2011 Annual Markets Report

Internal Market Monitor
May 15, 2012

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. The *2011 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2011. 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, NCPC* [Net Commitment-Period Compensation] *costs and the performance of the Forward Capacity Market and FTR* [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.*[1]

The IMM submits this report simultaneously to the ISO and the United States 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 an RTO's* [Regional Transmission Organization's] *market monitor at the same time they are submitted to the RTO.*[2]

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 the 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 of the IMM presents the most important findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2011. A summary of the outcomes and market performance is included in Section 1.1. Section 2 and Section 3 include more detailed discussions of each of the markets, market results, and the IMM's analysis and recommendations. An appendix (Section 4) provides additional data on the markets. A list of acronyms and abbreviations also is included. Key terms are italicized and defined within the text and footnotes. To aid the reader in

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[1] 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" (April 17, 2012), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[2] 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).

understanding the report's findings, an overview of the New England electricity markets, how they function, and market monitoring is available on the ISO's website.[3]

All information and data presented are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.

[3] Overview of New England's Wholesale Electricity Markets and Market Oversight (May 15, 2012), http://www.iso-ne.com/pubs/spcl_rpts/index.html.

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Section 1
Executive Summary

The *2011 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. This section summarizes the region's wholesale electricity market outcomes for 2011, the important market issues and the IMM's 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 the ISO administers, and Section 4 is an appendix of additional data. A list of abbreviations and acronyms is included at the end of the report. To aid the reader in understanding the report's findings, an overview of the New England electricity markets, how they function, and market monitoring is available on the ISO's website.[4] Key terms are italicized and defined within the text and footnotes.

1.1 Summary of Market Outcomes

Over the long run, competitive and efficient electricity 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 (IMM) include reviewing the competitiveness of the wholesale electricity markets, reporting on market outcomes, and recommending improvements to the market design. The IMM's review of market outcomes and related information for 2011 shows that the wholesale electric markets operated competitively in 2011. Market concentration is low, and energy prices remain at levels consistent with the short-run marginal cost of production. The ISO operated through several severe weather events without major incident. Overall market outcomes were influenced by lower natural gas prices, higher-than-normal hydroelectric production, and low loads, which caused energy, congestion, and reliability costs to fall from 2010 levels.

Table 1-1 shows wholesale electricity costs (in dollars and dollars/megawatt-hour; $/MWh) by type and market in 2011 compared with 2010. Total costs declined by about 10%, while energy costs declined by about 6%. Total costs decreased more than energy costs alone because, in percentage terms, capacity and ancillary services costs dropped much more than energy costs. The decline in energy costs primarily was the result of a decrease in natural gas prices.[5] Natural gas prices fell by approximately 4.5% in 2011.

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[4] Overview of New England's Wholesale Electricity Markets and Market Oversight (May 15, 2012), http://www.iso-ne.com/pubs/spcl_rpts/index.html.

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

Table 1-1
Wholesale Market Cost Summary

Type	Annual Costs ($ Billions)			Average Costs ($/MWh)		
	2010	2011	% Change	2010	2011	% Change
Energy	6.63	6.17	−7%	50.98	48.00	−6%
Capacity	1.65	1.35	−18%	12.69	10.47	−17%
Ancillary Services	0.25	0.11	−56%	1.93	0.88	−55%
Total	8.53	7.63	−11%	65.60	59.35	−10%

A combination of high loads and forced outages during two days in 2011 caused unusual operating conditions that required system operators to initiate operating procedures to maintain reliability. On June 22 and December 19, total system capacity dropped below the level needed to meet load plus operating reserve, and several actions of Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*, were called.[6] Demand-response resources were dispatched to meet capacity deficiencies on both days, and in aggregate, they delivered most of the requested demand reduction. However, the amount of demand reduced by most *individual* demand-response resources did not equal the amount requested by the ISO. This was caused, in part, by the market rules that determine demand-resource performance incentives and penalties. In addition, several generating resources either failed to start or tripped off line. The IMM's review of these events has led to several recommendations and areas for further review.

The Forward Capacity Market (FCM) continues to provide sufficient resources to meet the region's resource adequacy requirements. The fifth Forward Capacity Auction (FCA #5) was held in March 2011 and, like the previous three FCAs, cleared at the auction floor price. The capacity price for FCA #5 was $3.21/kilowatt (kW)-month, which resulted in a capacity surplus of 3,718 megawatts (MW), a 31% drop from FCA #4. Capacity payments made to all resources in 2011 totaled $1.35 billion, an 18% drop from 2010.

Forward Reserve Market (FRM) auction revenues decreased by 84%, totaling $17.8 million in 2011. Systemwide clearing prices in the FRM auctions for summer 2011 and winter 2011/2012 were $4,500/MW-month and $4,350/MW-month, a drop of 24% and 21% from the prior year's auctions. Regulation payments decreased by 7%, totaling $13.3 million, primarily driven by a reduction in the regulation requirement in 2011, from an average requirement of 64 MW in 2010 to 60 MW in 2011.

Net Commitment-Period Compensation (NCPC) payments in 2011 continued the trend away from payments to resources committed to meet local reliability needs (e.g., second-contingency protection or voltage needs) to those committed to ensure that the availability of resources was sufficient to meet load plus operating reserves (referred to as *economic NCPC*).[7] In 2011, economic NCPC totaled $58.1 million, a drop of 31%, or $26.6 million, from 2010, while the costs associated with providing local second-contingency protection, distribution support, and voltage support held relatively flat at $15.5 million.

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[6] Operating Procedure No. 4, *Action during a Capacity Deficiency* (December 9, 2011), http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

[7] *Net Commitment Period Compensation* is a method of providing "make-whole" payments to market participants with resources dispatched out of economic-merit order for reliability purposes when the costs of providing energy or reserves from the resources would otherwise exceed the revenue paid to the market participant. *Economic NCPC* arises when the total cost of committing and operating a generating resource exceeds the revenues it earns from the sale of energy at the LMP.

1.2 Issues and Recommendations

The IMM has identified the following issues and makes the following recommendations for improving the market design on the basis of observations of participant behavior and market outcomes in 2011 and the analysis presented herein. The issues and recommendations are listed in priority order.

- Resources with a capacity supply obligation (CSO) but no day-ahead market position do not face any penalties associated with failing to respond successfully to ISO commitment and dispatch instructions in real time. The IMM recommends that resources with a capacity supply obligation that fail to deliver electric energy when requested in real time be subject to a penalty based on the cost that their unavailability has on the market. Implementing this recommendation will induce participants to incorporate into their offers the cost of maintaining real-time availability and thereby reveal the market's estimate of the cost of providing reliable electric energy. In addition, the implementation of a penalty for failing to perform or not being available would provide the proper signal for a resource that cannot operate for an extended time to exit the capacity market (see Section 3.5.5).

- Another concern is that resources may not be willing to provide electric energy if they cannot accurately reflect their costs in real time. The IMM recommends that the ISO implements market functionality that would allow resources to offer hourly and to update incremental supply offers within the operating day to reflect changes in fuel costs during the operating day. This change would have the benefit of allowing sellers to reflect costs more accurately in their offers and of allowing real-time electricity prices to reflect changes in the costs of the marginal fuels (see Section 3.5.5).

- Observations of resource performance under stressed system conditions suggest that incentives are insufficient to induce resources to follow dispatch instructions in the Real-Time Energy Market. The IMM recommends adopting a penalty that would be levied on resources that fail to follow dispatch instructions. The proposed penalty would be based on the additional costs that a resource's failing to follow dispatch instructions imposes on the market (see Section 2.1.5).

- Resources have continued to enter the capacity market, and surplus has been slow to exit the auctions as the price has fallen. The floor price, which has remained in place for the first six FCAs, is an important contributor to the surplus. Continuing the floor price enables inefficient capacity to remain in the market, while discouraging new, efficient resources from entering. The IMM recommends implementing the Federal Energy Regulatory Commission's (FERC) Minimum Offer Price Rule and eliminating the floor price. This will increase the likelihood that electric energy and capacity prices will support an efficient mix of resources over the long term (see Section 3.5.4).

- A review of the shape of each FCA's capacity supply curve shows that, given the FCA's vertical demand curve, a small increase or decrease in the Installed Capacity Requirement (ICR) could produce a disproportionally large change in price compared with any reasonable estimate of the increase or decrease in system reliability caused by the change in the ICR. The IMM recommends the development of a sloped demand curve for use in the market-pricing mechanism. The need for a sloped demand curve becomes more pressing with the modeling of capacity zones in the auction, allowing the prices to more efficiently signal the surplus and shortage in each zone (see Section 3.5.4).

- The IMM is concerned with the continued decline in the volume of virtual trades where virtual transactions are needed to provide an adequate level of liquidity in the Day-Ahead Energy Market. Analysis suggests a relationship between the allocation of Net Commitment-Period Compensation charges to virtual transactions and the observed decline in trading activity (see Section 3.1.2.5). The IMM recommended in the *2010 Annual Markets Report* that the ISO revise the market rules so that real-time NCPC charges do not prevent virtual transactions from providing the benefits of improved liquidity in the day-ahead market. The IMM continues to support this recommendation.[8]

- The tariff does not clearly specify instances when a demand-response asset should be treated as unavailable.[9] Nothing in the market rules prevents a real-time demand response (RTDR) or a real-time emergency generation (RTEG) asset that has shut down its facility (for retooling, for example), or that has had a demand-asset meter malfunction, from claiming a demand reduction. In these cases, a market participant could be paid improperly for apparent load reductions in response to an ISO's dispatch instruction. The IMM recommends that the ISO modify the tariff to define facility shutdowns and meter malfunctions as situations constituting a "forced" outage or unavailability for RTDR and RTEG assets, during which the assets are ineligible for compensation and the outages are promptly reported to the ISO (see Section 3.4.4.2).

- The market rules currently require owners of demand-response resources to submit and verify the integrity of the meter reads used to establish their resources' baseline consumption and demand reductions. The IMM contends that this approach introduces a conflict of interest because the party submitting the data used to determine payment is the party that will be paid. The IMM recommends that an unrelated party, such as the distribution utility, submit, or at the least verify, the meter data. The IMM also recommends tariff changes that would clarify that market participants report data-quality issues to the ISO in a timely manner and that they be required to refund any payments made based on inaccurately stated performance (see Section 3.4.4.1).

- The IMM is concerned that the Forward Reserve Market auction design is susceptible to possible price distortions and inefficiencies. This is a consequence of resources' offering into the market with effective zero price offers (see Section 3.3.4). The IMM does not know the true incremental cost of the resources in question, only that the costs arguably could not be zero. The IMM continues to review the market design for possible changes and may request information from lead participants to justify their offers to ensure efficient market outcomes.

1.3 Status of IMM Recommendations from the *2010 Annual Markets Report*

The status of IMM recommendations from the *2010 Annual Markets Report* are shown in Table 1-2.

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[8] *2010 Annual Markets Report* (AMR10) (June 3, 2011), http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

[9] The ISO operates under several FERC tariffs, including the *ISO New England Transmission, Markets, and Services Tariff* (ISO tariff) (2012), of which Section II is the *Open Access Transmission Tariff* (OATT) and Section IV is the *Self-Funding Tariff*. These documents are available at http://www.iso-ne.com/regulatory/tariff/index.html and http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

Table 1-2
Status of IMM Recommendations from the 2010 Annual Markets Report

Recommendation	Status
Revise the market rules so that real-time Net Commitment-Period Compensation charges are not allocated to virtual transactions	ISO response expected mid-2012
Revise the market rules to allow the FRM threshold price to be calculated daily using a daily fuel-price index	FERC filing mid-2012; effective Q4 2012
Review the way real-time prices are set to ensure that prices reflect supply and demand under all market conditions	Analysis to begin in 2012
Adopt an improved process for establishing initial baselines, and develop a more robust and accurate baseline methodology	Effective June 1, 2012, with transition price-responsive demand (PRD) rules
Review the Day-Ahead Load-Response Program (DALRP) participation and audit rules to prevent a resource from being compensated for a demand reduction under the DALRP during periods when the resource is shut down for reasons unrelated to its participation in the program	Effective June 1, 2012, with transition PRD rules
Reevaluate the asymmetric baseline adjustment rules for the DALRP	Effective June 1, 2012, with transition PRD rules
Revise the market rules regarding the a resource's failing to follow dispatch, and if appropriate, define "failing to follow dispatch" for purposes other than NCPC payment and price setting	Analysis to begin in 2012

Section 2
Real-Time Markets

ISO New England's (ISO) real-time markets include the Real-Time Energy Market, real-time reserves, and the Regulation Market. This section describes the 2011 outcomes of the real-time markets and the Internal Market Monitor's (IMM) recommendations for these markets. The section also summarizes the ISO's actions to ensure real-time reliability and includes the IMM's assessment of ISO operations.

2.1 Real-Time Energy Market

This section describes the outcomes, structure, and competitiveness of the Real-Time Energy Market, as well as a recommendation to improve the incentives for market participants to follow the ISO's dispatch instructions. The IMM's review of market outcomes shows that the Real-Time Energy Market was competitive in 2011.

The Real-Time Energy Market is the physical market in which generators and load-serving entities (LSEs) sell and purchase electricity. The ISO coordinates the production of electricity to ensure that the amount produced from moment to moment matches the amount consumed, while respecting transmission constraints. In real time, 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. 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 taken in the Day-Ahead Energy Market (discussed in Section 3.1) and actual production or consumption in the Real-Time Energy Market. Participants either pay or are paid the real-time LMP for the total amount of load or generation (in megawatt-hours; MWh) that deviates from their day-ahead schedule.

2.1.1 Prices

Real-time price data for 2011 and comparisons of the real-time prices with day-ahead prices are presented below. (See Section 3.1.1 for a full discussion on day-ahead pricing.)

2.1.1.1 Real-Time Prices

In 2011, the average real-time Hub price was $46.68/MWh, down from $49.56/MWh in 2010.[10] This price is consistent with observed market conditions, including natural gas prices, loads, hydroelectric production, and other available supply. Price differences among the load zones primarily stemmed from marginal losses, with little congestion at the zonal level.[11] Congestion primarily was restricted to smaller, more transient load pockets that formed when transmission or generation elements were out of service.

[10] 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 that represents an uncongested price. An *external interface node* is a proxy location used for establishing an LMP for energy received by market participants from, or delivered by market participants to, a neighboring balancing authority area. Throughout this report, average prices are calculated using a simple average method.

[11] The loss component of the LMP is the marginal cost of additional losses caused by supplying an increment of load at the location.

The Maine load zone continues to have the lowest average prices in the region, and the Connecticut load zone continues to have the highest. The average LMPs in the Maine load zone were about $1.73/MWh lower than the Hub price, largely because the marginal loss components of the LMPs in Maine were lower than those components at the Hub. The average LMPs in the Connecticut load zone were $1.27/MWh greater than the average Hub price, largely because the congestion components of the LMPs in Connecticut were higher than those components at the Hub. See Table 2-1.

Table 2-1
Simple Average Real-Time Hub Prices and Load-Zone Differences for 2010 and 2011 ($/MWh)

Location/Load Zone	2010	2011
Hub	$49.56	$46.68
Maine (ME)	−$2.49	−$1.73
New Hampshire (NH)	−$0.86	−$0.61
Vermont (VT)	$0.34	−$0.11
Connecticut (CT)	$1.21	$1.27
Rhode Island (RI)	−$0.69	−$0.54
Southeast Massachusetts (SEMA)	−$0.27	−$0.09
Western Central Massachusetts (WCMA)	$0.51	$0.56
Northeast Massachusetts (NEMA)	−$0.32	−$0.11

2.1.1.2 Day-Ahead and Real-Time Price Comparison

In 2011, average day-ahead prices at the Hub were $46.38/MWh, and average real-time energy prices at the Hub were $46.68/MWh. The average day-ahead-to-real-time price differential has been declining. In 2005, the annual average difference between day-ahead and real-time prices was 2.4% (day ahead greater than real time). In mid-2009, the relationship switched, and real-time prices averaged 1.15% greater than day-ahead prices. This relationship continued in 2011, with real-time prices averaging 0.65% greater than day-ahead prices, suggesting that the day-ahead market reasonably reflects expected real-time outcomes. See Table 2-2.

Table 2-2
2011 Annual and Quarterly Day-Ahead and Real-Time Hub Prices ($/MWh)

	Annual	Q1	Q2	Q3	Q4
Day ahead	$46.38	$57.53	$43.41	$46.77	$38.04
Real time	$46.68	$57.91	$43.52	$48.21	$37.28

In 2011, hourly real-time and day-ahead prices were highly correlated (0.73), as expected. Hourly real-time LMPs at the Hub for 2011 had a standard deviation of $25.36, while hourly day-ahead LMPs at the Hub for 2011 had a standard deviation of $19.58. Because *contingencies* (e.g., unplanned generation or transmission outages) and Minimum Generation Emergency conditions can occur in real time only, greater real-time price volatility is reasonably expected.[12] See Figure 2-1.

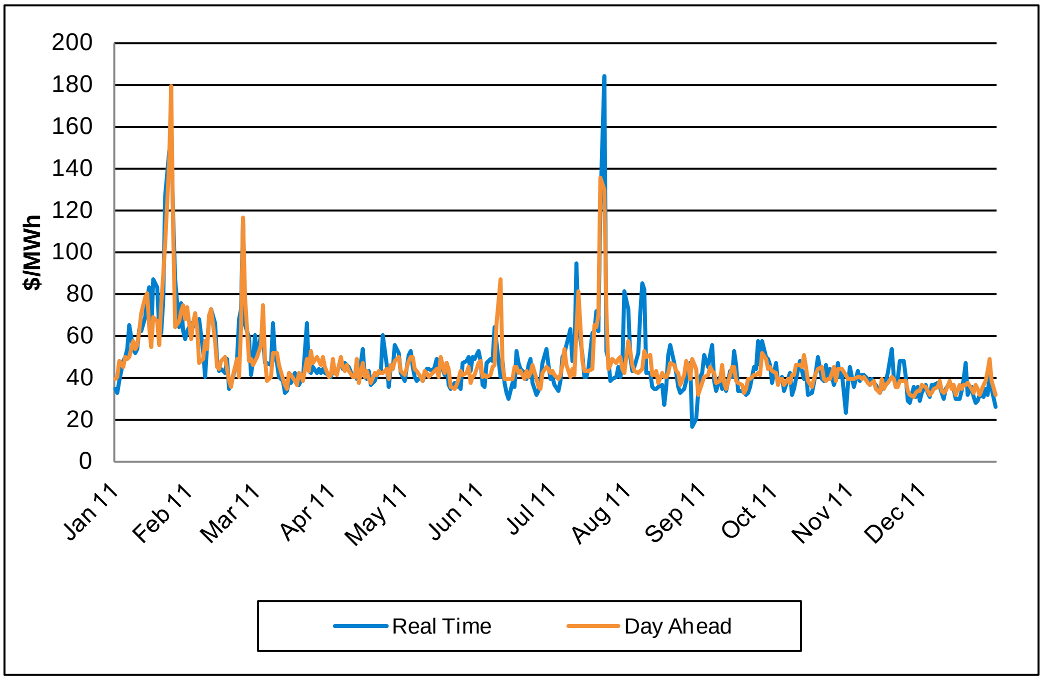

Figure 2-1: Average daily day-ahead and real-time Hub prices, 2011 ($/MWh).

2.1.2 Market Structure

A core function of the IMM is to monitor market participant behavior and detect deviations from competitive behavior with the goal of lowering the likelihood of participants' exercising market power. The exercise of market power is more likely when the market has fewer competitors. Thus, the structure of the market (i.e., the number of competitors, the nature of the product, and the frequency with which suppliers are *pivotal*—or can set prices and are necessary to meet demand) affects the ability of participants to raise price above marginal cost, which in turn has an impact on the market's ability to set price and sustain profits above the competitive level.

This section presents the results of the IMM's analysis of market structure (Section 2.1.4 examines conduct and performance). The IMM assesses several statistics:

- The percentage of generation produced in the annual peak hour from the four-largest suppliers
- The amount of energy purchased in the annual peak hour by the four-largest load-serving entities

[12] The declaration of a *Minimum Generation Emergency* resets the economic minimums of resources down to their emergency minimums (if available) to gain additional dispatchable range and administratively sets LMPs to zero. Minimum Generation Emergencies are called when the on-line generation comes close to exceeding system load plus net imports and all generation is operating at its economic minimum.

- Market concentration, as measured by the Herfindahl-Hirschman Index (HHI) (see Section 2.1.2.2)
- The number of hours in which participant portfolios were pivotal, as measured by the Residual Supplier Index (RSI) (see Section 2.1.2.3)

2.1.2.1 Market Share of Supply and Demand for the 2011 Peak Hour

A commonly used measure of market share is the percentage of the market controlled by the four-largest competitors (C4). The four-largest generating companies and the four-largest LSEs control slightly less than half of the supply and load in the region, with two of the largest suppliers also serving a large percentage of the load.

For the 2011 peak hour—July 22, 2011, hour ending (HE) 3:00 p.m.—generators produced 28,504 megawatts (MW) of electricity to serve load in New England.[13] The four-largest generation suppliers provided 42% of the total electricity produced in New England in that hour, while all other market participants provided 58% of the electricity generated in that hour. The participant that supplied the most generation to the system during the peak hour was Dominion Energy Marketing, which supplied 3,954 MW (14%) of the total electricity generated. NextEra Energy Power Marketing and Constellation each provided approximately 3,160 MW (11%) of the total generation, and H.Q. Energy Services provided 1,768 MW (6%) of total supply. See Figure 2-2.

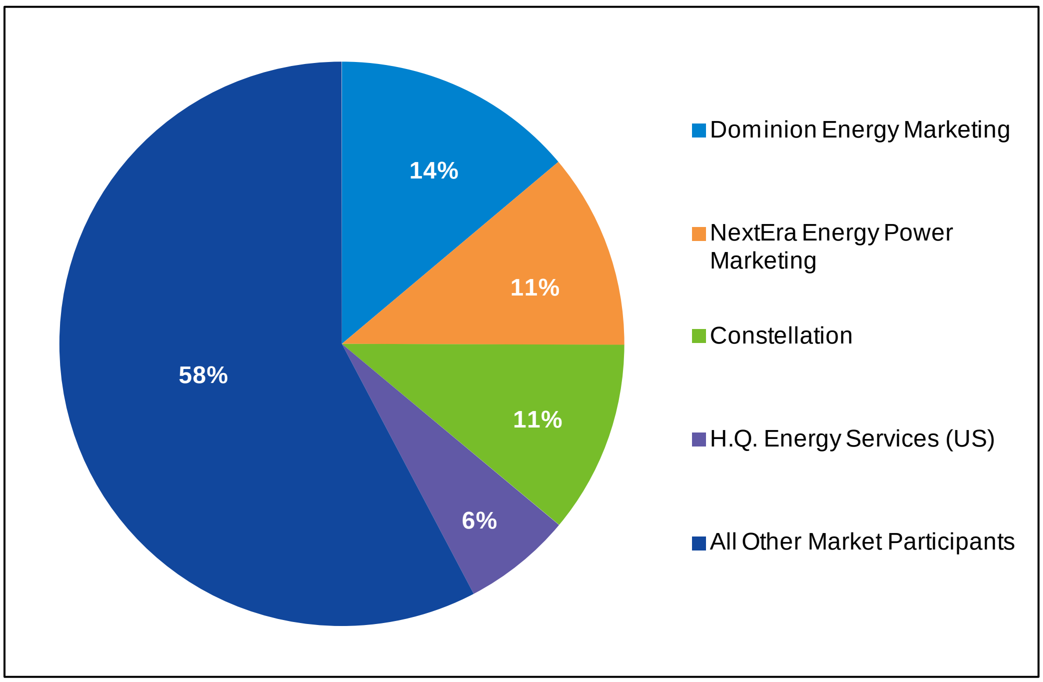

Figure 2-2: Market share of generation by participant, peak hour 2011 (July 22, hour ending 3:00 p.m.).

For the 2011 peak hour, the total amount of electricity purchased, or *real-time load obligation* (RTLO), was 28,108 MW.[14] Overall, the four-largest load-serving participants served 45% of the total system

[13] *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.

[14] Losses account for the difference between the 28,504 sold generation and the 28,108 MW bought generation.

load for the 2011 peak hour, while all other market participants served 55% of the total system load in that hour. The participant with the highest real-time load obligation, serving 6,883 MW (25%) of total system peak load, was Constellation. NextEra Energy Power Marketing served 2,376 MW (8%); the Hess Corporation, 1,989 MW (7%); and TransCanada Power Marketing, 1,447 MW (5%) of total system peak load in that hour. See Figure 2-3.

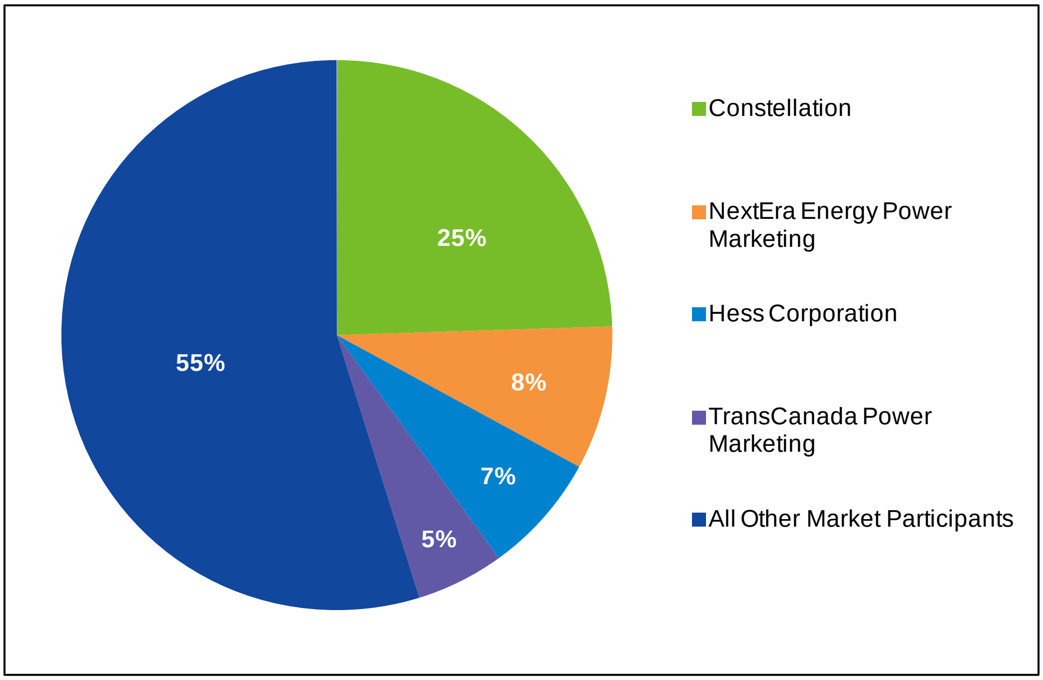

Figure 2-3: Real-time load obligation by participant, peak hour 2011 (July 22, hour ending 3:00 p.m.).

Figure 2-2 and Figure 2-3 show that NextEra and Constellation are the top-four participants for both load served and generation provided in the peak hour of 2011. These two participants accounted for 22% of the generation provided and 33% of the load served on the system in the peak hour. Participants with both load and generation generally have less incentive to exercise market power. Actions that would tend to raise prices to generation would come at a cost to load, and any actions that would suppress prices would come at a cost to generation. Consequently, the IMM is most concerned with a participant's net position and the conditions under which unilateral action might become profitable.

The IMM has reviewed the bidding behavior of all market participants as part of its monitoring and mitigation functions. While the IMM mitigated the offers of some resources, in 2011, the IMM did not identify behavior that suggested a more systematic attempt to use pricing power to manipulate market outcomes, either via economic or physical withholding.

2.1.2.2 Structural Measure of the Real-Time Energy Market

The *Herfindahl-Hirschman Index* is a measure of market concentration that gives larger weights to relatively larger firms. The HHI is calculated as the sum of the squared market shares, expressed as a percentage, of the firms in the market. The IMM presents both HHI and market share in this report; however, they differ in important aspects, as illustrated by the following example. Consider five firms that cover the entire market in two situations: first, when the market shares are 30%, 20%, 20%, 20%, and 10% and second, when the market shares are 57%, 11%, 11%, 11%, and 10%. In both cases, C4 is

90%, but the HHI is 2,200 in the first case and 3,712 in the second case. Because C4 is a simple sum of the shares of the four-largest firms, it is insensitive to how the sum is distributed among the top four firms, whereas the HHI is highly sensitive to the larger market shares. In addition, the United States (US) Department of Justice (DOJ) sets predetermined thresholds to separate unconcentrated markets from concentrated ones, and no such commonly used thresholds exist for C4.[15]

The IMM used cleared megawatts for each real-time pricing interval for calculating the market shares of each market participant and HHIs in the Real-Time Energy Market. The IMM ignored transmission constraints for several reasons:

- The market is largely unconstrained (see Section 2.1.2.3).
- When transmission constraints have affected price, the magnitude and geographical scope of the effect has been restricted.
- Constrained pricing intervals do not generally occur in a predictable way that would allow possible market manipulation.

Thus, the IMM assumed that an unconstrained market would not significantly affect the results of the HHI analysis.

The HHI calculation considers 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 IMM's HHI analysis. The interquartile range (i.e., the range between the 25th and 75th percentiles of observation) for peak-hour HHIs in 2011 was 669 to 754, while the median and maximum peak-hour HHIs were 711 and 901, respectively. The HHI results have not changed significantly over the past three years. Using the DOJ's *Horizontal Merger Guidelines*, the IMM determined that the Real-Time Energy Market in New England is not concentrated.

Table 2-3
Interquartile, Median and Maximum HHI, Median Hourly Load, Number of Participants, and Share of Top Participants (by Market Share) in Peak-Load and Lowest-Load Hours in 2011

	Interquartile Ranges	Median Load (MW)	Max HHI	Median HHI	Median Number of Participants	Median Share of Top *N* Participants			
						N=1	*N=4*	*N=8*	*N=16*
Peak hour	669 to 755	18,344	901	712	119	15.7%	45.1%	64.0%	83.4%
Lowest-load hour	803 to 969	11,980	1,171	889	114	19.4%	52.1%	70.9%	87.1%

The HHI generally is higher in low-load hours than peak hours. During low-load hours, large baseload units meet most of the demand. During peak load hours, resources owned by other participants enter the market, lowering the market share of the participants that control the majority of baseload

[15] 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.

resources, as well as the overall market concentration. This phenomenon becomes clearer considering that in 2009, the top four participants (by market share) comprised 52% of the market in the hours with the lowest load, compared with 45% for the peak hours.

2.1.2.3 Residual Supply Index

The systemwide Residual Supply Index measures the percentage of demand in a given hour (in megawatt-hours) that can be met without any capacity from the largest supplier. The RSI also measures the number of hours in which one or more supplier is pivotal, or can price above the competitive level, subject only to offer caps, mitigation measures, and the price elasticity of demand. When the RSI exceeds 100%, the system has sufficient capacity from other suppliers to meet demand without any capacity from the largest supplier. When the RSI is below 100%, a portion of the largest supplier's capacity is required to meet market demand, and the supplier is pivotal. As RSIs rise, the ability of market participants to unilaterally set prices above competitive levels decreases. RSIs generally are lowest during periods of high demand, indicating a drop in the level of competition as the system approaches its capacity limit.

Overall, the RSI analysis for 2011 suggests that suppliers in the system level and in the local reserve zones had limited ability to exercise market power.[16] The system-level analysis shows that pivotal suppliers existed during 47 hours in 2011, approximately 0.5% of all hours. This is a decrease from 2010, when suppliers were pivotal in 223 hours. See Figure 2-4.

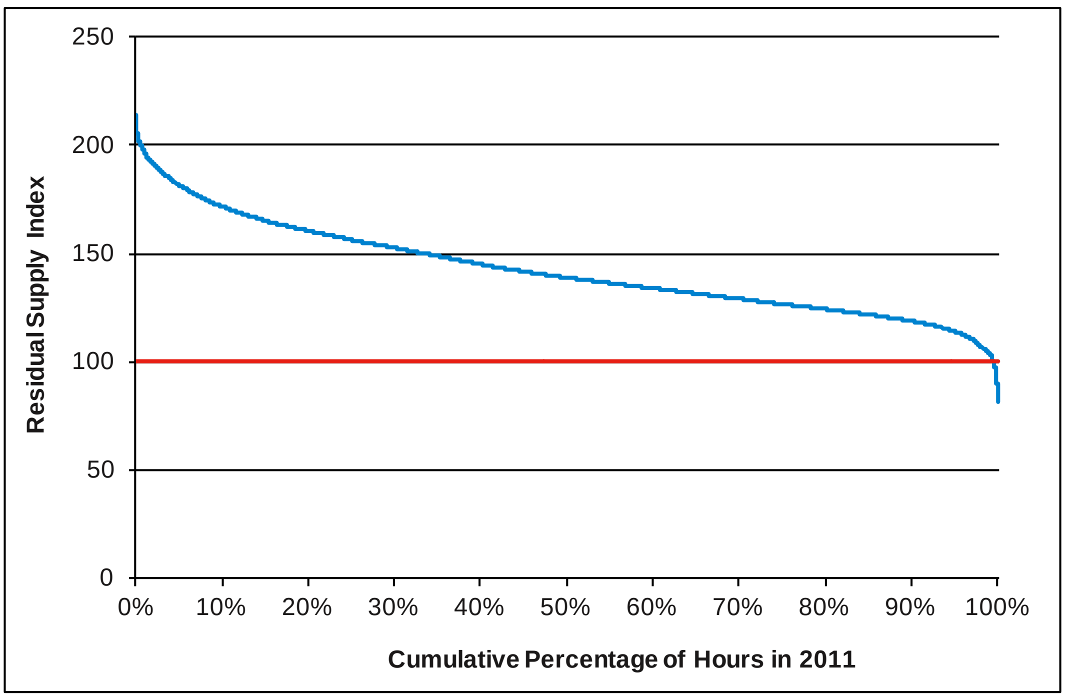

Figure 2-4: Systemwide Residual Supply Index duration curve, all hours, 2011.

To measure potential local market power caused by import constraints, the IMM analyzed local RSIs for the Southwest Connecticut (SWCT), Connecticut (CT), and NEMA/Boston (Boston) reserve zones. These areas were chosen because they more frequently are import constrained or have a more

[16] The region has four reserve zones—Connecticut, Southwest Connecticut (SWCT), NEMA/Boston, and the rest of the system (Rest-of-System, ROS). The *Rest-of-System* zone is the area excluding the other local reserve zones.

concentrated ownership than the overall system. In 2011, RSIs in the local zones were not noticeably higher than the systemwide RSI. The only exception was in October, in the Boston zone, where a supplier was pivotal for 35 hours because two large resources in the area were out of service. See Table 2-4.

Table 2-4
Local Area RSIs for Selected System Interfaces, January 2011 to December 2011

Month	Boston		Southwest Connecticut		Connecticut	
	Avg RSI	# of hours RSI <100	Avg RSI	# of hours RSI <100	Avg RSI	# of hours RSI <100
Jan	239	0	297	0	128	2
Feb	235	0	302	0	139	0
Mar	215	0	247	0	138	0
Apr	197	2	243	0	148	0
May	197	7	248	0	146	0
Jun	231	5	273	0	144	12
Jul	207	5	248	0	138	6
Aug	208	16	247	0	147	0
Sep	221	0	277	0	144	0
Oct	184	35	223	0	149	0
Nov	227	9	283	0	154	0
Dec	229	0	290	0	162	0

2.1.3 Relationship between Real-Time Energy Prices and Other Market Factors

This section describes the relationships between real-time electric energy prices and other market factors. Short-lived excursions in real-time prices (so-called price spikes) are explained by factors including sudden changes in weather, fuel prices, and unplanned generator or transmission outages.

2.1.3.1 Energy Prices and Marginal Units

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

In 2011, unconstrained pricing intervals accounted for approximately 94% of all the pricing intervals. During the unconstrained pricing intervals, natural-gas-fired units were marginal 68% of the time; natural gas was the fuel most frequently on the margin. The next-most-frequent fuels on the margin were coal and pumped-storage generation. When considering unconstrained and constrained periods together, natural gas was the marginal fuel during 74% of the pricing intervals. See Figure 2-5.

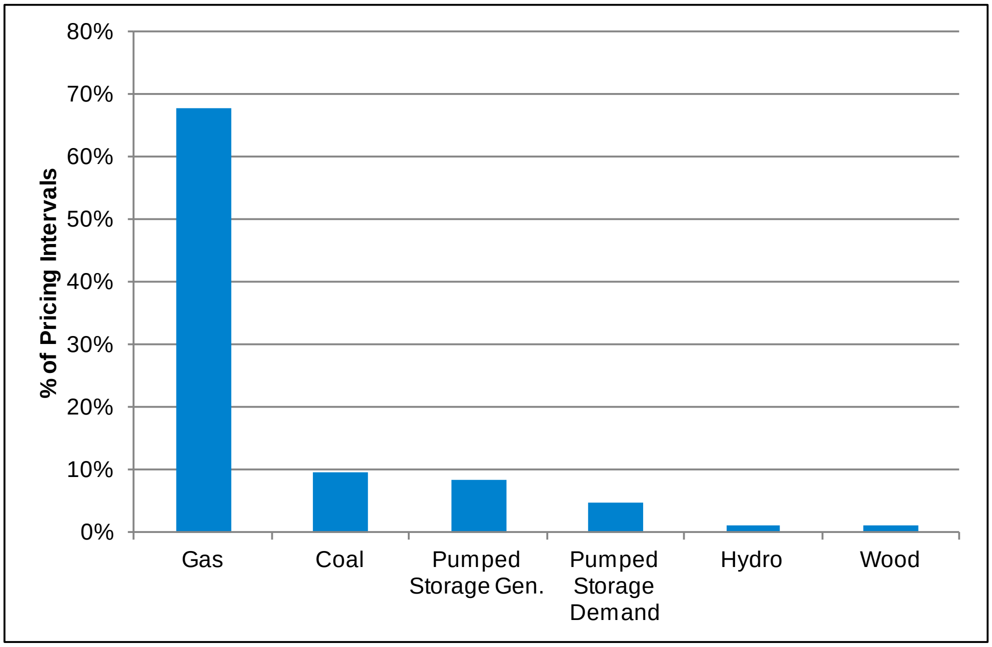

Figure 2-5: Marginal fuel-mix percentages of unconstrained pricing intervals, 2011.

2.1.3.2 Energy Prices and Natural Gas Prices

To determine how electricity prices varied with the price for natural gas, the IMM calculated the correlation between daily average natural gas prices and daily average real-time energy prices at the Hub. The correlation between the daily natural gas prices and real-time energy prices for 2011 was about 0.72.

Another measure of the relationship between real-time energy prices and natural gas prices is the *spark spread*. A spark spread is a measure of the gross margin (energy revenues minus fuel costs) from converting fuel to electricity for a typical natural-gas-fired power plant. The revenue for the spark spread is based on the wholesale price of electricity, the fuel cost, and the efficiency of a representative generation technology. In this case, the representative generation technology is a combined-cycle gas-turbine unit (CCGT) with a fuel-to-electricity conversion rate (heat rate) of 7,800 British thermal unit/kilowatt-hour (Btu/kWh). Figure 2-6 presents the quarterly estimated spark spreads for natural gas based on the following:

- The simple quarterly average real-time Hub price for on-peak hours from January 2009 through December 2011
- The fuel costs of a representative CCGT in New England, using the Algonquin gas price[17]
- A 7,800 Btu/kWh heat rate
- 100% availability

[17] 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.

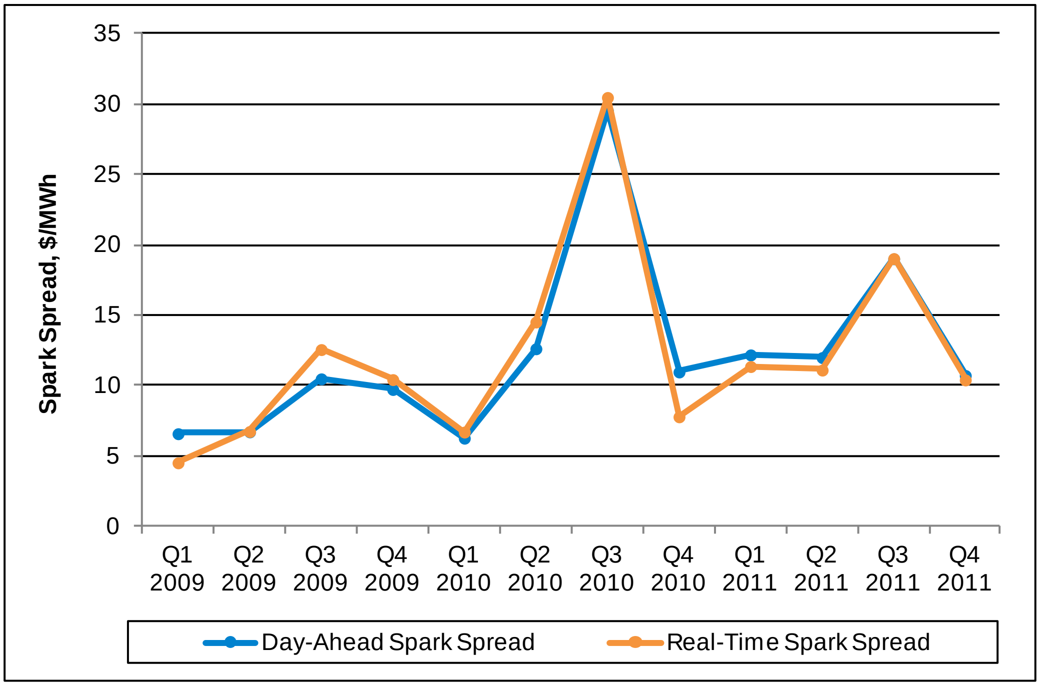

Figure 2-6: Quarterly estimated spark spreads for on-peak hours, 2009 to 2011 ($/MWh).

The results show that, on average, the representative gas unit earned a positive gross margin of approximately $13.61/MWh, or 29.3%, in day-ahead and $13.10/MWh, or 28.1%, in real-time.[18] The 2011 gross margins represent a decrease of 9% for day ahead and 12% for real time compared with 2010. The 2011 gross margins represent an increase of 62% for day ahead and 52% for real time compared with 2009.[19] Spark spreads for natural gas increased in the summer months of 2010 and 2011 when high loads called for more expensive gas- and oil-fired units to operate, setting price more frequently than in other quarters. Spark spreads are expected to increase in the summer months because high loads cause more expensive resources to be dispatched, which increases prices. The larger spark spread in 2010, relative to 2011, was the result of higher loads and the loss of a large flexible resource.

2.1.3.3 Energy Prices and Real-Time Demand

The demand for electricity in New England is weather sensitive and contributes to the seasonal variation in energy prices. The demand for electricity in New England, defined as *net energy for load* (NEL), was highest in the third quarter of 2011, at 35,531 gigawatt-hours (GWh).[20] The annual peak demand of 27,707 MW also occurred in the third quarter, on July 22. The first quarter had the second-highest demand for electricity in 2011, at 32,798 GWh of electric consumption, because of the cold weather in New England during January and February. As expected, the second and fourth quarters of 2011, with typically more mild temperatures, had the lowest demand for electricity. See Table 2-5.

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[18] For this analysis, the gross margin percentage is calculated as {(Avg. Hub LMP – Fuel Cost)/Avg. Hub LMP}.

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

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

Table 2-5
Energy Statistics, 2010 and 2011

	2010 Annual	2011 Annual	Q1	Q2	Q3	Q4
NEL (GWh)	130,771	129,158	32,798	30,310	35,531	30,519
Weather-normalized NEL (GWh)[(a)]	129,910	128,998	32,523	30,331	35,057	31,087
Recorded peak demand (MW)	27,102	27,707	21,053	23,322	27,707	19,341

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

Figure 2-7 shows real-time monthly LMPs and the cycle in seasonal demand over the past two years, illustrating the impact on price of higher demand in the winter and summer months and lower demand in the spring and autumn months. The correlation between the daily average hourly loads and real-time Hub prices was 0.57 for 2011 and 0.70 for 2010.

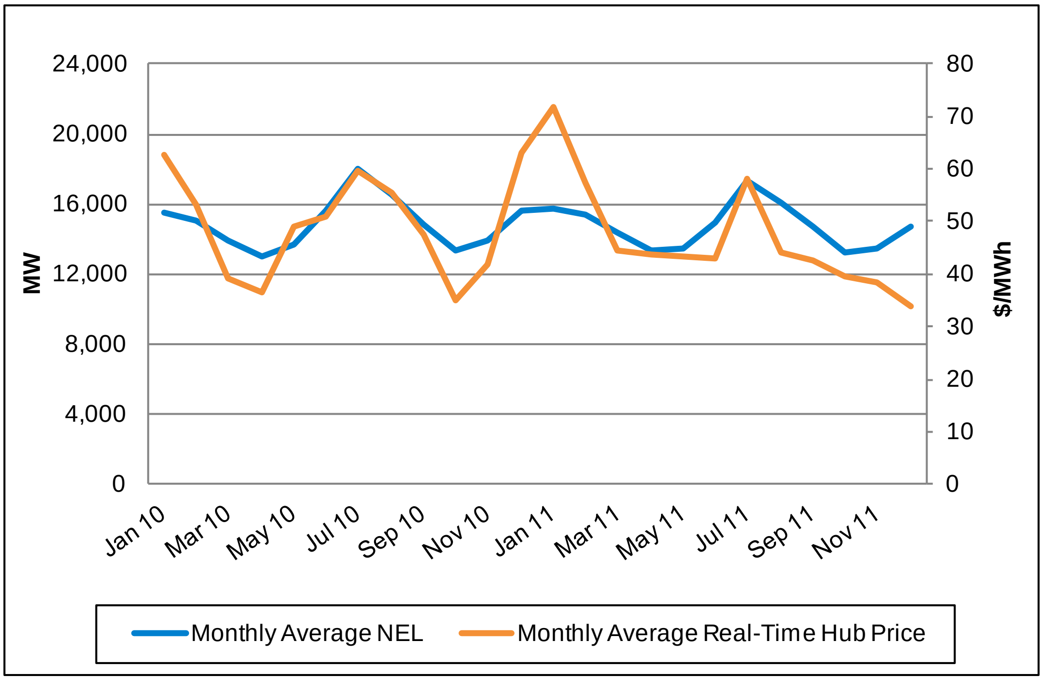

Figure 2-7: Monthly average net energy for load and real-time Hub prices, 2010 to 2011.

2.1.3.4 Energy Prices and System Conditions

Weather and other system conditions affected prices on a number of days in 2011:

- From January 23 through January 25, cold weather increased the demand for natural gas for heating and electric generation, resulting in high gas prices and electric energy prices above $100/MWh in both day-ahead and real-time.
- In late February, a supply interruption following an explosion on the TransCanada pipeline resulted in high gas prices and electric energy prices (see Section 2.4.2.1).
- On July 22, high loads (27,707 MW for the peak hour) resulted in high prices. As explained further below, the amount of operating reserves on the system fell below requirements,

which resulted in the ISO's implementation of Operating Procedure No. 4 (OP 4), Actions 1–3 and 5, and the posturing of resources.[21]

- On December 19, high loads, along with generator performance issues and a breaker trip, resulted in elevated prices.

The IMM further analyzed market conditions and performance on July 22, 2011, and December 19, 2011, when the ISO implemented actions of OP 4. The following is a summary of the main observations:

July 22, 2011:

- Prices were consistent with conditions, and participants acted competitively.
- Higher-than-forecasted temperatures and loads along with approximately 1,705 MW of generator performance issues, including trips, failures to start, and late starts, resulted in capacity and reserve shortages.
- The ISO implemented Actions 1, 2, 3, and 5 of OP 4 to help resolve the capacity deficiency.
- Real-time binding reserve constraints during OP 4 hours resulted in elevated real-time LMPs.
- The ISO dispatched 642 MW of real-time demand-response resources. While in aggregate, the resources delivered 648 MW of load reduction, the amount of demand reduced by most individual demand-response resources did not equal the amount requested by the ISO.[22]

December 19, 2011:

- Prices were consistent with conditions, and participants acted competitively. No suppliers were pivotal.
- Lower-than-forecasted temperatures resulted in higher-than-expected loads.
- Loads running over forecast, along with generator performance issues and a breaker trip, resulted in capacity and reserve shortages.
- The ISO implemented Actions 1 and 2 of OP 4 to help resolve the capacity deficiency.
- Real-time binding reserve constraints during OP 4 hours resulted in elevated real-time LMPs.
- The ISO dispatched 504 MW of real-time demand-response resources. During the period of 100% dispatch, the ISO obtained 77% of the requested load reduction.
- Several fast-start units were dispatched during the same period.[23] Performance was evaluated, relative to the unit's claimed capability, at 10 minutes and 30 minutes from receiving the ISO's dispatch instruction (see Section 2.2). The aggregate performance of the units with 10-minute capability was 78% at the 10-minute milestone. The aggregate

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[21] OP 4 refers to ISO New England Operating Procedure No. 4, *Action during a Capacity Deficiency* (December 9, 2011). The OP 4 guidelines contain 16 actions that can be implemented individually or in groups depending on the severity of the situation. OP 4 is available at http://www.iso-ne.com/rules_proceds/operating/isone/op4/.

[22] Real-time demand-response resources take on capacity supply obligations (CSOs) through the Forward Capacity Market and are activated by the ISO during OP 4 conditions; see Section 3.5.

[23] A fast-start generation unit can start up and be at full load in less than 30 minutes. A fast-start resource also can be a demand resource that helps with recovery from a contingency and assists in serving peak demand.

performance of the units with 30-minute capability (which includes the units with 10-minute capability) was 102% at the 30-minute milestone.

Pricing. Prices on July 22, 2011, were consistent with system conditions. The combination of high reserve prices and expensive oil resources contributed to high real-time LMPs. Real-time Hub LMPs were over $200/MWh for most of the day. The highest Hub LMP of $558.55/MWh occurred in hour ending 2:00 p.m. The Hub LMP reached $474.29/MWh, with reserve prices of $334.21/MWh, in the peak load hour. See Figure 2-8.

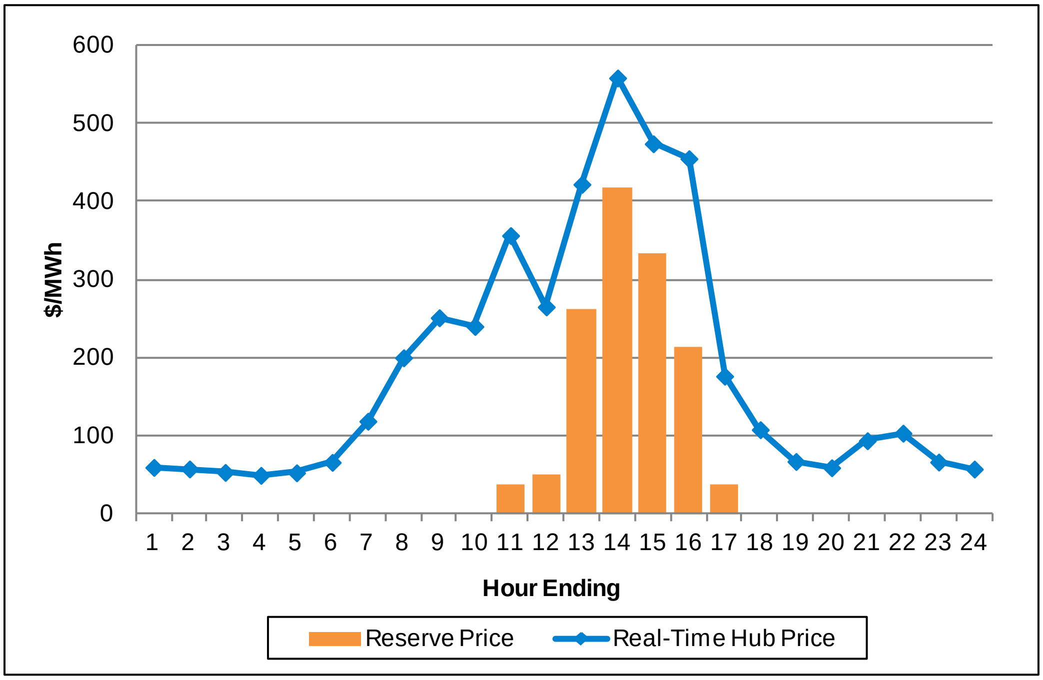

Figure 2-8: Real-time Hub LMP and 10-minute spinning reserve price, July 22, 2011.

On December 19, 2011, real-time Hub LMPs rose in HE 7:00 a.m. and HE 8:00 a.m. because of a reserve and capacity deficiency resulting from generator performance issues and a breaker trip. The reserve deficiency resulted in positive reserve pricing in these hours. The hourly price for units with 10-minute on-line capability (see Section 2.2) was $14.88/MWh in HE 7:00 a.m., which increased to $202.92/MWh in HE 8:00 a.m. The positive reserve pricing resulted in a peak real-time Hub LMP for the day of $277.59/MWh in HE 8:00 a.m. See Figure 2-9.

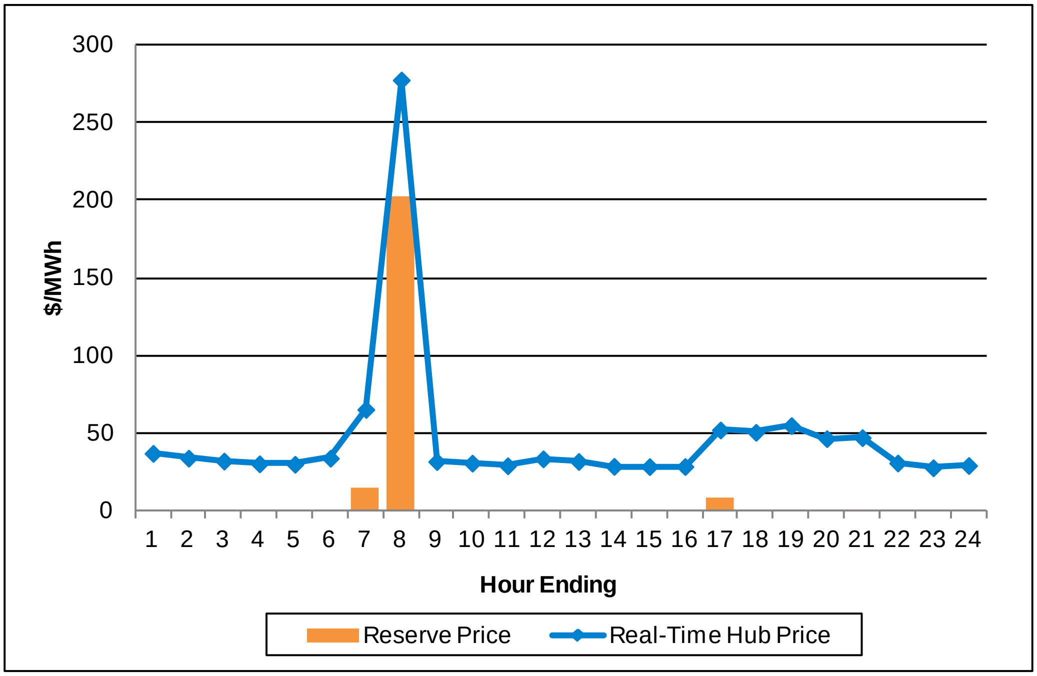

Figure 2-9: Real-time Hub LMP and 10-minute spinning reserve price, December 19, 2011.

Demand-Response Performance. On July 22, 2011, the net capacity supply obligation (CSO) of real-time demand-response resources was 642 MW.[24] At 12:15 p.m., the ISO dispatched 300 MW of real-time demand response systemwide. As system load continued to increase, the ISO dispatched the remainder of the real-time demand response at 1:16 p.m. for a total of 642 MW. In total, the ISO received 101% of the load reduction called for. While the demand resources appeared to have performed well in aggregate, performance was mixed zonally and for individual resources. Zonally, performance ranged from 46% to 129%, and individually, performance ranged from zero to over 200%.

On December 19, 2011, the net CSO of real-time demand-response resources totaled 504 MW. At 7:26 a.m., the ISO dispatched all real-time demand-response resources systemwide. As system conditions were returning to normal and reserves were being restored, the ISO reduced the amount of dispatched demand response to 300 MW at 9:30 a.m. On average, the real-time demand-response resources delivered 77% of the total load reduction the ISO dispatched.

The performance discrepancies for demand-response resources do not appear to be an attempt by market participants to manipulate market outcomes but rather the consequence of incentive problems in the Day-Ahead Load Response Program (DALRP) and Forward Capacity Market (FCM) provisions that allow so-called overperforming demand-response resources to receive an allocation of the penalties paid by underperforming resources. (Refer to Section 3.5.) Under the current market rules, a demand-response resource can be an aggregation of assets (i.e., individual companies and homes) located within the same geographic region called a "dispatch zone." The ISO issues dispatch instructions to each resource within a dispatch zone, requesting a specific megawatt load reduction from each resource. The market participant is responsible for managing the performance of its portfolio of assets to achieve the ISO-requested load reduction for each resource within the dispatch

[24] The net CSO excludes the transmission and distribution factor added to the capacity of a demand-response resource for Forward Capacity Market settlement purposes. (Section 3.5 contains more information on the FCM.)

zone. The dispatch zone model is important because it allows the ISO to request the amount of load reduction where it is needed to resolve a reliability problem. The incentives in the demand-resource performance incentive/penalty market rules create a conflict with the objectives of the dispatch zone model, especially when demand resources are dispatched in multiple dispatch zones. Market participants have the incentive to manage the performance of their entire portfolio of resources across multiple dispatch zones to achieve an aggregate reduction, rather than managing the performance of any individual resource within a dispatch zone. Such behavior has the potential to exacerbate a reliability problem, rather than helping to resolve it.

The market rule changes that the ISO made to comply with the Federal Energy Regulatory Commission's (FERC) Order 745 will address part of this incentive problem.[25] The ISO has proposed changes to the FCM market rules (refer to Section 3.5) that will replace the current demand-resource performance incentive and penalty rules with a performance-incentive structure comparable to that currently in place for generating resources.[26] These proposed FCM market rule changes are scheduled to be implemented coincident with the full integration of demand resources into the day-ahead and real-time energy markets in 2017.

2.1.3.5 Energy Prices and External Transactions

In 2011, 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 10,077 GWh for 2011, an 85% increase compared with the previous year. The increase in the net interchange is predominantly the result of lower exports from New England in 2011 compared with 2010. As described below, lower New England exports are not directly attributable to a price differential between New England and New York. See Figure 2-10.

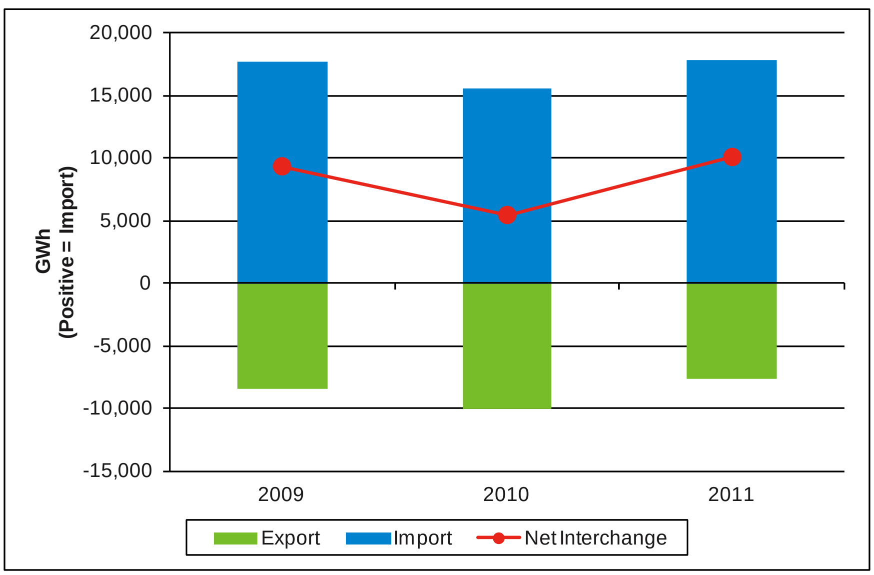

Figure 2-10: Scheduled imports and exports and net external energy flow, 2009 to 2011 (GWh).

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

[26] *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.

The current rules and systems that govern the interchange between New York and New England do not allow for the realization of all possible gains 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 flow 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.[27] See Table 2-6.

Table 2-6
Percentage of Time Transactions Are Scheduled in the Direction of the Higher Price on the Roseton Interface, 2009 to 2011

Year	Real Time	Day Ahead
2009	48%	62%
2010	48%	63%
2011	52%	57%

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, ample transmission capacity is available to move additional power from the lower-cost region to the higher-cost region. Potomac Economics, the ISO's External Market Monitor, estimates that if the transmission interface between New England and New York had been scheduled efficiently, the total production cost of meeting demand in the two regions (combined) would have been lower by a cumulative $77 million from 2006 through 2010.[28]

In July 2010, ISO New England and NYISO undertook a joint stakeholder project to evaluate the economic and operational performance of energy interchange on their interconnected transmission network.

As a part of the joint project, two solutions were evaluated—tie optimization and coordinated transaction scheduling (CTS):

- The core concept of tie optimization is for the ISOs to optimize their external transmission links in the same way, or as closely as possible, so that they optimize transmission internally. This achieves the lowest-possible production cost and efficiently uses the existing transmission infrastructure.

- Coordinated transaction scheduling employs higher-frequency scheduling and eliminates charges and credits on external transactions that deter trade. In contrast to the present interregional scheduling system, CTS features a simplified bid format, called an *interface bid*,

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

[28] See the ISO white paper, *Inter-Regional Interchange Scheduling (IRIS) Analysis and Options* (January 5, 2011), http://www.iso-ne.com/pubs/whtpprs/iris_white_paper.pdf.

for real-time scheduling and a coordinated acceptance of interface bids by the ISOs using an improved clearing rule.

On January 20, 2012, the stakeholders agreed to develop CTS as a primary option but left tie optimization as a viable option in the event that CTS proves to be ineffective. FERC accepted CTS on April 19, 2012.[29] The IMM supports the efforts to adopt rules and systems to implement CTS.

2.1.3.6 Energy Prices and Transmission Outages

According to the US Department of Energy (DOE) *2009 National Electric Transmission Congestion Study,* which summarized the amounts of congestion throughout the Eastern Interconnection, the New England system currently experiences little system congestion.[30] As a result, DOE has removed New England as an "area of concern" for the identification of National Interest Electric Transmission Corridors.[31]

Though congestion is no longer a major concern, short-term transmission issues, including planned or forced outages and transmission line trips, still affect market outcomes and prices.[32] Through its daily surveillance of the energy market, the IMM has observed that transmission issues resulting from planned or forced outages and trips can create binding constraints, which can contribute to transient congestion or elevated price levels on the system. The IMM also has observed that transmission issues, such as what occurred on December 19, 2011 (see Section 2.1.3.4), can contribute to temporary capacity shortages requiring relief under OP 4 actions.

2.1.4 Performance and Conduct Measures

In this section, the IMM presents the results of two metrics designed to reveal the extent to which market structure affected the ability of participants to sustain profits above the competitive level by raising electric energy prices above marginal costs. The first measure is important because the level of profits available in the market is a driver of capital-allocation decisions. The second measure is important because price is the principle means of coordinating short-run production and consumptions decisions. To the extent that either profits or prices are distorted as a result of the exercise of anticompetitive behavior (i.e., bids above cost), short- and long-term resource-allocation decisions can be distorted and increase overall costs.

2.1.4.1 Market-Share Weighted Gross Margin

The market-share weighted gross margin measures the extent to which market participants are able to realize gross profits above competitive levels. This measure takes the difference between two simulations of market outcomes: (1) a *benchmark case* that assumes all market participants bid at marginal cost and (2) a *test case* that uses the actual bids submitted by market participants during the year. The measure indicates the percentage of aggregate market profits explained by bids above cost.

[29] *Order Accepting Tariff Revisions, Subject to a Compliance Filing*, FERC 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.

[30] DOE, *2009 National Electric Transmission Congestion Study* (December 2009), http://www.congestion09.anl.gov/documents/docs/Congestion_Study_2009.pdf. The *Eastern Interconnection* is one of North America's major AC grids that, during normal system conditions, interconnects transmission and distribution infrastructure synchronously operating (at 60-hertz average) east of the Rocky Mountains and south to Florida, excluding Québec and the portion of the system located in the Electric Reliability Corporation of Texas (ERCOT).

[31] See the ISO's *2011 Regional System Plan* (RSP11) (October 21, 2011), http://www.iso-ne.com/trans/rsp/2011/index.html.

[32] 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, generally to perform maintenance.

If all participants bid in a strictly competitive way, that is, offer all output at cost, the measure has a value of zero. The IMM does not expect the value of this measure to be zero. However, given the prevailing supply surplus conditions, the IMM expects the value to be relatively small. Overall, the results of the analysis show that the additional gross margin earned by market participants is consistent with competitive outcomes.

The steps for calculating the market-share weighted gross margin are as follows:

- Calculate the *gross margin* as a percentage of the price that exceeds each resource's offer.
- Calculate the *weighted-average gross margin* for all resources for each hour, where the weights are each asset's market output as a percentage of total load in the hour.
- Weight the hourly values by the hourly loads to calculate the *market-share weighted gross margin* for the aggregate market for the year.

The IMM used a unit-commitment and dispatch simulation model to estimate the market-share weighted gross margin under the two scenarios described above and to measure the effect of offers that differ from the marginal cost on the gross margins earned in the market.[33] The IMM used resource offers and estimations of marginal cost to simulate the market outcomes under the two scenarios. The additional gross margin earned from megawatts offered over marginal cost was approximately 3.9% in 2009; 8.9% in 2010; and 4.7% in 2011. See Table 2-7.

Table 2-7
Market-Share Weighted Gross Margin, 2009 to 2011

Year	Offer Based	Cost Based	Difference
2009	34.40%	30.54%	3.87%
2010	39.99%	31.13%	8.87%
2011	36.37%	31.67%	4.69%

The outcomes are consistent with recent observations in the Real-Time Energy Market over the past three years. In 2010, real-time LMPs were higher than in 2009 and 2011. Higher natural gas prices increased all prices in 2010, relative to the prior year and the following year. Several factors, namely, less hydroelectric energy, higher loads, and the loss of a large flexible resource caused the market to require resources higher up on the supply curve. The results in Table 2-7 show that the measure of gross margin was roughly 4% higher in 2010 than in 2011. This result is expected for resources higher up on the supply curve, where it is steeper, that offer less competitively than resources further down on the supply curve. One possible explanation for this behavior is that as demand increases, fewer resources remain to meet that demand, and those resources can offer above their costs without losing market share. Section 2.1.4.2 describes that analysis of market competitiveness and shows that the market was more competitive in 2011 than in 2010.

The IMM made additional observations with the model. Because of operational limitations during the late night and early morning hours, baseload resources are willing to operate close to, or even below,

[33] The IMM used the PROBE, or "Portfolio Ownership & Bid Evaluation," simulation model for this analysis. The software simulates the day-ahead and real-time LMP-based market clearing. See http://www.power-gem.com/index_files/PROBE.htm.

their marginal costs. It follows that during these low-load hours, the gross margin the resources earn should be lower than the weighted average, or even negative. Model results support this hypothesis, as shown in Table 2-8. In 2009, the market-share weighted gross margin in HE 1:00 a.m. to HE 5:00 a.m. (low-load hours) was −13%, and in the peak hours, the additional weighted gross margin was 10.44%. In the low-load hours in 2010, the gross margin earned was 5.5%, while the additional weighted gross margin was 9.63%. For 2011, the market-share weighted gross margin was −12.86%, and during peak hours, the additional weighted gross margins was 12.65%.

Table 2-8
Market-Share Weighted Gross Margin during Low-Load and Peak-Load Hours, 2009 to 2011

	HE 1:00 to HE 5:00 a.m. (Low-Load Hours)			Daily Peak-Load Hours		
Year	**Offer Based**	**Cost Based**	**Difference**	**Offer Based**	**Cost Based**	**Difference**
2009	−3.54%	9.48%	−13.02%	45.74%	35.31%	10.44%
2010	12.30%	6.80%	5.50%	51.08%	41.45%	9.63%
2011	8.73%	21.60%	−12.86%	48.48%	35.83%	12.65%

2.1.4.2 The Competitiveness Measure

The IMM also calculates a competitiveness measure that estimates the percentage of the price that is a consequence of the offers above cost. In a perfectly competitive market, all participant offers would equal marginal cost. Whereas, the market-share weighted gross margin is an average measure that indicates the impact of offers above cost on the aggregate gross margins available in the market, the competitiveness measure assesses the impact of these same offers on the margin by examining their impact on price. The analysis shows that competition among suppliers limits their ability to offer profitably substantially above marginal cost.

For this analysis, the IMM calculated the LMPs for the benchmark case and test case. The competitiveness measure (L_t) is the percentage of the offer-based LMP resulting from marginal offers above cost and is calculated as follows:

$$L_t = \frac{LMP_t^o - LMP_t^c}{LMP_t^o}$$

Where LMP_t^o is the offer-based LMP at time t, and LMP_t^c is the cost-based LMP at time t.

A larger L_t means that a larger percentage of price is the result of marginal offers above cost. Unlike the market-share weighted gross margin, a change in an inframarginal resource's marginal cost or market share does not change the competitiveness measure; only the offers of marginal units have an impact on this measure.[34]

For most of the hours in 2011, offers above marginal cost added no more than 11% to the real-time price. The mean for the competitiveness measure was 5.80% in 2011—lower than the 12.82% mean

[34] As discussed in Section 2.1.2.3, the RSI is the other measure of competitiveness calculated by the IMM for units on the margin. The RSI shows the possibility of noncompetitive behavior, while the competitiveness measure shows the extent of the impact of additional revenues earned in the market from offers at the margin.

in 2010 but slightly higher than the 4.78% mean in 2009.[35] Table 2-9 shows the summary results of the competitiveness measure.

Table 2-9
Competitiveness Measure Results, 2009 to 2011 (%, $/MWh)

Year	Competitiveness Measure Median %	Competitiveness Measure Mean %	Median (LMP^o – LMP^c) ($/MWh)	Mean (LMP^o – LMP^c) ($/MWh)
2009	8.10%	4.78%	3.21	4.13
2010	13.67%	12.82%	5.62	7.92
2011	10.16%	5.80%	3.92	6.37

To put these results in context, the IMM's offer-mitigation rules allow participants to submit offers $25/MWh above reference levels in constrained areas and $100/MWh above reference levels in unconstrained areas without review. If the market were not competitive, the profit-maximizing strategy at least some of the time would be to submit offers $25/MWh to $100/MWh above marginal cost, depending on system conditions. If this strategy were viable, instead of the marginal resource adding 5.80% on average to its offer, the market would observe a 37% to 70% adder above cost on the typical offer. Clearly, this is not the case.

2.1.5 Real-Time Market Recommendations for Failing to Follow Dispatch Instructions in the Real-Time Energy Market

In the *2010 Annual Markets Report*, the IMM reported on the events of September 2, 2010, when the ISO failed to timely return the area control error (ACE) to predisturbance levels after the loss of a large resource.[36] Analysis revealed that an inadequate response to dispatch instructions contributed in part to the performance problem. The IMM also observed similar generator performance issues on July 22 and December 19, 2011 (see Section 2.1.3.4). The IMM is concerned that the market design does not provide proper incentives to follow real-time dispatch instructions.

When a resource fails to follow dispatch instructions, the ISO dispatches other units to balance the system, resulting in higher total production costs than otherwise would have been incurred.[37] In the Real-Time Energy Market (at least at the five-minute dispatch level), demand does not respond to changes in price (i.e., the demand curve is vertical). Consequently, the cost that a resource that fails to follow dispatch instructions imposes on the market equals the change in production costs, where the change in production costs depends on the cost of the nonperforming resource and the cost of the resource(s) selected to replace it. A resource that fails to follow dispatch instructions should pay a penalty that compensates the market for the incremental production costs incurred as a result of its

[35] The median percentage of additional revenues earned from offers at the margin is subject to measurement error.

[36] *2010 Annual Markets Report* (AMR10) (June 3, 2011), http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html. In New England, the *area control error* is the instantaneous difference between the net actual and the biased scheduled interchange (i.e., transfer of electric energy between two balancing authority areas), accounting for the effects of frequency bias and correction for meter error. ACE must be restored to its predisturbance value within 15 minutes, and operating reserves must be restored, as required by the North American Electric Reliability Corporation's (NERC) BAL-002-0, "Resource and Demand Balancing," disturbance control standard (April 1, 2005), http://www.nerc.com/files/BAL-002-0.pdf Also see *ISO New England Manual for Definitions and Abbreviations* (Manual 35) (October 2010), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

[37] *Undergeneration* is the focus of this section. The analysis is similar for *overgeneration*.

failure to follow instructions. To provide a strong incentive for resources to follow instructions, the penalty should have the following features:

- Reflect relative scarcity conditions in the market, imposing a much higher cost when there is little or no surplus and relatively smaller penalties when the surplus is substantial.

- Allow for an efficient breach, that is, it should not be punitive. Rather, if the cost of following the dispatch instruction exceeds the incremental production cost impact, the resource should be allowed make the economic choice and accept the penalty.

- Minimize incentives for economic withholding. A penalty for a nonperforming resource that equals the production-cost impact provides no incentive for the holders of small portfolios to withhold output. The approach also mitigates such incentives for all but very large portfolios (none of which are present in New England).

2.2 Real-Time Reserves

This section summarizes the performance of the real-time reserves markets. In real time, the dispatch of resources to meet the energy and reserve requirements is jointly optimized. In the presence of a binding reserve constraint, the real-time reserve price is equal to the opportunity cost of the resource not dispatched for energy to satisfy the reserve requirement, capped by the Reserve Constraint Penalty Factor (RCPF).[38]

The ISO's operating-reserve requirements are described in Operating Procedure No. 8 (OP 8), *Operating Reserve and Regulation*.[39] As specified in OP 8, the ISO must maintain a sufficient amount of 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.[40] The ISO has real-time reserve requirements (in MW) for the following reserve categories (or products):

- **Ten-minute spinning reserve (TMSR):** This is the highest-quality 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.
- **Ten-minute nonspinning reserve (TMNSR):** This is the second-highest quality reserve product. TMNSR is provided by off-line units that require a successful start up (i.e., electrically synchronize to the system and increase output within 10 minutes) to ensure that needed reserves actually will be available in response to a contingency.[41]
- **Thirty-minute operating reserve (TMOR):** This is the lowest-quality 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.

[38] 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.

[39] See Operating Procedure No. 8, *Operating Reserves and Regulation* (January 7, 2011), http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html.

[40] See the ISO's RSP11, Section 6, for additional information on operating-reserve requirements, http://www.iso-ne.com/trans/rsp/2011/index.html.

[41] *Ten-minute nonspinning reserve* also is called 10-minute nonsynchronized reserve.

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 reserve requirements while respecting transmission constraints. The dispatch uses each resource's real-time energy offer; there is no separate real-time reserve offer. Other features of the dispatch algorithm are as follows:

- In the presence of a binding reserve constraint, the system dispatch may reduce the output of an otherwise economic unit in the energy market to create reserves on the system. When this occurs, the opportunity cost of altering the dispatch determines the market clearing price for the reserve product.
- The market will not redispatch resources to meet reserves at any price. If the redispatch costs would otherwise exceed the RCPF reserve price caps, the price will be set equal to the penalty factor and the market software no longer will issue dispatch instructions.[42]
- The market software optimizes the use of local transmission interfaces to minimize the cost of satisfying all reserve and energy requirements in the region.

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

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

The price of higher-quality reserve products must be at least has high as the price of lower-quality reserve 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.

Average nonzero annual reserve prices increased for TMNSR and TMOR in 2011 compared with 2010; however, the frequency of binding reserve constraints for TMNSR and TMOR decreased. This decrease offset the increase in price, which resulted in a 50% reduction in real-time reserve payments. See Table 2-10.

[42] Altering the dispatch is considered too costly when this cost will exceed the Reserve-Constraint Penalty Factor for a particular type of reserve. When sufficient reserves are not available to satisfy reserve requirements (i.e., reserves are short), RCPFs are used to allow the Real-Time Energy Market's optimization software to find a feasible solution, despite not being able to meet the reserve requirement. The RCPFs are $50/MWh for systemwide TMSR, $850/MWh for systemwide total 10-minute reserve, $100/MWh for systemwide 30-minute reserve constraint, and $250/MWh for each local reserve constraint.

Table 2-10
Average Reserve Prices and Frequencies for Intervals with Nonzero Prices, 2010 to 2011[a]

Product	Year	Average Annual Price ($/MW/ 5-Min. Interval)	Frequency (% of Total 5-Min. Intervals)
10-minute spinning reserve	2010	$33.55	3.9%
	2011	$24.70	4.0%
	% Change	***–26.4%***	***2.6%***
30-minute nonspinning reserve	2010	$79.05	1.0%
	2011	$110.92	0.1%
	% Change	***40.3%***	***–90.0%***
30-minute operating reserve	2010	$69.71	0.6%
	2011	$73.74	0.3%
	% Change	***5.8%***	***–50.0%***

(a) Prices are presented for the Rest-of-System reserve zone.

In 2011, the total real-time reserve payments were $9.5 million. In 2010, real-time reserve payments totaled $18.7 million. From 2010 to 2011, real-time payments for TMSR decreased by 41%, TMNSR decreased by 66%, and TMOR decreased by 66%. Overall, reserve payments decreased by approximately 50%. See Table 2-11.

Table 2-11
Real-Time Reserve Payments, 2009 to 2011 ($)

Year	Systemwide TMSR	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR	Total
2009	4,294,434	3,051,208	105,467	172,563	89,318	138,834	7,851,823
2010	9,998,572	6,896,142	639,148	762,404	342,996	105,834	18,745,096
2011	5,931,579	2,373,491	220,488	535,377	354,332	56,249	9,471,516

The lower frequency of binding constraints in 2011 was the result of the following:

- Increases in supply, specifically more hydroelectric energy and the return of a large, flexible unit from an extended outage
- An overall reduction in demand, freeing up on-line resources to provide reserves

The need to redispatch the system to satisfy requirements for TMNSR and TMOR more often explains why average TMSR prices were higher in 2010 than in 2011 ($33.55 per pricing interval in 2010, compared with $24.70 per interval in 2011). The frequency of binding constraints across zones was highly consistent in 2011; most of the price variation among zones resulted from a variation in TMOR price levels and not from the frequency with which the TMOR constraint bound. Connecticut and Southwest Connecticut experienced TMOR prices that were 6% to 12% higher than for the other zones. See Table 2-12.

Table 2-12
Real-Time Reserve Clearing Prices for Nonzero Price Intervals, 2011

Product	Reserve Zone	Price ($/MW/ 5-Minute Intervals)	Frequency (% of 5-Minute Intervals)
TMSR	Connecticut	25.75	4.3%
	NEMA/Boston	25.25	4.3%
	Rest of System	24.70	4.2%
	Southwest Connecticut	25.75	4.3%
TMNSR	Connecticut	109.96	0.4%
	NEMA/Boston	101.21	0.4%
	Rest of System	110.92	0.4%
	Southwest Connecticut	109.96	0.4%
TMOR	Connecticut	78.06	0.4%
	NEMA/Boston	69.77	0.4%
	Rest of System	73.74	0.3%
	Southwest Connecticut	78.06	0.4%

2.3 Regulation Market

This section presents data about the participation, outcomes, and competitiveness of the Regulation Market in 2011. The IMM concludes that the Regulation Market was competitive in 2011.

The Regulation Market is the mechanism for selecting and paying resources needed to balance supply levels with the second-to-second variations in demand and to assist in maintaining the frequency of the entire Eastern Interconnection. The objective of the Regulation Market is to acquire adequate resources such that the ISO meets the North American Electric Reliability Corporation's (NERC) *Real Power Balancing Control Performance Standard* (BAL-001-0).[43] 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%.[44]

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 unit-specific opportunity cost

[43] NERC is the electric reliability organization (ERO) certified by FERC to establish and enforce reliability standards for the bulk power system. This standard (effective May 13, 2009) can be accessed at http://www.nerc.com/page.php?cid=2|20. Additional information on NERC requirements is available at http://www.nerc.com (2011).

[44] The primary measure used for evaluating control performance, Control Performance Standard 2 (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).

payment.[45] Unit-specific opportunity cost payments are not included as a component of the regulation clearing price.

2.3.1 Regulation Pricing

In 2011, the average regulation price of $7.17/MWh was slightly higher than the 2010 price of $7.07/MWh. See Table 2-13.

Table 2-13
Regulation Prices, 2009 to 2011 ($/MWh)

Year	Minimum	Average	Maximum
2009	$0.00	$9.26	$100.00
2010	$0.00	$7.07	$82.24
2011	$0.00	$7.17	$95.00

Payments to resources providing regulation service totaled $13.3 million in 2011, a decrease of $1 million from the 2010 costs of $14.3 million. As explained below, the cost decrease is consistent with a reduction in the regulation requirement in 2011, from an average requirement of 63.67 MW in 2010, to 59.62 MW in 2011.

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 60 MW in 2011. The regulation requirement in New England typically is highest in the early morning and the late evening. The higher regulation requirement during these hours is the result of load variability and supply uncertainty.

The ISO seeks to maintain CPS 2 within the range of 92% to 97%. The ISO has continually met its more stringent, self-imposed CPS 2 targets. For 2011, the ISO achieved a minimum value of 93.9% and a maximum of 96.3%. The higher performance of the Regulation Market has been achieved while decreasing the regulation requirement and lowering costs.

The ISO has been able to reduce the regulation requirement because of the excellent performance of the resources providing regulation. One of the contributing factors to the high performance is the incentive structure that compensates faster-responding units for their higher contribution to regulation service.

2.3.3 Competitiveness of the Regulation Market

The IMM reviewed the competitiveness of the Regulation Market 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 abundance of regulation resources implies that market participants have little opportunity to engage in economic or physical withholding. The IMM concluded that the Regulation Market was competitive in 2011.

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[45] A *regulation opportunity cost payment* is compensation to a pool-scheduled generator for providing regulation service during all or portion of an hour.

Figure 2-11 shows the average and maximum regulation requirement (demand) and the average regulation supply for 2011 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.

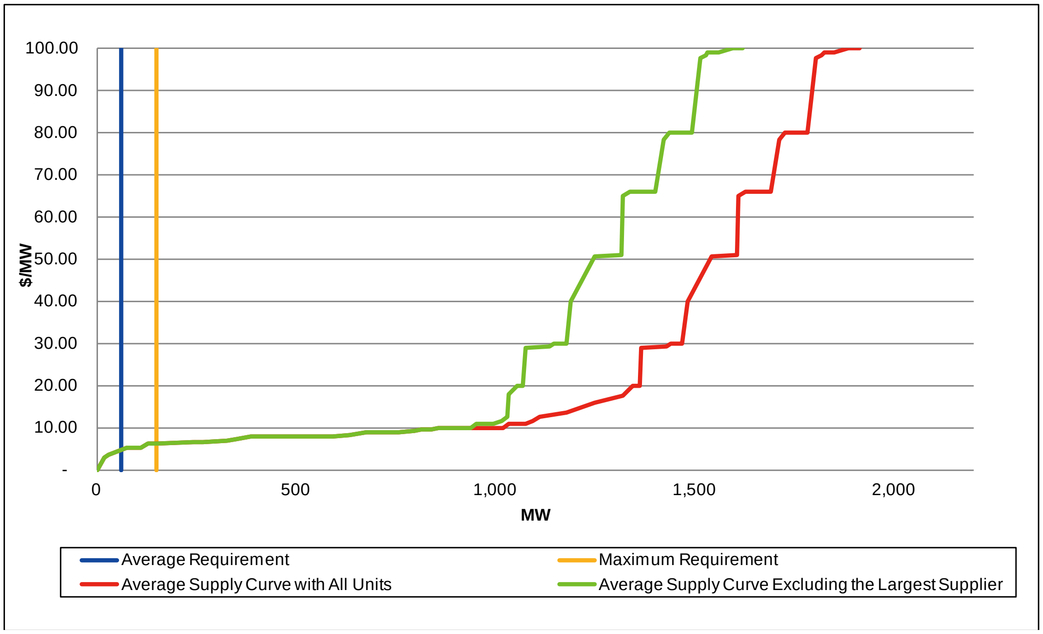

Figure 2-11: Regulation Market demand average and maximum requirements and supply curves with and without the largest supplier, 2011 (MW and $/MW).

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 2-12, the regulation requirement and RSI are inversely correlated. In 2011, 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.

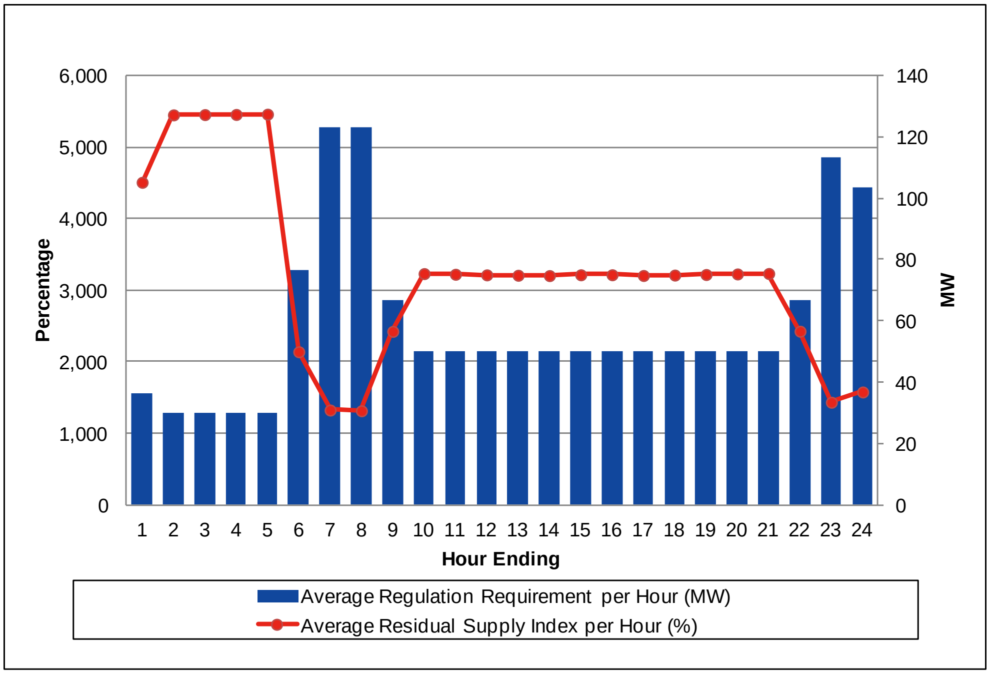

Figure 2-12: Average regulation requirement and residual supply index per hour, 2011.

2.4 Reliability and Operations Assessment

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

2.4.1 Daily Reliability

The ISO is required to operate New England's wholesale power system to the reliability standards developed by NERC, the Northeast Power Coordinating Council (NPCC), and the ISO through open stakeholder processes.[46] 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 balance 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:

- Economic/first-contingency Net Commitment-Period Compensation
- Local second-contingency Net Commitment-Period Compensation
- Voltage reliability payments
- Distribution reliability payments

[46] 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/page.php?cid=2|20 (2011). For more information on NPCC standards, see https://www.npcc.org/Standards/default.aspx (2011). The ISO's system operating procedures are available at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

2.4.1.1 Daily Reliability Payments for 2011

Daily reliability payments totaled $73.6 million in 2011, or approximately 1% of the total wholesale cost of electricity. See Table 2-14.

Table 2-14
Total Daily Reliability Payments by Quarter, 2011 ($)

	2011	Q1	Q2	Q3	Q4
Total Daily Reliability Payments	$73,569,931	$24,495,526	$13,414,394	$20,938,442	$14,721,569

Daily reliability payments decreased $21.8 million (23%) from 2010, and first-contingency NCPC payments decreased by $26.6 million in 2011. The drop in first-contingency NCPC payments was attributable to several factors: the return of a large, flexible resource that was not available from May 2010 to December 2010; the removal of an increased reserve requirement imposed after the September 2, 2010, NERC standard violation; and the addition of new capacity to the system in 2011. See Table 2-15.

Table 2-15
Total Daily Reliability Payments, 2010 and 2011 ($)

Payment Type	2010	2011	Difference	% Change
Economic and first-contingency payments	84,719,772	58,137,524	−26,582,247	−31%
Second-contingency reliability payments	3,898,515	6,150,674	2,252,159	58%
Distribution	1,635,375	3,358,238	1,722,864	105%
Voltage	5,084,097	5,923,494	839,398	17%
Total	95,337,758	73,569,931	−21,767,827	−23%

Transmission investments in Connecticut, NEMA/Boston, and SEMA have reduced the need for out-of-market (OOM) commitments of local second-contingency protection resources (LSPCRs), and LSCPR payments continued to remain low in 2010 and 2011. One exception was in October 2011, when the ISO had to commit resources to protect against second-contingency losses while transmission and generation facilities were out of service for planned maintenance. Figure 2-13 summarizes the NCPC payments made to generators for LSCPR, distribution, and voltage and economic (first-contingency) NCPC.

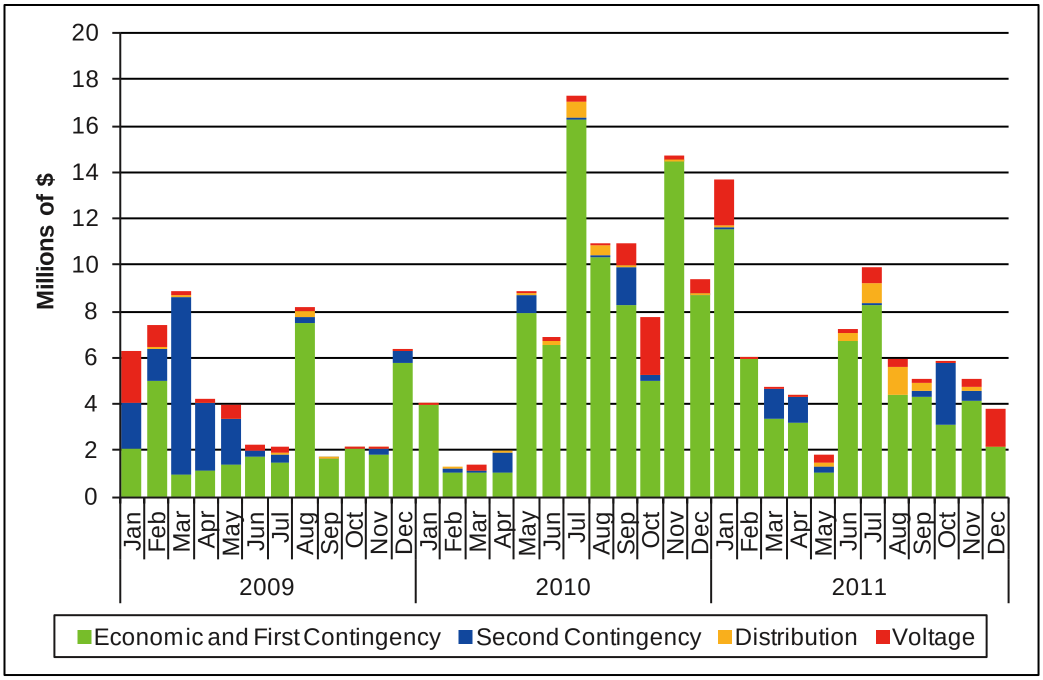

Figure 2-13: Daily reliability payments by month, January 2009 to December 2011 (millions of $).

2.4.1.2 Supplemental Commitments

Each day after the clearing of the Day Ahead Energy Market, ISO New England performs a Reserve Adequacy Analysis (RAA) and, if necessary, commits generators to meet capacity and reserve requirements. The RAA commits generators whenever insufficient capacity clears in the day-ahead market to meet the ISO load forecast plus operating reserve requirement. The amount of capacity on line affects LMPs and NCPC costs. With too much capacity on line, LMPs are likely to be artificially low and NCPC costs high. Too little capacity on line may compromise reliable operation and lead to artificially high prices.

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

In 2011, the IMM observed that supplemental commitment levels tend to exhibit some seasonality. During times of higher demand levels—winter and summer months—operators commit more units to counteract ramping and minimum-run-time constraints. As a result, supplemental commitment levels tend to be greater during the winter and summer months and lower during the spring and fall.

Figure 2-14 illustrates the minimum, maximum, and average supplemental commitments for each month of 2011. For each month, the yellow-dashed line represents the range of values in the month with the maximum value at the top, the minimum at the bottom, and the blue line representing the average. On most days in 2011, no generators were committed supplementally, thus, the minimum for each month is zero. The day with the highest level of supplemental commitments in 2011 was June 9, where 1,624 MW (eight units) of supplemental capacity was committed. High, temperature-driven loads were forecasted for this day but did not materialize. See Section 2.4.2.1.

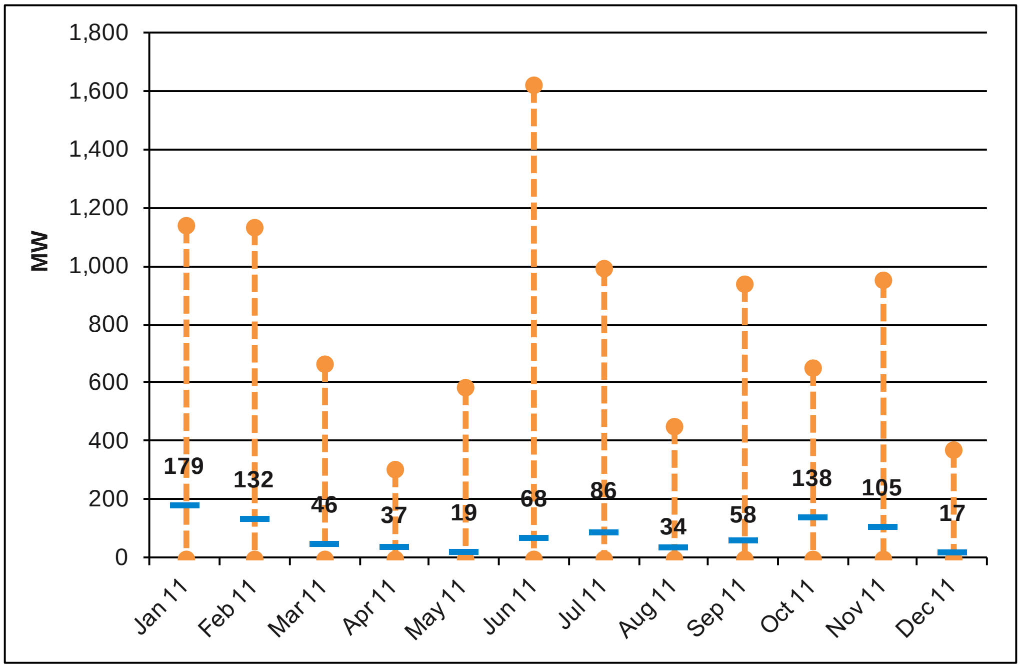

Figure 2-14: Monthly average, maximum, and minimum of daily supplemental commitments, January to December 2011 (MW).

2.4.2 IMM Market Operations Summary

This section discusses the ISO's operations for 2011. It includes an evaluation of ISO Operations during a number of extreme weather events during the year and a review of the audits the ISO participated in during 2011.

2.4.2.1 Operations and Extreme Events in 2011

In 2011, a number of events presented challenges for ISO Operations. These events included, among other things, an explosion on the gas system, a tornado, a hurricane and resultant floods, and an early winter snowstorm. The IMM reviewed the events and operator actions in 2011, which are summarized below, and concluded that the actions of ISO Operations generally resulted in prices that were consistent with system conditions and the resources supplying energy:

- **February 22–23 gas-line explosion:** On Sunday, February 20, 2011, the TransCanada Gas Pipeline, near Orient Bay, Ontario, experienced a *force majeure* event resulting from an explosion on one of its three main trunk lines that occurred on Saturday, February 19, about 11:00 p.m.[47] Because of the uncertainty with Canadian supply through the Iroquois and Portland interconnections to New England, coupled with normal winter-seasonal constraints, the gas market imposed critical notices and operational flow orders on those parties with nonfirm arrangements. The IMM reviewed the gas-unit performance and determined their behavior was consistent with the New England gas pipeline operators' issuing of critical

[47] *Trunk lines* are large-diameter pipelines.

capacity notices, restrictions to intraday cycle nominations, and gas system constraints caused by the TransCanada gas-line explosion.[48]

- **June 1 tornado:** Severe weather resulted in thunderstorms for much of New England, and hail and tornadoes affected western Massachusetts. The severe weather caused several line trips and real-time binding constraints.

- **June 9 hot and humid weather:** In anticipation of the hot and humid weather forecast for June 9, ISO Operations staff was in close coordination with the gas pipeline companies, transmission owners and operators, and generation operators to ensure readiness. The number of units committed supplementally was consistent with the forecasted peak load of 26,300 MW, which required all resources to be on line except one. Even though there were gas restrictions, the expected high demand never materialized in real-time, and, as a result, the restrictions did not have an adverse impact on the ability of gas generators to provide sufficient generation to the system.

- **Hurricane Irene:** On Sunday, August 28, Hurricane Irene hit New England as a tropical storm, crossing through Connecticut and western Massachusetts. In preparation for the storm, ISO Operations was in close coordination with the designated entities that operate generating resources, participants, and others to communicate and coordinate action plans and had committed additional generation to provide storm support in the event of system contingencies. Over 2,000,000 customers were without power Sunday night, and 43 transmission lines were out of service at the height of the storm.[49]

- **October 29 snowstorm:** On Saturday, October 29, and continuing into Sunday, October 30, New England experienced a "rare and historic October nor'easter." The effects of the storm were comparable to the impacts from Hurricane Irene, with an estimated 1.8 million customers without power on October 30. Fifty-five transmission lines were out of service; the majority of transmission outages were caused by trees outside the utility rights-of-way falling onto the transmission lines.

2.4.2.2 Audits

In 2011, 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:

- **SOC 1 Type 2 examination (formerly the SAS 70 audit)**—In November 2011, the ISO successfully completed a SOC 1 Type 2 examination, which resulted in an "unqualified opinion" about the description of the market operations and settlements systems. Developed by the American Institute of Certified Public Accountants, the SOC 1 examination covers aspects of a service organization's internal controls over financial reporting that may be relevant to a user entity's internal controls. Entities such as Regional Transmission Organizations complete SOC 1 examinations to assist user entities in evaluating their internal controls over financial reporting.

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[48] For a complete analysis on the events of February 22–23, see *Q1 2011Quarterly Markets Report* (May 27, 2011), http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2011/index.html.

[49] Forty-one 115 kV lines and two 230 kV lines were out of service. See the ISO"s *NEPOOL Participants Committee Report* presentation (September 2011), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2011/sep92011/coo_report_sept_2011.pdf.

The ISO's SOC 1 Type 2 examination is a rigorous review that entails detailed testing of the business processes and information technology for bidding, accounting, billing, and settling the market products of electric energy, regulation, transmission, capacity, load response, reserves, and associated market transactions. Conducted by the auditing firm KPMG LLP, the Type 2 examination covered the 12-month period from October 1, 2010, through September 30, 2011. The SOC 1 Type 2 examination reviews the following:

- The auditor's opinion on the fairness of the description of the 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 2011 SOC 1 Type 2 report is available to participants upon request through the ISO external website.[50]

- **Market-System Software Recertification**—The ISO has committed to a practice of 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.[51] This recertification takes place every two years or sooner, in 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 2011, PA Consulting issued the following certifications:

  - Auction Revenue Rights Market Software, December 21, 2011
  - Financial Transmission Rights Test Software, December 21, 2011
  - Forward Capacity Reconfiguration Auction Clearing Engine Software, December 21, 2011

- **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 day-ahead areas.

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[50] 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, 2010 to September 30, 2011, Prepared Pursuant to Statement on Standards for Attestation Engagements No.16*. This report is available to participants by request through the ISO external website, http://www.iso-ne.com/aboutiso/audit_rpts/index.html and http://www.iso-ne.com/aboutiso/audit_rpts/SAS70Request.do.

[51] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III, *Market Rule 1* (March 1, 2012), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

Section 3
Forward Markets

This section describes the 2011 outcomes and recommendations regarding the ISO's forward markets, including the Day-Ahead Energy Market, the Forward Reserve Market, and the Forward Capacity Market. The outcomes and recommendations for Financial Transmission Rights and demand resources also are discussed.

3.1 Day-Ahead Energy Market

This section describes the outcomes of the ISO's Day-Ahead Energy Market for 2011. In the day-ahead market, load-serving entities (LSEs) may submit energy demand schedules, which express the LSEs' willingness to pay for electric energy in this market. Each generator with a capacity supply obligation (CSO) (see Section 3.5) must offer into the day-ahead market a quantity at least equal to its CSO. In addition, any market participant may submit virtual demand bids or supply offers into the day-ahead market. Generator offers and virtual bids and offers are submitted at a nodal level and indicate the willingness to buy or sell a quantity of electric energy in the day-ahead market. The day-ahead market accepts (clears) bids and offers to maximize economic efficiency by equating supply and demand, subject to transmission constraints. The day-ahead market results are posted at 4:00 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 this market receive day-ahead Net Commitment-Period Compensation (NCPC).

The IMM is concerned with the declining number of virtual trades where virtual transactions are necessary to provide an adequate level of liquidity. The IMM's concern is that further reductions in virtual trading, below current levels, may have an adverse impact on the efficiency of the market. The IMM does not know how much further virtual transactions can be reduced without there being an adverse impact on the Day-Ahead Energy Market but feels the observed trend is worrisome. The IMM recommended in the *2010 Annual Markets Report* that the ISO revise the market rules so that real-time NCPC charges do not prevent virtual transactions from providing the benefits of improved liquidity in the day-ahead market. The IMM continues to support this recommendation.

3.1.1 Day-Ahead Pricing

The average day-ahead Hub price in 2011 was $46.38/MWh. As in real-time, this price is consistent with observed market conditions, including natural gas prices, loads, hydroelectric production, and other available supply. Price differences among the load zones primarily stemmed from marginal losses, with little congestion at the zonal level. Congestion primarily was restricted to smaller, more transient load pockets that formed when transmission or generation elements were out of service.

The Maine and Connecticut load zones continued to have the lowest and highest average prices in the region, respectively. The average LMPs in the Maine load zone were about $0.80/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 Connecticut load zone were $1.09/MWh greater than the average Hub price, largely because the congestion components of the LMP in Connecticut were higher than those components at the Hub. These results are similar to 2010 outcomes. See Table 3-1.

Table 3-1
Simple Average Day-Ahead Hub Prices
and Load-Zone Differences for 2009, 2010, and 2011 ($/MWh)

Location/ Load Zone	2009	2010	2011
Hub	$41.54	$48.89	$46.38
Maine	−$1.93	−$2.19	−$0.80
New Hampshire	−$0.67	−$0.87	−$0.45
Vermont	$0.05	$0.68	$0.28
Connecticut	$1.21	$1.87	$1.09
Rhode Island	−$0.39	−$0.79	−$0.61
SEMA	$0.17	−$0.56	−$0.20
WCMA	$0.36	$0.63	$0.53
NEMA	−$0.09	−$0.67	−$0.24

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

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

3.1.2.1 Price Setting in the Day-Ahead Market

In the day-ahead market, generators set price approximately 42% of the time in 2011, and virtual transactions set price approximately 27% of the time. These percentages are similar to 2010, when generators set price 39% of the time, and virtual transactions set price 34% of the time. This analysis shows that virtual transactions are needed for clearing the day-ahead market. See Figure 3-1.

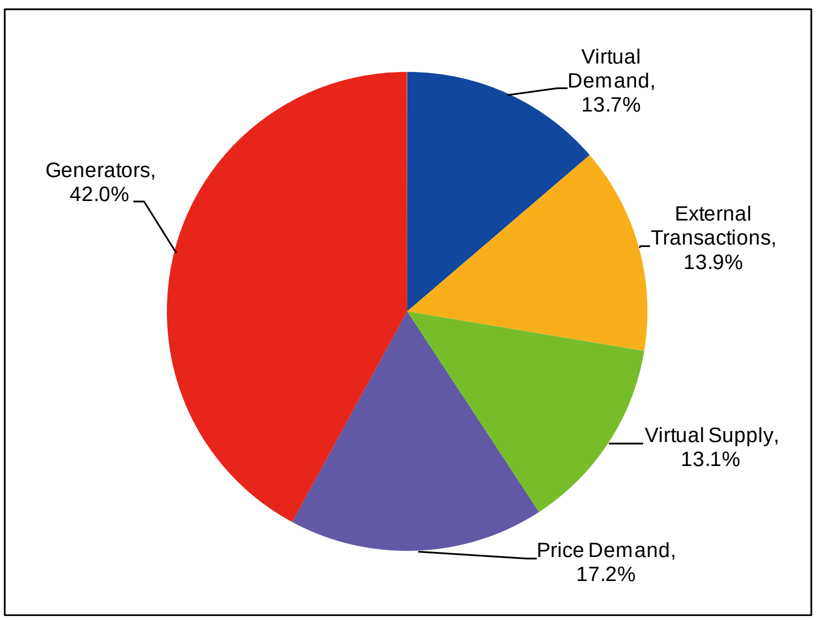

Figure 3-1: Percentage of price setting in the day-ahead market, 2011.

3.1.2.2 Day-Ahead Demand for Electric Energy

Although fixed demand (i.e., load that LSEs want to clear irrespective of price) has remained at approximately 86,000 GWh over the past two years, fixed demand has continued to increase in percentage, from 61% of total cleared demand in 2009, to 63% in 2010, and to 65% in 2011. Virtual demand has decreased in both volume and as a percentage of total cleared demand, while price-sensitive demand and exports have remained relatively stable over the three-year period. See Figure 3-2, which shows the total volume of day-ahead cleared demand for 2009 through 2011.

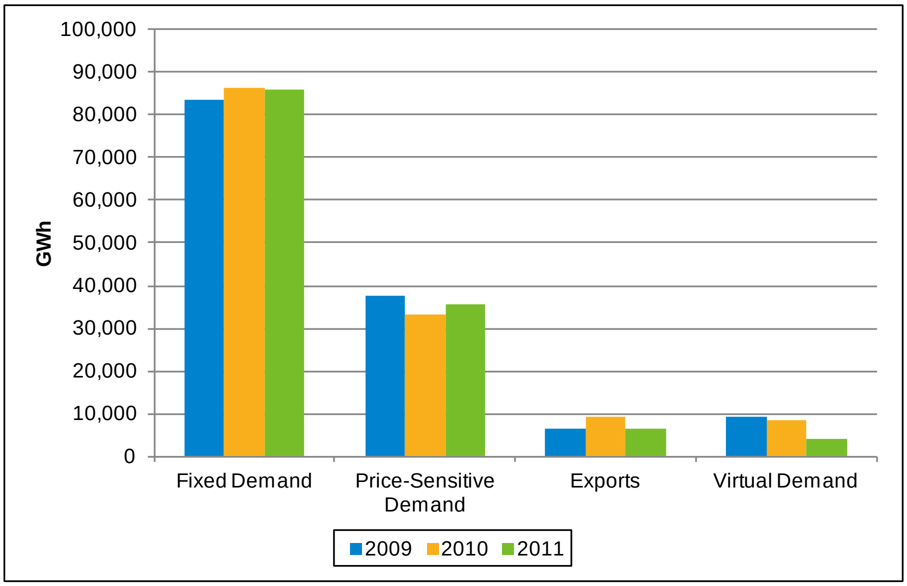

Figure 3-2: Total volume of day-ahead demand cleared, 2009 to 2011.

3.1.2.3 Day-Ahead Demand Compared 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 quantity of supplemental (balancing) commitments made in the Real-Time Energy Market.[52] The day-ahead cleared demand as a percentage of real-time load is a metric of how the amount of demand clearing in the day-ahead markets affects the amount and frequency of balancing commitments in the real-time energy market. Although the percentage of demand purchased in the day-ahead market varies from month to month, the annual percentage has remained relatively stable at approximately 93% from 2009 through 2011.[53]

3.1.2.4 Day-Ahead Supply 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. The IMM regularly reviews day-ahead self-schedules for evidence of uneconomic production, which may indicate an attempt to suppress market prices below economic levels. Self-scheduling behavior has been consistent over the past several

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[52] Supplemental commitments are made through the Reserve Adequacy Analysis process (see Section 2.4.1.2).

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

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

years, and the IMM has not found any evidence of an attempt to manipulate market outcomes via self-schedules.

Day-ahead self-schedule volumes decreased by 11,000 GWh from 2010 to 2011. Day-ahead self-schedule volumes accounted for 54% of total volumes, down from 60% in 2010. The decrease in self-schedules was because several nuclear units were out of service for maintenance in the spring and fall. As expected, economic supply offers increased, accounting for 31% of total volumes in 2011 compared with 26% in 2010. Import volumes have remained stable over the three-year period. As described in more detail in Section 3.1.2.5, the volume of virtual supply has decreased over the past three years. See Figure 3-3.

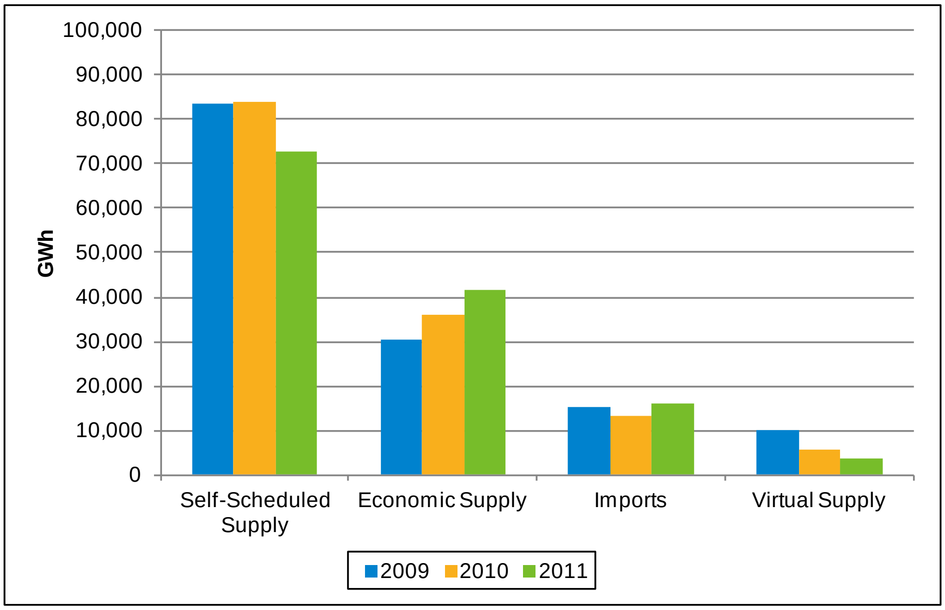

Figure 3-3: Total volume of day-ahead supply cleared, 2009 to 2011 (GWh).

3.1.2.5 Virtual Transactions

Virtual transactions allow participants to buy or sell power in the Day-Ahead Energy Market, regardless of the control of physical resources. Virtual transactions allow participants to arbitrage price differences between day ahead and real time, converging prices and producing more efficient Day-Ahead Energy Market outcomes. They also make balancing supply and demand in the Day-Ahead Energy Market more likely.

Cleared virtual supply offers (increments, virtual offers, or "incs") in the day-ahead market at a particular location in a certain hour create a financial obligation for the participant to buy back the offer quantity in the real-time market at that location in that hour. Cleared virtual demand bids (decrements, virtual bids, or "decs") in the day-ahead market create a financial obligation to sell the bid quantity in the real-time market. The difference between the day-ahead and real-time LMPs at the location and in the hour the offer or bid clears determines the profitability of a virtual transaction.

2011 Trends for Virtual Transactions. In 2011, submitted and cleared virtual transactions continued the declining trend reported in the *2010 Annual Markets Report*. Submitted virtual demand bids and virtual supply offers totaled approximately 31,915 GWh in 2011, a decline of 24% compared with 2010, and a decline of 53% compared with 2008. Cleared virtual transactions totaled approximately

7,500 GWh in 2011, a 47% decline compared with 2010, and a 76% decline compared with 2008. See Figure 3-4.

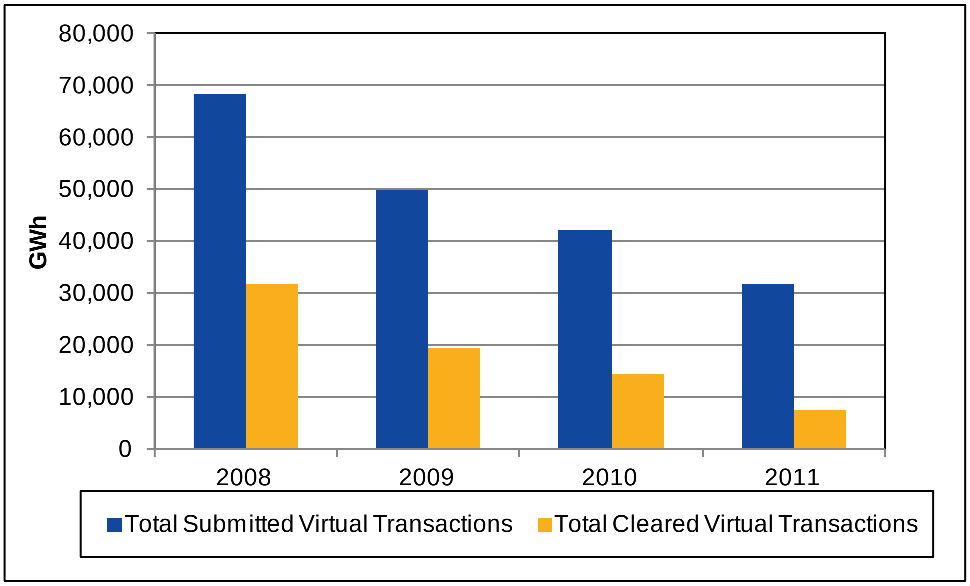

Figure 3-4: Total submitted and cleared virtual transactions, 2008 to 2011 (GWh).

The IMM analyzed trends in virtual trading at the Hub, load zones, internal network nodes, and the external interface nodes (the "node categories") for 2008 through 2011.[54] In 2011, each of the node categories registered double-digit percentage declines in cleared volumes compared with 2008. The decline in virtual trading, particularly at the network nodes, is a cause of concern, as the liquidity is generally lowest at the network nodes compared with the Hub and load-zone nodes that typically have more transactions. The virtual transactions bring additional liquidity to the network nodes, which is important for efficient market clearing. The trends in the virtual trading for 2011 were as follows:

- Cleared volumes at the Hub declined 26% between 2010 and 2011.
- Cleared volumes at the load zones declined approximately 12% between 2010 and 2011.
- Cleared volumes at the internal network nodes in 2011 declined approximately 91% compared with 2008. In 2008, 2009, and 2010, the internal network nodes cleared more virtual transactions (65%, 79%, and 54%, respectively) than any other node category; however, in 2011, the internal network nodes only accounted for 25% of all trades.
- Cleared volumes at external interface nodes declined 9% between 2010 and 2011. See Figure 3-5.

[54] Refer to Section 2.1.1.1 for a definition of the node categories.

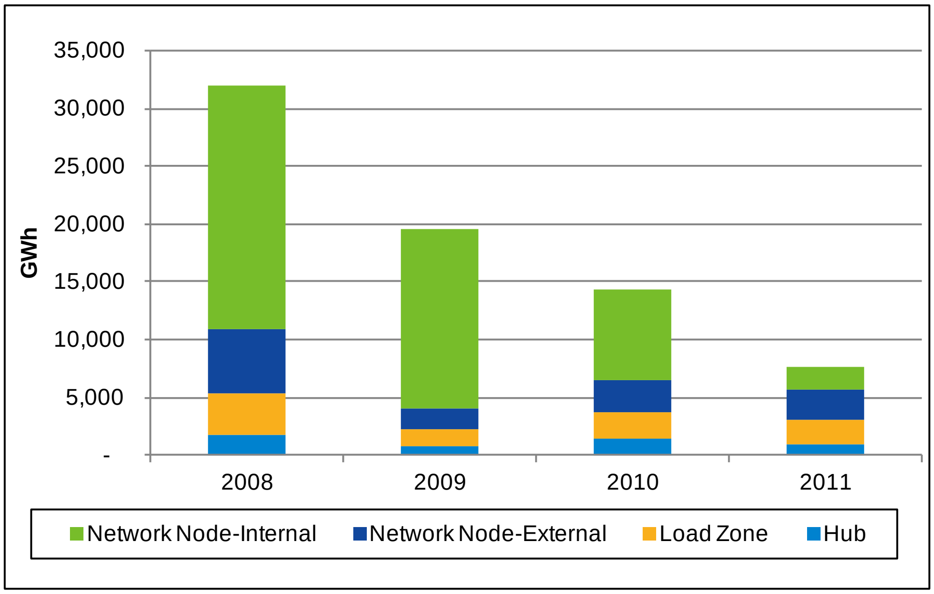

Figure 3-5: Total cleared virtual trade volumes by node category, 2008 to 2011 (GWh).

Two types of participants engage in virtual trading:[55]

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

In 2011, the number of hedgers declined to 12 participants from 17 to 18 participants in 2008 through 2010. The number of arbitragers declined to 46 participants in 2011 from 63 participants in 2010. See Table 3-2.

Table 3-2
Virtual Trading Participant Composition, 2008 to 2011

Participant Type	2008	2009	2010	2011
Hedgers	17	18	17	12
Arbitragers	66	59	63	46
Total	83	77	80	58

The declining trend appears to hold for hedgers and arbitragers. For the hedgers, the total cleared virtual transactions declined by nearly 5,000 GWh overall from 2008 to 2011, a decline of 88%. The

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

decline among arbitragers for the same period totaled about 19,400 GWh, or a decline of approximately 74%. See Figure 3-6.

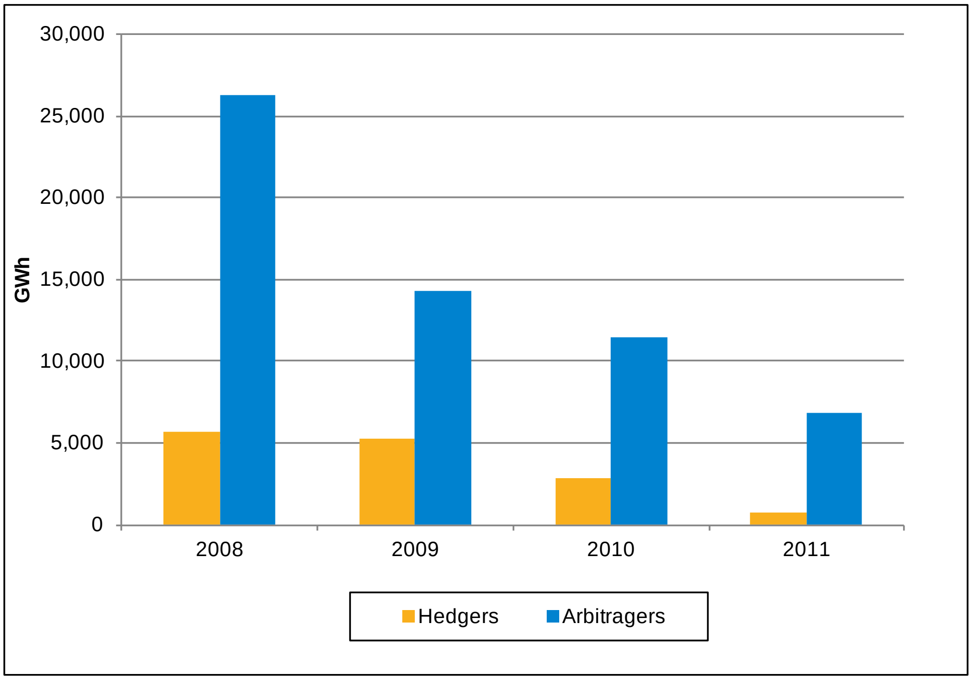

Figure 3-6: Total cleared virtual volumes by participant type, 2008 to 2011 (GWh).

High transaction costs resulting from NCPC charges have contributed to the decline in the number of participants using virtual trades, created a barrier for new participants to join, and caused existing participants to leave.[56] Merger and acquisition activity also has reduced the number of participants over the past four years.

Trend Analysis. The IMM has identified the following reasons for the decline in the virtual transaction volumes:

- **Changes and volatility in transaction costs resulting from NCPC charges:** Higher transaction costs lead to lower potential profits for a virtual trader. Higher volatility increases the risk of participating in the market. Traders participate in the market *only* if the potential difference in day-ahead and real-time prices is *at least* high enough to cover the transaction costs. The IMM has concluded that NCPC charges allocated to virtual transactions is the major contributor to transaction costs incurred by a virtual trader.

- **Differences between the day-ahead and real-time LMP:** The profits earned by the virtual traders are directly dependent on the differences in day-ahead and real-time prices. Recent declines in hourly price differences have reduced the arbitrage opportunity for traders, resulting in fewer cleared transactions. This analysis is not yet complete; the IMM will report results in the future.

[56] While NCPC charges generally have declined in recent years, second-contingency NCPC charges to local load have shifted to economic NCPC charges to all load *plus virtual transactions.*

The IMM based its estimation of the transaction cost on the daily real-time first-contingency charges.[57] The median estimated NCPC transaction cost increased from $0.26/MWh in 2008 to $0.45/MWh in 2011, an increase of 42%.[58] The median estimated transaction cost per megawatt-hour increased more than threefold from 2009 to 2010. The median transaction cost declined 28% in 2011 compared with 2010 but remains high compared with the 2008 to 2009 levels. Even with a decline in transaction cost and dispersion in 2011 compared with 2010, cleared transactions have continued to decline, which implies that the effects of high and uncertain transaction costs in 2010 continue to persist.

To illustrate the significance of high transaction costs on trading decisions, assume a risk-averse trader has perfect foresight into the price differences between the day-ahead and real-time markets but is uncertain about transaction costs. Also assume that this hypothetical player bases his expectations for future transaction costs on historical transaction costs and that this player is risk averse for engaging in virtual trading. Under these assumptions, the price difference for 2011 would need to be approximately $6.55/MWh. This is the 90th percentile transaction cost in 2010, as shown in Table 3-3.

Table 3-3
Estimated NCPC Charges to Virtual Transactions, 2008 to 2011 ($/MWh)

Year	Median	75th Percentile	90th Percentile	95th Percentile	Interquartile Range
2008	0.26	0.65	1.92	2.91	0.53
2009	0.19	0.68	2.18	2.89	0.59
2010	0.62	2.25	6.55	9.16	2.11
2011	0.45	1.60	3.91	7.52	1.44

The 90th and 95th percentile values in 2010 and 2011 show that traders with a greater degree of risk aversion will only engage in virtual trades if the expected price difference is high enough to offset the transaction cost.

The interquartile range further suggests the distribution of transaction costs have changed significantly from 2008/2009 (that had stable NCPC transaction costs relative to the median) to 2010/2011 (volatile NCPC transaction costs relative to the median). The interquartile range has increased by more than 100% in 2011 compared with 2008.[59] The mix of risk profiles in the market is unknown, but a portion of risk-averse virtual traders will not participate if the transaction costs are too volatile. This partially explains the lower participation levels observed with a number of participants and at internal network nodes.

[57] The transaction cost per megawatt-hour is estimated to be the total real-time first-contingency charges divided by the total megawatt-hour deviation in real-time from the close of the day-ahead market. The estimated per-megawatt-hour charge does not distinguish between the charges allocated to virtual load and the charges allocated to virtual supply. This charge is estimated for the Hub. It excludes local NCPC charges for voltage (i.e., voltage-ampere reactive, or VAR) control and local must-run resources (LSCPR and special-constraint resource [SCR] flags).

[58] Because several extreme values for the estimated transaction costs were observed, the median was used instead of the average to calculate typical transaction costs. In addition, because transaction costs are never negative, the distribution of the transaction costs is not normal.

[59] This change in distribution likely is the result of the change in the type of NCPC, from NCPC paid to resources for second-contingency coverage to economic NCPC, which is allocated to all load and virtual transactions.

Traders require high potential price differences in the day-ahead and real-time markets to compensate for the risk from high and uncertain transaction costs. The absolute price differences between day ahead and real time directly determine the profit of a virtual trader.

The IMM calculated the absolute difference between hourly day-ahead and real-time LMPs at the Hub for 2008 through 2011. The median price difference for 2008 was $8.61/MWh, which declined in subsequent years. However, the median price difference as a percentage of the day-ahead clearing price has remained relatively constant, varying between the 9% and 12%. The lowest percentage price difference, 9.74%, was observed in 2009, and the highest price difference, 11.44%, was observed in 2008. See Table 3-4.

Table 3-4
Absolute Price Difference between Day-Ahead and Real-Time Prices at the Hub, 2008 to 2011

Year	Median Absolute Price Difference ($/MWh)	Median % Absolute Price Difference (% of Day-Ahead LMP)
2008	8.61	11.44%
2009	3.75	9.74%
2010	4.62	10.31%
2011	4.49	10.69%

The absolute price difference does not imply that a trader can expect a positive payoff by following a naïve strategy of clearing only a virtual supply offer or a virtual demand bid every hour. An analysis of the price data shows that a participant who submitted a 1 MW virtual demand bid at the Hub for every hour in 2011 would have gained approximately $2,561, or a 0.6% return on investment without accounting for transaction costs. Conversely, a trader who placed a 1 MW virtual supply offer at the Hub for every hour in 2011 would have lost $2,561 without adjusting for transaction costs. All gains are lost once transaction costs are added to each transaction. The naïve strategy for virtual demand bidding loses $11,770, post NCPC transaction charges for 2011, and the naïve strategy for virtual supply positioning loses $16,892, post NCPC transaction charges for 2011. See Table 3-5 and Table 3-6.

Table 3-5
Percentage of Profitable Hours and Gains with Virtual-Demand-Bid-Only Strategy, 2011

	% of Hours with Positive Real-Time Premium	% of Hours with Negative Real-Time Premium	Gain
Without Transaction Cost	42.97%	57.03%	$2,561
With Transaction Cost	36.67%	63.33%	−$11,771

Table 3-6
Percentage of Profitable Hours and Gains with Virtual-Supply-Offer-Only Strategy, 2011

	% of Hours with Positive Day-Ahead Premium	% of Hours with Negative Day-Ahead Premium	Gain
Without Transaction Cost	57.03%	42.97%	−$2,561
With Transaction Cost	49.51%	50.49%	−$16,893

Overall, the volume of trading for virtual transactions and the level of participation continued to decline in 2011, which implies that the effects of high and uncertain transaction costs observed in 2010 continue to persist. Fewer virtual trades are taking place at the network nodes where virtual transactions are necessary to provide an adequate level of liquidity.

The relatively flat absolute price difference between the day-ahead and real-time prices suggests a decline in potential returns for virtual market participants. At the same time, high and volatile transaction costs resulting from NCPC charges have added to the risk of virtual trading. As a result, for each level of potential returns, a corresponding increase in the level of risk exists that reduces the expected payoffs for participants.

Furthermore, NCPC transaction costs are extremely volatile and difficult to estimate. This results in limited participation in virtual trading because participants with a low risk tolerance are likely to leave and potentially new risk-averse participants may not engage in virtual trading at all. The declines observed are consistent with rising and volatile transaction costs resulting from NCPC charges to virtual transactions. Price convergence between day-ahead and real-time prices is likely to suffer because of reduced virtual trading. The IMM is concerned that the volume of virtual trades has a tipping point beyond which the efficiency of the market would be compromised. The IMM does not know where this point lies, but the observed trend is worrisome. The IMM continues to analyze the market.

The IMM recommended in the *2010 Annual Markets Report* that the ISO revise the market rules so that real-time Net Commitment-Period Compensation charges are not allocated to virtual transactions. The IMM continues to support this recommendation.

3.2 Financial Transmission Rights

This section summarizes the 2011 activities and results associated with Financial Transmission Rights (FTRs).

Financial Transmission Rights allow participants to hedge transmission congestion and provide a financial instrument to arbitrage differences between expected and actual day-ahead congestion. The *financial transmission right* 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.[60] 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 equal to the difference between the prices at the sink location and the source location in the FTR auction.

The ISO conducts one annual and 12 monthly FTR auctions for buying and selling FTRs. Annual FTRs are offered in a single auction for the ensuing year, 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

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

expected transmission capability for the month is available.[61] 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 receive a portion of FTR Auction Revenues.

Financial players who have no physical obligations in the ISO markets also may 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 payoff. These activities add liquidity to the FTR auctions. Participation by financial players 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

The ISO conducts annual and monthly auctions for FTRs. Revenues collected from the auctions are distributed back to congestion paying LSEs.[62]

There were 42 participants who participated in at least one of the 13 FTR auctions in 2011. This number is down from 2010, in which 54 participants participated in at least one of the FTR auctions.

The total volume of megawatts bought and sold in the 2011 FTR auctions, regardless of directional flow, was 582,190 MW.[63] Of the total megawatts bought and sold in FTR auctions in 2011, the percentage of megawatts associated with counterflow positions was 18%, similar to 2010. Counterflow FTR positions free up transmission capacity that would have otherwise been constrained. Figure 3-7 shows the volume of megawatts bought and sold in each monthly FTR auction in 2011.

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

[62] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III.5.2, *Market Rule 1* "Transmission Congestion Credit Calculation," (March 8, 2012), http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_1-12.pdf.

[63] The totals were 539,348 MW in the 12 monthly auctions and 42,842 MW in the annual auction.

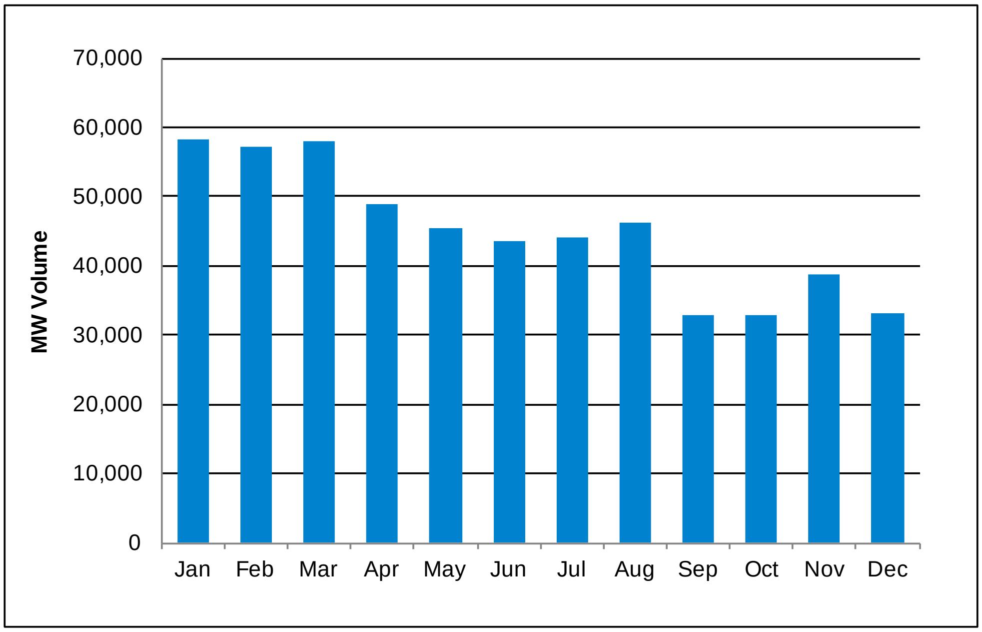

Figure 3-7: FTR monthly volumes, 2011 (MW).

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

The total net revenue from the 12 monthly auctions and the single annual auction was $23.5 million, a 22% drop from 2010.[64] Of the $23.5 million in net revenue, $7.2 million was from the 12 monthly auctions. See Figure 3-8.

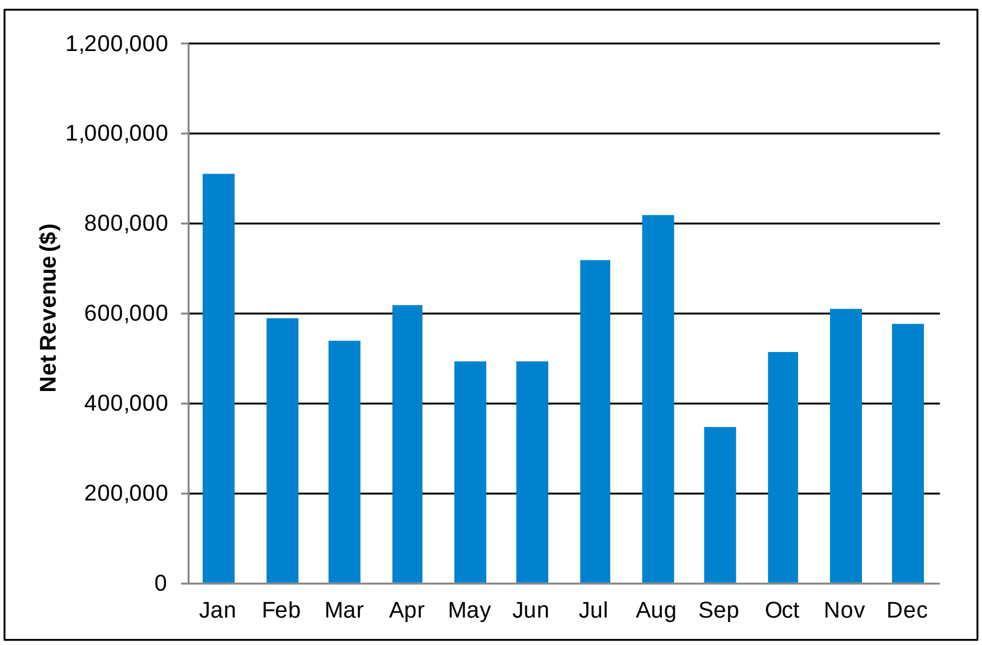

Figure 3-8: FTR monthly net revenues, 2011 ($).

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

If FTR participants had perfect foresight, total auction revenue would equal the day-ahead congestion revenue; however, various factors contribute to differences between the two revenue streams. A primary contributing factor to the difference is the large time gap between the FTR auction and when the actual congestion is realized. One of the consequences of this time gap is that FTRs bought and sold in the auction are based on market information available at the time of the auction and do not account for any post-auction changes that may affect congestion on the transmission system. Some of these changes could include unforeseen generator and transmission outages, which can result in some expected deviation between the day-ahead congestion revenue and the total auction revenue.

In 2009, the annual auction revenues from the sale of FTRs exceeded realized day-ahead congestion by 266%, indicating that market participants did not anticipate the drop in congestion revenues that occurred in 2009 relative to 2008. This mismatch was generally corrected—first in the monthly auctions for 2009 and then in the annual 2010 FTR auction—when total auction revenues dropped from $71.1 million in 2009 to $30.2 million in 2010. Congestion increased in 2010, which resulted in auction revenues being lower than day-ahead congestion revenues by 19%. In 2011, both total auction revenue and the day-ahead congestion revenue decreased from 2010, indicating that market participants who bought FTRs anticipated the direction, but not the magnitude, of the change in congestion revenue that occurred in 2011. See Table 3-7.

Table 3-7
Comparison of Day-Ahead Congestion Revenue to Auction Revenue, 2009 to 2011

	Day-Ahead Congestion Revenue (Millions $)	Total Auction Revenue (Millions $)	Auction Revenue as % of Day-Ahead Congestion Revenue
2009	26.7	71.1	266%
2010	37.3	30.2	81%
2011	18.0	23.5	131%

The IMM reviewed the most-active FTR participants in 2011. Activity 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 three participants that were most active with FTRs in 2011, who accounted for more than 50% of total transacted megawatts, were financial players. Financial players are more likely to buy and sell FTR positions many times as new information becomes available. The four-largest load servers accounted for 13% of total FTR trading activity.[65] The same four-largest generators accounted for 12% of activity with FTRs in 2011.[66] See Figure 3-9.

[65] The top-four LSEs in 2011 for the peak load hour were Constellation, NextEra, Hess, and TransCanada. See Section 2.1.2.1.

[66] The top-four generation participants in 2011 for the peak hour were Dominion, NextEra, Constellation, and H.Q. Energy Services.

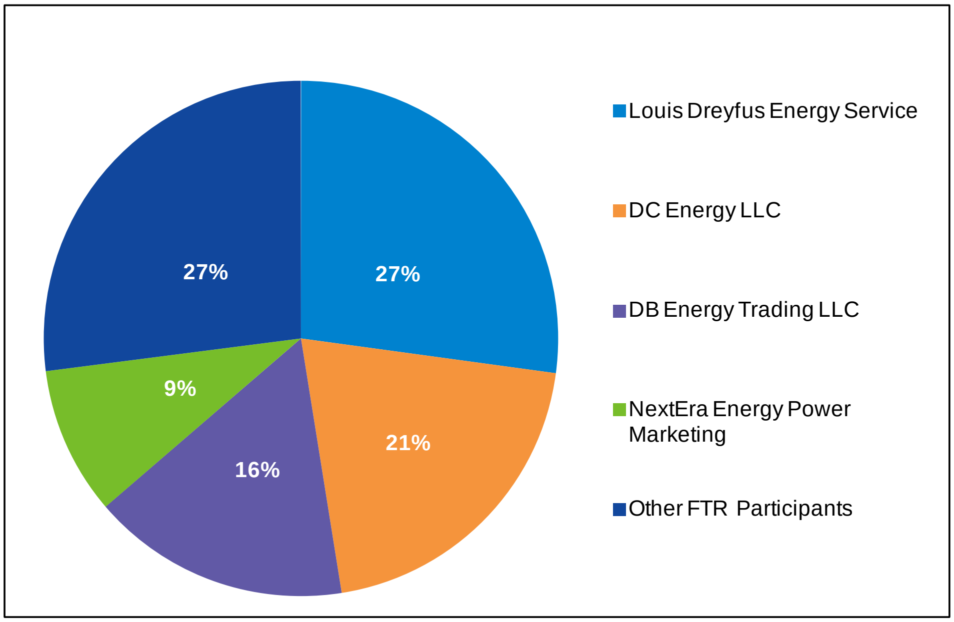

Figure 3-9: FTR participant activity, 2011 (%).

3.3 Forward Reserve Market

This section presents data about the participation, outcomes, and competitiveness of the two forward-reserve auctions conducted in 2011. The IMM concludes that the auction design is susceptible to price distortions and inefficiencies as a consequence of resources' offering into the market with effective zero-price offers.

To maintain system reliability, all bulk power systems maintain reserve capacity to respond to contingencies, such as unexpected outages (refer to Section 2.2). The objective of the locational Forward Reserve Market (FRM) is to procure operating reserves from participants with resources that can provide reserves. The ISO purchases system 10-minute nonspinning reserve and 30-minute operating reserve (TMOR) and locational TMOR through the FRM. Auctions are held twice a year, for a summer delivery period and a winter delivery period. Participants submit offers to sell a quantity of a 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

The clearing price in the FRM auctions in summer 2011 and winter 2011/2012 were $4,500/MW-month and $4,350/MW-month. These are the lowest prices in the FRM since its inception in 2004. In particular, compared with auctions held before winter 2010/2011, where Connecticut and Southwest Connecticut reserve prices were very close to, or at, the ceiling price of $14,000/MW-month, prices in these areas have since declined by two-thirds. See Table 3-8.

Table 3-8
Auction Clearing Price, Four-Most-Recent FRM Auctions ($/MW-month)

Location	Product	Summer 2010	Winter 2010/2011	Summer 2011	Winter 2011/2012
CT	TMOR	$13,900.00	$6,023.74	$4,500.00	$4,350.00
NEMA/Boston	TMOR	$0.00	$0.00	$4,500.00	$4,350.00
SWCT	TMOR	$13,900.00	$6,023.74	$4,500.00	$4,350.00
Systemwide	TMNSR	$5,950.00	$5,500.00	$4,500.00	$4,350.00
Systemwide	TMOR	$5,950.00	$5,500.00	$4,500.00	$4,350.00

The net payments to FRM resources equal the FRM auction clearing price minus the Forward Capacity Market clearing price. The FCM clearing price for the 2011/2012 capacity commitment period was $3,600/MW-month; the net payment received by reserve providers was $900/MW-month for the summer 2011 auction and $750/MW-month for the winter 2011/2012 auction.

The 2011 auctions had no price separation because new resources were built in Connecticut and Southwest Connecticut, and the *external reserve support* (ERS)—the ability to import power into those regions—has improved, as described in Section 3.3.3.

3.3.2 Market Requirements

The ISO defines locational requirements, as well as a systemwide requirement, for each reserve product procured in the auction.[67] The systemwide requirement for TMNSR in summer 2011, as well as winter 2011/2012, was 800 MW. The combined requirements for TMNSR and TMOR in summer 2011 was 1,550 MW, and the requirement for winter 2011/2012 was 1,575 MW. Local reserve requirements for NEMA/Boston and SWCT are zero because the external reserve supports exceeded the local second contingencies in these locations in the auctions held in 2011. See Table 3-9.

Table 3-9
Local Reserve Requirements
Summer 2011 and Winter 2011/2012 Forward Reserve Auctions (MW)

Location Name	Product	Summer 2011	Winter 2011/2012
CT	TMOR[(a)]	723	772
NEMA/Boston	TMOR[(a)]	0	0
SWCT	TMOR[(a)]	0	0
Systemwide	TMNSR	800	800
Systemwide	TMOR[(a)]	1,550	1,575

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

[67] The TMNSR and TMOR requirements are based on first and second-contingency losses (refer to Section 2.2). The methodology to calculate these requirements are described in OP 8, *Operating Reserve and Regulation* (January 7, 2011), http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html, and *the ISO New England Manual for Forward Reserve* (Manual M-36) (June 1, 2011), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

3.3.3 External Reserve Support

Through ERS, resources within a local region as well as reserves available in other locations, if needed, can satisfy second contingencies. As a result of transmission upgrades, the ERS in many import-constrained regions has increased. The most notable enhancements in ERS have taken place in Connecticut and Southwest Connecticut, where improvements in ERS have reduced the minimum amount of reserve capacity that must be sourced from local resources. See Table 3-10.

Table 3-10
External Reserve Support in the Past Four FRM Auctions (MW)

Location Name	Summer 2010	Winter 2010/2011	Summer 2011	Winter 2011/2012
CT	0	0	490	457
NEMA/Boston	1,370	834	1,394	958
SWCT	782	1,098	560	720

3.3.4 Observations and Concerns

The IMM is concerned that the Forward Reserve Market auction design is susceptible to possible price distortions and inefficiencies because of resources' offering into the market with effective zero-price offers.

For the summer 2011 and winter 2011/2012 Forward Reserve Market auctions, the IMM observed offers at $3,600/MW-month in Connecticut and Southwest Connecticut. An offer of $3,600/MW-month is effectively $0 after netting out the Forward Capacity Market clearing price of $3,600/MW-month.

The IMM observed no scarcity in any of the regions. It also did not identify any impediment to competition on the suppliers' side of the market. Given the structure of the payments in the market, and the existence of positive incremental costs for supplying reserve (including opportunity costs), it would be unreasonable for resources to offer their reserve at or below the Forward Capacity Market clearing price of $3,600/MW-month. As outlined below, offers at or below the FCM clearing price are arguably below the incremental cost of supply for three main reasons:

- The net payment received by resources offering at the FCM clearing price would be zero had the market cleared at their offers.
- To ensure the supply of reserves, the ISO assesses penalties on nonperforming and noncomplying resources. In 2011, on average, 5.8% of the forward credit paid to the resources was taken back in penalties. Participants could avoid these penalties by not participating in the FRM and, therefore, should include them in the formation of their bids. See Table 3-11.

Table 3-11
Quarterly Forward Reserve Market Forward Credit and Penalties in 2011 ($)

	2011	Q1 2011	Q2 2011	Q3 2011	Q4 2011
Forward credit	$18,942,002	$6,215,069	$5,345,961	$3,952,486	$3,428,486
Total penalties	−$1,098,349	−$231,100	−$347,137	−$352,025	−$168,087

- Because FRM participants are required to bid into the Real-Time Energy Market at or above the threshold price determined by the ISO, they forego the inframarginal revenues they would earn in the energy market when the price is between their incremental cost and the FRM threshold price.[68] A profit-maximizing participant would weight this forgone revenue against the revenues that could be earned in the FRM.

When participants are assumed to make and receive all payments within the market, their offers below the incremental cost of supplying reserves would only increase the likelihood that the participants would incur losses. As a result, the only resources that have the incentive or ability to offer this way profitably are those able to make up any possible losses through an out-of-market (OOM) revenue source.

Offers at $3,600/MW-month primarily are located in Connecticut and Southwest Connecticut. The IMM has identified a total of 560 MW of such offers in the summer 2011 FRM auction and 614 MW of such offers in the winter 2011/2012 auction. The main concern regarding these offers is that they could result in prices that are lower than the cost of providing the service, which could lead to a shortage of resources willing to provide the service in the long term.

3.3.4.1 Price Impact on Auction Results

Participants that submitted offers at or below $3,600/MW-month may have distorted market outcomes. By replacing the effective zero-price offers with $14,000/MW-month offers, the IMM estimated the upper bound on the price impact. The effects depend on the location of the participants. For the summer 2011 auction, the effects were as follows:

- The clearing price would increase from $4,500/MW-month to $5,080/MW-month for Connecticut and Southwest Connecticut for both products.
- For all other locations, the price would go up from $4,500/MW-month to $4,845/MW-month.
- The payments to the participants for each megawatt would increase from $900/MW-month to $1,480/MW-month for Connecticut and Southwest Connecticut.
- For all other locations, the payments would increase from $900/MW-month to $1,245/MW-month.

For the winter auction of 2011/2012, the effects were as follows:

- The estimated price would increase from $4,350/MW-month to $5,100/MW-month in Connecticut and Southwest Connecticut.

[68] This forgone revenue is roughly equal to the probability of the price being between the unit's cost and the threshold price, times the average of the threshold price and incremental cost, times the cleared megawatts.

- The estimated price would increase from $4,350/MW-month to $4,500/MW-month in all other locations.
- The payments to participants would increase from $750/MW-month to $1,500/MW-month in Connecticut and Southwest Connecticut and $900/MW-month in other regions.

The IMM does not know the true incremental cost of the resources in question, only that the costs are unlikely to be zero. It is possible that these units have incremental cost below $900/MW-month or $750/MW-month. The price would not be affected if the true incremental cost of the resources that submitted these offers were less than or equal to $900/MW-month in the summer auction and $750/MW-month in the winter auction. Therefore, these offers possibly have had a limited impact on market outcomes, if any. If this is the case, the resources with offers less than or equal to $900/MW-month in the summer auction and $750/MW-month in the winter auction would be inframarginal, and outcomes remain unchanged at $4,500/MW-month in the summer auction and $4,350/MW-month in the winter auction.

3.3.4.2 Price Effects of Transmission Improvements

The estimates above also highlight the effects of the improvements made to the transmission lines to the Connecticut and Southwest Connecticut regions. Even when all the offers at or below $3,600/MW-month are essentially removed from the market, prices in these previously disconnected locations remain significantly below the levels they reached in earlier auctions. This happens because an improvement in the ERS reduces the dependence on (relatively more expensive) local reserves, resulting in lower prices, even in the absence of offers at or below an FCM clearing price of $3,600/MW-month.

3.3.4.3 Summary of Offer Behavior

The principal implication of the offer behavior in the 2011 auctions is that the auction design is susceptible to possible price distortions and inefficiencies resulting from resources' offering into the market with effective zero-price offers. The only resources that have the incentive or ability to offer profitably this way are those able to make up any losses through an out-of-market revenue source. To ensure efficient outcomes, even in the face of such out-of-market distortions, the IMM continues to review the market design for possible design changes and may request information from the corresponding lead participants to justify their offers.

3.4 Demand Resources

This section presents data about the participation and outcomes of demand resources in 2011. The IMM makes recommendations to improve the accuracy of demand-resource data and to improve the reporting about demand-resource availability.

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 Forward Capacity Market. Under the FCM, demand resources compete in the Forward Capacity Auction (FCA), take on capacity 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.

The active demand resources include the following:

- **Real-time demand-response resources (RTDR):** Resources in this category reduce load within 30 minutes of receiving a dispatch instruction from the ISO. These resources are dispatched when the ISO forecasts OP 4 Action 2 or higher the day before the operating day or implements OP 4 Action 2 or higher during the operating day.[69]

- **Real-time emergency generation resources (RTEG):** Resources in this category reduce load by transferring load that would otherwise be served from the electricity grid to emergency generators. The transfer must take place within 30 minutes of receiving a dispatch instruction from the ISO. These resources are dispatched when the ISO implements OP 4 Action 6, which coincides with a 5% voltage reduction requiring more than 10 minutes to implement. These resources must be available from 7:00 a.m. to 7:00 p.m. Monday through Friday on nonholidays. These resources must limit operation to 600 MW to comply with the generation's federal, state, or local air quality permits, or combination of permits, and the ISO's market rules.

The passive demand resources include the following:

- **On-peak resources:** Resources in this category include energy-efficiency projects and distributed generation that reduce load during predefined periods (i.e., demand-resource on-peak hours).

- **Seasonal-peak resources:** Resources in this category include energy-efficiency projects where the project's load reduction is weather sensitive. Resource performance is measured during the periods coinciding with high system loads (i.e., demand-resource seasonal-peak loads).

In 2011, 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:

- **Real-Time Price-Response (RTPR) Program:** This program provided financial incentives to market participants to reduce load voluntarily when the ISO forecasted LMPs to be greater than or equal to $100/MWh. Participants were paid the higher of $100/MWh or the real-time LMP.

- **Day-Ahead Load-Response Program (DALRP):** This optional program allowed market participants with assets registered as RTDR or RTPR to offer load reductions in response to day-ahead LMPs. Market participants were paid the day-ahead LMP for their cleared offers and were obligated to reduce load by the amount cleared day ahead. The participant was then charged or credited at the real-time LMP for any deviations in curtailment in real time compared with the amount cleared day ahead.

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[69] OP 4 is available at http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

Both the RTPR program and DALRP are scheduled for retirement on May 31, 2012, and will be replaced with a new program designed to comply with FERC Order 745.[70] The new "transitional" program is anticipated to 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.[71]

3.4.1 Demand Resources in the Forward Capacity Market

The total capacity supply obligation for all demand resources participating in the FCM increased by 14% in 2011 compared with 2010, a gain of 244 MW. The capacity supply obligations for active demand resources decreased by 9%, and the CSOs for passive demand resources increased by 67% in 2011 compared with 2010.[72] The quantity of passive demand resources increased in a period when the price for capacity ($/kW-month) decreased. See Table 3-12.

Table 3-12
Capacity Supply Obligation by Demand-Resource Type (MW), 2010 and 2011

	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	
2010 year end	669	522	1,191	406	118	524	1,716
2011 year end	649	436	1,085	617	259	876	1,960
% change 2010 to 2011	−3%	−16%	−9%	52%	119%	67%	14%

Two market participants control 68% of the RTDR and RTEG resources. Figure 3-10 shows the market participants with active demand resources in the FCM, as well as the percentage capacity supply obligation (in MW) represented by these participants.

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

[71] Currently, the transitional rules are to remain in effect until June 1, 2016. However, in April 2012 the ISO requested that the transitional rules remain in effect for an additional year until FCM rules that address how capacity resources will be integrated into the energy markets become effective. See *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). RTEG resources will be prohibited from participating in the day-ahead and real-time energy markets because of air permit restrictions.

[72] Values are based on the resources' CSOs as of December 31, 2010, and December 31, 2011.

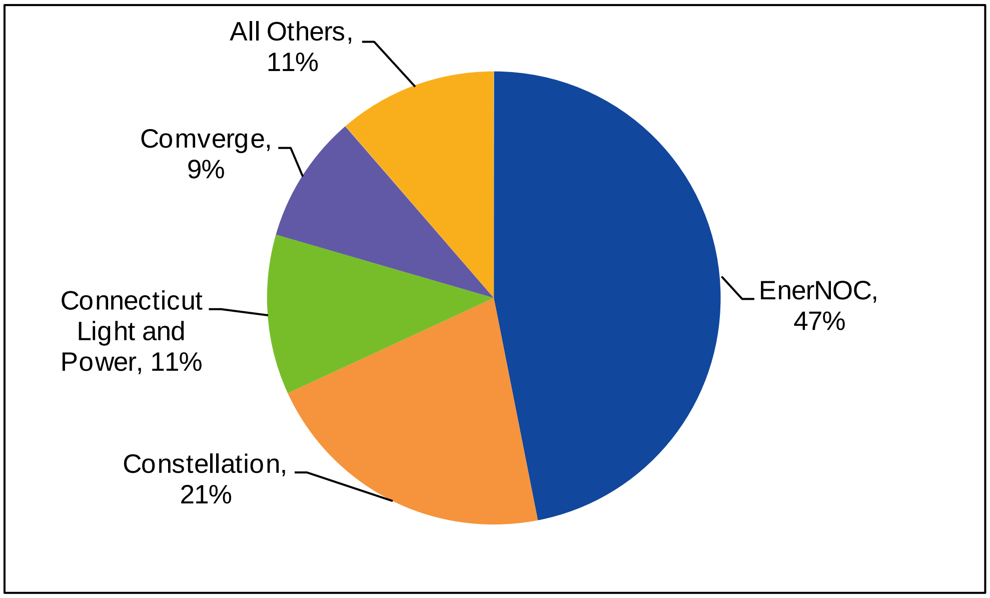

Figure 3-10: Percentage distribution of active demand resources by the capacity supply obligations of lead participants, 2011.

Figure 3-11 shows the market participants with passive demand resources in the FCM, as well as the percentage capacity supply obligation (in MW) represented by these participants. The top two participants control 43% of the total CSO.

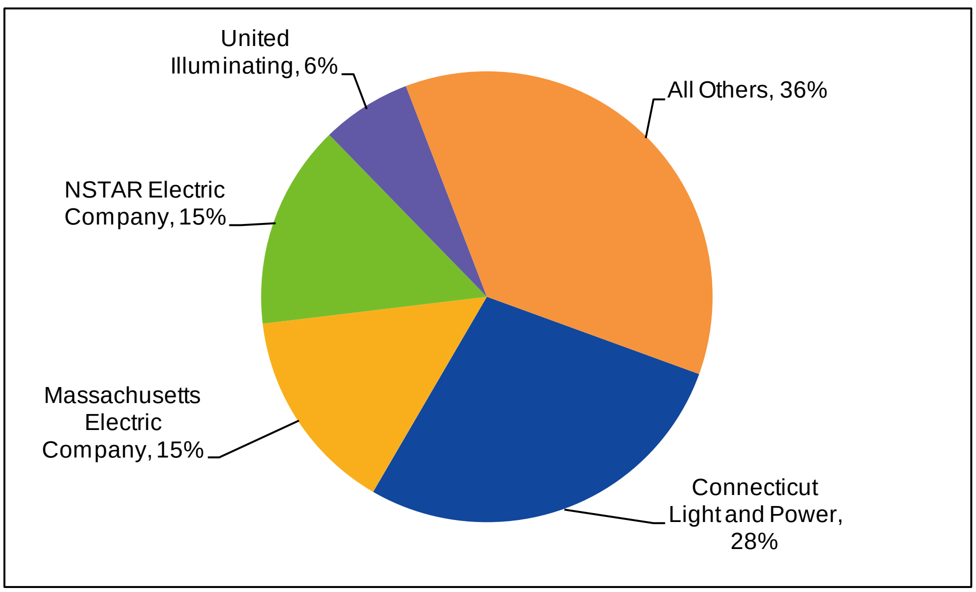

Figure 3-11: Percentage distribution of passive demand resources by capacity supply obligation by lead participant, 2011.

Most active demand resources are offered by market participants that either provide demand-response services exclusively or provide demand-response services and competitive electricity supply. In contrast, most passive demand resources are offered by market participants that are investor-owned utilities and, for the most part, the passive demand resources are state-sponsored energy-efficiency programs.

3.4.2 Demand-Resource Payments

As shown in Table 3-13, demand-response payments totaled $104.3 million in 2011 compared with $143.2 million in 2010. Over 93% of total payments to demand resources in 2011 were capacity payments, which was nearly identical to the percentage in 2010. From January 1, 2010, to May 31, 2010, capacity payments were based on the transition-period capacity-payment rates ($/kW-month) and capacity values determined pursuant to the rules of the demand-response programs. From June 1, 2010, to December 31, 2011, capacity-payment rates were based on the FCM capacity clearing price and capacity values determined pursuant to the rules of the FCM. Demand-response capacity payments were lower in 2011 compared with 2010 because of a reduced capacity-payment rate. In addition, the decrease in capacity values from 2010 to 2011 resulted from the integration of the demand-response program into the FCM and changes to the methodology used to determine a demand-response resource's monthly capacity value.

Table 3-13
Total Payments to Demand-Response Resources, 2010 and 2011

Period	Capacity Payments	% of Total	DALRP Payments	% of Total	RTPR Payments	% of Total	Total Payments
2010	$134,456,420	93.9%	$7,763,220	5.4%	$942,307	0.7%	$143,161,947
2011	$97,591,566	93.5%	$6,296,955	6.0%	$455,462	0.4%	$104,343,983
Difference	($36,864,854)	–	($1,466,265)	–	($486,845)	–	($38,817,964)
% Difference	−27.4%	–	−18.9%	–	−51.7%	–	−27.1%

The remainder of the payments to demand resources in 2011, approximately 6% of the total, was for load reductions in the two expiring price-response programs—the Real-Time Price Response Program and the Day-Ahead Load Response Program.

Refer to Section 4.2.2 for additional information on the RTPR program and the DALRP.

3.4.3 Future Changes to the Price- Response Programs based on FERC Order No. 745

In the *2010 Annual Markets Report*, the IMM made several observations and recommendations regarding the design of the RTPR program, DALRP, and the participation of demand resources in general. Several of the IMM's recommendations have been incorporated into the market rules filed by the ISO in compliance with FERC's *Final Rule on Demand Response Compensation in Organized Wholesale Energy Markets* (Order No. 745).[73] The ISO proposed a two-stage implementation approach that will put in place a "transition-period" program on June 1, 2012. With an anticipated implementation date of June 1, 2017, a second set of market rules that will fully integrate demand resources into the Day-Ahead and Real-Time Energy Markets will replace the transition-period rules. The following is a summary of the design components of the transition period:

- **Calculating the initial baseline—**Initial calculations of a resource's baseline consumption will require a minimum of 10 consecutive days of meter data. A larger sample size of 10 days,

[73] See *Demand Response Compensation in Organized Wholesale Energy Markets* (March 15, 2011), http://www.iso-ne.com/regulatory/ferc/orders/2011/mar/rm10-17-000_3-15-000_demand_resp_order.pdf.

compared with the current requirement of five days, will improve the initial estimated baseline.

- **Allowing symmetric adjustments to the baseline**—Currently, baseline adjustments are *asymmetric* and can only increase, reflecting the asset's current consumption patterns. Currently, on the morning of an event day, even if a participant's energy consumption is less than its baseline, the asset's baseline is not adjusted downward. Thus, the asset's baseline is overstated relative to its energy consumption for the event day. Under the new rule, baseline adjustments on the days that demand-response resources are dispatched will be *symmetric* (i.e., the baseline will be able to increase or decrease). Under the new rule, the asset's baseline will be adjusted downward to reflect the actual consumption before the interruption, which will improve the accuracy of the load-reduction calculation.
- **Refreshing the baseline—**Currently, an asset's baseline does not include data from days when an asset clears in the DALRP or participates in an RTPR program or reliability event. If an asset clears on multiple consecutive days, the baseline can be carried forward for an extended period of time; the baseline becomes "frozen" and may not reflect the asset's current energy consumption pattern. Under the new rule, the decision to include metered data in the baseline calculation is made by observing the past 10 days of the same day type, (for example, weekdays) and counting how many of these 10 (nonevent) days are included in the baseline calculation. A minimum of three days of these nonevent days is required for refreshing the baseline. If the minimum criterion is not met, the metered data for the day's event will be included in the baseline calculation regardless of whether or not the resource cleared for the day. The "refreshing" of the baseline with more current data will improve the baseline's accuracy and reduce bias.
- **Compensating resources relative to their offer and performance—**Currently, the market rules allow for a participant to offer a load reduction in the DALRP at the minimum of 100 kW. If the real-time prices are favorable, the participant has an incentive to deliver more than 100 kW of load reduction. If the prices are not favorable in real-time, the participant is only responsible for buying back the 100 kW if their performance does not deviate from the adjusted baseline. Thus, the minimum bid of 100 kW gives the participant little risk, yet much opportunity in real-time if prices are high. The new market rule, whereby a participant's compensation is limited to 200% of the amount it offers, will provide an incentive for market participants to follow their cleared day-ahead demand-reduction schedules.

3.4.4 Demand-Response Recommendations

3.4.4.1 Recommendations to Improve the Accuracy of Demand-Resource Data

The IMM has observed instances of market participants submitting inaccurate meter data to the ISO for demand resources, specifically, by the owners of RTDR assets in the FCM that choose to participate in the DALRP. While current requirements include an annual independent audit of the meter data verification and submission procedures, and the Measurement and Verification of Demand Reduction (MVDR) Manual includes a number of meter data verification requirements, the IMM believes that a significant factor contributing to inaccurate meter data is that market participants report all meter data to the ISO without any third-party verification.[74]

[74] *ISO New England Manual for Measurement and Verification of Demand-Reduction Value from Demand Resources*, (Manual M-MVDR) (May 6, 2011), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

Inaccurate meter data used in the calculation of baselines and load reductions can lead to downstream consequences for ISO settlements, system operations, and system planning. Specifically, the following can occur if meter data are overstated:

- Some market participants with demand resources can receive compensation for capacity and energy based on overstated performance.
- Other market participants could pay for something they did not receive.
- ISO system operators may rely on a demand resource that has overstated capability.
- The ISO can procure too little capacity in an FCA because some demand resources have overstated their capability.

The IMM believes that many of these quality problems for demand-resource meter data stem from a lack of transparency in the data (i.e., the market participant for demand-resource assets controls all the data submitted to the ISO) and a lack of incentives for motivating market participants to report accurate data to the ISO. One cause of this problem is that market participants for demand resources serve as both the lead participants and meter readers. A conflict of interest can arise when the market participant with a financial interest in the performance of the asset (as a lead participant) also controls and reports the meter data (as a meter reader) the ISO uses to determine the performance and financial compensation of the asset.

The IMM recommends remedying this through tariff changes that would require a party independent from the market participant with registered RTDR assets, such as the local distribution utility, to provide meter data to the ISO. The IMM also recommends that market participants notify the ISO as soon as the participant determines that inaccurate information has been submitted for any demand resource or demand-resource asset. The changes should include minimum validation requirements for meter data and asset-descriptive information.

Including data-validation requirements in the ISO's tariff will enhance the ISO's and IMM's enforcement of such requirements when referrals to FERC are required. Finally, requiring market participants to self-report data quality issues to the ISO in a timely manner and to refund payments based on inaccurately stated performance will further clarify expectations for proper market participant behavior and responsibilities.

3.4.4.2 Recommendations to Improve Demand-Resource Availability Reporting

Under the current market rules, load reductions have been calculated for RTDR and RTEG assets when the retail customers associated with these assets have not taken any deliberate actions to reduce load. This can happen, for example, when a meter malfunction results in zero load reported for the period. The IMM also has observed that load reductions were calculated for assets during periods when a business was closed and the asset's meter reported low or zero load values. In both cases, market participants were compensated for load reductions that were not the result of the asset taking actions in response to the ISO's dispatch instructions or LMPs.

The current market rule requires market participants to submit to the ISO a two-day forecast of their RTDR and RTEG resources' hourly load-reduction capability.[75] If one or more of the retail customers associated with a resource cannot reduce load in response to an ISO dispatch instruction (e.g., the business is closed, equipment is shut down for maintenance, or the meter has malfunctioned), the

[75] See *Market Rule 1*, Section III.13.6.1.5.2.

market participant is required to reflect the reduced load-reduction capability in their hourly load-reduction capability forecast. The IMM recommends modifying the market rule to require market participants to submit hourly capability forecasts at the asset level because baselines and load-reduction calculations are done at the asset level. The IMM also recommends modifying the market rule to require asset-level hourly load-reduction capability information to be factored into the baseline and load-reduction calculations. With this modification, the baselines for assets that have malfunctioning meters or no load-reduction capability would not be affected, and load reductions would not be calculated.

3.5 Forward Capacity Market

The Forward Capacity Market rules required the IMM to publish a review of the market after the completion of the second Forward Capacity Auction and to review FCM's performance in its Annual Markets Report. This section reviews the outcomes for the first five FCAs, assesses the FCM by comparing those outcomes to its objectives, and makes several recommendations to improve the FCM.

The Forward Capacity Market is a long-term wholesale market that assures resource adequacy, locally and systemwide. It does this by compensating generation and demand resources for fixed capacity costs not covered through the other markets.[76] Capacity resources can include supply from power plants and import capacity or the decreased use of electricity through demand resources. To purchase enough qualified resources to satisfy the region's future needs and allow enough time to construct new capacity resources, FCAs are held each year approximately three years in advance of when the capacity resources must provide service. New and existing capacity resources that qualify for an FCA can 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, the capacity willing to remain in the auction at some price level will equal or fall below the *Installed Capacity Requirement* (ICR), the needed capacity level the ISO has determined according to NERC standards and NPCC and ISO New England requirements to maintain reliability.[77] FCM resources still in the auction at this point move on to the auction-clearing stage of the FCA, during which market-clearing auction software is run to determine the minimal capacity payment and calculate final capacity-zone clearing prices.

Reconfiguration auctions take place before and during the capacity commitment period to allow participants to buy and sell capacity obligations and adjust their positions annually or within a commitment period. Annual reconfiguration auctions (ARAs) to acquire one-year commitments are held approximately two years, one year, and just before the FCA commitment period begins. Monthly and seasonal reconfiguration auctions, held beginning the first month of a commitment period, adjust the annual commitments during the commitment period.

Two key provisions of the capacity payment structure are the *peak energy rent* (PER) adjustment and availability penalties incurred for unavailability during shortage events. The PER adjustment reduces capacity market payments for all capacity resources when prices in the electric energy markets go above the PER threshold (i.e., *strike*) price, which is an estimate of the cost of the most expensive

[76] One reason that all fixed costs are not recovered in the energy markets is because a price cap in the energy market (see Section 2.1) limits energy offers to $1,000/MWh.

[77] For more information on NERC standards, see http://www.nerc.com/page.php?cid=2|20 (NERC, 2011). For more information on NPCC standards, see https://www.npcc.org/Standards/default.aspx (2011).

resource on the system. *Shortage events* are periods when reserves fall below the system reserve requirements for 30 minutes or more. Shortage-event availability penalties are assessed for resources with capacity supply obligations that are unavailable during defined shortage events. The PER adjustment and shortage-event penalties discourage withholding in the energy market.

3.5.1 Capacity Market Outcomes

3.5.1.1 Forward Capacity Market Results

Table 3-14 shows the total amount of capacity cleared in the auction for each FCM commitment period, the capacity needed (ICR), the surplus capacity, the net capacity additions for that period, and the capacity price.

Table 3-14
FCM Capacity Commitment Period Results (MW and $kW-month)

Factor	FCM Capacity Commitment Period[(a)]				
	2010/ 2011	2011/ 2012	2012/ 2013	2013/ 2014	2014/ 2015
Capacity resources (MW)	34,078	37,283	36,996	37,500	36,918
Net ICR (MW)	32,305	32,528	31,965	32,127	33,200
Surplus (MW)	*1,773*	*4,755*	*5,031*	*5,373*	*3,718*
Net capacity additions (MW)[(b)]	900	2,760	1,329	1,490	1,176
Capacity price ($/kW-month)	4.50	3.60	2.95	2.95	3.21

(a) FCM period began June 1, 2010.

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

3.5.1.2 Reconfiguration and Bilateral Auction Results

The annual and monthly reconfiguration auctions provide participants the opportunity to exchange CSOs within a commitment period for an annual commitment period or monthly. Each reconfiguration auction clears at a different price and quantity depending on the amount of CSOs participants are willing to acquire and transfer. Table 3-15 shows that the clearing prices in the annual reconfiguration auctions have steadily declined and are significantly lower than the price in the corresponding FCA.

Table 3-15
Annual Reconfiguration Auction Clearing Prices and Quantities

Commitment Period	Auction	Cleared CSOs (MW)	Clearing Price ($/kW-month)
2010/2011	ARA #2	198	1.50
	ARA #3	444	1.43
2011/2012	ARA #2	188	1.00
	ARA #3	362	0.93
2012/2013	ARA #2	636	0.94

Table 3-16 shows the clearing prices and quantities in the monthly reconfiguration auctions, which also have declined over time and are significantly lower than the price in the corresponding FCA.

Table 3-16
Clearing Prices and Quantities in the Monthly Reconfiguration Auctions

Commitment Period	Average of Monthly Cleared CSOs (MW)	Weighted Average of Monthly Clearing Price ($/kW-month)
2010/2011	176	1.09
2011/2012	378	0.43

All monthly reconfiguration auctions have not been completed for all months in the 2011/2012 capacity commitment period. For the 2010/2011 commitment period, auction clearing prices ranged from $0.73/kW-month to $2.25/kW-month. Monthly cleared volumes have ranged from 56 MW (for the July 2010 commitment month) to 326 MW (for February 2011). For the 2011/2012 commitment period, the prices ranged from $0.18/kW-month to $1.01/kW-month, and cleared volumes ranged from 227 MW (for August 2011) to 560 MW (for February 2012).

There appears to be a negative relationship between the price and cleared CSO megawatts, which is consistent with expectations. The participant who has a cleared CSO in an FCA has an incentive to transfer the CSO if the difference between the FCA clearing price and the reconfiguration price is positive. At lower reconfiguration auction clearing prices, the potential payoff of transferring a CSO increases, resulting in the transfer of more CSOs.

3.5.2 Trends in Cleared Capacity in FCA #1 to FCA #5

Table 3-17 presents data for generation, demand response, and import capacity cleared for each capacity commitment period.

Table 3-17
Cleared Capacity Resources for Each FCM Capacity Commitment Period (MW)

Factor	FCM Capacity Commitment Period				
	2010/ 2011	**2011/ 2012**	**2012/ 2013**	**2013/ 2014**	**2014/ 2015**
Installed generation SCC[(a)]	30,865	32,207	32,228	32,247	31,439
Demand resources (capacity obligation)[(b)]	2,279	2,778	2,868	3,261	3,468
External capacity contracts[(a)]	934	2,298	1,900	1,992	2,011
Surplus above the ICR	1,773	4,755	5,031	5,373	3,718
Total capacity resources	34,078	37,283	36,996	37,500	36,918

(a) Data for FCM periods are based on cleared megawatts. Seasonal claimed capability (SCC) is the summer or winter claimed capability of a generating unit or ISO-approved combination of units that represents the maximum dependable load-carrying ability of the unit or units, excluding the capacity required for station use.

(b) Data for FCM commitment periods are based on cleared megawatts, including those for energy efficiency and demand-response resources, which reflects the 600 MW RTEG cap.

Two trends have continued through the first five FCAs. One trend is the clearing of far more capacity than is needed to meet the Installed Capacity Requirement. The second is the addition of large amounts of demand resources and imports that started in the FCM transition period. The surplus capacity cleared after FCA #1 was 1,773 MW, which rose to 5,373 MW after FCA #4 and dropped to 3,718 MW after FCA #5.

Table 3-18 shows the change in capacity by type from before transition-period payments were started in 2006/2007 to the 2014/2015 commitment period of FCA #5. It shows the trend that most resources added in recent years have been demand resources or imports. Over half of the net resource additions were from demand resources, about 28% were imports, and only 16% were from generating resources.

Table 3-18
Cumulative Capacity Additions by Type of Resource (MW)

Year	Generation	Demand	Imports	Total
2014/2015	31,439	3,468	2,011	36,918
2006/2007	30,509	314	451	31,274
Net increase	930	3,154	1,560	5,643
% of net increase	16.5	55.9	27.6	100

Between 2006 and 2011, 728 MW of capacity retired. Additionally, Salem Harbor station, with a total capacity of 744 MW, is retiring effective June 1, 2014.

3.5.3 Forward Capacity Market Performance

This section reviews how well the FCM has met its objectives in attracting sufficient capacity and appropriately pricing that capacity.

3.5.3.1 Reliability Needs and Performance

The FCM was designed to send price signals that attract new resources and maintain existing resources to meet the region's resource adequacy standard. The FCM design was intended to reveal the cost of new entry (CONE) through the FCA and pay this price to all resources. The FCM also had provisions that changed the price in the event that subsidized or out-of-market resources prevented the price from being set and permitted demand resources to participate in the market. The FCM design also recognized that the need for capacity could vary by region and provided for the establishment of capacity zones. However, the rules around the creation of zones are weak, requiring zones to be established only before an FCA when resources in a zone were insufficient to meet the capacity need, rather than during an FCA based on the capacity leaving the market.

Since the start of transition-period payments and continuing through each FCA, more than enough capacity has been available to meet New England's Installed Capacity Requirement. Thus, the FCM has met its primary purpose. Additionally, the rules to facilitate the participation of demand resources in the capacity market successfully attracted these resources.

The FCM has helped meet the region's reliability needs at prices noticeably lower than the cost of new generation. Each FCA has cleared at the floor price for the auction. The significant surplus since the start of the transition period at capacity prices lower than the estimated cost of new entry can be attributed to several factors:

- **First, the amount of capacity paid during the transition period was not limited.** Transition payments attracted a significant amount of demand resources and capacity imports into the market, much of which has remained.
- **Second, the need for capacity since the transition period has grown only modestly.** The ICR increased at an average annual rate of 1.35% from the 2006/2007 commitment period to the 2014/2015 commitment period, for a total increase of 3,374 MW. This ICR growth is about 1,000 MW less than the surplus of 4,337 MW available in June 2007, the first summer after the start of transition payments.
- **Third, demand-response resources and imports have shown they can enter the market quickly and at prices lower than the estimated cost of new entry for new generators.**
- **Fourth, a significant amount of resources whose estimated cost of new entry exceeded the auction clearing price entered the market.** This out-of-market entry is the result of state concerns over the risk of high capacity prices and state policy objectives that have encouraged the development of demand-side and renewable resources.

Table 3-19 shows the new generation and demand resources and the megawatts and percentages of that new generation provided by OOM resources for the first five FCAs.

Table 3-19
New In- and Out-of-Market Resources
and OOM Resources as a Percentage of All New Resources (MW, %)[a]

Type of Resource	FCA #1	FCA #2	FCA #3	FCA #4	FCA #5	Total
New generation and demand resources	900	1,231	512	659	305	3,608
In-market resources	860	337	239	111	124	1,671
Out-of-market resources	40	894	273	548	181	1,936
% OOM	4%	73%	53%	83%	59%	54%

(a) Net of repowerings

Table 3-19 shows that 54% of all new resources added have been out of market and that the percentage has been as high as 83% of all new resources in a single year. Generation and demand resources both have been out-of-market resources, but as Table 3-20 shows, a higher percentage of generation has been out of market. Two new generation projects, the Kleen project and the Connecticut request for proposals (RFP) for peaking resources, sponsored by the State of Connecticut, represent most of the out-of-market generation.

Table 3-20
Percentage of Out-of-Market New Capacity,
by Resource Type, FCA #1 to FCA #5[a]

Type of Resource	Total New Capacity Added (MW)	Total OOM Added (MW)	% OOM
Generation	1,212	1,070	88
Demand	2,396	866	36

(a) Net of repowerings

While the amount of OOM entry has been substantial, it has not yet affected the auction clearing price because the capacity surplus at the start of each auction has been sufficient to cause the auction to clear at the floor price. The out-of-market entry has not yet triggered the implementation of the Alternative Price Rule, in part because of the rule's trigger.[78] At the start of an auction, if the amount of existing capacity, including the OOM capacity from prior auctions, exceeds the net ICR for that auction, no new capacity is needed and the Alternative Price Rule is not triggered. Table 3-21 shows that even if there was no out-of-market capacity, new capacity would not be needed and the Alternative Price Rule would not be triggered.

Table 3-21
Capacity Surplus, Net of Out-of-Market Capacity (MW)

FCA	Existing Capacity[(a)]	Existing Capacity, Net of OOM	Net ICR	Starting Surplus	Cleared OOM Capacity[(b)]
FCA #1	34,234	34,234	32,305	1,929	40
FCA #2	35,212	35,172	32,528	2,644	1,268
FCA #3	37,357	36,049	31,965	4,084	695
FCA #4	37,132	35,129	32,127	3,002	548
FCA #5	36,855	34,304	33,200	1,104	181

(a) Refers to existing capacity supply offers at the beginning of the auction (qualified capacity net of administrative, static and permanent delist offers). An existing resource can submit a *delist bid* to indicate that it wants to opt out of the auction before the existing capacity qualification deadline and does not want a capacity obligation below a certain price. Several types of delist bids exist, including static delist bids, dynamic delist bids, permanent delist bids, nonprice retirement bids, export delist bids, and administrative export delist bids.

(b) Refers to OOM at beginning of the auction (all OOM offers, including repowering projects).

While the above analysis shows that OOM resources have not yet directly affected the clearing price in an FCA, they may have prevented a zone from being created in a Forward Capacity Auction. The IMM reviewed whether the generation resources added by the State of Connecticut have prevented the formation of a zone. Attachment K of the ISO's *Open Access Transmission Tariff* (OATT) lists resources contractually committed pursuant to a state RFP or similar process.[79] To date, the Connecticut units are the only resources in Attachment K. Table 3-22 compares the total resources in Attachment K with the need for capacity in Connecticut. It shows that even in the absence of the Attachment K resources, the Connecticut capacity zone would have had enough capacity to prevent the creation of a capacity zone. The surplus would have been much lower, but the Connecticut zone would have met the local sourcing requirements (LSRs).[80]

[78] The *Alternative Price Rule* ensures that the capacity clearing price reflects the cost of new entry when entry of new resources was prevented because of the presence of out-of-market capacity. This rule sets the clearing price at the lesser of the CONE or the price at which the last new capacity offer left the auction. The rule is described in detail in *Market Rule 1*, Section III.13.2.7.8 (March 1, 2012), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[79] *ISO New England Open Access Transmission Tariff* (March 1, 2012), http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

[80] A *local sourcing requirement* is the minimum amount of capacity that must be electrically located within an import-constrained load zone to meet the ICR.

Table 3-22
Connecticut OOM Resources and Zonal Formation (MW)[(a)]

Auction	Existing Attachment K Resources	New Attachment K Resources	Total Attachment K Resources	Surplus in CT Zone	Adj. Surplus in CT Zone	System Surplus	Adj. System Surplus
FCA #2	0	1,008	1,008	1,406	398	4,755	3,747
FCA #3	1,003	173	1,176	2,375	1,199	5,031	3,855
FCA #4	1,176	18	1,194	1,818	624	5,373	4,179
FCA #5	1,176	3	1,179	1,927	748	3,718	2,539

(a) The Connecticut zone surplus was adjusted for the Attachment K resource CSO.

3.5.3.2 Peak Energy Rent

The peak energy rent adjustment reduces capacity market payments for all non-demand-capacity resources when prices in the energy market rise above the PER threshold (i.e., strike) price.[81] The 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 provides an additional incentive for capacity resources to be available during peak periods because capacity payments are reduced for all capacity resources, even those not producing energy when the LMP exceeds the PER strike price. The PER adjustment also discourages physical and economic withholding because a resource that withholds to raise price does not earn energy revenues, while its foregone revenues are deducted from the capacity market settlement. The PER adjustment also is a hedging mechanism for load against high prices in the energy market.[82]

On December 1, 2010, the fuel used to calculate the PER adjustment was changed from the lower cost of natural gas and No. 2 fuel oil to the higher cost.[83] 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 PER adjustment is calculated from a moving 12-month average, the gas-based, calculated strike price and adjustment still had some effect on the PER adjustment through November 2011.

PER adjustments decreased through 2011 resulting from the increase in the strike price. From the implementation of the FERC order in December 2010 through the end of 2011, no hours had a positive hourly PER. As a result, the PER adjustment fell to zero in December 2011, when all effects from a gas-based, calculated strike price had ended. See Figure 3-12.

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[81] Demand resources are exempt from the PER adjustment.

[82] Note that lower volatility of total payments might not affect the entire amount paid by the load participants in the long run, as the lower PER adjustment amounts would be reflected in resources' capacity bids.

[83] See ER11-2427-000, *Order Accepting Tariff Provisions in Part, and Rejecting Tariff Provisions in Part* (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, meaning that 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.

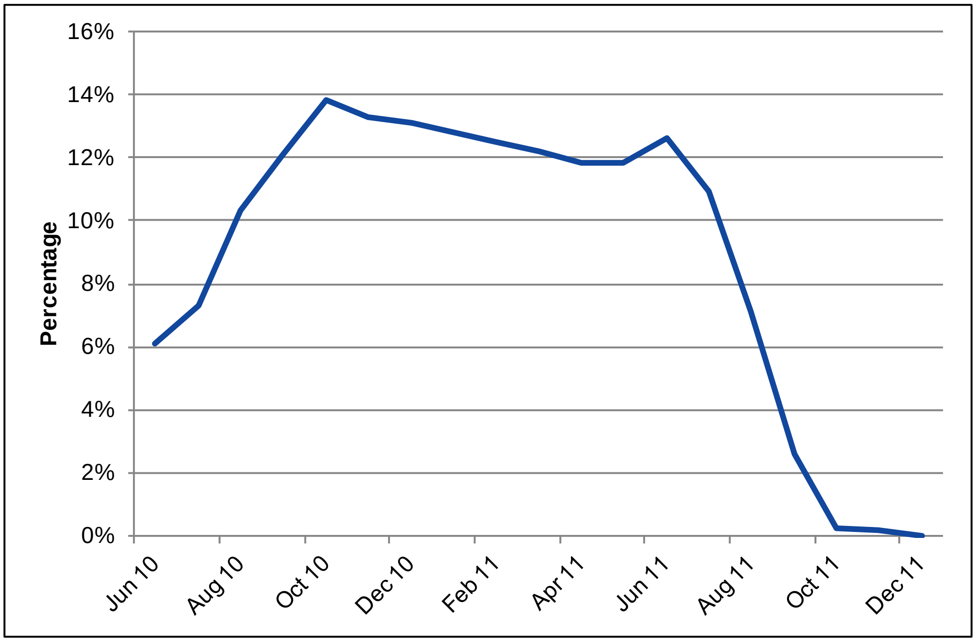

Figure 3-12: Peak energy rent adjustment as a percentage of supply credit in Rest-of-Pool, June 2010 to December 2011.

These results are expected because the higher strike price means that the PER adjustment is triggered less often. While the two main functions of PER (i.e., to reduce the incentive to exercise market power and provide a hedging mechanism) are weakened because of this change, the IMM believes PER is still effective.

3.5.4 Forward Capacity Market Pricing Recommendations

One of the assumptions in the FCM design is that the capacity price would converge to the cost of new entry. Before the implementation of the FCM, the industry assumed that the cost of new entry would be determined by the cost of a new peaking unit. Under this assumption, few resources would be added if prices in the capacity market did not rise to the cost of new generation. The activity in the New England market since the start of the transition period belies this assumption. Most new capacity (about 4,600 MW) has been demand resources and imports, with costs apparently far below the consensus cost of new generation. As part of recent work to implement a Minimum Offer Price Rule (see more below), the IMM has estimated the cost of new entry for a new gas turbine (GT) to be at least $10/kW-month and the cost for a new combined-cycle gas turbine (CCGT) to be at least$11.00/kW-month.

Entry at low prices and little market exit have resulted in continued capacity surplus. It seems reasonable to conclude that the floor price, which has remained in place for the first five FCAs, is an important contributor to the surplus. The original market rules included a three-year price collar. The price-floor portion of that collar has been extended through FCA #6, and a request is before FERC to extend it at least through FCA #7. Maintaining the floor price will result in continued surplus and depressed capacity prices, which discourages the exit of inefficient resources and the entry of new, efficient ones.

The principal reason the floor price has been extended are concerns that the Alternative Price Rule does not adequately remedy the price-suppression effects of OOM resources on the capacity clearing price.[84] The floor price provides very rough justice and compensates capacity providers for the effects that subsidized capacity has on the market. A process to improve the pricing and mitigation aspects of the FCM has been ongoing. In April 2011, FERC rejected the ISO's approach and ordered the ISO to develop an alternative, buyer-side mitigation proposal, the Minimum Offer Price Rule, recognizing that (1) effective buyer-side mitigation is necessary to price new capacity efficiently and (2) after implementing the improved buyer-side mitigation, the floor price should be removed. The IMM recommends implementing FERC's Minimum Offer Price Rule and removing the floor price as soon as possible.

Price volatility in the capacity market is a concern of market participants and market designers. The vertical demand curve in the first capacity market in 2000 contributed to abrupt price changes that started the long-running debate about the New England capacity market. To dampen price volatility, the FCM includes several design features that create elasticity, or slope, in the supply curve:

- Making market entry easier and thereby increasing competition through the forward nature of the market
- Including demand-side resources and capacity imports in the market, which also increases competition
- Enabling existing resources to set a price for market exit through delist bids

To understand how effective the FCM design has been at creating an elastic supply curve, the IMM constructed the supply curves for each auction.[85] Figure 3-13 shows the average supply curve for resources that qualified for each FCA and left the market before the auction reached the floor price. Figure 3-13 does not include any of the resources that remained in the auction, only those that left the auction before it cleared at the floor price. The full supply curve would include a horizontal line at the floor price going from zero megawatts to the over 34,000 MW that cleared in each auction.

[84] Revisions to the *ISO New England Transmission, Markets and Services Tariff Related to Forward Capacity Market*, ER12-953-000 (January 31, 2012), http://www.iso-ne.com/regulatory/ferc/filings/2012/jan/er12-953-000_fcm_redesign_1-31-2012.pdf.

[85] For ease of presentation and analysis, the average supply curve for the first five FCAs is presented here. The individual supply curves are in the appendix, Section 4.2.3.1.

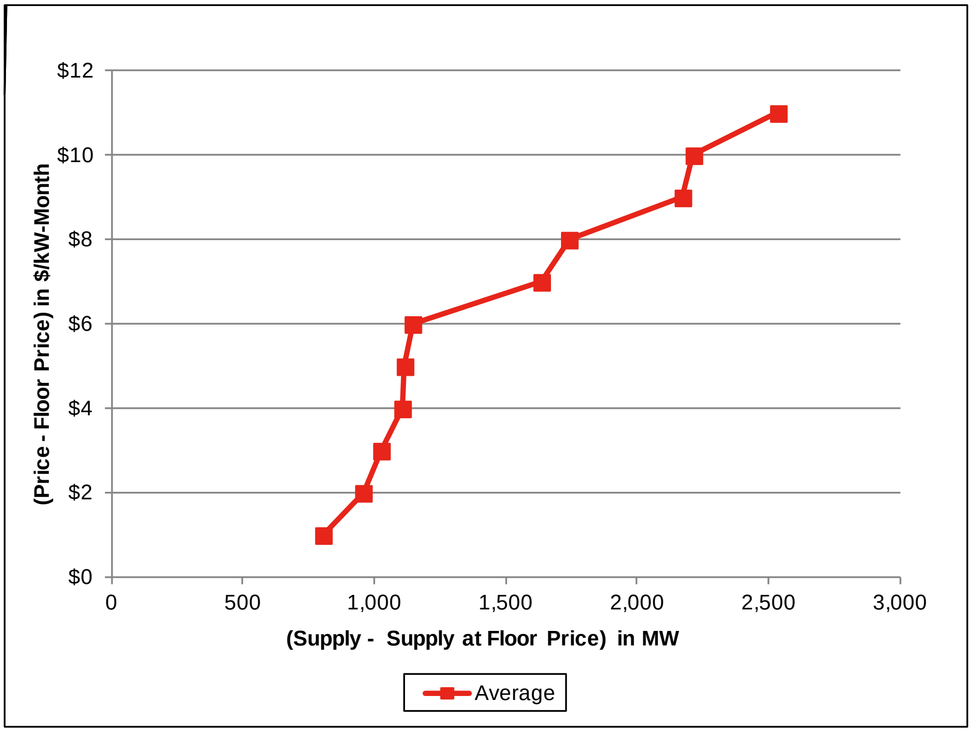

Figure 3-13: Average supply curve, FCA #1 to FCA #5.

Figure 3-13 also shows that the average supply curve has two distinct regions. In the higher-priced region (between $6 and $10/kW-month above the floor price), the curve is relatively elastic with approximately 1,500 MW leaving the auction in that range. In the lower-priced region (between the floor price and $4/kW-month above the floor price), only about 500 MW of capacity left the auction. For a given auction, a small shift in the demand curve (i.e., increase in ICR) could have a significant impact on the auction clearing price.

As illustrated in Figure 3-14, a shift in the demand curve (i.e., an increase in the ICR of about 150 MW [from D_1 to D_2]) could increase the price from about $5.50/kW-month (about $2.00/kW-month above the floor price) to about $9.50/kW-month (to about $6.00/kW-month above the floor price). This is a change in price of over 70% for a change in purchased capacity of less than a one-half of one percent. It does not seem plausible that the large price change associated with this small change in procured capacity reflects a proportional increase in expected reliability.

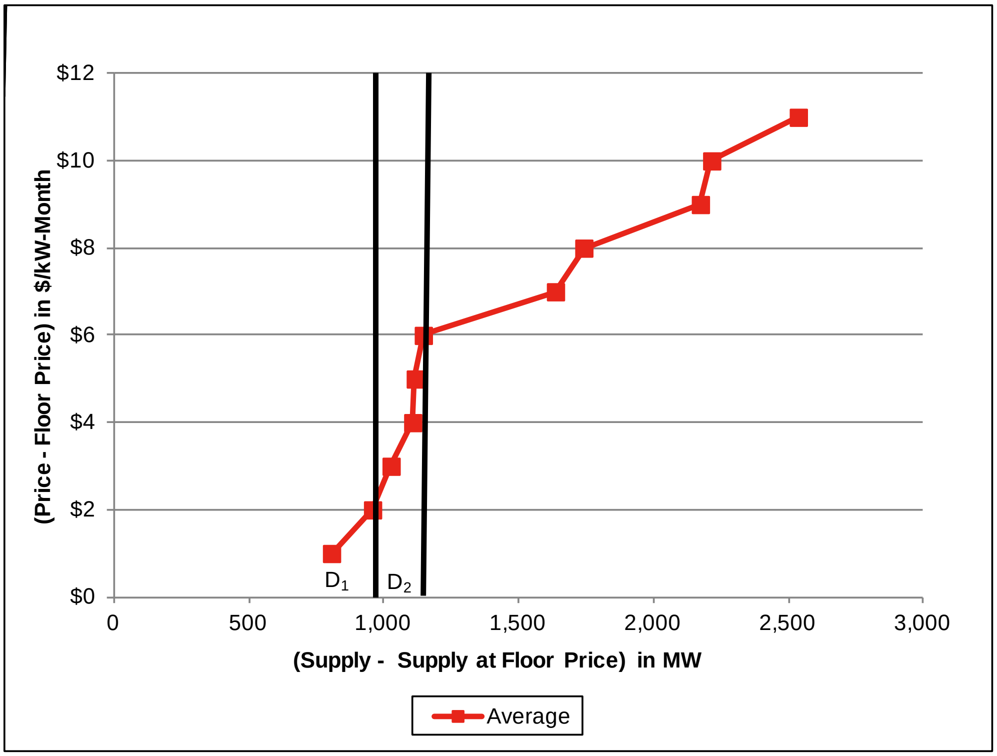

Figure 3-14: Average supply curve, FCA #1 to FCA #5.

This review of capacity market pricing supports two recommendations:

- Implement the Minimum Offer Price Rule and eliminate the floor price to increase competition between resources to remain in the market as well as enter the market. This will increase the likelihood that electric energy and capacity prices will support an efficient mix of resources over the long term. Maintaining the floor price makes it less likely that efficient new resources will enter the market.

- Develop a sloped demand curve for use in the market pricing mechanism. The shape of the supply curve above the floor price in each of the auctions shows that, for a significant portion of the supply curve, a small change in quantity can cause a large change in price. A sloped demand curve can reduce this price volatility. The need for a demand curve becomes more pressing with the modeling of zones in the auction. Because zones have not yet been modeled in the auction, capacity prices do not reflect the capacity balance in each zone. The combination of modeling the zones in the auction and implementing a demand curve would send price signals that reveal the relative surplus and shortage in each zone.

3.5.5 Forward Capacity Market Obligations and Recommendations to Better Align the FCM with Energy Market Incentives

One of the challenges of designing a capacity market is defining the capacity product. Unlike electric energy, which is physical and measurable, the capacity product is defined by the obligations and penalties imposed on capacity resources by the market rules. The obligations placed on resources in the capacity market should assure the reliable operation of the power system every day and provide incentives for resources to operate as efficiently as possible.

3.5.5.1 Capacity Market Obligations and Incentives

Two broad categories of obligations are placed on generators in the current tariff. One set applies to all resources, while another set applies only to capacity resources. The obligations that apply to all resources include the following:

- Supplying applicable offer data
- Responding to ISO directives to start, shutdown, or change generator output or scheduled voltage or reactive levels
- Continuously maintaining all offer data concurrent with on-line operating information.[86]

These obligations are necessary for the system operator to know which resources are available, their operating characteristics, and their dispatch costs.

Three additional obligations are imposed on capacity resources:

- Offering resources into the Day-Ahead and Real-Time Energy Markets
- Having their time-based operating parameters meet certain criteria
- Following outage-scheduling rules.

Market Rule 1, Section III.13.6.1.1.1, details the first two obligations for capacity resources:[87]

> *A Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both the Day- Ahead Energy Market and Real-Time Energy Market at a MW amount equal to or greater than its Capacity Supply Obligation whenever the resource is physically available. If the resource is physically available at a level less than its Capacity Supply Obligation, however, the resource shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market at that level. Day-Ahead Energy Market Supply Offers from such Generating Capacity Resources shall also meet one of the following requirements:*
>
> *(a) the sum of the Generating Capacity Resource's notification time plus start time plus minimum run time plus minimum down time is less than or equal to 72 hours; or*
> *(b) if the Generating Capacity Resource cannot meet the offer requirements in Section III.13.6.1.1.1(a) due to physical design limits, then the resource shall be offered into the Day-Ahead Energy Market at a MW amount equal to or greater than its Economic Minimum Limit at a price of zero or shall be self-scheduled in the Day-Ahead Energy Market at a MW amount equal to or greater than the resource's Economic Minimum Limit.*

These energy and capacity market obligations are intended to maintain reliable operation by requiring capacity resources to be available for dispatch (i.e., offer each day) when they are not on a planned or forced outage and to require all resources to follow dispatch instructions when operating. When these obligations work as intended, all resources offer each day and operate when called on. The market rules include provisions that reinforce these obligations. One important provision is the requirement that resources that clear in the day-ahead market but do not provide their committed energy must buy the energy back in the real-time market. This provision sends strong price signals to

[86] See *Market Rule 1*, Section III.1.7.20 (b).

[87] See *Market Rule 1*, Section III.13.6.1.1.5(c).

resources that clear in the day-ahead market to provide the energy in real-time. A second provision is the shortage-event penalty in the Forward Capacity Market.

These obligations, together with the fundamental energy market incentive that generators only earn money if they provide energy, are sufficient to ensure that the energy supply is reliable under most operating conditions. However, recent events have highlighted that this set of penalties and incentives may be inadequate to ensure a reliable supply in certain circumstances:

- If a resource does not clear in the day-ahead market and fails to operate or meet its desired dispatch points when called on to operate in real time, it faces no penalties or financial consequences.

Providing incentives to perform affects resource behavior in important ways. Generally, performance incentives encourage resources to maintain their equipment and to have the fuel to operate reliably when called on. The reliability of the fuel supply is an issue in New England because of the region's dependence on natural gas. Because most generators in the region do not have firm transportation contracts, it is sometimes uncertain whether they will be able to obtain gas to operate when demand for natural gas is high, generally on cold winter days and on summer days when maintenance on the pipeline system reduces the availability of fuel in a particular location. Stronger performance incentives would provide signals for resources to firm up natural gas supplies or burn an alternative fuel if their ability to obtain natural gas would be highly unlikely.

3.5.5.2 Examples of Resource Unavailability

The IMM is aware of several instances during which resources initially declared available to the ISO Control Room were later declared unavailable when called on because of an inability to obtain gas or an inability to obtain gas at a price that could be recovered in the electricity markets:

- Almost daily in winter 2010/2011, a resource declared to the ISO it was out of service at 11:00 p.m. The participant stated it could always get gas up to 11:00 p.m., but after this time, if the intraday gas price were not consistent with its electric power offer, it would choose to go out of service until the next gas day.
- In January 2012, the ISO committed a resource to operate through 11:00 p.m., the next day. About 4:00 a.m., the market participant informed the ISO that the resource was coming off line because of a lack of fuel.
- Also in January 2012, the ISO issued a start-up order for a resource to provide operating reserves. After the start up, the resource called back to inform the ISO that the unit was unavailable because of a lack of fuel. The participant later stated that the gas price was not economic with their electric power offer, so they chose to go out of service rather than procure fuel at a loss.

This uncertainty causes the ISO's system operations group to take actions to assure reliable operation. These actions typically include committing additional generation to cover the possibility that one or more gas-fired generators will not have fuel. To date, these actions have been successful in maintaining system reliability but may come at the cost of increased out-of-market commitments and distorted energy market prices.

3.5.5.3 Market Design Recommendations

These instances demonstrate the need for making several improvements to the market design. The first is the need for stronger performance incentives, as discussed above. The second is a need for hourly offers and intraday reoffers in the energy markets. While these improvements could be made independently, both are necessary to provide the strongest possible incentives for resources to be well-maintained and to have the fuel to operate whenever called on. Both are needed because if resources have incentives to perform but cannot accurately reflect the cost of providing energy, the performance incentives may be ineffective and unfairly penalize resources for acting rationally.

Implement Hourly Offers and Intraday Offers. The implementation of hourly offers and intraday reoffers would enable a resource to reflect accurately the cost of providing energy and therefore have the proper incentive to provide energy. In the current energy market, resources submit a single offer that applies to all hours of the day. It must be submitted by noon the day before the operating day and can only be changed during the reoffer period between 4:00 p.m. and 6:00 p.m. the day before the operating day. As noted in the IMM's observations, resources have sometimes been unwilling to procure natural gas because the price for obtaining natural gas on short notice was significantly higher than the electricity price and the resource would have been unlikely to make money by selling electricity using natural gas at that price.[88]

To address the problem of resources not being willing to provide energy because they cannot accurately reflect their costs, and more generally to enable prices to accurately reflect the cost of providing energy, the IMM recommends implementing hourly offers that can be updated during the operating day. This would help assure resource owners that they could at least recover their costs if they procure the gas. Additionally, since the energy market offer would reflect the cost of intra-day natural gas, it would make the energy price a more accurate reflection of the cost to meet the last increment of demand.

Provide Stronger Performance Incentives. Because a resource that does not clear in the day-ahead market that is called to deliver energy in real-time is not penalized for failing to deliver energy, it has fewer incentives than resources that clear in the day-ahead market to firm up fuel supply or take other actions to be available to provide energy. Adding a penalty for resources that are called on in real-time but fail to perform would give these resources similar performance incentives as those that clear in the day-ahead market.

To address this concern, the IMM recommends that resources with a capacity supply obligation that fail to provide energy when needed in real-time or are unavailable because of a forced outage be subject to a penalty based on the cost that their unavailability has on the market. For example, this cost could be calculated based on the impact that the failure to supply had on energy prices or on the total production costs. This recommendation is for all resources with a capacity supply obligation that are not available to perform for any reason except ISO-approvd outages. Implementing this recommendation will reveal the cost of a reliable energy market by including in both the energy price and the capacity price the market's estimate of the cost of providing reliable energy. Part of the implementation of this penalty would include reviewing the mitigation rules to allow the expected value of penalties to be properly included in reference prices.

This recommendation would help address another issue in the capacity market. Currently, a capacity resource cannot lose money beyond its capacity supply obligation by failing to perform. In fact, the only time the resource is at risk is during shortage events, which have not yet occurred. Consequently, if a resource suffers an extended outage or even is unexpectedly retired, it may decide to maintain its capacity obligation because there is little risk of a shortage event and it would continue to receive

[88] NCPC would be based on a resource's original offer, not its cost, absent a FERC filing.

capacity payments. A penalty for failing to perform or be available would provide the proper signal for a resource that cannot operate for an extended time to exit the capacity market.

3.5.6 Recommendation for Modeling Capacity Zones

Under the current rules, a zone is modeled only when there is a shortage in the zone under all conditions before the start of the auction. The inadequacy of the current approach is shown in Table 3-23, which presents the capacity and local sourcing requirement for the NEMA/Boston zone for the first six FCAs. It shows that the zone is nearly short of capacity at the start of FCA #6. However, because the zone is not being modeled in FCA #6 and the zone has no demand curve, the price for capacity in NEMA/Boston will be the same as the price in the Rest-of-Pool capacity zone, which is quite likely to be the floor price. This fails to alert the market that NEMA/Boston is almost short of resources and reduces the incentives to develop resources in the zone.

To provide proper price signals that a zone may be running short of capacity, the IMM recommends modeling all zones in the auction as soon as possible.

Table 3-23
NEMA/Boston Capacity and Local Sourcing Requirement (MW)

Auction	Total Capacity in NEMA/Boston	Local Sourcing Requirement	Surplus in NEMA/Boston Zone
FCA #1	3,424	2,246	1,178
FCA #2	3,784	2,016	1,768
FCA #3	3,827	2,019	1,808
FCA #4	3,952	2,957	995
FCA #5	3,943	3,046	897
FCA #6	3,331	3,289	42

Section 4
Data Appendix

This appendix contains details on the energy, forward capacity, locational forward reserve, and regulation markets. It also contains information about actions taken to ensure reliability and the tariff charges that fund ISO operations and provide compensation for the products and services provided by participants through the tariff.

4.1 Real-Time Energy Markets

This section has information about the Real-Time Energy Market covered in this report that is not essential for evaluating its competitiveness and efficiency.

4.1.1 Real-Time Market

4.1.1.1 Pricing

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

Table 4-1
Average Day-Ahead Premium, 2009 to 2011 ($/MWh)

Location	2009	2010	2011
CT	−$0.16	−$0.01	−$0.48
Hub	−$0.47	−$0.67	−$0.29
ME	−$0.38	−$0.37	$0.64
NEMA	−$0.34	−$1.02	−$0.42
NH	−$0.47	−$0.68	−$0.13
RI	−$0.44	−$0.76	−$0.36
SEMA	−$0.34	−$0.95	−$0.40
VT	−$0.49	−$0.33	$0.10
WCMA	−$0.45	−$0.55	−$0.31

4.1.1.2 Market Structure

Table 4-2 presents additional statistics on the Herfindahl-Hirschman Indices.

Table 4-2
HHI Statistics for New England, 2009 to 2011

	HHI Statistics for the Peak Load Hour			HHI Statistics for the Lowest Load Hour		
Year	Median	Mean	Max	Median	Mean	Max
2009	731	738	1,102	980	961	1,477
2010	732	745	1,091	991	987	1,408
2011	712	713	901	889	886	1,171

4.1.1.3 Relationships to Pricing and Other Factors

Figure 4-1 and Table 4-3 show a three-year comparison of annual average fuel prices for main fuel types.

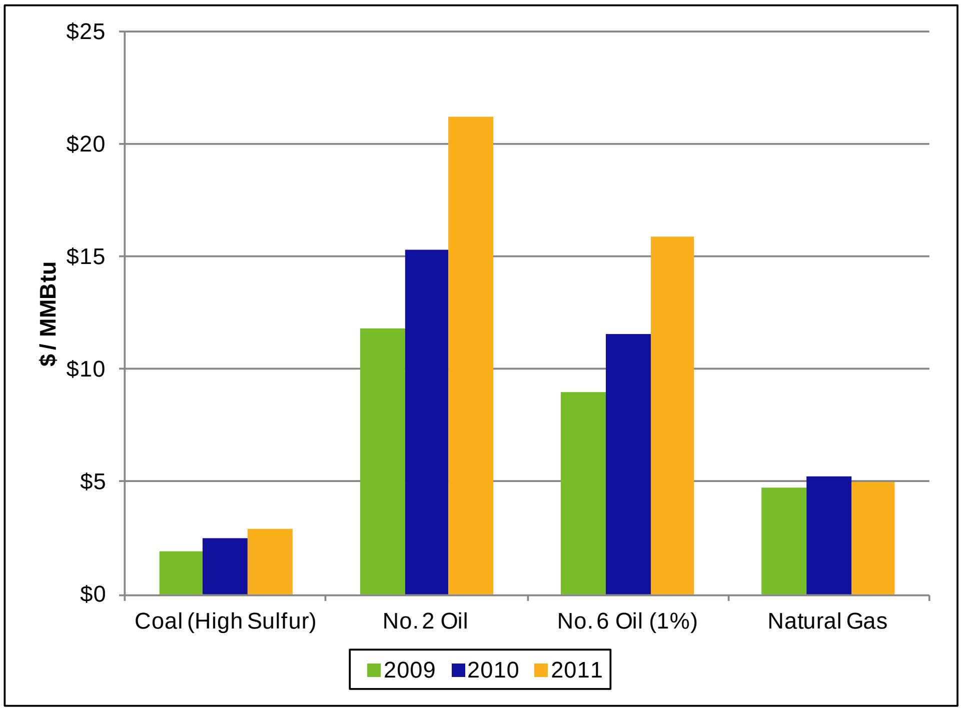

Figure 4-1: Average annual fuel prices for selected input fuels, 2009 to 2011 ($/MMBtu).

Table 4-3
Average Annual Fuel Prices for Selected Input Fuels, 2009 to 2011 ($/MMbtu)

Fuel	2009	2010	2011	% Change 2010 to 2011[(a)]
Natural gas	4.77	5.21	4.98	-4.5%
Coal (high sulfur)	1.95	2.49	2.88	15.8%
No. 6 oil (1%)	9.00	11.60	15.90	37.0%
No. 2 oil	11.78	15.31	21.22	38.6%

(a) The numbers and percentages are rounded and thus show slight variations.

The three-year monthly average fuel-price series is shown in Figure 4-2.

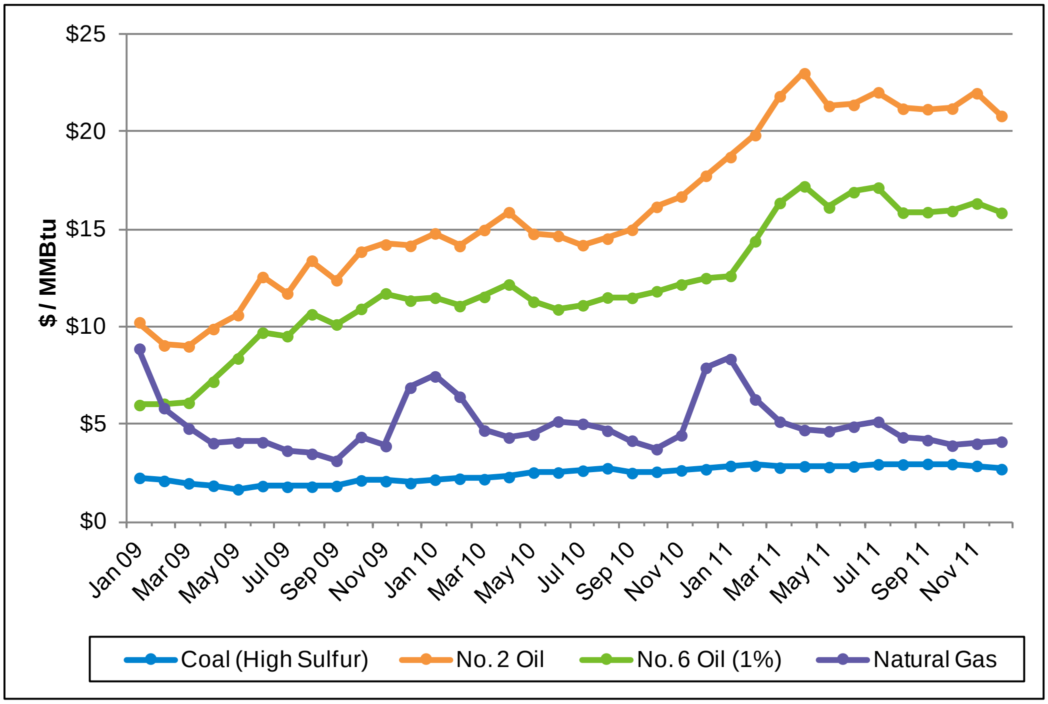

Figure 4-2: Average monthly fuel prices for selected input fuels, 2009 to 2011 ($/MMBtu).

Table 4-4 shows the average and minimum heat rates of generating resources in New England by technology and fuel type.

Table 4-4
Average and Minimum Heat Rates for New England Generators, 2011 (Btu/kWh)

Technology	Fuel Type	Average Heat Rate	Minimum Heat Rate
Combined cycle	Gas	8,000	6,900
	No. 6 oil (1%)	10,100	10,100
Combustion turbine	Diesel	12,100	11,400
	Gas	10,900	8,900
	Jet fuel	13,000	10,400
	No. 2 oil	16,100	15,500
Steam turbine	Coal	9,600	8,700
	Gas	11,000	10,200
	No. 6 oil (1%)	10,400	9,000
	Other	0	0
	Wood	12,700	10,000

Table 4-5 shows annual generation capacity factors by fuel type for 2009 to 2011.

Table 4-5
Yearly Capacity Factors by Fuel Type, 2009 to 2011 (%)

Fuel	2009	2010	2011 (descending sorted)	Change 2011 to 2010
Refuse	85.88%	83.75%	90.30%	6.55%
Refuse/natural gas	76.52%	82.02%	89.23%	7.20%
Nuclear	89.67%	93.98%	84.84%	−9.14%
Wood/propane	97.25%	96.68%	80.61%	−16.07%
Wood/coal	81.09%	80.57%	78.63%	−1.94%
Wood	71.20%	87.47%	68.64%	−18.84%
Hydro	56.67%	51.99%	65.96%	13.97%
Coal	67.10%	88.87%	56.17%	−32.70%
Refuse/wood	77.33%	92.06%	52.17%	−39.90%
Wind	28.54%	61.90%	49.00%	−12.90%
Wood/natural gas	47.67%	58.25%	48.68%	−9.57%
Natural gas	39.65%	45.13%	47.68%	2.55%
Natural gas/oil	20.69%	25.09%	26.08%	0.99%
Coal/oil	37.39%	34.89%	16.32%	−18.57%
Oil/natural gas	2.92%	4.07%	2.15%	−1.91%
Oil	0.70%	0.78%	0.55%	−0.23%

The annual Weighted Equivalent Availability Factors (WEAFs) of New England generating units by class are shown in Table 4-6.

Table 4-6
New England System Weighted Equivalent Availability Factors (%), 2009 to 2011

	2009	2010	2011
System average	87	88	86
Fossil steam	89	88	87
Coal	82	83	76
Coal/oil	84	86	90
Oil	91	90	89
Oil/gas	92	90	93
Wood/refuse	89	91	87
Nuclear	89	94	83
Jet engine	97	95	95
Combustion turbine	94	95	90
Combined cycle	81	86	86
Pre-1999 combined cycle	88	91	91
New installed (1999–2008) combined cycle	79	85	85
Hydro	96	94	93
Pumped storage	96	56	78
Diesel	96	95	95

Table 4-7 shows a three-year comparison of annual generation by fuel type.

Table 4-7
Yearly Generation by Fuel Type, 2009 to 2011 (MW)

Fuel	2009	2010	2011 (descending sorted)	Change 2011 to 2010	% Change
Gas	38,163	42,030	46,378	4,348	11%
Nuclear	36,231	38,364	34,283	4,081	−11%
Oil/gas	12,487	15,541	15,925	384	3%
Coal	14,558	14,131	7,079	7,052	−48%
Total renewables	7,331	7,686	7,263	423	−6%
Hydro: run of river and pondage	8,354	7,227	8,253	1,026	12%
Wood/refuse	4,082	3,770	3,280	490	−12%
Refuse	2,504	2,851	2,671	180	−7%
Hydro: pumped storage	1,419	854	1,149	295	21%
Oil	895	570	282	288	−32%
Wind	261	491	760	269	103%
Landfill gas	256	342	335	7	−3%
Steam	155	167	146	21	−14%
Methane/refuse	44	37	31	6	−14%
Steam/refuse	28	27	29	2	7%
Solar	1	2	10	8	800%
Under 5 MW	–	–	–	–	0%
Total generation (GWh)	119,437	126,403	120,613	5,790	−5%

A three-year comparison of hydroelectric production is presented in Figure 4-3.

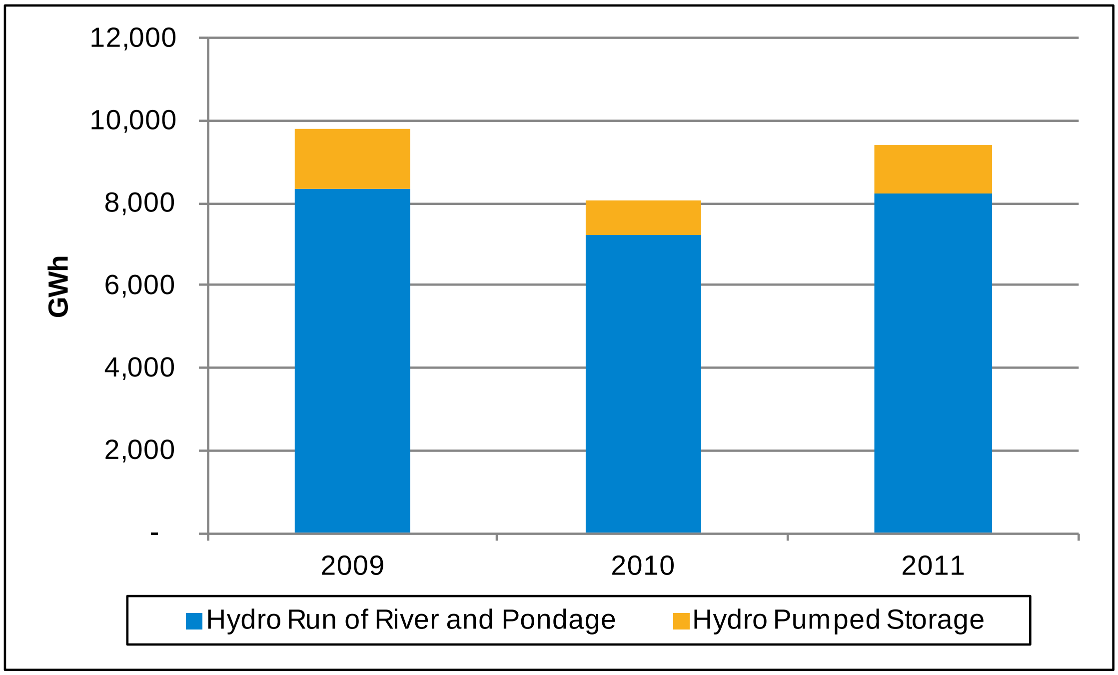

Figure 4-3: Hydroelectric energy production for New England, 2009 to 2011 (GWh).

A comparison of monthly wind production for 2010 and 2011 is shown in Figure 4-4.

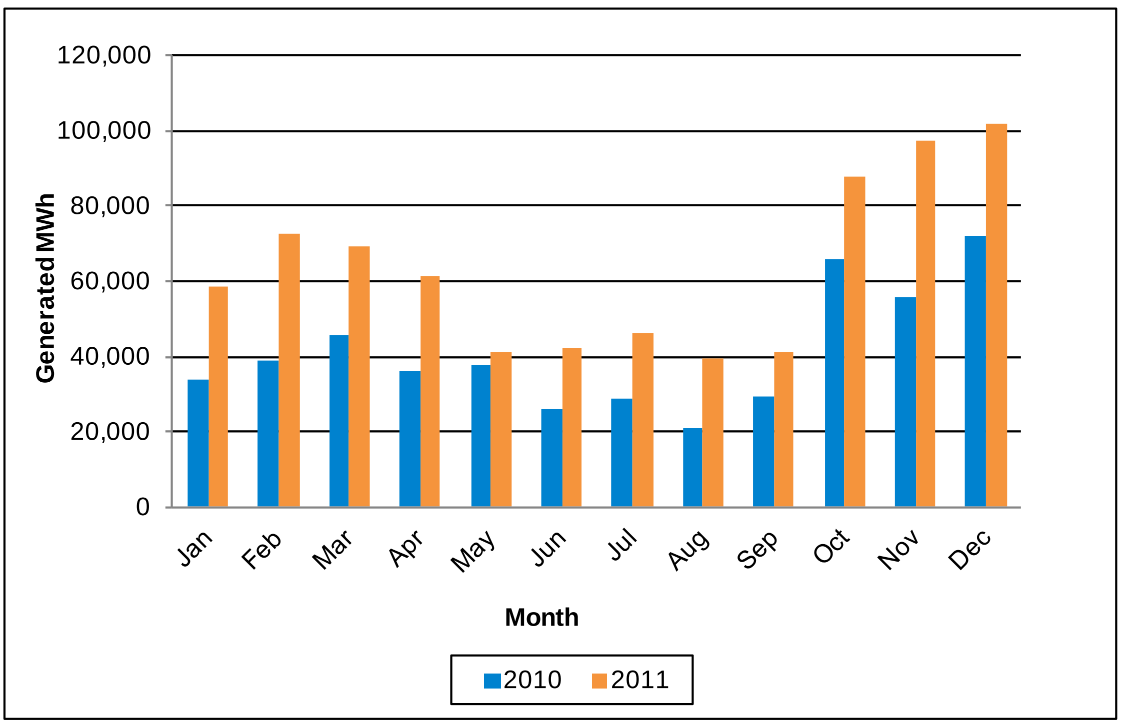

Figure 4-4: Wind generation by month for New England in 2010 and 2011 (MWh).

A three-year summary of real-time self-scheduled generation by resource class is in Figure 4-5.

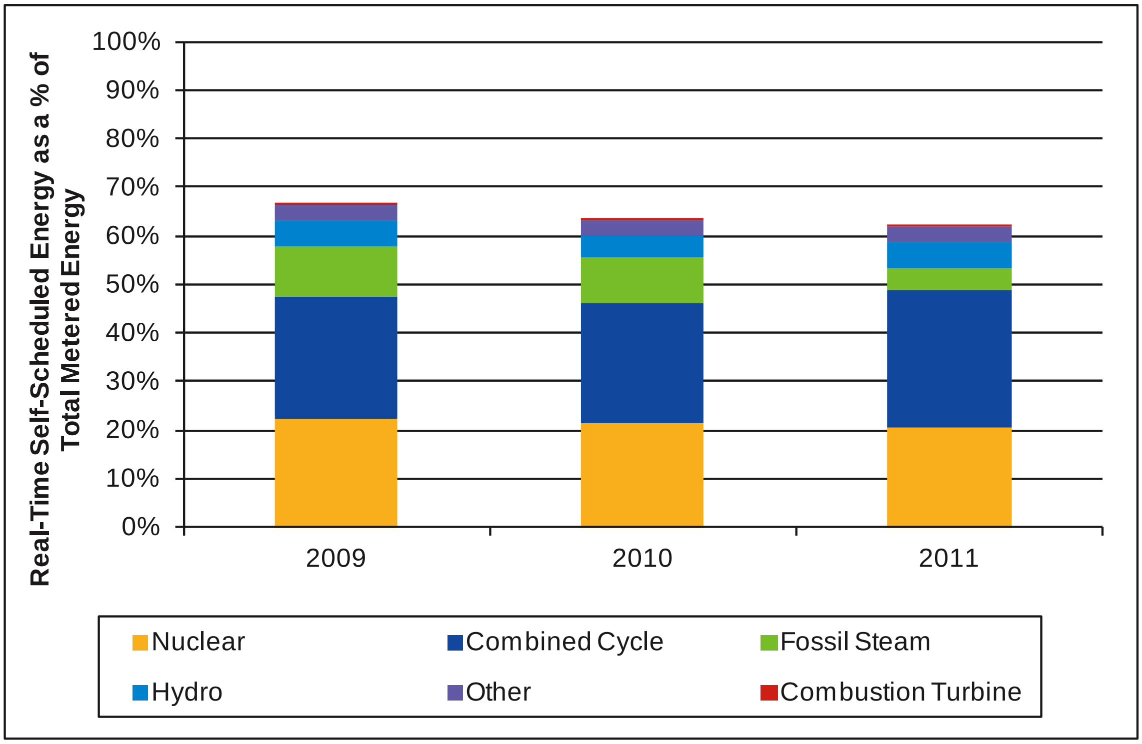

Figure 4-5: Total real-time self-scheduled electric energy as a percentage of total metered energy, 2009 to 2011.

Table 4-8 shows the difference between day-ahead and real-time self-scheduled generation.

Table 4-8
Day-Ahead, Real-Time, and
Real-Time Supplemental Self-Schedules, 2010 to 2011 (GWh)

Year	Month	Day-Ahead Self-Schedule (GWh)	Real-Time Self-Schedule (GWh)	Real-Time Supplemental Self-Schedule (GWh)	Percentage (Day Ahead/ Real Time)
2010	Jan	7,519	8,131	612	92%
	Feb	6,664	7,110	446	94%
	Mar	7,192	7,723	531	93%
	Apr	6,298	6,768	471	93%
	May	5,846	6,356	510	92%
	Jun	7,279	7,821	542	93%
	Jul	7,938	8,410	471	94%
	Aug	7,476	8,035	559	93%
	Sep	6,783	7,208	425	94%
	Oct	7,164	7,700	536	93%
	Nov	6,305	6,865	561	92%
	Dec	7,315	8,159	844	90%
2011	Jan	7,594	8,375	781	91%
	Feb	6,289	7,305	1,016	86%
	Mar	6,575	7,773	1,198	85%
	Apr	4,625	5,968	1,342	78%
	May	5,321	6,195	874	86%
	Jun	6,389	7,391	1,002	86%
	Jul	7,444	8,408	964	89%
	Aug	6,903	7,735	832	89%
	Sep	6,012	6,822	810	88%
	Oct	4,197	4,999	802	84%
	Nov	5,026	5,923	898	85%
	Dec	6,213	7,218	1,004	86%

Table 4-9 shows the net interchange by interface for 2009, 2010, and 2011.

Table 4-9
Net Interchange, by Year, by Interface, 2009 to 2011 (GWh)

External Interface	2009	2010	2011
Hydro Quebec Highgate	1,466	1,419	1,567
Hydro Quebec Phase I/II	9,362	7,794	9,923
New Brunswick	1,564	722	865
NY-NNC (Northport)	−560	−533	−962
NY-AC (Roseton)	−388	−1,558	889
NY-Cross-Sound Cable (Shoreham)	−2,111	−2,405	−2,205

Figure 4-6 shows a summary of 2011 net interchange by interface.

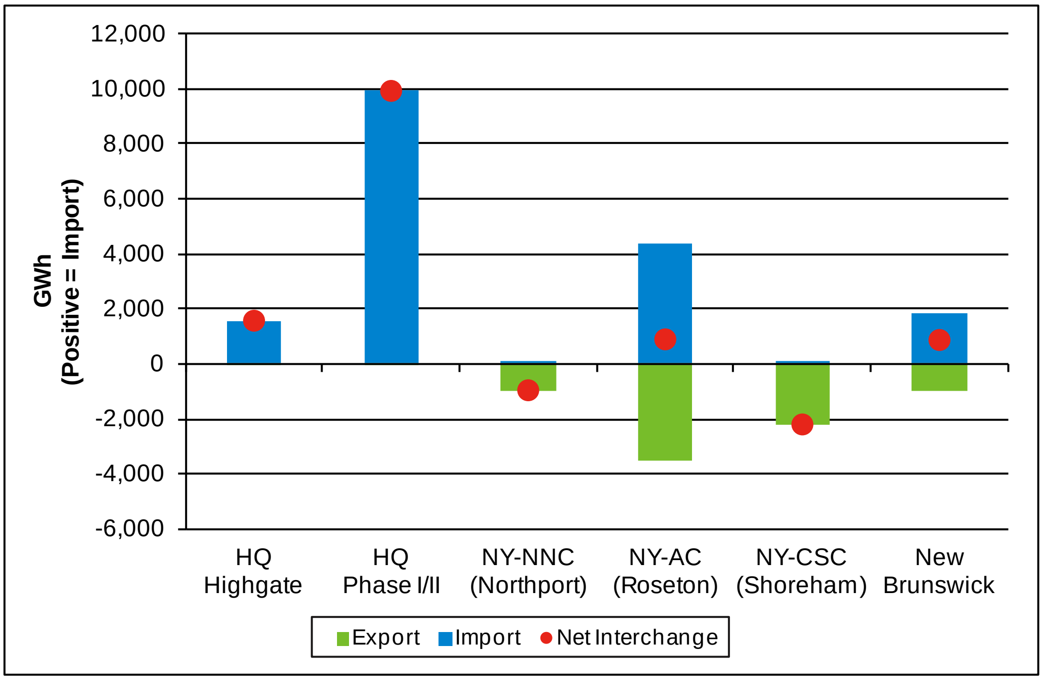

Figure 4-6: Scheduled imports and exports and net external energy flow, by interface, 2011 (GWh).

Average monthly temperatures for 2011 compared with normal monthly temperatures are shown in Figure 4-7.

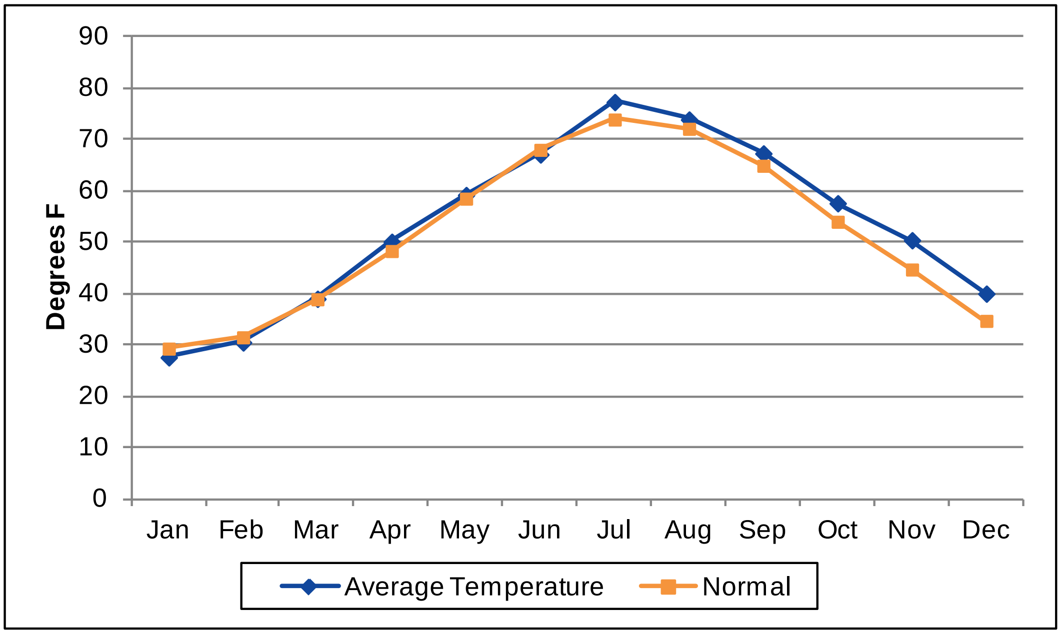

Figure 4-7: Average monthly 2011 temperatures compared with normal temperature values (°F).

Average monthly day-ahead and real-time Hub prices are shown in Figure 4-8.

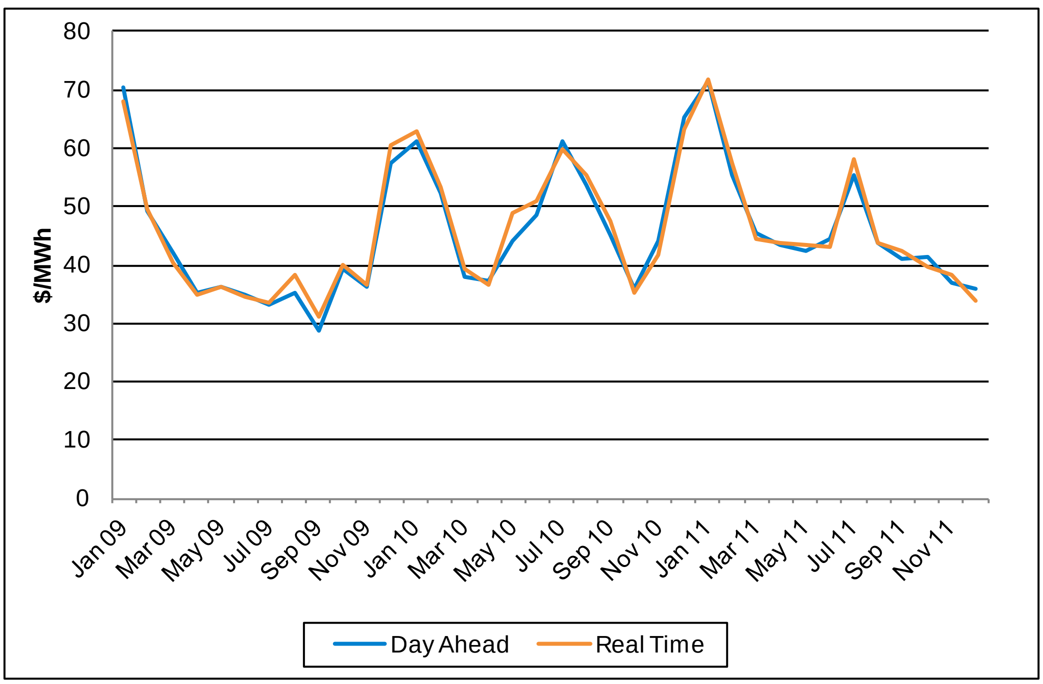

Figure 4-8: Average monthly day-ahead and real-time Hub prices, 2009 to 2011 ($/MWh).

Table 4-10 is a summary of annual demand statistics for 2009 through 2011.

Table 4-10
Annual and Peak Electric Energy Statistics, 2009 to 2011

	2009	2010	2011	% Change 2010 to 2011
Annual NEL (GWh)	126,839	130,771	129,158	−1.2%
Normalized NEL (GWh)	128,268	129,910	128,998	−0.7%
Recorded peak demand (MW)	25,100	27,102	27,707	2.2%
Normalized peak demand (MW)	27,220	27,075	27,240	0.6%

Figure 4-9 shows the long-term New England load-factor trend.

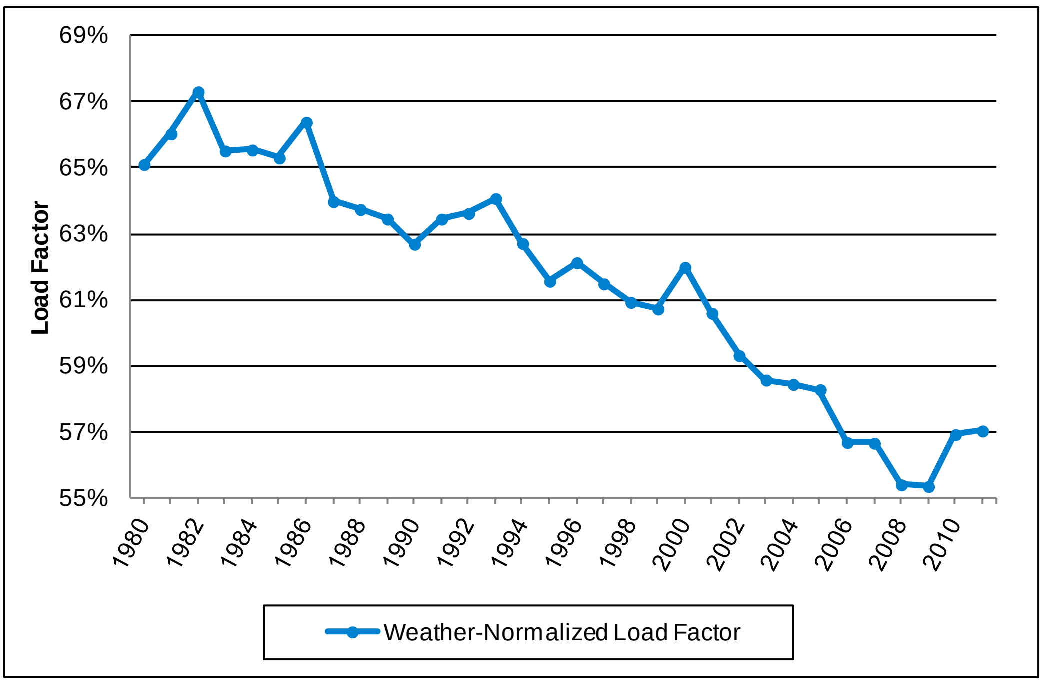

Figure 4-9: New England summer-peak load factors, weather-normalized load, 1980 to 2011.

Table 4-11 is a summary of demand-response performance by load zone for July 22, 2011. Table 4-12 is a summary of demand-response performance by load zone for December 19, 2011.

Table 4-11
Demand-Response Performance by Load Zone (100% Dispatch), July 22, 2011

Load Zone	Net CSO	Event Performance MW at 100% Dispatch	Percentage
Connecticut	147.74	129.10	87%
Maine	180.77	232.10	128%
NEMA	45.99	59.33	129%
New Hampshire	36.02	34.91	97%
Rhode Island	50.25	23.27	46%
SEMA	40.97	28.79	70%
Vermont	40.17	44.20	110%
WCMA	100.49	96.12	96%
New England	**642**	**648**	**101%**

Table 4-12
Demand-Response Performance by Load Zone (100% Dispatch), December 19, 2011

Load Zone	Net CSO (MW)	Event Performance MW at 100% Dispatch	Percentage
Connecticut	102.4	63.7	62%
Maine	182.9	135.5	74%
NEMA	24.4	24.9	102%
New Hampshire	43.0	20.7	48%
Rhode Island	28.2	29.9	106%
SEMA	18.9	16.8	89%
Vermont	40.5	48.1	119%
WCMA	63.6	46.4	73%
New England	**503.9**	**386.0**	**77%**

Figure 4-10 shows the annual all-in wholesale electricity cost for 2011.

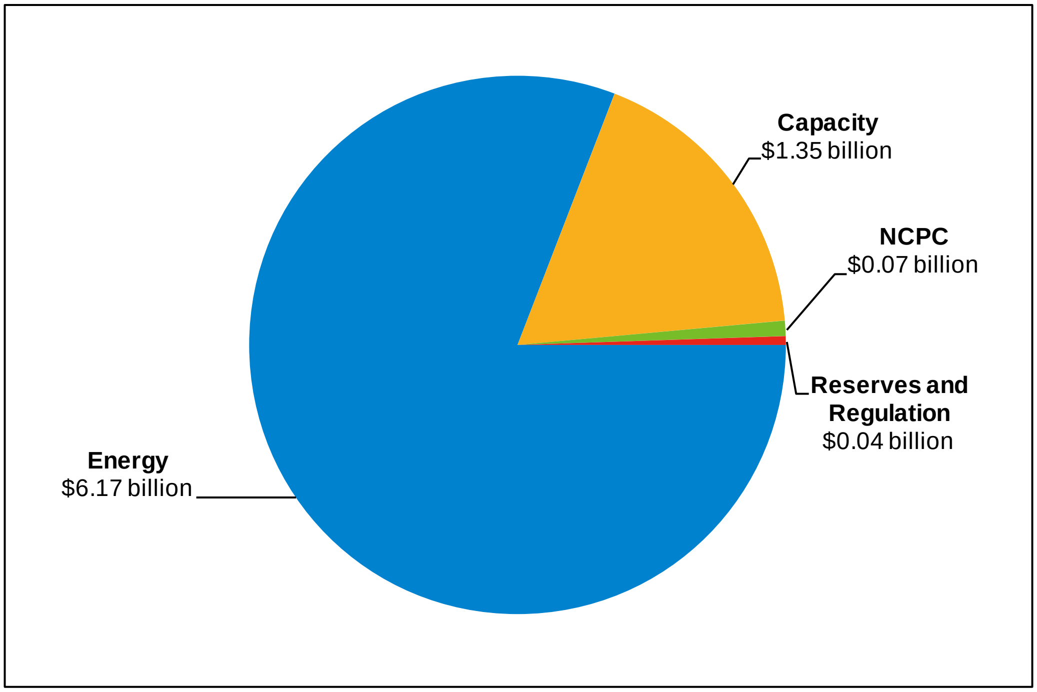

Figure 4-10: All-in cost, 2011 ($).

Figure 4-11 shows the average annual all-in wholesale electricity cost ($/MWh) and natural gas prices for 2009 through 2011.

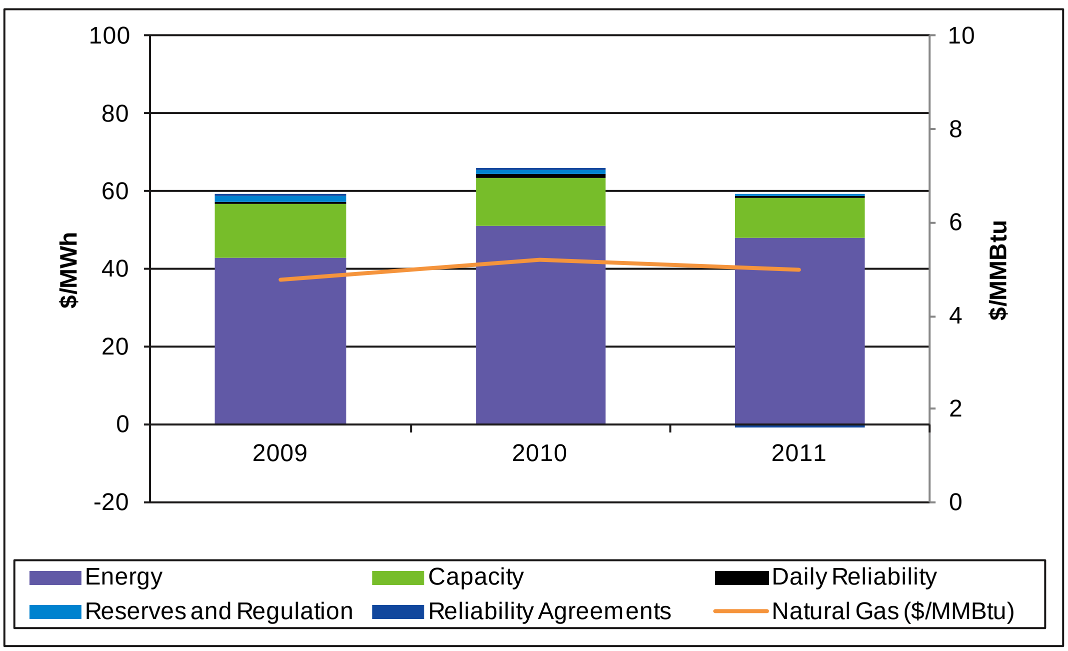

Figure 4-11: All-in cost, 2009 to 2011 ($/MWh).

Notes: The daily reliability and Reliability Agreement costs are allocated systemwide to enable a systemwide rate to be calculated. These costs actually are allocated to the load zone in which they occur. MMBtu stands for *millions of British thermal units*, a measure of the amount of heat energy in natural gas.

Source: Natural gas price information provided by the Intercontinental Exchange, Inc. (ICE), http://www.theice.com.

4.1.2 Regulation Appendix

Table 4-13 is a summary of 2011 regulation clearing prices by month.

Table 4-13
Monthly Regulation Clearing Price Statistics, 2011 ($)

Month	Minimum	Average	Maximum
Jan	$0.00	$9.15	$93.31
Feb	$4.00	$9.14	$95.00
Mar	$4.68	$7.78	$61.23
Apr	$3.37	$6.17	$13.14
May	$4.68	$6.56	$15.04
Jun	$3.00	$7.00	$15.75
Jul	$3.00	$7.10	$60.00
Aug	$3.91	$6.94	$21.91
Sep	$4.59	$6.66	$21.72
Oct	$4.91	$6.38	$12.41
Nov	$4.26	$6.61	$16.78
Dec	$5.00	$6.58	$17.25

Figure 4-12 shows the NERC CPS 2 compliance requirement and the monthly ISO performance for 2011.

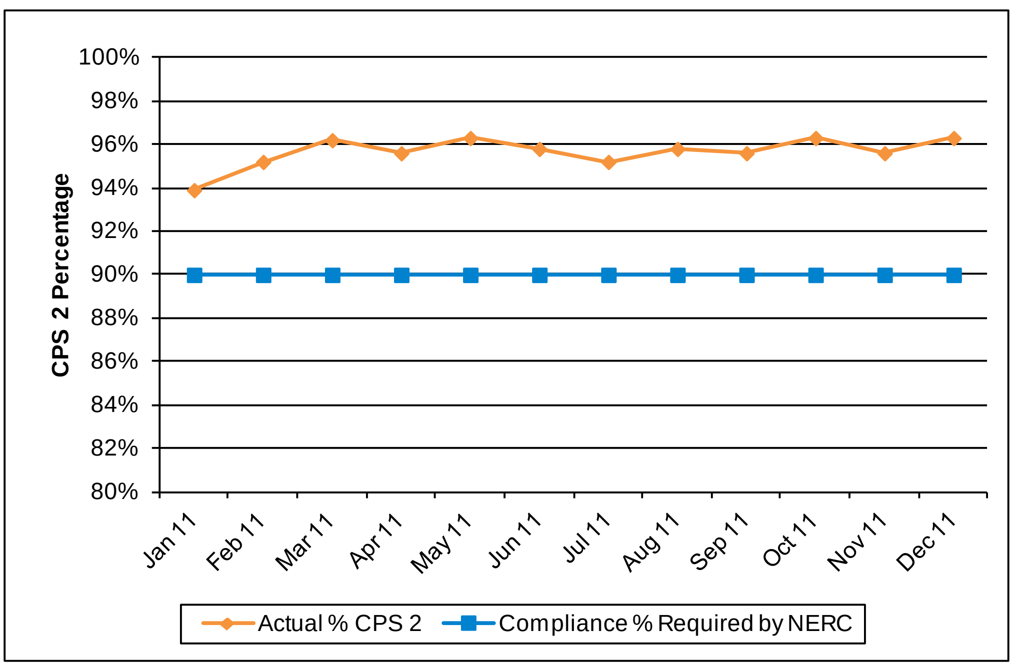

Figure 4-12: CPS 2 compliance, 2011 (%).

Figure 4-13 shows the monthly average regulation requirements for 2009 to 2011.

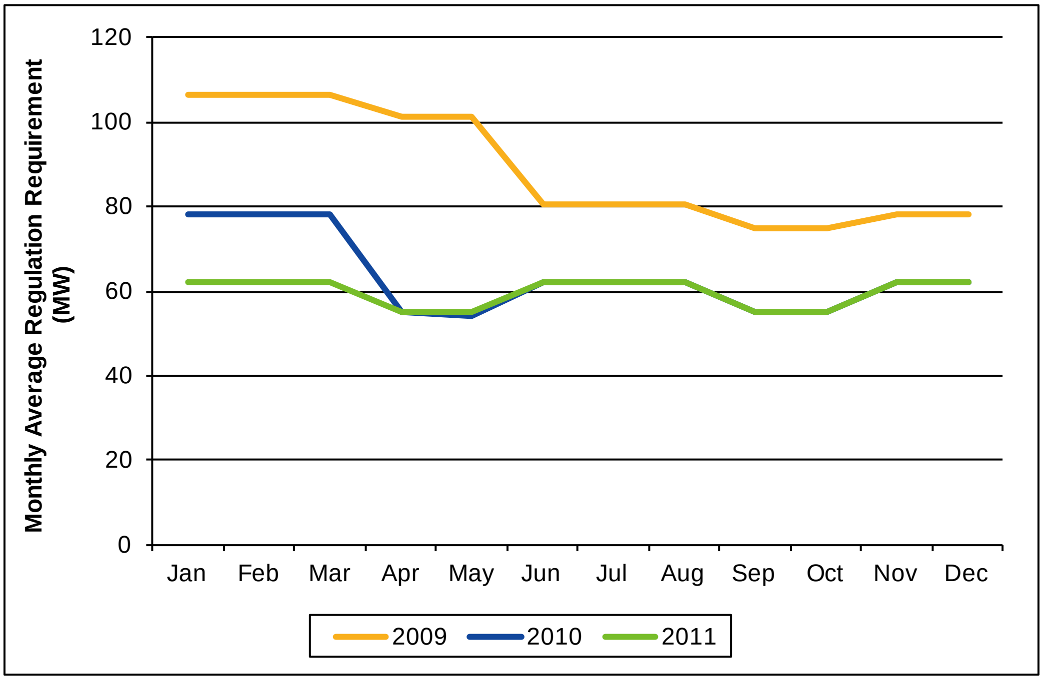

Figure 4-13: Monthly average regulation requirements, 2009 to 2011 (MW).

Figure 4-14 shows the 2010 and 2011 Regulation Market payments by component.

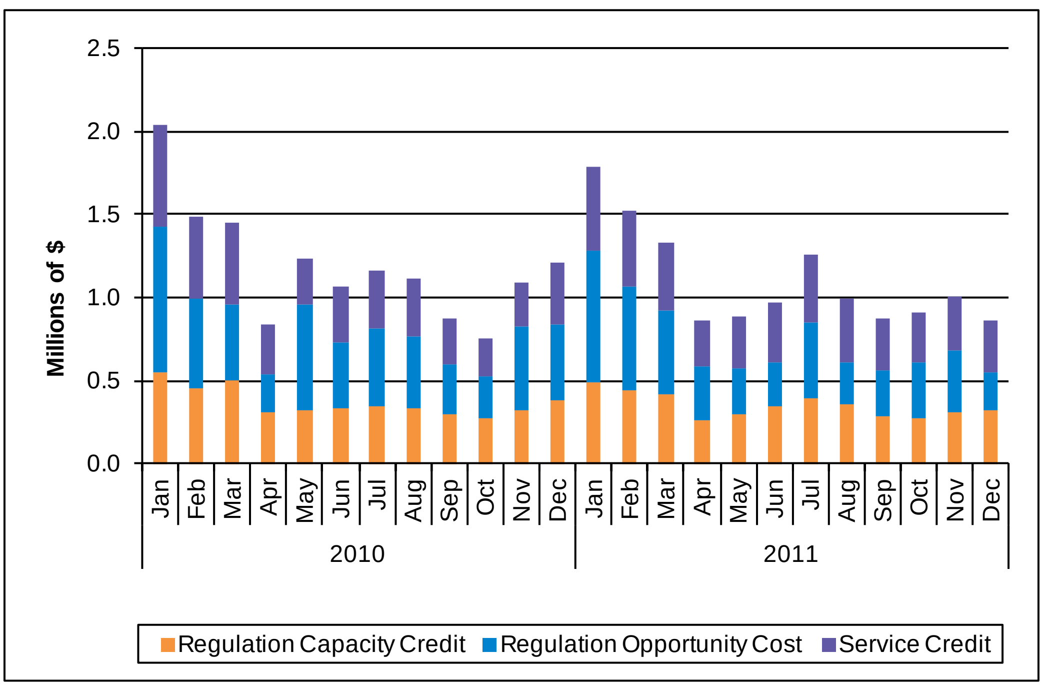

Figure 4-14: Total regulation payments by month, 2010 to 2011 (millions of $).

Figure 4-15 shows the regulation capability by month for 2011.

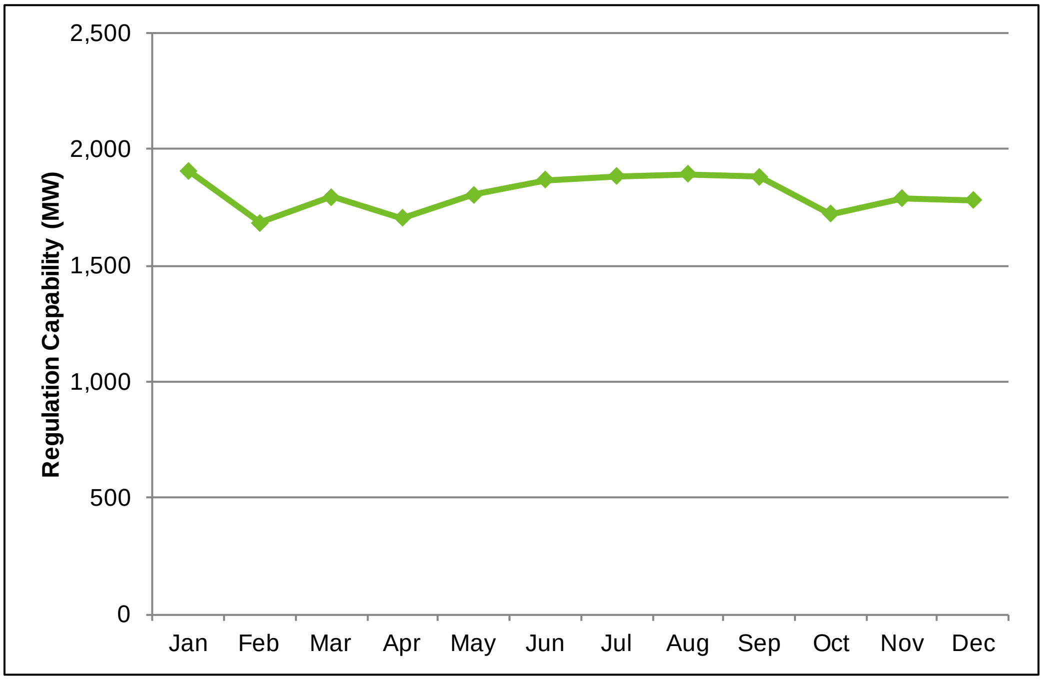

Figure 4-15: Total available regulation capability, 2011 (MW).

Figure 4-16 shows the percentage of regulation capacity and mileage by resource type for 2011.

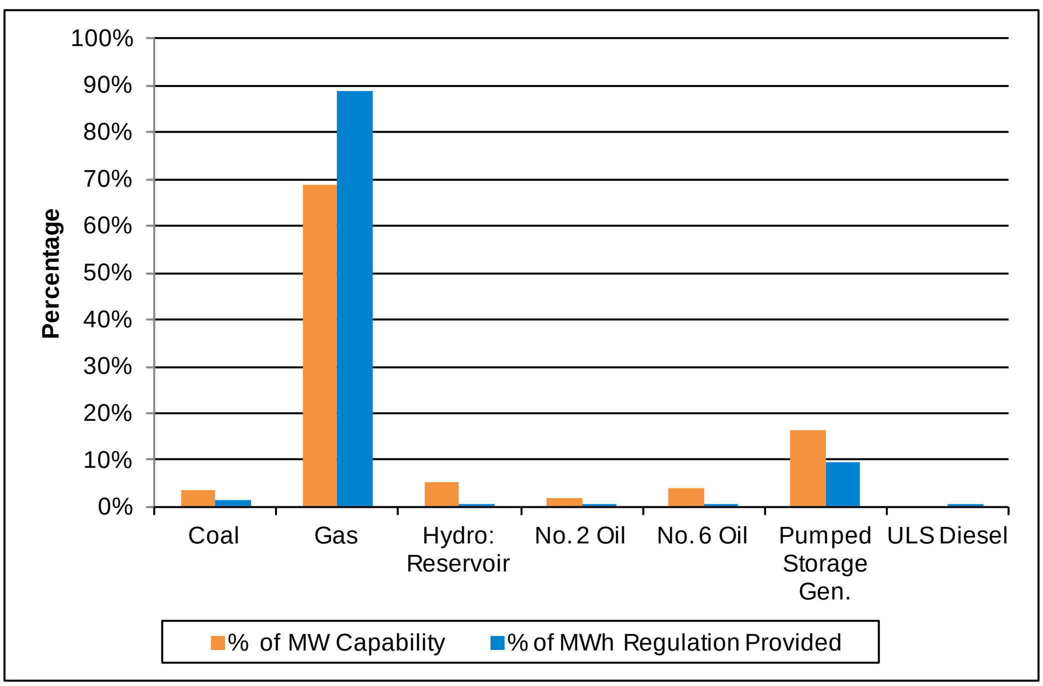

Figure 4-16: Regulation capability and mileage provided by fuel type, 2011.

4.1.3 Reliability and Operations Assessment Appendix

This section includes information on net tariff charges as well as a listing of hours the system was under Minimum Generation Emergency events or Master/Local Control Center Procedure No. 2 (M/LCC2), *Abnormal Conditions Alert*.

Total payments under each ISO schedule are shown in Table 4-14.

Table 4-14
ISO Self-Funding Tariff Charges ($)

Date	Schedule 1: Scheduling, System Control, and Dispatch Service	Schedule 2: Energy Administration Service	Schedule 3: Reliability Administration Service
2011 Total	$30,713,027	$58,737,112	$40,832,080

Total payments under each OATT schedule are shown in Table 4-15.

Table 4-15
OATT Charges ($)

Date	Schedule 1	Schedule 2: CC	Schedule 2: VAR	Schedule 8: TOUT	Schedule 9: RNS	Schedule 16: Black Start	Schedule 19: SCR
2011 Total	$33,918,040	$23,767,023	$5,942,855	$7,454,790	$1,296,492,754	$10,058,434	$3,358,238

Table 4-16 lists the days when M/LCC2 or OP 4 was declared in 2011.

Table 4-16
M/LCC2 and OP 4 Events, 2011

Date	Event	Area Affected
Jan 23	M/LCC2	For all dates, all of New England was affected for capacity.
Apr 22	M/LCC2 / OP 4	
Apr 28	M/LCC2	
Jun 1	M/LCC2	
Jul 11	M/LCC2	
Jul 21	M/LCC2	
Jul 22	MLCC2 / OP4	
Aug 26	M/LCC2	
Sep 14	M/LCC2	
Oct 6	M/LCC2	
Oct 28	M/LCC2	
Dec 19	M/LCC2	
Dec 19	OP4	

Table 4-17 shows the days and times when Minimum Generation Emergencies were declared.

Table 4-17
Minimum Generation Emergency Events, 2011

Date	Hours Declared
Jan 2	4:00 a.m.–7:15 a.m.
Jan 3	3:00 a.m.–5:30 a.m.
May 24	4:00 a.m.–5:00 a.m.
Jun 3	3:00 a.m.–5:00 a.m.
Jun 13	2:00 a.m.–6:00 a.m.
Jun 15	1:00 a.m.–4:00 a.m.
Jun 25	3:00 a.m.–5:00 a.m.
Jul 4	3:00 a.m.–5:00 a.m.
Jul 16	6:00 a.m.–7:15 a.m.
Aug 16	2:00 a.m.–6:00 a.m.
Aug 28	12:15 p.m.–8:30 p.m.
Aug 28	11:00 p.m.–midnight
Aug 29	Midnight–9:00 a.m.
Aug 30	2:30 a.m.–6:00 a.m.
Sep 20	2:00 a.m.–5:00 a.m.
Oct 30	2:00 a.m.–6:30 a.m.
Oct 30	4:00 p.m.–6:00 p.m.
Dec 20	2:00 a.m.–5:00 a.m.
Dec 28	2:00 a.m.–5:30 a.m.
Dec 31	5:00 a.m.–8:00 a.m.

4.1.3.1 IMM Mitigation and Investigation Activities

Four Day-Ahead Energy Market mitigation events and four Real-Time Energy Market mitigation events occurred 2011. There were 17 instances of day-ahead NCPC mitigation, and 23 events in which daily real-time NCPC payments paid to participants were mitigated retroactively. One participant had its FTR revenues, associated with three paths, reduced by a total of $1,295.21, pursuant to the FTR revenue-capping provisions of *Market Rule 1*.[89]

Investigations and Referrals to FERC. Before 2011, the IMM had six open referrals before FERC. In 2011, the IMM made three additional nonpublic referrals, and FERC closed five, bringing the year-end total of open referrals made by the IMM before FERC to four. Of the five referrals FERC closed in 2011, it closed three with no action. It imposed penalties to the participant in one case. In another case, the participant had forgone payment as part of ISO's data-reconciliation process. If the ISO had not withheld this payment, FERC likely would have assessed a civil penalty.

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

4.1.3.2 Major Market Transactions—Generation

- In January 2011, Constellation Energy announced a $1.1 billion agreement to buy the 2,950 MW Boston Generating fleet in New England. Under the agreement, Constellation Energy acquired Boston Generating's five power plants in the Boston area: four natural-gas-fired plants, including Mystic units #8 and #9 (1,580 MW), Fore River (787 MW), and Mystic unit #7 (574 MW), as well as a fuel oil plant, Mystic Jet (9 MW). These facilities supply nearly half the electricity demand for the Boston metropolitan area. Before this acquisition, Constellation Energy had no generation assets in the Boston area.

- In April 2011, Exelon Corporation and Constellation Energy announced an agreement to combine the two companies in a stock-for-stock transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Exelon's power marketing business (Power Team) and Constellation's retail and wholesale business will be consolidated under the Constellation brand and be headquartered in Baltimore. Both companies' renewable energy businesses also will be headquartered in Baltimore.

- In December 2011, Entergy Corporation announced it had completed the purchase of the Rhode Island State Energy Center (RISEC), an approximately 583 MW natural-gas-fired combined-cycle generating plant located in Johnston, Rhode Island, from subsidiaries of NextEra Energy Inc. for approximately $346 million.

- In March 2011, Capital Power Corporation announced an agreement to acquire Bridgeport Energy, LLC, which owns the Bridgeport Energy facility, from affiliates of LS Power Equity Advisors, LLC for $355 million. Bridgeport Energy is a 520 MW natural-gas-fired combined-cycle power generation plant located in Bridgeport, Connecticut.

- In February 2011, Capital Power Corporation announced an agreement to acquire two generating facilities from Brick Power Holdings LLC (Brick Power), one facility located in Tiverton, Rhode Island (Tiverton) and one in Rumford, Maine (Rumford). Both plants are natural-gas-fired combined-cycle power generation facilities and have a maximum combined capacity of 549 MW.

4.1.3.3 Major Market Transactions—Transmission and Distribution

- In July 2011, Central Vermont Public Service Corporation (CVPS) and Gaz Métro Limited Partnership (Gaz Métro) announced an agreement for the sale of CVPS that would result in the combination of CVPS and Green Mountain Power Corporation (GMP). CVPS is the largest electric power utility in Vermont, serving nearly 160,000 customers in 163 cities and towns. Green Mountain Power generates, transmits, distributes, and sells electricity in Vermont and serves more than 96,000 customers.

4.1.3.4 Administrative Price Corrections

Table 4-18 shows the ISO's administrative price corrections for 2011.

Table 4-18
Administrative Price Corrections, 2011

Location/Load Zone	Congestion Component
Data error	25
Hardware/software outage, scheduled	5
Hardware/software outage, unscheduled	0
Software limitation	1
Software error	0
Dead-bus logic	58

4.2 Forward Markets

4.2.1 Congestion and FTR

4.2.1.1 Congestion and Congestion Revenues

Figure 4-17 is a summary of monthly day-ahead and real-time congestion revenues in 2011.

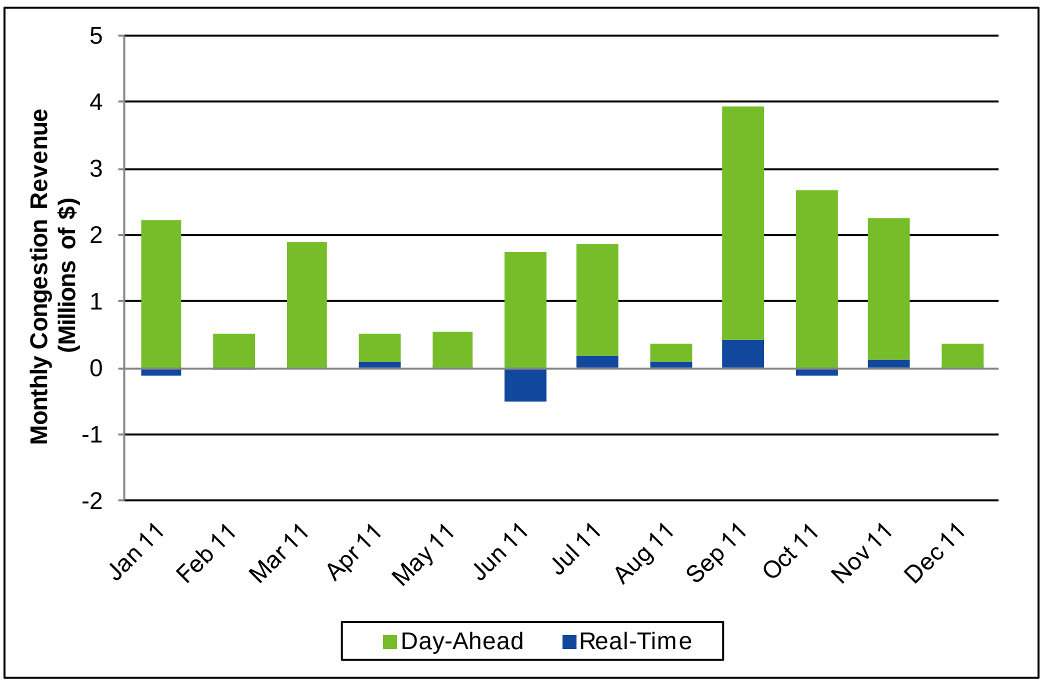

Figure 4-17: Day-ahead and real-time congestion revenue by month, 2011 (millions of $).

Table 4-19 and Table 4-20 show the annual average marginal congestion component and marginal loss component for the Hub and eight load zones in 2011.

Table 4-19
Average Day-Ahead Marginal Congestion Component, Marginal Loss Component, and Combined, 2011 ($/MWh)

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−$0.19	$0.02	−$0.17
Maine	$0.31	−$1.28	−$0.97
New Hampshire	−$0.21	−$0.40	−$0.61
Vermont	−$0.17	$0.28	$0.12
Connecticut	$0.23	$0.69	$0.92
Rhode Island	−$0.23	−$0.55	−$0.78
SEMA	−$0.22	−$40.14	−$0.37
WCMA	−$0.02	$0.39	$0.37
NEMA	−$0.15	−$0.27	−$0.41

Table 4-20
Average Real-Time Marginal Congestion Component, Marginal Loss Component, and Combined, 2011 ($/MWh)

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−$0.17	$0.06	−$0.11
Maine	−$0.43	−$1.41	−$1.84
New Hampshire	−$0.27	−$0.45	−$0.72
Vermont	−$0.24	$0.02	−$0.22
Connecticut	$0.40	$0.76	$1.16
Rhode Island	−$0.17	−$0.48	−$0.65
SEMA	−$0.17	−$0.04	−$0.20
WCMA	$0.12	$0.32	$0.44
NEMA	−$0.08	−$0.14	−$0.22

4.2.1.2 FTR Auction Revenue Distribution

Table 4-21 is a summary of Auction Revenue Rights distributions for 2009 to 2011.

Table 4-21
Total Auction Revenue Distribution, 2009 to 2011 ($)

	2009	2010	2011
Qualified Upgrade Awards	2,940,675	3,074,310	2,203,086
Excepted transactions[a]	532	2,160	929
NEMA contract holders	154,826	130,563	92,900
ARR holders	67,957,265	26,950,479	21,183,093
Total auction revenue	71,053,298	30,157,511	23,480,009

(a) *Excepted transactions* are certain power transfers and other uses of the pool transmission facilities effected under transmission agreements in effect on November 1, 1996, as specified in the ISO's *Open Access Transmission Tariff*, Section II.40, and for the time periods described therein. These transactions are included in the OATT, Attachments G, G-1 and G-3; http://www.iso-ne.com/regulatory/tariff/index.html.

Figure 4-17 shows the ARR distributions by zone for 2011.

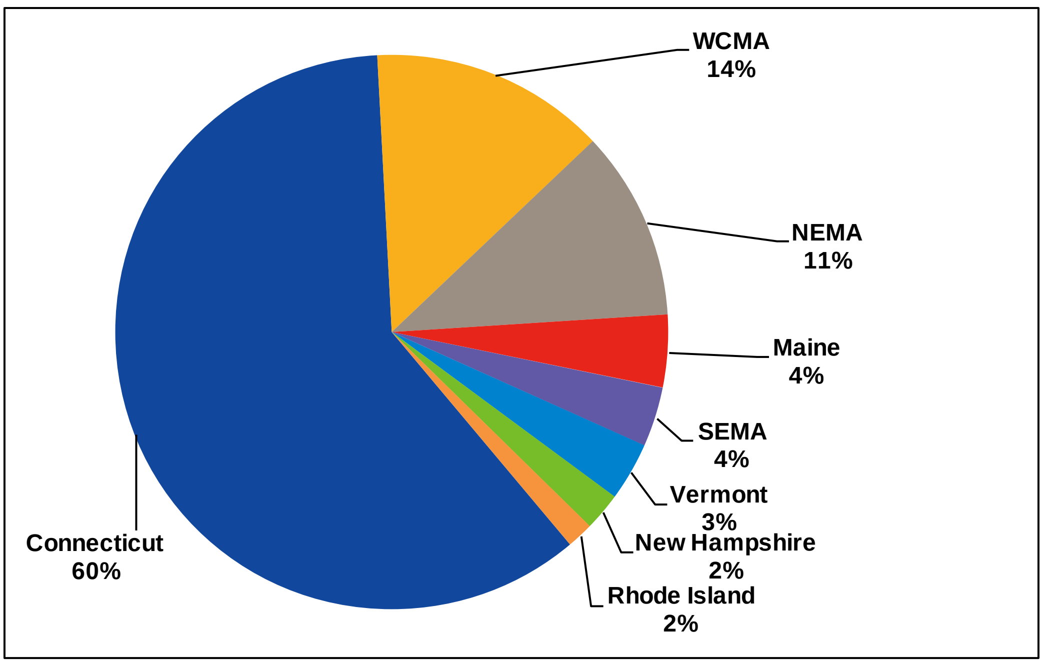

Figure 4-18: Load-share ARR distribution by load zone, 2011.

Table 4-22 shows data for the Congestion Revenue Balancing Fund for 2011.

Table 4-22
Congestion Revenue Balancing Fund, 2011 ($, %)

Month	Fund Adj.	Day-Ahead Congestion Revenue	Real-Time Congestion Revenue	Negative Target Allocation (paid in by participants)	Positive Target Allocation (paid out to participants)	Monthly Fund Surplus or Shortfall	Amount Paid Out to Positive Target Allocations	Interest	FTR Capping	Ending Balance	Cumulative Balance for Year End	Percent Positive Allocation Paid
Jan	399	2,238,987	−124,201	860,634	−2,758,495	217,323	−2,758,495	552	2,298	220,174	220,174	100.00%
Feb	148	509,079	−745	205,424	-454,838	259,067	−454,838	180	0	259,247	479,421	100.00%
Mar	−49	1,871,785	15,133	801,926	−3,100,855	−412,081	−2,688,775	79	0	79	479,500	86.71%
Apr	1,108	446,938	88,058	142,235	-541,245	137,093	−541,245	198	0	137,291	616,791	100.00%
May	7,582	534,955	13,227	363,325	−982,147	−63,058	−919,089	105	35	140	616,930	93.58%
Jun	111	1,761,332	−496,060	576,367	−2,514,366	−671,973	−1,842,393	101	0	101	617,032	73.27%
Jul	−26	1,681,964	182,371	306,504	−1,845,441	325,373	−1,845,441	266	0	325,639	942,671	100.00%
Aug	407	259,647	100,848	116,039	-320,796	155,332	−320,796	255	0	155,588	1,098,258	100.00%
Sep	925	3,502,063	437,958	503,273	−3,958,271	486,567	−3,958,271	186	0	486,753	1,585,011	100.00%
Oct	−1,070	2,673,708	−113,983	1,373,809	−4,051,191	−118,727	−3,932,464	202	0	202	1,585,213	97.07%
Nov	1,125	2,119,695	136,848	884,735	−3,012,120	128,032	−3,012,120	249	0	128,281	1,713,494	100.00%
Dec	388	356,883	1,236	99,424	−526,476	−68,545	-−457,931	329	0	329	1,713,823	86.98%

4.2.2 Demand Response

4.2.2.1 Demand-Response Assets

Table 4-23 shows demand-response asset megawatts by demand-resource type and load zone as of January 1, 2012.

Table 4-23
Demand-Response Asset Enrolled Megawatts by Demand-Resource Type and Load Zone
(as of January 1, 2012)

Zone	Real-Time Demand-Response Resource	Real-Time Emergency Generation Resource	On-Peak Demand Resource	Seasonal-Peak Demand Resource	Total
CT	269	313	99	284	965
ME	395	24	67	–	486
WCMA	172	70	72	28	342
NEMA	94	93	108	–	295
SEMA	74	49	65	3	191
NH	74	42	58	–	174
RI	62	44	47	1	154
VT	87	15	46	–	149
Total	1,227	650	592	316	2,755

4.2.2.2 Real-Time Price-Response Program Interruptions

Table 4-24 shows the number of days and megawatt-hours of interruption for the RTPR in 2011.

Table 4-24
Real-Time Price-Response Interruptions in 2011

Month	# of Days with RTPR Event	MWh Interrupted in Real Time	Payment for RTPR ($)
Jan	17	1,317	$133,759
Feb	9	574	$57,667
Mar	3	140	$14,429
Apr	5	346	$34,616
May	0	0	$0
Jun	2	128	$12,991
Jul	12	1,063	$164,497
Aug	3	224	$28,389
Sep	1	4	$363
Oct	0	0	$0
Nov	2	19	$2,097
Dec	4	47	$4,652
Total	58	3,862	$455,462

4.2.2.3 Day-Ahead Load-Response Program

Table 4-25 shows a summary of assets in the Day-Ahead Load-Response Program for 2011.

Table 4-25
Number of Assets and Maximum Capacity of Enrolled Assets in the Day-Ahead Load-Response Program, 2011 (MW)

Month	Number of Assets	Maximum Capacity of Enrolled Assets (MW)
Jan	928	777
Feb	928	777
Mar	929	778
Apr	918	771
May	888	723
Jun	882	748
Jul	898	759
Aug	898	763
Sep	897	763
Oct	898	763
Nov	873	741
Dec	911	823

Figure 4-19 shows for 2011 a comparison of the monthly DALRP minimum offer prices and the average day-ahead LMP at the Hub for nonholiday weekdays between 7:00 a.m. and 6:00 p.m.

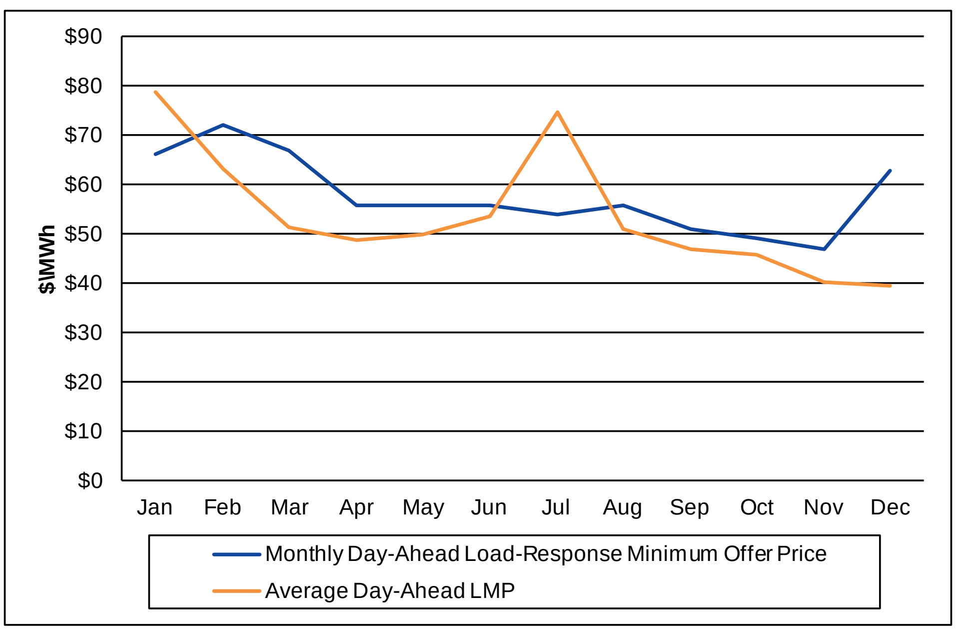

Figure 4-19: DALRP minimum offer price compared with the monthly average day-ahead Hub LMPs, 2011 ($/MWh).

Table 4-26 shows a monthly summary of the average megawatts and DALRP offer prices for 2011.

Table 4-26
DALRP Offers Compared with Minimum Offer Prices (MW and $/MWh), 2011

Month	Average MW per Offer	Average Offer Price ($/MWh)	Minimum Offer Price Threshold ($/MWh)
Jan	0.101	$66.00	$66.00
Feb	0.102	$72.00	$72.00
Mar	0.101	$67.00	$67.00
Apr	0.100	$68.41	$56.00
May	0.100	$56.00	$56.00
Jun	0.101	$56.00	$56.00
Jul	0.101	$54.04	$54.00
Aug	0.101	$56.00	$56.00
Sep	0.106	$51.02	$51.00
Oct	0.103	$49.02	$49.00
Nov	0.353	$47.85	$47.00
Dec	0.115	$63.00	$63.00

Table 4-27 shows the number of days in each month when the DALRP assets had cleared offers, along with the megawatt quantities and payments for 2011. Table 4-28 shows average daily offer volumes.

Table 4-27
DALRP Cleared Offers and Payments, 2011 (MWh and $)

Month	# of Days with DALRP MWh Cleared	Day-Ahead Cleared MWh	MWh Interrupted in Real Time	Total Payment
Jan	21	11,510	17,994	$1,720,311
Feb	15	6,122	10,053	$871,992
Mar	10	1,965	1,688	$132,807
Apr	12	3,874	1,544	$91,830
May	8	2,982	1,414	$83,368
Jun	17	4,702	2,950	$212,203
Jul	19	12,059	14,379	$1,814,145
Aug	15	6,781	6,592	$413,676
Sep	14	6,073	5,399	$292,987
Oct	17	7,253	10,681	$551,256
Nov	20	317	1,054	$59,600
Dec	10	799	800	$52,780
Total	178	64,439	74,550	$6,296,955

Table 4-28
Average Hourly DALRP Offers, 2011 (MW and $/MWh)

Month	Hourly Offers (MW)	Enrolled Capacity (MW)	Minimum Offer Price ($/MWh)	Average Offer Price ($/MWh)
Jan	81.07	777	$66.00	$66.00
Feb	93.61	777	$72.00	$72.00
Mar	92.61	778	$67.00	$67.00
Apr	91.19	771	$56.00	$68.41
May	64.08	723	$56.00	$56.00
Jun	88.46	748	$56.00	$56.00
Jul	88.74	759	$54.00	$54.04
Aug	88.80	763	$56.00	$56.00
Sep	92.94	763	$51.00	$51.02
Oct	90.23	763	$49.00	$49.02
Nov	14.01	741	$47.00	$47.85
Dec	100.58	823	$63.00	$63.00

4.2.3 Forward Capacity Market

4.2.3.1 FCA Supply Curves

Figure 4-20 through Figure 4-24 show the FCA supply curves for the five auctions.

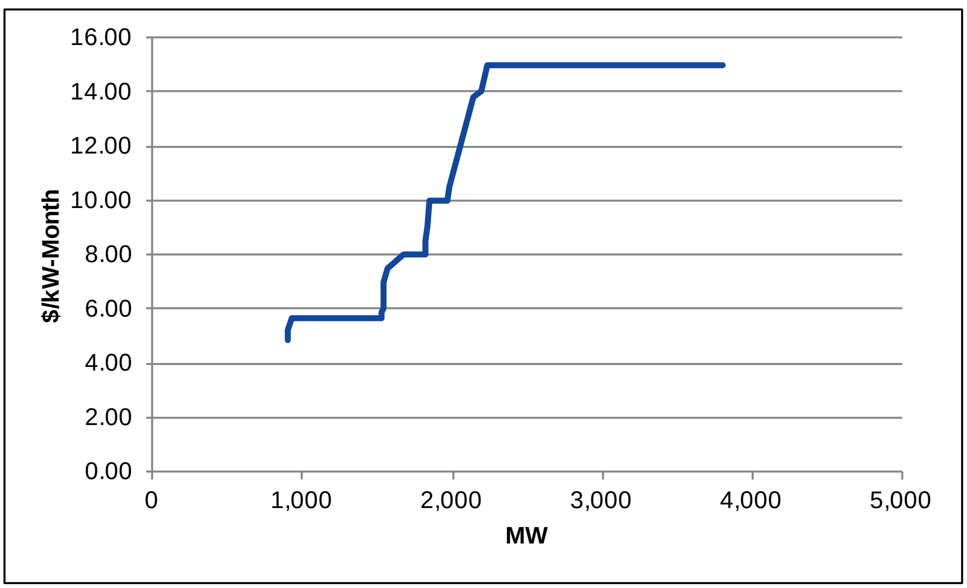

Figure 4-20: Supply curve, FCA #1.

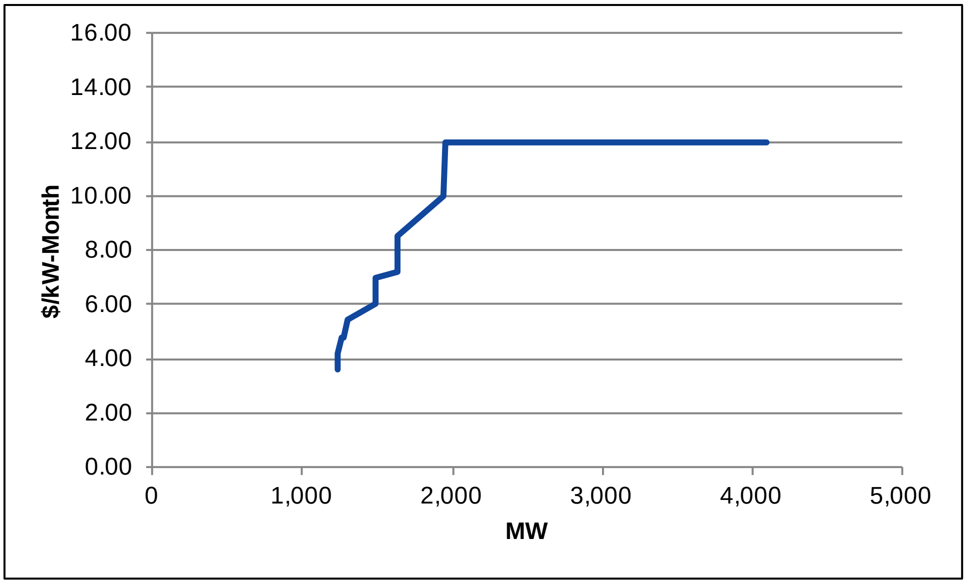

Figure 4-21: Supply curve, FCA #2.

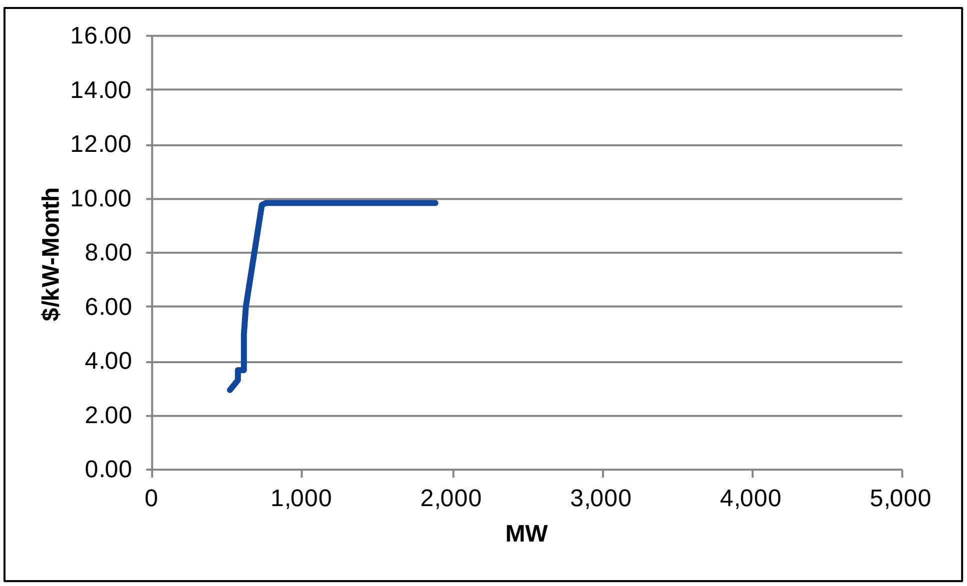

Figure 4-22: Supply curve, FCA #3.

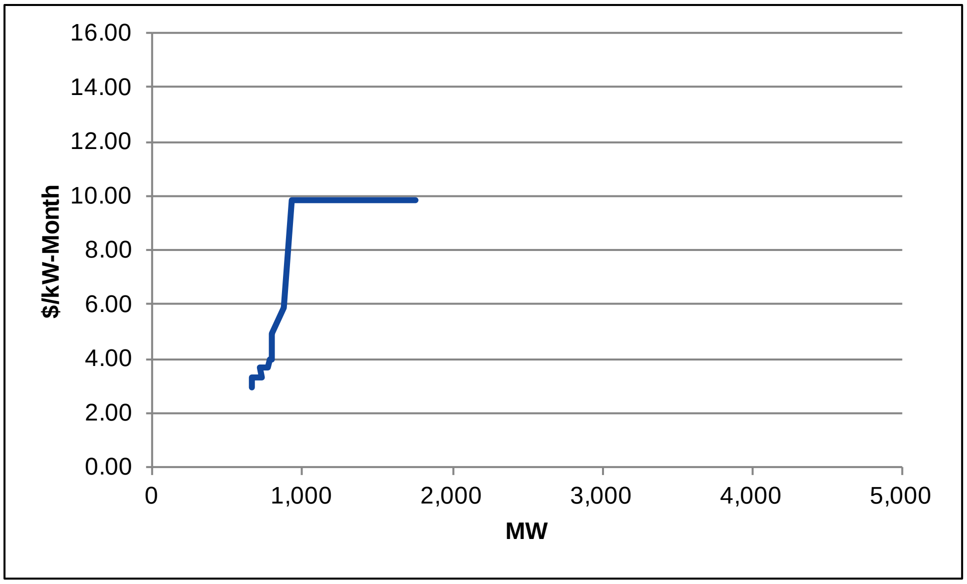

Figure 4-23: Supply curve, FCA #4.

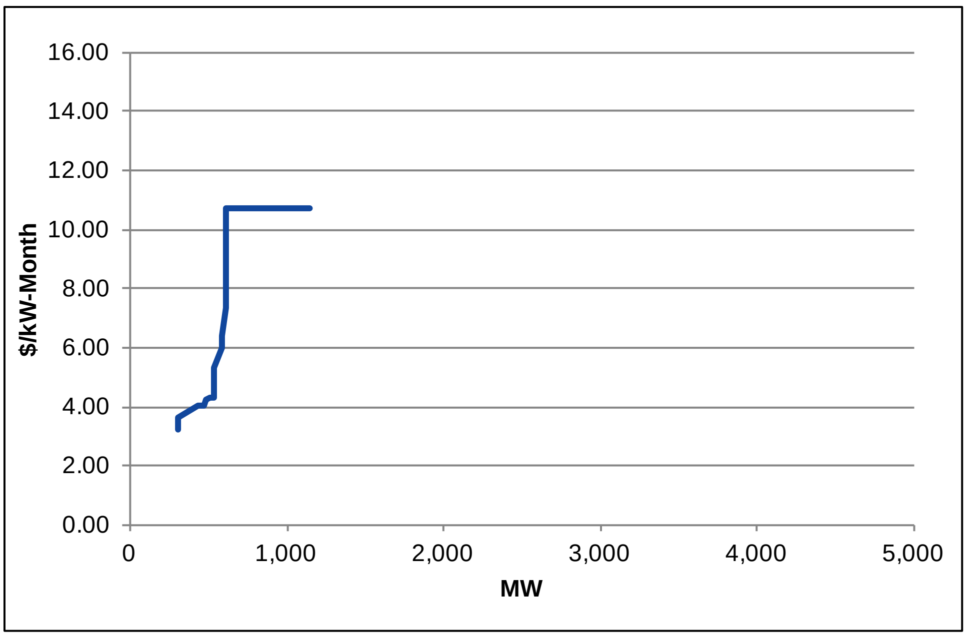

Figure 4-24: Supply curve, FCA #5.

4.2.3.2 Reconfiguration Auction Results and Bilateral Transactions

Table 4-29 shows annual bilateral transaction quantities.

Table 4-29
Annual Bilateral Transaction Quantities

Commitment Period	Auction	Total Traded CSOs (MW)
2010/2011	ARA #2 bilateral period 1	960
2011/2012	ARA #2 bilateral period 1	1,152
	ARA #2 bilateral period 2	3
	ARA #3 bilateral period 3	665
2012/2013	ARA #2 bilateral period 1	252
	ARA #2 bilateral period 2	253

Table 4-30 shows monthly bilateral transactions for 2011.

Table 4-30
Monthly Bilateral Transactions: Traded Quantity

Commitment Period	Average of Monthly Cleared Quantity (MW)
2010/2011	168
2011/2012	517

4.2.3.3 Price Convergence across Auctions

Figure 4-25 shows the trend in CSO prices for the same commitment period from the FCA to the monthly reconfiguration auctions.

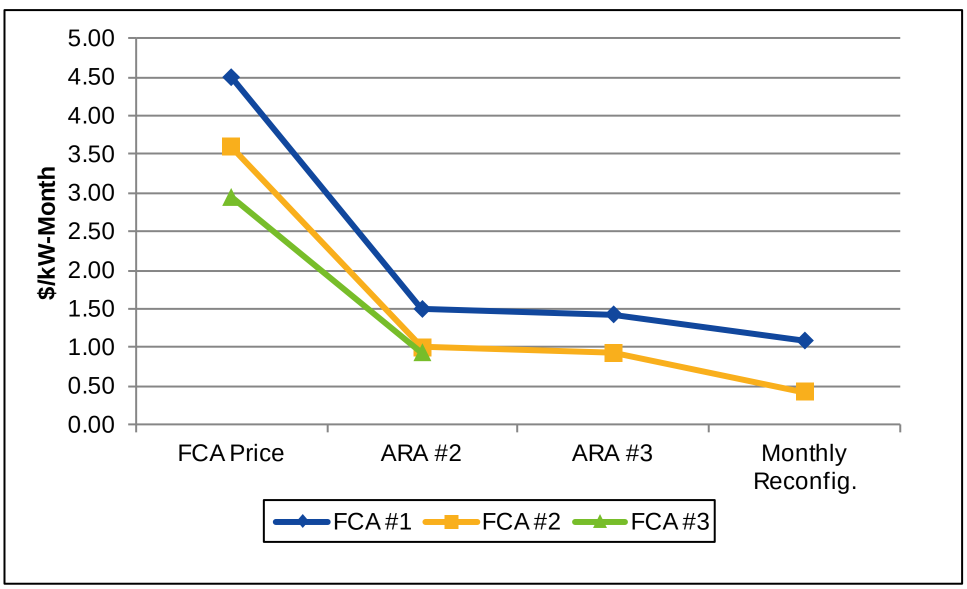

Figure 4-25: CSO prices from the FCA to the monthly reconfiguration auctions.

List of Acronyms and Abbreviations

Acronyms and Abbreviations	Description
AC	alternating current
ACE	area control error
AMR	Annual Markets Report
AMR10	*2010 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
C8	eight-largest competitors
CCGT	combined-cycle gas turbine
CONE	cost of new entry
CPS 2	NERC *Control Performance Standard 2*
CSC	Cross-Sound Cable
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CTS	Coordinated Transaction Scheduling
CVPS	Central Vermont Public Service Corporation
DALRP	Day-Ahead Load Response Program
DOE	US Department of Energy
DOJ	US Department of Justice
EMM	External Market Monitor
ERCOT	Electric Reliability Council of Texas
ERO	electric reliability organization
ERS	external reserve support
F	Fahrenheit
FCA	Forward Capacity Auction

Acronyms and Abbreviations	Description
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
FTR	Financial Transmission Right
GMP	Green Mountain Power
GT	gas turbine
GWh	gigawatt-hour
HE	hour ending
HHI	Herfindahl-Hirschman Index
Highgate	Vermont–Hydro Quebec Interconnection
HQICC	Hydro-Québec Phase I/II Interface
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
IMM	Internal Market Monitor
ISO	Independent System Operator, ISO New England
kW	kilowatt
kWh	kilowatt-hour
kW-mo	kilowatt-month
L_{10}	Limit 10
LMP	locational marginal price
LSCPR	local second-contingency protection resource
LSE	load-serving entity
LSR	local sourcing requirement
L_t	Symbol for the competitiveness level of the LMP
ME	State of Maine and Maine load zone
M/LCC2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour

Acronyms and Abbreviations	Description
NCPC	Net Commitment-Period Compensation
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NERC	National Electric Reliability Corporation
NH	State of New Hampshire, New Hampshire load zone
NNC	Norwalk Harbor–Northport, NY, Cable (formerly called the New York 1385 transmission line)
NPCC	Northeast Power Coordinating Council
NY	State of New York
NYISO	New York Independent System Operator
NY-NNC	Norwalk Harbor–Northport, NY, Cable (formerly called the New York 1385 transmission line)
NY-AC	New York Alternating-Current Interface
NY-CSC	New York Cross-Sound Cable
OATT	*Open Access Transmission Tariff*
OOM	out of market
OP 4	ISO Operating Procedure No. 4
OP 8	ISO Operating Procedure No. 8
PER	peak energy rent
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PRD	price-responsive demand
Q	quarter
RAA	Reserve Adequacy Analysis
RAS	Reliability Administration Service
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RFP	request for proposals
RI	State of Rhode Island, Rhode Island load zone

Acronyms and Abbreviations	Description
RISEC	Rhode Island State Energy Center
RNS	Regional Network Service
ROS	Rest-of-System reserve zone
RSI	Residual Supply Index
RSP11	*2011 Regional System Plan*
RTDR	real-time demand response
RTEG	real-time emergency generation
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTPR	real-time price response
SAS 70	Former audit of market operations and settlement systems
SCC	seasonal claimed capability
SCR	special-constraint resource
SEMA	Southeast Massachusetts load zone
SOC1	Present audit of market operations and settlement systems
SWCT	Southwest Connecticut
TMNSR	10-minute nonspinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TOUT	through-or-out service
TTC	total transfer capability
US	United States
VAR	voltage ampere reactive (voltage control)
VT	Vermont and Vermont load zone
WCMA	Western/Central Massachusetts
WEAF	Weighted Equivalent Availability Factors