-11
GPA Payments, 2014 ($ Thousands)

Month	Real-Time Generator Performance Audit Payment
Jan	0
Feb	0
Mar	0
Apr	0
May	0
Jun	0
Jul	0
Aug	0
Sep	0
Oct	0
Nov	380.3
Dec	25.0
Total	405.2

2.1.4.3 Winter Reliability Program

The winter reliability programs for 2013/2014 and 2014/2015 constitute the ISO's most direct actions to address fuel assurance, recognizing that winter solutions are a short-term measure and do not drive long-term investment.

The central component of the winter reliability programs has been the provision of direct financial incentives to generators to maintain on-site oil inventories. By ensuring that oil- and dual-fuel-fired generators do not run out of oil, the winter programs have directly addressed concerns about generator reliance on pipeline deliveries of fuel during periods of high natural

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[64] ISO New England and NEPOOL, *Market Rule 1 Revisions Relating to Auditing of Generation Resources*, Docket No. ER13-1323-000 (November 6, 2012), http://www.iso-ne.com/regulatory/ferc/filings/2012/nov/er13-323-000_11-6-2012_audit_claim.pdf.

[65] *Market Rule 1*, Appendix K, *Winter Reliability Solutions*, http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_k.pdf.

gas demand and stress on the pipeline system. The ISO concluded that the resources and inventory procured through the 2013/2014 Winter Reliability Program were vital to grid operation during stretches of extremely cold weather.

The 2014/2015 Winter Reliability Program built off the prior winter program, providing incentives for resources to enter into contracts for liquefied natural gas and including additional market monitoring changes designed to provide dual-fuel resources greater flexibility. In an order issued in January 2015, FERC clarified that any interim winter program, if deemed necessary, must be "an appropriate market-based solution."[66] On February 19, 2015, the ISO filed for rehearing of this order, urging the commission to permit an expansion of the existing winter program; alternatively, the ISO proposed additional increases to the Reserve Constraint Penalty Factors (see Section 2.2) to provide incentives to generators to be available in the real-time market during shortage conditions. On April 17, 2015, the Commission granted the ISO's rehearing request, finding that an expanded version of the winter program might better produce the desired reliability results than the introduction of a market-based solution. The Commission also noted its expectation that the ISO abide by its commitment to work with stakeholders to expand any future out-of-market winter reliability program so that it is fuel neutral, or explain why a fuel neutral program is not feasible.[67]

The results of the 2014/2015 Winter Reliability Program have been positive. The program has drawn robust participation from oil-, gas-fired, and dual-fuel generators that stocked oil and contracted for liquefied natural gas. The program also attracted new demand-response resources. During February 2015's extremely cold weather, oil resources had sufficient fuel to maintain reliability. Finally, six units representing over 1,700 MW took advantage of new incentives for generators to add dual-fuel capability, which is significant for long-term fuel security. The pay-for-performance market construct will be fully implemented beginning June 1, 2018. This construct will provide strong incentives for resources to be available and perform well during shortage conditions and should eliminate the need for a winter reliability program.

2.1.4.4 Exemption for dual-fuel generators from the requirement to provide documentation when natural gas and oil prices converge

In July 2014, the ISO proposed a package of market rule changes to implement the Winter Reliability Program 2014/ 2015.[68] As part of this package, changes were proposed to the requirements for dual-fuel generators to justify and demonstrate the use of the higher-priced fuel during periods of heightened gas price and volume uncertainty. Previously, a market participant with a dual-fuel generator was required to notify the IMM of its intention to burn the higher-priced fuel, explain why the lower-priced fuel was unavailable, and, afterwards, provide documentation to prove that it actually burned the higher-priced fuel. If the market participant failed to do this, the IMM would mitigate the dual-fuel generator's supply offer (calculated using the higher-priced fuel) by replacing it with the dual-fuel generator's reference level calculated based on the lower-cost fuel. This could have the effect of reducing the dual-fuel generator's NCPC payments.

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[66] See *Order on Clarification*, 150 FERC ¶ 61,029 at P 10 (January 20, 2015).

[67] See *Order Granting Rehearing*, 151 FERC ¶ 61,052 at P 17 (April 17, 2015).

[68] ISO New England Inc. and New England Power Pool, Docket No. ER 14-2047-001, *Winter 2014-15 Reliability Program* (July 11, 2014), http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14_2407_000_win_rel_pro_7_11_2014.pdf

The proposed change addressed concerns that the prevailing rules diminished the economic benefits of investing in dual-fuel capability by restricting a market participant's ability and operational flexibility to manage its fuel supply during times of uncertainty and price volatility in the natural gas market. During such times, market participants often have difficulty determining in advance of submitting a supply offer which fuel—oil or natural gas—would cost the least.

The IMM proposed that a dual-fuel generator be exempt from the requirement to justify and verify the use of the higher-priced fuel when oil and natural gas index prices converge. Specifically, this convergence would be when the ratio of the generator's higher-priced fuel index price to its lower-priced fuel index price is less than or equal to 1.75.[69] The ratio is based on a historical analysis of requests from generators to be evaluated on their higher-priced fuel, known as a dual-fuel override (DFO) request, or to be evaluated on a different price than the default index price, known as a fuel-price adjustment (FPA) request. Market participants submit DFO and FPA requests when they are faced with uncertainty of being able to procure the lower-priced fuel quantity needed to satisfy their supply-offer obligations or are exposed to natural gas price risk.

<u>Basis for the *1.75 Ratio Exemption Rule*</u>. Based on analysis as described in the ISO's July 11, 2014, filing, the natural gas index price is likely to be representative of the generators' fuel price for a given pipeline when the ratio of the higher-priced fuel (typically oil) to the lower-priced fuel (natural gas) is fairly large. Conversely, the natural gas index price for any given pipeline is less likely to be representative of the price faced by any particular generator on a pipeline when the ratio of the higher-priced index to the lower-priced index is relatively low.

When the ratio is low (when gas and oil prices converge) , dual-fuel generators are also more likely to offer on the basis of oil, given both the volume and price uncertainly associated with the procurement of natural gas in the spot market. The ratio of 1.75 is a good indicator of natural gas volume and price uncertainly. The ratio strikes an appropriate balance in terms of the benefits of allowing dual-fuel generators the flexibility to manage their fuel, thereby incenting dual-fuel capability. The ratio also minimizes any potential real-time exposure to the market of generators with local market power offering on the basis of the higher-priced fuel and burning the lower-cost fuel.

The proposed changes went into effect on December 3, 2014.[70] However, in its order approving the proposed changes, FERC expressed concern that the 1.75 ratio was determined based on 14 months of data that included the unusually cold 2013/2014 winter months, even though the changes were proposed as permanent measures. Therefore, the ISO was directed to continue to analyze the appropriateness of the 1.75 ratio and include its analysis and recommendations as part of the *2014 Annual Markets Report*.

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[69] For example, if the day-ahead index price of natural gas is $5/MMBtu and the day-ahead index price of No. 2 oil is $20/MMBtu the ratio would be calculated as $20 divided by $5 or 4.0. On the other hand, if the day-ahead index price of natural gas is $30/MMBtu and the day-ahead index price of No. 2 oil is $20/MMBtu, the ratio would be calculated as $30 divided by $20 or 1.5.

[70] FERC, *Order Accepting Tariff Revisions*, , 148 FERC ¶ 61,179, (September 9, 2014), http://www.iso-ne.com/static-assets/documents/2014/09/er14-2407-000_9-9-14_order_accept_winter_reliability.pdf.

Review of *1.75 Ratio Exemption Rule*. The initial analysis that covered January 2013 to March 2014 was expanded by an additional eleven months by including FPA and DFO data through the end of February 2015.

First, it was assessed whether the relationship between natural gas and oil prices changed significantly since the original study period. Figure 2-18 shows the ratio of the higher-priced fuel to the lower-priced fuel (between Algonquin gas and No. 2 oil) on a weekly average basis. The shaded area depicts the period covered by the original analysis, which supported the 1.75 ratio. The exhibit shows that the ratio continues to drop below the 1.75 value during long parts of the winter season when gas price levels and volatility are typically at their highest. From spring 2014, the decrease in gas prices outpaced the decrease in oil prices, thereby showing a higher ratio of oil prices to gas prices compared with 2014. This component of the analysis does not indicate a fundamental change or shift in the relationship between gas and oil prices in New England, which would itself merit a reconsideration to the 1.75 ratio.

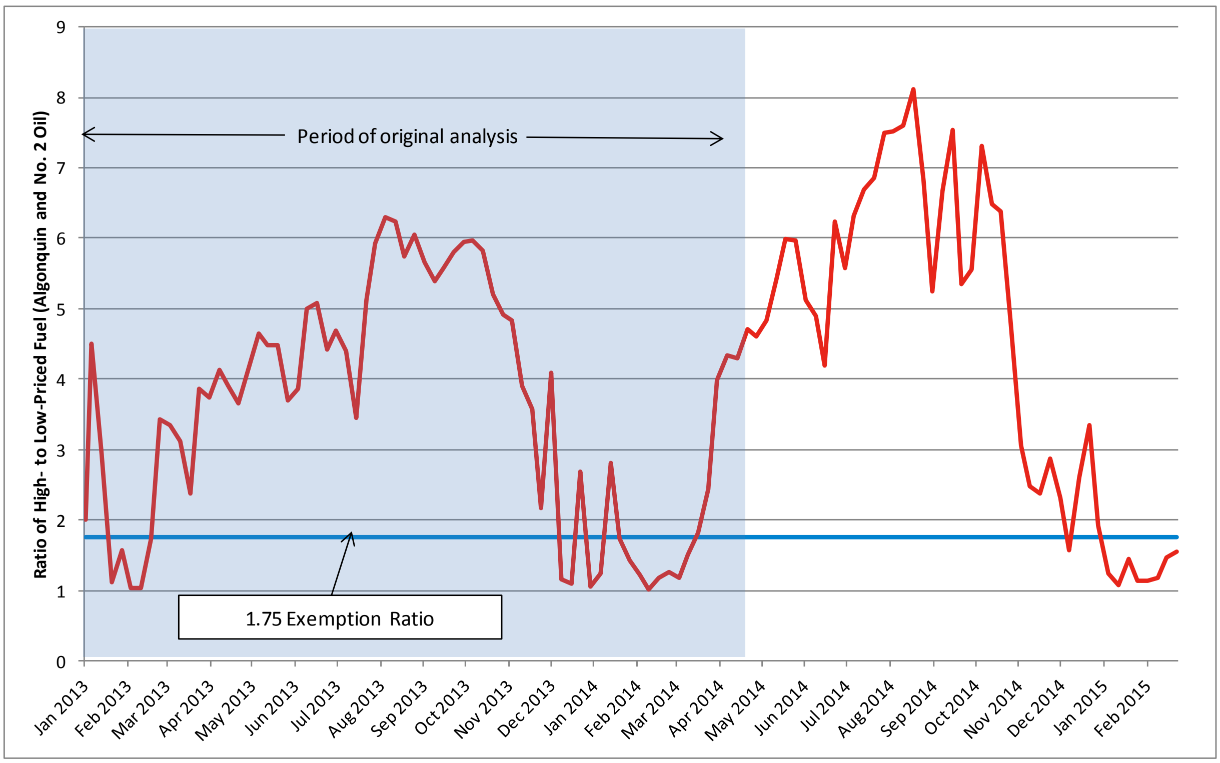

Figure 2-18: Ratio of the higher-priced fuel to lower-priced fuel for No. 2 oil and Algonquin indices, January 1, 2013, to February 28, 2013.

During the extended study period the implementation of EMOF on December 3, 2014 significantly changed how DFOs and FPAs are submitted. Before EMOF, FPAs and DFOs were submitted for an entire 24-hour period for a given market, day ahead or real time. This was because supply offers were constant across all 24 hours. Under EMOF, participants have the ability to submit different offers for each hour and can update these offers throughout the operating day. Consequently, FPAs and DFOs can now vary by hour and, likewise, can be updated throughout the operating day. To account for this significant design change, the analysis was separated between the pre-EMOF period (January 2013 through December 2, 2014) and the EMOF period (from December 3, 2014 through February 28, 2015).

As discussed above, between January 2013 and March 2014, approximately 67% of the DFO requests were submitted when the ratio of the higher-price fuel to the lower-price fuel was less than 1.75. The analysis considered all DFO requests below a maximum ratio of 5.5 and when the generator requesting a DFO actually operated. When including all observations (including those above 5.5), 62% of the DFO requests were received at ratios less than 1.75 (from generators that operated).

The results are similar when the analysis is extended through the implementation of EMOF, with 61% of all DFO requests received when the ratio was less than 1.75. This result is expected given that from April 2014 to December 2, 2014, the analysis added only 23 observations. See Table 2-12.

Table 2-12
Percentage of DFOs and FPAs when the Ratio is less than 1.75

Time Period	DFOs	FPAs
January 2013 to March 2014 *Original Analysis*	67%	55%
January 2013 to December 2014 *Pre EMOF*	61%	32%
December 2014 to March 2015 *EMOF*	82%	70%

As observed in the original analysis, 55% of the FPA requests were submitted when the ratio of the higher- to-lower-priced fuel was less than 1.75. The results change somewhat when the study period is extended through December 2, 2014 with the share of total FPAs received when the ratio was less than 1.75 falling to 32%. This is the result of there being only two days from April 2014 through December 2, 2014 when the ratio of the higher-priced fuel to the lower-priced fuel fell below 1.75. In that that eight-month period FPAs continued to be submitted by participants accounting for 40% of the total FPA requests, albeit at a much reduced premium over the index price compared to the more volatile winter months.

On approximately 70% of the days during the EMOF period, the ratio of the higher-to-lower-priced fuel was less than 1.75. As expected, the DFO requests were heavily concentrated during this period. As discussed, under EMOF, dual-fuel generators can submit and update the fuel or fuels (in the case of fuel blending) associated with their supply offer on an hourly basis. The analysis focused on the supply offer in effect during hour ending 6:00 p.m (a "peak" hour). Hour ending 7:00 a.m. (an "off-peak" hour) was also analyzed with similar results. Over the winter period since the start of EMOF, over 82% of the DFO requests for generators that actually operated were received when the ratio was less than 1.75.

With respect to FPAs, since the start of EMOF, 70% of the requests were submitted when the ratio of higher-to-lower-priced fuels was less than 1.75. As expected, during this period in general natural gas and oil price converged more frequently, indicating greater natural gas procurement and price uncertainty.

Conclusion and recommendation. In its September 9, 2014, order, FERC expressed concerns with respect to the 1.75 ratio being based on somewhat limited data, including an abnormally cold winter period with significant price volatility, and ordered the IMM to continue to analyze the appropriateness of the ratio. As a case in point, natural gas prices in winter 2014/2015 were significantly less volatile than in 2013/2014 (see Section 2.1.3.3 and Figure 2-10). Both oil and gas prices have decreased significantly on average since the original study period and continue to converge during winter months as gas price levels pick up significantly. The number of DFO and FPA requests also continues to be concentrated when the ratio of higher-priced fuels to lower-priced fuels is low, highlighting the natural gas volume and price uncertainty that generators experience.

The analysis shows that, notwithstanding the reduction in natural gas price volatility this past winter, the 1.75 ratio continues to be a reasonable and appropriate indicator of oil and natural gas price convergence. Consequently, the 1.75 ratio should remain the threshold for exempting dual-fuel units from the requirement to justify and provide documentation on the use of the higher-priced fuel. In addition, the IMM will continue to assess this ratio on the basis of how generators are using the provision and on prevailing market conditions.

2.2 Real-Time Operating Reserves

This section summarizes the performance of the real-time operating reserves markets. Operating Reserve is capacity available to the ISO that can be converted into energy within a short interval so that the system can be operated reliability in the event of unforeseen incidents such as the loss of major elements of generation or transmission equipment. In real-time, the dispatch of resources to meet the energy and operating reserve requirements is jointly optimized. In the presence of a binding reserve constraint, the real-time operating reserve price is equal to the opportunity cost of the resource not dispatched for energy to satisfy the operating reserve requirement, capped by the Reserve Constraint Penalty Factor (RCPF).[71]

2.2.1 Real-Time Operating Reserve Types and Dispatch

The ISO's operating reserve requirements are described in Operating Procedure No. 8 (OP 8), *Operating Reserve and Regulation*.[72] As specified in OP 8, the ISO must maintain a sufficient amount of operating reserves for the system as a whole and for identified transmission-import-constrained areas to be able to recover from the loss of the first-largest contingency within 10 minutes. The ISO has real-time operating reserve requirements (in MW) for the following categories (or products):

- **10-minute spinning reserve (TMSR):** This is the highest-quality operating reserve product. TMSR is provided by on-line resources able to increase output within 10 minutes, allowing the system a high degree of certainty for being able to recover quickly from a significant system contingency.
- **10-minute non-spinning reserve (TMNSR):** This is the second-highest quality operating reserve product. TMNSR is provided by off-line units that require a successful startup (i.e., electrically synchronize to the system and increase output within 10

[71] RCPFs are administratively set limits on redispatch costs the system will incur to meet reserve constraints. Each type of reserve constraint has a corresponding RCPF. In December 2014, the RCPF for 30-minute operating reserve was increased to $1,000/MWh from $500/MWh, and the RCPF for 10-minute non-spinning reserve was increased to $1,500/MWh from $850/MWh.

[72] See Operating Procedure No. 8, *Operating Reserves and Regulation* (May 2, 2014), http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf

minutes) to ensure that needed operating reserves actually will be available in response to a contingency.[73]

- **Thirty-minute operating reserve (TMOR):** This is the lowest-quality operating reserve provided by less-flexible resources within the system (i.e., on-line or off-line resources that can either increase output within 30 minutes or electrically synchronize to the system and increase output within 30 minutes in response to a contingency).

TMSR and TMNSR can be used to meet the TMOR requirements but not the other way around.

In the Real-Time Energy Market, the dispatch algorithm optimizes the use of generating resources to meet energy and operating reserve requirements while respecting transmission constraints. The dispatch uses each resource's real-time energy offer; there are no separate real-time operating reserve offers. Other features of the dispatch algorithm include the following:

- In the presence of a binding operating reserve constraint, the system dispatch may reduce the output of an otherwise economic unit in the energy market to create operating reserves on the system. When this occurs, the opportunity cost of altering the dispatch determines the market-clearing price for the operating reserve product.
- The market-clearing software will not redispatch resources to meet operating reserves at any price. When the redispatch costs exceed the RCPF, the price will be set equal to the penalty factor and the market software will not continue redispatching resources to meet operating reserves.[74]
- The market software optimizes the use of local transmission interfaces to minimize the cost of satisfying all operating reserve and energy requirements in the region.

To ensure that the incentives for providing the individual operating reserve products are correct, the market's prices maintain an ordinal ranking consistent with the quality of the operating reserve provided, as follows:

$$\text{TMSR} \geq \text{TMNSR} \geq \text{TMOR}$$

The price of higher-quality operating reserve products must be at least as high as the price of lower-quality products. For example, if the ISO alters the dispatch to provide TMOR at a cost of \$40/MWh, the prices for TMSR and TMNSR both must equal or be greater than \$40/MWh.[75]

2.2.2 Real-Time Operating Reserve Outcomes

Average annual operating reserve prices in dispatch intervals with positive operating reserve prices decreased for all products in 2014 compared with 2013. While the number of dispatch

[73] *Ten-minute non-spinning reserve* also is called 10-minute nonsynchronized reserve.

[74] When an RCPF is reached and the Real-Time Energy Market's optimization software stops redispatching resources to satisfy the reserve requirement, the ISO will manually redispatch resources to obtain the needed reserve.

[75] This price "cascading" occurs when a binding operating reserve constraint exists and higher-quality products obtain the same pricing as lower-quality operating reserve products. Because TMSR is the highest-quality product, TMNSR is the second-highest, and TMOR is the lowest-quality operating reserve product, the TMSR price is always greater than or equal to the TMNSR and TMOR prices, and the TMNSR price is always greater than or equal to the TMOR price

intervals with positive pricing for TMSR increased, the number of dispatch intervals with positive TMNSR and TMOR prices decreased. Although the percentage change in the number of dispatch intervals with positive prices is significant, the absolute number of dispatch intervals with positive prices was still low in 2014. See Table 2-13. Note that large percentage changes in average operating reserve prices seasonally and year-over-year are not uncommon. Fuel-price variation, load forecast errors, unexpected changes in system conditions, and many other factors can influence the frequency and level of operating reserves prices. However, while the change in average price might be large, the low frequency of operating reserve pricing results in very small overall market settlement impacts, as demonstrated by the payment data shown in the table.

Table 2-13
Average Operating Reserve Prices and Frequencies for Intervals with Positive Prices, 2013 to 2014[(a]

Product	Average Annual Price			Frequency		
	2013	2014	% Change	2013	2014	% Change
	($/MW/5-Min. Interval)			(% of Total 5-Min. Intervals)		
10-minute spinning reserve (TMSR)	92.44	40.94	***−55.7%***	3.2%	6.0%	***89.3%***
10-minute non-spinning reserve (TMNSR)	212.34	187.81	***−11.6%***	1.1%	0.9%	***−25.4%***
30-minute operating reserve (TMOR)	202.02	180.61	***−10.6%***	1.1%	0.9%	***−24.1%***

(a) Prices are presented for the Rest-of-System reserve zone. Average operating reserve prices are based on the preliminary prices and would not include any ex-post pricing adjustments. Ex-post adjustments to 5-minute operating reserve prices are not available.

Operating reserve pricing occurs when the system must redispatch resources away from the lowest-cost solution for satisfying energy requirements and incur additional costs to meet the system operating reserve requirement. When this happens, the operating reserve price is the opportunity cost of the least expensive resource whose energy output is reduced to provide operating reserves during redispatch. As a practical matter, the cost incurred to redispatch on-line 10-minute operating reserve assets is lower, on average, than the cost incurred to redispatch less flexible resources to provide the 30-minute operating reserves.

Table 2-13 shows that positive nonzero prices for TMSR occurred in approximately six times as many intervals as positive pricing for TMOR, but prices, on average, were significantly lower than for the other products. These low average prices are the result of low prices during the intervals when only the TMSR pricing occurred, and all other products were priced at $0/MWh. The TMSR interval price was relatively low, reflecting a lower average cost after redispatch.

Table 2-14 compares the frequency and average prices (during nonzero pricing intervals) across operating reserve zones for 2014. The frequency of binding constraints across zones was highly consistent in 2014. Only the NEMA/Boston zone experienced binding constraints and prices that were different from the Rest-of-System zone. NEMA/Boston had a higher frequency for all operating reserve products, higher average prices for TMSR, and reduced average prices for TMNSR and TMOR compared with the other zones.

Table 2-14
Real-Time Operating Reserve Clearing Prices for Nonzero Price Intervals, 2014[(a)]

Product	Operating Reserve Zone	Price ($/MW/ 5-Minute Intervals)	Frequency (% of 5-Minute Intervals)
TMSR	Connecticut	40.94	6.02%
	NEMA/Boston	43.15	6.26%
	Rest-of-System	40.94	6.02%
	Southwest Connecticut	40.94	6.02%
TMNSR	Connecticut	187.81	0.85%
	NEMA/Boston	167.67	1.09%
	Rest-of-System	187.81	0.85%
	Southwest Connecticut	187.81	0.85%
TMOR	Connecticut	180.61	0.85%
	NEMA/Boston	162.07	1.09%
	Rest-of-System	180.61	0.85%
	Southwest Connecticut	180.61	0.85%

(a) Average operating reserve prices are based on the preliminary prices and would not include any ex-post pricing adjustments. Ex-post adjustments to 5-minute reserve prices are not available.

Table 2-15 summarizes operating reserve payments for 2012 to 2014. The payments declined from 2013 to 2014. Except for NEMA/Boston TMOR payments, operating reserve payments decreased across all products and regions, with the largest decrease occurring for systemwide TMNSR.

Table 2-15
Operating Real-Time Reserve Payments, 2012 to 2014 ($ Millions)

Year	Systemwide TMSR	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR	Total
2012	11.4	12.2	1.4	3.2	1.2	0.4	**29.8**
2013	18.0	26.1	2.9	4.9	1.4	0.7	**54.0**
2014	14.4	17.4	1.8	3.3	0.6	1.1	**38.6**

In 2014, the total real-time operating reserve payments were $38.6 million. In 2013, real-time operating reserve payments totaled $54.0 million, a significant increase from $29.8 million in 2012. As discussed in the *2013 Annual Markets Report*, the increase in payments between 2012 and 2013 resulted from several changes in operating reserve programs.[76] Although operating reserve payment totals may change significantly on a percentage basis from year to year as a result of changes in operating reserve programs, fuel prices, and system conditions, total payments for operating reserves are relatively small, compared with overall energy market and capacity market payments.

[76] While changes in the ISO's reserve markets in 2013 and 2014 have increased payments, large year-to-year variation is not unusual for reserve payments. Significant levels of reserve payments are incurred during system

With respect to the implementation of pay-for-performance (see Section 3.4.3.3), the ISO made a compliance filing on July 14, 2014, in response to a FERC order requiring the ISO to increase Reserve Constraint Penalty Factors for 30-minute operating reserves, from $500/MWh to $1,000/MWh, and 10-Minute non-spinning reserves, from $850/MWh to $1,500/MWh. That change was implemented on December 3, 2014.

2.3 Regulation Market

This section presents data about the participation, outcomes, and competitiveness of the Regulation Market in 2014. The Regulation Market was competitive in 2014.

The Regulation Market is the mechanism for selecting and paying resources needed to balance supply levels with the second-to-second variations in electric power demand and to assist in maintaining the frequency of the entire Eastern Interconnection.[77] The objective of the Regulation Market is to acquire adequate resources such that the ISO meets NERC's *Real Power Balancing Control Performance Standard* (BAL-001-0).[78] NERC establishes technical standards, known as Control Performance Standards, for evaluating area control error (unscheduled power flows) between balancing authority areas (e.g., between New England and New York). For New England, NERC has set the Control Performance Standard 2 (CPS 2) at 90%.[79]

The regulation clearing price (RCP) is calculated in real time and is based on the regulation offer of the highest-priced generator providing the service. Compensation to generators that provide regulation includes a regulation capacity payment, a service payment, and a make-whole payment.[80] Unit-specific opportunity cost payments are included as a component of the regulation clearing price.

2.3.1 Regulation Pricing

In 2014, the average regulation price of $19.06/MWh was 63% higher than the 2013 price of $11.68/MWh. See Table 2-16.

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contingency periods (such as the loss of a large generator), extreme weather fluctuations, and other events that require the conversion of available reserves into electric energy or that otherwise limit the reserves available to the system. The frequency and magnitude of these events vary each year.

[77] The *Eastern Interconnection* consists of the interconnected transmission and distribution infrastructure that synchronously operates east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas, Newfoundland, Labrador, and Québec.

[78] This NERC standard (effective April 1, 2014) can be accessed at http://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx?jurisdiction=United States. Additional information on NERC requirements is available at http://www.nerc.com (2013).

[79] The primary measure for evaluating control performance, (CPS 2), is as follows:

> *Each balancing authority shall operate such that its average area control error (ACE) for at least 90% of clock-10-minute periods (six nonoverlapping periods per hour) during a calendar month is within a specified limit, referred to as L_{10}.*

More information on NERC's Control Performance Standard 2 is available at http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf (Resource and Demand Balancing; BAL).

[80] These make-whole payments ensure that units providing regulation service are compensated for the capacity cost, service cost, and unit-specific opportunity cost.

Table 2-16
Regulation Prices ($/MWh) and Total Payment (Million $), 2012 to 2014

Year	Minimum Price ($/MWh)	Average Price ($/MWh)	Maximum Price ($/MWh)	Total Payment (Million $)
2012	0	6.75	70.33	11.6
2013	0	11.68	692.08	20.4
2014	0	19.06	1,407.43	28.8

Payments to resources providing regulation service totaled $28.8 million in 2014, a 41% increase from the total regulation payments in 2013.

An interim Regulation Market solution was implemented on July 1, 2013, to address the major elements of FERC Order 755.[81] The interim solution incorporates regulation opportunity costs into the uniform regulation clearing price. Because a regulation unit's opportunity cost is affected by the Real-Time Energy Market price, the volatility of the regulation clearing price is closely related to the Real-Time Energy Market price. The maximum regulation price observed in 2014 of $1,407.43/MWh is consistent with the real-time price of $1,116.63/MWh in the prior hour.

The market efficiency and competiveness are not affected by the interim solution. However, the increase of total regulation payments is largely attributable to the market rule change. The increase in the overall natural gas price, in particular in the first quarter of 2014, has also contributed to the increase in regulation capacity and service costs and therefore the total regulation payment.

2.3.2 Requirements and Performance

New England's hourly regulation requirement has been decreasing steadily from an average requirement of 181 MW in 2002, to below 60 MW in 2013 and 2014. The average hourly regulation requirement was virtually unchanged from 59.51 MW in 2013 to 59.52 MW in 2014. The regulation requirement in New England varies throughout the day and typically is highest in the early morning and the late evening. The higher regulation requirement during these hours is the result of load variability.

The ISO seeks to maintain NERC Control Performance Standard 2 within the range of 90% to 100%. The ISO has continually met its more stringent, self-imposed CPS 2 targets. For 2014, the ISO achieved a minimum value of 91.5% and a maximum value of 96.7%.

2.3.3 Competitiveness of the Regulation Market

The competitiveness of the Regulation Market was reviewed using demand and supply curves and the results of the hourly average residual supply index for the Regulation Market (see Section 2.3). Both these measures examine the market structure and resource abundance. The

[81] *ISO New England Inc. and NEPOOL, Regulation Market Opportunity Cost Change*, Docket No. ER13-1259-000, FERC filing (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. FERC, *Regulation Market Opportunity Cost Change*, Docket No. ER13-1259-000, letter order (June 27, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/jun/er13-1259-000_6-17-13_ltr_order_accept_reg_mrkt_rev.pdf.

abundance of regulation resources implies that market participants have little opportunity to engage in economic or physical withholding. The Regulation Market was competitive in 2014.

Figure 2-19 shows the average and maximum regulation requirement (demand) and the average regulation supply for 2014 with and without the largest supplier. Because both the average and maximum regulation requirement lie to the far left end of the regulation supply curve, regulation prices do not change significantly with changes in regulation supply. If the largest supplier were removed from the Regulation Market, the impact on regulation prices would be very small. Consequently, no Regulation Market supplier can profitably withhold its resource(s) from the market.

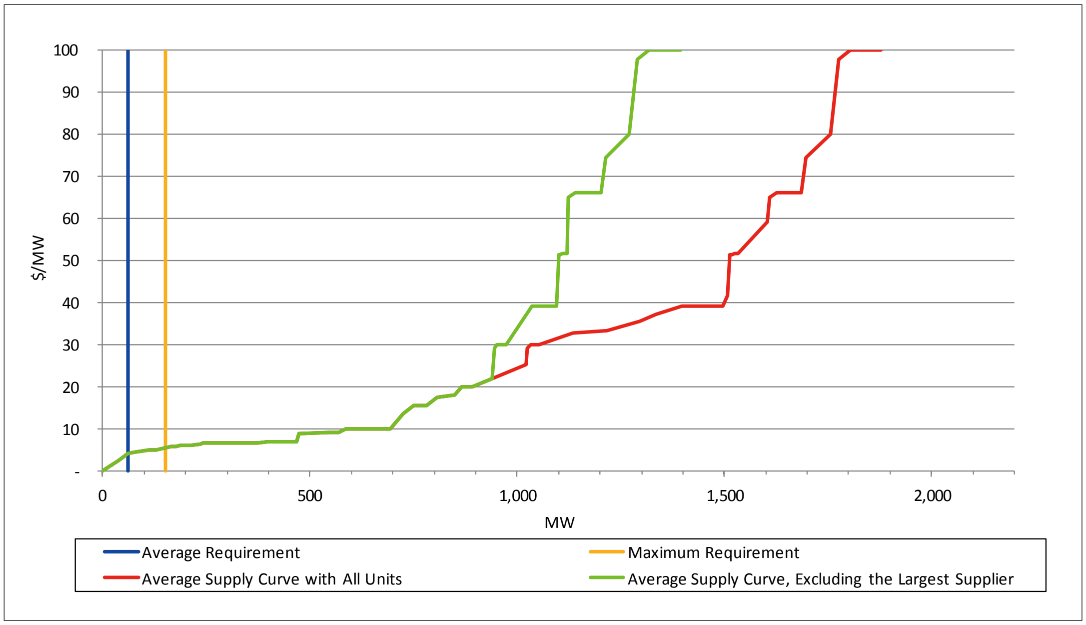

Figure 2-19: Regulation Market demand, average, and maximum requirements and supply curves with and without the largest supplier, 2014 (MW and $/MW).

Competitive conditions, along with changes in the regulation requirement, can vary during the day because of load variability and supply uncertainty. As shown in Figure 2-20, the regulation requirement and RSI are inversely correlated. In 2014, the lowest hourly average RSI did not fall below 1,000%, implying that, on average, the system has the capability to serve 10 times the regulation requirement without the largest regulation supplier, even in the hours with the greatest regulation requirement.

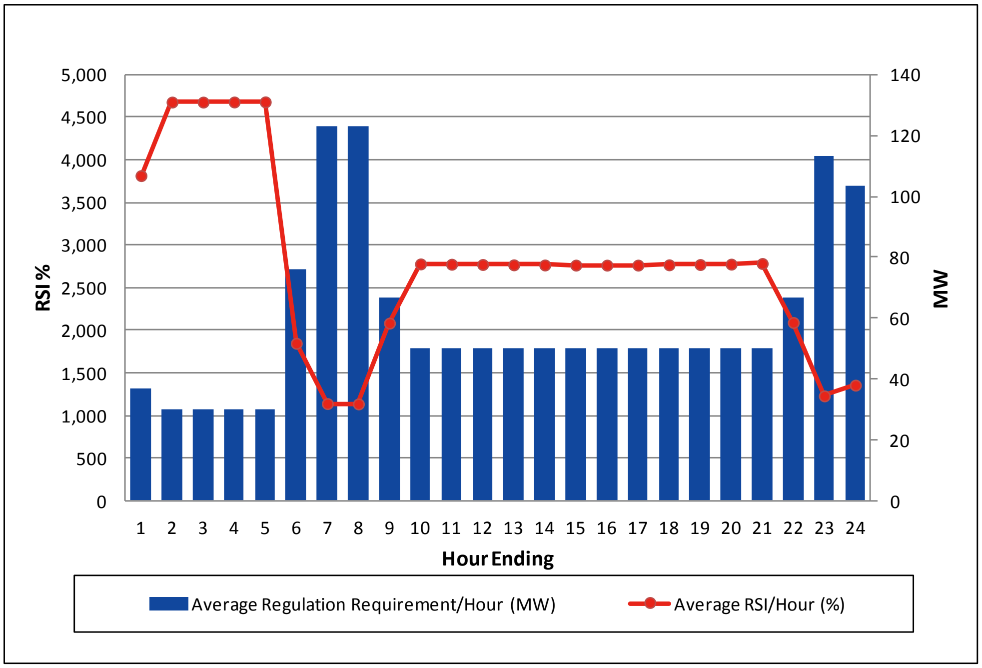

Figure 2-20: Average regulation requirement and residual supply index per hour, 2014.

Section 3
Forward Markets

This section describes the 2014 outcomes and recommendation regarding the ISO's forward markets, including the Day-Ahead Energy Market, Financial Transmission Rights, the Forward Reserve Market, and the Forward Capacity Market.

3.1 Day-Ahead Energy Market

This section provides information on the outcomes of the ISO's Day-Ahead Energy Market for 2014.

The day-ahead market allows buyers and suppliers of electricity to make purchase and sale decisions the day before the operating day. Load-serving entities (LSEs) acting on behalf of end-users may submit energy demand schedules, which express their willingness to buy a quantity of electricity at prescribed prices. Many suppliers have the option to submit day-ahead supply offers, which express their willingness to sell a quantity of electricity at prescribed prices. Suppliers with a capacity supply obligation (CSO) (see Section 3.4) must offer to sell electricity into the day-ahead market at a quantity at least equal to its CSO. In addition, as described in Section 3.1.4, any market participant may submit *virtual* demand bids (i.e., decrement bids) or supply offers (increment offers) into the day-ahead market. As the name implies, virtual demand bids and supply offers do not require a market participant to have physical load or supply.

Generator offers and virtual bids and offers are submitted at a nodal level (see Section 2.1) and indicate the willingness to buy or sell a quantity of electric energy in the day-ahead market at that location. The ISO uses a clearing algorithm that selects bids and offers to maximize social welfare, subject to transmission constraints. The day-ahead market results are posted no later than 1:30 p.m. the day before the operating day. Resources that clear in the Day-Ahead Energy Market but do not recover their as-bid costs from the market receive day-ahead Net Commitment-Period Compensation.

3.1.1 Day-Ahead Pricing

The average day-ahead Hub price in 2014 was $64.57/MWh. This price is consistent with observed market conditions, including natural gas prices, load levels, and available supply. Price differences among the load zones primarily stemmed from marginal losses, with little congestion at the zonal level. Congestion was typically restricted to smaller, more transient load pockets that formed when transmission or generation elements were out of service.

The Maine load zone continues to have the lowest average price in the region. The average LMPs in the Maine load zone were $2.61/MWh lower than the Hub price, largely because the marginal loss component of the LMPs in Maine were lower than those components at the Hub. The average LMPs in the Northeastern Massachusetts (NEMA), Southeastern Massachusetts (SEMA), and Rhode Island load zones were $0.41, $0.14, and $0.41/MWh greater, respectively, than the average Hub price, largely because the congestion components of the LMP in these zones were higher than those components at the Hub. See Table 3-1.

Table 3-1
Simple Average Day-Ahead Hub and Load-Zone Prices for 2012, 2013, and 2014 ($/MWh)

Location/ Load Zone	2012	2013	2014
Hub	36.08	56.42	64.57
Maine	35.90	54.48	61.95
New Hampshire	35.92	55.98	64.12
Vermont	36.25	55.36	63.81
Connecticut	36.77	55.43	64.09
Rhode Island	36.24	57.79	64.97
SEMA	36.09	57.02	64.71
WCMA	36.98	56.37	64.66
NEMA	36.15	56.90	64.98

3.1.2 Price Setting in the Day-Ahead Market

As shown in Figure 3-1, in the day-ahead market, generators set price approximately 42% of the time in 2014, and virtual transactions (see Section 3.1.4) set price approximately 32% of the time. These percentages are similar to 2013, when generators set price approximately 42% of the time, and virtual transactions set price approximately 33% of the time.

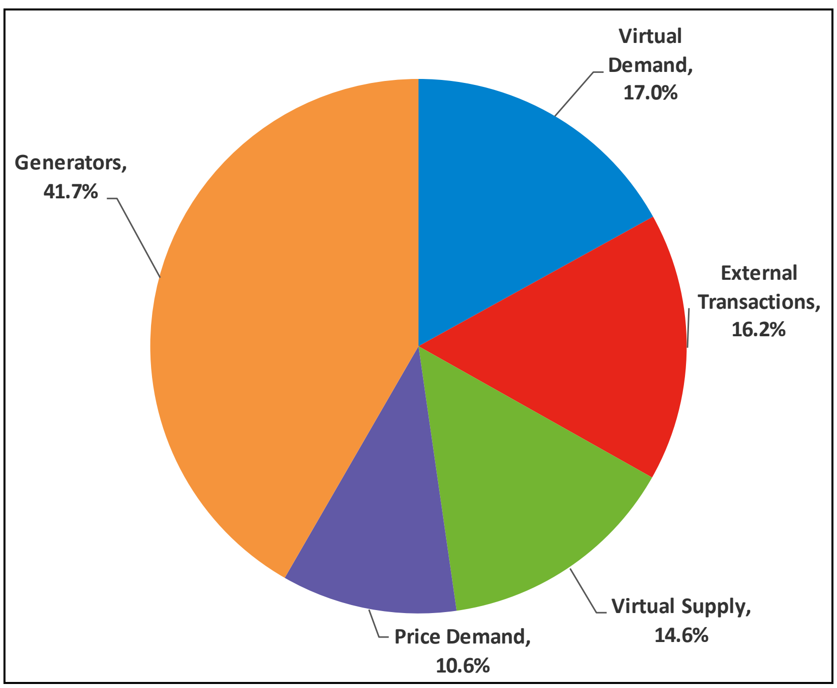

Figure 3-1: Percentage of price setting in the day-ahead market, 2014.

3.1.3 Day-Ahead Demand for Electric Energy

Fixed demand (i.e., load that LSEs purchase at any price) increased by 3,284 GWh in 2014 from 2013, which increased fixed demand as a percentage of total demand cleared in the day-ahead market from 70% in 2013 to 74% in 2014. Virtual demand and exports have decreased in both volume and as a percentage of total cleared demand over the most recent three-year period (see Section 3.1.4 and Section 2.1.3.5). Price-sensitive demand's share of total day-ahead cleared demand declined from 25% in 2013 to 23% in 2014. See Figure 3-2.

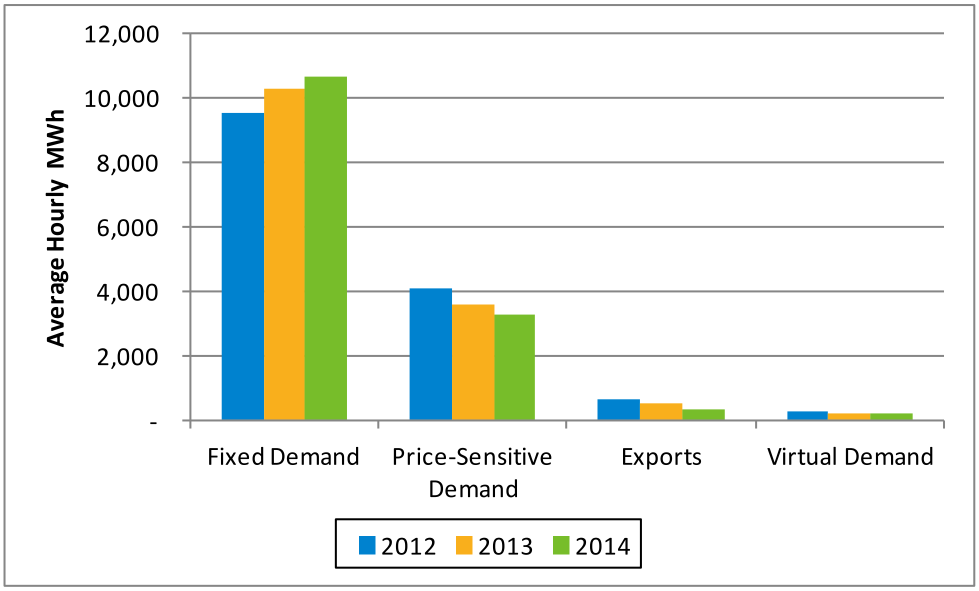

Figure 3-2: Hourly average day-ahead demand cleared, 2012 to 2014 (average MWh).

3.1.4 Virtual Transactions

Virtual transactions allow participants to buy or sell power in the Day-Ahead Energy Market without owning physical supply or load. Virtual transactions help converge day-ahead and real-time prices through arbitrage.

Cleared virtual supply offers (*increments*) in the day-ahead market and at a particular location in a certain hour, create a financial obligation for the participant to buy back the bid quantity at the real-time market price at that location in that hour. Cleared virtual demand bids (*decrements*) in the day-ahead market, create a similar financial obligation to sell the bid quantity at the real-time market price. The difference between the hourly day-ahead and real-time LMPs at the location at which the offer or bid clears determines the financial outcome for a particular participant.

Submitted and Cleared Virtual Transactions. In 2014, the volume of cleared virtual transactions (in GWh) were slightly lower than 2013, while submitted virtual transactions increased from the previous year. Cleared virtual transactions had decreased significantly in both 2012 and 2013. Together, the volume of submitted virtual demand bids and virtual supply offers totaled 30,305 GWh in 2014. The volume of submitted virtual transactions increased in 2014, the result of three participants' increased activity at external nodes. Most of the virtual transactions submitted by the participants to the external nodes did not clear. In fact, if the activity of these three participants is removed from the total volume, submitted virtual transactions only increased by 4% in 2014. Cleared virtual transactions totaled 3,794 GWh, a 0.4% decrease from 3,809 GWh in 2013. See Figure 3-3.

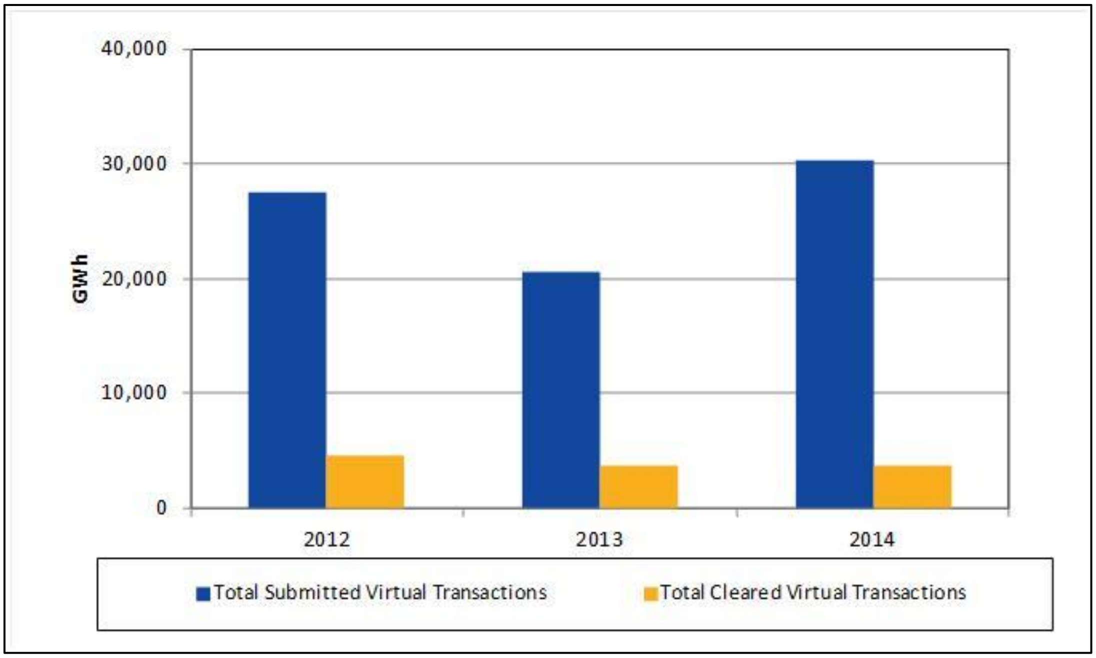

Figure 3-3: Total submitted and cleared virtual transactions, 2012 to 2014 (GWh).

After accounting for the bidding activity of three participants at external nodes, the volume of trading for virtual transactions increased only modestly in 2014. The overall decline of cleared virtual transactions in the long run continues to imply that the effects of high and uncertain transaction costs observed continue to persist, as documented in past Annual Markets Reports.

We continue to support the recommendation that the ISO should revise the market rules so that real-time Net Commitment-Period Compensation charges are not allocated to virtual transactions.

In 2014, the ISO proposed market rule changes to strengthen the incentive for load serving entities, exporters and virtual demand bidders to buy energy in the day-ahead energy market. The proposed rule changes would have excluded positive load deviations from real-time first contingency NCPC charges. However, stakeholders did not support the proposed change and the ISO opted not to file the proposed change with FERC. The ISO plans to commence a stakeholder process in 2015 to address the NCPC cost allocation issues in general including the method used to allocate first-contingency NCPC charges to both virtual demand and supply deviations.

3.1.5 Day-Ahead Supply and Self-Scheduling of Electric Energy

Market participants have the option to self-schedule their generation resources in the day-ahead market. By self-scheduling, the market participant becomes a price taker, essentially offering to sell a specified quantity at the prevailing day-ahead price. Self-scheduling behavior has been consistent over the past several years.

Day-ahead self-schedule volumes decreased by 336 GWh from 2013 to 2014. Day-ahead self-schedule volumes in 2013 and 2014 accounted for 55% of total volumes. Economic supply offers decreased to 25% of the total, slightly lower than the levels observed in 2013. Virtual supply slightly increased in both volume and as a percentage of total cleared supply. Import volumes increased volume over the past two years and comprised 18% of total cleared supply in 2014. See Figure 3-4.

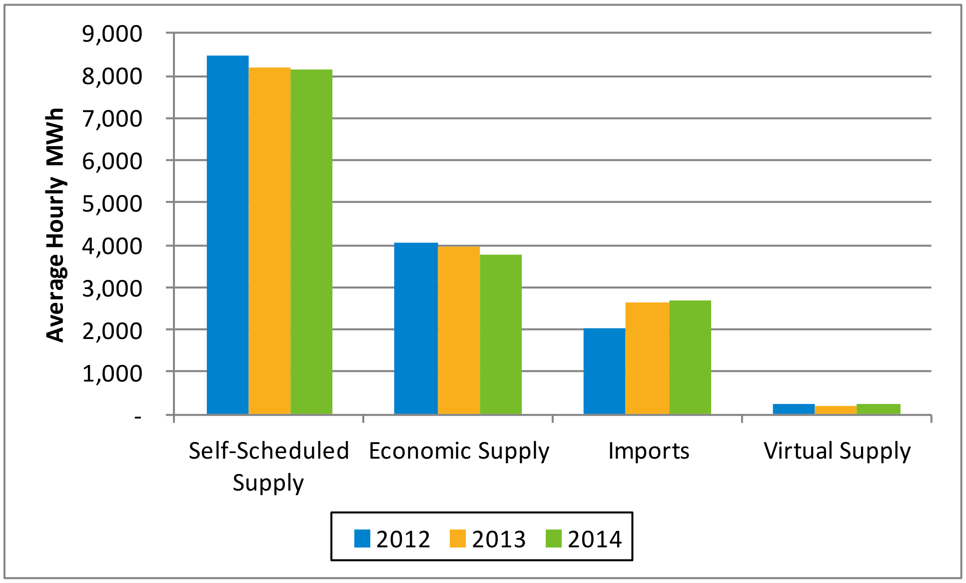

Figure 3-4: Hourly average day-ahead supply cleared, 2012 to 2014 (average MWh).

3.1.6 Relationship between Day-Ahead Energy Prices and Other Market Factors

This section compares day-ahead demand with real-time demand and analyzes the bidding behavior of load-serving entities in the day-ahead and real-time markets.

3.1.6.1 Comparison of Day-Ahead Demand with Real-Time Demand

The quantity of demand clearing in the day-ahead market is one of the factors that can have an impact on the amount of supplemental (balancing) commitments made in the reserve adequacy analysis, referred to as RAA commitments. On average, the percentage of demand purchased in the day-ahead market is fairly constant from month to month. The annual percentage of day-ahead demand cleared as a percentage of real-time demand has increased slightly, from 94% in 2013 to 96% in 2014.[82]

3.1.7 Day-Ahead Energy Market Lerner Index

This section analyzes market competitiveness and shows that the Day-Ahead Energy Market was competitive in 2014.

In this analysis, the *Lerner Index* estimates the component of the price that is a consequence of offers above cost. The Lerner Index measures price distortion. Since price is the principle means of coordinating short-run production and consumption decisions, when either profits or prices are distorted as a result of the exercise of uncompetitive behavior (i.e., bids above marginal cost), short- and long-term resource-allocation decisions can be distorted and increase overall

[82] The energy purchased in the day-ahead market is 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).

costs. In a perfectly competitive market, all participants' offers would equal their marginal costs. The analysis shows that competition among suppliers limited their ability to offer substantially above marginal cost.

To calculate the Lerner Index, the Day-Ahead Energy Market clearing was simulated under two scenarios:[83]

- Scenario 1 is an *offer case* that uses the actual offers market participants submitted for the Day-Ahead Energy Market.
- Scenario 2 is a *marginal cost case* that assumes that all market participants offer at an estimate of the participant's short-run marginal cost.

The percentage difference between the annual generation-weighted average LMPs for the offer case and the marginal cost case simulations was then calculated. The Lerner Index (L) is calculated as follows:

$$L = \frac{LMP_O - LMP_{MC}}{LMP_O} \times 100$$

Where:

LMP_O is the annual generation-weighted average LMP for the offer case.

LMP_{MC} is the annual generation-weighted average LMP for the marginal cost case.

A larger L means that a larger component of the price is the result of marginal offers above the participant's marginal cost. A change in an inframarginal resource's marginal cost or market share does not change the Lerner Index; only the offers of marginal units have an impact on this measure.

For 2014, offers above marginal cost added no more than approximately 9% to the Day-Ahead Energy Market price. Table 3-2 shows the summary results of the Lerner Index. These results are within normal year-to-year system and modeling variability for this measure.[84]

Table 3-2
Lerner Index, 2012 to 2014 (%)

Year	Lerner Index
2012	9.9
2013	4.3
2014	9.0

83 The IMM uses the PROBE, or "Portfolio Ownership and Bid Evaluation," simulation model for this analysis. The software simulates the day-ahead LMP-based market clearing. See http://www.power-gem.com/PROBE.htm.

84 Note that the IMM's estimates of marginal cost may understate or overstate actual costs, and the simulations are subject to modeling error.

To put these results in context, in constrained areas, the offer-mitigation rules allow participants to submit offers the lesser of $25/MWh or 50% above reference levels without review. In unconstrained areas, the rules allow offers that are the lesser of $100/MWh or 300% above reference levels without review.

The size of these threshold limits allow for inaccuracies due to estimation errors and simplifications that must be made as part of the method of estimating each resource's marginal costs. If the market were not competitive, the profit-maximizing strategy, at least some of the time, would be for participants to submit offers $25/MWh to $100/MWh above their marginal costs, depending on system conditions. If this strategy were viable, instead of the marginal resources adding 9% on average to their offers, the market would observe a much larger adder above marginal cost on the typical offer.

3.2 Financial Transmission Rights

This section summarizes the 2014 activities and results associated with Financial Transmission Rights (FTRs).

Financial Transmission Rights allow participants to hedge transmission congestion costs by providing a financial instrument to arbitrage differences between expected and actual day-ahead congestion. The FTR instrument entitles the holder to receive, over a monthly or annual period, a stream of revenues (or obligates it to pay a stream of charges) that arise when the transmission grid is congested in the Day-Ahead Energy Market. The FTR payoff is based on the difference between the day-ahead congestion components of the hourly LMPs at each of the two pricing locations (nodes) that define the FTR and its megawatt quantity acquired in the FTR auctions.[85] Participants can acquire FTRs for any path on the system defined by two pricing locations. The origin location of an FTR is called the *source* point, and the FTR delivery location is called the *sink* point. The price of a particular FTR is determined by the difference between the prices at the sink location and the source location in the FTR auction.

Annual FTRs are offered in a single auction, and additional monthly FTRs are offered before each month during the year. The annual FTR auction makes available up to 50% of the transmission system capability expected to be in service during the year. In the monthly auctions, up to 95% of the expected transmission capability for the month is available.[86] The total volume of FTRs transacted in each auction is a function of the offers and bids submitted subject to the transmission limits modeled.

Participants buy or sell FTRs for different reasons. Participants with physical generation or load may choose to use FTRs as a tool for managing congestion risk associated with delivery obligations. A load-serving entity may choose to purchase FTRs to protect against transmission costs associated with congestion on particular paths or in particular zones where its load is served. Congestion-paying LSEs receive *Auction Revenue Rights* (ARRs), which are rights to

[85] The minimum quantity for an FTR is 0.1 MW.

[86] The remaining 5% is reserved to account for unplanned outages.

receive a portion of FTR auction revenues. Revenues collected from the auctions are distributed back to congestion-paying LSEs.[87]

Financial participants who have no physical obligations in the ISO markets may also buy and sell FTRs. These participants attempt to profit by arbitraging the difference between the prevailing FTR price and the FTR's true value as reflected in its payout. These activities add liquidity to the FTR auctions. Participation by financial participants can increase or decrease the total auction revenues. FTR paths that clear with a positive price result in increased auction revenues, while paths with negative clearing prices result in decreased auction revenues. Efficient auction outcomes are those that result in average path prices that have a risk-adjusted profit of zero.

3.2.1 FTR Auction Results

Forty-seven participants took part in at least one of the 13 FTR auctions in 2014, down from the 48 participants who took part in at least one of the FTR auctions in 2013.

The total megawatts bought and sold in the 2014 FTR auctions, regardless of directional flow, were 604,391 MW. Of this total, the percentage of megawatts associated with counterflow positions was 20%, up from 16% in 2013. Counterflow FTR positions free up transmission capacity that otherwise would have been constrained. Figure 3-5 shows the volume of megawatts bought and sold in each monthly FTR auction in 2014.

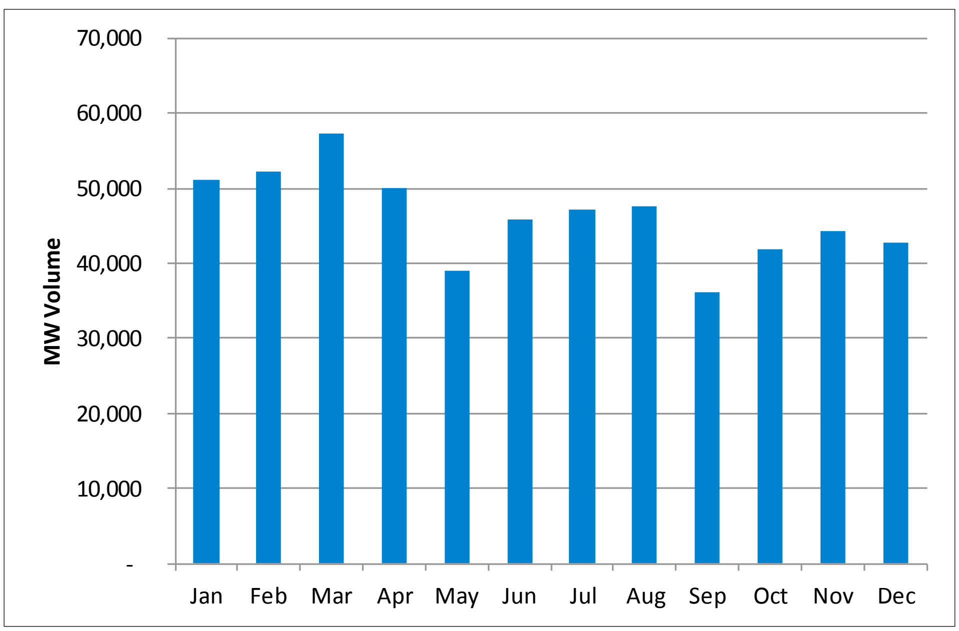

Figure 3-5: FTR monthly volumes, 2014 (MW).

Note: All megawatts, whether prevailing flow or counterflow, are treated as positive megawatts in this figure.

[87] *ISO New England Inc. Transmission, Markets, and Services Tariff*, Section III.5.2, *Market Rule 1* "Transmission Congestion Credit Calculation" (February 16, 2015), http://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

The total net revenue from the 12 monthly auctions and the single annual auction was $31.8 million, a 58% increase from 2013.[88] Of the $31.8 million in net revenue, $12.7 million was from the 12 monthly auctions.[89] See Figure 3-6.

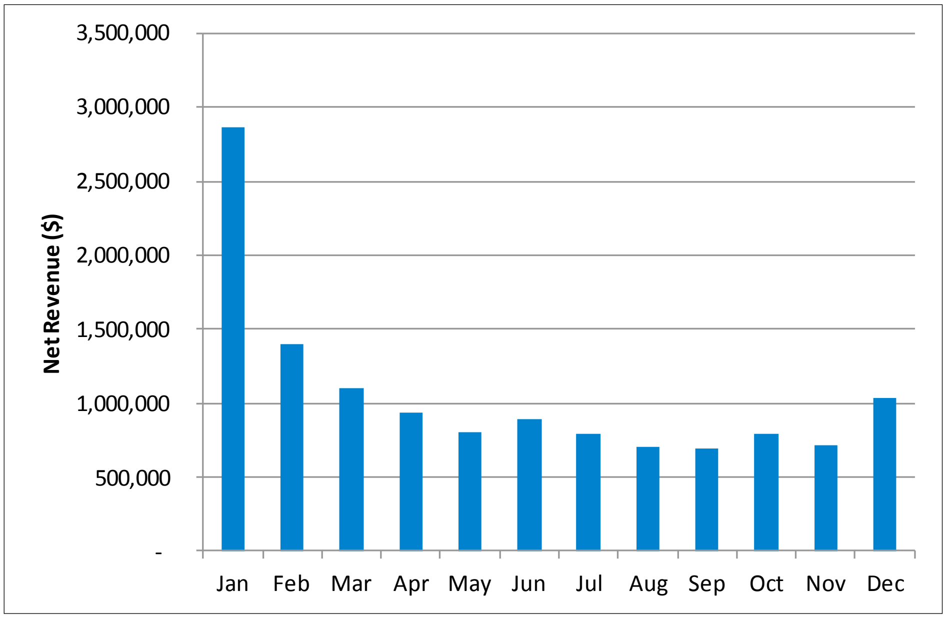

Figure 3-6: FTR monthly net revenues, 2014 ($).

If FTR participants had perfect foresight, the total auction revenue would equal the day-ahead congestion revenue; however, market prices, the actual availability of generators, and the actual outages on the transmission system differ from the assumptions in the FTR auction, causing actual congestion to be different from what cleared in the auction.

In 2014, the day-ahead congestion revenue was $34.2 million, a decrease from the $46.2 million of day-ahead congestion revenue in 2013. Although the day-ahead congestion revenue decreased by 26% in 2014, the total auction revenue increased by 57%, from $20.1 million in 2013 to $31.6 million in 2014. In 2014, auction revenues were more representative of day-ahead congestion revenue than for prior years. Despite these shifts, congestion revenue was still adequate to fully fund FTR positions such that there was no shortage that needed to be allocated back to FTR holders. See Table 3-3.

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[88] Net revenue for the monthly auctions = (net revenue of bought FTRs) – (net revenue of sold FTRs).

[89] Beginning in 2013, the FTR annual auction was revised from a single-round auction to a two-round auction. See ISO New England Inc. and NEPOOL, *FTR Annual and Monthly Auction Changes*, Docket No. ER12-2195-000, FERC filing (July 3, 2012), http://www.iso-ne.com/regulatory/ferc/filings/2012/jul/er12-2195-000_7-3-12_ftr_changes_part_1_of_2.pdf.

Table 3-3
Comparison of Day-Ahead Congestion Revenue with Auction Revenue, 2012 to 2014

	Total Auction Revenue (Millions $)	Day-Ahead Congestion Revenue (Millions $)	Auction Revenue as % of Day-Ahead Congestion Revenue
2012	16.1	29.3	55%
2013	20.1	46.2	43%
2014	31.6	34.2	92%

The most active FTR participants in 2014 were reviewed. Activity in this analysis is defined as the sum of all megawatts transacted by a participant, regardless of whether the FTRs were prevailing flow, counterflow, bought, or sold. The two most active participants with FTRs in 2014 were financial players who accounted for approximately 38% of total transacted megawatts. Financial participants are more likely to buy and sell FTR positions many times as new information becomes available. See Figure 3-7.

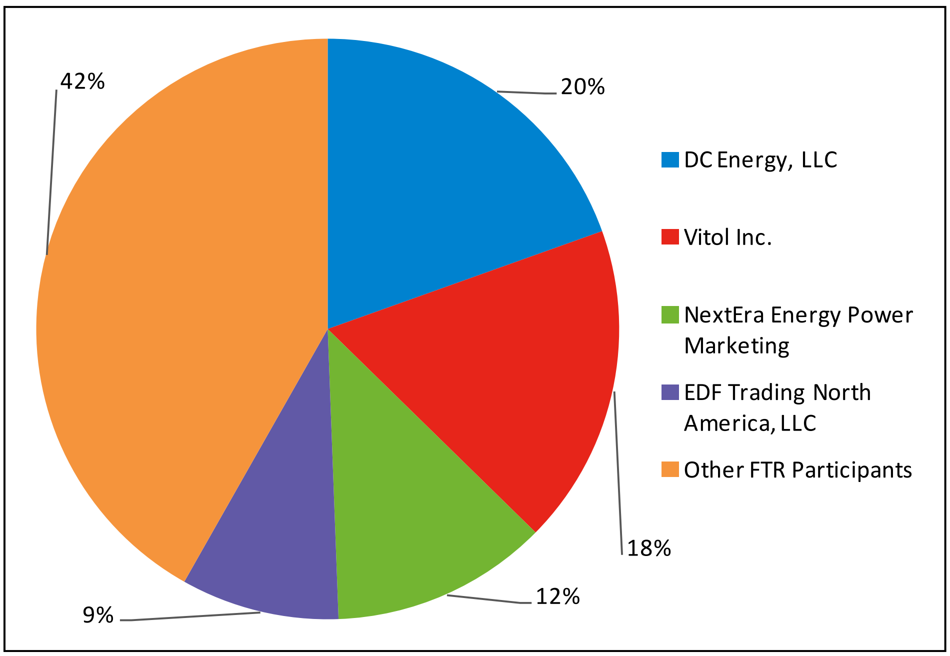

Figure 3-7: Participant share of FTR activity, 2014.

3.3 Forward Reserve Market

This section presents the outcomes of the two forward-reserve auctions conducted in 2014.

To maintain system reliability, all bulk power systems maintain operating reserve capacity to respond to contingencies, such as unexpected outages (refer to Sections 2.1.1.2 and 2.1.4). The locational FRM procures operating reserve capacity from participants with resources that can provide reserves, including 10-minute non-spinning reserve (TMNSR), 30-minute operating reserve (TMOR), and locational TMOR. Auctions are held twice a year, for a summer delivery period and a winter delivery period. Participants submit offers to sell a quantity of an operating reserve type in a particular location and at a specific price. During the delivery period, a participant with an obligation must assign resources daily to meet the obligation or incur nonperformance penalties.

3.3.1 Auction Results

In 2014, FRM prices for the systemwide products increased in both the summer and the winter auctions. The 2014 summer systemwide TMNSR price increased 114% relative to summer 2013. Similarly, the 2014 winter systemwide TMNSR price increased by 6%.

The clearing price in the FRM auction in summer 2014 was $12,709/MW-month. In the winter 2014/2015 auction, the clearing price was $8,990/MW-month. See Table 3-4.

Table 3-4
Auction Clearing Price, Four Most Recent FRM Auctions ($/MW-month)

Location	Product	Summer 2013	Winter 2013/2014	Summer 2014	Winter 2014/2015
CT	TMOR	5,946	6,290	12,709	8,990
NEMA/Boston	TMOR	5,946	6,290	12,709	8,990
SWCT	TMOR	5,946	6,290	12,709	8,990
Systemwide	TMNSR	5,946	8,451	12,709	8,990
Systemwide	TMOR	5,946	6,290	12,709	8,990

The net payments to FRM resources equal the FRM auction clearing price minus the Forward Capacity Market (FCM) clearing price. The FCM clearing price for the 2014/2015 capacity commitment period (see Section 3.4) was $3,209/MW-month; therefore, the net payment received by operating reserve providers was $9,500/MW-month for the summer 2014 auction and $5,781/MW-month for the winter 2014/2015 auction. Price separation across regions did not occur in the winter 2014/2015 FRM auction. The winter 2013/2014 auction had price separation with the TMNSR and TMOR products, which is attributable to increased systemwide operating reserve requirements.[90]

Several factors contributed to the auction clearing price increase observed in the summer 2014 auction. First, total TMNSR and TMOR requirements increased from 2,072 MW in the summer 2013 auction to 2,464 MW in the summer 2014 auction. The addition of replacement reserves contributed to an increase in the total reserve requirement. During summer 2014, the replacement reserve requirement was 160 MW. The increase in reserve requirement necessitated moving further up the supply curve to higher priced offers in order to clear the required quantity. Second, the FRM penalty structure changed after the winter 2013/2014 delivery period. Market participants who fail to meet their FRM obligation are now subject to higher penalties. Market participants may have quantified their expected exposure to these penalties and incorporated those risks into their offers. Third, the forward-reserve heat rate, used in the calculation of the daily forward-reserve threshold price, increased from 16,010

[90] The ISO proposed higher reserve requirements in 2012 to address risks identified in its Strategic Planning Initiative. This increase in reliability was acquired through the markets, including the local Forward Reserve Market. The increased requirement went into effect for the summer 2013 auction.

Btu/kWh in the summer 2013 auction to 18,310 Btu/kWh in the summer 2014 auction, and it increased from 15,962 Btu/kWh in the winter 2013/2014 auction, to 18,973 Btu/kWh in the winter 2014/2015 auction.[91] These increases imply a higher energy market threshold price at or above which designated resources must offer, and therefore higher opportunity costs of participating in the FRM.

Clearing prices decreased between the summer 2014 auction and the winter 2014/2015 auction. This was the result of a significant increase in supply and a modest decrease in demand between the auctions.

- The amount of supply offered into the auction to meet the TMNSR and TMOR requirements increased by almost 13%. Systemwide TMOR supply offered into the auction increased from 711 MW in the summer 2014 auction to 960 MW in the winter 2014/2015 auction, a 35% increase. Systemwide TMNSR supply offered into the auction increased from 2,509 MW in the summer 2014 auction to 2,669 MW in the winter 2014/2015 auction, a 6% increase.

- Both total TMNSR and TMOR requirements decreased from the summer 2014 auction to the winter 2014/2015 auction by about 3%. The TMNSR requirement went from 1,573 MW to 1,562 MW (a 1% decrease), while the TMOR requirement went from 891 MW to 831 MW (a 7% decrease).

3.3.2 Market Requirements

The ISO defines locational requirements, as well as a systemwide requirement, for each operating reserve product procured in the auction.[92] As noted above, in 2013 the ISO filed rules to increase the forward reserve requirements in alignment with other efforts to improve system recovery from contingencies. As a result, the systemwide requirements for TMNSR increased. The summer 2013 and winter 2013/2014 requirements were 1,349 MW and 1,532 MW, respectively. In summer 2014 and winter 2014/2015, these requirements increased to 1,573 MW and 1,562 MW, respectively. This represents a 17% increase in the summer requirements and a 2% increase in the winter requirements. See Table 3-5.

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[91] The heat rate used for a specific Forward Reserve Procurement Period is the implied heat rate value that occurs at the 97.5th percentile. Before the summer 2014 auction, the heat rate was calculated based on the historical period from the start of Standard Market Design (2013) to the most recent available data. Starting in the summer 2014 auction, the historical data were truncated to the last five-year period.

[92] The TMNSR and TMOR requirements are based on first- and second-contingency losses (refer to Sections 2.1.4 and 2.2.1). The methodology to calculate these requirements is described in OP 8 (Section 2.2.1) and *the ISO New England Manual for Forward Reserve* (Manual M-36) (December 3, 2013), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

Table 3-5
Local Operating Reserve Requirements
Summer 2014 and Winter 2014/2015 Forward Reserve Auctions (MW)

Location Name	Product	Summer 2013	Winter 2013/2014	Summer 2014	Winter 2014/2015
CT	TMOR[(a)]	747	578	900	363
NEMA/Boston	TMOR[(a)]	0	0	0	0
SWCT	TMOR[(a)]	0	155	94	87
Systemwide	TMNSR	1,349	1,532	1,573	1,562
Systemwide	TMOR[(a)]	723	915	891	831

(a) TMNSR also can be used to satisfy this requirement.

The additional systemwide requirement increased the amount of TMNSR that would be procured during the summer 2014 and winter 2014/2015 periods. The local operating reserve requirement for NEMA/Boston was zero because the external operating reserve support exceeded the local second contingency capacity requirement in this location in the auctions held in 2014.

3.3.3 External Reserve Support

Through external reserve support (ERS), resources within a local region as well as operating reserves available in other locations, if needed, can satisfy second contingency capacity requirements. As a result of transmission upgrades, the ERS to several import-constrained regions has changed. See Table 3-6.

Table 3-6
External Reserve Support in the Past Four FRM Auctions (MW)

Location Name	Summer 2013	Winter 2013/2014	Summer 2014	Winter 2014/2015
CT	464	650	319	861
NEMA/Boston	1,224	2,109	959	1,723
SWCT	1,172	347	401	686

3.4 Forward Capacity Market

This section provides information on the 2014 outcomes of the Forward Capacity Auctions (FCAs), trends in capacity supply obligations, and FCM performance. An update is also provided on recent as well as proposed market rule enhancements.

The Forward Capacity Market is a long-term market designed to procure the resources needed to meet the region's local and systemwide resource adequacy requirements. The FCM is designed to procure and price capacity before the system will need it. This facilitates attracting new capacity resources (e.g., generation, imports, and demand resources), maintaining more efficient existing resources, and retiring less efficient resources through a coordinated market to meet the region's resource adequacy standard. The region developed the FCM in recognition of the fact that the energy market does not provide sufficient revenue to facilitate new investment or, in many cases, cover the cost of maintaining and operating existing resources. If the capacity market does not replace this "missing" revenue, suppliers could not expect to recover their total costs and would not enter the marketplace—or would soon exit. In this event, additional demand would go unserved and reliable service would not be achieved. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue and thereby induce suppliers to undertake the investments necessary for reliable electric power service.

To allow enough time to construct new capacity resources, Forward Capacity Auctions are held each year, 40 months in advance of when the capacity resources must provide service. The period during which the resource is to provide service is called the capacity commitment period (CCP). Both new and existing capacity resources must qualify for an FCA to participate in the auction.

Each Forward Capacity Auction is conducted in two stages: a descending-clock auction followed by an auction-clearing process. The descending-clock auction consists of multiple rounds. During one of the rounds in each auction, the amount of capacity willing to remain in the auction at a given price level will equal or fall below the *Installed Capacity Requirement* (ICR).[93] FCM resources that remain in the auction receive the FCA clearing price, as determined in the auction-clearing stage of the FCA.

Reconfiguration auctions take place before and during the capacity commitment period to allow participants with capacity supply obligations to trade their positions with other resources that do not have CSOs or wish to assume additional CSOs. Annual reconfiguration auctions (ARAs) to acquire one-year commitments are held approximately two years, one year, and just before the capacity commitment period begins. Monthly reconfiguration auctions, held beginning the first month of a capacity commitment period, adjust the annual commitments during the commitment period.

Two key provisions of the capacity payment structure currently are the peak energy rent (PER) adjustment and the penalties incurred for resource unavailability during shortage events (i.e., periods of scarcity).

3.4.1.1 Peak Energy Rent

The *peak energy rent* adjustment is primarily a protection for load against energy prices in real-time that are above a threshold (i.e., *strike price*.), which is an estimate of the cost of the most expensive resource on the system. Load has paid in advance for sufficient capacity to maintain reliability through the FCM. The PER adjustment limits the gains to generators and import capacity resources, even those not producing energy, who sold capacity forward in the FCM in hours with high real-time prices resulting from shortage conditions.[94] This helps ensure that load does not pay through the FCM to maintain a fleet that meets reliability conditions and then later pay when those reliability conditions are not met and result in high real-time prices. The

[93] The ICR is the minimum amount of resources (level of capacity) a balancing authority area needs in a particular year to meet its resource adequacy planning criterion, according to *NPCC Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System*. This criterion states that the probability of disconnecting any firm load because of resource deficiencies shall be, on average, not more than 0.1 day per year.

[94] Demand resources are excluded from the PER adjustment.

PER value is based on revenues that would be earned in the energy market by a hypothetical peaking unit with heat rate of 22,000 British thermal units/kilowatt-hour (Btu/kWh) that uses the more expensive of either natural gas and No. 2 fuel oil.

The PER adjustment also discourages physical and more extreme economic withholding. The revenue adjustment resulting from the PER adjustment is based on the entire quantity sold in the capacity market, not just the portion of that capacity subject to the high real-time price. As a result, a withholding strategy that increases real-time price above the PER strike price can cause a significant revenue adjustment for the portfolio that outweighs the potential benefits of withholding.[95]

3.4.1.2 Performance Incentives and Penalties

The current FCM design includes penalties for resources that are unavailable during shortage events, in theory, creating an incentive for resources to be available during these events. Paying for actual performance during shortage events provides an incentive to resource owners to make investments to ensure that their resources will be ready and able to provide energy or operating reserves during these periods. To be effective, the capacity market must replicate the performance incentives that would exist in a fully functioning and uncapped energy market by linking payments to performance during scarcity conditions. Without this linkage, individual suppliers would lack the incentive to make investments that ensure the performance of their resources when needed most. Also, absent these incentives, resources that have not made such investments, and are presumably less reliable as a result, would become more likely to clear in future FCAs because they can offer at lower prices. This can create a structural bias in the FCM to clear less reliable resources, which will erode reliability over time.

Under the current FCM design, the consequences for nonperformance are negligible. Even with recent revisions to the shortage-event definition, as described in Section 3.4.3.3, shortage events are extremely rare. Furthermore, the current rules include numerous exemptions under which resources are considered "available" during a shortage event even when they do not provide any energy or operating reserves. Finally, even when a capacity resource is exposed to penalties under the current design, these penalties are capped such that FCM obligations can have no net loss.

The pay-for-performance design, described in more detail in Section 3.4.3.3, will replace the current FCM design starting in the 2018/2019 capacity commitment period with one that is a true, two-settlement forward market. Pay for performance is built around a well-defined product—the delivery of energy and operating reserves when they are needed most. Its rules apply in the same manner to all resource types, without exceptions. Pay-for-performance is expected to create strong incentives for resource performance, consistent with the goals of the capacity market.

3.4.2 Capacity Market Auction Outcomes

This section reviews the outcomes and performance for the fourth through eighth FCAs and represents the auctions conducted through the reporting periods. Information on past capacity commitment periods is included in prior Annual Markets Reports.

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[95] The lower volatility of total payments might not affect the entire amount that load participants pay in the long run because the resources' capacity bids reflect the lower PER-adjustment amounts.

3.4.2.1 Overview of Forward Capacity Market Results[96]

Table 3-7 shows the following data for FCA #4 through FCA #8:

- Total amount of capacity cleared in each auction
- Amount of capacity needed (i.e., the net ICR [NICR])
- Amount of surplus or deficit capacity
- Net capacity additions for that period
- Capacity price

Table 3-7
FCM Capacity Commitment Period Results, 2013/2014 to 2017/2018
(MW and $/kW-month)

Factor	FCM Capacity Commitment Period[(a)]				
	2013/ 2014	**2014/ 2015**	**2015/ 2016**	**2016/ 2017**	**2017/ 2018**
Cleared capacity resources (MW)	37,500	36,918	36,309	36,220	33,702
Net ICR (MW)	32,127	33,200	33,456	32,968	33,855
Surplus (Deficit) (MW)	5,373	3,718	2,853	3,252	(153)
Net capacity additions (MW)[(b)]	1,490	1,176	2,041	2,763	1,536
Capacity price ($/kW-month)	2.95	3.21	3.13	3.15[(c)]	7.03[(d)]

(a) The FCM period began June 1, 2010; the capacity commitment period 2013/2014 is for the fourth FCA.

(b) Net capacity additions reflect cleared new capacity, excluding repowering projects and including imports.

(c) The NEMA/Boston capacity price was administratively set to $14.999/kW-month for new resources. All other resources were paid $3.15/kW-month.

(d) Insufficient competition was triggered in the auction; existing (non-NEMA/Boston) resources will be $7.025/kW-month. The Capacity Carried Forward Rule was triggered in NEMA/Boston; new and existing resources in this zone will receive $15/kW-month.

3.4.2.2 Reconfiguration and Bilateral Auction Results

The annual and monthly reconfiguration auctions provide participants the opportunity to exchange the CSOs they have for an annual commitment period or for a particular month. Each reconfiguration auction clears at a different price and quantity depending on the amount of CSO megawatts participants are willing to acquire and transfer. Table 3-8 shows that the clearing prices in the annual reconfiguration auctions increased steadily and were lower than the prices in the corresponding FCAs (shown in Table 3-7). The clearing price, while still less than the corresponding FCA, has been increasing to reflect the lower capacity margins expected for future capacity delivery periods.

[96] Sections 3.4.3.2 and 3.4.3.4 discusses the results of the eighth FCA in more detail.

Table 3-8
Annual Reconfiguration Auction Clearing Prices and Quantities, 2014/2015 to 2016/2017 (MW and $/kW-month)

Commitment Period	Auction	Cleared CSOs (MW)	Clearing Price ($/kW-month)
2014/2015	ARA #3	628	1.93
2015/2016	ARA #2	486	2.75
2016/2017	ARA #1	814	3.15[a]

(a) In this reconfiguration auction, NEMA/Boston had a clearing price of $12.11/kW-month.

Table 3-9 shows the clearing prices and quantities in the monthly reconfiguration auctions. Monthly auction clearing prices have increased thus far in the monthly auctions for the 2014/2015 commitment period compared with the 2013/2014 commitment period, the result of generation exiting during the capacity period.[97]

- For the 2013/2014 commitment period, the monthly prices ranged from $0.25/kW-month to $2.00/kW-month, and cleared volumes ranged from 169 MW (for June 2013) to 1,344 MW (for February 2014).
- The 2014/2015 commitment period, to date, has obtained prices ranging from $0.25/kW-month to $2.65/kW-month, whereas cleared volumes have ranged from 618 MW (for December 2014) to 912 MW (for November 2014).

Table 3-9
Clearing Prices and Quantities in the Monthly Reconfiguration Auctions, 2013/2014 to 2014/2015 (MW and $kW-month)

Commitment Period	Average of Monthly Cleared CSOs (MW)	Weighted Average of Monthly Clearing Price ($/kW-month)
2013/2014	778	0.87
2014/2015 (to date)	806	1.52

3.4.3 Trends in Capacity Supply Obligations

Table 3-10 presents data for generation, demand response, and import capacity cleared in the FCA for each capacity commitment period from 2013/2014 to 2017/2018.

[97] All the monthly reconfiguration auctions have not been completed for all months in the 2014/2015 capacity commitment period.

Table 3-10
FCA Cleared Capacity Resources for Each FCM Capacity Commitment Period, 2013/2014 to 2017/2018 (MW)

Factor	FCM Capacity Commitment Period				
	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017	2017/ 2018
Installed generation[(a)]	32,247	31,439	30,757	31,641	29,425
Demand resources (capacity obligation)	3,261	3,468	3,628	2,748	3,041
External capacity contracts[(a)]	1,992	2,011	1,924	1,830	1,237
Surplus (deficit) above the ICR	5,373	3,718	2,853	3,252	(153)
Total capacity resources	37,500	36,918	36,309	36,220	33,702

(a) Data for FCM commitment periods are based on cleared megawatts, including those for energy efficiency and demand-response resources, which reflect the 600 MW cap for real-time emergency generation (RTEG); see Section 3.5.1.

Historically, more capacity cleared than the amount needed to meet the Installed Capacity Requirement. The committed capacity had risen to a high surplus of 5,373 MW for the 2013/2014 capacity commitment period. However, for the 2017/2018 capacity commitment period, the amount of committed capacity dropped to a deficit of 153 MW.

As shown in Table 3-11, resources have shed a portion of their CSO obtained in the FCA in advance of the commitment period. The changes in CSOs are due to various actions a participant or the ISO can take from the time of the FCA to the start of the commitment period. These actions include the following:

- Electing to prorate (i.e., reduce) a resource's CSO in the event excess capacity is obtained in the FCA[98]
- Submitting offers in the ARA due to changes in the ICR[99]
- Participating in the ARA and monthly reconfiguration auctions to increase or decrease the CSOs between resource types
- Receiving a flag for having a significant decrease in capacity, which may result in a reduction in a resource's CSO
- Terminating a resource in accordance with *Market Rule 1*, Section III.13.3.4 or III.13.1.4.6.2, [100]

Obligations can also be reduced or eliminated if capacity, previously held in the FCA for reliability, is released after the reliability constraint has been addressed.

[98] As described in *Market Rule 1*, Section III.13.2.7.3, resources can elect to prorate the FCA CSO if the capacity clearing price floor was reached in the FCA and capacity in excess of the ICR was procured.

[99] As described in *Market Rule 1*, Section III.13.4.3, the ISO may submit supply offers and demand bids in ARAs to address year-to-year changes in the ICR.

[100] *Market Rule 1*, Section III.13.3.4, is "Covering Capacity Supply Obligation where Resource Will Not Achieve Commercial Operation by the Start of the Capacity Commitment Period." Section III.13.4.2.1.3 is "Significant Decrease in Capacity."

Table 3-11
FCA Qualified Capacity and Obligations, FCA #4 to FCA #8 (MW)

FCM Capacity Commitment Period	Resource Type	FCA Qualified Capacity	FCA Obligation[(a)]	June Obligation
2013/2014	Demand resource	4,147	3,349	1,665
	Generation	33,665	32,247	29,702
	Import	2,600	1,992	1,258
2014/2015	Demand resource	4,146	3,590	1,888
	Generation	32,863	31,439	29,704
	Import	2,352	2,011	1,167
2015/2016	Demand resource	4,257	3,645	2,483
	Generation	32,209	30,757	29,644
	Import	2,135	1,924	1,337
2016/2017	Demand resource	3,674	2,748	2,465
	Generation	32,463	31,641	29,347
	Import	2,435	1,830	1,616
2017/2018	Demand resource	3,277	3,041	2,856
	Generation	29,790	29,425	29,418
	Import	1,826	1,237	1,237

(a) This represents the FCA obligation before a resource's proration election and does not account for the 600 MW RTEG cap.

Table 3-11 shows the change from FCA qualified capacity, from obtaining the initial obligation, to the result in the delivery month at the beginning of the commitment period. The June obligations shown in the table reflect the CSOs as of February 23, 2015, and the levels of activity that have occurred for that obligation month. Not all annual and monthly reconfiguration auctions have occurred for the 2015/2016, 2016/2017, and 2017/2018 commitment periods. For example, no reconfiguration auctions have occurred for the 2017/2018 commitment, while ARA #1 and a bilateral period have occurred for the 2015/2016 commitment period.

3.4.3.1 Peak Energy Rent Trends

On December 1, 2010, the fuel used to calculate the PER adjustment was changed from the lower price of natural gas and No. 2 fuel oil to the higher price of the two.[101] As a result, the strike price increased from approximately $116/MWh on November 30, 2010, to $425/MWh on December 1, 2010. Because the amount of the PER adjustment is calculated from a moving 12-month average, the gas-based strike price and adjustment affected the PER adjustment through November 2011.

PER adjustments decreased through 2011 because of an increase in the strike price. From the effective date (December 2010) of the February 17, 2011, FERC order through the end of 2012

[101] FERC, *Order Accepting Tariff Provisions in Part, and Rejecting Tariff Provisions in Part*, Docket No. ER11-2427-000, (February 17, 2011), http://www.iso-ne.com/regulatory/ferc/orders/2011/feb/er11-2427-000_2-17-11_partial_accept-reject_tariff_rev.pdf. At the beginning of the FCM transition period (December 2006), and during most of the transition period, the prices of natural gas and oil were close to each other. Thus, the difference between adopting one or the other fuel as the standard was not substantial. This changed, however, when gas and oil prices diverged in January 2009.

(and in particular, for all of 2012), no hours had a positive hourly PER.[102] As a result, the PER adjustment fell to zero in December 2011 when all effects from a gas-based calculated strike price ended.[103] PER adjustments have increased from mid-2013 to the present as a result of elevated fuel costs and load levels leading to higher real-time prices, especially during cold and hot weather periods. When real-time energy prices exceed the PER threshold, the PER adjustment is triggered. See Table 3-12.

Table 3-12
Monthly PER Adjustments, 2011 to 2014 ($ Millions)

Month	2011	2012	2013	2014
January	17.6	–	–	3.2
February	17.2	–	0.4	2.9
March	16.8	–	0.4	2.8
April	16.3	–	0.4	2.8
May	16.3	–	0.4	2.8
June	14.0	–	0.4	2.9
July	12.1	–	0.5	2.8
August	7.9	–	1.9	1.3
September	2.9	–	1.9	1.3
October	0.3	–	2.0	1.3
November	0.2	–	2.0	1.3
December	–	–	2.3	1.1
Total	121.7	–	12.6	26.6
Total 2011 to 2014				**160.9**

On March 6, 2015, the ISO and the New England Power Pool (NEPOOL) filed market rule changes to eliminate PER on a prospective basis starting with the capacity commitment period that begins on June 1, 2019.[104] The mechanism is no longer needed to serve its intended purposes, and retaining the mechanism could result in higher capacity market costs without producing any substantial benefits. Changes to the New England region's electricity market since the mechanism was first put in place has reduced concerns about the exercise of market power:

- First, a number of rule changes have improved real-time price formation, resulting in a high percentage of expected real-time load clearing in the day-ahead market. This

[102] *Id.*

[103] *2011 Annual Markets Report*, Section 3.5.3.2, http://www.iso-ne.com/static-assets/documents/markets/mkt_anlys_rpts/annl_mkt_rpts/2011/2011_amr_final_051512.pdf.

[104] *ISO New England Inc. and New England Power Pool, Docket No. ER15- -000, PER Mechanism Changes*, FERC Filing (March 6, 2015), http://www.iso-ne.com/static-assets/documents/2015/03/er15-1184-000_3_6_15_fcm_per.pdf. The region's private and municipal utilities formed NEPOOL to foster cooperation and coordination among the utilities in the six-state region and ensure a dependable supply of electricity. Today, NEPOOL members serve as ISO stakeholders and market participants; the NEPOOL stakeholder process provides advisory input on market, reliability, and *Open Access Transmission Tariff* (OATT) matters. More information is available at http://www.iso-ne.com/committees/nepool_part/index.html.

means that most suppliers who have taken on a day-ahead obligation have a strong disincentive to seek increased prices in real time.

- Second, the pay-for-performance changes that will become effective in 2018 (see Section 3.4.3.3) replicate the intended incentives of the PER mechanism. The potential additional protection provided by peak energy rent while PFP is in place has been evaluated. PFP provides adequate disincentives to exercise market power through physical withholding given the portfolio composition requirements and information barriers to successfully execute physical withholding. Also, the IMM has a range of tools to detect and address physical withholding.
- Third, improved, automated Real-Time Energy Market mitigation measures have been put in place.

These rule changes, combined with the IMM and FERC's authority to investigate and sanction economic withholding, should sufficiently remove any incentive for capacity suppliers to seek to exercise market power. Given this, the IMM did not oppose the proposal eliminating the PER.

3.4.3.2 Detailed Results of the Eighth Forward Capacity Auction

This section presents the FCA #8 results in detail and a review of the results. On February 3, 2014, ISO-NE conducted the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period (FCA #8).

The auction began at the starting price of $15.82/kW-month and stopped with the withdrawal of capacity at a price of $14.99/kW-month. At that point, all system and zonal capacity requirements were satisfied and the FCA #8 clearing price was set by an auction clearing function at $15.00/kW-month. While the auction clearing price was $15.00/kW-month, the Insufficient Competition rule resulted in two-tiered pricing throughout the system where new resources would receive the auction clearing price of $15.00/kW-month and existing resources would receive the administrative price of $7.025/kW-month.[105]

However, the Carry Forward rule applied in NEMA/Boston due to excess procurement in the prior auction. The Carry Forward rule effectively raised the price paid to existing resources in NEMA/Boston to $15.00/kW-month. The final pricing for FCA #8, after application of the various pricing rules, is shown in Table 3-13 below.

Table 3-13
FCA #8 Prices

	New Resources ($/kW-month)	Existing Resources ($/kW-month)
NEMA/Boston	$15.00	$15.00
Maine, Connecticut and Rest-of-Pool	$15.00	$7.03

In most of the prior auctions, new and existing resources were paid the same clearing price. FCA #8 was different. In FCA #8, there were not enough new resources competing to satisfy the

[105] The $7.025/kW-month administrative price was pre-determined by the ISO and approved by the FERC in a January 24, 2014 Order.

region's capacity requirement. This condition is called "Insufficient Competition" and occurs when there is not enough existing capacity to meet the entire capacity requirement and not enough competition among new capacity to meet the remaining or residual capacity requirement. [106] Under this condition, the Insufficient Competition pricing rule is applied which is a market power mitigation feature of pricing in the capacity market. It is designed to balance the interests of buyers paying for capacity by building in price protection under conditions of scarcity and the interests of developers by paying a price that reflects the need to attract new resources and retain existing capacity.

Applying the insufficient competition rule would have resulted in all new resources in the region being paid the FCA #8 clearing price of $15/kW-month and all existing resources in the region being paid an administratively set price of $7.025/kW-month.

Conditions in the NEMA/Boston zone created an exception to the Insufficient Competition rule. In FCA #7, a large new resource cleared (the 674 MW Footprint Power facility) resulting in approximately 500 MW of excess supply in the NEMA/Boston zone. The excess supply in the NEMA/Boston zone from FCA #7 triggered the "carry forward rule" for pricing in the NEMA/Boston zone for FCA #8.[107] The intent of the carry forward rule is to reset the clearing price administratively when new additional capacity would have been needed (and would have set the clearing price), but could not because of excess new capacity procured in the prior auction. The carry forward rule applies the same price to new and existing resources in the zone. In addition, the NEMA/Boston area was an import constrained zone for FCA #8 and resources within an import constrained area cannot be paid less than the price set for resources in the rest of pool.[108] Therefore, new and existing resources in the NEMA/Boston zone were paid the same $15.00/kW-month capacity clearing price as new resources in the other zones.

The ISO's filing of the results of FCA #8 became effective on September 18, 2014. In its order on FCA #8 results, FERC noted that the tariff may be insufficient to ensure just and reasonable rates, given the changing balance of supply and demand in New England. FERC explained that although it had previously determined that most imports should be treated like existing internal resources for mitigation purposes, the tariff did not at the time require that the importers' delist bids be consistent with their net risk-adjusted going-forward costs and opportunity costs, as it does with respect to the delist bids for other existing resources. FERC concluded that this circumstance may create an opportunity for importers to exercise market power, and it may otherwise result in preferential or unduly discriminatory treatment favoring importers over other capacity resources. As a result, FERC required the ISO to either revise its tariff to provide for a review of import offers before each FCA or to show why it should not be required to do so. The ISO submitted a compliance filing to the show-cause order on October 16, 2014, in which it proposed more comprehensive mitigation riles for imports, and FERC conditionally accepted the tariff revisions on December 15, 2014.[109]

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[106] *Market Rule 1*, III.13.2.8.2.

[107] *Market Rule 1*, III.13.2.7.9.

[108] The import-constrained zone rule ensures that prices in import-constrained zones where capacity is, by definition, less abundant reflect that relative scarcity when compared to prices in zones that are not import-constrained where capacity is more abundant. See *Market Rule 1,* III. 13.2.7.1.

[109] FERC, *Order Conditionally Accepting Tariff Revisions and Directing Compliance Filings*, (December 15, 2014), http://www.iso-ne.com/static-assets/documents/2014/12/er15-117-000_el14-99-000_12-15-14_order_accept_show_cause_compliance.pdf.

Maximum Capacity limits (MCLs) and Local-Sourcing Requirements (LSRs) for FCA #8. Table 3-14 shows the system and local capacity requirements for FCA #8. Approximately 33,800 MW of capacity were needed to ensure systemwide resource adequacy. At the local level, capacity purchases from the Maine zone were limited to 3,960 MW because of an export constraint. The Connecticut and NEMA/Boston zones are import-constrained zones. A local-sourcing requirement for the CT zone of approximately 7,300 MW and an LSR for NEMA/Boston of approximately 3,400 MW were included for each region in the auction.

Table 3-14
Capacity Requirements or Limits for FCA #8 (MW)

Auction	Net Installed Capacity Requirement	Maximum Capacity Limit	Local-Sourcing Requirement	
	Systemwide	Maine	CT	NEMA/Boston
FCA #8	33,855	3,960	7,319	3,428

Resource Qualification. Table 3-15 summarizes the existing and new qualified capacity for FCA #8 by zone and compares this capacity to the relevant capacity requirement (i.e., NICR, MCL, and LSR). Systemwide, existing capacity (34,983 MW) was approximately 1,100 MW greater than the NICR of 33,855 MW. For the local zones, existing capacity slightly exceeded the MCL for Maine; new capacity in Maine added to this excess. In the import-constrained areas, Connecticut was able to satisfy its local capacity requirement with existing capacity, and proposed new capacity for Connecticut added a small amount to the area totals. NEMA/Boston lacked sufficient existing capacity to satisfy the local capacity requirement; therefore, this zone required new capacity to meet its LSR.

Table 3-15
Qualified Capacity Compared with Requirement or Limit, FCA #8 (MW)

Zone	Existing	New	Total	Capacity Requirement or Limit
Connecticut	9,275	7	9,282	7,319
Maine	3,536	272	3,808	3,960
NEMA/Boston	3,695	183	3,878	3,428
Rest-of-Pool	16,226	1,699	17,925	19,148
Total	**32,732**	**2,161**	**34,893**	**33,855**

Table 3-16 shows the breakdown of qualified capacity by resource type for each zone. Proposed new additions to capacity were small compared with import resources in the Rest-of-Pool zone and generator resources in NEMA/Boston. Consistent with the ISO tariff rules, import capacity qualifies as new capacity in each auction. Therefore, import capacity receives an annual, rather than long-term, obligation to supply capacity to the New England market if it clears. For FCA #8, almost all the "new" capacity within the Maine zone was import capacity.

Table 3-16
Qualified Capacity by Resource Type and Qualification Status, FCA #8 (MW)

Zone	Existing			Existing Total	New			New Total	Total
	Demand	Generator	Import		Demand	Generator	Import		
Connecticut	833	8,441	-	9,275	7	-	-	7	9,282
Maine	387	3,149	-	3,536	32	6	234	272	3,808
NEMA/Boston	468	3,227	-	3,695	170	14	-	183	3,878
Rest-of-Pool	1,194	14,943	89	16,226	185	11	1,503	1,699	17,925
Total	**2,882**	**29,760**	**89**	**32,732**	**394**	**30**	**1,737**	**2,161**	**34,893**

Fifty delist bids from existing capacity resources were entered in the auction for FCA #8. The ISO retained all these bids for a total of 425 MW, provided by both demand resources (160 MW) and generation resources (265 MW). All the delist bids were for a single year, allowing these resources to retain the option of re-entering the capacity market during FCA #8. See Table 3-17.

Table 3-17
Delisted Capacity by Zone and Resource Type, FCA #8 (MW)

Zone	Demand	Generator	Total
Connecticut	81	-	81
Maine	4	1	5
NEMA/Boston	15	21	36
Rest-of-Pool	60	243	303
Total	**160**	**265**	**425**

3.4.3.3 FCM Performance Incentives

As discussed in the *2012 and 2013 Annual Markets Report*, design features of the FCM, built to ensure that resources perform when system reliability is at risk, have not been effective. Through the end of 2014, only one shortage event has occurred, and peak energy rent deductions remain low compared with total FCM payments.

The ISO has undertaken several actions to strengthen the FCM incentive structure:

- **Definition of the FCM Shortage-Event Trigger:** A shortage event can be triggered when the Reserve Constraint Penalty factor for 30-minute operating reserves is activated for 30 or more contiguous minutes and Action 2 under OP 4 is implemented for the same 30 contiguous minutes. Under the prior rule, a shortage-event was triggered only when an RCPF was activated for 10-minute non-spinning reserves for 30 or more contiguous minutes. This change was implemented in November 2013.
- **FCM Pay-for-Performance Market Design:** The pay-for-performance design is based on the two-settlement logic generally used in forward markets, which entails two key elements. The first element is a forward position in which a quantity of capacity is obligated, or sold, in the capacity auction. Each megawatt is paid at the auction clearing price, and the sale creates a resource-specific physical obligation and forward financial position in the capacity market. A resource's forward financial position is a share of the system's energy and reserve requirements during operating reserve deficiencies. The

second element includes a settlement for deviations. A resource that delivers more than its share of the system's requirements during an operating reserve deficiency (i.e., an overperformer) will be paid for that incremental production. If it delivers less than its share (i.e., it underperforms), it will "buy out" of its position by paying other resources that did deliver. Positive and negative deviations are paid or charged at the same rate specified in the tariff.

The two-settlement approach is standard in forward contracts, both for electricity and commodities, ranging from oil to pork bellies to iron ore. In fact, the two-settlement design underlies the design of New England's day-ahead and real-time electricity markets and is well understood by stakeholders.

Under PFP, buyers will pay the auction clearing price to all resources that clear in the auction. Because the overperformers will be paid by the underperformers, buyers will not bear the short-run risk of covering any unexpectedly high performance payments. This will continue to provide buyers with a predictable capacity price three years out, after the close of each Forward Capacity Auction. Having underperformers pay overperformers will also provide strong incentives for each resource to perform as needed and for overperformers to benefit by helping meet the system's needs. These incentives will place performance risk on all FCM resources, and each resource will be allowed to price this risk in its future capacity auction bids.

Pay-for-performance will become fully effective on June 1, 2018. With respect to the implementation of pay-for-performance, the ISO made a compliance filing on July 14, 2014, in response to a FERC order requiring the ISO to increase Reserve Constraint Penalty Factors for 30-minute operating reserves, from $500/MWh to $1,000/MWh, and 10-minute non-spinning reserves, from $850/MWh to $1,500/MWh.[110] This change was implemented on December 3, 2014. Other portions of the rule pertaining to certain changes to the tariff's defined terms and FCM rules that must apply during the qualification process for FCA #9 became effective on June 9, 2014.[111]

3.4.3.4 Additional Analysis and Review of Capacity Market Mitigation Rules

The results of the FCA #8 auction and the show-cause order triggered additional analysis and review of the capacity market mitigation rules. Recent and future rule changes that have been or are currently going through the stakeholder process include the following:

Import cost reviews (FCA #9). In the October 16, 2014, filing, the ISO submitted rule revisions to provide for the review and potential mitigation of importers' supply offers before each annual Forward Capacity Auction.[112] The rule revisions determine which import suppliers have market power (that is, which are "pivotal") and to mitigate these suppliers in a manner consistent with the mitigation applied to existing resources.

[110] *ISO New England Inc. and New England Power Pool, Docket No. EL14-52-000; Compliance Filing of Two-Settlement Forward Capacity Market Design*, parts 1 and 2 of 2 (July 14, 2014) http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14_2419_000_pfp_comp_7_14_2014.pdf and http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14_2419_001_pfp_comp_7_14_2014.pdf.

[111] FERC, *Order on Compliance Filing* (October 2, 2014), http://www.iso-ne.com/static-assets/documents/2014/10/er14-2419-000_-001_10-2-14_pay_for_performance_compliance_order.pdf

[112] ISO New England Inc., *Response to Order to Show Cause*, (October 16, 2014), http://www.iso-ne.com/static-assets/documents/2014/10/er15-117-000_show_cause_10-16-2014.pdf.

Most imports are qualified as new capacity for treatment in the auction. Grandfathered imports (or imports associated with a long-term contract that cleared as new capacity in a prior FCA and are still under contract) are qualified as existing capacity. Because most imports have single-year contracts, most imports are qualified as new capacity each year. This differs from how generation and demand resources are qualified as *new* or *existing*. For these resources, all capacity is *new* until it has cleared in a prior FCA, after which it is always treated as *existing*.

Existing import capacity resources may not exit the FCA above the dynamic delist threshold, unless the IMM has reviewed and approved the participant's submitted delist bid. If the lead market participant of an existing capacity resource is determined to be pivotal, the existing import capacity resources may not exit the FCA at prices above the approved delist bid but rather only at the approved delist bid price. Existing import capacity resources that do not submit a delist bid may exit the auction at prices below the dynamic delist bid threshold without any review.

Under the proposed rule changes, the vast majority of new import capacity resources are treated similar to "existing resources" for determining whether market power mitigation will be needed. These imports will be subject to supplier-side mitigation in the same way that existing resources are currently evaluated, and these imports will be exempt from buyer-side mitigation.

Comprehensive pivotal supplier test (FCA #10). The pivotal supplier test that currently applies only to import portfolios will be combined with the test that applies to suppliers generally. The comprehensive pivotal supplier test will do the following:

- Consider both existing internal resources and import resources when assessing the competitiveness of supply
- Account for system constraints (e.g., capacity transfer limits)
- Be conducted closer to the start of the Forward Capacity Auction

Changes associated with the auction process are also being proposed to complement the proposed pivotal supplier test.

Zonal sloped demand curves (FCA #10). In its May 30, 2014 order, FERC accepted the systemwide sloped demand curve for the FCM.[113] The sloped demand curve at the system level was in effect for FCA #9.

Along with ISO management we have identified issues regarding the potential for market power to be exercised that can have an inappropriate impact on prices and scarcity pricing within capacity zones with zonal demand curves, specifically within import-constrained capacity zones.[114]

113 FERC, *ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Tariff Revisions*, 147 FERC ¶ 61,173 (May 30, 2014) (the May 30, 2014, order).

114 Currently, four capacity zones exist for FCA #9. Three are localized and are import constrained, and the fourth is the Rest of Pool zone that represents the balance of the system requirements beyond those reflected in the three import-constrained zones.

Compared with the system as a whole, import-constrained capacity zones inherently are relatively small and have a higher risk of being structurally uncompetitive. Adding price responsiveness through a sloped demand curve can dampen the financial impact of the exercise of market power. The extent to which zonal curves themselves can address market power depends on several factors, including the degree of price responsiveness (the slope of the demand curve), the concentration of ownership of existing resources within the zone, and the ability of new entry from suppliers without market power to contest the market share of existing capacity.

In zones that do not have adequate supply or sufficient competition, which could be brought on by several factors, the appropriateness of relying solely on the sloped demand curve to address noncompetitive conditions is currently being discussed and evaluated with stakeholders. Two administrative pricing rules are in place in the tariff that prevent the potential for market power and artificially high prices when competition is insufficient (see above) or the supply is inadequate.

Accuracy of static delist bids (FCA #10). Flexibility in submitting, modifying, and withdrawing static delist bids was originally created so that the price of one of these bids could be fine-tuned (downward only) should the factors making up the price vary between the submittal of the delist bid and the Qualification Determination Notification (QDN). Under the current rules, a participant may submit a static delist bid and, after a review during the finalization window, can do any one of the following:

- Withdraw the static delist bid, whether or not the bid was mitigated
- Lower the static delist bid price from either the accepted price or, if mitigated, from the mitigated price
- Convert a delist bid into a nonprice retirement request

While this flexibility originally was anticipated to create some upward pressure on submitted prices, the actual degree of price reductions observed during the finalization windows to date has been significant (approximately 32% on average for FCA #8 and #9). See Figure 3-8.

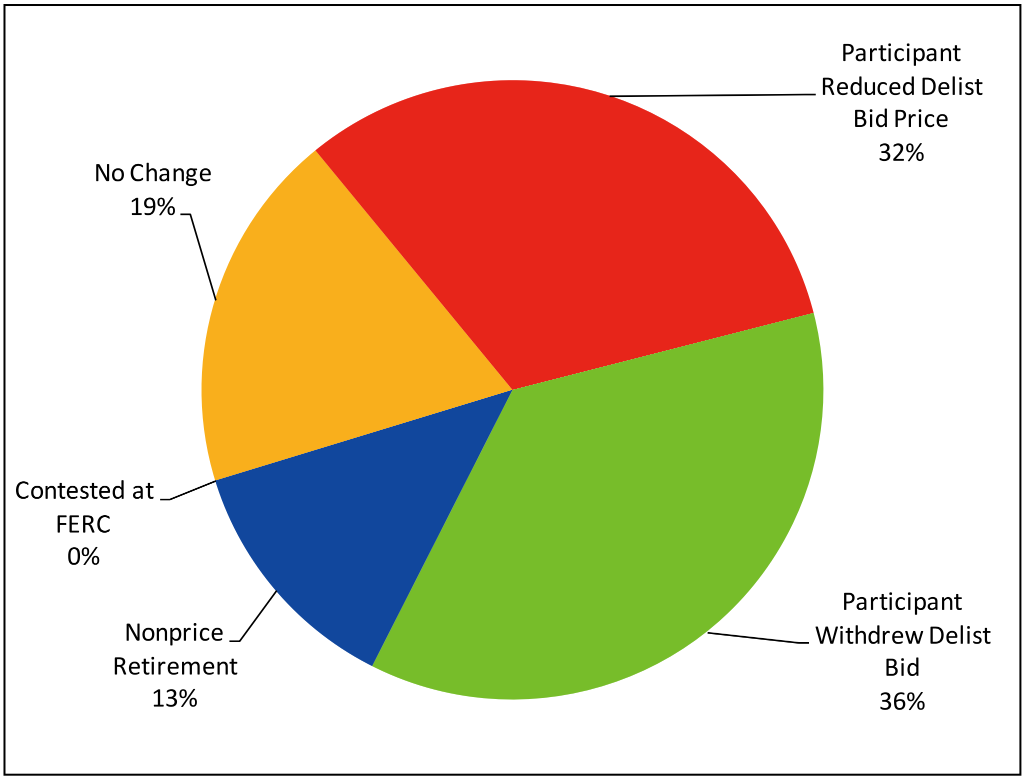

Figure 3-8: Changes in static delist bids from a review of FCA #8 and FCA #9.

Figure 3-8 also shows the percentage of submitted static delist bids completely withdrawn (approximately 36% of those submitted for FCA #8 and #9), whether or not the submitted price was mitigated. Without a static delist bid, the resource is a price-taker in the auction, unless the auction price falls below the $3.94/kW-month, below which stage it can choose to dynamically delist.

On May 1, 2015, the IMM filed market rule changes that address the potential exercise of market power in the Forward Capacity Market. The first two parts of the market rule changes address the treatment of de-list bids. First, the IMM proposed to increase the Dynamic De-List Bid Threshold from $3.94 to $5.50/kW-month. This change was intended to avoid having the IMM review de-list bid information at prices that already are low enough to ensure that there will be adequate competition in the market, so that the exercise of market power is not a concern.

Second, the IMM proposed to limit the amount of flexibility that is currently afforded to capacity suppliers to modify Static De-List Bids after those bids have been submitted and reviewed by the IMM and also to eliminate the option to replace a Static De-List Bid with a Non-Price Retirement Request in certain instances. These changes are intended to encourage the submission of Static De-List Bids that are closer to actual cost and remove any incentive for capacity suppliers to use the Static De-List Bid process to explore whether the IMM will allow bid prices that substantially exceed costs. Together, these two changes are motivated by the desire to maintain the continued integrity of the market power mitigation structure in the capacity market and to allow both the IMM and capacity suppliers to focus more closely on those bids that actually raise significant market power concerns.

The third part of the proposed changes involves improvements to the pivotal supplier test that the IMM administers prior to the auction to determine if a capacity supplier has the potential to exercise market power. The proposed market rule establishes a single pivotal supplier test that applies to both capacity imports and existing resources. The improvements include a consistent treatment of interface constraints for purposes of determining whether a supplier is pivotal, moving the performance of the test closer to the time of the auction and a new definition of "control" that will more accurately account for which resources should be included in the assessment of a supplier's overall capacity portfolio.

The fourth and final part of the proposed changes involves improvements to the rules governing the treatment of import capacity resources in the Forward Capacity Auction. The proposed changes will ensure that capacity imports that are more akin to existing resources receive the same mitigation treatment in the Forward Capacity Auction as existing resources. The changes also will ensure that capacity imports that are more akin to new resources receive the same treatment as other new resources during the conduct of the auction.

Dynamic delist change (FCA #10). In the FCM, two types of delist bids enable a resource to leave the capacity market for a single capacity commitment period. Resources that wish to leave the market at prices equal to or above the dynamic delist bid threshold must submit static delist bids in advance of the FCA for review. If resources wish to leave the market at prices below the dynamic delist bid threshold price, they may submit a dynamic delist bid during the FCA without review.

The dynamic delist bid threshold used for FCA #9 did not explicitly account for a risk premium, yet all the submitted static delist bids for FCA #9 included a risk premium. The IMM recommends raising the dynamic delist threshold from $3.94/kW-month (FCA #9 price) to $5.50/kW-month (FCA #10 price), which represents a competitive offer from a fossil steam unit, the type of existing capacity resource most likely to seek to leave the auction and therefore could be the marginal unit if more existing capacity exists than needed to meet the ICR. In addition, the IMM will recalculate the dynamic delist bid threshold no less than once every three years. When the dynamic delist bid threshold is recalculated, the results of the recalculation with stakeholders will be reviewed, and the new dynamic delist bid threshold will be filed with FERC before the existing capacity qualification deadline for the associated FCA.

Uneconomic nonprice retirements (NPRs) (FCA #11). The owners of existing generators can potentially exercise market power in an import-constrained zone through the uneconomic retirement of an existing resource.[115] When existing and new supply are not abundant in a capacity zone, an incumbent supplier can seek to retire an existing resource to reduce available supply. This action will have a price-increasing effect within that capacity zone, which will benefit the remainder of the supplier's portfolio in that capacity zone. In cases where capacity zones are sufficiently small, the retirement of even a single resource of moderate size can have a significant price impact even with sloped zonal demand curves.

Market rule changes are being recommended that will provide a process for reviewing options for capacity market participation or retirement, and market power mitigation measures in the capacity auction. The proposed process, with these components, eliminates the potential that a capacity auction will be executed with known market power resident through early resource

[115] Uneconomic retirement is the premature withdrawal of a generation resource's capacity from the capacity market if expectations over its remaining life indicate that continued operation of the resource would be economically viable.

retirement. It will also provide a means for resources to retire through the market, as opposed to administratively as is now the case, and potentially be replaced by new generation in that same capacity auction. The External Market Monitor has also recommended that the ISO adopt a measure that addresses the potential for retirement delist bids to be used to increase FCA prices above competitive levels.[116]

3.5 Demand Response

The following section reviews the participation and outcomes of demand resources in New England for 2014.

3.5.1 Background and Review

Demand resources have been part of New England's wholesale electricity market since the start of the markets in 2003 when the ISO implemented a series of demand-response programs. Over the years, the programs were enhanced to include three basic categories: demand response that reduced load to support system reliability, demand response that reduced load in response to wholesale energy prices, and demand resources that reduced load through energy efficiency and other nondispatchable measures.

In 2010, demand resources were integrated into the FCM where they offer in the Forward Capacity Auctions, take on capacity supply obligations, and receive capacity payments comparable to other supply-side resources. The two broad categories of demand resources in the FCM are active and passive demand resources. *Active demand resources* are dispatchable and reduce load in response to ISO dispatch instructions. *Passive demand resources* are not dispatchable and provide load reductions during predetermined periods.

In addition to *real-time demand response* (RTDR) resources, which reduce load within 30 minutes of receiving an ISO dispatch instruction, active demand resources include *real-time emergency generation* (RTEG) resources, which reduce load by transferring load that otherwise would be served from the electricity grid to emergency generators. Passive demand resources include on-peak resources, such as energy-efficiency projects and *distributed generation* (DG) that reduce load during predefined periods, and seasonal-peak resources, such as energy-efficiency projects where the project's load reduction is weather sensitive.[117]

In 2012, from January 1 through May 31, the ISO administered two demand-response programs that provided financial incentives for customers to reduce load in response to day-ahead and real-time energy prices: the Real-Time Price-Response (RTPR) Program and the Day-Ahead Load-Response Program (DALRP). An optional program, the Transitional Price-Responsive Demand (TPRD) Program, designed to comply with FERC Order 745 (Demand-Response Compensation in Organized Wholesale Energy Markets), replaced both the RTPR program and

[116] Potomac Economics, *2013 Assessment of the ISO New England Electricity Markets*, June 25, 2014, http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf.

[117] Distributed generators are a subset of demand-side resources and consist of relatively small-scale sources of power (i.e., several kilowatts to tens of megawatts in capacity) connected to the grid at the distribution or substation level, not the regional power system. DG technologies include both renewable resources (e.g., solar photovoltaics, wind turbines, fuel cells, biomass, and small hydro) and conventional resources (e.g., diesel reciprocating engines and gas turbines). RTEG is distributed generation the ISO calls on to operate during a 5% voltage reduction that requires more than 10 minutes to implement (i.e., OP 4 Action 6 or more severe actions) but must limit its operation to 600 MW to comply with the generation's federal, state, or local air quality permit(s) and the ISO's market rules.

the DALRP and is currently in effect.[118] Similar to the DALRP, the TPRD program allows market participants with assets registered as RTDR resources to offer load reductions in response to day-ahead LMPs. Market participants are paid the day-ahead LMP for their cleared offers and are obligated to reduce load by the amount cleared day-ahead. The participant is then charged or credited at the real-time LMP for any deviations in curtailment in real-time compared with the amount cleared day-ahead. The TPRD program will remain in effect until June 1, 2017, at which time new market rules will become effective that will fully integrate dispatchable demand resources into the Day-Ahead and Real-Time Energy Markets.[119]

FERC Order 745 Legal Status. FERC Order 745 was challenged in 2012 in the D.C. Circuit of the US Court of Appeals. Order 745 requires regional transmission organizations to pay the full LMP for load reductions produced by demand-response resources participating in organized wholesale energy markets subject to certain conditions. The case was argued in front of three judges in September 2013. In May 2014, the D.C Circuit issued an opinion (by a 2 to 1 vote) vacating the order, stating that, among other things, FERC lacked jurisdiction to promulgate the rules established by Order 745.[120] However, the D.C. Circuit also stayed the mandate to vacate Order 745 pending the outcome of any further appeal to the United States Supreme Court.

In July 2014, FERC asked the D.C. Circuit to rehear the case *en banc*—a request for rehearing before the full 11-member court. In September 2014, the D.C. Circuit denied FERC's request for this rehearing. In January 2015, the US Department of Justice, on behalf of FERC, petitioned the US Supreme Court to review the D.C. Circuit's decision and overturn its ruling. The US Supreme Court will likely decide on whether to hear the case sometime in spring 2015.

Until a final decision is reached on the D.C. Circuit's vacatur of Order 745 the ISO's demand-response rules contained in the tariff will continue to apply. If vacatur ultimately stands, the D.C Circuit Court's ruling would be remanded to FERC for further action.

3.5.2 Demand Resources in the Forward Capacity Market

As shown in Table 3-18, the total CSOs for all demand resources participating in the FCM increased by 19% in 2014 compared with 2013, a gain of 286 MW.[121] The CSOs of passive demand resources accounted for the vast majority of the increase, 240 MW (84%). The increase in the CSOs over the year is mainly attributable to energy-efficiency programs administered by local utilities.

[118] ISO New England Inc., *Order No. 745 Compliance Filing*, FERC Docket No. ER11-4336-001 (August 19, 2011), http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/er11_4336-001_prd_filing.pdf.

[119] In April 2012, the ISO requested that the transitional rules remain in effect until June 1, 2017, when FCM rules address how capacity resources will be integrated into the energy markets. *ISO New England Inc., Market Rule 1 Price-Responsive Demand FCM Conforming Changes for Full Integration*, Docket No. ER12-1627-000 (filed April 26, 2012), http://www.iso-ne.com/regulatory/ferc/filings/2012/apr/er12-1627-000_4-26-2012_prd.pdf. RTEG resources will be prohibited from participating in the day-ahead and real-time markets because of air permit restrictions.

[120] United States Court of Appeals, *Electric Public Supply Association v. FERC* (May 23, 2014), http://www.cadc.uscourts.gov/internet/opinions.nsf/DE531DBFA7DE1ABE85257CE1004F4C53/%24file/11-1486-1494281.pdf.

[121] This table shows the net CSO value held by demand resources for December 2013 and December 2014 in time after trading out of obligations awarded in the primary forward capacity auction.

Table 3-18
Capacity Supply Obligations by Demand-Resource Type, December 2013 and December 2014 (MW)

	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	
Dec 2013	268	127	395	812	328	1,140	**1,535**
Dec 2014	296	145	441	1,033	347	1,380	**1,821**
2013 to 2014 % change	10%	14%	12%	27%	6%	21%	**19%**

Figure 3-9 and Figure 3-10 illustrate market participants and their CSO (measured as a percentage of total megawatts) for both active and passive demand resources. Two participants accounted for 82% of the RTDR and RTEG resources. Figure 3-9 illustrates the market participants with active demand resources as of December 2014, as well as the percentage of CSOs (in MW) represented by these participants. These results are similar to December 2013. Figure 3-10 illustrates the market participants with passive demand resources as of December 2014 and the percentage of CSOs represented by these participants. Similar to December 2013, the top two participants accounted for approximately 41% of the total.

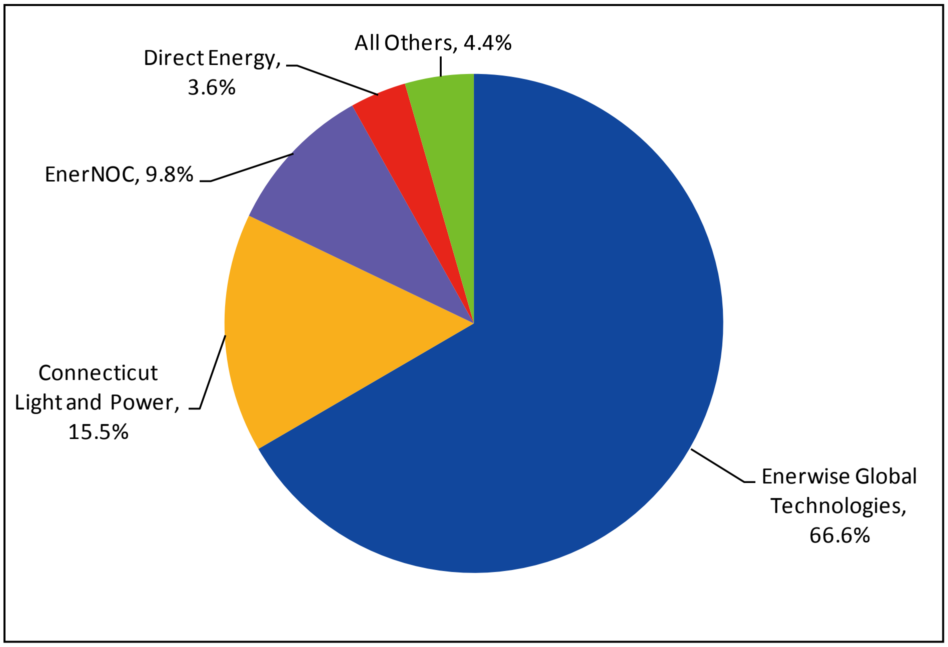

Figure 3-9: Distribution of active demand-resource CSOs (in MW) by lead participant, as of December 2014 (%).

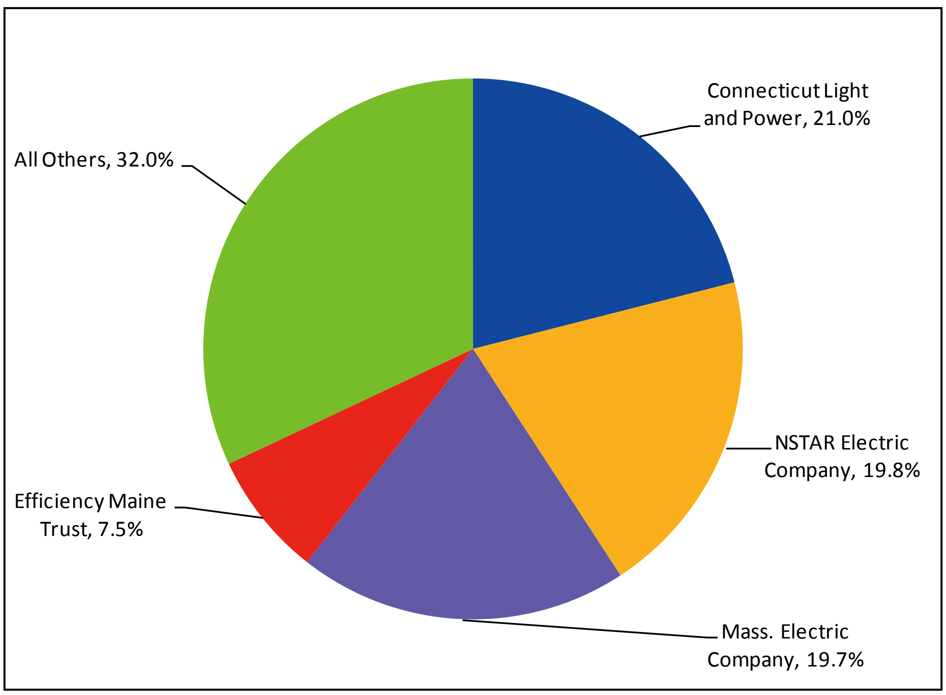

Figure 3-10: Distribution of passive demand-resource CSOs (in MW) by lead participant, as of December 2014 (%).

Typically, the market participants that provide demand-response services offer most of the active demand resources, while the market participants that are investor-owned utilities and part of state-sponsored energy-efficiency programs offer most of the passive demand resources.

3.5.3 Demand-Resource Payments

As shown in Table 3-19, demand-resource payments totaled $90.3 million in 2014 compared with $87.5 million in 2013, an increase of 3.2%. Capacity payments are based on the FCM capacity clearing price and capacity values determined pursuant to the rules of the FCM. Total demand-resource capacity payments were slightly higher in 2014 compared with 2013. Capacity payment rates ($/kW-month) were also slightly higher in 2014 relative to 2013.

Table 3-19
Total Payments to Demand-Response Resources, 2013 and 2014 ($ Millions)

Year	Capacity Payments	Transitional PRD Payments	Total Payments
2013	87.5	4.7	92.2
2014	90.3	3.9	94.2
Change	2.8	(0.8)	2.0
% Change 2013 to 2014	3.2%	-17.2%	2.2%

The remainder of the payments to demand resources in 2014, approximately 4%, was for load reductions in the current transitional Price-Responsive Demand Program.

3.5.4 2014 Demand-Response Recommendation and Follow Up of 2013 Recommendations

Two recommendations for demand response were made in the *2013 Annual Markets Report.* One recommendation concerned demand-response baselines and their predictive power (accuracy) in forecasting various resource load shapes. The second recommendation addressed third-party verification of meter data submitted by market participants for their demand-response resources.

3.5.4.1 Follow Up and Recommendation on the Methodology for Determining Demand-Resource Baselines

In 2014, the ISO researched various alternative baseline methodologies to improve the accuracy of estimated baselines in predicting actual load shapes. The work performed by the ISO was submitted to an independent consulting firm with expertise in both the power industry and statistical modeling. Currently, the independent consulting firm is reviewing the proposed methodology the ISO submitted, as well as possibly proposing recommendations for further improvements that may be discovered during the review process. The planned implementation date for the new baseline methodology is currently June 1, 2017, at which time new market rules will become effective that will fully integrate dispatchable demand resources into the day-ahead and real-time markets (also see Section 3.5.1). Given the uncertainty in FERC jurisdiction over demand-response participation in energy markets as previously discussed, the ISO's current plan to fully integrate demand response into the energy markets on June 1, 2017, including the implementation of any baseline changes, may need to be modified.

If, and when, the new baseline methodology is implemented, the new methodology's predictive ability in estimating a resource's actual load should be made transparent to the market. The accuracy of the new baseline methodology should be made available to the market by whatever metrics the ISO believes would best describe how well the methodology is performing. While any methodology will perform better for some demand-response resource load profiles than others, a report reflecting the accuracy over the broad array of resources will give more confidence in the methodology and ultimately its ability to measure load reductions produced by demand-response resources.

3.5.4.2 Follow Up on Third-Party Verification of Meter Data

A much broader filing with FERC addresses the 2013 AMR's recommendation regarding the validation of meter data from market participants, which becomes effective in capacity commitment periods on and after June 1, 2017.[122] The 5-minute interval meter data reported by the market participant can be from the same revenue-quality meter the distribution company uses for billing purposes. Another requirement is that, if the 5-minute interval meter data from a market participant is *not* from the distribution company's revenue-quality meter used for billing purposes, the market participant must validate and provide documentation to the ISO that the difference between the values recorded by the market participant's meter and the distribution company's billing meter are within ± 2.0%. Linking the participants' submittal data with the local distribution companies' metering should significantly reduce erroneous data submittals.

[122] *Order Accepting Market Rule Provisions to integrate PRD*, Docket No. ER15-257-000, 001, 002 (filed January 9, 2015), http://www.iso-ne.com/static-assets/documents/2015/01/er15-257-000-001-002_1-9-15_order_accept_rev_integrate_prd.pdf.

Section 4
Other Market Information

In 2014, the following audits were conducted to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders.

4.1 SOC 1 Type 2 Examination

In November 2014, the ISO successfully completed a Service Organization Controls (SOC) 1 Type 2 examination, which resulted in an "unqualified opinion" about the description of the market administration and settlements systems. Developed by the American Institute of Certified Public Accountants, the SOC 1 examination covers aspects of a service organization's systems for processing transactions that may be relevant to a user entity's internal controls for financial reporting. Entities such as Regional Transmission Organizations complete SOC 1 examinations to assist user entities in evaluating their internal controls over financial reporting.

The ISO's SOC 1 Type 2 examination is a rigorous examination that entails detailed testing of the business processes and information technology for bidding, accounting, settlement, and billing the market products of electric energy, regulation, transmission, capacity, demand response, reserves, and associated market transactions. The Type 2 examination covered the 12-month period from October 1, 2013, through September 30, 2014. The SOC 1 Type 2 examination reviews the following:

- The fairness of the description of the market administration and settlements systems' controls designed and implemented throughout the period
- Whether the controls were suitability designed to provide reasonable assurance that the control objectives would be achieved if the controls operated effectively throughout the period and user entities applied the complementary user entity controls contemplated in the design
- The controls tested, which together with the complementary user-entity controls, were those necessary to provide reasonable assurance that the control objectives were achieved throughout the period

The ISO conducts a SOC 1 Type 2 examination annually. The 2014 SOC 1 Type 2 report is available to participants upon request through the ISO external website.[123]

4.2 Market-System Software Recertification

The ISO has committed to engaging an independent third party, PA Consulting, to review and certify that the market-system software complies with *Market Rule 1*, the manuals, and standard operating procedures.[124] This recertification takes place every two years or sooner, in

[123] KPMG. *Report on Management's Description of its System and the Suitability of the Design and Operating Effectiveness of Controls Pertaining to the Market Operations and Settlements System for the Period October 1, 2013, to September 30, 2014*. This report is available to participants by request through the ISO external website, http://www.iso-ne.com/isoexpress/soc-1-type-2-report-request.

[124] *Market Rule 1,* http://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1.

the case of a major market-system enhancement or new market features. After conducting detailed tests and analyses of the applicable mathematical formulations, PA Consulting issues a compliance certificate for each market-system module it audits. The certificates provide assurance that the software is operating as intended and is consistent with *Market Rule 1* and associated manuals and procedures.

In 2014, PA Consulting issued the following certifications:

- Locational Forward Reserve Market Software, July 9, 2014
- Locational Marginal Price Calculator Market Software, June 26, 2014, and December 3, 2014
- Scheduling, Pricing, and Dispatch—Day-Ahead Market Software, January 7, 2014, June 26, 2014, and December 3, 2014
- Scheduling, Pricing, and Dispatch—Unit Dispatch Scheduling Market Software, June 26, 2014, and December 3, 2014
- Forward Capacity Auction Market Clearing Engine Software, December 24, 2014
- Forward Capacity Reconfiguration Auction Clearing Engine Software, July 8, 2014

4.3 Internal Audits

The ISO New England Internal Audit Department conducted a number of internal controls and compliance audits in the Forward Capacity Market, demand-resource, and information technology areas.

Acronyms and Abbreviations

Acronyms and Abbreviations	Description
°F	degrees Fahrenheit
AC	alternating current
ACE	area control error
AMR	Annual Markets Report
ARA	annual reconfiguration auction
ARR	Auction Revenue Rights
BAL-001-0	NERC's *Real Power Balancing Control Performance Standard*
Btu	British thermal unit
C4	four largest competitors
Carry Forward Rule	*Capacity Carry Forward Rule*
CCGT	combined-cycle gas turbine
CCP	capacity commitment period
CPS 2	NERC *Control Performance Standard 2*
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CTS	Coordinated Transaction Scheduling
DALRP	Day-Ahead Load Response Program
DFO	dual-fuel override
DG	distributed generation
DOE	US Department of Energy
DOJ	US Department of Justice
ecomax	economic minimum limit
ecomin	economic maximum limit
EIA	US Energy Information Administration (of DOE)
EMM	External Market Monitor
EMOF	Energy Market Offer Flexibility
ERS	external reserve support
F	Fahrenheit
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FPA	fuel-price adjustment
FRM	Forward Reserve Market
FTR	Financial Transmission Right
GPA	generator performance audit
GWh	gigawatt-hour

Acronyms and Abbreviations	Description
HE	hour ending
HHI (also H)	Herfindahl-Hirschman Index
HQ	Hydro-Québec
IC Rule	*Insufficient Competition Rule*
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
IMM	Internal Market Monitor
ISO	Independent System Operator, ISO New England
ISO tariff	*ISO New England Transmission, Markets, and Services Tariff*
kW	kilowatt
kWh	kilowatt-hour
kW-mo	kilowatt-month
L	symbol for the competitiveness level of the LMP
LEG	limited-energy generator
LMP	locational marginal price
LNG	liquefied natural gas
LSE	load-serving entity
LSR	local sourcing requirement
M-36	*ISO New England Manual for Forward Reserve*
MCL	maximum capacity limit
ME	State of Maine and Maine load zone
Min Gen	Minimum Generation (Min Gen Emergency)
M/LCC2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NCPC	Net Commitment-Period Compensation
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NH	State of New Hampshire, New Hampshire load zone
NICR	net Installed Capacity Requirement
NPCC	Northeast Power Coordinating Council

Acronyms and Abbreviations	Description
NPR	nonprice retirement request
NY	State of New York
NYISO	New York Independent System Operator
OATT	*Open Access Transmission Tariff*
OP 4	ISO Operating Procedure No. 4
OP 8	ISO Operating Procedure No. 8
ORP	offer-review price
ORTP	offer-review trigger price
PER	peak energy rent
PFP	pay for performance
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PRD	price-responsive demand
Q	quarter
QDN	Qualification Determination Notification
RAA	reserve adequacy analysis
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RI	State of Rhode Island, Rhode Island load zone
RSI	Residual Supply Index
RTDR	real-time demand response
RTEG	real-time emergency generation
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTPR	real-time price response
SEMA	Southeast Massachusetts load zone
SOC 1	present audit of market operations and settlement systems
SWCT	Southwest Connecticut
TMNSR	10-minute non-spinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TPRD	transitional price-responsive demand
TTC	total transfer capability
US	United States
VT	Vermont and Vermont load zone
WCMA	Western/Central Massachusetts