2009 Annual Markets Report

Internal Market Monitor
May 18, 2010

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 *2009 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2009. 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.12.3, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*:

> The [IMM] will present an annual review of the operations of the New England markets, which 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.[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 2009. A summary of the data and outcomes is included in Section 1. 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 presented in Section 2. Section 3 through Section 7 include more detailed discussions of each of the markets, market results, and the IMM's analysis and recommendations. An appendix 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.

[1] FERC, Electric Tariff No. 3, Section III, *Market Rule 1, Standard Market Design*, Appendix A: Market Monitoring, Reporting and Market Power Mitigation, III.A.12.3, Reporting (effective July 1, 2005).

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

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Section 1
Summary of New England's Wholesale Electricity Markets in 2009

Competitive and efficient electricity markets provide the incentives to maintain an adequate supply of electric energy, over the long run, at prices that are consistent with the cost of providing it. The core responsibilities of the ISO New England (ISO) Internal Market Monitor (IMM) include reviewing the competitiveness of the wholesale electricity markets and recommending improvements when necessary. The IMM analyzed the 2009 performance of the ISO-administered markets and determined that the outcomes were consistent with competitive markets. Market concentration is low, new participants seek to enter the market, and energy prices remain at levels consistent with the short-run marginal cost of production.

The *2009 Annual Markets 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 and performance criteria. This section summarizes the region's wholesale electricity market outcomes for 2009, the market issues that arose during the year and the IMM's recommendations for addressing these issues, the overall competitiveness of the markets, and market mitigation and market reform activities. A discussion of how the markets work and of the IMM's market oversight role is included in Section 2. Section 3 through Section 7 contain a more thorough discussion of the 2009 market results and the IMM's operation. Section 8 is an appendix of additional data from the ISO markets. A list of abbreviations and acronyms is included at the end of the report. Key terms are italicized and defined within the text and footnotes.

1.1 Summary of Market Outcomes

During 2009, overall energy prices, transmission congestion revenue, and reliability costs all decreased, in response to changes in several key market inputs: lower, less volatile fuel prices; a continued, near-record level of hydroelectric production; reduced consumption of electric energy; and a reduced need to operate generation for local second-contingency protection.[3] Key market inputs and outcomes are as follows:

- The total cost of electric energy fell 50%, from \$10.6 billion in 2008 to \$5.3 billion in 2009.[4]
- Total congestion, as measured by the value of the Congestion Revenue Balancing Fund (CRBF), decreased \$96 million (almost 80%), from \$121 million in 2008 to \$25 million in 2009.[5]

[3] A *second contingency* (N-1-1) is when a power system element is unavailable and another contingency occurs. A *first contingency* (N-1) is when any power system element becomes unavailable.

[4] The total cost of electric energy is approximated as the product of the annual net energy load (NEL) for the region and the average annual real-time locational marginal price (LMP) at the Hub. NEL is calculated as total generation (not including the generation used to support pumping at pumped-storage hydro generators), plus net imports. LMPs are identified at 900 pricing points (*pnodes*) on the system as a way for wholesale electric energy prices to efficiently reflect the value of electric energy at different locations based on the patterns of load, generation, and the physical limits of the transmission system. The *Hub* is a collection of pnodes that represents an uncongested price for electric energy. *Load zones* are aggregations of pnodes within specific areas.

- The costs associated with providing local second-contingency protection and voltage support fell by $189.7 million, or almost 90%, from 2008 to 2009.

- Compared with 2008, average prices for all major fuel types were lower in 2009. Natural gas prices fell by 54%; residual fuel oil prices, 29%; distillate fuel oil prices, 43%; and coal prices, 46%.

- Yearly hydroelectric production in 2009 was at near-record levels, 31% over the average hydro production from 2000 to 2007, and just 3% below the record levels set in 2008.

- Net energy for load (NEL) in 2009 was almost 5,000 gigawatt-hours (GWh) (3.7%) lower than in 2008 and approximately 7,600 GWh (5.7%) lower than in 2007.[6]

- The third Forward Capacity Auction (FCA) of the Forward Capacity Market (FCM) was held in October 2009, clearing at the floor price of $2.95/kilowatt (kW)-month because of a capacity surplus.

- The first Annual Reconfiguration Auction (ARA) for the FCM commitment period 2010/2011 was successfully held in May, clearing 197.6 megawatts (MW) at $1.50/kW-month.[7]

- The capacity market transition payments made to all resources in 2009 totaled $1,765 million.[8]

1.2 Competitiveness of the ISO Energy Market

To assess the competitiveness of the electric energy markets, the IMM examined two types of measures of market competitiveness: structural measures of competitiveness, which analyze the concentration of generation resource ownership in the New England markets; and price-based measures, which compare wholesale market prices to the estimated cost of providing electric energy. The results of the concentration analyses show that the market is structurally competitive, and in instances in which inadequate transmission or peak load levels create the possibility of noncompetitive behavior, mitigation rules provide behavior remedies. Market results show that electric energy prices reflect supplier costs to produce electric energy (i.e., largely fuel prices), which

[5] The CRBF accumulates hourly congestion revenues from both the Day-Ahead and Real-Time Energy Markets that accrue as a result of dispatching the system to serve all loads most economically in the presence of transmission constraints.

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

[7] In FCM reconfiguration auctions, capacity supply obligations (CSOs) are traded monthly, seasonally, and annually to clear supply offers and demand bids for each *capacity zone* (i.e., geographic subregions of the New England area that may represent load zones that are export constrained, import constrained, or contiguous—neither export nor import constrained). A *capacity commitment period* is also known as a *capability year* and runs from June 1 through May 31 of the following year. A *capacity supply obligation* is a requirement for a resource to provide capacity to satisfy a portion of the ISO's Installed Capacity Requirement (ICR) that is acquired through an FCA, a reconfiguration auction, or a CSO bilateral contract through which a market participant may transfer all or part of its CSO to another entity.

[8] FCM transition payments replaced the Installed Capacity (ICAP) Market in December 2006 and will continue until May 31, 2010. The 2010/2011 FCM commitment period will begin on June 1, 2010.

is consistent with the finding that the market is competitive. The results of these analyses are included below and in Section 3.

The structural measures used were the Herfindahl-Hirschman Index (HHI) and the Residual Supply Index (RSI).[9] The HHI of about 600 for the entire New England region for 2009 indicates the market is not concentrated at the systemwide level. This HHI is well below the 1,000 level that the U.S. Department of Justice (DOJ) uses as a threshold measure of an unconcentrated market.[10]
The RSI results for 2009 show that output from the largest supplier was required to meet demand during 46 hours in August. Figure 1-1 shows a duration curve of systemwide RSI calculations for the year. A review of the RSIs for the local reserve zones, Connecticut (CT) and Northeast Massachusetts/ Boston (NEMA/Boston), during July, August, and September 2009 suggest a slightly higher level of market concentration.[11] In the CT local reserve zone, a supplier was pivotal 7.6% of the time. The NEMA/Boston local reserve zone was slightly more concentrated, with a pivotal supplier during 16.8% of hours. The RSI analysis suggests that suppliers in the local reserve zones may have the ability to exercise market power. This reinforces the importance of offer-mitigation measures for import-constrained areas to prevent suppliers with market power from using it to raise prices.

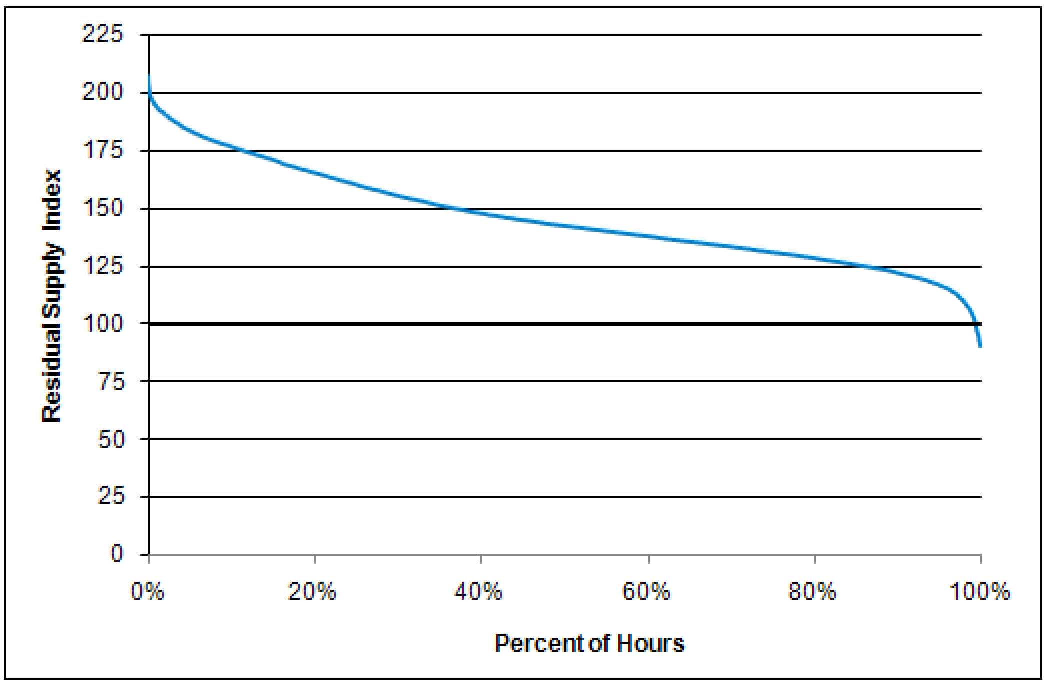

Figure 1-1: 2009 Residual Supply Index duration curve.

[9] The *Herfindahl-Hirschman Index* (HHI) is a measure of market concentration based on generating capacity. The systemwide *Residual Supply Index* (RSI) measures how much of the load in a given hour in megawatt-hours can be met without any capacity from the largest supplier. Suppliers that are necessary to meet demand are termed "pivotal" and can affect market prices.

[10] The Department of Justice defines markets with an HHI below 1,000 points to be unconcentrated, an HHI between 1,000 and 1,800 points to be moderately concentrated, and an HHI above 1,800 points to be highly concentrated. (U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, April 8, 1997; http://www.usdoj.gov/atr/public/guidelines/horiz_book/15.html).

[11] 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 defined as the area excluding the other, local reserve zones.

The price-based measure used is the competitive benchmark.[12] The competitive benchmark model compares market prices modeled using participant offers with modeled market prices based on IMM estimates of resource marginal costs. The modeled electric energy prices using participants' actual supply offers (offer-intercept prices) are compared to modeled prices using estimated short-run variable costs as supply offers (benchmark prices). The average annual offer intercept price is $37/megawatt-hours (MWh), while the benchmark price is $36/MWh.

The results of the competitive benchmark model are used to calculate the Quantity-Weighted Lerner's Index (QWLI), which are shown in Table 1-1. The QWLI is the percentage markup of price over marginal cost. The diagnostic value of the QWLI is not its absolute value, which can be confounded by estimation error in the model and in the estimates of marginal costs, but rather changes in its value through time, considered together with other measures of market performance. The QWLI results, along with a general lack of concentration and energy market prices that are closely correlated with the fuel prices, support the conclusion that market prices are consistent with prices expected when resource owners offer at their short-run variable costs.[13]

Table 1-1
Quantity-Weighted Lerner Index, %[(a)]

2004	2005	2006	2007	2008	2009
−6	1	1	2	−1	5

(a) The QWLI = [(annual market cost based on market prices − annual market cost based on marginal cost estimates)/ annual market cost based on market prices].

Figure 1-2 shows average actual and fuel-adjusted real-time electric energy prices for 2000 to 2009. The fuel-adjusted electric energy price is a metric developed by the IMM to estimate the impact that input fuel prices have on electric energy prices. After adjusting for changes in fuel prices, average energy prices have remained stable since 2000.

[12] The *competitive benchmark price model* estimates market prices based on marginal costs and actual offers.

[13] The correlation between natural gas (the dominant marginal fuel) and on-peak real-time energy prices (Hub LMPs) is approximately 0.96; the variance in natural gas prices explains about 87% of the variance in on-peak real-time Hub LMPs.

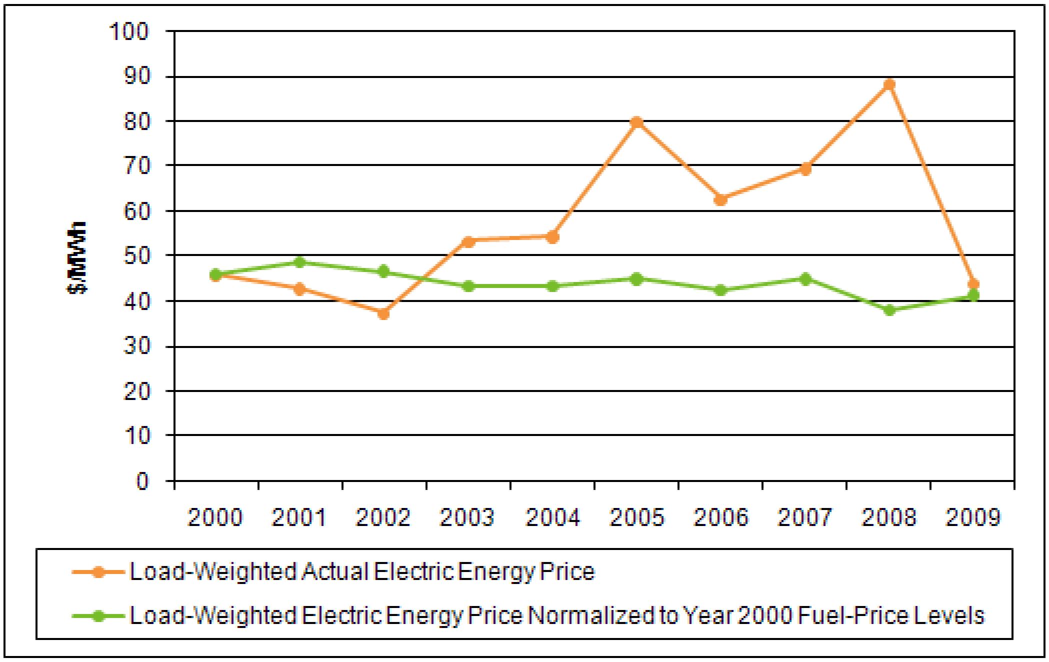

Figure 1-2: Actual and fuel-adjusted average real-time electric energy prices, 2000 to 2009.
Note: The prices are average Hub prices weighted by system load.

1.3 Market Results and Findings

The key results and findings for the energy and reserve markets in 2009 are an overall reduction in energy prices and congestion costs and an increase across the year in the frequency and magnitude of nonzero real-time reserve prices. The IMM also observed a shift in the relationship between day-ahead and real-time prices in the late second quarter, with day-ahead prices switching from prices that were higher than real-time prices, on average, to prices that were lower than real-time prices, on average. These market outcomes are consistent with observed changes in several key inputs: in particular, lower, less volatile fuel prices; continued near-record levels of hydro production; a reduction in the consumption of electric energy; and a reduced need to operate generation for local second-contingency protection.

1.3.1 Energy Market and Real-Time Reserve Pricing

This section provides the key results and findings for the energy markets in 2009 with comparisons to previous years.

1.3.1.1 Electric Energy Prices

The average day-ahead and real-time electric energy prices at the New England Hub in 2009 were \$41.54/MWh and \$42.02/MWh, respectively. The average day-ahead to real-time price differential has been declining from an annual average difference of 2.4% in 2005 to −1.15% in 2009. Table 1-2 summarizes average annual and quarterly day-ahead and real-time Hub prices for 2009.

Table 1-2
2009 Day-Ahead and Real-Time Hub Prices, $/MWh

	Annual	Q1	Q2	Q3	Q4
Day ahead	41.54	54.17	35.52	32.38	44.32
Real time	42.02	52.80	35.24	34.30	45.89
Difference	**–0.48**	**1.37**	**0.28**	**–1.92**	**–1.57**

These data show that in mid-2009, the quarterly average price difference changed from positive to negative and the annual average difference is negative, while in previous years it has been positive. This change in the price relationship followed transmission projects' being placed in service in Southwest Connecticut (SWCT) (in late 2008 through early 2009) and in Lower Southeast Massachusetts (SEMA) (at the end of the second quarter).[14] These transmission projects eliminated the need to make local second-contingency protection resource (LSCPR) commitments. The projects' being placed in service also allowed a tightening of real-time commitment practice, which further reduced the amount of capacity committed above minimum requirements, improving dispatch and pricing. An observed consequence of these changes to the system was an increase in the volatility of real-time price outcomes, marked by the more frequent dispatch of peaking units, nonzero real-time reserve prices, and declarations of Master/Local Control Center (M/LCC) Procedure No. 2, *Abnormal Conditions Alert* (M/LCC2).[15] Additional discussion of operations is included in Section 7.

If the apparent shift in the relationship between average day-ahead and real-time prices continues, the expected profit-maximizing strategy would be to decrease the volume of virtual supply offers submitted and to increase the volume of virtual demand bids and physical load bids during the second half of 2009. To date, while the data show a decline in virtual supply offers, they do not show a discernible increase in either virtual demand bids or physical load bids relative to the first half of the year. Moreover, in the fourth quarter of 2009, while average real-time prices were more than $3/MWh higher than day-ahead prices, cleared day-ahead load as a percentage of real-time load declined, increasing load servers' exposure to the higher average real-time prices.

The reduced participation in the virtual market may prevent convergence of day-ahead and real-time prices. The IMM will continue to monitor the performance of the Day-Ahead and Real-Time Energy Markets with particular attention to the relationship between day-ahead and real-time prices and the activities of virtual players and their role in causing convergence in day-ahead and real-time prices. Refer to Section 3.3.3 for additional discussion and analysis.

Compared with 2008, prices for all major fuel types were lower in 2009. Natural gas prices decreased by 54%; residual fuel oil prices, 29%; distillate fuel oil prices, 43%; and coal prices, 46%. Figure 1-3, which shows the percentage change in monthly natural gas prices and the percentage change in monthly real-time LMPs, demonstrates that changes in electricity prices closely track changes in natural gas prices. In the second half of 2009, natural gas prices fell more steeply than real-time

[14] New England is divided into the following eight load zones: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).

[15] Master/Local Control Center (M/LCC) Procedure No. *2, Abnormal Conditions Alert* (March 12, 2009); http://www.iso-ne.com/rules_proceds/operating/mast_satllte/mlcc2.pdf.

LMPs because of two main factors. First, peaking units, most of which do not burn natural gas, were dispatched and set prices more frequently, and second, the frequency and magnitude of real-time reserve prices increased, which increased the real-time LMP.

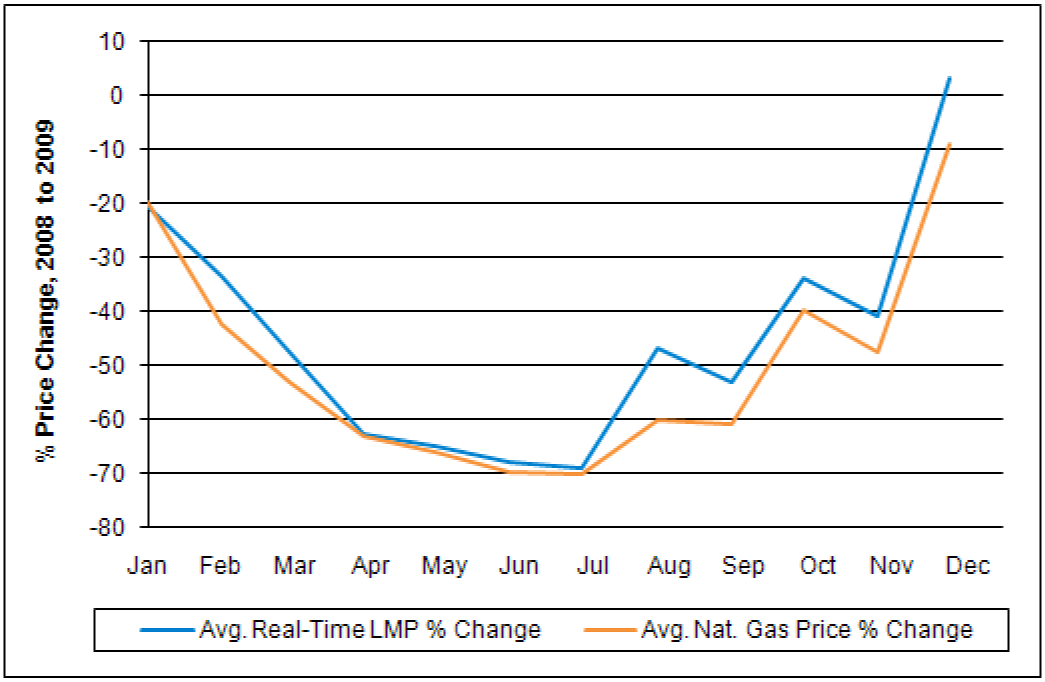

Figure 1-3: Percentage change in real-time locational marginal prices (LMPs) and natural gas, 2008 to 2009.

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

Weather-normalized net energy for load in 2009 was 2.2% lower than in 2008.[16] The 2009 summer peak was 3.9% lower than in 2008; 1.1% lower, weather-normalized. The decline in weather-normalized net energy for load suggests that broader declines in economic activity have affected electric energy consumption. Table 1-3 summarizes actual and normalized loads for 2007 through 2009.

[16] *Weather-normalized* results are those that would have been observed if weather were the same as the long-term average.

Table 1-3
Annual and Peak Electric Energy Statistics, 2007 to 2009

	2007	2008	2009	% Change 2008 to 2009
Annual NEL (GWh)[(a)]	134,466	131,743	126,842	−3.7%
Normalized NEL (GWh)	134,153	131,127	128,224	−2.2%
Recorded peak demand (MW)	26,145	26,111	25,081	−3.9%
Normalized peak demand (MW)	27,460	27,765	27,460	−1.1%

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

On the supply side, hydroelectric production was up, and fossil-fuel-fired generation production was generally down. Yearly hydroelectric production in 2009 was at near-record levels, 31% over the historical average hydro production from 2000 to 2007, and just 3% below the record levels seen in 2008.[17] The maximum daily hydro production occurred on July 6, 2009, with hydroelectric production accounting for 16% of total supply.[18] Overall, hydroelectric production accounted for 8% of total energy production in 2009.

1.3.1.2 Real-Time Reserve Prices

In real time, the scheduling 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).[19] As 2009 progressed, the frequency and magnitude of nonzero real-time reserve prices increased. This change is a direct consequence of changes in the transmission system topology, which have decreased the need for operators to meet reserve requirements with out-of-market (OOM) LSCPR commitments.

Because transmission improvements dramatically reduced LSCPR commitments in the latter half of 2009, instead of unloaded on-line generation, the next-available resource often is an off-line peaking unit. Thus, when contingencies such as loss of a transmission line or a generation unit occur, fewer megawatts of relatively inexpensive on-line generation are available to meet the increased energy or reserve needs.[20] This leads to the more frequent binding of reserve constraints (in particular, 10-minute spinning reserve [TMSR]) at higher prices.[21]

[17] Percentages are based on historical data reported by the ISO at http://www.iso-ne.com/nwsiss/grid_mkts/enrgy_srcs/index-p1.html and subsequent Web site pages. Refer to Section 8 for additional information.

[18] Total supply includes electrical generator output and net interchange megawatts.

[19] RCPFs are administratively set limits on redispatch costs the system will incur to meet reserve constraints. Each reserve constraint has a corresponding RCPF.

[20] These on-line resources are inexpensive in a relative sense only. The only cost considered during dispatch is the incremental cost of energy reflected in the energy offer. The costs associated with starting the unit and operating at minimum, which may be significant, are considered sunk costs and thus not part of the dispatch evaluation.

[21] TMSR is operating reserve provided by on-line operating generation that can increase output within 10 minutes in response to a contingency.

The reduction in out-of-market commitment for local second-contingency protection improves efficiency in two ways. First, because the system has less out-of-market energy, energy prices more accurately reflect the marginal cost of meeting the next increment of load. Second, the cost of providing reserve is included in a visible market price rather than in Net Commitment-Period Compensation (NCPC) payments made to out-of-market generation.[22]

Table 1-4 shows the increase in the frequency of binding reserve constraints and the increase in the average price during intervals with positive reserve prices after the Tremont East improvements went in service in Lower SEMA, eliminating the need to have a Canal unit on line for LSCPRs.

Table 1-4
2009 Systemwide TMSR Price Statistics

	Jan to Jun	Jul to Dec	Change	% Change
Number of five-minute intervals with positive TMSR prices	1,013	1,560	547	54%
Percentage of intervals with nonzero prices	1.95%	2.95%	1.0%	51%
Average TMSR price for intervals with nonzero prices	$18.37	$36.41	$18.04	98%

1.3.1.3 Minimum Generation Emergencies

Minimum Generation Emergencies (MinGen Emergencies) are declared when the on-line generation on the system comes close to exceeding the load on the system. They typically are declared in the overnight hours when resources are operating at economic minimums to be available for the higher load hours the next day. The declaration of a Minimum Generation Emergency is not principally a reliability action but rather an administrative market mechanism that sets LMPs to zero to provide a price signal to participants to increase consumption or reduce generation.

The IMM has observed a significant increase in the frequency of declared MinGen Emergencies in 2009 over previous years; increasing from eight hours spread over three months in 2007, to 32 hours over six months in 2008, and finally to 97 hours over nine months during 2009. Over the same period, average load levels during MinGen Emergencies have declined, from 12,300 MW in 2007 and 12,500 MW in 2008, to 11,000 MW in 2009.

While the number of hours with MinGen Emergency declarations has increased, the amount of megawatt-hours self-scheduled into the day-ahead and real-time markets also has increased.[23] This is contrary to expectations given the increased number of hours with prices at zero. The reasons are not immediately obvious why dispatchable generators would prefer to self-schedule their output into the

[22] *Net Commitment Period Compensation* (NCPC) provides 'make-whole' payments to market participants with resources whose operating costs exceed energy revenues over the 24-hour dispatch day. NCPC is paid to resources for providing first- and second-contingency voltage support and control and distribution system protection in either the Day-Ahead or Real-Time Energy Markets. The accounting for the provision of these services is performed daily and considers a resource's total offer amount for generation, including start-up fees and no-load fees, compared with its total energy market value during the day. If the total value is less than the offer amount, the difference is credited to the market participant. For more information, see *Market Rule 1,* Section III, Appendix F: Net Commitment-Period Compensation Accounting; http://www.iso-ne.com/regulatory/tariff/sect_3/.

[23] Almost 95% of self-scheduled megawatt-hours in real time are self-scheduled day ahead. Much of the increment self-scheduled in real time comes from intermittent generators or resources seeking the real-time price.

Day-Ahead Energy Market rather than accept financial schedules that respect their economics and then make real-time physical scheduling decisions on that basis. If a participant did not receive a day-ahead schedule on the basis of its supply offer and anticipated that the real-time price was going to be higher than its operating costs, nothing in the rules would prevent self-scheduling these supply increments in real time. The practice of self-scheduling in the day-ahead market sacrifices this option value and reduces the flexibility of the resources available to the operators in real time.[24] The IMM recommends that the ISO reevaluate the energy market rules to ensure that all resources have the correct incentives under all conditions to submit price-based offers into the Day-Ahead and Real-Time Energy Markets.

1.3.1.4 Congestion Revenue and Financial Transmission Rights

In 2009, the value of the congestion fund was $25.1 million, and the sum of day-ahead and real-time loss charges was $34.3 million. In 2008, the value of the congestion fund was $121 million, and the total marginal loss fund was $98 million. The congestion fund in 2009 represented just 0.5% of the energy market value in 2009. The reduction in the value of the congestion fund was caused by a reduction in the amount of congestion on the system due to the completion of new transmission and a reduction in the cost of congestion caused by lower LMPs.

In 2009, the Financial Transmission Rights (FTRs) auction revenue far exceeded realized congestion revenue, as shown in Table 1-5.[25] Participants overestimated levels of congestion, apparently misestimating the impact of the transmission work going in service in 2009 and the impact of changes in fuel prices and the level and patterns of consumption.

Table 1-5
Summary of Congestion Revenue and Auction Revenue

	Day-Ahead Congestion Revenue (Millions $)	Total Auction Revenue (Millions $)	Auction Revenue as % of Day-Ahead Congestion Revenue
2007	130.1	122.8	94%
2008	125.4	116.7	93%
2009	26.7	71.1	266%

Based on the measure of a net hedge (i.e., total revenues from FTRs and Auction Revenue Rights [ARR] compared with FTR costs) the FTR markets provided an effective hedge for many participants in 2009.[26] Figure 1-4 presents, at a participant level, FTR net revenues (the orange bars) and the "net hedge" realized both by holding an FTR and by receiving ARR revenues during the year (the blue dots). While most participants with only an FTR position lost money in 2009, most participants with both an ARR allocation and an FTR position made money after combining their FTR results and ARR receipts.

[24] *Option values* occur when future market conditions are highly uncertain, the uncertainty is resolved over time, and strategies based on subsequent events are allowed to be revised.

[25] FTRs allow participants to hedge against the economic impacts associated with transmission congestion and provide a financial instrument to arbitrage differences between expected and actual day-ahead congestion.

[26] ARRs are a mechanism used to distribute auction revenue to congestion-paying LSEs and transmission customers that have supported the transmission system; see Section 2.6.3.

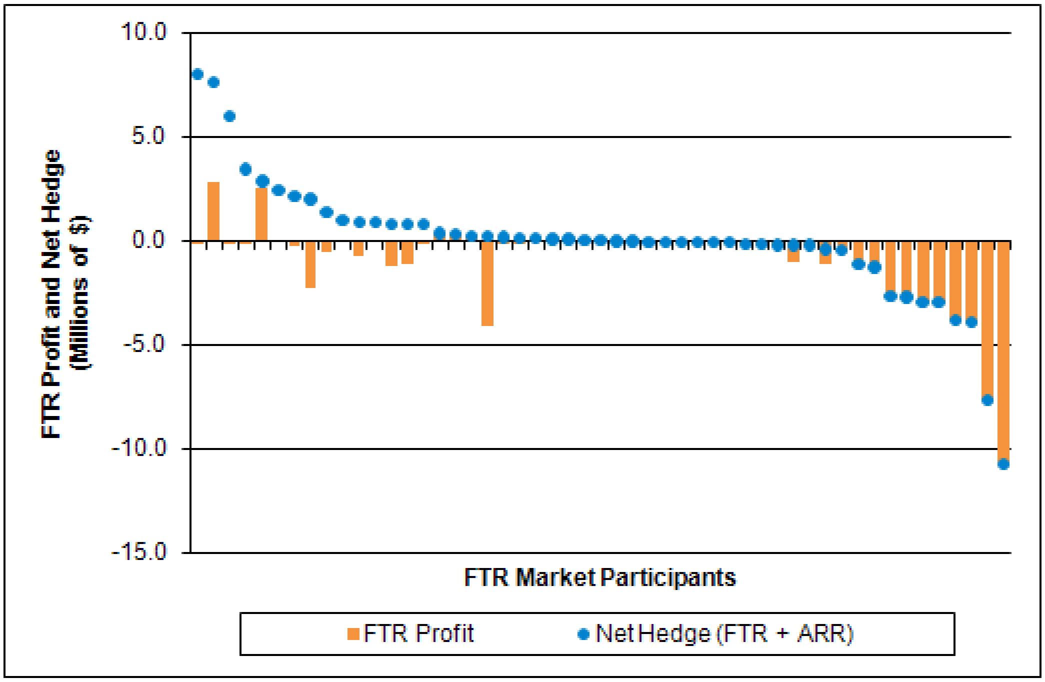

Figure 1-4: Overlay of FTR participant profitability and total hedge after including ARR revenue, 2009.

1.3.1.5 Demand Resources

The number of megawatts of demand resources participating in ISO markets increased in 2009.[27] Total enrollments were 2,546 MW in December 2008 and 2,998 MW in December 2009. The increase came from the 30-minute and Two-Hour Demand-Response Programs and other demand resources (ODRs).[28] Enrollments in the Real-Time Price-Response Program decreased slightly, while profiled demand-response enrollments did not change.[29] Figure 1-5 shows demand-response and ODR program enrollments by quarter for 2005 through 2009.

[27] A *demand resource* is a source of capacity whereby a consumer reduces the demand for electricity from the bulk power system in response to a request from the ISO to do so for system reliability reasons or in response to a price signal.

[28] *Demand response* is when market participants reduce their consumption of electric energy from the network in exchange for compensation based on wholesale market prices. O*ther demand resources* are demand-side resources, such as energy efficiency, load management, and distributed generation at a retail customer's site, that are outside the ISO's control but that reduce demand by a least 100 kW; participate as capacity resources in the New England Balancing Authority Area; and are subject to ISO measurement, verification, and review procedures to demonstrate their total amount of demand reduction.

[29] *Price response* is the reduction of electricity consumption in response to a price signal in exchange for compensation based on wholesale electricity prices.

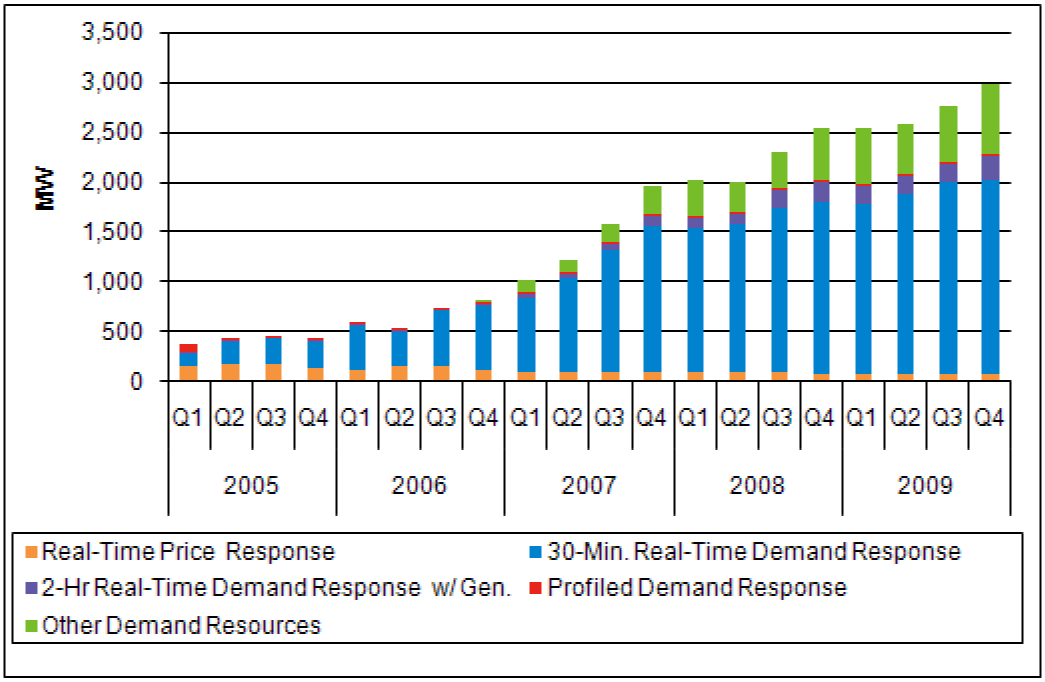

Figure 1-5: Quarterly demand-resource enrollments, 2005 to 2009.

The Real-Time Price-Response Program was activated a total of 78 days in 2009, down from 207 days in 2008. The Day-Ahead Load-Response Program (DALRP) produced interruptions on 126 days in 2009, up from 103 days in 2008. Although the monthly average day-ahead prices in 2009 were consistently below the trigger prices, which are a function of a fixed heat rate and a fuel-price index, and were substantially lower than prices in 2008, the trigger price was exceeded in more days in 2009 than in 2008.[30] A total of 45,803 MWh of load was interrupted during the year from all demand-response programs. In total, demand resources provided 507 GWh of load reduction in 2009, with the majority (462 GWh) coming from other demand resources, such as energy-efficiency projects. The 507 GWh represents 0.4% of total system load for the year. (Section 3.5.3)

Payments for all demand-resource programs totaled $111.5 million in 2009. Forward Capacity Market transition payments made to eligible demand resources rose from $77.6 million in 2008 to $106.8 million in 2009 due to increased program enrollments and a higher transition payment rate. Of the demand response receiving transition payments, approximately 20% was energy efficiency.

The ISO filed rules with FERC to extend the price-response programs without modifications until the rules to implement the long-term price-responsive demand (PRD) solution are in service.[31] The IMM has observed that the use of the Reserve Adequacy Analysis (RAA) LMP as a price trigger for these programs results in the dispatch of the demand resources under these programs in many hours when

[30] A generator's *heat rate*, traditionally reported in Btu/kWh, is the rate at which it converts fuel (Btu) to electricity (kWh) and is a measure of the thermal efficiency of the conversion process.

[31] See *ISO New England Inc. and New England Power Pool, Tariff Revisions Regarding Extension of the Real-Time Price Response Program and Day-Ahead Load Response Program; Docket No. ER09-___-000* (ER09-1737-000) (September 23, 2009) for more information; http://www.iso-ne.com/regulatory/ferc/filings/2009/sep/er09-___-000_9-23-09_price_load_response_ext.pdf.

the realized LMPs are lower than the "resource bids."[32] Because the program is triggered based on forecasted prices, and the price forecast that is produced by the RAA process is a poor predictor of real-time prices, demand-response resources are being called to reduce demand unnecessarily, resulting in administrative and market costs without benefits. Because the inclusion of the RAA LMP as currently calculated as a price trigger introduces sufficient inefficiency to the design, the IMM recommends revising the rules to either exclude this price trigger or to modify the methodology used to calculate it.

1.3.2 Reliability and Operations

As of December 2009, the total costs associated with LSCPRs and voltage were near zero, and based on current system topology, generation, and load patterns, ISO System Operations expects a limited and substantially reduced need in the future to operate generators for LSCPRs or voltage compared with recent years. Table 1-6 summarizes the total out-of-market payments to generators for LSCPRs, distribution, and voltage.

Table 1-6
Real-Time Out-of-Market
Reliability Payments to Generators, $ Millions

Payment Type	2008	2009	Difference	% Change
Local Second-Contingency Commitments	182.49	17.22	−165.28	−91%
Distribution	1.47	0.59	−0.88	−60%
Voltage	29.39	5.02	−24.37	−83%
Total	213.35	22.83	−190.52	−89%

The need to commit generators out of market to maintain system reliability and to compensate them with Net Commitment-Period Compensation has been a long-standing issue in New England. The energy market employs a two-part payment rule consisting of the LMP and NCPC. The sum of all NCPC components is only 0.75% of total compensation to generators. Economic NCPC was 0.43% of the total generator compensation and is incurred largely as a consequence of the energy market's three-part bidding structure.[33] Economic NCPC will not be eliminated by changes made to the transmission system. On the other hand, improvements to the transmission system have all but eliminated the need to commit generation as LSCPRs and have allowed revisions to voltage guides, dramatically reducing the need to run generation to support or protect system voltages.

Two sets of transmission improvements account for the reductions in reliability-related commitment costs observed in 2009. First, transmission upgrades in Southwest Connecticut have significantly reduced the need for LSCPR commitments during the peak. Similarly, the Tremont East

[32] The ISO performs the RAA at the close of the real-time market reoffer period to ensure that adequate resources are committed for meeting the forecasted load and operating-reserve requirements for the Real-Time Energy Market.

[33] 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. Generating resources submit three-part bids that reflect the cost of start up, no-load operation, and incremental energy production. The price received by the marginal resource equals its incremental energy offer. At this price, the resource earns no contribution against its start up and no-load costs. The generating resource is made whole for such shortfalls accumulated across the operating day through the payment of economic NCPC.

improvements for Cape Cod in Lower SEMA put into service in June all but eliminated the need to commit a Canal unit. Figure 1-6 illustrates the dramatic decline in LSCPR costs since the Tremont East upgrades went into service.

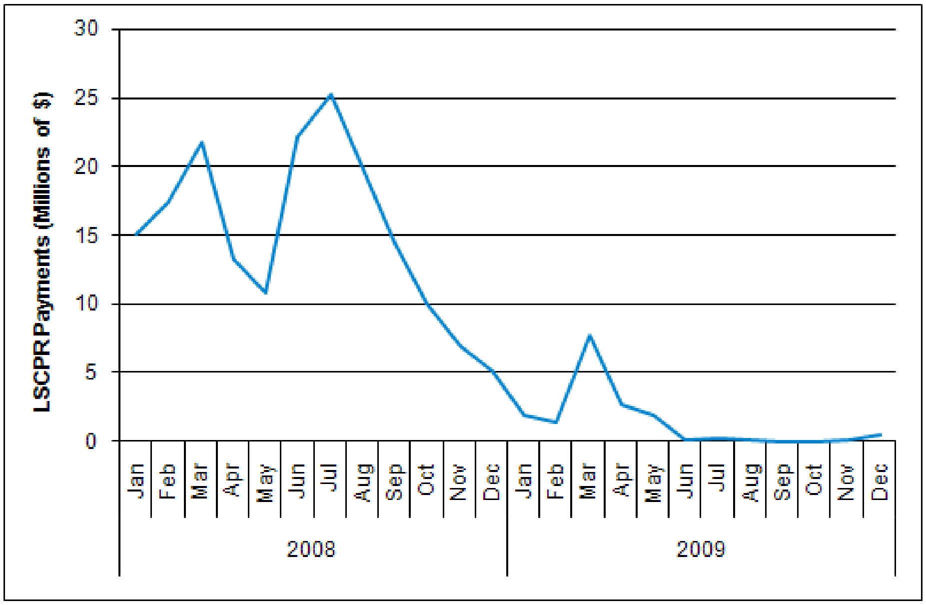

Figure 1-6: Monthly charges for local second-contingency-protection resources.

The reduction in commitments for LSCPRs and voltage reduced the amount of capacity committed above minimum requirements. Figure 1-7 shows the average amount of capacity committed after day ahead and not dispatched above its economic-minimum limit.

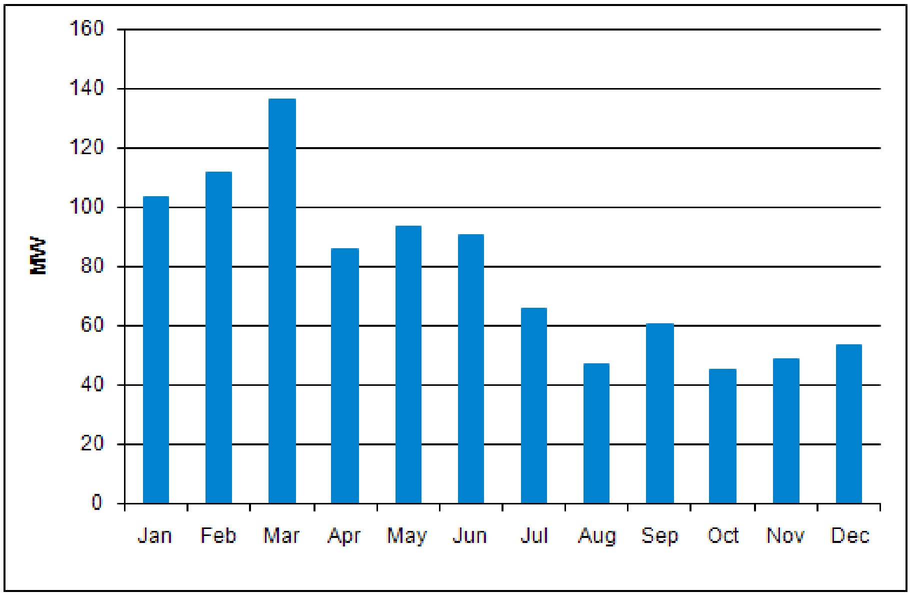

Figure 1-7: Average generation committed after day ahead and operated at economic minimum, 2009, MW per month.

Review of the data and conversations with System Operations suggest that, more than at other times, when little to no surplus is available from the unloaded capability of generators committed for reliability, all resources available to the ISO must operate consistently with their supply offers. Operations has expressed concern that, of the resources currently receiving capacity payments and relied on as capacity, many are older fossil steam units that have not logged an operating hour in six months or longer. There is a risk that these resources will fail to start or operate through a duty cycle when eventually scheduled to operate. The IMM will continue to monitor the performance of these resources and the actions the ISO takes to incorporate generator performance risk into its power system management and resource-scheduling decisions.

1.3.3 Forward Capacity Market and Transition Period

This section summarizes the 2009 activities related to the Forward Capacity Market, including the FCM transition period payments and the results of the third FCA and the first Annual Reconfiguration Auction. It also includes an assessment of some aspects of the FCM design.

1.3.3.1 FCM Transition Period

FCM transition payments will continue until the beginning of the 2010/2011 capacity commitment period when the FCM payments based on the auction results will begin. FCM transition payment rates were $3.75/kW-month from June 2008 through May 2009 and then increased to $4.10/kW-month in June 2009, as laid out by the FCM settlement. During 2009, FCM transition payments to qualifying capacity resources totaled $1.8 billion compared with $1.5 billion in 2008. Table 1-7 summarizes the capacity requirements, the average adjusted capacity supplied, and the total payments in each transition-period year. The average unforced capacity (UCAP) supply that is paid the transition rate is greater than the annual ICR because the FCM transition rules require that all existing capacity be eligible for the transition payments.[34]

Table 1-7
Installed Capacity (ICAP) Market/FCM Transition Payment

Year	Average UCAP Supply (MW)	Annual ICR Requirement (MW)	Total Payment ($)	ICAP Transition Payment Rate ($/kW-month)	
				Jan–May	June–Dec
2007	34,985	31,270	1,280,464,983	3.05	3.05
2008	36,331	32,160	1,505,257,134	3.05	3.75
2009	37,236	31,823	1,765,901,336	3.75	4.10

1.3.3.2 Forward Capacity Auction

Each of the three FCAs has procured the capacity needed to meet the region's resource adequacy requirements, or the net Installed Capacity Requirement (NICR). Table 1-8 shows that the total of existing and new qualified capacity exceeded the NICR by 21% in FCA #1, by 32% in FCA #2, and

[34] *Unforced capacity* is the amount of installed capacity associated with a generating unit, adjusted for availability.

by 34% in FCA #3. Because each FCA cleared capacity in excess of that necessary to meet the NICR, the floor price was reached in each auction.[35]

Table 1-8
Results of the First Three Forward Capacity Auctions

	FCA #1	FCA #2	FCA #3
Total qualified (MW)	39,165	42,777	42,746
Total cleared (MW)[(a)]	34,077	37,283	36,996
NICR (MW)	32,305	32,528	31,965
Excess cleared (MW)[(a)]	1,772	4,755	5,031
Clearing price ($/kW-month)	4.50	3.60	2.95

(a) Excludes real-time emergency generation (RTEG) resources in excess of 600 MW.

None of the auctions had import-constrained capacity zones; the ISO determined that each potential import-constrained area had sufficient existing capacity. Maine was modeled as an export-constrained capacity zone in the three auctions.

1.3.3.3 Out-of-Market New Resources and In-Market New Resources

Out-of-market resources, which participate in the FCM at prices below their costs, include certain new resources with offer prices less than 0.75 times the cost of new entry (CONE), new self-supplied resources, capacity carried forward from previous auctions, and capacity under ISO-issued requests for proposals (RFPs).[36] Table 1-9 shows the new in-market and OOM capacity that cleared in the first three FCAs. In FCA #3, OOM new entry was 695 MW, or 25% of cleared new capacity.

[35] In the table, the total amount cleared excludes real-time emergency generation (RTEG) resources in excess of 600 MW. RTEG is distributed generation that the ISO calls on to operate during certain voltage-reduction or more severe actions but must limit its operation to comply with the generation's federal, state, or local air quality permit(s), or combination of permits. Real-time emergency generators are required to begin operating within 30 minutes, which results in increasing supply on the New England grid, and also to continue that operation until receiving a dispatch instruction allowing them to shut down. Because real-time emergency generators are allowed to run only during voltage-reduction or more severe actions, the market rules limit their total obligation to 600 MW.

[36] The CONE is used to (1) establish the starting price for each FCA, (2) set thresholds for reviewing delist bids to deter the exercise of market power, (3) set initial pricing for some reconfiguration auctions, and (4) determine pricing when the supply is inadequate and competition is insufficient. The CONE is derived from the capacity clearing price from previous FCAs, except for FCA #1, where it was administratively set.

Table 1-9
Cleared New, In-Market, and
Out-of-Market Capacity, FCA #1, FCA #2, and FCA #3, MW

Auction	Type of Resource	Generation	Demand Resources	Imports	Total
FCA #1	New cleared	40	860	0	900
	In-market	0	860	0	860
	Out-of-market	40	0	0	40
FCA #2	New cleared	1,156	448	1,529	3,134
	In-market	38	298	1,529	1,864
	Out-of-market	1,118	150	0	1,268
FCA #3	New cleared	1,670	309	817	2,796
	In-market	1,095	189	817	2,101
	Out-of-market	575	120	0	695

1.3.3.4 Delisted Capacity Resources

Table 1-10 shows the accepted delist bids from existing resources.[37] In FCA #3, existing import capacity accounted for the largest proportion of delisted capacity. The ISO approved 1,710 MW of existing resources to delist, and 581 MW in the NEMA/Boston area were rejected. Delisted resources helped reduce the excess capacity but were not sufficient to raise the price above the floor price. Most of the delist requests were dynamic bids submitted below 0.8 times the CONE. The static bids were delists for export or administrative reasons. Permanent delist requests totaled 6.6 MW in FCA #3.

Table 1-10
Delisted Existing Resources by Type, MW

Resource Type	FCA #1	FCA #2	FCA #3
Generation	622 (64%)	350 (39%)	543 (32%)
Demand resources	296 (31%)	489 (55%)	257 (15%)
Import	51 (5%)	51 (6%)	910 (53%)
Total delisted	970	890	1,710

[37] An existing resource can submit a *delist bid* in an FCA to indicate that it wants to opt out of the auction before the deadline for qualifying existing capacity and does not want the capacity obligation below a certain price. *Static delist bids* are submitted for a resource before the auction and cannot be changed during the auction. *Permanent delist bids* prohibit resources from participating in any future auctions unless they qualify for and clear as a new resource in a subsequent FCA. As of the date of the permanent delisting, permanently delisted resources are prohibited from assuming any capacity obligation. *Dynamic delist bids* are submitted by participants during an auction. Unlike other types of delist bids, dynamic delist bids can be offered below 0.8 times the CONE threshold price, and the Internal Market Monitor does not review these bids in advance. Qualified new resources can leave the auction without delisting.

1.3.3.5 Annual Reconfiguration Auction

Table 1-11 shows the results of the first ARA for the 2010/2011 capacity commitment period.[38] The clearing price was $1.50/kW-month, well below the FCA #1 price of $4.50/kW-month. A total of 31 participants participated in this ARA, with 12 participants placing both bids and offers.

Table 1-11
Summary of Annual Reconfiguration Auction for the 2010/2011 Commitment Period

Capacity Zone Type	Rest-of-Pool	New York AC Ties	Total
Total offers submitted (MW)	915.0		**915.0**
Total bids submitted (MW)	−6,473.0	−153.4	**−6,626.5**
Total offers cleared (MW)	197.6		**197.6**
Total bids cleared (MW)	−117.6	−80.0	**−197.6**
Net capacity cleared (MW)	80.0	−80.0	**0.0**
Clearing price ($/kW-mo)	1.5	1.5	**1.5**

1.3.3.6 Assessment of the Forward Capacity Market

The IMM finds that the results of FCA #3 are competitive.[39] This finding is based on an effective auction design, rigorous qualification requirements, an abundance of initial offers, and the absence of anticompetitive behavior observed during the conduct of the auction.

Delist Bids. The rules concerning the determination of the level of static delist bids did not receive detailed attention in the IMM's June 2009 report or in the stakeholder process. The importance of delist bids to the market has increased because of the current surplus capacity situation in which a delist bid set the FCA clearing price. The IMM reviewed whether delist bids improve the Forward Capacity Market's efficiency and whether the rules governing the pricing of delist bids are efficient and prevent the exercise of market power (see Section 4.8). Based on this review, the IMM concluded that the use of delist bids in the FCM design generally improves price formation because it enables participants to leave the capacity market when the cost of remaining in the market exceeds the benefit. Allowing participants to leave the market when it is not cost-effective to remain decreases risk, which lowers long-run costs.

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[38] Pursuant to Section III.13.4.5.1 of *Market Rule 1*, the first ARA will not be conducted for the first five capability years; thus, a total of two ARAs will be held for each of the first five capability years. Therefore, while the capacity values presented in Table 1-11 are for the first ARA to be held for the 2010/2011 capability year, under the terminology used in Section 13 of *Market Rule 1* (which contains the rules for the FCM), this reconfiguration auction is technically the "second" reconfiguration auction for the 2010/2011 capability year. See http://www.iso-ne.com/regulatory/ferc/filings/2009/jan/er09-640-000_1-30-09_icr_filing.pdf.

[39] Testimony of David LaPlante in *Forward Capacity Auction Results Filing*, FERC Docket No. ER10-186-000 (October 30, 2009), p, 2, lines 8–11; http://www.iso-ne.com/regulatory/ferc/filings/2009/oct/er10-___-000_10-29-09_fca_3_results_filing.pdf.

However, this review identified an issue with the determination of the going-forward costs used to calculate the correct price for both static and permanent delist bids. The current rules calculate going-forward costs under the assumption that the resource is going to leave the energy market. However, the appropriate going-forward cost calculation for a resource in the capacity market is based on the costs that are avoided by leaving the capacity market. Because a resource is not required to leave the energy market if it is not in the capacity market, the inclusion of costs avoided by leaving the energy market in a delist bid is appropriate only if a resource is intending to leave the energy market. The IMM recommends that the rules governing the calculation of both permanent and static delist bids be revised to address this issue.

Zonal Modeling and Pricing. The IMM noted in the FCM Report that in the absence of market power, the ideal would be for all zones to be included in the auction. The report also stated that market power concerns outweigh the potential efficiencies of this ideal approach, particularly in concentrated, constrained zones.[40] With the goal of moving closer to the ideal, the FCM Report recommended that permanent delist bids be included in zonal modeling and pricing. Recent ISO-proposed changes move the design even closer to the ideal by also including static delist bids from nonpivotal suppliers in zonal modeling and pricing.[41] However, to enable zones to be modeled in the auctions and essentially enable all bids to affect zonal pricing and creation, a comprehensive mitigation approach for all delist bids is required.

Implementing these recommendations to take into account whether a resource remains in the energy market would be part of a comprehensive mitigation approach and may further increase the ability of delist bids to affect zonal creation and pricing.

OOM Capacity and the Alternative Price Rule. The large amount of surplus capacity in FCA #3 indicates sufficient supply-side competition in the FCM. However, the conclusion of competition must be tempered by the fact that the surplus capacity includes 2,003 MW of out-of-market capacity. OOM capacity offers into the auction at prices below its estimated long-run costs, which (absent a price floor) would lower prices in the FCA. However, since the amount of surplus capacity in all three FCAs to date has exceeded the amount of OOM capacity, the OOM capacity did not cause the floor price to be reached. Given the price collar, the results of the first three FCAs are consistent with the outcome of a competitive market.[42]

The Alternative Pricing Rule (APR) for capacity is intended to correct for distortions when OOM entry in an FCA prevents in-market new capacity from setting the clearing price and prices fall below competitive or efficient levels.[43] The rule was not triggered in FCA #3 because the existing qualified capacity (37,695 MW) exceeded the NICR of 31,965 MW, and no new capacity was needed.

The floor price and the large amount of OOM capacity will prevent the FCA from determining a competitive price for capacity; unless these issues are addressed, FCM prices will be either too high

[40] *Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements* (FCM Report), ISO New England Filing, FERC Docket No. ER09-1282-000 (June 5, 2009), p 4, 5; available at http://www.iso-ne.com/markets/mktmonmit/rpts/other/fcm_report_final.pdf.

[41] *ISO New England Inc. and New England Power Pool, Docket No. ER10-_____-000,Various Revisions to FCM Rules Related to FCM Redesign*, FERC Docket No. ER10-722-000 (February 22, 2010); http://www.iso-ne.com/regulatory/ferc/filings/2010/feb/er10-___-000_02-22-10_fcm_redesign_filing.pdf.

[42] The price collar is a set of upper and lower bounds on the FCA clearing price identified for each FCA per *Market Rule 1*, Section III.13.2.7.3, Capacity Clearing Price Collar.

[43] See *Market Rule 1*, Section III.13.2.7.8, Alternative Capacity Price Rule.

because of the floor price or too low because of OOM capacity. The IMM supports the elimination of the floor price as soon as possible and improvements to the APR to better address the impacts of large amounts of OOM capacity on the price from the FCA.

1.3.4 Forward Reserve Market

Two Forward Reserve Market (FRM) auctions were conducted in 2009: in April, for summer 2009, and in August, for the winter 2009/2010 period. The SWCT and CT reserve zones continue to have supply deficiencies. The persistent capacity deficiency means that all suppliers in these zones are pivotal and that the local market is concentrated. The auction clearing price in the CT and nested SWCT reserve zones was set administratively at the price cap of $14.00/kW-month in both auctions. The NEMA/Boston TMOR clearing prices fell to zero because of reduced local requirements.

1.3.4.1 Competitiveness of the Reserve Market

Structural analysis of the FRM auctions indicates a moderate to high concentration of New England-wide reserve products, based on Herfindahl-Hirschman Indices ranging from 1,200 to 2,200. Prices in the locational Forward Reserve Market have been decreasing for systemwide products, indicating that competition may be lowering prices in the systemwide FRM. However, the Connecticut reserve zone is not competitive. Connecticut has insufficient reserve capacity to meet the zonal reserve requirements. Consequently, the Connecticut and SWCT reserve zones have cleared at the price cap of $14.00/kW-month in each reserve auction.

1.3.4.2 Locational Forward-Reserve Auction Results

The results of the locational forward-reserve auctions are shown in Table 1-12. Prices for New England systemwide 10-minute nonspinning reserve in both the summer and winter auctions declined from 2008 to 2009. Prices in the Connecticut and Southwest Connecticut reserve zones remained at the $14.00/kW-month cap because of insufficient capacity in Connecticut to meet the minimum purchase requirement. Transmission improvements into the NEMA/Boston local reserve zone over the past few years have essentially rendered that area unconstrained. Absent a binding constraint in the auction, the local TMOR price is zero.

Table 1-12
Results of Locational Forward-Reserve Auctions, $/kW-Month

Reserve Zone	Reserve Category	Summer 2008	Summer 2009	Winter 2008/2009	Winter 2008/2009
Systemwide	TMNSR	8.88	6.30	6.74	6.08
Systemwide	TMOR	6.50	$0	4.99	0
SWCT	TMOR	14.00	14.00	14.00	14.00
CT	TMOR	14.00	14.00	14.00	14.00
NEMA/Boston	TMOR	14.00	0	5.55	0

1.3.5 Regulation Market

The Regulation Market provides moment-to-moment balancing services to assure that generation and load are kept balanced in real time. This market functioned well in 2009. During the year, the ISO consistently exceeded the North American Electric Reliability Corporation (NERC) reliability standards for this area and reduced the capacity on regulation.[44]

The structure of the Regulation Market is evaluated using two metrics: HHI and RSI. The HHI for the New England Regulation Market is based on summer capabilities of regulation capacity to offer into the market. The maximum eligible regulation capability (MW) over all hours in the month for each lead participant's portfolio of resources was used in the HHI and RSI analyses. Throughout the year, the monthly HHI varied from a low of 784 to a high of 863, with an annual average of 835. The monthly RSIs exceeded 1,000 for every month in 2009. The results of the HHI and RSI analyses indicate that the Regulation Market is structurally competitive.

Regulation payments to generators for providing regulation totaled $23.1 million in 2009, a decrease of $27.4 million from the 2008 cost of $50.5 million. The cost decrease was caused by two main factors. First, the regulation requirement has fallen, reducing the regulation credit. Second, decreases in energy prices have lowered the opportunity cost of providing regulation service.

1.3.6 Annual All-In Wholesale Electricity Cost

The total all-in cost of wholesale electric energy fell from $12.9 billion ($96.84/MWh) in 2008 to $7.5 billion ($58.36/MWh) in 2009, a decrease of $5.4 billion ($38.48/MWh), or 40%.[45] The all-in cost value includes the cost of electric energy, forward reserves, regulation, capacity reliability commitments, and FERC-approved Reliability Cost-of-Service Agreements (Reliability Agreements). Figure 1-8 shows the average annual all-in wholesale electricity cost metric and natural gas prices for 2007 through 2009.

[44] NERC reliability standards can be accessed at http://www.nerc.com/page.php?cid=2|20 (Princeton, NJ: NERC, 2009).

[45] The *all-in* cost metric includes costs allocated to both wholesale load obligations and network load. The energy portion of the all-in cost is a zonal load-weighted average of zonal prices. This is a slightly different concept than the system load-weighted average Hub price reported in the fuel-adjusted price analysis shown in Section 1.3.6 and Section 3.3.2, and the simple average Hub price. This analysis uses this metric of zonal load-weighted averages of zonal prices because it better represents the prices load actually paid. The ISO publishes a separate wholesale load cost metric that includes only costs allocated to real-time load obligations.

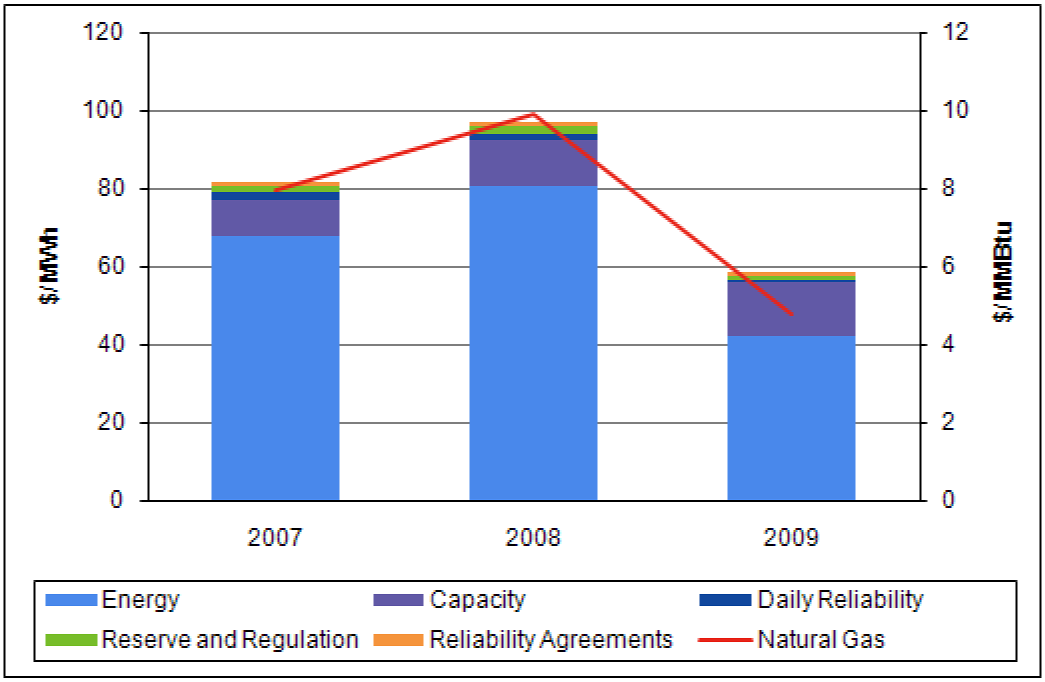

Figure 1-8: All-in cost for electricity.

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.

With the exception of capacity, the cost for all components fell by a combined 48%. Capacity costs increased consistent with the *Market Rule 1*-prescribed FCM transition rate increase of $0.35/kW-month on June 1, 2009, from $3.75/kW-month to $4.10/kW-month.[46] The main factors that drove the drop in the all-in electricity cost in 2009—fuel prices, loads, and hydro production—are addressed above.

1.4 Mitigation and Market Reform Activities

This section summarizes IMM process audit, mitigation, market reform, and referral activities in 2009.

1.4.1 IMM Process Audit

In 2009, the ISO Board of Directors retained KPMG to audit the policies, processes, and procedures of the IMM. This audit followed the discovery of an analytical error that resulted in incorrect statements made in testimony submitted in a proceeding before FERC regarding capacity imports.[47] KPMG made detailed recommendations for revising IMM policies, processes, and procedures, with special attention to controls. As committed, by end of the first quarter 2010, the IMM had successfully revised all its processes and procedures consistent with the KPMG recommendations.

[46] *Market Rule 1*, Section II.8.1, Billing Procedure.

[47] For additional information, see *Compliance Filing of ISO New England Inc.*, FERC Docket No. ER09-873-___ (July 13, 2009).

1.4.2 Mitigation and Market Reforms

According to *Market Rule 1*, Appendix A, the IMM has the authority and responsibility to mitigate electric energy offers under certain circumstances, as well as to apply rules that identify participant behavior that results in NCPC payments in excess of defined thresholds and virtual transactions that increase the hourly value of an FTR the participant holds. During 2009, no participant behavior required the application of Day-Ahead or Real-Time Energy Market mitigation. Daily real-time NCPC payments paid to participants were retroactively mitigated on four days during 2009. There were no instances of day-ahead NCPC mitigation. Two participants had FTR revenues, associated with 21 paths, reduced by a total of $14,777 pursuant to the FTR revenue-capping provisions of *Market Rule 1*.[48]

Based in part on previous IMM recommendations, three market rule reforms were implemented during 2009, and a fourth was implemented January 1, 2010.

- Effective July 1, 2009, reformed rules regarding the offering of capacity-backed import external transactions, and penalties for noncompliance with these rules, became effective. The rules had the desired impact of providing the incentive for participants to offer competitively priced energy transactions to back capacity obligations and shifted the risk associated with failure to perform from New England load to the participants receiving the FCM transition payments.

- A market rule reform was implemented October 1, 2009, that tightens the mitigation thresholds applied to resources that are committed for local reliability.[49] This is the first phase of a two-phase reform. In the first phase, the tighter mitigation standards are implemented within the existing mitigation framework. In the second phase, mitigation will be integrated with the commitment and dispatch systems to allow mitigation to occur before commitment.

- As part of its review of the delist bid for Salem Harbor for FCA #3, the IMM identified that special rules needed to be developed for the treatment of common costs for multi-unit stations that want to delist. The IMM proposed a treatment of the Salem Harbor delist bid for FCA #3 that FERC accepted, subject to the filing of permanent rules to address the issue. The IMM developed a new methodology and submitted rule-change language to FERC in February 2010.[50]

- On January 1, 2010, the local Reserve Constraint Penalty Factor was changed from $50/MWh to $250/MWh. This change is expected to provide more efficient real-time dispatch and pricing.

1.4.3 Behavior Requiring Referral to FERC

Market Rule 1, Appendix A, provides the IMM with a limited set of circumstances for applying mitigation activities without additional FERC involvement: energy market mitigation, NCPC

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[48] *Market Rule 1,* Section III.A.8.4, Appendix A: Cap on FTR Revenues.

[49] *Order Conditionally Accepting Market Rule 1 Revisions,* FERC Docket No. ER09-1546-000 (October 2, 2009); http://www.iso-ne.com/regulatory/ferc/orders/2009/oct/er09-1546-000_10-2-09_ncpc_price_mit.pdf.

[50] *ISO New England Inc. and New England Power Pool, Docket No. ER10-_____-000, Tariff Provisions Related to Delist Bids for Stations with Common Costs* (Salem Harbor common cost filing) (February 16, 2010); http://www.iso-ne.com/regulatory/ferc/filings/2010/feb/er10-___-000_02-16-10_common_costs.pdf.

mitigation, and FTR capping. When the IMM identifies other forms of potentially noncompetitive market participant behavior, *Market Rule 1* requires the IMM to refer the situation to FERC, which then investigates the conduct and applies penalties, as warranted.

In 2009, the IMM made two nonpublic referrals to FERC, bringing the total number of referrals made by the IMM open before FERC to five. No referrals were closed in 2009.

1.5 Summary of IMM Recommendations

Based on observations of participant behavior and market outcomes in 2009 and the analysis presented herein, the IMM identified the following issues and makes the following recommendations for improving the market design. The issues and recommendations are listed in order of importance. Refer to the cross-referenced sections for further explanations of the identified issues.

1. **ISSUE:** The rules governing the calculation of static and permanent delist bids in the Forward Capacity Market are intended to result in a delist bid that reflects the net risk-adjusted going-forward cost of the resource. However, the current rules do not distinguish between the going-forward costs of resources wanting to exit the energy market and those resources wanting to remain in the energy market. As a practical matter, the going-forward costs for a resource that wants to remain in the energy market will be much lower than for those that want to leave the energy market.

RECOMMENDATION: The IMM recommends reviewing and revising the definition of net risk-adjusted going-forward costs and opportunity costs as applied to static and permanent delist bids with particular attention to the difference between the going-forward costs of resources that exit the energy market and those that remain in the energy market. The resolution of this issue may increase the ability of delist bids to affect zonal pricing and creation. (See Section 4.4.6.)

2. **ISSUE:** The IMM has observed a significant increase in the frequency of declared MinGen Emergencies from a total of 8 hours in 2007 to 82 hours in 2009. The existing procedure that administratively sets all prices to zero does not provide appropriate incentives to maximize resource flexibility and make price-based offers into the market under all conditions.[51]

RECOMMENDATION: The IMM recommends that the ISO consider changing the rules to provide stronger incentives for market participants to submit economic offers into the Day-Ahead and Real-Time Energy Markets, including the use of negative offers and bids, and allowing real-time offers and bid modifications. (See Section 3.3.9.)

3. **ISSUE:** In September 2009, the ISO filed rules with FERC to extend the price-response programs without modifications until the rules are in service to implement the long-term price-responsive demand solution.[52] The real-time price response program uses estimated prices from the Reserve Adequacy Analysis as a price trigger. Allowing RAA prices to

[51] *Market Rule 1*, Sections 2.5.c and 2.6.c (http://www.iso-ne.com/regulatory/tariff/sect_3/index.html), and *Manual 11*, Sections 2.5.12.2 and 2.5.13.2 (http://www.iso-ne.com/rules_proceds/isone_mnls/index.html).

[52] *ISO New England Inc. and New England Power Pool, Tariff Revisions Regarding Extension of the Real-Time Price-Response Program and Day-Ahead Load-Response Program; Docket No. ER09-___-000* (September 23, 2009); http://www.iso-ne.com/regulatory/ferc/filings/2009/sep/er09-___-000_9-23-09_price_load_response_ext.pdf.

trigger the program dispatches the resources in many hours when the realized locational marginal prices are well below the forecasted prices.

RECOMMENDATION: The IMM recommends revising the price-response program rules either to exclude RAA prices as a trigger or to modify the methodology used to calculate prices in the RAA process. (See Section 3.5.3.)

Section 2
Overview of New England's Wholesale Electricity Markets and Market Oversight

ISO New England (ISO) is responsible for overseeing and administering New England's competitive wholesale electricity markets. These markets work together to ensure the constant availability of electricity from the bulk power grid for the region's 6.5 million households and businesses and 14 million people. In 2009, more than 400 market participants participated in one or more markets with a combined value of $7.5 billion (energy, capacity, forward reserves, regulation, and daily reliability payments). Participants also have the opportunity to hedge against the costs associated with transmission congestion through the FTR market and the associated auction revenue distributions. The wholesale electricity markets and market products in New England are as follows:

- **Day-Ahead Energy Market**—allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time; facilitates electric energy trading.
- **Real-Time Energy Market**—coordinates the dispatch of generation and *demand resources* to meet the demand for electricity and to meet reserve requirements.[53]
- **Forward Capacity Market (FCM)**—ensures the sufficiency of installed capacity, which includes demand resources, to meet the future demand for electricity.
- **Financial transmission rights (FTRs)**—allows participants to hedge against the economic impacts associated with transmission congestion and provides a financial instrument to arbitrage differences between expected and actual day-ahead congestion.
- **Ancillary services**
    - **Regulation Market**—compensates participants whose resources are controlled by the ISO using automated signals to increase or decrease output moment by moment to balance the variations in instantaneous demand and the system frequency; demand varies second to second, and the system frequency must kept at a constant rate.
    - **Forward Reserve Market (FRM)**—compensates generators for the availability of their *unloaded* operating capacity that can be converted into electric energy within 10 or 30 minutes when needed to meet system contingencies, such as unexpected outages.[54]
    - **Real-time reserve pricing**—is the ISO's mechanism to implement *scarcity pricing*, which compensates participants with on-line and *fast-start* generators for the increased value of their electric energy when the system or portions of the system are

[53] *Demand resources* are installed measures (i.e., products, equipment, systems, services, practices, and strategies) that result in additional and verifiable reductions in end-use demand on the electricity network during specific performance hours.

[54] *Unloaded* operating capacity is operational capacity that is not generating electric energy but that could convert to generating energy. A *contingency* is the sudden loss of a generation or transmission resource. A *first contingency* (N-1) is when the first power element (facility) of a system is lost, which has the largest impact on system reliability. A *second contingency* (N-1-1) is the loss of the facility that would have the largest impact on the system after the first facility is lost.

short of reserves.[55] It also provides efficient price signals when redispatch is needed to provide additional reserves to meet requirements.

- **Voltage support**—compensates resources for maintaining voltage-control capability, which allows system operators to maintain transmission voltages within acceptable limits.

- **Other services and products**—The ISO procures and compensates participants for other services and products as required by the ISO's *Open Access Transmission Tariff* (OATT).[56] A summary of these payments is provided in Section 8, the Data Appendix.

The ISO relies on two independent market monitoring units—one internal and one external—to quickly detect and mitigate anticompetitive market behavior or outcomes. The Internal Market Monitor (IMM) is referred to as the Internal Market Monitoring Unit, and the External Market Monitor (EMM) is referred to as the External Market Monitoring Unit. Every year, the ISO's market monitors review and report on market results and offer insights into the markets' competitiveness and effectiveness as well as areas of market design and operation that need enhancement or improvement.

This section describes the key features of each of the wholesale energy markets the ISO oversees and administers. It also summarizes the market oversight, analysis, and mitigation activities for the New England markets.

2.1 Electric Energy Markets

The primary objective of the electricity markets operated by ISO New England is to ensure a reliable and economic supply of electricity to the high-voltage power grid. The markets include a Day-Ahead Energy Market and a Real-Time Energy Market. In what is termed a *multi-settlement system*, each of these markets produces a separate but related financial settlement. The Day-Ahead Energy Market produces financially binding schedules for the sale and purchase of electricity one day before the operating day. However, supply or demand for the operating day can change for a variety of reasons, including generator reoffers of their supply into the market, real-time hourly *self-schedules* (i.e., choosing to be on line and operating at minimum regardless of the price of electric energy), self-curtailments, transmission or generation outages, and unexpected real-time system conditions. Physically, real-time operations balance instantaneous changes in supply and demand to ensure that wholesale customers receive the electric energy they demand from the system and that adequate reserves are available to operate the transmission system within its limits. Financially, the Real-Time Energy Market settles the differences between the day-ahead scheduled amounts of load and generation and the actual real-time load and generation. Participants either pay or are paid the real-time *locational marginal price* (LMP) for the amount of load or generation in megawatt-hours (MWh) that deviates from their day-ahead schedule.

[55] *Fast-start resources* are resources that are able to respond quickly to system contingencies that remove equipment from service.

[56] The ISO operates under several FERC tariffs, including the *ISO New England Transmission, Markets, and Services Tariff* (2009), of which Section II is the *Open Access Transmission Tariff* (OATT) and Section IV is the *Self-Funding Tariff*. These documents are available online at http://www.iso-ne.com/regulatory/tariff/index.html and http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

This section summarizes the key features of the ISO's Day-Ahead and Real Time Energy Markets, including locational marginal pricing; the factors influencing electric energy supply offers, demand bids, and LMPs; and virtual and real-time trading.

2.1.1 Locational Marginal Prices and Pricing Locations

Locational marginal pricing is a way for wholesale electric energy prices to efficiently reflect the value of electric energy at different locations based on the patterns of load, generation, and the physical limits of the transmission system. Wholesale electricity prices are identified at 900 pricing points (i.e., *pnodes*) on the bulk power grid. LMPs differ among these locations because transmission and reserve constraints prevent the next-cheapest megawatt (MW) of electric energy from reaching all locations of the grid. Even during periods when the cheapest megawatt can reach all locations, the marginal cost of physical losses will result in different LMPs across the system.

If the system were entirely unconstrained and had no losses, all LMPs would be the same, reflecting only the cost of serving the next increment of load. This incremental megawatt of load would be served by the generator with the lowest-cost energy offer that is available to serve that load, and electric energy from that generator would be able to flow to any node over the transmission system.

New England has five types of pnodes: one type is an external proxy node interface with neighboring *balancing authority areas*, and four types are internal to the New England system.[57] The internal pnodes include individual generator-unit nodes, load nodes, *load zones* (i.e., aggregations of load pnodes within a specific area), and the Hub. The *Hub* is a collection of locations with a load-weighted price intended to represent an uncongested price for electric energy; facilitate trading; and enhance transparency and liquidity in the marketplace. New England is divided into the following eight load zones: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).Generators are paid the real-time LMP for electric energy at their respective nodes, and participants serving demand pay the price at their respective load zones.[58] The load-zone price is a load-weighted average price of the load-node prices in that zone.

Import-constrained load zones are areas within New England that must use more expensive generators than the rest of the system because local, inexpensive generation or transmission-import capability are insufficient to meet both local demand and reserve requirements. *Export-constrained load zones* are areas within New England where the available resources, after serving local load, exceed the areas' transmission capability to export excess electric energy.

2.1.2 Electric Energy Supply Offers and Demand Bids

LMPs are determined by supply offers and demand bids. Generator supply offers are influenced by production costs and supplier operating characteristics. For most electricity generators, the cost of fuel is the largest variable production cost, and as fuel costs change, the prices at which generators submit offers in the marketplace change correspondingly. Since fuel prices alone account for a large

[57] A *balancing authority area* is a group of generation, transmission, and loads within the metered boundaries of the entity (*balancing authority*) that maintains the load-resource balance within the area. Balancing authority areas were formerly referred to as *control areas*. Further information is available in the NERC glossary at http://www.nerc.com/docs/standards/rs/Glossary_12Feb08.pdf.

[58] *Market Rule 1* contains provisions that allow participants that meet certain requirements to request nodal pricing for load. However, the number of participants that have exercised this option and the quantity of load these participants serve is very small relative to the zonal load levels.

portion of electricity prices, as fuel prices change year to year, electricity prices change accordingly. The demand bids for electric energy reflect a participant's load-serving requirements and accompanying uncertainty, tolerance for risk, and expectations about congestion on the system caused by transmission constraints. The market-clearing process for the Day-Ahead Energy Market calculates and publishes LMPs at the various pnodes based on supply offers, external transaction offers, virtual (financial) offers and bids, and day-ahead demand bids. The market-clearing process for the Real-Time Energy Market is based on supply offers, real-time load, and offers and bids to sell (import) or buy (export) energy over the external interfaces.

2.1.2.1 Actual and Virtual Trading in the Day-Ahead Energy Market

The intersection of the supply and demand curves as offered and bid, along with transmission constraints and other system conditions, determines the Day-Ahead Energy Market price at each node and results in the binding financial schedules and commitment orders (refer to Figure 2-1). Market participants that have *real-time load obligations* (RTLOs) (i.e., they are serving load) may submit demand bids in the Day-Ahead Energy Market. Participants may bid *fixed demand* (i.e., they will buy at any price) and *price-sensitive demand* (i.e., they will buy up to a certain price) at their load zone (or pnode, for some participants that meet certain requirements). Generating units may submit three-part supply offers for their output at the pricing node specific to their location, including start-up, no-load, and incremental energy offers. Start-up offers reflect the costs associated with bringing a unit from an off-line state to the point of synchronizing with the grid. No-load offers reflect the hourly cost of operating that does not depend on the megawatt level of output. Incremental energy offers represent the willingness of participants to operate a resource at higher output levels for higher compensation. The incremental energy offers produce the upward sloping supply curve that is used to calculate the LMP. Market participants have the incentive to submit offers for start-up, no-load, and incremental energy consistent with their true costs to maximize the chance they will be running at profitable levels.

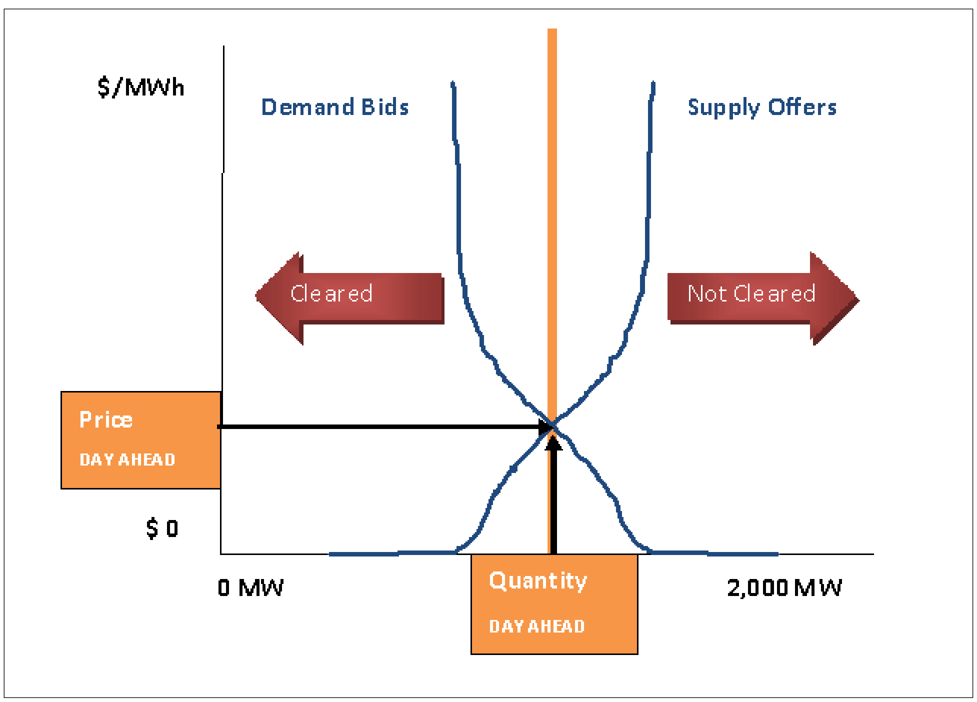

Figure 2-1: Intersection of supply and demand curves indicating the clearing price.

Any participant that satisfies the financial-assurance requirements detailed in the market rules also may bid price-sensitive *virtual demand* at any pricing node on the system in the Day-Ahead Energy Market. Participants also may offer *virtual supply*. Virtual trading enables market participants that are not generator owners or load-serving entities (LSEs) to participate in the Day-Ahead Energy Market by establishing virtual (or financial) positions. It also allows more participation in the day-ahead price-setting process, allows participants to manage risk in a multi-settlement environment, and enables arbitrage that promotes price convergence between the day-ahead and real-time markets.

Demand bids and virtual demand bids both can be used to hedge the difference between day-ahead and real-time prices. Demand bids are well suited to hedge RTLOs, and virtual demand bids can be used to arbitrage expected differences between day-ahead and real-time prices at a node or to hedge a nodal load.

For each megawatt of virtual supply that clears in the Day-Ahead Energy Market, the participant receives the day-ahead LMP and has a financial obligation to pay the real-time LMP at the same location. For each megawatt of cleared virtual demand, the participant pays the day-ahead LMP and receives the real-time LMP at that location. That is, an accepted virtual supply offer in the Day-Ahead Energy Market is offset by a "purchase" in the Real-Time Energy Market, and a cleared virtual demand bid in the Day-Ahead Energy Market is offset by a "sale" in the Real-Time Energy Market. While these transactions affect the day-ahead prices, they do not represent physical supply or withdrawal of energy in real time. The financial outcome for a particular participant is determined by the difference between the day-ahead and real-time LMPs at the location at which the participant's offer or bid clears, plus all applicable transaction costs, including daily reliability costs (refer to Section 2.5).

2.1.2.2 Real-Time Market Supply and Demand and Generator Commitment

The Real-Time Energy Market is a physical delivery market rather than a financial forward market like the Day-Ahead Energy Market. The Real-Time Energy Market is the environment in which the ISO control room commits and dispatches physical resources to meet actual real-time load, including the minute-to-minute balancing of energy and reserves while accounting for transmission system limits and the need to provide contingency coverage. While the financial schedules produced by the Day-Ahead Energy Market clearing process provide a starting point for the operation of the Real-Time Energy Market, the amount of needed and available supply at each location can increase or decrease for a number of reasons. First, all generators have the flexibility to revise their incremental energy supply offers during the *reoffer period*.[59] In addition, generating-unit and transmission line outages, along with unexpected changes in demand, can cause the ISO to call on additional generating resources to preserve the balance of supply and demand.

As part of its Reserve Adequacy Analysis (RAA) process, the ISO also may be required to commit additional generating resources to support local-area reliability or to provide contingency coverage, which ensures that the system reliably serves actual demand; the required operating-reserve capacity is maintained; and transmission line loadings are safe. For this process, the ISO evaluates the set of generator schedules produced by the Day-Ahead Energy Market solution, any self-schedules that were submitted during the reoffer period, and the availability of resources for commitment near real time. The ISO will commit additional generation if the Day-Ahead Energy Market generation schedule, plus the self-scheduled resources and available off-line fast-start generation, does not meet

[59] The *reoffer period* is the time spanning 4:00 p.m. and 6:00 p.m. on the day before the operating day during which a market participant may submit revised resource offers.

the real-time forecasted demand and reserve requirements that ensure system reliability (see Section 2.3 for more on reserves).

All the circumstances that affect the level of generator dispatch, such as changes in the level of demand, actual generator availability, and system operating conditions, affect the real-time LMPs. At times, in import-constrained areas, where transmission interfaces limit the flow of economic energy, demand is high relative to local economic supply, and more expensive generation may need to be called on. This results in higher LMPs in that area and lower LMPs on the export side of the interface. In contrast, in export-constrained areas—which contain more low-priced capacity relative to local demand and export capacity—relatively low-cost energy is available to serve load but cannot be dispatched while respecting transmission limitations. These areas can experience lower LMPs compared with unconstrained areas that can more readily export excess supply. Financially, the Real-Time Energy Market is settled based on the deviation between the day-ahead market outcome schedule and the actual production or consumption of electricity in real time.

2.2 Forward Capacity Market

In 2002, the FERC charged the ISO with revising the Installed Capacity (ICAP) Market to better address resource adequacy and local reliability issues in New England.[60] This directive culminated in a Settlement Agreement that was negotiated before a FERC settlement judge and was approved by numerous stakeholders, including state officials, utility companies, generating companies, consumer representatives, regulators, and other market participants.[61] On June 16, 2006, FERC approved the agreement, which provided a framework for drafting the Forward Capacity Market rules. FERC approved the FCM rules on April 16, 2007.

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. The market is designed to promote economic investment in supply and demand resources where they are needed most. Capacity resources may be new or existing resources and include supply from power plants, 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, Forward Capacity Auctions (FCAs) are held each year approximately three years in advance of when the capacity resources must provide service. Capacity resources compete in the annual FCA to obtain a commitment to supply capacity in exchange for a market-priced capacity payment.

The period between the December 2006, when the FCM Settlement Agreement terminated the Installed Capacity Market, and June 1, 2010, when the winners of the first FCA must deliver capacity, is referred to as the FCM transition period. The FCM Settlement Agreement prescribed a schedule of fixed payments to resource owners during this time to compensate them for maintaining their availability and developing new capacity.

[60] *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing* (SMD Order), FERC Docket Nos. ER02-2330-000 and EL00-62-039 (September 20, 2002), p. 37.

[61] For background information, see *Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues,* FERC Docket Nos. ER03-563-000, -030, -055 (filed March 6, 2006; as amended March 7, 2006).

This section describes the design of the Forward Capacity Market and FCAs and financial-assurance mechanisms and oversight procedures that are in place for this market.

2.2.1 Capacity Requirements

The capacity needed to satisfy the region's systemwide future load and reliability requirements is called the *Installed Capacity Requirement* (ICR).[62] The net Installed Capacity Requirement (NICR) values are the ICRs for the region, minus the tie-reliability benefits associated with the Hydro-Québec Phase I/II Interface (termed HQICCs).[63] Other key FCM inputs include locational capacity needs to ensure that local areas secure ample supplies during the auction for maintaining reliability during the capability period when transmission constraints prevent the system from delivering the needed electric energy to the area. The FCM auction assumptions are based on network models that account for the power lines that will be in service no later than the first day of the relevant capacity commitment period.[64]

The locational information is provided for specific *capacity zones* (i.e., geographic subregions of the New England Balancing Authority Area that may represent load zones that are export constrained, import constrained, or contiguous—neither export nor import constrained). Import-constrained areas, which have insufficient local capacity, are assigned a *local sourcing requirement* (LSR). Export-constrained areas, which have a surplus of capacity, are assigned a *maximum capacity limit* (MCL).

During each FCA, existing FCM resources are limited to a service period of one capacity commitment period, while new resources may commit to as many as five such periods at the FCA price. Performance penalties for delivery shortfalls during the service period ensure that resources purchased through the auction will be available when needed.

2.2.2 Cost of New Entry

The *cost of new entry* (CONE) is a threshold price used to calculate the starting price for each Forward Capacity Auction.[65] These prices are based on the estimated fixed costs for developing capacity resources in the region and the clearing price of previous FCAs. CONEs establish a $/kilowatt (kW)-month value of the cost for an investor to develop, site, and maintain a new simple-cycle gas-fired generator in New England's market. This would include such costs as siting, permitting, developing, and purchasing land, as well as fixed ongoing operation costs, such as staffing, maintenance, taxes, and recovery of the investment over time. The CONE was set at $7.500/kW-month for the first FCA, $6.000/kW-month for the second FCA, and $4.918/kW-month for FCA #3.

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[62] The ICR is the total amount of installed capacity the system needs to meet the Northeast Power Coordination Council (NPCC) loss-of-load expectation criterion (LOLE) to not disconnect load more than one time in 10 years. The ICR is filed with FERC before each auction. For additional information on the LOLE criterion, refer to the ISO's *2009 Regional System Plan* (RSP09) (http://www.iso-ne.com/trans/rsp/2009/index.html) and NPCC criteria at http://www.npcc.org/documents/regStandards/Criteria.aspx (New York: NPCC Inc., 2007).

[63] As defined in the ISO's tariff, the HQICC is a monthly value that reflects the annual installed capacity benefits of the HQ Interconnection, as determined by the ISO using a standard methodology on file with FERC.

[64] A *capacity commitment period* is also known as a *capability year* and runs from June 1 through May 31 of the following year. *In service* is when a unit or transmission line is available for use.

[65] The cost of new entry also is used for controlling market power concerns with "delist bids" (see below) and in determining reserve pricing (see Section 2.3.2) when supply is inadequate and competition is insufficient.

2.2.3 Resource Qualification

Because only resources with a capacity supply obligation (CSO) are required to offer into the Day-Ahead Energy Market, and because only the ICR amount is procured in the auction, it is critical for each FCA to procure only those capacity resources that will be commercial and available at the beginning of each capability year.[66] Although generating, demand, and import resources all may participate in the FCA to receive a CSO, the FCA treats new and existing capacity resources differently. Each type of resource has a distinctive qualification process designed to determine the amount of qualified capacity that a particular resource can supply and to certify that each resource can reasonably be expected to be available during the relevant commitment period (approximately three years after the auction).

2.2.3.1 Existing Capacity Resource Qualification

The qualification process for existing capacity resources begins with the ISO's determination of each resource's *summer-qualified capacity* (i.e., the maximum amount of capacity a resource can offer in the FCA during the commitment period's summer portion, which is June through September). For existing resources, the qualification process relies on a resource's demonstrated performance over the previous five years. The ISO also determines each resource's *winter-qualified capacity* for the winter portion of the commitment period (October through May).[67]

The ISO notifies existing resources of their qualified capacity at least two weeks before the existing capacity qualification deadline so that participants may verify that their qualified capacity is correct or seek redress by demonstrating that a different capacity quantity is appropriate. All existing resources are included in the auction at the lower of their summer- and winter-qualified capacity. They also are automatically entered into the capacity auction and assume a capacity supply obligation for the relevant commitment period, unless they submit a "delist bid" that subsequently clears in the auction.

Delist bids. 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 the capacity obligation below a certain price. Several types of delist bids exist:

- *Static delist bids* are submitted for a resource before the auction and cannot be changed during the auction. They may reflect either the cost of the resource or a reduction in ratings as a result of ambient air conditions.[68] The ISO may be required to submit a static delist bid on behalf of a resource if the resource's summer-qualified capacity is greater than its winter-qualified capacity because the resource will not be able to supply its awarded capacity during the winter period.

[66] A *capacity supply obligation* is a requirement for a resource to provide capacity, or a portion of capacity, to satisfy a portion of the ISO's Installed Capacity Requirement that is acquired through an FCA, a reconfiguration auction, or a CSO bilateral contract through which a market participant may transfer all of part of its CSO to another entity.

[67] The methodology for qualifying intermittent resource capacity, such as wind resources, is contained in *Market Rule 1*, Section III.13, Forward Capacity Market; http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[68] "Ambient air" delist bids are those made to reflect that a thermal generator's summer capability is less than its winter capability because high ambient air temperatures can reduce the generator's capacity ratings.

- *Dynamic delist bids* are submitted by participants during an auction. Unlike other types of delist bids, dynamic delist bids can be offered below 0.8 times the CONE threshold price, and the Internal Market Monitor does not oversee these bids (see below).

- *Permanent delist bids* prohibit resources from participating in any future auctions unless they qualify for and clear as a new resource in a subsequent FCA. Additionally, as of the date of the permanent delisting, permanently delisted resources are prohibited from assuming any capacity obligation.

- *Nonprice retirement bids* are requests to retire the entire capacity of a generating capacity resource. These requests are subject to review for reliability impacts, but generating capacity resources that have had such requests denied must still retire as soon as practicable after the ISO has determined that the bid must be rejected for reliability reasons. Once submitted, nonprice retirement requests supersede any previous delist bids for the same capacity commitment period.

- *Export delist bids* are similar to static delist bids but may have an opportunity cost component as part of the cost data.

- *Administrative export delist bids* are submitted for capacity exports associated with multi-year contracts and are initiated using the same requirements as for export delist bids.

The ISO reviews all delist bids for reliability purposes. Every delist bid submitted is binding and may not be withdrawn or modified after the submittal deadline.[69] Except for permanent delist bids, all delist bids are effective for the relevant commitment period only. All resources with nonpermanent delist bids are considered to be participating anew without any associated delist bid at the beginning of the next commitment-period qualification.

Internal Market Monitor oversight. To address market power concerns, during the qualification process, the Internal Market Monitor reviews all delist bids that existing generators submitted at prices above the CONE to determine whether bid prices are consistent with a resource's net risk-adjusted going-forward costs and opportunity costs as specified in the rules. All delist bids, except dynamic delist bids, must include sufficient documentation for the Internal Market Monitor to make these determinations; the Internal Market Monitor may reject delist bids that have insufficient supporting documentation for the delist price. Static delist bids, export delist bids above 0.8 times the CONE, and permanent delist bids above 1.25 times the CONE are subject to Internal Market Monitor review. Permanent delist bids that are greater than 0.8 times the CONE but less than or equal to 1.25 times the CONE are presumed to be competitive.

The Internal Market Monitor does not review ambient air delist bids and subsequent years of an administrative export delist bid. The Internal Market Monitor also does not review the costs of delist bids, submitted at any time during the auction, at or below 0.8 times the CONE. These bids are dynamic delist bids that are reviewed for any potential reliability need, however, similar to all delist bids.

[69] To provide market transparency to potential new capacity suppliers, all delist bids submitted during the qualification process are posted in advance of the deadline for new resources to submit bids, with the exception of *dynamic delist bids,* which are submitted during the auction.

No later than 120 days before the auction, the ISO must notify participants whether their delist bids are qualified to participate in the FCA. All accepted delist bids will be entered into the auction. For delist bids that are excluded from the auction as a result of the Internal Market Monitor's review, the ISO will explain in the notification correspondence the specific reasons for not accepting the bid and the Internal Market Monitor's derivation of an alternate delist price.[70] The participant may opt to use this alternate price by informing FERC, subject to applicable market rules.

2.2.3.2 New Capacity Resource Qualification

Like existing resources, new supply-side and demand-side resources must undergo a qualification process to be able to participate in the FCM. Additionally, some resources that previously were counted as existing capacity (including deactivated or retired resources), and incremental capacity from existing resources, may opt to be treated as new capacity resources in the FCM, subject to certain requirements.

To keep barriers to entry low and increase competition, the financial assurance required from new capacity suppliers is relatively low—a minimal level of credit enables more competitors to enter the market because they are not required to assume a relatively large financial guaranty during the project's development. However, because new commitments can be backed by a relatively low amount of financial security, they must undergo a rigorous qualification process and demonstrate that they can provide the capacity they plan to offer in the auction. This process ensures that any new project that clears in an auction can be interconnected before the delivery period and that the participant can back all capacity obligations with tangible assets to build the project.

New supply-side resources. For new power plant proposals, the ISO conducts several different power studies to ensure that a generator can electrically connect to the power grid without having a negative impact on reliability or violating safety standards. The qualification review also assesses the project's feasibility (i.e., whether it realistically can be built and commercialized before the beginning of the relevant capability year). Each new supply-side resource also must be evaluated to ensure that it would be able to provide effective incremental capacity to the system. An overlapping interconnection impact analysis is conducted for each new supply-side resource to assess whether it is capable of providing useful capacity and electric energy without negatively affecting the ability of other capacity resources to provide these services also.

The first step to qualify a new capacity resource is for project sponsors to submit a new capacity show-of-interest (SOI) form. The SOI form is a short application that requests a minimum amount of information (e.g., interconnection point, equipment configuration, megawatt capacity). By the new capacity qualification deadline, the sponsor also must submit a completed qualification package for the project. This package must include all the data required for the ISO to evaluate the interconnection of the project and its feasibility. Also at this time, new capacity import resources must provide documentation indicating the interface from which the capacity will be imported, the source of the capacity (from an external generating resource or from an adjacent balancing authority area), and the import's summer and winter capability ratings.

[70] FERC's FCM Settlement Agreement contained the thresholds for delist bids requiring IMM review: SMD Order. FERC Docket Nos. ER02-2330-000 and EL00-62-039 (September 20, 2002). p. 37.

New demand-side resources. Demand-reduction resource proposals undergo a feasibility review, during which the ISO ensures that the plans and methods for reducing electricity use meet industry standards. This is the prime mechanism for assessing demand-response project criteria because these projects have no interconnection impact. For this review, demand resources submit a measurement and verification plan, which outlines the project and its development and how the demand reduction is to be achieved. However, some demand-response resources are available only during the summer, and alone, they would not be able to satisfy the year-long delivery requirement. To address this issue, the FCM allows a summer-only resource, such as demand response, to combine its offer with a winter-only resource to form a composite offer. In addition to meeting the same qualification requirements as new and existing resources, demand-resource composite offers also must conform to whatever limitations exist between capacity zones used in the auction. A summer resource inside an import-constrained zone cannot combine with a winter resource outside that zone.

Internal Market Monitor oversight. Per *Market Rule 1,* the Internal Market Monitor must review offer prices submitted for new resources that intend to remain in the auction below 0.75 times the CONE to confirm that the offer price reflects the long-run cost of the resource.[71] Thus, the qualification packages for these resources must contain supporting cost information for Internal Market Monitor review. If the Internal Market Monitor determines that the offer is inconsistent with the long-run average costs, net of expected noncapacity revenues, capacity that clears at prices below 0.75 times the CONE will be considered to be offered below cost and thus out-of-market (OOM) for purposes of determining the applicability of the "Alternative Capacity Price Rule."[72]

Notification and filing. No later than 120 days before each FCA, the ISO notifies each sponsor engaged in the qualification process regarding whether its new capacity resource has been accepted for participation in the FCA, the qualified capacity of that resource, and the Internal Market Monitor's assessment, if the sponsor intends to offer the resource below 0.75 times the CONE. Additionally, all qualification results and auction inputs are filed with FERC. This informational filing is made approximately three months before the ISO conducts the auction and provides interested parties the opportunity to review and comment on the ISO's fulfillment of its responsibilities before conducting the FCA.

2.2.4 Auction Design

Each Forward Capacity Auction is conducted in two stages; a descending-clock auction followed by an auction clearing process. The descending-clock auction, run by an independent auctioneer, consists of multiple rounds. Before the beginning of each round, the auctioneer announces to all participants the start of-round and end-of round prices. During the round, participants submit offers expressing their willingness to keep specific megawatt quantities in the auction at different price levels within the range of the start-of-round and end-of-round prices. During one of the rounds, the capacity willing to remain in the auction at some price level will equal or fall below the ICR; the capacity level the ISO has determined according to North American Electric Reliability Corporation (NERC) standards and Northeast Power Coordinating Council (NPCC) and ISO New England requirements to maintain

[71] *Market Rule 1*, Section III.13.1, Standard Market Design, is available at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[72] The Alternative Capacity 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 at 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, available at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

reliability (see Section 2.5).[73] FCM resources still in the auction at this point pass on to the auction-clearing stage.

Table 2-1 shows the hypothetical result of a descending-clock FCA. This example assumes that the CONE is $7.50/kW-month; the ICR equals 30,000 MW; 23,000 MW of existing capacity will be participating, and thus 7,000 MW of new resources will be needed to meet the ICR; and 10,000 MW of new capacity will be participating.

Table 2-1
Sample Results from a Descending-Clock Forward Capacity Auction

Round	Start-of-Round Price ($/kW-mo)	End-of-Round Price ($/kW-mo)	End-of-Round Resource (MW)	Excess Capacity (MW)
1	$15.00[(a)]	$9.50	33,000	3,000
2	$9.49	$9.00	32,500	2,500
3	$8.99	$8.00	32,000	2,000
4	$7.99	$7.50	31,000	1.000
5	$7.49	$7.00	30,750	750
6	$6.99	$6.00	29,800	−200

(a) The start-of-round price = (CONE x 2).

All the capacity resources that remained in the auction at the end of round six pass through to the second stage of the FCA when market-clearing auction software is run to determine the minimal capacity payment and calculate final capacity-zone clearing prices. This step also includes a post-processing procedure that determines the final payment rate for each resource and its capacity supply obligation for the capacity commitment period. Thus, in the example of Table 2-1, after the sixth round, the market-clearing auction software is run to determine the resources and price that minimize cost at a purchase amount of 30,000 MW.

Reconfiguration auctions take place before and during the commitment period to allow participants to buy and sell capacity obligations and adjust their positions. These auctions are needed to add capacity to cover an increased ICR, to release capacity to match a decreased ICR, and to defer capacity requirements associated with existing capacity delist bids. Annual reconfiguration auctions 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 the first commitment period, adjust the annual commitments during the commitment period.

2.2.5 Capacity Payments

After June 1, 2010, when the FCM transition period ends, resources with capacity obligations obtained in the FCAs or subsequent reconfiguration auctions will be paid the auction clearing prices and not the flat rate they received during the transition period.

[73] For more information on NERC standards, see https://standards.nerc.net (Princeton: NERC, 2008). For more information on NPCC standards, see http://www.npcc.org/regStandards/Overview.aspx (New York: NPCC Inc., 2009).

Two key provisions of the capacity payment structure are the *peak energy rent* (PER) adjustment and availability penalties incurred for unavailability during shortage events. PER 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 resource on the system. This usually occurs when electricity demand is high. PER provides an additional incentive for capacity resources to be available during peak periods because capacity payments are reduced for all listed resources even if they are not producing energy when the LMP exceeds the PER threshold price. PER also discourages physical and economic withholding in the energy market because if a resource withholds to raise price, it does not earn energy revenues, while their foregone revenues are deducted from the capacity market settlement.

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 but are unavailable during defined shortage events. The availability penalties are a disincentive to withhold in the energy market.

2.3 Reserve Markets

To maintain system reliability, all bulk power systems, including ISO New England, need reserve capacity to be able to respond to contingencies, such as those caused by unexpected outages. *Operating reserves* are the unloaded capacity of generating resources, either off line or on line, that can deliver electric energy within 10 or 30 minutes.[74] ISO operating procedures require reserve capacity to be available within 10 minutes to meet the largest single system contingency (N-1). A resource's ability to provide 10-minute reserve from an off-line state is referred to as "claim-10" capability.[75] Additional reserves must be available within 30 minutes to meet one-half of the second-largest system contingency (N-1-1). The ISO identifies local second-contingency-protection resources (LSCPRs) to meet the second-contingency requirements in import-constrained areas of New England. A resource's ability to provide 30-minute reserve from an off-line state is referred to as "claim-30" capability. In general, capacity equal to between one-fourth and one-half of the 10-minute reserve requirement must be synchronized to the power system, or be *10-minute spinning reserve* (TMSR), while the rest of the 10-minute requirement may be *10-minute nonspinning reserve* (TMNSR). The entire 30-minute requirement may be served by *30-minute operating reserve* (TMOR) or the higher-quality 10-minute spinning reserve or nonspinning reserve. In addition to the systemwide requirements, 30-minute reserves must be available to meet the local second contingency in import-constrained areas.

In the New England system, participants with resources that provide reserves are compensated through both the locational Forward Reserve Market (FRM), which offers a product similar to a capacity product, and real-time reserve pricing. The FRM obligates participants to provide reserve capacity in real time through a competitive, intermediate-term forward-market auction. When the ISO dispatches resources in real time and sets LMPs, the process co-optimizes the use of resources for providing electric energy and real-time reserves. When resources are dispatched to a lower level in real time to provide reserve capacity rather than electric energy, a positive real-time reserve price for the product is set, recognizing the resource's opportunity cost of providing reserve rather than energy.

[74] Some demand-side resources also can provide reserves; see Section 2.7.

[75] After a unit is upgraded or maintained, it may request a reaudit to have its improved reliability reflected in its claimed values. Changes in total claim-10 and claim-30 capability also can result from new or existing units demonstrating their capability or any time the ISO requests a unit to start.

The real-time reserve prices also reflect additional costs to the system for dispatching some other, more expensive resource to provide electric energy to replace the output of the resource that was dispatched down.

The New England system has reserve requirements for its locational FRM and real operations. Systemwide requirements exist for TMSR, TMNSR, and TMOR. TMOR requirements exist for reserves in the region's four reserve zones—Connecticut (CT), Southwest Connecticut (SWCT), NEMA/Boston, and the rest of the system (Rest-of-System, ROS). The *Rest-of-System* zone is defined as the area excluding the other, local reserve zones.

This section provides an overview of the locational Forward Reserve Market for procuring reserve obligations for winter and summer periods. It also discusses real-time reserve pricing, which compensates resources that provide reserves needed in real time, and the ISO's implementation of scarcity pricing.

2.3.1 Forward Reserve Market

The Forward Reserve Market is designed to attract investments in, and compensate for, the type of resources that provide the long-run, least-cost solution to satisfying off-line reserve requirements. The locational FRM compensates participants with resource capacity located within specific subareas for making the type of electric energy market offers that would make them likely to be unloaded and thus available to provide energy within 10 or 30 minutes. Typically, these resources are fast-start units that run infrequently throughout the year (i.e., they have low *capacity factors*).[76] However, the FRM also compensates resources that commit to be on line without *Net Commitment-Period Compensation* (NCPC) and have upper portions of the dispatch range that typically are unloaded.[77]

The ISO conducts two FRM auctions, one each for the summer and winter reserve periods (June through September and October through May, respectively), that acquire obligations to provide prespecified quantities of each reserve product. Forward-reserve auction clearing prices are calculated for each reserve product in each reserve zone. When supply offers for forward reserve are not adequate to meet a requirement, the clearing price for that product is set to the price cap, which is $14.00/kW-month.[78] When enough supply is offered under the price cap to meet the requirement for a product in a particular zone, the auction clearing price for that product is set equal to the price of the marginal supply offer. Actual FRM payments to participants are reduced by the FCM transition rate (or the FCA auction price after June 1, 2010) to avoid compensating the same resource megawatt as both general capacity and forward-reserve capacity.

[76] A *capacity factor* is the ratio of the electric energy a generating unit produced for a certain period of time to the electric energy it could have produced at full operation during the same period.

[77] *Net Commitment Period Compensation* is a method of providing 'make-whole' payments to market participants with resources that are 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. NCPC is paid to resources for providing first- and second-contingency voltage support and control and distribution system protection in either the Day-Ahead or Real-Time Energy Markets. The accounting for the provision of these services is performed daily and considers a resource's total offer amount for generation, including start-up fees and no-load fees, compared with its total energy market value during the day. If the total value is less than the offer amount, the difference is credited to the market participant. For more information, see *Market Rule 1*, Section III, Appendix F: Net Commitment-Period Compensation Accounting, at http://www.iso-ne.com/regulatory/tariff/sect_3/.

[78] *Market Rule 1*, Section III.9.4, Forward Reserve Auction Clearing and Forward Reserve Clearing Prices (October 1, 2006); http://www.iso-ne.com/regulatory/tariff/sect_3/.

The forward-reserve auction clears megawatt obligations that are not resource specific. But before midnight of the day before the operating day, participants that win obligations in a forward-reserve auction must assign physical resources to satisfy their FRM obligations. To do so, before the end of the reoffer period for the Real-Time Energy Market, they submit electric energy offers that exceed a threshold price for designated resources they control to satisfy the obligation.

To attract and maintain resources that normally are expected to provide reserves instead of electric energy, the FRM requires the resources designated as forward-reserve resources to offer the megawatt quantity of energy equal to the FRM obligation at or above a threshold price. Participants would not be expected to designate resources that normally are *in merit* below this level because they would forego the energy revenue from operating.[79] Designating high-incremental-cost peaking resources, on the other hand, does not create a lost opportunity cost because the resource would not be dispatched to provide energy under normal circumstances.

The intent of the market design is to set threshold prices to approximate the marginal cost of a peaking resource with an expected capacity factor of 2 to 3%.[80] If the threshold price is set accurately, LMPs should exceed the threshold price only 2 to 3% of the time. A resource offered at exactly the threshold will then be dispatched only when the LMP exceeds the threshold price. If the threshold price is set too low, a forward-reserve-designated unit offered at the threshold price will be dispatched to provide electric energy more frequently and therefore will be unavailable to provide reserve. If this occurs more than 2 to 3% of the time, forward-reserve-designated resources will be dispatched more frequently than intended.[81] If participants expected LMPs to be higher than the threshold price on a regular basis, the reserve market could inadvertently attract resources that are better suited to provide electric energy than reserve.

The reserve obligations incurred in the auction can be met with bilateral transactions as well as any reserve-capable resource in the participant's portfolio. Bilateral trading of forward-reserve obligations allows suppliers facing unexpected unit outages to substitute alternative resources. This feature is useful to suppliers if the cost of expected penalties for nondelivery exceeds the cost of acquiring substitute resources through bilateral transactions. Failure to designate a unit they control or the transfer of the obligation to another participant results in the assessment of a "failure-to-reserve" penalty.

The locational FRM acquires only those resources needed to satisfy off-line reserve requirements, namely TMNSR and TMOR; spinning reserve is not acquired in the forward market. Unlike real-time reserve pricing, the locational FRM auction acquires an amount of off-line reserves specifically within the Rest-of-System zone. This requirement is intended to ensure that real-time reserve

[79] *Economic-merit order* (i.e., *in merit* or *in merit order*) is when the generators with the lowest-price offers are committed and dispatched first, and increasingly higher-priced generators are brought on line as demand increases.

[80] The formula for determining the forward-reserve threshold price is fixed for the duration of the forward-reserve period. This price changes monthly with fuel-price indices and is calculated as a heat rate multiplied by a fuel index. The forward-reserve heat rate also is fixed in the auction notice and does not change during the forward-reserve service period. The threshold price calculation uses the lesser of an index for No. 2 fuel oil and one for natural gas. (A generator's *heat rate*, traditionally reported in Btu/kWh, is the rate at which it converts fuel [Btu] to electricity [kWh] and is a measure of the thermal efficiency of the conversion process.)

[81] A threshold price can be lower than the LMP more than the intended 2 to 3% of the time if the fuel index used in calculating the threshold price is lower than actual fuel prices. The 2 to 3% target also can be surpassed if the system is tighter than expected more frequently, thus requiring the dispatch of less efficient resources. In this case, LMPs will be higher.

resources will be distributed throughout New England rather than concentrated in a few pockets. The ISO tariff requires 600 MW of Rest-of-System TMOR to be available. To meet this requirement reliably, the ISO has established an "R-factor" that is used to set auction requirements. The R-factor increases the amount of systemwide TMOR that is acquired in the auction to account for real-time failures to start. Currently, the R-factor is set at 1.33.

The cost of paying resources to provide reserves is allocated to market participants based on real-time load obligations in load zones.[82] These obligations are price-weighted by the relative forward-reserve clearing prices of the reserve zones that correspond to each load zone.[83]

2.3.2 Real-Time Reserve Pricing

The reliable operation of the system requires that real-time operating reserves be maintained for the system as a whole and for identified transmission-import-constrained areas.[84] The ISO's operating-reserve requirements, as established in Operating Procedure No. 8, *Operating Reserve and Regulation* (OP 8), protect the system from the impacts associated with a loss of generating or transmission equipment within New England.[85] According to OP 8, the ISO must maintain a sufficient amount of reserves to be able to recover from the loss of the first contingency within 10 minutes.

In real time, resources are dispatched in the least-cost way to meet the system's requirements for electric energy and reserves simultaneously. The system has real-time reserve requirements (MW) for the following reserve categories:

- System 10-minute spinning reserves
- System 10-minute nonspinning reserves
- System 30-minute operating reserves
- Zonal TMOR for each reserve zone other than the ROS zone

Reserve pricing optimizes the use of local transmission capabilities and generating resources to provide electric energy and reserves. This allows the dispatch software to choose whether transmission should be used to carry electric energy or left unloaded to provide reserves when satisfying zonal reserve requirements. This optimization is based on the real-time energy offers of resources; there are no separate real-time reserve offers. *Real-time reserve credits* are the revenues paid to participants with resources providing reserve during periods with positive real-time reserve prices.

Reserves may be allowed to decline below requirements in real time, such as during ISO Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*, if capacity is short and the system

[82] *Market Rule 1*, Manual 28, Accounting (December 1, 2007); http://www.iso-ne.com/rules_proceds/isone_mnls/.

[83] The forward-reserve prices for the ROS reserve zone are used to calculate the charges allocated to load-serving entities in the ME, NH, VT, RI, SEMA, and WCMA load zones. The forward-reserve prices for the SWCT and CT reserve zones are used to calculate the charges allocated to LSEs in the CT load zone, while the forward-reserve prices for the NEMA/Boston reserve zone are used to calculate the charges allocated to the NEMA load zone.

[84] Refer to the ISO's RSP09 for additional information on operating-reserve requirements; http://www.iso-ne.com/trans/rsp/2009/index.html.

[85] ISO Operating Procedure No. 8, *Operating Reserves and Regulation* (June 5, 2006); http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html.

cannot be redispatched to maintain reserve.[86] Before allowing reserve to decline, the system will redispatch resources to maximize the amount of reserve available. Redispatch typically involves decreasing the output of units with fast ramping capabilities that were providing electric energy and increasing the output of slower, more expensive units to replace this energy. The result is the decrease in electric energy output of the faster-ramping resources to provide reserve and the replacement of this lost energy with output from higher-cost resources, which results in higher electric energy prices (LMPs). The resulting real-time reserve prices represent the scarcity of reserve on the system. Local reserve shortages resulting from a complete capacity deficiency are rare. In most cases, reserve can be maintained through the process of redispatch, with appropriate compensation through real-time reserve pricing.

Reserve-constraint penalty factors (RCPFs) are administratively set limits on redispatch costs ($/megawatt hour; $/MWh) the system will incur to meet reserve constraints. Each constraint of a reserve requirement has a corresponding RCPF, shown in Table 2-2. The RCPFs are cumulative; the total redispatch cost the system will incur to preserve TMSR is the sum of the RCPFs for TMSR, TMNSR, and TMOR. Similarly, the total redispatch cost the system will incur to preserve TMNSR is the sum of the RCPFs for TMNSR and TMOR. The following table lists the RCPF values.

Table 2-2
New England Reserve-Constraint Penalty Factors, $/MWh

Constraint	Reserve-Constraint Penalty Factor
Systemwide TMSR constraint	50
Systemwide total 10-minute reserve constraint	850
Systemwide total 30-minute reserve constraint	100
Local 30-minute reserve constraint[(a)]	50

(a) On January 1, 2010, this value changed to $250.

2.4 Regulation Market

Regulation is the capability of specially equipped generators and other energy sources to increase or decrease their output every four seconds in response to signals they receive from the ISO to control slight changes on the system. This capability is necessary to balance supply levels with the second-to-second variations in demand and to assist in maintaining the frequency of the entire Eastern Interconnection.[87] This system balancing also maintains proper power flows into and out of the New England Balancing Authority Area.

The primary objective of the Regulation Market, which is the mechanism for selecting and paying resources needed to manage system balancing, is to ensure that the ISO meets NERC's *Real Power*

[86] 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/.

[87] 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 Council of Texas (ERCOT).

Balancing Control Performance Standard (BAL-001-0) for balancing authority areas.[88] The primary measure used for evaluating control performance is Control Performance Standard 2 (CPS 2), which is as follows:[89]

> *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}.*[90]

For the New England Balancing Authority Area, the CPS 2 annual average compliance target is 92 to 97%. The ISO periodically evaluates the regulation requirements necessary to maintain CPS 2 compliance. The regulation requirements (posted on the ISO's Web site) are determined by hour and vary by time of day, day of week, and month.[91]

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 unit-specific opportunity cost payments. Unit-specific opportunity cost payments are not included as a component of the regulation clearing price.

2.5 Reliability Costs

To maintain daily system reliability, the ISO is required to make generator commitments that supplement the market-clearing outcomes. Resources that are requested to operate out of merit or do not fully recover short-run operating costs are compensated with Net Commitment-Period Compensation. To maintain long-term reliability, the ISO administers FERC-approved agreements, called Reliability Cost-of-Service Agreements (Reliability Agreements), with certain generator owners.

This section discusses the types of reliability commitments and the process for making these commitments and allocating costs for resources committed in supplement to the market-clearing process. The section also contains information about the Reliability Agreements that compensate generation owners for maintaining resources deemed necessary for the reliable operation of the system.

2.5.1 Daily Reliability Commitments and Costs

The requirements for ensuring the reliability of New England's bulk power system reflect standards developed by NERC, NPCC, and the ISO through open stakeholder processes.[92] These requirements

[88] 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 (Princeton, NJ: NERC, 2010).

[89] 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).

[90] The *area control error* of the New England Balancing Authority Area is the actual net interchange minus the biased scheduled net interchange; see *ISO New England Manual for Definitions and Abbreviations—Manual 35*; http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

[91] The ISO's regulation requirements are available at http://www.iso-ne.com/sys_ops/op_frcstng/dlyreg_req/index.html.

[92] For more information on NERC standards, see https://standards.nerc.net (Princeton: NERC, 2009). For more information on NPCC standards, see http://www.npcc.org/regStandards/Overview.aspx (New York: NPCC Inc., 2009).

are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures.[93] To meet these requirements, the ISO may commit resources in addition to those cleared in the Day-Ahead Energy Market.

The ISO may commit and dispatch generation to create reserve that allows the system to recover from the loss of the first contingency within the specified time period by providing energy on short notice. Not having these resources committed to operate would pose a threat to the reliability of the system. Generators also can be committed to provide systemwide stability or thermal support or to meet systemwide electric energy needs during the daily peak hours. All generators have a minimum run time, and resources committed for peak hours often are still on line after the peak hours to satisfy minimum run-time requirements. The ISO also may commit resources to support second contingencies, to provide reactive power for voltage control or support, or to support local distribution networks. Resources that operate because the ISO requires them to do so but do not recoup their full operating costs (represented by their three-part offers) through electric energy market revenues are paid one of the following types of compensation:

- First-contingency Net Commitment-Period Compensation
- Local second-contingency Net Commitment-Period Compensation
- Voltage reliability payments
- Distribution reliability payments

Systemwide first-contingency costs are financially settled through first-contingency reliability payments paid by the entire system. Local second-contingency commitments costs are settled at the zonal level. The cost of resources committed to provide reactive power for voltage control or support are allocated to transmission owners locally, for high voltage, and systemwide, otherwise. The cost of local transmission-support costs are allocated to the transmission owner requesting the commitment.

2.5.1.1 Reliability Commitment Process

Electric energy market outcomes play an important role in the need for out-of-market commitments for reliability. While some commitments may be made before or immediately after the Day-Ahead Energy Market clears as part of the ongoing Reserve Adequacy Analysis, most are made after the reoffer period or later in the RAA process (see Section 2.1.2.2). This process is designed to maximize the opportunity for the market to respond to the need to ensure reliability and minimize the ISO's supplemental commitments to meet reliability criteria. Based on the RAA, commitments may be added or cancelled during the operating day if reliability needs change as a result of market response or other changed system conditions. When multiple generators are available to meet the RAA requirements, the ISO process selects the resources that will have the lowest total cost for starting and operating the resource at its minimum load for its minimum run time. To the extent that market outcomes and resource self-scheduling result in the commitment of resources needed for local reliability, the ISO does not have to manually commit resources for second-contingency or voltage services.

[93] The ISO's system operating procedures are available at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

2.5.1.2 Reliability Commitment Costs

Reliability payments are calculated in both the Day-Ahead Energy Market and Real-Time Energy Market. First-contingency and second-contingency NCPC payments, voltage-reliability payments, and distribution-reliability payments are made to eligible pool-scheduled generators whose output is constrained above or below the economic level, as determined by the LMP in relation to their offers. This compensation is based on a daily calculation comparing the generators' submitted offer cost for providing electric energy, including start-up and no-load offers and the incremental energy offers, to the resources' total energy market revenues for the day. This ensures that generators will follow dispatch instructions made to provide reliability even if a daily loss will result in the energy market at the offer cost. In the electricity industry, these payments are sometimes referred to as *uplift*. If a generator operates in economic-merit order, most of its compensation will be from the electric energy market.

While generators committed to ensure first-contingency coverage (systemwide reliability) may have been in merit during peak hours, they may be out of merit in other hours and will receive first-contingency reliability payments. Or, electric energy market revenues may have been insufficient to cover start-up costs and no-load costs for resources that are dispatched in economic-merit order to provide energy. First-contingency reliability payments are paid to resources committed by the ISO that do not recover the short-term variable operating costs for the day and are not designated to provide second-contingency reliability or to meet requirements for voltage or distribution system reliability.

2.5.1.3 Daily Reliability Cost Allocations

The out-of-market costs associated with daily reliability payments to generators are allocated to market participants. The allocation of voltage and distribution payments is governed by Section II of the ISO tariff (*Open Access Transmission Tariff*), whereas the allocation of first- and second-contingency payments is governed by Section III of the tariff (*Market Rule 1*).[94] According to the ISO tariff, all New England transmission owners share voltage payments on the basis of network load, and distribution payments are assigned directly to the transmission owners requesting the generator commitment to protect their distribution system.

First-contingency reliability costs in the Day-Ahead Energy Market are charged to participants in proportion to their day-ahead load obligations. In the Real-Time Energy Market, participants whose real-time load deviates from the day-ahead schedule and participants whose generators deviate from day-ahead schedules and are not following real-time dispatch instructions are charged in proportion to these deviations. Second-contingency reliability costs in the Day-Ahead and Real-Time Energy Markets generally are charged to participants in proportion to their load obligations in the respective markets. As part of a 2007 FERC Settlement Agreement, a two-condition, two-tiered threshold criterion was established that can change the allocation of real-time second-contingency charges, such that the charges are allocated to both network load and load obligation.[95]

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[94] The ISO tariff and its subsections are available at http://www.iso-ne.com/regulatory/tariff/index.html.

[95] *Letter Order Accepting ISO New England Inc.'s 5/18/07 Filing of a Rate Schedule in the Form of an Agreement Reached by the ISO-NE etc, Effective 7/1/07 under ER07-921.* FERC Docket No. ER07-921-000 (June 21, 2007).

2.5.2 Reliability Agreements

Reliability Agreements provide eligible generators with monthly fixed-cost payments for maintaining capacity that provides reliability services. These contractual arrangements, which are subject to FERC approval, provide financial support to ensure that units needed for reliability will continue to be available.

The Reliability Agreements in effect through June 2010 in New England are for full cost of service—the generator recovers its fixed costs in a monthly payment and its variable costs through electric energy offers made at short-run marginal cost. Variable costs not covered by energy market revenues are compensated through daily reliability payments. All capacity market revenues and energy market revenues received in excess of variable costs serve to reduce the monthly fixed-cost payment. Thus, the generator recovers no more than its fixed and variable costs.

2.6 Financial Transmission Rights

As mentioned in Section 2.1.1, transmission constraints can lead to price differences between different locations of the system, and the LMPs throughout the system can be broken down into a marginal cost of energy, which is constant across all nodes; the marginal cost of congestion, which is a measure of the cost of transmission congestion; and the marginal cost of physical losses.

The FTR markets and auction revenue distribution rules were designed to allow participants to hedge physical day-ahead congestion costs and enter the FTR markets to arbitrage FTR auction prices to the expected cost of future congestion. This section discusses the FTR auctions that provide a market-based allocation of future congestion revenue and the administrative distribution of the revenues from these auctions.

2.6.1 FTR Markets

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 costs) that arise when the transmission grid is congested in the Day-Ahead Energy Market. The amount is based on the difference between the day-ahead congestion components of the hourly LMPs at each of the two pnodes that define the FTR and its megawatt quantity acquired in the FTR auctions.[96] Participants can acquire FTRs for any path on the system that is 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 in the FTR auction price at the sink location price minus the source location price.

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 for on-peak and off-peak periods during the year. The auction process also allows participants that may not have physical energy obligations to arbitrage differences between the expected value of an FTR path, defined by the auction price, and the actual value of the FTR path (i.e., the difference between day-ahead congestion components of the source and sink nodes that define the FTR path). Efficient auction outcomes are those that result in average path profits that have a risk-adjusted profit of zero for both on-peak and off-peak FTRs.

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

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

2.6.2 FTR Settlements

Hourly congestion revenues from both the Day-Ahead and Real-Time Energy Markets are accumulated in the Congestion Revenue Balancing Fund (CRBF). Day-ahead congestion for any hour will be a positive value if transmission constraints contribute to price separation on the system. In real time, congestion revenue either can be positive or negative because the real-time market settles on deviations from day-ahead schedules.

Whenever there is congestion on the system in the Day-Ahead Energy Market, every FTR will have an hourly positive target allocation (PTA) or negative target allocation (NTA) that accumulates in the CRBF along with day-ahead and real-time congestion revenues. A *positive target allocation* is created when the congestion component at the sink location of the FTR is greater than the congestion component at the source location of the FTR. Holders of FTRs with positive target allocations are owed payments from the CRBF. A *negative target allocation* is created when the day-ahead sink congestion component of an FTR is less than the FTR's source congestion component. An FTR with a negative target allocation becomes a counterflow settlement with payments due to the CRBF.

The only connection that CRBF target allocations have to the FTR auctions are the megawatt quantities along with the source and sink locations of the FTRs; the prices paid and whether the FTRs were purchased with a negative value (i.e., counterflow FTRs) or a positive value (prevailing-flow FTRs) are irrelevant to the monthly settlement of the FTRs.

2.6.3 Auction Revenue Distribution

The sum of revenues collected during the FTR auctions is distributed to market participants. The ISO tariff includes provisions that allocate this FTR auction revenue back to congestion-paying load-serving entities and transmission customers or owners that have supported the transmission system. The tariff provides two broad classes of participants for the allocation of auction revenues: holders of Qualified Upgrade Awards (QUAs) and Auction Revenue Rights (ARRs). QUAs are assigned to entities that have improved the system's transmission capacity through specific projects, such as generation interconnections, and have accepted QUAs as compensation for a portion of the construction and maintenance of the improved infrastructure rather than network service rights payments. ARRs are the mechanism used to distribute the remainder of the auction revenue to congestion-paying LSEs and transmission customers that have supported the transmission system.

The costs associated with the FTR markets—the administrative costs of holding FTR auctions and settling the FTRs and the potential cost of participants' defaulting on their FTR portfolios—are passed through ISO tariff charges to those with transactions in the FTR market.

2.7 Demand Resources

Along with adequate supply and robust transmission infrastructure, demand resources, which include demand-response resources and "other demand resources" (ODRs), are an important component of a well-functioning wholesale market. The equipment, systems, services, and strategies that make up demand resources may include individual measures at individual customer facilities to reduce end-use demand during specific hours, or a portfolio of measures to reduce demand implemented by many customer facilities and aggregated as a single resource. *Other demand resources* consist of energy efficiency, load management, and distributed generation projects implemented by market participants at retail customer facilities. These resources tend to reduce end-use demand on the electricity network across many hours but usually not in direct response to changing hourly wholesale price incentives. Demand resources of all types may provide relief from capacity constraints and promote more economically efficient uses of electrical energy; some can serve as reserve capacity. In the Forward Capacity Market (see Section 2.2), some types of demand-response resources and ODRs can compete for capacity credits and are paid capacity transition payments similar to supply-side resources. The ISO has two broad categories of demand resources: active and passive. *Active demand resources* are dispatchable, while *passive demand resources* provide load reductions during performance hours. Energy efficiency and load management are examples of passive resources.

While the wholesale electricity markets account for differences in costs of supply that vary with time and location of consumption, demand resources account for differences in costs of service that vary with customers. For example, some customers can reduce their overall energy usage while maintaining the same level of productivity and comfort by implementing energy-efficiency measures. Other customers can supply capacity by eliminating their peak consumption. Others can provide reserves for themselves and others by offering to interrupt electricity usage on short notice. Still others may be able to provide real-time emergency generation (RTEG) in response to capacity deficiencies or system emergencies.[97]

The ISO's special-purpose demand-response programs (or wholesale market integration of demand resources) differentiate demand-resource owners by cost and assign them different market rates. This type of customer differentiation arises naturally in competitive markets whenever customer costs differ and allows lower-cost customers to reap the benefits of their lower costs. Programs that promote demand resources complement the wholesale electricity markets by offering program choices that recognize different customer costs and capabilities.

The ISO operates three real-time, reliability-activated demand-response programs and two price-activated demand-response programs—one based on day-ahead LMPs and one based on forecasted real-time LMPs. The reliability-activated demand-response programs are considered capacity resources by the FCM.

This section describes the ISO's demand-side initiatives.

2.7.1 Reliability Programs

The real-time demand-response programs activated for reliability reasons are as follows:

- **Real-Time 30-Minute Demand-Response Program—**requires demand resources to respond within 30 minutes of the ISO's instructions to interrupt. Participants in this program include

[97] Demand resources include some resources termed *real-time emergency generation*. RTEG is distributed generation that the ISO calls on to operate during certain voltage-reduction or more severe actions but must limit its operation to comply with the generation's federal, state, or local air quality permit(s), or combination of permits. Real-time emergency generators are required to begin operating within 30 minutes, which results in increasing supply on the New England grid, and also to continue that operation until receiving a dispatch instruction allowing them to shut down. Because real-time emergency generators are allowed to run only during voltage-reduction or more severe actions, the market rules limit total RTEG obligations to 600 MW.

emergency generators with emissions permits that limit their use to times when reliability is threatened.

- **Real-Time Two-Hour Demand-Response Program—**requires demand resources to respond within two hours of the ISO's instructions to interrupt.

- **Real-Time Profiled-Response Program—**designed for participants with loads under their direct control that can be interrupted within two hours of the ISO's instructions to do so. Individual customers participating in this program are not required to have an interval meter. Instead, participants are required to develop a measurement and verification plan for each of their individual customers, which must be submitted to the ISO for approval.

The real-time demand-response programs for reliability are activated during zonal or systemwide capacity deficiencies to help preserve system reliability. Because these demand-response resources are available only during capacity deficiencies, they cannot qualify as operating reserves, such as 30-minute operating reserves (see Section 2.3).

The reliability programs are available at certain steps during the ISO's prescribed OP 4 actions during a capacity deficiency. The Real-Time Profiled-Response Program and the Real-Time Two-Hour Demand-Response Program are activated at OP 4 Action 3, an action designed solely to activate demand-response programs. The Real-Time 30-Minute Demand-Response Program is activated at Action 9 (to implement voluntary load reductions and declare a Power Watch) or Action 12 (to implement voltage reductions). The participant makes the choice of Action 12 or 9 at the time of enrollment. Customer-owned emergency generators usually have environmental permit limitations that require the system operator to implement voltage reductions, Action 12, before calling on those resources.

2.7.2 Price-Response Programs

The ISO's two price-response programs are as follows:

- **Real-Time Price-Response Program—**a separate real-time demand-response program that involves voluntary load reductions by program participants eligible for payment when the day-ahead or forecast hourly real-time LMP is greater than or equal to $100/MWh and the ISO has transmitted instructions that the eligibility period is open. Participants are paid the higher of $100/MWh or the real-time LMP.

- **Day-Ahead Load-Response Program (DALRP)—**an optional program that allows a participant enrolled in any of the three reliability-based demand-response programs or the real-time price-response program to offer interruptions in response to Day-Ahead Energy Market prices. If an offer clears, the participant is paid the day-ahead LMP and is obligated to reduce load by the amount cleared day ahead.[98] The participant then is charged or credited at the real-time LMP for any deviations in curtailment during real time for the cleared interruptions.

[98] This clearing process takes place after the close of the Day-Ahead Energy Market and does not play a role in setting the day-ahead LMPs.

2.7.3 Other Demand Resources

ODR projects in New England are as follows:

- **Energy efficiency—**Two thirds of the ODR projects are energy-efficiency projects. The energy-efficiency projects that qualify as ODRs and are eligible to receive FCM payments during the market transition period are paid on the basis of measured reductions. For example, a participant that, during a factory upgrade, replaces older, less energy-efficient lights with more energy-efficient lighting would be paid capacity transition payments for the difference in wattage usage coincident with the performance hours.
- **Load management—**Load management includes a combination of measures, systems, and strategies at end-use customer facilities that curtail electrical usage or shift electrical usage from peak hours to other hours while maintaining an equivalent or acceptable level of service at those facilities. These measures include, for example, energy management systems, load-control end-use cycling, load-curtailment strategies, chilled water storage, and other forms of electricity storage.
- **Distributed generation—**Distributed generation resources are "behind-the-meter" generators, such as combined heat and power systems, and small-scale wind turbines and photovoltaic generation.[99] Roughly one-third of the ODR projects are distributed generation projects, although they account for a smaller percentage of the total capacity. Distributed generation resources are paid on the basis of measured electricity reduction at the meter. The capacity value is the generator output during performance hours taken from required interval meters on the generation equipment.

ODRs typically are nondispatchable assets, which perform differently than real-time demand-response assets. Currently, all registered ODRs operate under ODR performance hours, which are on-peak periods between 5:00 p.m. and 7:00 p.m. on nonholiday weekdays in December and January and between 1:00 p.m. and 5:00 p.m. nonholiday weekdays in June, July, and August.

2.8 Market Oversight and Analysis

The market monitoring structure implemented by the ISO relies on the ISO's Internal Market Monitoring Unit and the External Market Monitoring Unit, which currently is Potomac Economics. The internal market monitor reports administratively to the company's chief executive officer, whereas both market monitors report functionally to the Markets Committee of the ISO Board of Directors. Additionally, the Internal Market Monitor seeks regular input from the EMM to provide another independent review of significant market developments.

This reporting structure is analogous to the oversight structure of internal and external auditors in corporate finance. The functional reporting directly to the Markets Committee of an independent board provides the Internal Market Monitor with the independence vital to its obligation to inform regulators of any significant problems. The administrative reporting to the company's chief executive officer and day-to-day interaction with operational staff prevent the Internal Market Monitor from becoming isolated and support the ISO's responsibility to ensure that the New England markets and prices are fair, transparent, and competitive.

[99] *Behind-the-meter* generation is connected to the power grid at an electrical location that is on the load side of the metering facility that connects to the transmission system controlled by the ISO. Output from a behind-the-meter generator reduces the amount of electric energy that needs to be withdrawn from the ISO-controlled network.

This section provides information on the specific role of market monitoring in responding to violations of the market rules.

2.8.1 Role of Market Monitoring

Through the following five general monitoring activities, the Internal Market Monitor ensures that prices properly reflect competitive supply and demand conditions and assists FERC in enhancing the competitiveness of wholesale electricity markets for the benefit of consumers:

- Monitoring day-to-day participant behavior and market outcomes
- Mitigating participant behavior found to be anticompetitive as outlined in *Market Rule 1*[100]
- Investigating participant behavior that is not explicitly precluded by existing tariff provisions but that may be considered anticompetitive; making a referral to FERC for further analysis and possible sanctions when such behavior or anticompetitive outcomes are identified
- Evaluating and reporting on existing market rules, operating procedures, and market outcomes and making recommendations for improvements when necessary
- Evaluating new ISO initiatives and market design proposals to ensure that the revisions will support the efficient operation of competitive wholesale electricity markets

The Internal Market Monitor fulfills these activities by performing the following specific tasks:

- Identifying potential anticompetitive behavior by market participants
- Implementing the mitigation provisions of *Market Rule 1* when appropriate
- Immediately notifying appropriate FERC staff of instances in which the behavior of a market participant may require an investigation and evaluation to determine whether the participant has violated a provision of the ISO tariffs, market-behavior rule, or the *Energy Policy Act of 2005* (EPAct) (see below)[101]
- Providing support to the ISO in administering FERC-approved tariff provisions covering the ISO-administered markets
- Identifying ineffective market rules and tariff provisions and recommending proposed rule and tariff changes that will promote wholesale competition and efficient market behavior
- Providing comprehensive market analysis to evaluate the structural competitiveness of the ISO-administered markets and the resulting prices to identify whether markets are responding to customers' needs for reliable electricity supply at the lowest long-run cost
- Providing regular reports to the ISO's senior management and board of directors and state and federal regulatory agencies that describe and assess the development and performance of wholesale markets, including performance in achieving customer benefits, providing transparency, and meeting federal reporting guidelines

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[100] *Market Rule 1* and appendixes are available at http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[101] *Energy Policy Act of 2005*, Pub. L. No.109-58, Title XII, Subtitle B, 119 Stat. 594 (2005) (amending the *Federal Power Act*).

- Evaluating proposed changes in market rules and market design

The *Energy Policy Act of 2005* grants FERC broad authority to regulate manipulative or fraudulent behavior in the energy markets. FERC implemented its new authority by amending its existing regulations to prohibit any entity from directly or indirectly engaging in the following behavior in connection with the purchase or sale of electric energy or transmission services subject to its jurisdiction:

- Using or employing any device, scheme, or artifice to defraud
- Making any untrue or misleading statement
- Engaging in any fraudulent or deceptive act, practice, or course of business

These rules are intended to work in conjunction with the enhanced civil penalty authority extended to FERC as a component of EPAct. The Internal Market Monitor is obligated to refer to FERC any finding of a potential violation of EPAct or the market-behavior rules.

2.8.2 Market Monitoring and Mitigation

As specified in *Market Rule 1*, the Internal Market Monitor monitors the market impact of specific bidding behavior (i.e., offers and bids) and, in specifically defined circumstances, mitigates behavior that interferes with the competitiveness and efficiency of the energy markets and daily reliability payments. Whenever one or more participants' offers or declared generating-unit characteristics exceed specified offer thresholds and market-impact thresholds, or are inconsistent with the behavior of competitive offers, the Internal Market Monitor substitutes a default offer for the offer submitted by the participant. These criteria are applied each day to all participants in constrained areas. A less-restrictive set of thresholds is applied each day to systemwide pivotal suppliers.

2.8.3 ISO Self-Funding Tariff and the *Open Access Transmission Tariff*

The ISO operates under the *ISO New England Transmission, Markets, and Services Tariff* of which Section II is the *Open Access Transmission Tariff* and Section IV is the *Self-Funding Tariff*.[102] In addition to defining the rules and responsibilities of the ISO and market participants, the tariff outlines various schedules that define revenues to be collected by the ISO for operating the ISO as well as for compensating transmission owners for constructing and maintaining the transmission infrastructure controlled by the ISO and providing ancillary services that do not have markets.

The ISO *Self-Funding Tariff* contains rates, charges, terms, and conditions for the functions the ISO carries out. These services are as follows:

- **Schedule 1: Scheduling, System Control, and Dispatch Service—**scheduling and administering the movement of power through, out of, or within the balancing authority area
- **Schedule 2: Energy Administration Service (EAS)—**charges for services the ISO provides to administer the energy markets
- **Schedule 3: Reliability Administration Service (RAS)—**charges for services the ISO provides to administer the reliability markets

[102] These documents are available online at http://www.iso-ne.com/regulatory/tariff/index.html and http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

The OATT addresses the collection and distribution of payments for the following transmission services:

- **Schedule 1: Scheduling, System Control, and Dispatch Service—**involves scheduling and administering the movement of power through, out of, or within the New England Balancing Authority Area.
- **Schedule 2: Reactive Supply and Voltage Control (VAR)—**provides reactive power to maintain transmission voltages within acceptable ranges. Schedule 2 also includes calculations for capacity costs.
- **Schedule 8: Through or Out Service (TOUT)—**includes transactions that go through the New England Balancing Authority Area or originate on a pool transmission facility (PTF) and flow over the PTF before passing out of the New England Balancing Authority Area. Transmission customers pay the PTF rate for TOUT service reserved for them with respect to these transactions.
- **Schedule 9: Regional Network Service (RNS)—**is an ISO accounting service for regional network services. RNS allows network customers to efficiently and economically use their resources, internal bilateral transactions, and external transactions to serve their network load located in the New England area.
- **Schedule 16: System Restoration and Planning Service (Black Start)—**plans for and maintains adequate capability for the restoration of the New England Balancing Authority Area following a blackout.
- **Schedule 19: Special-Constraint Resource (SCR) Service of the *Open Access Transmission Tariff*—**includes the payments and charges for the out-of-merit commitment or operation of resources at the request of transmission owners or distribution companies to manage constraints not reflected in the ISO systems.

Section 3
Energy Market

This section describes the outcomes and competitiveness of the ISO's Day-Ahead and Real-Time Energy Markets, including congestion revenues, Financial Transmission Rights, reserve pricing, and demand resources. In 2009, the wholesale markets experienced decreases in electric energy prices, congestion, and reliability costs. These market outcomes essentially are a direct result of changes observed in several key inputs: lower, less volatile fuel prices; a continued near-record level of hydro production; reduced consumption of electric energy; and less need to operate generation for local second-contingency protection. In evaluating the competitiveness of the energy markets, the ISO relies on tests that measure market concentration and that compare price outcomes with the estimated cost of producing electricity.

3.1 Market Competitiveness and Efficiency

Competitive and efficient electricity markets provide the incentives to maintain an adequate supply of electric energy over the long run at prices that are consistent with the cost of providing it. To assess the competitiveness of the wholesale electric energy markets in New England, the IMM examined two types of measures of market competitiveness. One type includes structural measures that look at market concentration, and the second type includes price-based measures that compare price outcomes to the marginal cost of production:

- **Structural Measures**
    - **Herfindahl-Hirschman Index (HHI)—**measures market concentration of generating capacity. An HHI below 1,000 indicates a low concentration and therefore a market less susceptible to the exercise of market power.
    - **Residual Supply Index (RSI)—**measures the hourly percentage of load in megawatts that can be met without the largest supplier. Suppliers whose output is required to satisfy demand are termed "pivotal" and often can unilaterally affect market prices.
- **Price-Based Methods**
    - **Competitive benchmark price model—**compares model-derived prices based on competitive offers with model-derived prices based on actual offers. The results are used to calculate the Quantity-Weighted Lerner Index (QWLI) to assess the competitiveness of market outcomes.
    - **Correlated movement of input fuel price and electric energy prices—**assesses the statistical relationship between electric energy prices and the price of natural gas—the input fuel for generating resources that most frequently set LMPs.

This section presents the analyses of competitive market conditions during 2009 for the ISO's electric energy markets.

3.1.1 Structural Tests for Competition

Figure 3-1 shows the generation capability of the 10 lead participants with the largest portfolios as of July 1, 2009.[103] As in the previous year, the largest portfolio was owned by Dominion Energy Marketing, with 4,800 MW; followed by NextEra Energy, with 3,000 MW; and Boston Generating, with 2,600 MW. New England's largest provider, Dominion, has a 15% market share, while NextEra Energy FPL has a 10% market share. The total supply from all other participants, excluding the top 10 participants, is roughly 11,000 MW.

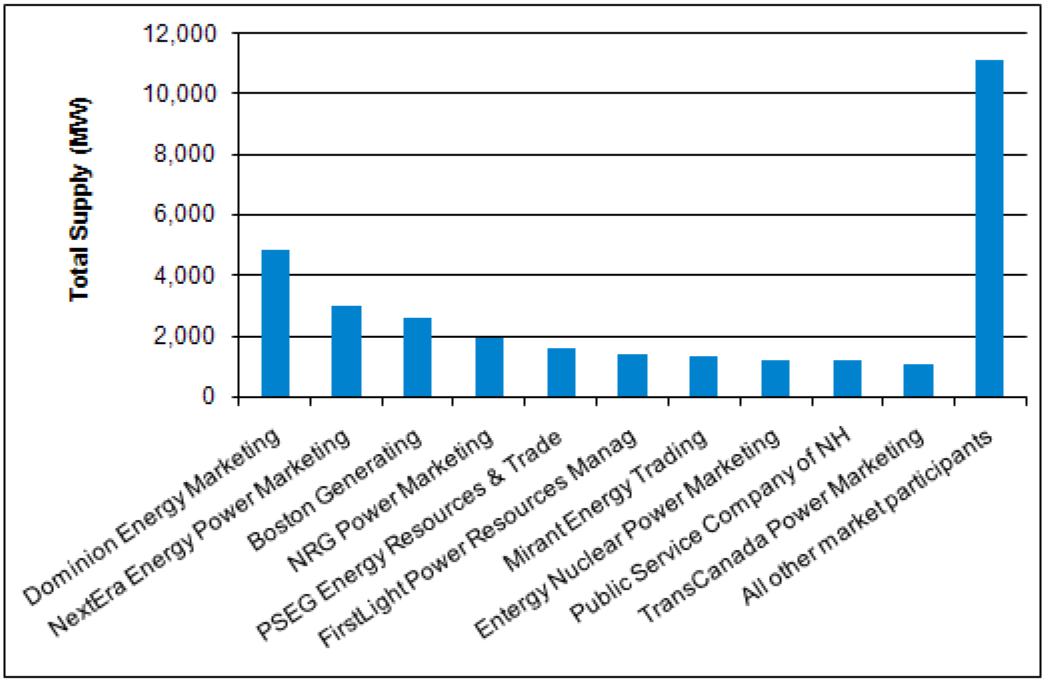

Figure 3-1: Generation capacity by lead participant, 2009, 1,000 MW and above.

3.1.1.1 Herfindahl-Hirschman Index

Market concentration is a function of the number of firms in a market and their respective market shares. For electricity markets, market share is estimated as the percentage of capacity megawatts controlled. The Herfindahl-Hirschman Index, a commonly used measure of market concentration, is calculated by summing the squares of each participant's market share. The HHI gives proportionately greater weight to the market shares of the larger firms, consistent with their greater importance in competitive interactions. Market concentration measured by the HHI typically is divided into three categories:[104]

[103] A *lead participant* is a company representing the resource in the ISO systems.

[104] *Horizontal Merger Guidelines* (Washington, DC: U. S. Department of Justice and Federal Trade Commission, April 8, 1997); http://www.usdoj.gov/atr/public/guidelines/horiz_book/15.html.

- Not concentrated (HHI below 1,000)
- Moderately concentrated (HHI between 1,000 and 1,800)
- Highly concentrated (HHI above 1,800)

These classifications are only indicative since a low-concentration index does not guarantee that a market is competitive; however, higher values generally indicate greater potential for participants to exercise market power.

Monthly systemwide HHIs for New England, based on the summer capabilities of all lead participants' internal resources, averaged 618 in 2009. This value has been relatively constant over the past three years. The result indicates that the New England electric energy markets are well within the "not concentrated" range. However, the systemwide HHI ignores transmission constraints and therefore may understate market concentration and consequently the degree to which some participants possess market power in load pockets.[105] Also, systemwide HHI may overstate market concentration because it does not account for contractual entitlements to generator output, which can decrease the incentive for resources to exercise market power.

3.1.1.2 Residual Supply Index Analysis

The Residual Supply Index is the percentage of demand (in MW) that can be met without the largest supplier. 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. A pivotal supplier can drive prices above the competitive level, subject only to offer caps, mitigation measures, and the price elasticity of demand. As RSIs rise, the ability of market participants to exert market power decreases. In addition to reporting hours when the RSI is below 100%, Market Monitoring reports the number of hours that the RSI is less than 110% to capture situations in which a single supplier cannot exercise market power but the level of competition in that hour is low.

Figure 3-2 shows RSIs as a percentage of total hours for 2009. RSIs generally are lowest during periods of high demand, indicating a drop in the level of competition as the system approaches its capacity limit. This analysis shows that pivotal suppliers existed at the system level during a total of 46 hours during one month in 2009, a decrease from 2008 when 51 hours were spread over two months. The RSI was less than 110% for 159 hours in 2009, a decrease from 2008 when the RSI was less than 110% for 311 hours. The monthly minimum RSIs ranged from 91% in August 2009 to 124% in June 2009. August is the only month in which the RSIs had values below 100%. The average monthly values ranged from 135% in August to 158% in June. The cooler temperatures in June contributed to lower loads than usual for that month and higher RSIs. These improvements in the level of competition are also due to lower loads throughout the year.

[105] *Load pockets* are areas of the system in which the transmission capability is not adequate to import energy from other parts of the system and demand is met by relying on local generation (e.g., Southwest Connecticut and the Boston area).

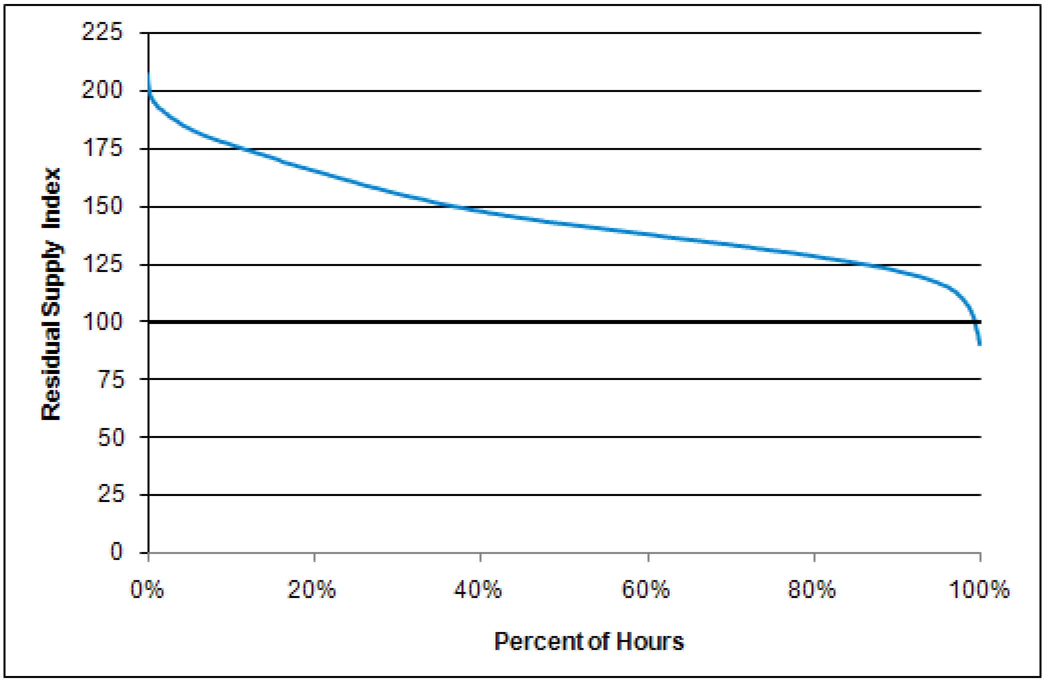

Figure 3-2: RSIs as a percentage of total hours, 2009.

To better understand potential local market power caused by import constraints, the IMM analyzed local RSIs for April, July, August, and September 2009. The analysis included the SWCT, CT, and NEMA/Boston reserve zones. These areas were chosen because they often are import constrained or have a high local HHI.

Table 3-1 shows RSIs below 100% in many hours, indicating the existence of a pivotal supplier with the potential to exercise market power. In 2009, some of the lowest RSIs in local areas were during maintenance months. A single participant was pivotal in each reserve zone. These results reinforce the importance of offer-mitigation rules for import-constrained areas to prevent suppliers with market power from using it to raise prices.

Table 3-1
Local Area RSI Calculations for Selected System Interfaces, 2009

Reserve Zone	Month	Number of Hours RSI < 100%	Number of Hours RSI < 110%	Percent Hours RSI < 100%	Percent Hours RSI < 110%	Average Monthly RSI	Maximum RSI	Minimum RSI
SWCT	Apr	0	0	0%	0%	165	225	124
	Jul	0	0	0%	0%	172	220	127
	Aug	0	0	0%	0%	163	217	128
	Sep	0	24	0%	3%	167	242	104
CT	Apr	35	147	5%	20%	126	177	93
	Jul	32	95	4%	13%	133	188	92
	Aug	109	218	15%	29%	126	189	84
	Sep	26	140	4%	19%	132	193	91
NEMA	Apr	84	209	12%	29%	123	183	91
	Jul	13	115	2%	15%	128	174	94
	Aug	126	254	17%	34%	121	170	82
	Sep	231	369	32%	51%	112	173	77

3.1.2 Price-Based Measures of Competitiveness

Price-based measures provide insight into the offer behavior of participants. If the market is competitive, at equilibrium, prices should approximate marginal costs.

3.1.2.1 Competitive Benchmark Analysis

The competitive benchmark (benchmark price) is a model-derived estimate of the market-clearing price that would have resulted had all market participants offered their electric energy at marginal cost and the system had been unconstrained.[106] The model derives the benchmark price in each hour by estimating the additional cost for the next megawatt (i.e., incremental cost) of the least expensive generating unit capable of producing one more megawatt. The benchmark price accounts for production costs, including environmental and variable operations and maintenance (O&M) costs, unit availability, and net imports.

Table 3-2 compares the annual average benchmark price with a second modeled price, the offer-intercept price. Comparing the benchmark price with the offer-intercept price over time can help assess the competitiveness of the market. The closer the two measures, the more competitive the market likely is. The offer-intercept price is derived using the same model as the benchmark price, but instead of using generator costs, it uses generators' actual supply offers. The metric used to compare the different price estimates is the Quantity-Weighted Lerner Index, which is a variant of the

[106] The tool evaluates the competitive performance of New England's wholesale electricity markets using a method similar to one developed by Bushnell and Saravia of the University of California Energy Institute. *See* James Bushnell and Celeste Saravia, *An Empirical Analysis of the Competitiveness of the New England Electricity Market.* (Berkeley: University of California Energy Institute, January 2002); http://www.iso-ne.com/pubs/spcl_rpts/2002/empir_assess_competitiveness_bushnell.pdf.

conventional Lerner Index. The conventional Lerner Index is widely used to assess the competitiveness of market outcomes and is calculated as “price minus marginal cost divided by price.” The QWLI substitutes the model-based offer-intercept price for the “market price” in the Lerner index.

Table 3-2
ISO Model Market Price Measures

Price Measure	2009 Price ($/MWh)	Quantity-Weighted Lerner Index (%)[a]					
		2004	2005	2006	2007	2008	2009
Benchmark price	36						
Offer-intercept price	37	−6	1	1	2	−1	5

(a) The QWLI = [(annual market cost based on market prices – annual market cost based on marginal cost estimates)/ annual market cost based on market prices].

The QWLI results suggest that the market participants continued to behave competitively through 2009. Table 3-2 shows that the QWLI increased from −1% in 2008 to 5% in 2009. This is a small year-to-year change. The QWLI, while a useful measure of market competitiveness, is subject to modeling error because of the necessary simplifying assumptions and the need to rely on estimates of generator-input cost and efficiency (e.g., environmentally limited units are not explicitly considered; hydroelectric units are assumed to be perfectly competitive). Therefore, small year-to-year changes are likely to mean little change in the market’s competitiveness. Trends in the index over time or larger movements would suggest changes in the market’s competitiveness requiring additional investigation.

The system load-weighted average real-time Hub price for 2009 was $42.61/MWh, about 11% higher than the modeled offer-intercept price.[107] Because the offer-intercept price is intended to model the Hub price, the difference between the actual Hub price and the offer-intercept price is a measure of modeling error in the competitive benchmark model. The IMM continues to work to improve the benchmark model.

The results of the concentration analysis show that the market is structurally competitive and, in instances in which inadequate transmission or peak load levels create the possibility of noncompetitive behavior, mitigation rules provide behavior remedies. The examination of market results shows that electric energy prices reflect the costs to suppliers of producing electric energy (i.e., largely fuel costs), which is consistent with the finding that the market is competitive.

[107] The system load-weighted average Hub price is used because it provides the closest conceptual match to the prices calculated by the benchmark model.

3.1.2.2 Comparison of Fuel Prices and Electric Energy Prices

Another indicator of market competitiveness is how electricity prices respond to changes in their input costs. Since fuel costs are by far the largest short-term cost component of generating electricity, electricity prices should change as fuel prices change. This section compares the average monthly percentage change in the prices of electricity and natural gas from 2008 to 2009. The results indicate that at the systemwide level, electricity prices continue to move in tandem with input fuel prices, particularly natural gas, supporting the conclusion that the electricity market is competitive.

Figure 3-3 shows the percentage change in monthly natural gas prices from 2008 to 2009 and the percentage change in monthly real-time electricity prices, demonstrating a close association between natural gas prices and electricity prices. Overall, the average annual price of electric energy dropped by 45% in 2009 compared with 2008, and the natural gas index dropped 52% in 2009. The deviation from the pattern in August was caused by a period in 2009 with high loads during which prices reflected the marginal cost of oil burning peaking resources and scarcity.

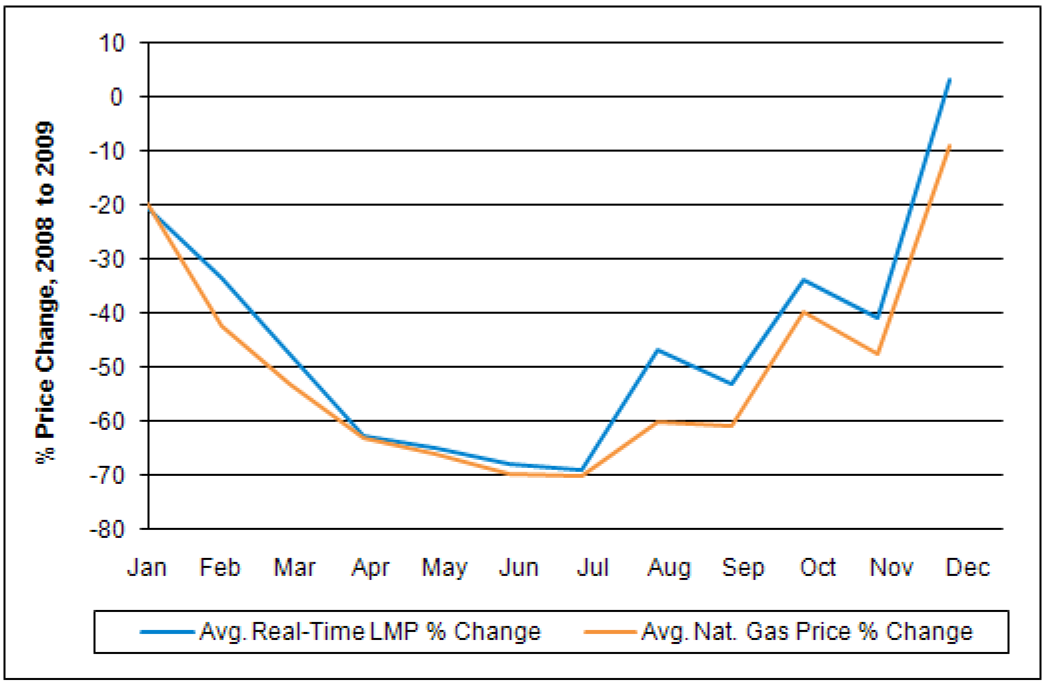

Figure 3-3: Percentage change in real-time LMPs and natural gas, 2007 to 2008.

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

Figure 3-4 shows that average annual input fuel prices decreased considerably in 2009. The price of natural gas has decreased to nominal values similar to those in 2000, while the price of oil has decreased to nominal values similar to those in 2006 to 2007. Compared with 2008, average annual prices have decreased by about 52% for natural gas, 27% for No. 6 oil (1%), and 42% for No. 2 oil.[108] Coal prices decreased by about 45% over this time period.

[108] The power industry uses several types of fuel oils to generate electricity. No. 2 oil—also referred to as distillate fuel oil, light fuel oil, or diesel fuel oil—is distilled from crude oil. Among other uses, it is used as a backup fuel for peaking power plants. No. 6 oil is referred to as residual fuel oil or heavy fuel oil. It is what remains of the crude oil after gasoline and the

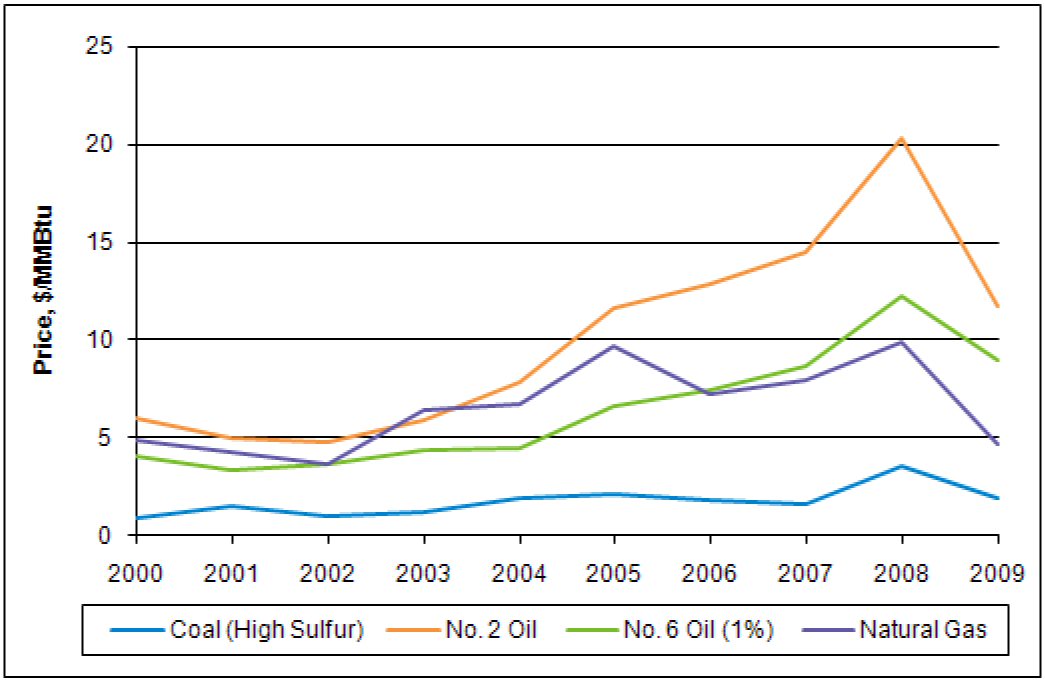

Figure 3-4: Average annual fuel prices for selected input fuels, 1999 to 2009.

Sources: Natural gas price information was provided by the Intercontinental Exchange, Inc. (ICE); http://www.theice.com. Coal and oil prices were provided by Argus Media; http://www.argusmedia.com/pages/StaticPage.aspx?tname=Argus+Home&pname=What%27s+New.

The magnitude of the price difference between input fuels varied over the two-year period, as shown in Figure 3-5. The relationship between No. 6 oil (1%) and natural gas prices in particular is important in New England's wholesale electricity markets for two reasons. First, at lower oil prices, efficient oil generators can compete with less efficient natural gas generators, lowering electricity prices. Second, when oil prices are low relative to natural gas prices and oil-fired units are needed for reliability, lower operating costs from oil-fired resources relative to natural-gas-fired resources lead to lower NCPC payments for reliability. In early 2008, No. 6 oil (1%) was slightly more expensive than natural gas and remained so until November 2008, when its price fell below natural gas prices for three months. In February 2009, the price of No. 6 oil (1%) again rose above the price for natural gas and remained higher for the remainder of the year.

distillate fuel oils are extracted. No. 6 oil is used by oil-burning power plants. No. 6 oil (1%) refers to the percentage of sulfur in the oil.

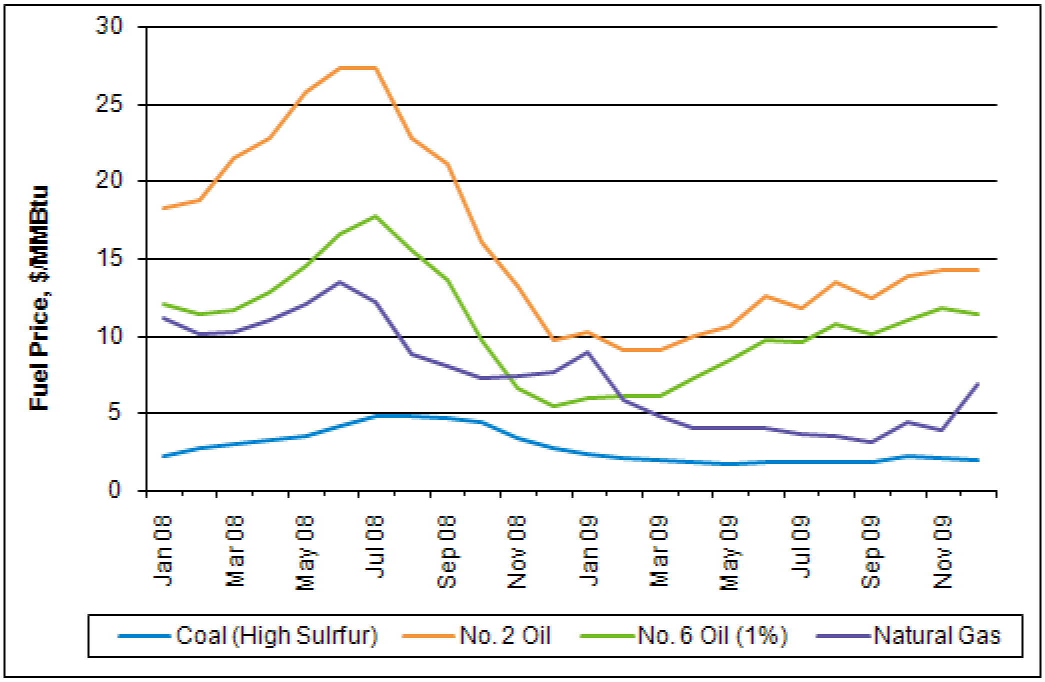

Figure 3-5: Average monthly fuel prices for selected input fuels, 2007 and 2008.

Sources: Natural gas price information was provided by the Intercontinental Exchange, Inc. (ICE); http://www.theice.com. Coal and oil prices were provided by Argus Media; http://www.argusmedia.com/pages/StaticPage.aspx?tname=Argus+Home&pname=What%27s+New/

The all-in wholesale electricity cost is an estimate of the total wholesale market cost of electric energy in $/MWh.[109] The all-in cost figure includes the cost of energy, Forward Reserve Market and real-time reserve pricing, regulation daily reliability costs, and FERC-approved reliability cost-of-service agreements (Reliability Agreements). Figure 3-6 shows the average annual all-in wholesale electricity cost metric and natural gas prices for 2007 through 2009.

[109] The *all-in* cost metric includes costs allocated to both wholesale load obligations and network load. The energy portion of the all-in cost is a zonal load-weighted average of zonal prices. This is a slightly different concept than the system load-weighted average Hub price reported in the fuel-adjusted price analysis shown in Section 3.3.2, and the simple average of wholesale prices at the Hub. This analysis uses this metric of zonal load-weighted averages of zonal prices because it better represents the prices load actually paid. The ISO publishes a separate wholesale load cost metric that includes only costs allocated to real-time load obligations.

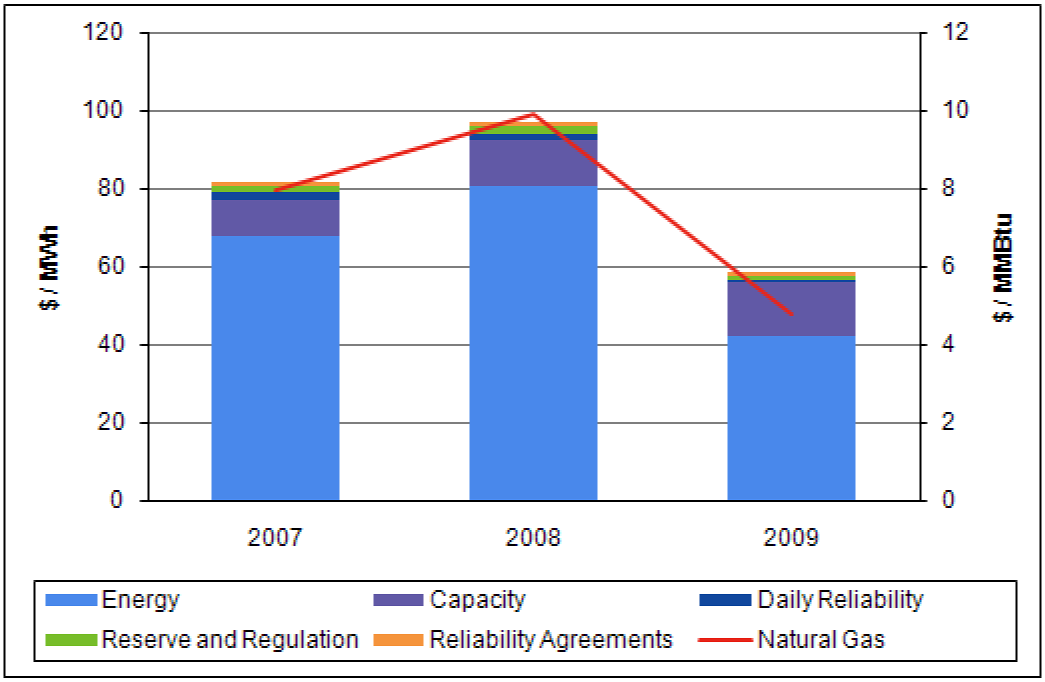

Figure 3-6: All-in cost for electricity.

Note: 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.

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

The all-in-cost fell almost 40%, from $96.84/MWh in 2008 to $58.36/MWh in 2009. The largest decrease was in electric energy costs; driven by lower fuel prices and lower load levels. Capacity costs increased consistent with the increase in the capacity transition rate prescribed in *Market Rule 1* from $3.75/kW-month to $4.10/kW-month on June 1, 2009. Daily reliability payments have decreased and are now less than 1% of the total all-in cost.

3.2 Day-Ahead Energy Market

This section presents the results of the day-ahead market in 2009. It examines prices and the types of demand and supply participating in the market.

3.2.1 Day-Ahead Prices

Table 3-3 shows day-ahead electricity prices for the Hub and the difference between the Hub price and prices for each of the eight New England load zones for 2008 and 2009. The average day-ahead Hub price in 2009 was lower than in 2008. The decrease in LMPs from 2008 to 2009 was primarily due to decreased fuel prices. During 2009, average day-ahead zonal prices did not vary more than about $0.70/MWh from the Hub, with the exception of Maine and Connecticut. Average LMPs in Maine were about $2.00/MWh lower than the Hub, in part due to a negative marginal cost of losses. The average CT load zone LMPs were $1.21/MWh greater than the average Hub price caused by the marginal cost of losses and transmission constraints. These patterns are similar to the price differences in 2008.

Table 3-3
Simple Average Day-Ahead Hub Prices
and Load-Zone Differences for 2008 and 2009, $/MWh

Location/Load Zone	2008	2009
Hub	80.43	41.54
Maine	−4.45	−1.93
New Hampshire	−1.32	−0.67
Vermont	0.47	0.05
Connecticut	4.33	1.21
Rhode Island	−1.18	−0.39
SEMA	2.03	0.17
WCMA	0.64	0.36
NEMA	−0.67	−0.09

3.2.2 Day-Ahead Demand for Electric Energy

Figure 3-7 shows the total percentage of day-ahead cleared demand by demand categories. Fixed demand has increased slightly as a percentage of total cleared demand, ranging from about 56% in both 2007 and 2008 to about 61% in 2009. In addition to fixed demand, price-sensitive demand decreased as a percentage of total cleared demand.

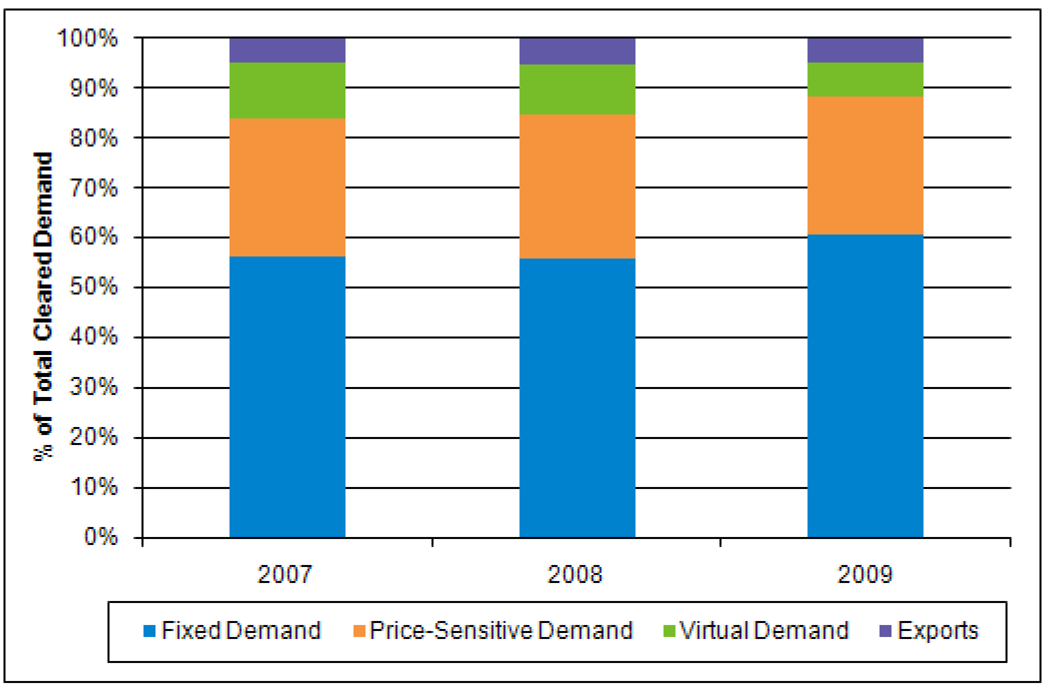

Figure 3-7: Day-ahead demand by category.

3.2.3 Day-Ahead Supply of Electric Energy

Figure 3-8 shows the percentage of submitted and cleared day-ahead fixed and price-sensitive supply offers, virtual supply, and imports for 2007, 2008, and 2009. Day-ahead fixed supply increased from 2008 to 2009 and accounted for over 60% of day-ahead supply in 2009. Cleared economic supply has decreased each year since 2007. Each year, virtual supply has been greater than virtual demand. While a large percentage of both day-ahead supply and demand was fixed, or price insensitive, sufficient quantities of price-sensitive supply and demand allowed for efficient price formation.

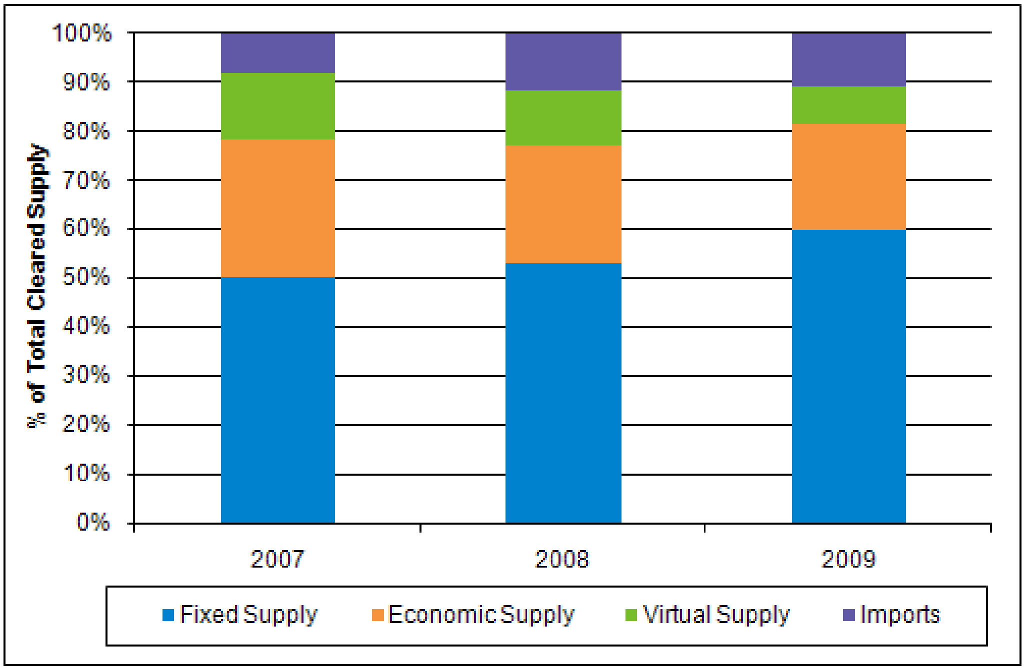

Figure 3-8: Day-ahead supply as a percentage of total cleared supply.

3.3 Real-Time Energy Market

This section presents the results of the Real-Time Energy Market in 2009. It reviews prices, the demand for electricity, total generation output, imports and exports, and real-time reserves, and it compares day-ahead and real-time prices.

3.3.1 Real-Time Prices

Figure 3-9 shows average monthly real-time Hub prices for New England over the past three years. The figure shows that prices during 2008 were high through August, when they dropped to the previous years' levels. In 2009, prices in all months except January and December were lower than in previous years. The increase in December 2009 is attributable to an increase in the price of natural gas. (Figure 3-3 shows the movements in natural gas and the Hub LMP.)

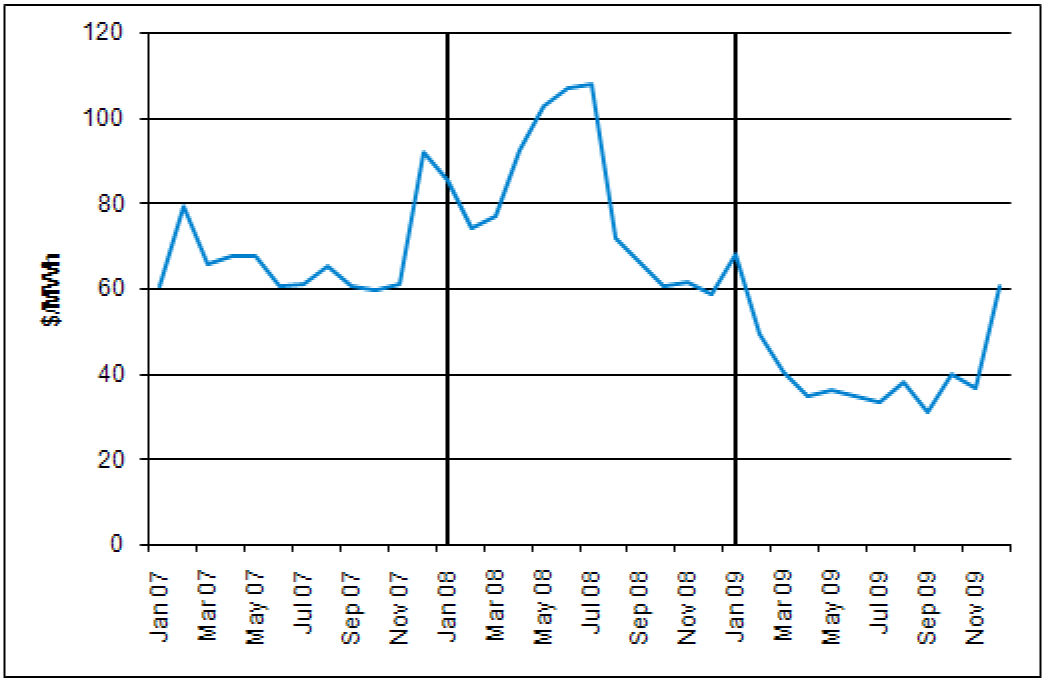

Figure 3-9: Average monthly real-time Hub prices, 2007 to 2009.

Table 3-4 shows real-time electricity prices for the Hub and the difference between the Hub and each of the eight New England zones for 2008 and 2009. The average Hub price during 2009 was lower than during 2008. The decrease in Hub LMPs from 2008 to 2009 was primarily due to decreased fuel prices. During 2009, average real-time zonal prices did not vary more than about $0.70/MWh from the Hub, with the exception of Maine and Connecticut. Average LMPs in Maine were about $2.00/MWh lower than the Hub, in part due to negative marginal-loss costs. Average LMPs for the CT load zone were almost $0.90/MWh higher than the Hub, as a result of the marginal cost of losses and import constraints into Connecticut.

Table 3-4
Simple Average Real-Time Hub Prices and Load-Zone Differences for 2008 and 2009, $/MWh

Location/Load Zone	2008	2009
Hub	80.56	42.02
Maine	−5.20	−2.02
New Hampshire	−1.24	−0.67
Vermont	0.38	0.06
Connecticut	2.78	0.90
Rhode Island	−1.10	−0.43
SEMA	0.79	0.04
WCMA	0.66	0.34
NEMA	−0.25	−0.22

3.3.2 Fuel-Adjusted Price

Figure 3-10 shows the annual average load-weighted Hub prices and the annual average load-weighted fuel-adjusted electric energy prices for 2000 to 2009. The IMM developed the fuel-adjusted electric energy price to estimate the impact of input fuel prices on electric energy prices. While informative, the approach provides only a rough estimate because it does not account for the dispatch changes that may occur as relative fuel prices change or load growth and resource mix that also change over time.

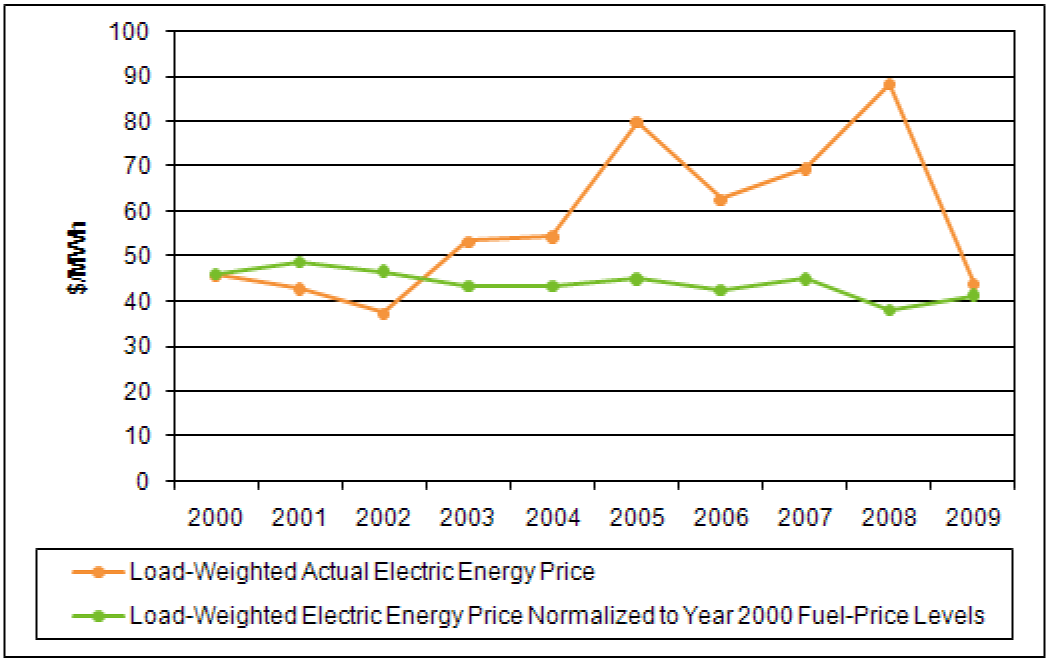

Figure 3-10: Actual and fuel-adjusted average real-time electric energy prices, 2000 to 2008.

Note: Prices are system load-weighted average Hub prices.

3.3.3 Difference between Day-Ahead and Real-Time Prices

As Table 3-5 shows, the average day-ahead and real-time energy prices at the New England Hub in 2009 were $41.54/MWh and $42.02/MWh, respectively. The average day-ahead to real-time price differential has been declining through time. In 2005, the annual average difference 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 (i.e., a −1.15% day-ahead to real-time price difference).

Table 3-5
2009 Annual and Quarterly
Day-Ahead and Real-Time Hub Prices, $/MWh

	Annual	Q1	Q2	Q3	Q4
Day ahead	41.54	54.17	35.52	32.38	44.32
Real time	42.02	52.80	35.24	34.30	45.89

The maps in Figure 3-11 show the average annual nodal LMPs as color gradations from blue, representing $36/MWh or less, to red, representing prices of $48/MWh and higher. Southeast Massachusetts and Southwest Connecticut had the highest average day-ahead prices, while Maine had the lowest prices. The biggest difference between day-ahead and real-time prices occurred in Southeast Massachusetts due to the need to operate a resource for reliability reasons in that area for the first part of the year. The resource was not included in the day-ahead market but was included in the real-time market, thereby lowering prices in real time. While virtual transactions reduced the difference between day-ahead and real-time prices in SEMA somewhat, they did not fully close the gap.

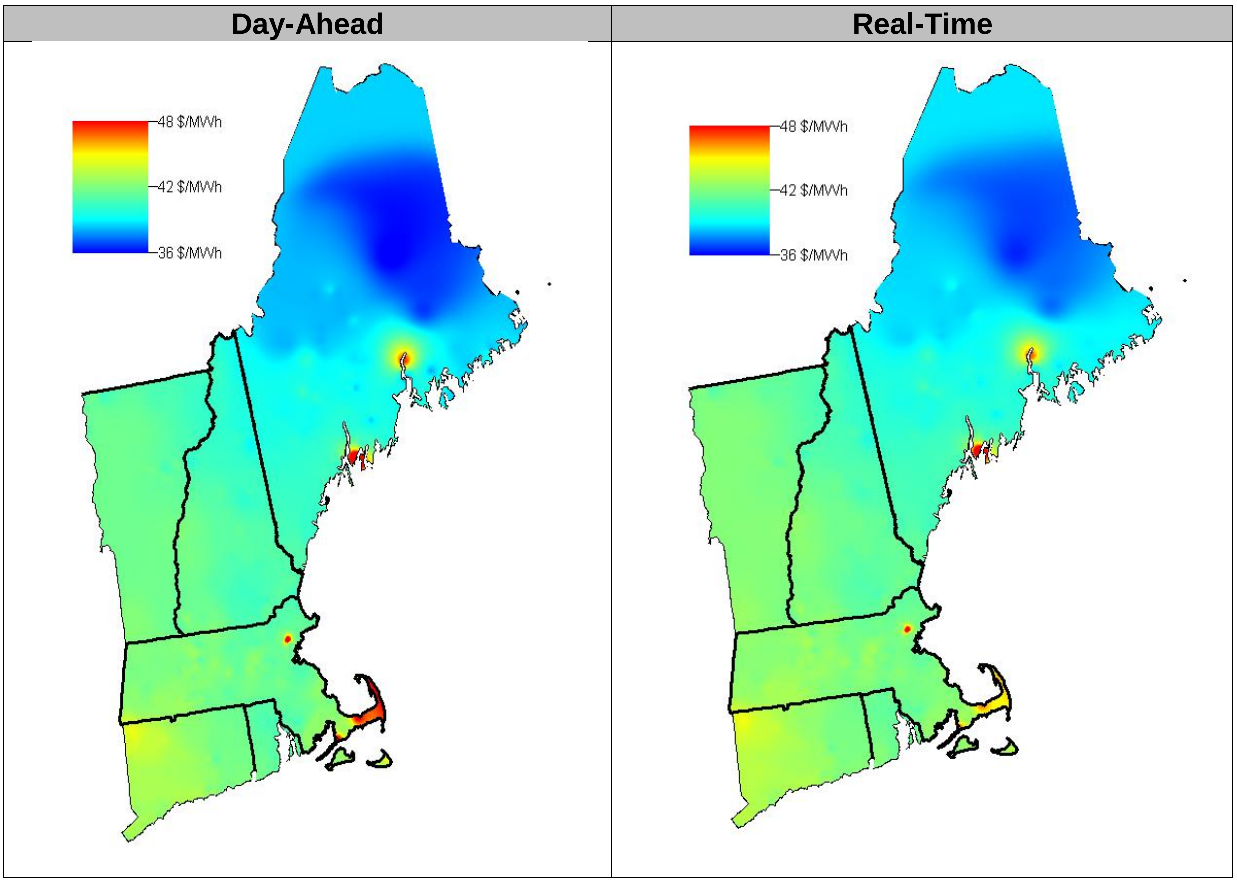

Figure 3-11: Average nodal prices, 2009, $/MWh.

Note: The extreme maximum values of nodal LMPs are not included in the scale to provide greater resolution in the price differences shown in the figures. The actual maximum average annual LMP for the day-ahead market was $70.62/MWh, and the true minimum was $35.77/MWh. The actual maximum for the real-time market was $68.10/MWh, and the actual minimum was $36.39/MWh.

Improvements to the transmission system in SWCT and SEMA have reduced the amount of capacity committed out-of-market for reliability purposes. Figure 3-12 shows the average amount of capacity committed after the day-ahead market and not dispatched above its economic minimum limit.

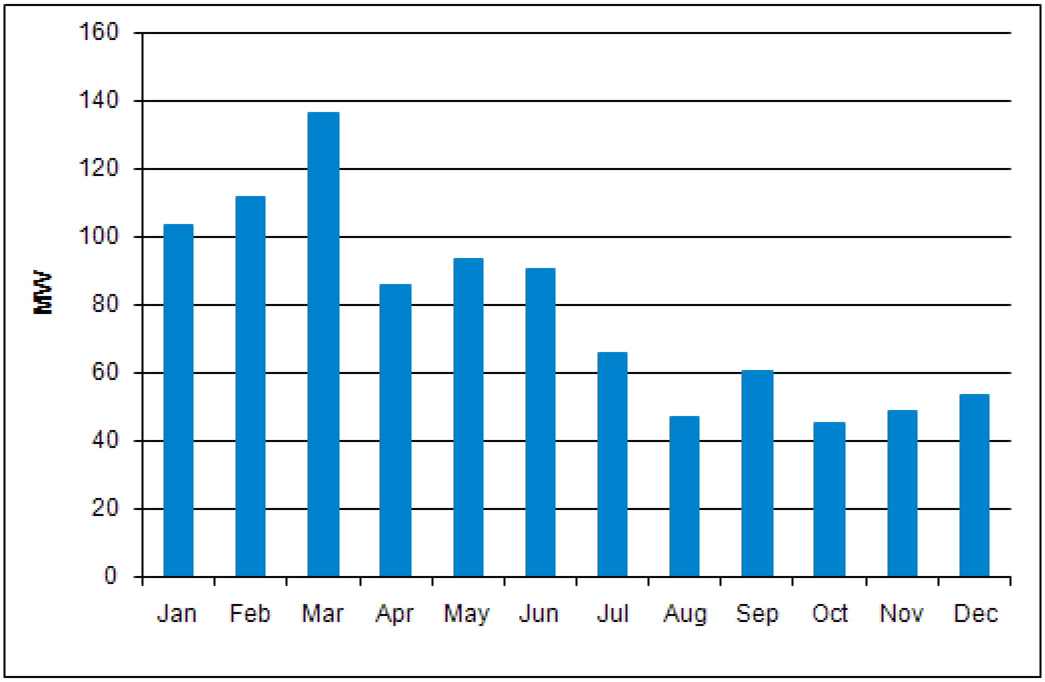

Figure 3-12: Average generation committed after the day-ahead market and operated at economic minimum, 2009, MW.

Given the apparent shift in the price relationship between average day-ahead and real-time prices (i.e. real-time prices are now higher than day-ahead prices), a decrease in the volume of virtual supply offers submitted would be expected as would an increase in the volume of virtual demand bids and physical load bid into the day-ahead market during the second half of 2009. This change in behavior would be consistent with a profit-maximizing strategy of buying at low prices day-ahead and selling at high prices in real-time.

An analysis of the price data shows that a participant that submitted a 1 MW virtual demand bid at the Hub in every hour starting in July would have gained approximately $7,700. However, while the data show a decline in virtual supply offers, they do not show a discernible increase in either virtual demand bids or physical load bids relative to the first half of the year (when day-ahead prices exceeded real-time prices, on average). Moreover, in the fourth quarter of 2009, while average real-time prices were more than $3/MWh higher than day-ahead prices, the percentage of real-time load that cleared the day-ahead market decreased, which increased the exposure by load servers to the higher real-time prices.

A review of the market results suggests that the observed behavior is consistent with risk preferences and expected returns relative to the opportunity cost of participating in the virtual markets. Assuming the virtual demand bidding strategy described above, in the first two quarters of 2009, the return on the virtual demand bid position would have been −1.3%. In the second half of 2009, the same strategy would have yielded a return of 4.5%. However, the distribution of returns between the first half of the year and second half of the year changed in important ways, with the volatility of returns as measured by the standard deviation of the sample increasing by almost 62%, from 19.2 to 31%, and the skewness of the distribution increasing by 146%, from 1.3 to 3.2. While the absolute returns available in the market increased, the riskiness of the market also increased. More importantly though, because the forecast distributions assumed in investment models are generally based on factors derived from historical market data, that the virtual demand bidding strategy would have a positive payoff could not have been known with any reasonable level of confidence until several months of market outcomes were accumulated—the IMM did observe some financial players taking virtual demand bid positions in late 2009 after a few months' absence. Of the participants that generally would take arbitrage and speculative positions, all but the most risk tolerant most likely opted not to take virtual demand bid positions in favor of other investments. This left the market primarily to those participants that use virtual demand bids as a hedging tool.

Few parties apparently were willing to take virtual demand bid positions given the prevailing risk profile of that instrument under prevailing market conditions during the latter half of 2009. This is likely an extension of the increased risk aversion witnessed across the economy during the last year and a half. In addition, participants may have been slow to recognize changes in system operations. The failure of market participants to participate fully in the virtual market may mute the beneficial function of virtual bids and offers. The IMM will continue to monitor the performance of the Day-Ahead and Real-Time Energy Markets with particular attention to the activities of virtual players and their role converging day-ahead and real-time prices.

3.3.4 Day-Ahead Supply Compared with Real-Time Supply

Figure 3-13 shows the monthly average quantity of cleared day-ahead supply from generators and net imports compared with the average monthly net energy for load (NEL)—a measure of real-time supply needs—for 2009.[110] Overall, the average day-ahead supply cleared at 102% of average NEL in 2009. Variability from month to month can be attributed to seasonal variations in load and changes in participant offer behavior.

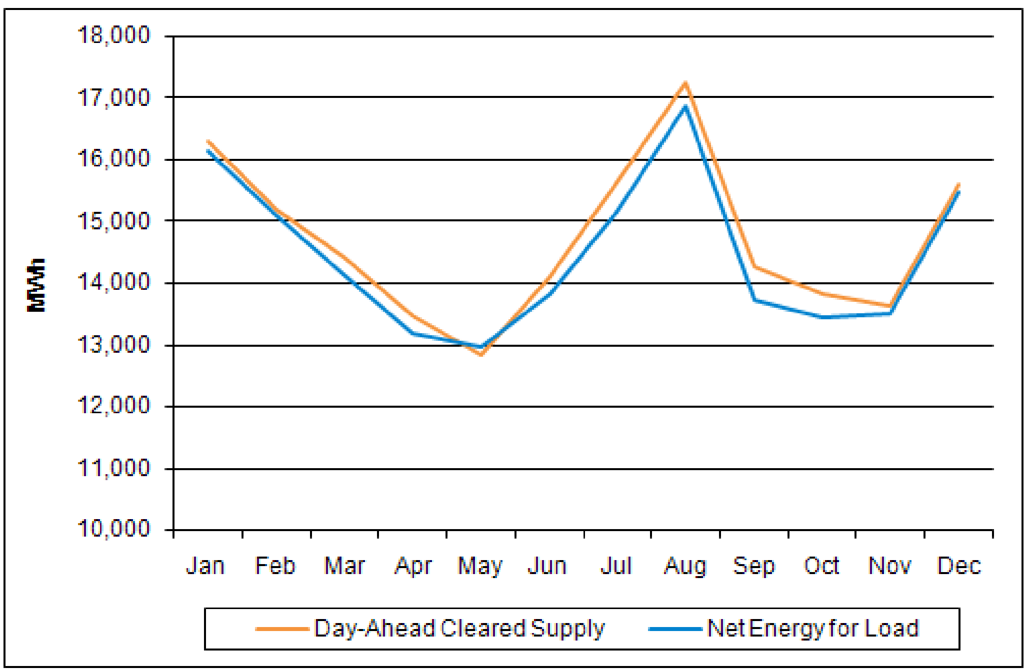

Figure 3-13: Day-ahead cleared supply compared with net energy for load, 2009.

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

3.3.5 Real-Time Demand

Table 3-6 shows that the actual demand for electricity decreased by about 4% from 2008 to 2009 while weather-normalized demand decreased by about 2%.[111] The drop in electric energy consumption from 2008 is consistent with the overall decline in economic activity.

Table 3-6
Annual and Peak Electric Energy Statistics, 2006 to 2009

	2007	2008	2009	% Change 2008 to 2009
Annual NEL (gigawatt-hour; GWh)	134,466	131,743	126,842	−3.7%
Normalized NEL (GWh)	134,153	131,127	128,224	−2.2%
Recorded peak demand (MW)	26,145	26,111	25,081	−3.9%
Normalized peak demand (MW)	27,460	27,765	27,460	−1.1%

As illustrated in Figure 3-14**,** New England monthly temperatures in 2009 generally were consistent with long-term averages. Overall, temperatures in the first three quarters were slightly lower than normal. The most extreme departures were the colder-than-normal temperatures in January (which increased demand) and June and July (both of which lowered demand).[112] June 2009 was one of the coolest on record for the Northeast. Most days were dominated by rain, thunderstorms, and cloudy, cool days. In Boston, the average temperature was 63.3 degrees, which is 4.7 degrees cooler than average. Precipitation was measurable (0.01 inch or more) in 16 days during June 2009. The average is 10 days.

[111] *Weather-normalized* results are those that would have been observed if weather were the same as the long-term average.

[112] Weather information is available at http://www.weather.gov/climate/index.php?wfo=box. Normalized climate values cover 1971 to 2000.

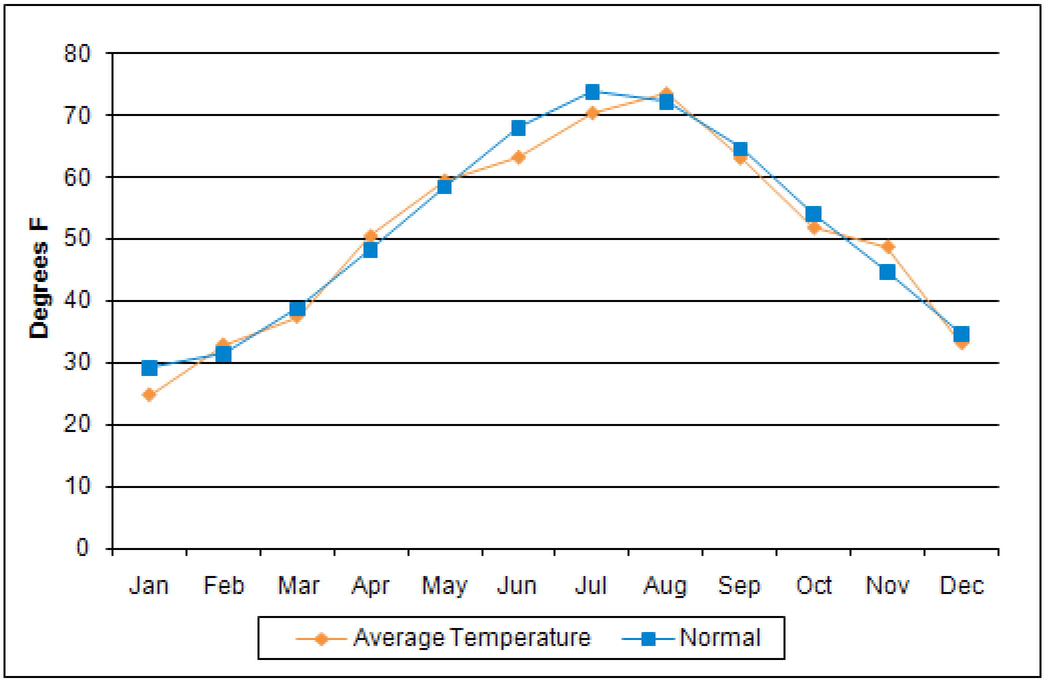

Figure 3-14: Average monthly 2009 temperatures compared with normal temperature values.

Load factors are important to the electricity markets because they indicate the amount of capacity that must be maintained year-round to meet the high loads that may last only for a few hours during the year. Figure 3-15 shows the long-term trend of declining load factors for New England expressed as a percentage for weather-normalized load.[113] New England is a summer-peaking region because of the use of air conditioning in hot weather. The increase in the use of air conditioning has outpaced the growth in overall energy consumption, causing load factors to decline. In addition to air-conditioning saturation, the conversion from individual room air conditioning to central air conditioning and an increase in the size of the homes being cooled have contributed to the long-run decline in the summer-peak load factor.

[113] A *weather-normalized load factor* is the ratio of the average hourly demand during a year to the peak hourly demand, both adjusted to normal weather conditions.

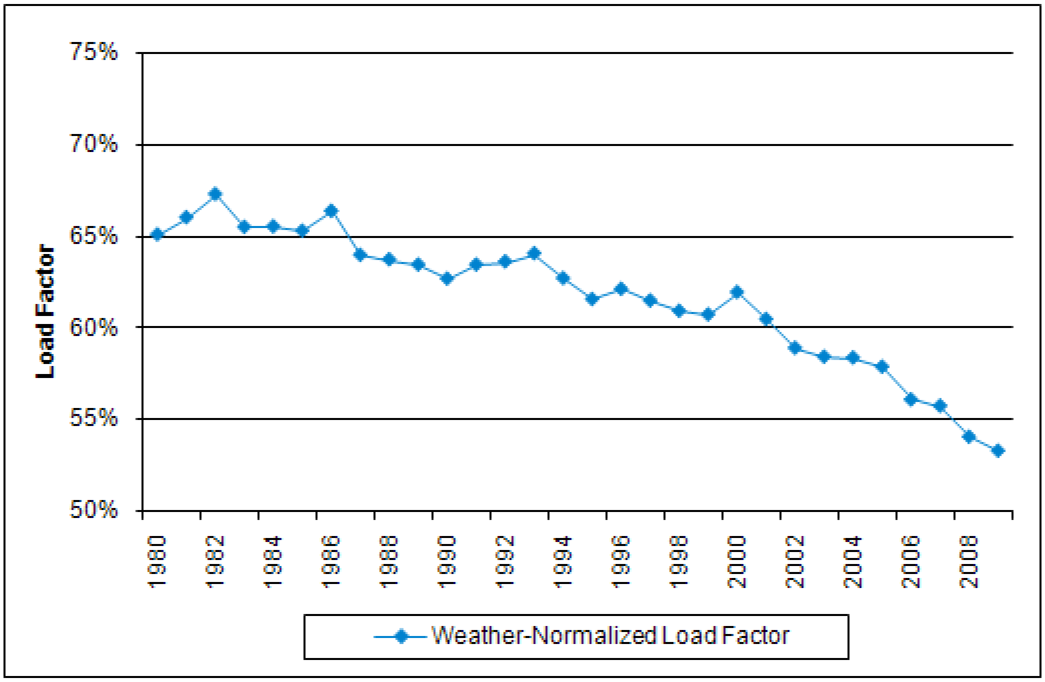

Figure 3-15: New England summer-peak load factors, weather-normalized load, 1980 to 2009.

3.3.6 Real-Time Supply

This section presents data on real-time summer capacity, generation by fuel type, self-scheduled generation, and the results of a marginal unit analysis.

3.3.6.1 Summer Capacity

Figure 3-16 shows summer capacity (MW) by fuel type for 2009.[114] In 2009, dual-fueled generators capable of burning gas made up 38% of installed capacity, while oil-fired generators made up 25% of installed capacity. Environmental restrictions on emissions from burning oil can limit the total number of hours per year a generator can operate on oil. Many dual-fueled generators capable of burning either oil or natural gas operate primarily on natural gas.

[114] Detailed information about generating capacity is available in the ISO's forecast reports of capacity, energy, loads, and transmission. See http://www.iso-ne.com/trans/celt/report/index.html.

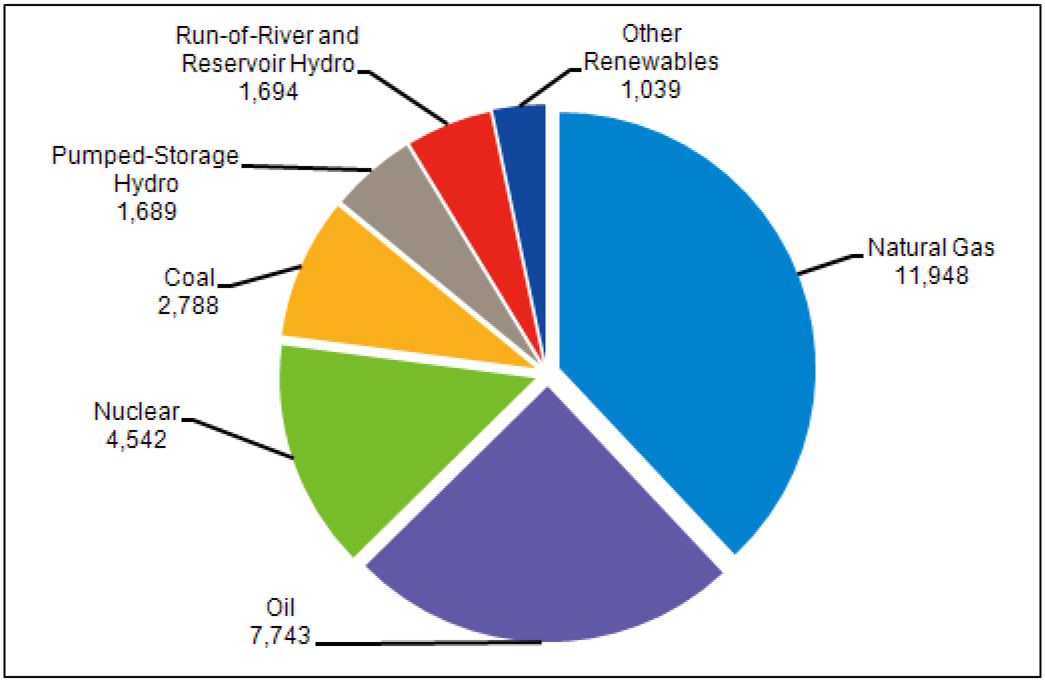

Figure 3-16: System summer capacity by fuel type, 2009.

The total 2009 generation claimed for capability is 31,443 MW, up 341 MW from the 2008 level of 31,102 MW. The 341 MW increase is the result of new generation, existing generation re-ratings, or "behind-the-meter" generation.

3.3.6.2 Generation by Fuel Type

Figure 3-17 shows actual generation by fuel type as a percentage of total generation for 2008 and 2009. The figure shows the fuels used to generate electric power, which differ from the capacity fuel mix shown above and the marginal unit by fuel type shown later in Figure 3-22 (see Section 3.3.6.6). The percentage of total electric energy generated by gas-fired and gas- and oil-fired plants in New England was about 43% in 2009. Nationwide, about 22% of electric energy is produced by power plants fueled by natural gas.[115]

[115] Energy Information Administration, *Electricity Generation* (Washington, DC: U.S. DOE, September 2008); available at http://tonto.eia.doe.gov/energyexplained/index.cfm?page=electricity_in_the_united_states#tab2 (accessed February 3, 2010).

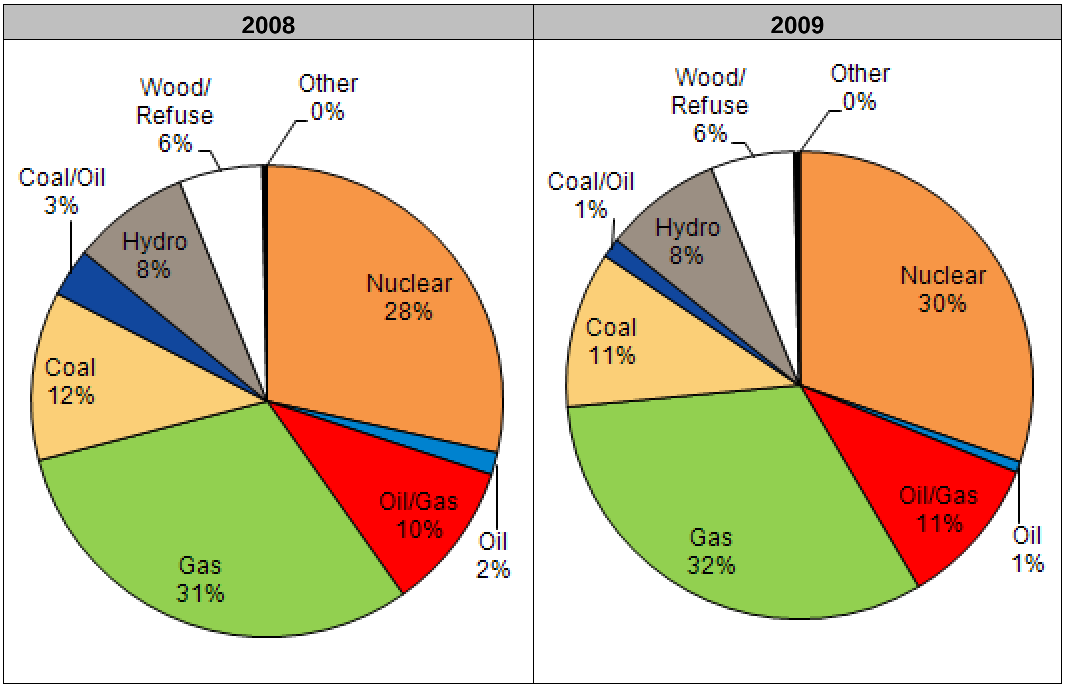

Figure 3-17: New England generation by fuel type, 2008 and 2009.

3.3.6.3 Spark Spreads

A spark spread is a measure of the gross margin (energy revenues minus fuel costs) from converting fuel to electricity based on the wholesale price of electricity and the cost of producing electricity with a given fuel. Figure 3-18 presents monthly estimated natural gas spark spreads based on the unweighted monthly average real-time Hub price for on-peak hours (in $/MMBtu) from January 2007 through December 2009 and the estimated cost of a typical gas unit in New England. The figure assumes the Algonquin gas price and a 7,800 Btu/kWh heat rate of converting fuel to electricity. The results show that, on average, gas units are earning a positive gross margin, with the typical spark spread lying between $5/MWh and $10/MWh. The average gas unit presented here earned a gross margin of approximately $3.20/kW-month.

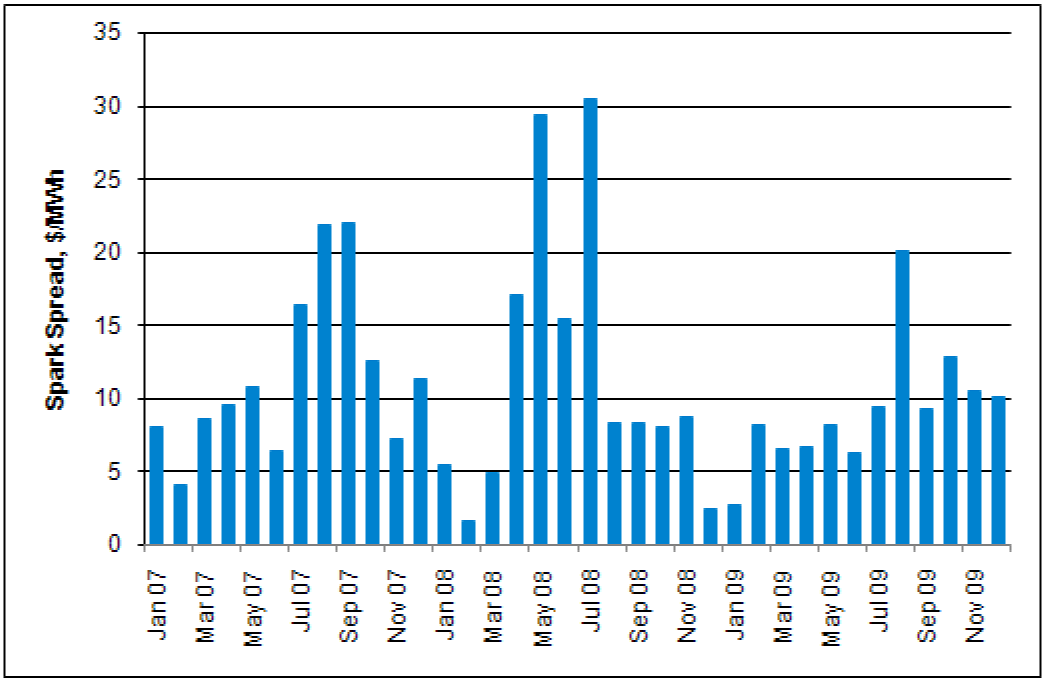

Figure 3-18: Monthly spark spreads for on-peak hours, 2007 to 2009.

3.3.6.4 Hydroelectric Output

Yearly hydroelectric production in 2009 was at near-record levels, 31% over the historical average hydro production from 2000 to 2007, and just 3% below the record levels seen in 2008.[116] The maximum daily hydro production occurred on July 6, 2009, with hydro electric production accounting for 16% of total supply.[117] Over the course of the year, hydroelectric resources produced 8% of total system generation.

Figure 3-19 shows hydroelectric production for New England by seasons. The data are organized into seasonal averages for 2003–2007, 2008, and 2009.[118] The data show that 2008 and 2009 hydroelectric production increased for all seasons compared with the 2003–2007 averages. In particular, the summer average production levels for 2008 and 2009 were both about 53% over the 2003–2007 average levels.

[116] Percentages are based on annual historical generation data reported by the ISO at http://www.iso-ne.com/nwsiss/grid_mkts/enrgy_srcs/index-p1.html and subsequent web pages. Refer to Section 8.1 for additional information.

[117] Total supply includes electrical generator output and net interchange megawatts.

[118] For this analysis, seasons are defined as three-month periods: December to February, March to May, June to September, and October to November. Using this definition, the winter season includes December data from one year and the January and February data from the next year. Therefore, the output for December 2008 is included in the total output for winter 2009.

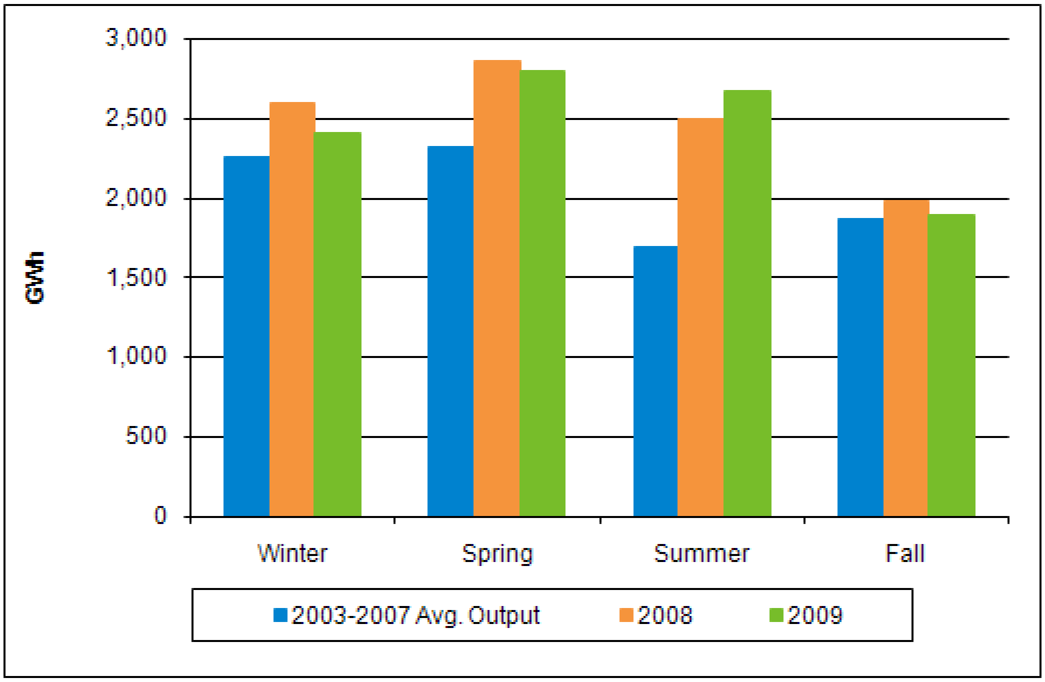

Figure 3-19: Historical hydroelectric energy production by season for New England, 2003 to 2007 average, 2008, and 2009, GWh.

3.3.6.5 Self-Scheduled Generation

Figure 3-20 shows real-time self-scheduled generation as a percentage of total electric energy produced from 2007 through 2009. Self-scheduling is of interest because self-scheduled generators are willing to operate at any price and are not eligible to set clearing prices. Participants may choose to self-schedule their generators' output for a variety of reasons. For example, those with day-ahead generation obligations may self-schedule in real time to ensure that they meet their day-ahead obligations. Participants with fuel contracts that require them to take fuel also may self-schedule. In addition, participants may self-schedule resources to prevent the units from being cycled off overnight and then started up again the next day. In 2009, self-scheduled generation averaged 66% of total real-time energy, up from 64% in 2008.

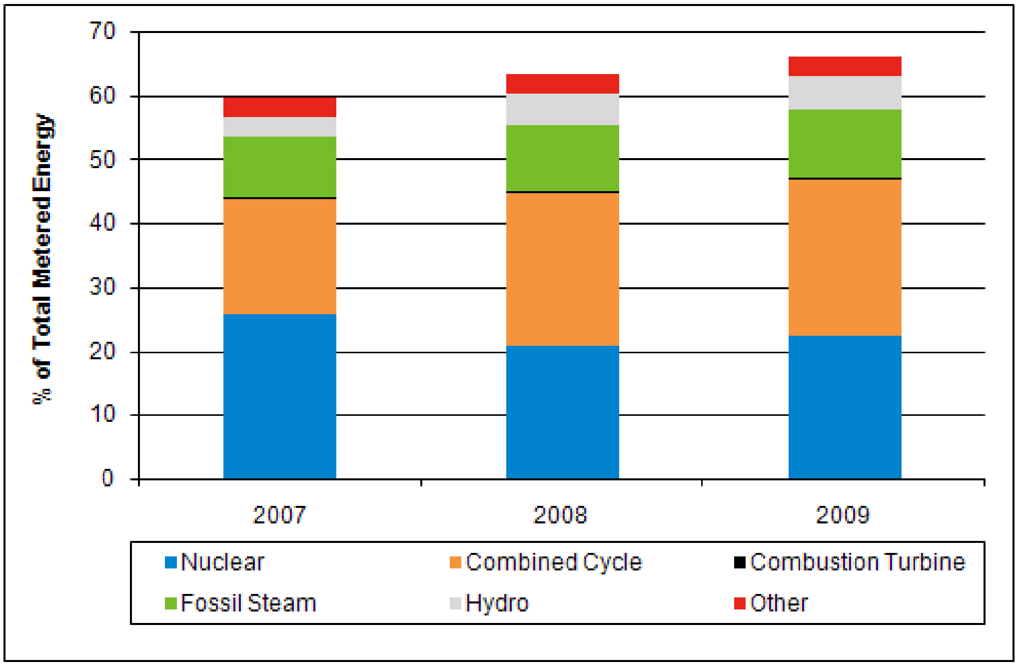

Figure 3-20: Total real-time self-scheduled electric energy as a percentage of total metered energy, 2007 to 2009.

Figure 3-21 shows real-time generation that was self-scheduled, by technology type, as a percentage of each type's total metered electric energy. Nuclear generators in New England have historically self-scheduled their generation; therefore, 100% of the metered energy generated by all nuclear plants is self-scheduled energy. All other generator categories except combustion turbines self-scheduled a higher percentage of their energy in 2009 than in 2008.

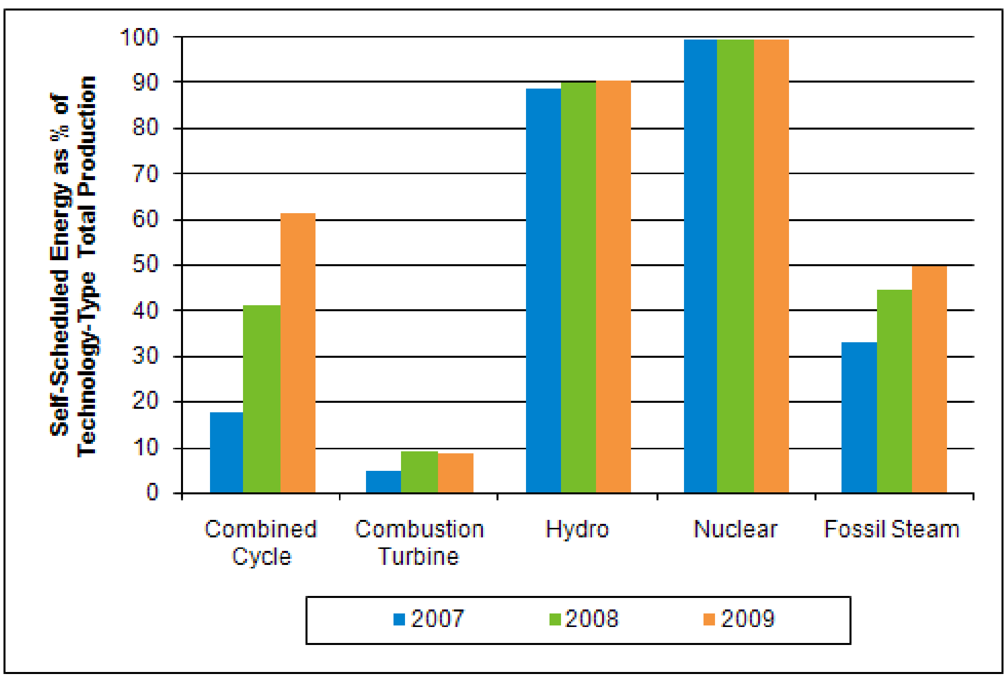

Figure 3-21: Total real-time self-scheduled electric energy as a percentage of each technology's total annual energy production, 2007 to 2009.

Table 3-7 shows cleared supply from self-scheduled generation in the day-ahead market and the amount of self-scheduled generation in the real-time market for 2008 and 2009. Over time, additional self-scheduled megawatts committed outside of the day-ahead market have declined. Overall, the percentage of self-scheduled generation supply in real-time that cleared as a self-schedule in day-ahead increased from 91% in 2008 to 94% in 2009.

Table 3-7
Day-Ahead, Real-Time, and
Real-Time Supplemental Self-Schedules, 2008 to 2009, GWh

Year	Month	Day-Ahead Self-Schedule (GWh)	Real-Time Self-Schedule (GWh)	Real-Time Supplemental Self-Schedule (GWh)	Percent (Day Ahead/ Real Time)
2008	Jan	6,142	7,259	1,024	85%
	Feb	6,070	7,280	1,117	83%
	Mar	6,709	7,706	1,210	87%
	Apr	5,486	6,159	997	89%
	May	5,910	6,443	673	92%
	Jun	7,194	7,758	533	93%
	Jul	7,879	8,496	564	93%
	Aug	7,576	8,121	617	93%
	Sep	6,890	7,297	545	94%
	Oct	6,531	6,976	407	94%
	Nov	6,501	7,081	445	92%
	Dec	7,368	7,927	579	93%
2009	Jan	7,729	8,333	559	93%
	Feb	6,896	7,305	603	94%
	Mar	7,556	8,044	409	94%
	Apr	7,146	7,563	488	94%
	May	6,295	6,755	417	93%
	Jun	6,892	7,338	460	94%
	Jul	7,383	7,806	447	95%
	Aug	8,087	8,540	422	95%
	Sep	6,886	7,247	453	95%
	Oct	5,794	6,202	361	93%
	Nov	5,871	6,336	409	93%
	Dec	6,791	7,371	465	92%

3.3.6.6 Marginal Unit Analysis

Because the price of electricity changes as the price of the marginal fuel changes, analyzing marginal units by fuel type helps explain changes in electricity prices. During all pricing intervals, the system has one marginal unit that is classified as the *unconstrained* marginal unit. In a locational marginal pricing market, however, more than one marginal unit exists when transmission constraints are present. For example, during high loads, the interface between Connecticut and the rest of the New England power system could become constrained, and generation in Connecticut would need to be *dispatched up* to meet load. In this case, there would be two marginal units, one on each side of the constrained interface.

Figure 3-22 shows the percentage of total pricing intervals during which each input fuel was marginal during 2009. Figure 3-22 includes only the unconstrained periods. When combining both unconstrained and constrained periods, the marginal fuel type during more than 60% of the pricing intervals is natural gas. The next most frequent fuels on the margin are coal and pumped-storage generation and demand.[119]

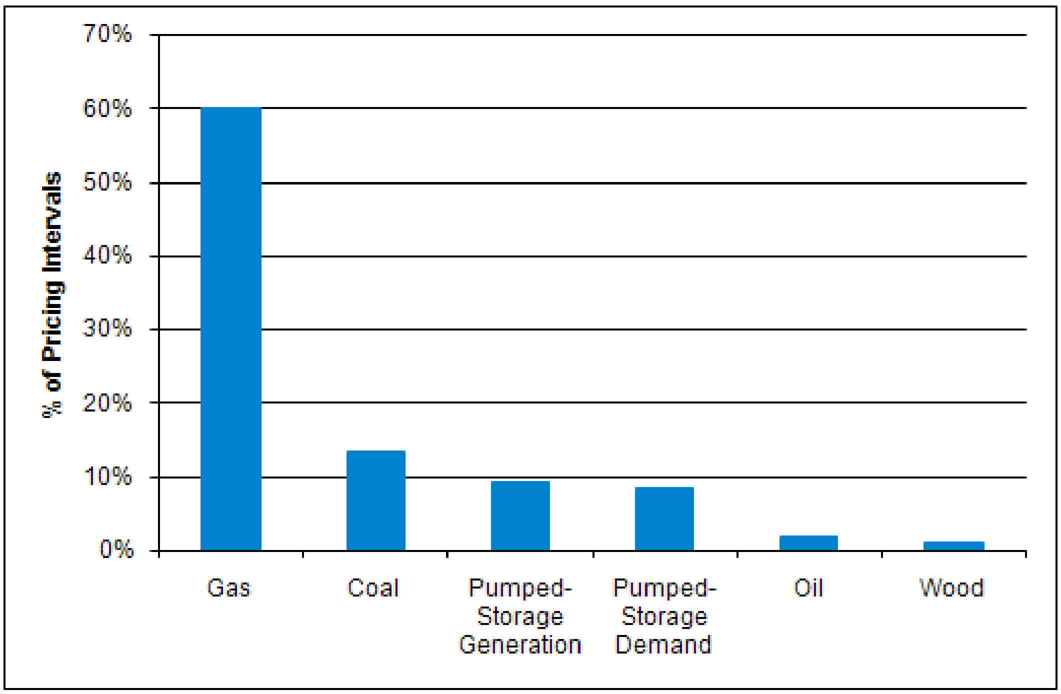

Figure 3-22: Marginal fuel-mix percentages of unconstrained pricing intervals, 2009.

Note: The figure includes each marginal unit; when the system has more than one marginal unit at the same time, the marginal minutes are distributed equally across the marginal units' fuel types.

3.3.6.7 Displacement of Coal-Fired Generation by Natural-Gas-Fired Generation

The Market Monitoring unit evaluated the relationship between gas-fired and coal-fired generation in 2009. Specifically, the IMM analyzed whether, given the low gas prices in 2009, gas-fired generators

[119] The demand side of a pumped-storage facility is modeled as a *dispatchable asset-related demand* (DARD). DARD is able to submit bids and may be dispatched according to those bids by the real-time scheduling pricing and dispatch software. If the DARD is marginal, it may set price.

displaced some coal-fired generation in the region during some dispatch intervals. Over the longer term, the displacement of coal-fired generation by natural gas is of interest nationally because it can reduce carbon emissions.

Coal units generally are baseload generation in New England. Coal accounts for approximately 2,800 MW of New England's total capacity and 11% of the energy production. In contrast, natural gas accounts for almost 12,000 MW of New England's total capacity and 32% of the energy production. In unconstrained areas, coal-fired generation was marginal approximately 14% of the time, while gas-fired generation was marginal approximately 60% of the time.

To evaluate whether gas could have displaced coal generation any time during the year, for each day in 2009, the IMM estimated the operating cost of the most expensive coal-fired unit in the region and compared it to the estimated cost of the least expensive gas-fired unit.[120] Figure 3-23 shows that during some days in August, September, October, and November, gas indices approached or were lower than coal. On these days, cheaper gas generation may have displaced some more expensive coal generation. These results show overall that even the most expensive coal resource remains economic relative to the least expensive gas unit.

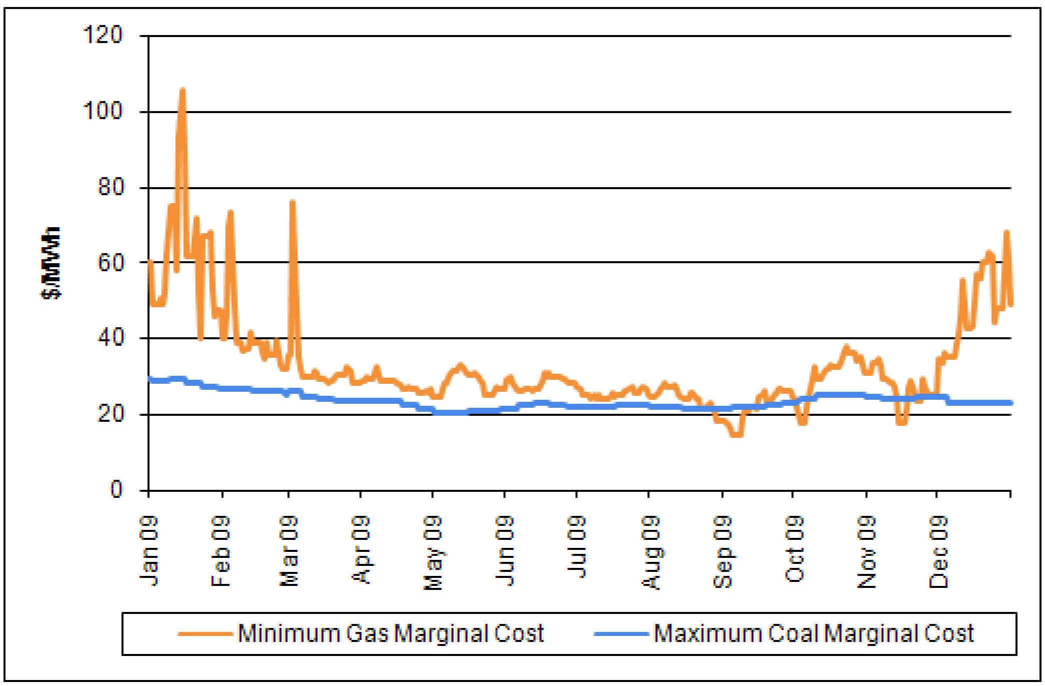

Figure 3-23: The cost of the least expensive gas plant compared with the cost of the most expensive coal plant in New England, 2009, $/MWh.

3.3.7 Real-Time Reserves and Reserve Payments

Table 3-8 shows, by reserve zone, the average five-minute-interval real-time reserve clearing prices during intervals with nonzero prices and the percentage of nonzero-priced intervals for each reserve

[120] This analysis does not take into consideration overall capacity and the availability of coal and gas units during this timeframe, system dispatch, and generator minimum run time, nor does it account for costs other than fuel.

product and zone combination. The percentage of nonzero-priced intervals is an indicator of the frequency of binding reserve constraints. The NEMA/Boston reserve constraint bound more frequently than the constraints in CT or Rest of System but with lower average prices.

Table 3-8
Real-Time Reserve Clearing Prices for Nonzero Price Intervals, 2009

Reserve Zone	TMSR[a]		TMNSR[a]		TMOR[a]	
	Price ($/MWh)	% Nonzero Intervals	Price ($/MWh)	% Nonzero Intervals	Price ($/MWh)	% Nonzero Intervals
CT	29.32	2.46%	58.90	0.81%	62.60	0.14%
SWCT	29.32	2.46%	58.90	0.81%	62.60	0.14%
NEMA/Boston	29.05	2.60%	53.37	0.96%	42.39	0.29%
Rest of System	29.31	2.45%	59.07	0.81%	64.75	0.13%

(a) TMSR refers to 10-minute spinning reserve. TMNSR refers to 10-minute nonspinning reserve. TMOR refers to 30-minute operating reserves. See to Section 2.3.

Total real-time reserve payments in 2009 were $7.9 million, a decrease from $16.8 million in 2008. Table 3-9 shows real-time reserve payments by product. Real-time payments for 10-minute spinning reserve fell by 56%, and 10-minute nonspinning reserve costs fell by 52% from 2008 to 2009. Payments for all 30-minute operating-reserve products fell by 10%. The large increase in 2008 payments was due to overnight shortages of reserves.

Table 3-9
Real-Time Reserve Payments, 2007 to 2009, $/MWh

Year	Systemwide TMSR	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/ Boston TMOR	Total
2007	3,053,694	2,158,986	140,847	851,559	220,593	143,033	6,568,714
2008	9,802,141	6,430,973	88,481	324,020	77,914	75,553	16,799,082
2009	4,295,033	3,051,191	105,469	172,899	89,602	138,834	7,853,028

Figure 3-24 shows real-time reserve credits by month for 2009. As 2009 progressed, the frequency and magnitude of real-time reserve prices increased. This change in real-time reserve price outcomes is a direct consequence of changes in the system topology, which have allowed operators to reduce commitments of local second-contingency-protection resources and thereby reduce the degree to which the system relies on the available dispatchable range of on-line resources to meet reserve requirements. With on-line generating resources available to provide real-time reserves, real-time reserve constraints bind infrequently, and when the constraints do bind, the prices tend to be low because the opportunity cost of on-line resources to provide reserves tends to be small. The IMM made several observations, particularly for the latter half of 2009:

- Resources previously committed for local second-contingency protection are no longer on line.
- The next available resource often is an off-line peaking unit.
- Constraints bind more frequently (TMSR in particular).
- Prices are higher, on average, when the reserve constraints do bind

All other things equal, the consequence is a more efficient dispatch and improved short-run price signals.

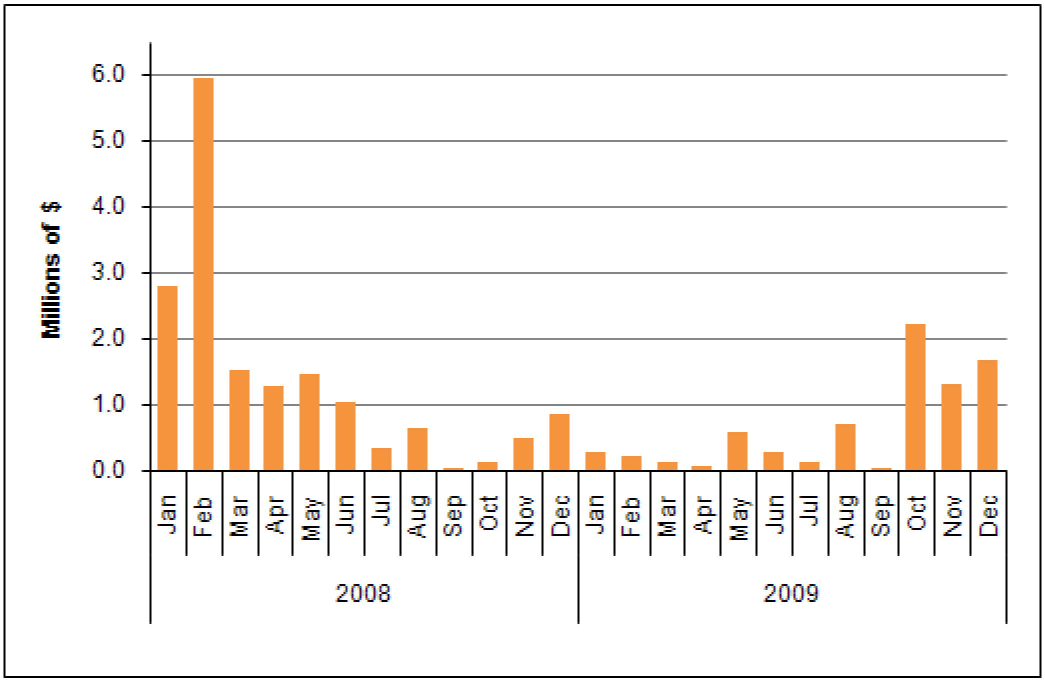

Figure 3-24: Total real-time reserve credit, 2009.

Table 3-10 shows the increase in the frequency of binding reserve constraints and the increase in the average price during intervals with positive reserve prices after the Tremont East improvements went in service in Lower SEMA, eliminating the need to commit a Canal unit.

Table 3-10
2009 Systemwide TMSR Price Statistics

	Jan–Jun	Jul–Dec	Change	% Change
Number of intervals with positive TMSR prices	1,013	1,560	547	54%
Percentage of intervals with nonzero prices	1.95%	2.95%	1.0%	51%
Average TMSR price for intervals with nonzero prices	$18.37	$36.41	$18.04	98%

3.3.8 Net Interchange with Neighboring Regions

During 2009, New England was a net importer of power, with net imports from Canada exceeding net exports to New York. Net interchange with neighboring balancing authority areas totaled 9,331 GWh for 2009 or about 7.4% of total load. Figure 3-25 shows imports and exports by interface. Average metered flow by hour for all external interfaces is included in the appendix, Section 8.1.

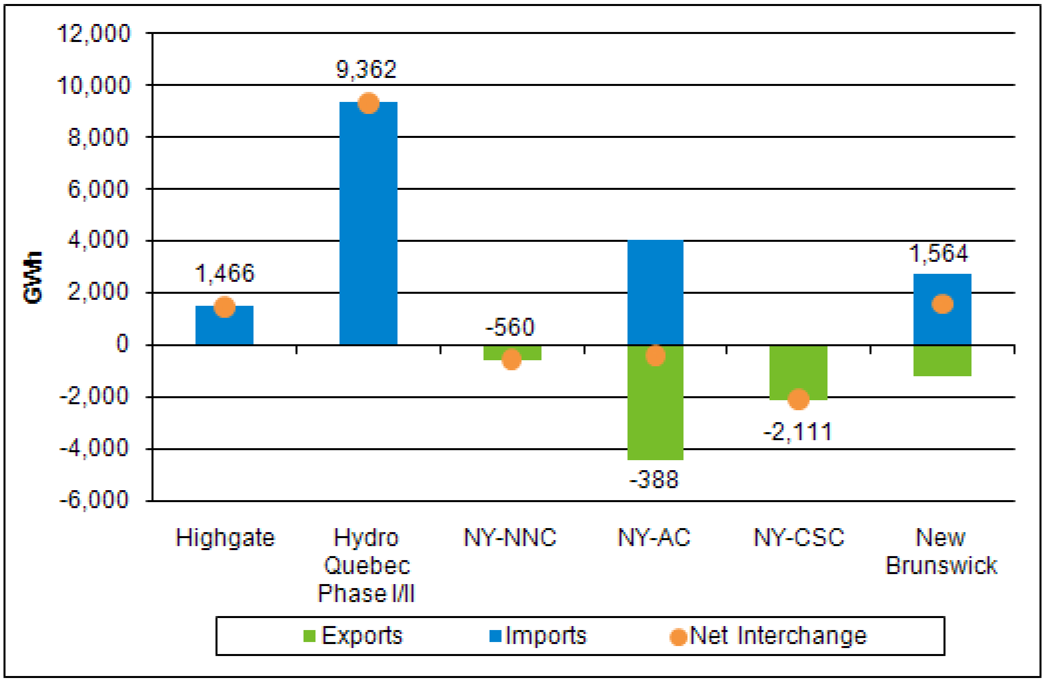

Figure 3-25: Imports and exports by interface, 2009.

Note: NNC stands for the Norwalk Harbor–Northport, NY, cable-replacement project (formerly known as the 1385 cable). NY–AC stands for the New York Alternating-Current Interface. CSC stands for the Cross-Sound Cable.

3.3.9 Minimum Generation Emergencies

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.

Figure 3-26 shows the number of hours per month with Minimum Generation Emergency conditions for 2007 through 2009. The number of hours with Minimum Generation Emergency conditions has seen a large increase, from a total of eight hours spread over three months in 2007; to 32 hours over six months in 2007; to 31 hours over six months in 2008; and, finally, to 82 hours over nine months during 2009. Load has decreased during Minimum Generation Emergencies over time. Hourly load during the minimum-generation conditions averaged 12,400 MW in 2007, 11,600 MW in 2008, and 10,750 MW in 2009.

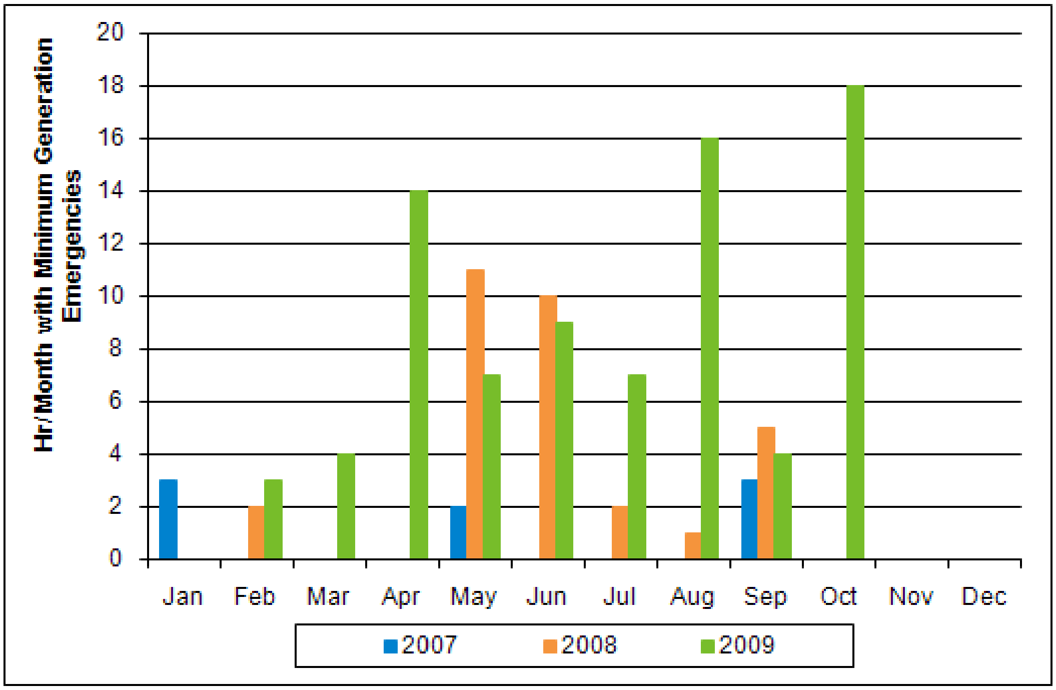

Figure 3-26: Hours per month with Minimum Generation Emergencies, 2007 to 2009.

Contrary to expectations, while the number of dispatch intervals with prices set to zero (or near zero) has increased, the amount of self-scheduled and inflexible or nondispatchable megawatt-hours scheduled day ahead and in real time has increased, as discussed above. The existing market rules may not provide appropriate incentives to maximize resource flexibility and make price-based offers into the market under all conditions. The IMM recommends that the ISO reevaluate the rules to ensure that all resources have incentives under all conditions to submit economic offers into the Day-Ahead and Real-Time Energy Markets. Changes to consider include allowing negative offers or bids day ahead or in real time and allowing real-time offer and bid modifications.

Figure 3-27 shows the megawatt-hours of generation on line during minimum generation emergencies by fuel type. While the hours of minimum generation have increased, the megawatt-hours for coal and oil units saw substantial decreases. Gas and nuclear generation has remained flat, and hydro generation has increased.

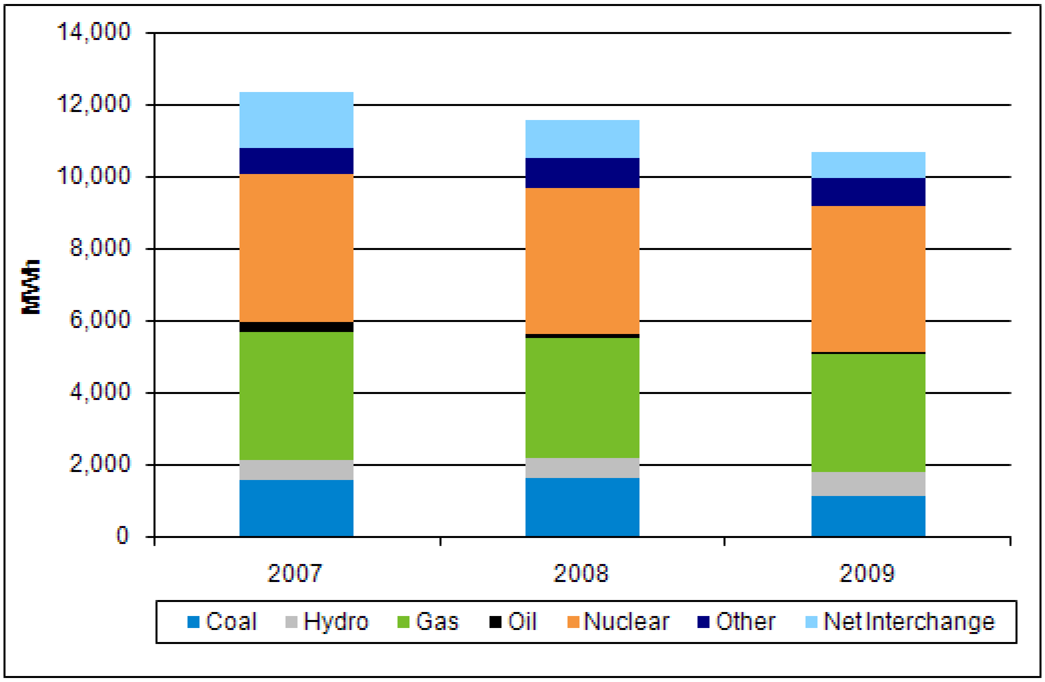

Figure 3-27: Generation on-line during Minimum Generation Emergencies, 2007 to 2009, MWh.

Additional information on Minimum Generation Emergencies is included in Section 8.5.

3.3.10 Generating Unit Availability

Table 3-11 reports the annual Weighted Equivalent Availability Factors (WEAFs) of New England generating units for 2000 to 2009.[121] As shown, the availability of generators has been increasing in general from a low of 81% in 2000 to a high of 90% in 2007, dropping to 86% in 2008 and then increasing to 87% in 2009.

[121] The term *weighted* means that averaging is proportional to unit size, so that a 100 MW unit counts 10 times more than a 10 MW unit. *Equivalent* means that both deratings (partial outages) and full-unit outages are counted proportionally to the available megawatts.

Table 3-11
New England System Weighted Equivalent Availability Factors, %

	2000[(a)]	2001	2002	2003	2004	2005	2006	2007	2008	2009
System Average	81	89	88	88	88	89	89	90	86	87
Fossil Steam	78	84	85	87	86	86	88	87	85	89
Coal	n/a	88	84	84	83	88	84	87	81	82
Coal/oil	n/a	86	74	84	88	88	85	79	90	84
Oil	n/a	84	86	84	84	84	89	84	80	91
Oil/gas	n/a	80	84	91	87	84	91	89	89	92
Wood/refuse	n/a	95	94	94	93	93	93	92	92	89
Nuclear	89	91	91	91	94	89	93	92	90	89
Jet engine	88	92	94	94	97	95	96	97	95	97
Combustion turbine	83	89	93	93	97	95	95	94	90	94
Combined cycle	80	84	90	85	86	86	84	86	83	81
Pre-1999 combined cycle	89	94	92	91	92	92	92	92	92	88
New installed 1999–2008) combined cycle	67	76	90	84	84	86	81	83	80	79
Hydro	81	95	96	95	94	94	96	96	97	96
Pumped storage	86	93	87	92	90	92	91	98	93	96
Diesel	88	98	98	98	95	98	99	97	98	96

(a) Beginning in 2000, the ISO began separating the "fossil-steam" category into the five categories as noted. In this context, "n/a" stands for "not calculated."

3.4 Congestion Revenue and Financial Transmission Rights

This section provides information on the value of congestion revenue and the results of the Financial Transmission Rights (FTR) markets. FTRs are a speculative instrument for some participants, a strict hedging tool for others, and a mixture of both for others.

3.4.1 Congestion and Congestion Revenue

Figure 3-28 shows total congestion revenue by month from 2007 through 2009. Total congestion revenue decreased almost 80% from 2008 to 2009, dropping from $121 million to $25 million. This decrease in congestion revenue is consistent with recent improvements in the system's transmission infrastructure, lower load levels, and lower input fuel prices. The combined effect of lower load and transmission improvements means the number of hours with binding transmission constraints and the cost of redispatch to manage those constraints should decrease. The data bear this out; during 2008, 65% of hours were congested compared with 39% in 2009.[122]

[122] A congested hour is defined as any hour when the Hub had a nonzero congestion component, indicating a binding constraint is somewhere on the system.

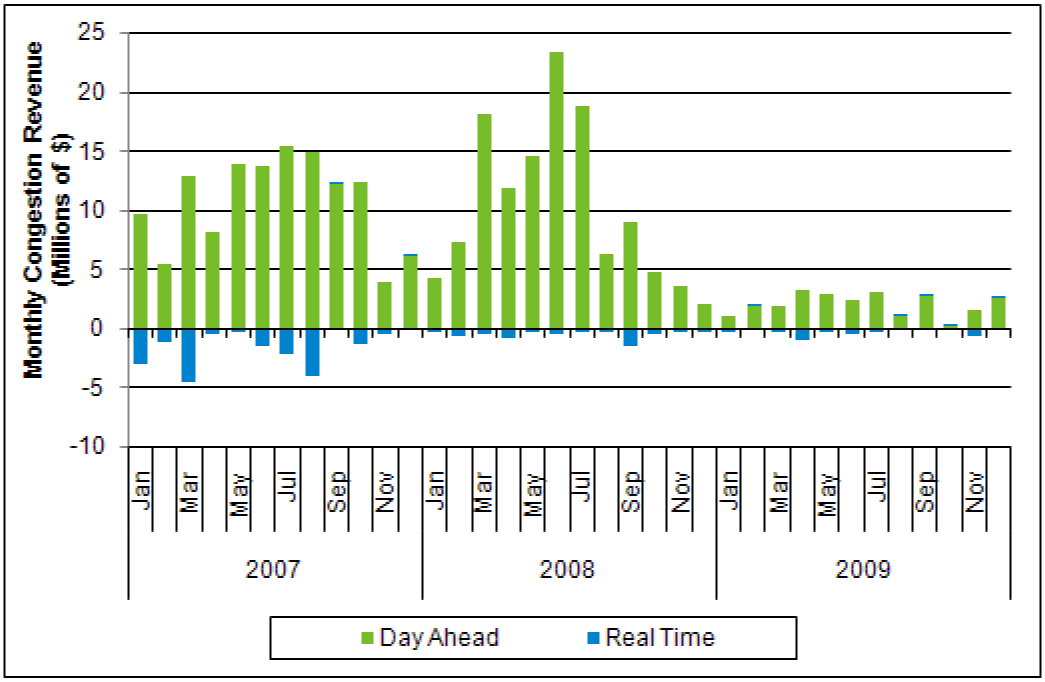

Figure 3-28: Day-ahead and real-time congestion revenue by month, 2007 to 2009.

Transmission improvements and lower loads also result in lower congestion revenue because demand intersects relatively flat portions of the supply curve more often, reducing the additional cost to the system of redispatching resources to maintain transmission flow limits.

3.4.2 Financial Transmission Rights and Auction Revenue Rights

The ISO conducts the annual and monthly auctions for FTRs. Revenues collected from the auctions are distributed back to market participants according to the ISO tariff and *Market Rule 1*.

3.4.2.1 FTR Auction Results

The annual auction for FTRs covering the 2009 calendar year was held in December 2008 and offered 50% of the system's transmission capability. FTR auctions also were held for each month in 2009. In each of the monthly auctions, the remaining balance of the transmission capability, accounting for expected outages within that month, is made available.[123] The number of participants bidding in each auction ranged from 33 participants in the February and December monthly auctions to 40 participants in the August 2009 auction, similar to the range of FTR participation in previous years. In 2009, revenue from the 12 monthly auctions and the single annual auction totaled $71 million; a 40% drop from 2008.

Figure 3-29 shows the annual and average monthly megawatt volume that cleared the FTR auctions for 2007 through 2009. The volume of annual megawatts dropped from 2008, while the average volume in the monthly auctions increased slightly compared with previous years. Figure 3-30 shows the average annual FTR price converted into a monthly value and the average monthly auction prices

[123] During each of the monthly FTR auctions, the remaining capacity of the transmission system is sold, except for 5% to account for unplanned outages.

for 2007 through 2009. As the monthly average quantity of megawatts transacted increased from 2008, the average price dropped from $144/MW to $42/MW.

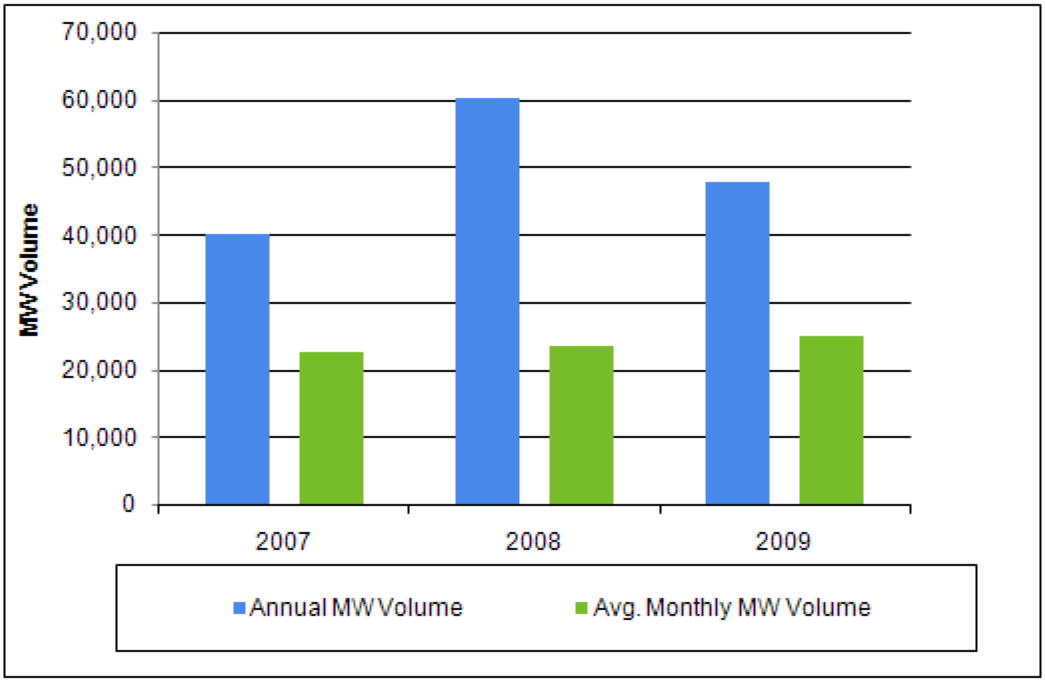

Figure 3-29: Annual and average monthly auction volumes, 2007 to 2009.

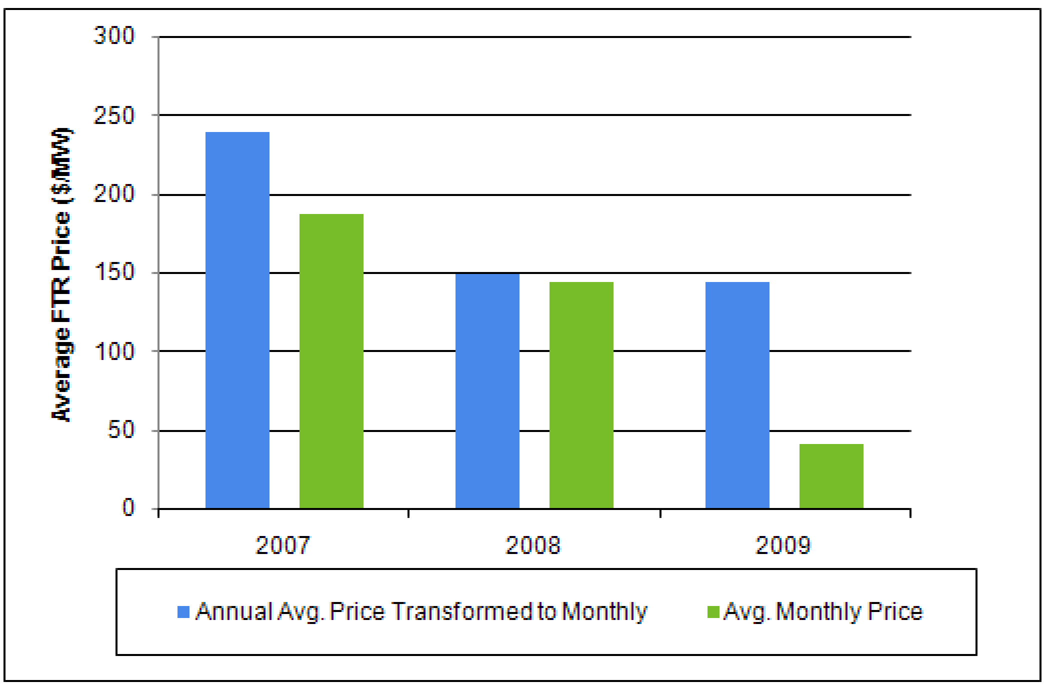

Figure 3-30: Annual prices converted to monthly equivalent price and average monthly auction prices, 2007 to 2009.

Even with this large decrease in average monthly FTR auction prices, the market prices for FTRs exceeded the actual level of congestion in the day-ahead market. Table 3-12 shows the day-ahead congestion revenue as a percentage of auction revenue for 2007 through 2009. For 2007 and 2008, the FTR prices reasonably estimate future day-ahead congestion, while in 2009 the FTR prices exceeded realized day-ahead congestion by 266%. The prices participants paid in the FTR auctions were not consistent with the lower levels of congestion experienced throughout 2009. This large and unusual difference between day-ahead congestion revenue and auction revenue suggests that the market was dominated by load-serving participants using FTRs as a hedge (those whose FTR bids are a function of both expected congestion revenues and ARR distributions) and that the financial FTR participants generally did a poor job of estimating congestion for 2009.

Table 3-12
Comparison of Day-Ahead Congestion Revenue to Auction Revenue, 2007 through 2009

	Day-Ahead Congestion Revenue (Millions $)	Total Auction Revenue (Millions $)	Auction Revenue as % of Day-Ahead Congestion Revenue
2007	130.1	122.8	94%
2008	125.4	116.7	93%
2009	26.7	71.1	266%

3.4.2.2 FTR Auction Revenue Distribution

The FTR settlements distribute actual congestion revenue from the Day-Ahead and Real-Time Energy Markets to FTR holders as determined in the FTR market auctions. The ISO tariff dictates that revenue from the auctions is distributed to holders of Qualified Upgrade Awards and Auction Revenue Rights holders. As shown in Table 3-13, the majority of the auction revenue is distributed to Auction Revenue Rights holders.

Table 3-13
Total Auction Revenue Distribution, 2007 through 2009, $

	2007	2008	2009
QUA dollars	3,343,390	7,997,938	2,940,675
Excepted transaction dollars[(a)]	267,209	137,592	532
NEMA contract dollars	465,603	207,897	154,826
Load-share dollars	118,735,550	108,387,117	67,957,265
Total auction revenue	122,811,752	116,730,543	71,053,298

(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.

In 2009, almost 96% of the total auction revenue was distributed to load-share ARR holders. Figure 3-31 shows the percentage of the total ARR distributions by load zone. In 2009, most ARRs were distributed to participants in the Connecticut and SEMA load zones.

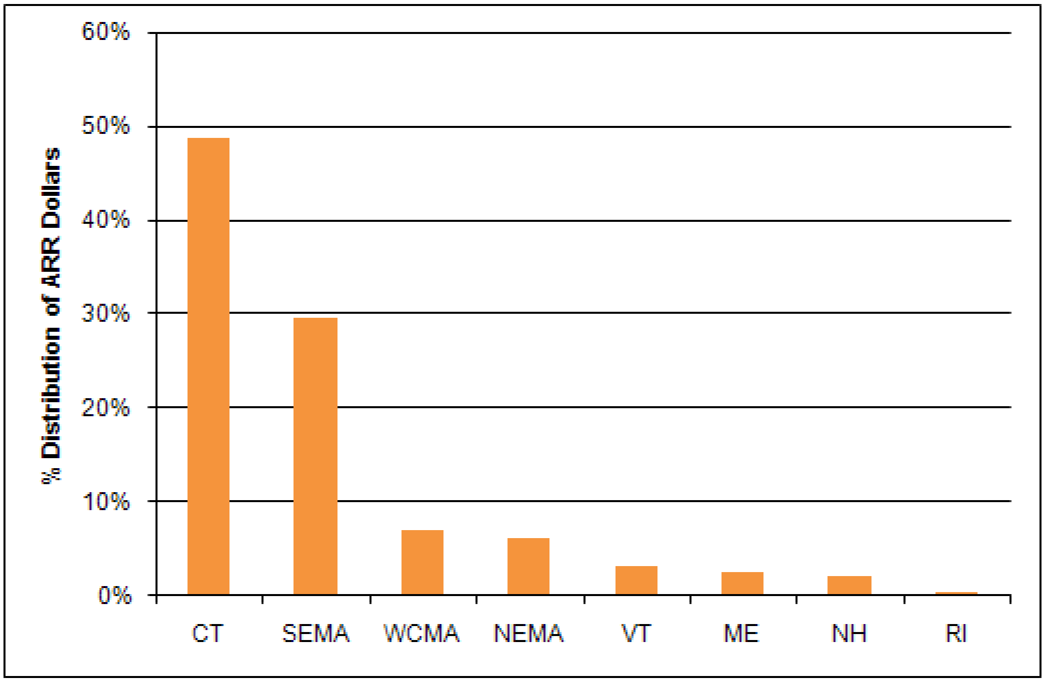

Figure 3-31: Load-share ARR distribution by load zone, 2009.

3.4.2.3 FTR Profitability and Hedging Performance

Figure 3-32, like Table 3-13, suggests participants failed to predict day-ahead congestion patterns accurately. Figure 3-32 compares two concepts at a participant level: (1) the FTR net revenues, and (2) a "net hedge" of FTR and ARR revenues combined. Most participants lost money in FTRs. In total, participants in the FTR market received, including the year-end distributions of the Congestion Revenue Balancing Fund, approximately $46 million less than they paid in the auctions. The participants using the FTR market as a hedge (as well as other participants receiving auction revenues) benefited from the miscalculation of future congestion through a relatively high total auction revenue distribution. The total net position of participants that both received auction revenues and participated in the FTR market is almost $8 million. The remaining auction revenue was distributed to ARR and QUA holders that did not participate in the FTR market.

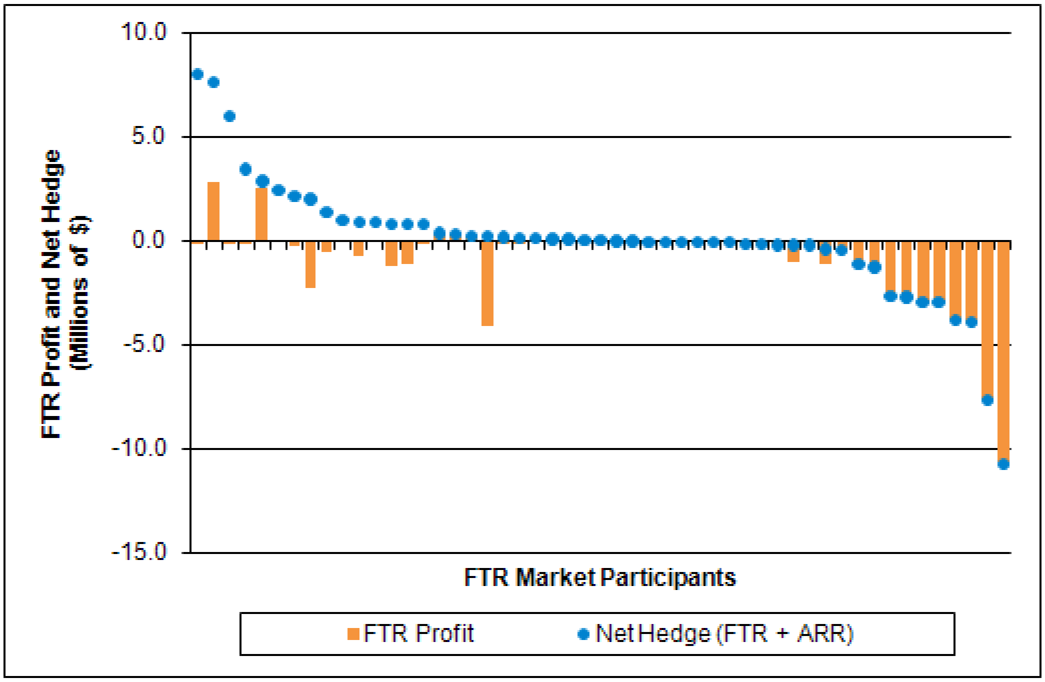

Figure 3-32: Overlay of FTR participant profitability and total hedge after including ARR revenue, 2008.

The Congestion Revenue Balancing Fund is made up of the monthly surpluses and shortfalls that are accrued during the year and paid out at year-end.[124] In 2009, the year-end balance of the Congestion Revenue Balancing Fund was $1,370,878, while the sum of monthly shortfalls was −$2,522,785.16. The surplus was allocated to participants with shortages on a pro rata share, resulting in eventual payment of 80% of the positive target allocations owed to holders of FTRs.

3.4.3 Congestion and Financial Transmission Rights Conclusions

Both congested hours and total congestion revenue were down from previous years. This is consistent with recent transmission improvements and lower load levels for the year.

As a financial instrument, the large difference between expected congestion (auction revenues) and actual congestion suggests that market participants did not accurately value FTRs. As a group, participants in the FTR market received approximately $46 million less than they paid in the auctions, and participants that both received auction revenues and participated in the FTR market gained almost $8 million, on average.

3.5 Demand Resources

The ISO has two sets of demand-resource programs. The first set consists of programs triggered by reliability events and hourly price-based programs. The second is a capacity-based program called *other demand resources* (ODRs). This section includes participation and performance data on both sets of programs, as well as analysis and recommendations to improve the benefits these programs provide to the markets.

[124] Table 8-10 in Section 8.1.4 shows the components of the Congestion Revenue Balancing Fund for each month of 2009.

3.5.1 Demand-Resource Program Participation

The number of megawatts of demand resources participating in ISO markets increased modestly in 2009. Total enrollments were 2,546 MW in December 2008 and 2,998 MW in December 2009. The increase came from the 30-Minute and Two-Hour Demand-Response Programs and other demand resources. Enrollments in the Real-Time Price-Response Program decreased slightly, while profiled demand-response enrollments did not change. Figure 3-33 shows demand response and ODR program enrollments by quarter for 2005 through 2009.

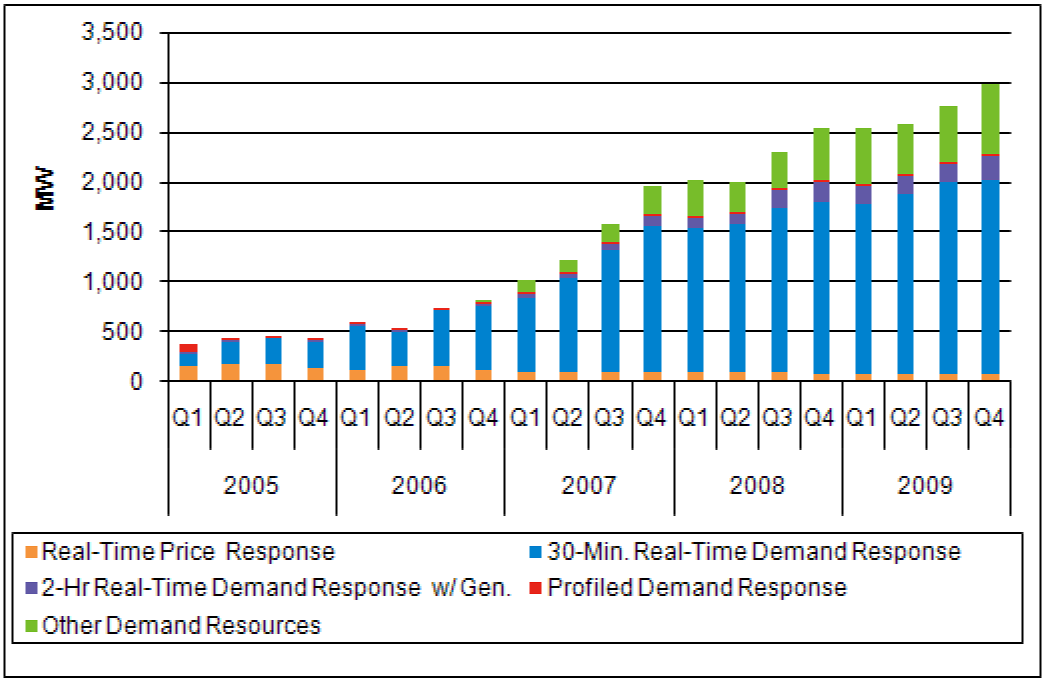

Figure 3-33: Quarterly demand-resource enrollments, 2005 to 2009.

Note: Refer to Section 2.7 for a description of these programs.

Enrollment in the demand-resource programs has increased since the introduction of capacity market transition payments in December 2006.[125] Demand resources, except for resources in the price-response programs, qualify as capacity and are eligible for transition payments.

Table 3-14 shows a state-by-state breakdown of demand-response assets and megawatts of participation during December 2009. Connecticut has the most megawatts enrolled, followed by Massachusetts and Maine. Demand resources in Maine include several large industrial customers.

[125] See the ISO's *2006 Annual Markets Report* available at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

Table 3-14
Demand-Response Assets by State, December 2009

State	# of Assets	Total MW	% of Total	Real-Time Price Response (MW)	Real-Time 30-Min Demand Response (MW)	Real-Time Two-Hour Demand Response (MW)	Profiled Demand Response (MW)
CT	1,464	764.1	33%	3.0	740.8	20.4	0.0
VT	156	100.9	4%	1.8	82.7	10.5	5.9
MA	1,437	648.7	28%	48.4	533.8	66.6	0.0
RI	278	134.6	6%	14.3	108.2	12.1	0.0
NH	207	106.9	5%	4.5	97.0	5.4	0.0
ME	133	533.6	23%	0.0	400.8	121.8	11.0
Total	**3,675**	**2,289**	**100%**	**72.0**	**1,963.3**	**236.8**	**16.9**

Table 3-15 shows the changes from 2008 to 2009 in the number of assets and number of megawatts enrolled in demand-response programs, along with the percentage change in the number of megawatts. The total number of megawatts enrolled in programs in New Hampshire declined, while the other states saw increases in enrolled megawatts.

Table 3-15
Demand-Response Program Enrollment Changes, by State, December 2008 to December 2009

Change 2008 to 2009							
State	**Assets**	**Total MW**	**Real-Time Price Response (MW)**	**Real-Time 30-Min Demand Response (MW)**	**Real-Time Two-Hour Demand Response (MW)**	**Profiled Demand Response (MW)**	**State MW Change %**
CT	−34	19.4	−4.3	3.4	20.4	0.0	2.6%
VT	46	13.0	−1.1	16.5	−2.4	0.0	14.8%
MA	329	155.8	−6.6	138.9	23.8	0.0	31.6%
RI	51	39.9	−2.1	36.5	5.5	0.0	42.1%
NH	59	−12.9	0.0	−15.1	2.3	0.0	−10.8%
ME	44	44.5	0.0	54.8	−10.3	0.0	9.1%
Total	**495**	**259.7**	**−14.1**	**235.0**	**39.3**	**0.0**	**12.8%**
Systemwide % change from 2008	**16%**	**13%**	**−16%**	**14%**	**20%**	**0%**	

3.5.2 Demand-Response Interruptions

The ISO demand-resource programs involve a combination of reductions in load from the bulk grid with different triggers and obligations categorized into demand-response programs and “other demand resources” (refer to Section 2.7.3). The demand-response programs produce interruptions when the ISO initiates an event for the particular program, while interruptions from ODRs are measured during prespecified periods. This section describes the megawatt-hour interruptions and payments made during 2009.

3.5.2.1 Summary of Interruptions

Load interruptions occur when an ISO-initiated event is activated or when a participant in the Day-Ahead Load-Response Program, whose day-ahead load-interruption offer was accepted, meets or exceeds its obligation to interrupt load in real time. As described in Section 2.7.2, a Real-Time Price-Response Program event is activated when a forecasted real-time price exceeds $100/MWh. A reliability event is activated when OP 4 Action 3, 9, or 12 is called at the zonal or systemwide level.

The Real-Time Price-Response Program was activated a total of 78 days in 2009, down from 207 days in 2008. The DALRP produced interruptions on 126 days in 2009, up from 103 days in 2008. Table 3-16 lists the number of days with an interruption by program type. A total of 45,803 MWh of load were interrupted during the year from all demand-response programs. Figure 3-34 shows interruptions by load-reduction type. See Section 2.7.2 for a description of the features and payment structures of the Day-Ahead Load-Response and Real-Time Price Response Programs.

Table 3-16
Number of Interruption Days in 2009

Demand-Response Program	Number of Days with Interruptions
Real-Time 30-Minute Program with emergency generation	4
Real-Time 30-Minute Program without emergency generation	2
Real-Time Two-Hour Program	1
Real-Time Profiled Program	1
Real-Time Price-Response Program	78
Day-Ahead Load-Response Program	126

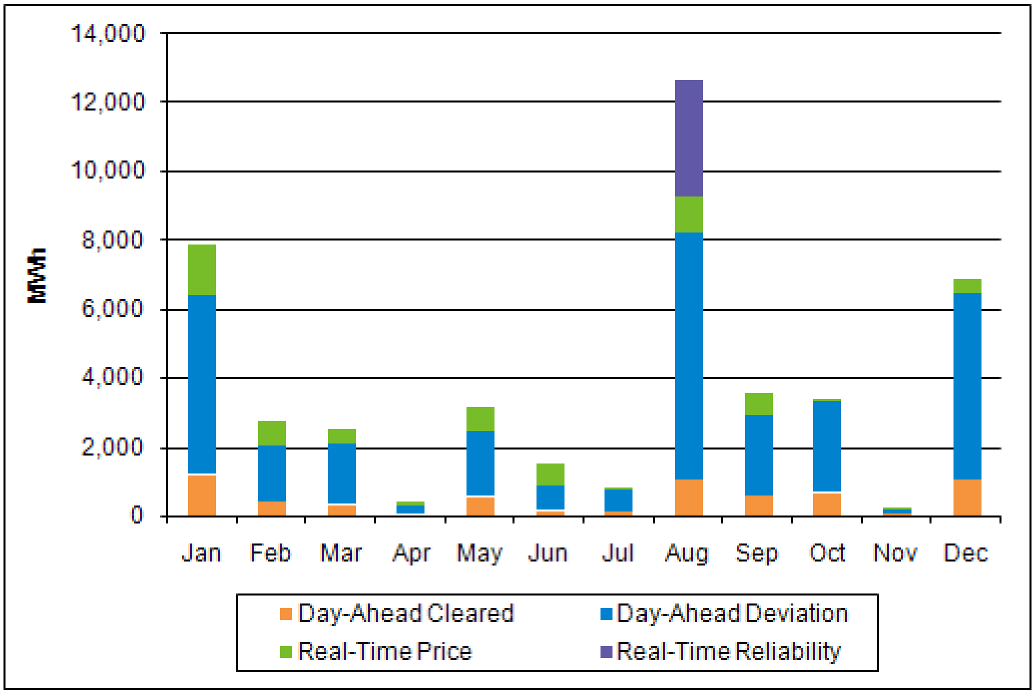

Figure 3-34: Interruptions by load-reduction programs, 2009, MWh.

Note: The megawatt-hours of real-time reliability programs for August are from program audits. The ISO must conduct a demand-response program audit for any zone that was not part of an OP 4 event during the calendar year before August 15. The audit must take place (when required) between August 15 and August 31. Because the reliability programs are triggered specifically by OP 4 actions but no OP 4 events took place during 2009, all enrolled resources needed to be audited before the end of August (see Section 3.5.4).

Table 3-17 details the payments made to demand-response programs in 2009. Payments for all demand-resource programs totaled $111.5 million in 2009. The majority of this total was paid to reliability programs as capacity market transition payments. Transition payments rose from $77.6 million in 2008 to $106.8 million in 2009. Increased program enrollments and a higher transition payment rate caused the change.

Table 3-17
Demand-Response Payments, 2009, $

Demand-Response Program	Payment ($)[(a)]
Total payments made to Day-Ahead Load-Response Program	2,567,378
Total payments for Real-Time Price-Response Program	597,455
Total payments to reliability programs for real-time events/audits	1,614,149
Total capacity market transition payments made to reliability programs	106,775,377
Grand Total	111,554,359

(a) These values do not include transition payments made to ODR resources.

Payments to resources in the Day-Ahead Load-Response and Real-Time Price-Response programs were lower in 2009 than in 2008. Participants in the DALRP were paid $2.5 million in 2009, down from $6.7 million in 2008. More than half of the 2008 payments made to resources participating in the DALRP were made in January and February 2008. In February 2008, the ISO made changes to the DALRP design to address problems with strategic bidding. The combination of these rule changes and lower 2009 LMPs caused the decrease in payments.

Payments in the real-time program declined from $5.1 million in 2008 to $597,455 in 2009. Lower 2009 LMPs, which caused less frequent activation and lower payments when activation did occur, were responsible for this decrease.

The three real-time reliability programs (30-Minute and Two-Hour Demand-Response and Profiled Response) were activated during an audit in August 2009. They were not activated in real time during any nonaudit periods in 2009. Payments to these resources for their performance during the audit totaled $1.6 million. In 2008, resources in these programs were paid $1.4 million.

3.5.2.2 Other Demand Resources

Other demand resources are specific resources or programs created by the FCM Settlement Agreement consisting of energy-efficiency programs, load management programs, and distributed generation.[126] ODRs are compensated through the capacity market; the resources are not eligible for payment in the Day-Ahead or Real-Time Energy Markets. ODRs received $31.6 million in capacity market transition payments in 2009.

Figure 3-35 summarizes the load reductions provided by ODRs throughout 2009. As Figure 3-35 shows, most monthly ODR reductions come from energy-efficiency projects, with smaller amounts from distributed generation and load management. ODRs have lower winter ratings than summer ratings, which accounts for the lower performances from January through March and again in December. Unlike other resources, capacity for ODRs is measured by monthly energy reductions.

[126] For background information, see *Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues*, FERC Docket Nos. ER03-563-000, -030, -055 (filed March 6, 2006; as amended March 7, 2006).

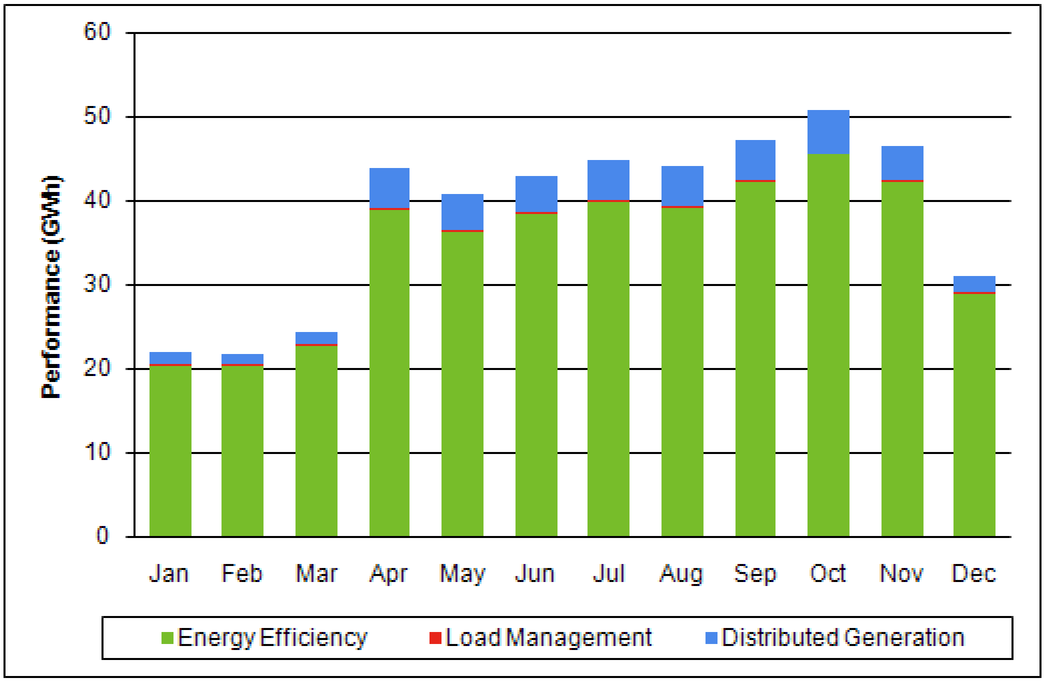

Figure 3-35: Estimated monthly energy reductions from ODRs, by resource type, 2009.

3.5.3 Analysis of Price-Response Programs

The two price-response programs (the Real-Time Price-Response Program and the Day-Ahead Load-Response Program) were originally scheduled to expire on June 1, 2010. However, both programs have been extended for two additional years, to June 1, 2012, while the ISO and its stakeholders determine how to integrate price-responsive demand (PRD) into the energy markets.[127] The filing extension included provisions to make a needed change to the DALRP eligibility criteria in addition to revising the programs' expiration dates. No changes were made to the payment rates, minimum offer prices, activation criteria, cost-allocation method, or participants' rights and obligations.

3.5.3.1 Day-Ahead Load-Response Program Interruptions

Participants who offer load response into the Day-Ahead Energy Market must offer at or above a minimum price. The price is calculated as a heat rate of 11.37 MMBtu/MWh multiplied by a monthly fuel index.[128] Figure 3-36 compares the monthly day-ahead load-response minimum offer price with the average day-ahead LMP at the Hub for nonholiday weekdays between 7:00 a.m. and 6:00 p.m. On average, day-ahead LMPs were lower than the DALRP minimum offer price.

[127] For more information, see *ISO New England Inc. and New England Power Pool, Tariff Revisions Regarding Extension of the Real-Time Price Response Program and Day-Ahead Load Response Program; Docket No. ER09-___-000*, FERC Docket No. ER09-1737-000 (September 23, 2009); http://www.iso-ne.com/regulatory/ferc/filings/2009/sep/er09-___-000_9-23-09_price_load_response_ext.pdf.

[128] The 11.37 MMBtu/MWh heat rate is specified in the tariff.

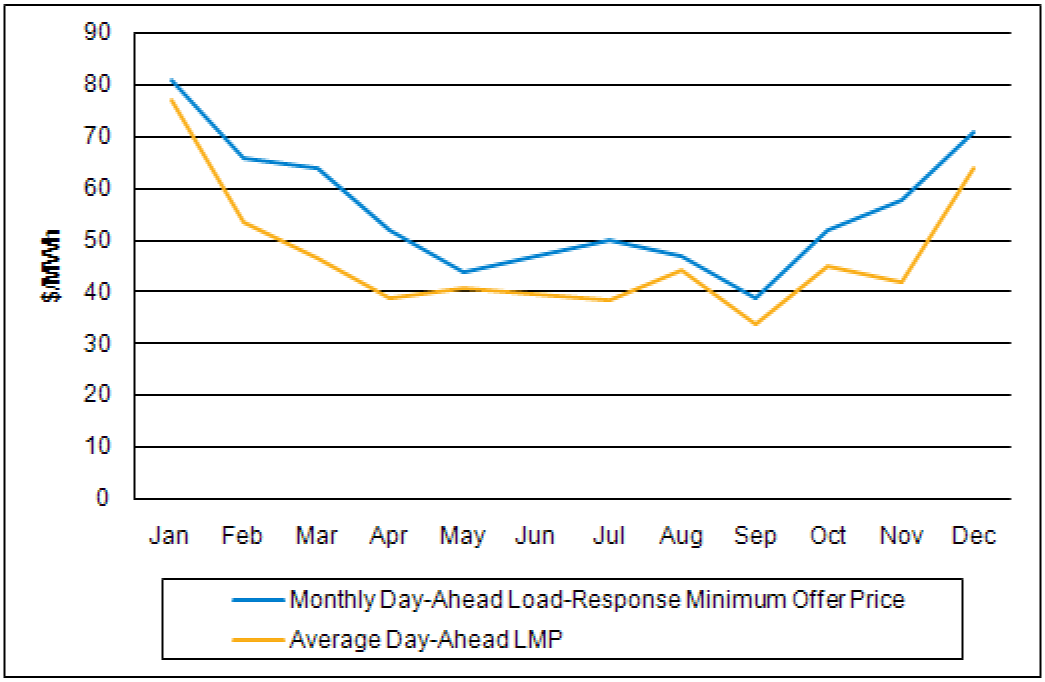

Figure 3-36: Monthly day-ahead load-response minimum offer price compared with the average monthly day-ahead LMP, 2009, $/MWh.

3.5.3.2 Real-Time Price-Response Program Interruptions

The Real-Time Price-Response Program is activated on weekdays when any zonal price during hour ending (HE) 8:00 a.m. to HE 6:00 p.m. is forecast to be $100/MWh or higher.[129] Forecasts include the Day-Ahead Energy Market prices and LMPs calculated during the ongoing Reserve Adequacy Analysis process. When the program is activated, real-time price response resources reduce load during HE 2:00 p.m. to HE 5:00 p.m. in the winter and HE 12:00 p.m. (noon) to HE 5:00 p.m. in the summer.

Table 3-18 shows Hub LMPs on days when the Real-Time Price-Response Program was activated. It compares average real-time LMPs for the hours of the program activation with the average of the highest daily day-ahead and RAA LMPs during HE 8:00 a.m. to HE 6:00 p.m. (the trigger hours) on days when the program was activated.

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

Table 3-18
Average Hub LMPs for
Real-Time Price-Response Program Hours, 2009, $/MWh

Month	Real-Time LMPs Activated Hours	Day-Ahead LMPs Trigger Hours	RAA LMPs Trigger Hours
Jan	71.69	104.19	601.79
Feb	47.81	64.46	483.65
Mar	62.03	77.72	426.85
Apr	39.32	44.61	748.13
May	50.40	45.12	536.12
Jun	46.65	43.26	298.08
Jul	69.50	46.96	129.38
Aug	81.41	60.76	8,525.02
Sep	41.51	42.73	846.79
Oct	64.07	55.46	529.67
Nov	27.69	48.62	1,122.47
Dec	63.53	89.28	520.74

In most hours in 2009 when the Real-Time Price-Response Program was activated, it was triggered by high LMPs calculated in the RAA process. Prices in the Day-Ahead Energy Market and Real-Time Energy Market were much lower than the LMPs from the RAA process. The Hub day-ahead LMP was $100/MWh or more on only 12 of the 78 days when the program was activated.

The LMPs produced by the RAA process are not an accurate predictor of real-time LMPs. The IMM recommends removing RAA LMPs from the Real-Time Price-Response Program trigger. The trigger could be based solely on the day-ahead LMP, or it could be changed to an indexed trigger price. The filing to extend the price-response programs stated that no changes would be made to the programs during the extension period, but the IMM considers the inclusion of the RAA LMPs in the trigger to be a severe enough inefficiency to warrant a revision to the existing rules.

3.5.4 Real-Time Demand-Response and Profiled-Response Program Audit Performance, August 2009

On August 17–18 and 24–25, 2009, in accordance with the ISO's load-response program rules, the ISO conducted an audit of the resources participating in the Real-Time Demand-Response and Profiled-Response Programs on these days.[130] All the real-time reliability program resources were

[130] The *ISO New England Load Response Program Manual* (October 1, 2007) requires the ISO to conduct a demand-response program audit for any zone that was not part of an OP 4 event during the calendar year before August 15. The rule

activated on these days for audit purposes. As provided in the program rules, the audit was unannounced and was conducted as a real program event. The activations of the programs during the audit were staggered across four days.

The audit included 2,992 assets with a total maximum interruptible capacity of 2,019.8 MW and adjusted capacity of 1,700 MW.[131] Interrupted megawatts totaled 1,685 MW; 83% of maximum interruptible capacity and 99% of adjusted capacity.[132] These totals include megawatts from assets that exceeded their adjusted capacity, which in aggregate may offset some underperformance by other assets. Relative to the audit requirements of the programs, these resources performed well on average. However, since the audit requirements for the FCM are different than the program requirements, these performance data may or may not be indicative of expected performance of the same assets under the FCM.

Figure 3-37 compares the total megawatts interrupted during the audit with the maximum interruptible capacity and adjusted capacity for the resources enrolled in each program.

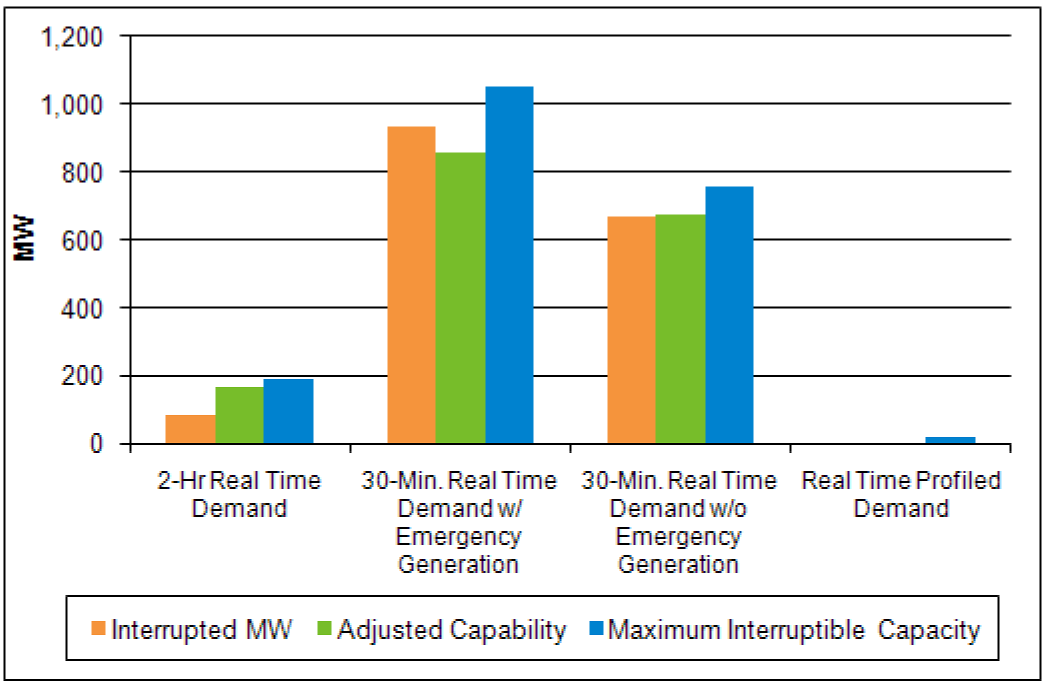

Figure 3-37: Audit results by program, 2009.

3.5.5 Conclusions about Demand Resources

Enrollments in demand-resource programs increased in 2009, driven by the 30-Minute and Two-Hour Demand-Response Programs and other demand resources. Demand resources provided a total of

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requires the audits (when necessary) to occur between August 15 and August 31. See http://www.iso-ne.com/rules_proceds/isone_mnls/index.html, M-LRP Load-Response Program.

[131] *Maximum interruptible capacity* is the contracted number of megawatts or registered amount for a resource. *Adjusted capacity* reflects interruptions from previous events and may be lower than the maximum interruptible capacity if a resource underperformed.

[132] *Interrupted megawatts* is the maximum interruption achieved by a resource in any 5-minute recording interval during a load-response event or audit.

507 GWh of load reduction in 2009, with the majority (462 GWh) coming from other demand resources, such as energy-efficiency projects.

Payments to demand-response resources were $111.5 million, including $106.5 million in capacity market transition payments. ODRs received $31.6 million in transition payments.

3.6 Oversight

This subsection summarizes the Internal Market Monitoring Unit's mitigation and investigation activities in 2009.

3.6.1 Market Mitigation Activities

Under *Market Rule 1*, the IMM monitors the market impact of specific bidding behavior (i.e., offers and bids) and, in specifically defined circumstances, mitigates behavior that interferes with the competitiveness and efficiency of the energy markets and daily reliability payments.

3.6.1.1 Mitigation under Market Rule 1*, Appendix A, Section 5: Economic Withholding and Uneconomic Production*

Economic withholding occurs when a supplier offers output to the market at a price above its full incremental costs. If the offer also is above the market price, the output is not sold. For example, during periods of high demand and high electric energy prices, all generation capacity with full incremental energy costs that do not exceed the energy price should be producing energy or supplying operating reserves through redispatch. Failing to do so would be an instance of economic withholding.

A two-part conduct-impact test for triggering mitigation is used in New England. First, supplier conduct is tested to determine whether the supplier may have attempted withholding. If it fails this conduct test, a test for market impact is applied. If a supplier fails this test by increasing market prices by more than a defined threshold, mitigation is imposed. The mitigation imposed for economic withholding is to replace the supplier's offer with a reference level intended to represent the supplier's full incremental costs. These criteria are applied each day to all participants in constrained areas. A less restrictive set of thresholds is applied each day to systemwide pivotal suppliers.

Mitigation was applied four times during 2009. All the mitigation events were for economic withholding for NCPC. No mitigation was imposed for economic withholding in the Day-Ahead or Real-Time Energy Markets, and the systemwide thresholds did not trigger mitigation of electric energy suppliers that were pivotal in 2009. In addition to taking these specific actions, the Internal Market Monitoring Unit had nearly daily discussions with individual participants concerning specific market behavior.

3.6.1.2 Resource Audits

Market Rule 1, Appendix A, Section 4.2.2, authorizes the IMM to verify forced (i.e., unplanned) outages. The IMM uses all available data to determine whether a plant inspection is warranted. If an inspection is appropriate, the IMM contacts both the plant management and the lead participant representing the resource to coordinate access to the plant and a visual inspection of the reported cause of the forced outage. If the results of a plant inspection suggest that the resource owner has physically withheld the resource, the ISO obtains appropriate additional information. If the completed review shows that physical withholding has taken place, the ISO may refer that participant, as outlined in Appendix A of *Market Rule 1*.

During 2009, the IMM requested detailed plant information and operator logs for a number of cases. In each case, the IMM monitored for potential physical withholding of a resource and determined that a plant inspection was not warranted.

3.6.1.3 Cap on FTR Revenues

Market Rule 1, Appendix A, Section 8.4, authorizes the IMM to cap the revenues of FTR holders that use virtual transactions to create congestion that increases the value of the FTR path. When this occurs under the defined thresholds of Section 8.4 of Appendix A, the FTR path is "capped" to the amount that the participant originally paid for the FTR path. In 2009, the IMM capped a total of $14,777 in revenues on over 21 FTR paths.

3.6.2 Market Investigation Activities

The *Energy Policy Act of 2005* grants FERC broad authority to regulate manipulative or fraudulent behavior in the energy markets. FERC implemented its new authority by amending its existing regulations to prohibit any entity from directly or indirectly engaging in the following behavior in connection with the purchase or sale of electric energy or transmission services subject to its jurisdiction:

- Using or employing any device, scheme, or artifice to defraud
- Making any untrue or misleading statement
- Engaging in any fraudulent or deceptive act, practice, or course of business

Under EPAct and Section 14 of Appendix A, if the IMM finds a potential violation of EPAct or the market-behavior rules, it is required to make a referral to FERC. While the Internal Market Monitoring Unit does not have to prove that a market violation has occurred, it is obligated to provide sufficient credible information to warrant further investigation by FERC.

In 2009, the IMM made two nonpublic referrals to FERC, bringing the total amount of opened IMM referrals before FERC to five. No referrals were closed in 2009. The IMM and the ISO also responded to various requests from FERC for additional information in connection with the alleged market violations that were referred, as well as other FERC activities and investigations.

Section 4
Forward Capacity Market

This section summarizes the 2009 activities related to the Forward Capacity Market, including the FCM transition period payments, the results of the first three Forward Capacity Auctions, and the first Annual Reconfiguration Auction.[133] It also contains an assessment of certain features of FCM that have become more important because of the current capacity surplus.[134] Refer to Section 2.2 of this document for an explanation of the structure of the FCM, the auction process, and IMM oversight.[135]

4.1 FCM Transition Period

As defined in the FCM Settlement Agreement, FCM transition payments replaced the Installed Capacity Market in December 2006 and will continue until the 2010/2011 capacity commitment period when the FCM payments based on the auction results will begin. FCM transition payment rates were $3.75/kW-month from June 2008 through May 2009 and then increased to $4.10/kW-month in June 2009, as laid out by the FCM settlement. During 2009, FCM transition payments to qualifying capacity resources totaled $1.8 billion compared with $1.5 billion in 2008. Table 4-1 summarizes the capacity requirements, the total capacity purchased, and the total payments in each transition period year.

Table 4-1
ICAP/FCM Transition Payment

Year	Average UCAP Supply (MW)	Annual Installed Capacity Requirement[(a)] (MW)	Total Payment ($)	ICAP Transition Payment Rate ($/kW-month)	
				Jan–May	Jun–Dec
2007	34,985	31,270	1,280,464,983	3.05	3.05
2008	36,331	32,160	1,505,257,134	3.05	3.75
2009	37,236	31,823	1,765,901,336	3.75	4.10

(a) The Installed Capacity Requirement is listed in the *Forward Capacity Informational Filing* to FERC (http://www.iso-ne.com/regulatory/ferc/orders/2009/sep/er09-1424-000_9-18-09_fca_informational_filing.pdf).

4.2 Forward Capacity Auction Results

Each of the three FCAs has procured the capacity needed to meet the region's resource adequacy requirements. Table 4-2 shows that the total of existing and new qualified capacity exceeded the

[133] Throughout Section 4, the results for FCA #1 and FCA #2 are from the *Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements* (FCM Report), ISO New England FERC filings, Docket No. ER09-1282-000 (June 5, 2009), available at http://www.iso-ne.com/markets/mktmonmit/rpts/other/fcm_report_final.pdf.

[134] FCA #1, for the capacity commitment period of June 1, 2010, through May 31, 2011, was held February 4–6, 2008. FCA #2, for the capacity commitment period of June 1, 2011, through May 31, 2012, was held December 8–10, 2008. FCA #3, for the capacity commitment period of June 1, 2012, through May 31, 2013, was held October 5-6, 2009.

[135] More detailed information about capacity requirements, the FCM qualification process, and qualified capacity are contained in the ISO's filings to FERC and FERC orders associated with the FCM, available at http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/index.html.

NICR by 21% in FCA #1, by 32% in FCA #2, and by 34% in FCA #3.[136] Moreover, because each FCA cleared capacity in excess of that necessary to meet the NICR, the floor price was reached in each auction. These results are consistent with the outcome of a competitive market with excess supply.

Table 4-2
Results of the First Three Forward Capacity Auctions

	FCA #1	FCA #2	FCA #3
Total qualified (MW)	39,165	42,777	42,746
Total cleared (MW)[(a)]	34,077	37,283	36,995
NICR (MW)	32,305	32,528	31,965
Excess cleared (MW)[(a)]	1,772	4,755	5,030
Clearing price ($/kW-month)	4.50	3.60	2.95

(a) Excludes real-time emergency generation (RTEG) resources in excess of 600 MW.

Given the constraints of the price collar, the FCAs have performed successfully in determining capacity clearing prices that reflect robust supply and sufficient competition.[137] Consistent with the excess supply outcome, each auction cleared at its specified floor price—$4.50/kW-month in FCA #1, $3.60/kW-month in FCA #2, and $2.95/KW-month in FCA #3. Cleared resources have the option either to prorate their obligation quantities and receive the full payment per megawatt, or to prorate their payments and retain the obligation for the full quantity of accepted capacity. Prorating the capacity obligation reduces the amount of capacity the ISO procures, while prorating the payments reduces the effective prices paid for the resources. In either case, the total capacity payment remains the same.[138]

None of the auctions had local sourcing requirements; the ISO determined that each potential import-constrained area had sufficient existing capacity. Maine was modeled as an export-constrained capacity zone in the three auctions; FCA #1 had a 3,855 MW maximum capacity limit (MCL), FCA #2 had a 3,395 MW MCL; and FCA #3 had a 3,257 MW MCL.

[136] The results of FCA #3 are described in the ISO New England Inc. FERC filing, *Forward Capacity Auction Results*, Docket No. ER10-186-000 (October 29, 2009) (http://www.iso-ne.com/regulatory/ferc/filings/2009/jul/er09-___-000_07-07-09_info_filing_third_fca.pdf), except for the "total qualified MW," which is from the ISO presentation to the Planning Advisory Committee available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/nov182009/fca3_results.pdf.

[137] The price collar is a set of upper and lower bounds on the FCA clearing price identified for each FCA per *Market Rule 1*, Section III.13.2.7.3. The "inadequate supply" and "insufficient competition" conditions worked as designed and appropriately were not triggered; see *Market Rule 1*, Section III.13.2.7.3 and Section III.13.2.8.

[138] If all resources opted to retain their full obligations, the prorated capacity payment would have been $4.25/kW-month in FCA #1, and $3.12/kW-month in FCA #2 in both capacity zones. In FCA #3, the capacity payment in the Rest-of-Pool zone would be prorated to $2.54/kW-month and to $2.47/kW-month in Maine. See the *Forward Capacity Auction Results Filing*.

4.3 Qualification of Resources

A large amount of capacity with diverse ownership participated in all three auctions. Table 4-3 summarizes the qualified existing capacity included in each FCA.[139] These values do not include delist bids or any new capacity resources being treated as existing resources in the first auction.[140]

Table 4-3
Qualified Existing Capacity
Participating in the Forward Capacity Auction, MW

Type of Resource	FCA #1	FCA #2	FCA #3
Generation	31,447	31,401	32,636
Imports	1,269	1,311	2,164
Demand resources	1,990	2,978	2,845
Total	**34,705**	**35,690**	**37,645**

Table 4-4 shows qualified new capacity that participated in the auctions. Qualified capacity from new resources increased 59% from the first to the second auction. Between FCA #2 and FCA #3, the amount of new capacity participating fell by 28%.

Table 4-4
Qualified New Capacity Participating
in the Forward Capacity Auctions, MW

Type of Resource	FCA #1	FCA #2	FCA #3
Generation	2,353	3,299	2,830
Imports	658	2,613	1,751
Demand resources	1,449	1,176	519
Total	**4,459**	**7,088**	**5,100**

4.4 Cleared Capacity and Delistings

Each of the first three FCAs concluded with more capacity than needed to meet the NICR. FCA #1 cleared 34,077 MW, exceeding the NICR by 1,772 MW. FCA #2 cleared 37,283 MW, a surplus of 4,755 MW over the NICR of 32,528. FCA #3 ended with an excess supply of 5,030 MW above the NICR of 31,965 MW.[141] Table 4-5 shows cleared capacity by resource type for the three auctions.

[139] The qualified resource numbers for FCA #3 as reported in the ISO presentation to the Planning Advisory Committee available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/nov182009/fca3_results.pdf.

[140] For FCA #1 only, qualified new capacity projects had the option to participate in the market as existing resources.

[141] FCA #3 results are from Attachment A of the *Forward Capacity Auction Results Filing* to FERC (http://www.iso-ne.com/regulatory/ferc/filings/2009/jul/er09-___-000_07-07-09_info_filing_third_fca.pdf), also contained in the spreadsheet

Table 4-5
Capacity Cleared in Auctions, MW and Percentage of Total

Type of Resource	FCA #1	FCA #2	FCA #3[a]
Generation	**30,865 (90%)**	**32,207 (86%)**	**32,228 (87%)**
Existing	30,825	31,050	30,558
New	40	1,157	1,670
Imports	**934 (3%)**	**2,298 (6%)**	**1,900 (5%)**
Existing	934	769	1,083
New	0	1,529	817
Demand resources[b]	**2,279 (7%)**	**2,778 (8%)**	**2,868 (8%)**
Existing	1,419	2,330	2,559
New	860	448	309
Total	**34,077**	**37,283**	**36,996**

(a) FCA #3 results from Attachment A of the *Forward Capacity Auction Results Filing* to FERC, as contained in the spreadsheet available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp13/fca13/fca3_monthly_ob_v2.xls.

(b) The 2,778 MW total for demand resources for FCA #2 reflects the 600 MW RTEG cap. An additional 159 MW of RTEG above the cap also was procured, making the total demand resources 2,937 MW. The 2,868 also reflects the 600 MW RTEG cap. An additional 30 MW of RTEG above the cap also was procured, making the total demand resources 2,898 MW.

4.4.1 Resources Cleared by Location

As noted, none of the three auctions modeled any import-constrained zones because preauction screens showed that no potential import-constrained zones needed additional capacity to meet reliability requirements.[142] Each of the auctions cleared more capacity in the CT and NEMA load zones than needed to meet their local sourcing requirements. The Maine export constraint was modeled but experienced no price separation when the auction cleared at the floor price, even though cleared capacity in FCA #3 exceeded Maine's maximum capacity limit. Price separation did not occur because the excess capacity in Maine remained at the floor price, so continuing the auction and reducing the excess capacity were not possible. Table 4-6 shows the breakdown by location for the three FCAs.

available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp13/fca13/fca3_monthly_ob_v2.xls. The NICR value can be found on p. 7 of this filing.

[142] However, in FCA #3, existing capacity in Boston would have been insufficient to meet the more stringent Transmission Security Analysis criteria if Salem Harbor had been allowed to delist as requested; see Section 4.4.6.

Table 4-6
Resources Cleared by Location, MW

	FCA #1			FCA #2			FCA #3[a]		
	CT	**NEMA**	**Maine**	**CT**	**NEMA**	**Maine**	**CT**	**NEMA**	**Maine**
Cleared Capacity	8,210	4,532	2,517	9,103	3,847	3,538	9,237	3,703	3,598
LSR	7,017	2,246	3,855 (MCL)	6,817	2,016	3,395 (MCL)	6,640	2,019	3,257 (MCL)
Excess Capacity	1,193	2,286		2,286	1,831		2,597	1,684	

(a) FCA #3 results from Attachment A of the *Forward Capacity Auction Results Filing* to FERC, as contained in the spreadsheet available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp13/fca13/fca3_monthly_ob_v2.xls.

Figure 4-1 shows the distribution of total cleared resources by load zone, and Figure 4-2 shows the distribution of new cleared resources by load zone. In FCA #3, most new capacity was from generation in the SEMA load zone.

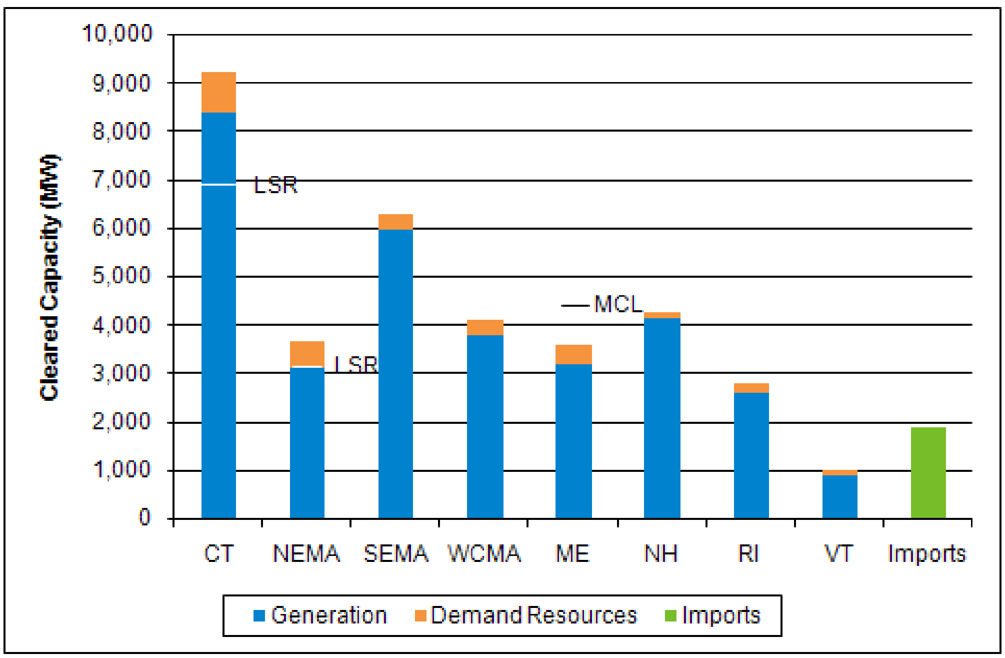

Figure 4-1: FCA #3 auction results for total cleared resources.

Note: In FCA #3, existing capacity in Boston would have been insufficient to meet the more stringent Transmission Security Analysis criteria if Salem Harbor had been allowed to delist as requested; see Section 4.4.6.

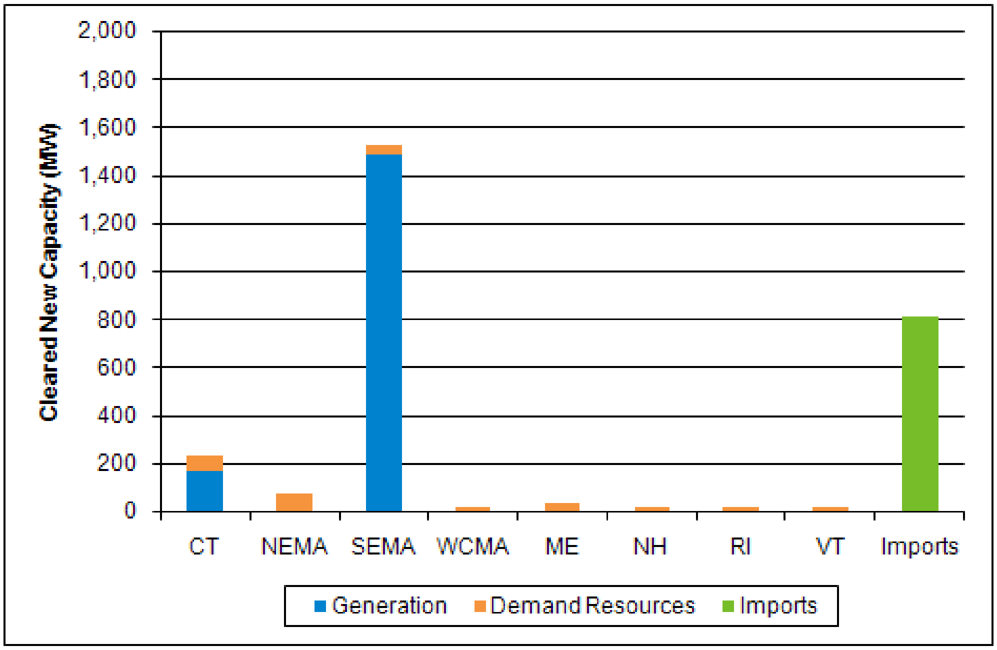

Figure 4-2: FCA #3 auction results for new cleared resources.

Note: In FCA #3, existing capacity in Boston would have been insufficient to meet the more stringent Transmission Security Analysis criteria if Salem Harbor had been allowed to delist as requested; see Section 4.4.6.

4.4.2 Imports

Imports to the ISO may come from the Hydro-Québec, New York ISO (NYISO), and New Brunswick systems. As shown in Table 4-7, 61% of the qualified capacity from import resources came from the Hydro-Québec system in FCA #1, although only 200 MW of these resources cleared in the auction.[143] In contrast, all the qualified import resources from the NYISO system (38% of qualified imports) cleared in FCA #1.

In FCA #2, import capacity from NYISO was highest among both qualified imports (72%) and cleared imports (59%). The cleared import capacity from both Hydro-Québec and NYISO in FCA #2 was greater than in FCA #1.

In FCA #3, qualified import capacity was fairly evenly split between New York (44%) and Hydro-Québec (48%), while New Brunswick's share was about 7% of the total qualifying import capacity. All of New Brunswick's qualifying capacity cleared in FCA #3, and New York had the greatest share of cleared import capacity.

[143] FCA #3 results for "cleared imports" are from Attachment A of *Forward Capacity Auction Results Filing* to FERC (October 30, 2009), as contained in the spreadsheet available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp13/fca13/fca3_monthly_ob_v2.xls, and Attachment C of *Informational Filing for Qualification in the Forward Capacity Market*, FERC Docket No. ER09-___-000 (July 7, 2009; revised July 30, 2009); http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/index.html.

Table 4-7
Sources of Qualified and Cleared Imports, MW

	FCA #1		FCA #2		FCA #3	
System	**Qualified**	**Cleared**	**Qualified**	**Cleared**	**Qualified**	**Cleared**
Hydro-Québec	1,167	200	727	662	1,886	679
NYISO	734	734	2,842	1,352	1,729	921
New Brunswick	26	0	355	284	300	300
Total	**1,926**	**934**	**3,924**	**2,298**	**3,915**	**1,900**

In FCA #1, no new import resources cleared. Of the 2,298 MW of import resources that cleared in FCA #2, 1,529 MW were new resources. A slight majority of the new import capacity was from the NYISO system, with the remaining from Hydro-Québec. FCA #3 cleared 817 MW of new import capacity.

In FCA #1, imports represented 2.7% of the cleared capacity; 6.2% in FCA #2, and 5.1% in FCA #3.[144]

4.4.3 Demand Resources

A notable feature of the first three auctions is the amount of capacity from demand resources that qualified and cleared. As shown in Table 4-5 demand resources accounted for 7% to 8% of the cleared capacity.

The total capacity from demand resources participating in the auction amounted to 12% and 14% of the projected ISO peak load for the 2010/2011 and 2011/2012 capacity commitment periods, respectively.[145] For the 2012/2013 commitment period, qualified capacity from demand resources represented 11.6%.[146] Cleared demand resources ranged from 8% to 10% of the peak load forecast across the three auctions. However, a substantial amount of qualified capacity from new demand resources participating in the auction did not clear (41% in FCA #1, 62% in FCA #2, and 40% in FCA #3).

As shown in Figure 4-3, in FCA #1 and FCA #2, the majority of cleared demand capacity came from active demand resources (real-time demand response or real-time emergency generation), and the rest was from passive demand resources (on-peak and seasonal demand resources). In FCA#3, 1,825 MW came from active demand resources and 1,073 came from passive demand resources.

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[144] See the ISO's informational FERC filings for FCA #1 (November 6, 2007), FCA #2 (September 9, 2008), and FCA #3 (July 7, 2009); http://www.iso-ne.com/markets/othrmkts_data/fcm/filings/index.html.

[145] The 29,035 MW peak load forecast for 2010/2011 and the 29,405 MW peak load forecast for 2011/2012 were used. *Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits, and Related Values for the 2010/2011 Capability Year*, FERC Docket No. ER-08-41-000 (October 11, 2007), p. 11. *Filing of Installed Capacity Requirement, Hydro-Quebec Interconnection Capability Credits, and Related Values for the 2011/2012 Capability Year*, FERC Docket No. ER-08-1512-000 (September 9, 2008), p. 11.

[146] The peak load forecast for 2012/2013 is 29,020 MW, from *Filing of Installed Capacity Requirement, Hydro-Quebec Interconnection Capability Credits, and Related Values for the 2012/2013 Capability Year*, FERC Docket No. ER09-___-000 (July 7, 2009).

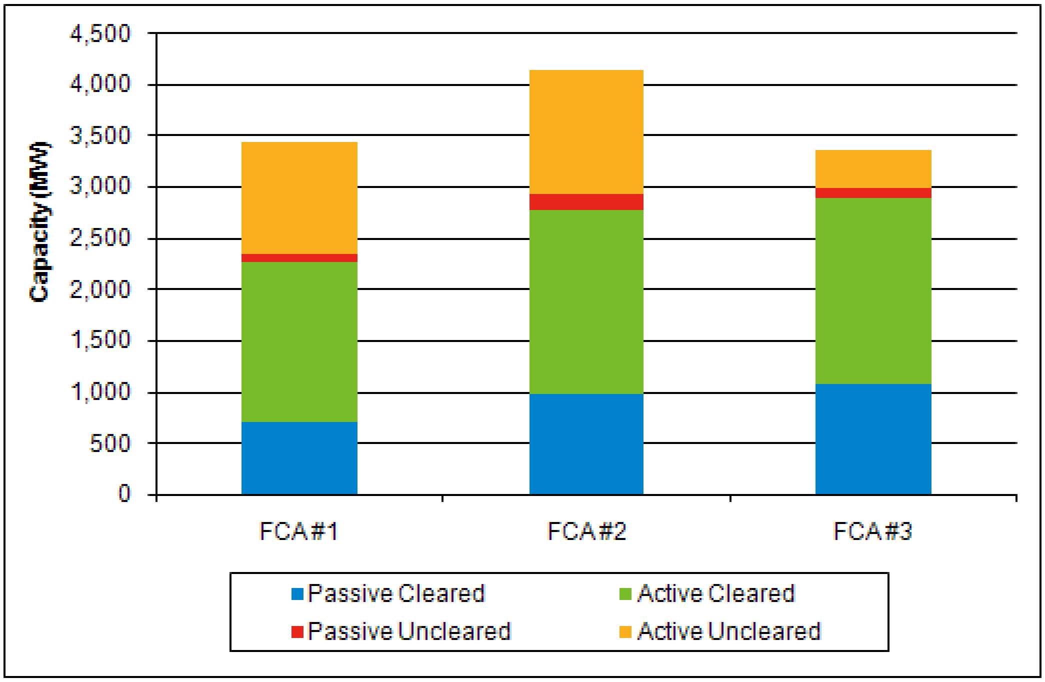

Figure 4-3: Auction results for qualified demand resources.

Note: Cleared demand resources are from Attachment A of the *Forward Capacity Auction Results Filing* to FERC, as contained in the spreadsheet available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp13/fca13/fca3_monthly_ob_v2.xls.

Table 4-8 provides a breakdown of the auction results by type of demand resource and identifies the amount of new resources. The amount of cleared, new demand resources in FCA #3 declined from FCA #2. The decline was most significant for new "active" resources, which dropped from 186 MW to 98 MW. The amount of uncleared capacity also declined significantly.

Table 4-8
Auction Results for Qualified Demand Resources by Type, MW

Demand Resources	Type of Demand Resource	FCA #1	FCA #2	FCA #3
Existing cleared	Active	999	1,614	1,727
	Passive	420	716	862
New cleared	Active	580	186	98
	Passive	280	262	211
Existing delisted	Active	570	648	256
	Passive	1	0	1
New uncleared	Active	522	571	113
	Passive	66	157	96
Total cleared		2,279	2,778	2,898
Total uncleared		1,159	1,375	466

Opportunities exist for demand resources to be an efficient substitute for generation capacity, especially because of the region's low load factor (i.e., the ratio of the average hourly load during a year to peak hourly load). Figure 4-4 shows the load-duration curves for the 500 highest demand hours in 2007, 2008, and 2009. Near-peak load levels occur in only a few hours. For example, Figure 4-4 shows that demand resources that can operate for up to 100 hours could have reduced the peak load by up to 3,000 MW to 4,000 MW in 2007 to 2009. This observation suggests that the 2,300 to 2,900 MW of demand resources that cleared in the three FCAs (see Figure 4-3) would be required to interrupt consumption in only a small number of hours.

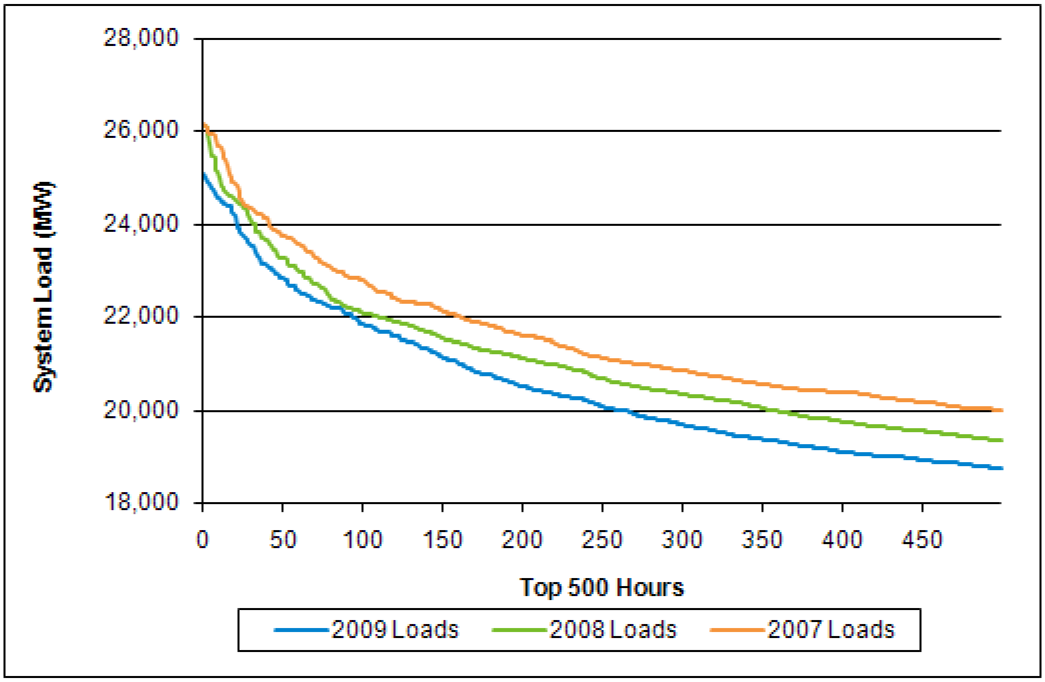

Figure 4-4: Load-duration curves for the 500 highest-demand hours in 2007, 2008, and 2009.

Note: From the spreadsheets *2007_smd_hourly.xls, 2008_smd_hourly.xls, and 2009_smd_hourly.xls*, available at http://www.iso-ne.com/markets/hstdata/znl_info/hourly/index.html.

4.4.4 Out-of-Market New Resources and In-Market New Resources

Out-of-market resources, which participate in the FCM at prices below their costs, include certain new resources with offer prices less than 0.75 times the CONE, new self-supplied resources, capacity carried forward from previous auctions, and capacity under ISO-issued RFPs.[147] Table 4-9 shows the new in-market and OOM capacity that cleared in the first three FCAs.

[147] See *Market Rule 1*, Section III.13.2.7.8.1, First Alternative Price Rule.

Table 4-9
Cleared New, In-Market, and
Out-of-Market Capacity, FCA #1, FCA #2, and FCA #3, MW[(a)]

Auction	Type of Resource	Generation	Demand Resources	Imports	Total
FCA #1	Cleared new	40	860	0	900
	In-market	0	860	0	860
	Out-of-market	40	0	0	40
FCA #2	Cleared new	1,156	448	1,529	3,134
	In-market	38	298	1,529	1,864
	Out-of-market	1,118	150	0	1,268
FCA #3	Cleared new	1,670	309	817	2,796
	In-market	1,095	189	817	2,101
	Out-of-market	575	120	0	695

(a) As reported in the informational filing to FERC on July 7, 2009, the IMM denied 1,912 MW of new capacity offered at less than 0.75 X CONE for FCA #3. Cleared capacity by type and status is listed in Attachment A of the Forward Capacity Auction Results Filing to FERC, as contained in the spreadsheet available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp13/fca13/fca3_monthly_ob_v2.xls.

In FCA #1, 40 MW (4% of the cleared new capacity) were from OOM generation with offer prices less than 0.75 times the CONE, and no other categories of OOM resources participated in the auction. In FCA #2, the amount of OOM new entry increased to 1,268 MW (41% of cleared new capacity), primarily from 994 MW of resources with low offers under state contracts in Connecticut. This contributed to the significant excess capacity in FCA #2 in which the existing capacity already was greater than the NICR. In FCA #3, OOM new entry was 695 MW, or 25% of cleared new capacity.

In each of the auctions, the cleared OOM capacity was well below the excess capacity that cleared, such that the auctions would have cleared with excess capacity at the floor price even if none of the OOM capacity had cleared. Nevertheless, the existing OOM capacity and any additional OOM capacity in future auctions will inefficiently lower FCA prices and thereby deter new entry. The long-term impacts of OOM resources on FCM performance warrant continuous monitoring and assessment.

The Alternative Pricing Rule corrects for distortions when OOM entry in an FCA prevents in-market new capacity from setting the clearing price when prices fall below competitive or efficient levels.[148] This rule was not triggered in FCA #1 because the 40 MW of new OOM capacity was less than the new capacity requirement of 441 MW. The APR was not triggered in FCA #2 because the existing qualified capacity (35,479 MW) exceeded the NICR of 32,528 MW, so no new capacity was required. The rule also was not triggered in FCA #3 because the existing qualified capacity (37,645 MW) exceeded the NICR of 31,965 MW.

[148] See *Market Rule 1*, Section III.13.2.7.8, Alternative Capacity Price Rules.

4.4.5 Delisted Capacity Resources

Table 4-10 shows the accepted delist bids from existing resources.[149] In FCA #1, most of the delisted capacity came from generation resources, which requested to delist 1,300 MW. The ISO approved 970 MW and rejected 330 MW. Roughly one-third of the delist requests from existing generation resources came from nine generating units (454 MW total) seeking to delist their entire capacity.

Demand resources dominated the delisting requests in FCA #2. Delist requests totaled 890 MW, all of which were approved. Thirteen generation units made full delist requests, corresponding to 183 MW.

Table 4-10
Delisted Existing Resources by Type, MW

Resource Type	FCA #1	FCA #2	FCA #3[(a)]
Generation	622 (64%)	350 (39%)	543 (32%)
Demand resources	296 (31%)	489 (55%)	257 (15%)
Import	51 (5%)	51 (6%)	910 (53%)
Total delisted	**970**	**890**	**1,710**

(a) The data for FCA #3 do not include 6.6 MW of administrative permanent delist bids because of a failure to submit an updated measurement and verification plan pursuant to the tariff.

In FCA #3, existing import capacity accounted for the largest proportion of delisted capacity. The ISO approved 1,710 MW of existing resources to delist, and 581 MW in the NEMA/Boston area were rejected.

In all three FCAs, delisted resources helped reduce the excess capacity but did not cause the price to rise above the floor price.

As shown in Figure 4-5, most of the delist requests in each of the auctions were dynamic bids. The static delist bids were the second largest category. Export and administrative delists were constant at 100 MW for each auction. Permanent delist requests were negligible in the first two FCAs and amounted to 6.6 MW in FCA #3.

[149] Qualified new resources can leave the auction without delisting.

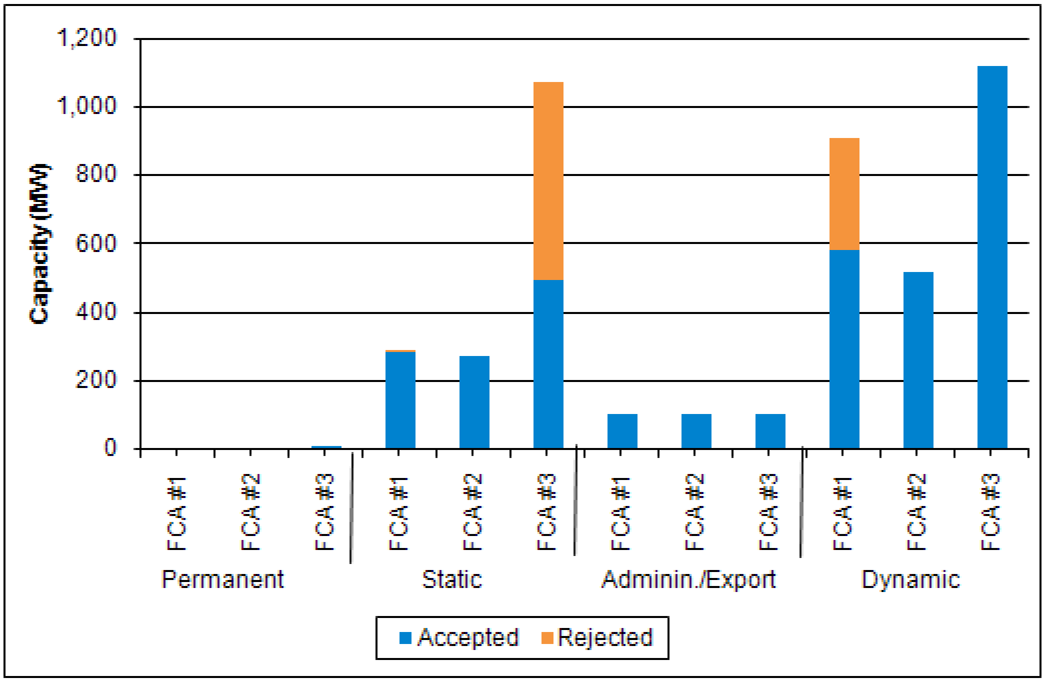

Figure 4-5: Requests for various types of capacity delistings, FCA #1, FCA #2, and FCA #3.

Figure 4-5 also shows delist requests that were accepted and rejected. For reliability reasons, the ISO rejected 330 MW of delist bids from existing generation resources (representing two units in Connecticut) in FCA #1. No delist bids were rejected in FCA #2. In FCA #3, the ISO rejected 581 MW of delist bids from two units in NEMA/Boston. As in FCA #1, the capacity from rejected delist bids is substantially below excess capacity, and the rejection would have no impact on clearing prices.

4.4.6 Rejected Delist Bids

In FCA #3, Dominion Resources sought to delist the entire Salem Harbor station, which consists of four resources: three coal units and one oil unit for a total of 743 MW. The IMM reviewed these bids according to *Market Rule 1* and submitted revised delist bids to FERC for approval. After FERC review, delist bids were included in FCA #3 for all four units at Salem Harbor station. Two of the units, Salem Harbor #1 (82 MW) and Salem Harbor #2 (80 MW), were allowed to delist. However, the other two units, Salem Harbor #3 (150 MW) and Salem Harbor #4 (431 MW) were not permitted to delist but were retained to meet reliability needs in the greater Boston area.[150]

[150] See the testimony of Stephen J. Rourke, *Forward Capacity Results Filing*, Attachment D, FERC Docket No. ER10-___-000 (October 30, 2009); http://www.iso-ne.com/regulatory/ferc/filings/2009/oct/er10-___-000_10-29-09_fca_3_results_filing.pdf. His testimony is redacted but summarized on page 10 of the filing.

4.5 Capacity Supply Curves

Figure 4-6 depicts the supply curves from the three auctions.[151] These curves reflect the offer prices from new resources and delist bid prices from existing resources that were revealed as resources that exited the auction as the descending clock progressed.[152] The lower portions of the supply curves are flat because this is where the clock stopped. Therefore, no further information is available to determine lower levels of prices acceptable to the remaining capacity. However, the remaining capacity includes both new and existing resources. The fact that these resources remained in the auction indicates that the cost of new entry for some new resources and the going-forward costs for many existing resources are at or below the floor price.

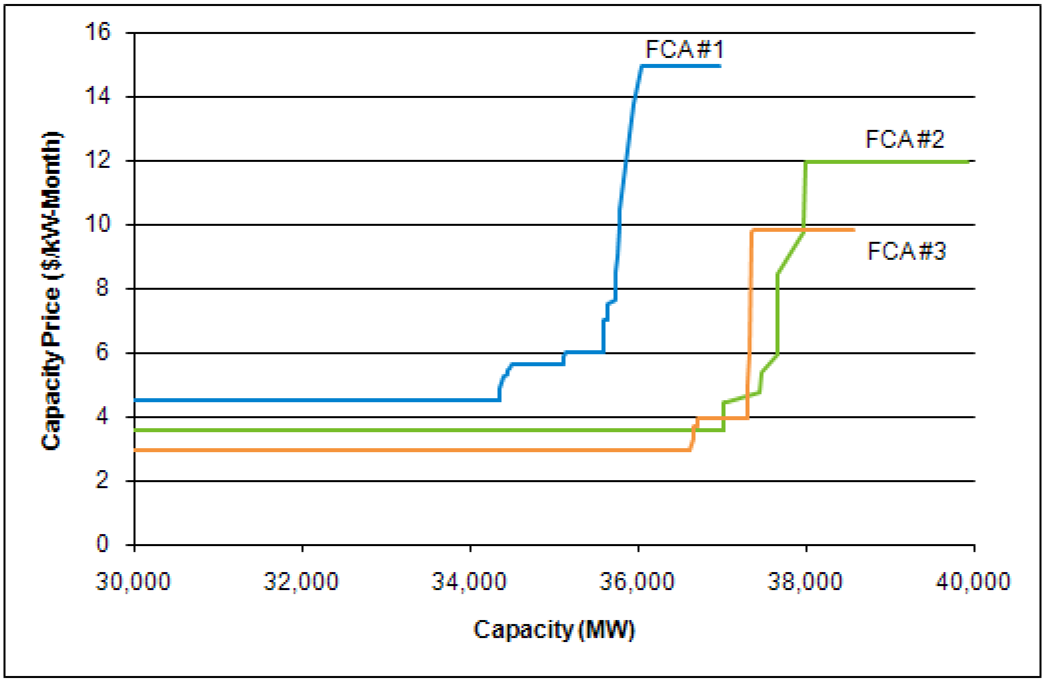

Figure 4-6: Supply curves: FCA #1, FCA #2, and FCA #3.

4.6 Annual Reconfiguration Auction

Table 4-11 shows the results of the first Annual Reconfiguration Auction for the 2010/2011 capacity commitment period.[153] In this table, offers are positive numbers and bids are negative numbers. The clearing price was $1.50/kW-month, well below the FCA #1 price of $4.50/kW-month, and 80 MW

[151] These supply curves are constructed from the results of FCA #1, FCA #2, and FCA #3, which are available at http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/ccp13/fca13/fca3_monthly_ob_v2.xls.

[152] These supply curves do not reflect the caps on import resources because of the external interface limits and the 600 MW cap on RTEG resources.

[153] Pursuant to Section III.13.4.5.1 of *Market Rule 1*, the first ARA will not be conducted for the first five capability years; thus, a total of two ARAs will be held for each of the first five capability years. Therefore, while the capacity values presented in Table 4-11 are for the first ARA to be held for the 2010/2011 capability year, under the terminology used in Section 13 of *Market Rule 1* (which contains the rules for the FCM), this reconfiguration auction is technically the "second" reconfiguration auction for the 2010/2011 capability year. See http://www.iso-ne.com/regulatory/ferc/filings/2009/jan/er09-640-000_1-30-09_icr_filing.pdf.

changed hands. Table 4-12 shows that a total of 31 companies participated in the reconfiguration auction. Some companies placed both bids and offers.

Table 4-11
Summary of Annual Reconfiguration Auction for 2010/2011 Commitment Period

Capacity Zone Type	Rest of Pool	New York AC Ties	Total
Total offers submitted (MW)	915.0		**915.0**
Total bids submitted (MW)	−6,473.0	−153.4	**−6,626.5**
Total offers cleared (MW)	197.6		**197.6**
Total bids cleared (MW)	−117.6	−80.0	**−197.6**
Net capacity cleared (MW)	80.0	−80.0	**0.0**
Clearing price ($/kW-month)	1.5	1.5	**1.5**

Table 4-12
Company Summary for 2010/2011 Annual Reconfiguration Auction

Statistics Summarized	Total
Total number of companies participating in the reconfiguration auction	33
Number of companies placing demand bids	19
Number of companies placing supply offers	25
Number of companies placing both demand bids and supply offers	11
Rejected offers	0

4.7 Competitive Pricing of Import Offers

In 2008, pursuant to a May FERC order, the ISO and the IMM developed changes to the rules determining how capacity imports must offer into the energy market.[154] The proposal will require priced capacity imports to offer energy at a competitive price, replacing the rules that permit capacity imports to offer up to the $1,000/MWh price cap. A second change revises the penalty paid by a capacity importer when the ISO requests electric energy from an energy transaction that is supporting a capacity import, and the energy does not flow in real time. The proposal replaces the earlier "failure-to-deliver" penalty structure with one that bases the penalty on the percentage of hours during which electric energy is requested but not delivered from a capacity contract. The proposed rule was filed with FERC in March 2009 and was approved for implementation on July 1, 2009.

[154] *Order Approving Tariff Changes*, FERC Docket No. ER08-697-000 (May 20, 2008).

In the period following the May 2009 order, the monthly transactions that were supported by high energy offers at least once during the month declined rapidly. This is illustrated in Figure 4-7, which graphs the transaction megawatts supported by energy offers exceeding $660/MWh, the threshold for defining high offers, and the average price of the high offers. Such energy offers disappeared after the effective date of July 1, 2009.

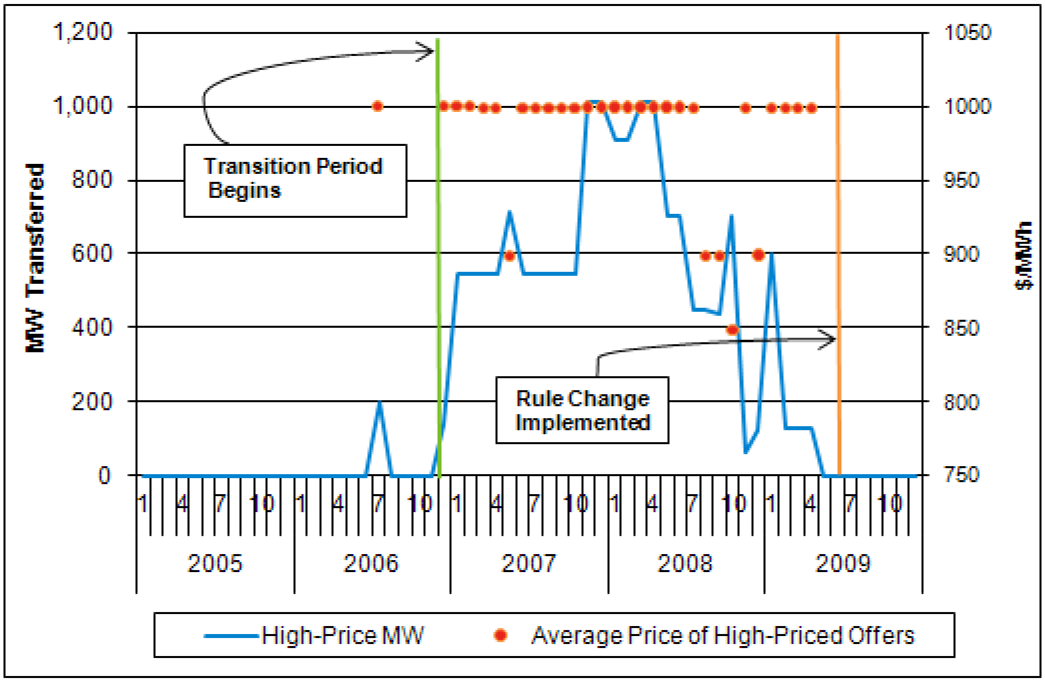

Figure 4-7: Quantities and average prices of capacity backing external transactions offered at high prices, Northern New York interface.

4.8 Assessment of FCM Price Formation with Capacity Surplus

In 2009, the ISO and FCM Working Group discussed the recommendations contained in the IMM's June 2009 FCM Report about improving the Alternative Price Rule and price formation when OOM capacity prevents new capacity from setting the FCA price.[155] The ISO included many of these recommendations for improving the FCM design in rule changes it filed with FERC in February 2010. However, the market rules concerning the evaluation and mitigation of delist bids did not receive as much attention in the IMM report or in the stakeholder process. The importance of delist bids to the market has increased because of the current surplus capacity situation in which a delist bid may set the FCA clearing price. The IMM has assessed the role of delist bids in the FCA and finds them an important part of the design, but revisions to the rules concerning the evaluation and mitigation of delist bids are needed to assure that delist bids are made at competitive levels.

This section reviews the role of delist bids in the FCA and strategies for entering and exiting the capacity market. It focuses on whether delist bids improve market efficiency and whether the rules

[155] FCM Report (June 5, 2009); http://www.iso-ne.com/markets/mktmonmit/rpts/other/fcm_report_final.pdf.

governing the evaluation and mitigation of delist bids are sufficient and appropriate. A summary and recommendations are provided.

4.8.1 The Efficiency of FCAs with Delist Bids

Overall, the IMM has determined that the use of delist bids in the FCM design generally improves market efficiency because it enables participants to leave the capacity market when the cost of remaining in the market exceeds the benefit. Allowing participants to leave the market when it is not cost effective to remain lowers long-run costs by decreasing risk.

The permanent delist bid allows generation resources considering retirement to evaluate their going-forward economics in the marketplace and base the retirement decision on revealed market information. A permanently delisted resource cannot offer into a subsequent FCA auction or reconfiguration auction, and it cannot assume a capacity supply obligation. A permanent delist bid should include an *option-value* component that reflects the value of remaining in the market and being able to realize future revenues.[156]

During a period of uncertainty (e.g., wide variation in fuel costs) the option value could be significant. A generator would be less willing to retire if there were significant probability, although not certainty, of future profit. Thus, when the option value of retiring is significant, a generator may stay in the market for extra years. Even when current-year costs exceed current-year revenues, retiring a generator when current-year net revenues are negative or are expected to continue to be negative ignores the prospect that prices might improve sufficiently to recover the losses incurred at present. Including this option premium in the bid would lower the resource owner’s permanent delist bid below the going-forward costs calculated using a traditional accounting-based avoided cost analysis.

Static delist bids allow resources to opt out of a capacity supply obligation for one year. Static delist bids provide economic benefit by allowing flexibility in capacity imports, uneconomic demand resources to exit the market, internal generation resources to pursue capacity-revenue opportunities in neighboring markets, and internal resources to manage their capacity-delivery obligations while repowering. Owners of statically delisted resources retain the option to bid into any subsequent FCA’s primary or reconfiguration auction. A static delist bid, therefore, should include little or no option-value component and instead should reflect the going-forward costs calculated using a traditional accounting-based differential analysis. However, as discussed below, the differential analysis should be based on the costs that will truly be avoided in the commitment period.

Absent the market-power issue associated with pivotal suppliers, static delist bids facilitate short-run trading opportunities and delivery risk management. Reconfiguration auctions enable further dynamic adjustments of capacity supply obligations, which improve the efficiency of final allocations; allowing statically delisted units to bid into these auctions might be advantageous.

Overall, the advantages of permanent and static delist bids outweighs the disadvantages due to possible market power exercise. Permanent and static delist bids offer trading options that reduce investment risks and thus lower entry costs for new generators. Delist bids allow participants to arbitrage risks, similar to derivative trading that facilitates risk management. Without static delist

[156] Option values occur when future market conditions are highly uncertain, the uncertainty is resolved over time, and strategies based on subsequent events are allowed to be revised.

bids, a resource owner might perceive a risk that a listed unit's capacity payment would, in some years, be insufficient compensation for forgoing the ability to export capacity or make it difficult to leave the market temporarily to improve or repower the plan.

4.8.2 Evaluation and Mitigation of Delist Bids

The market rules allow a resource to delist from the capacity market and still participate in the other ISO administered markets. However, for evaluating delist bids, the current market rules calculate going-forward costs under the assumption that the resource is going to leave the energy and reserve markets. The measure of going-forward costs to use in calculating a delist bid should account for those costs avoided by shedding the capacity supply obligation. Because a resource is not required to leave the energy market even if it is not in the capacity market, including in a delist bid the costs avoided by leaving the energy market is not appropriate, unless the resource is intending to leave the energy market. The IMM recommends that it work with the ISO and stakeholders to review and revise, as appropriate, the rules pertaining to the evaluation and mitigation of delist bids, with particular attention to the definition of net risk-adjusted going-forward costs and opportunity costs.

The rejection of the Salem Harbor delist bid in FCA #3 illustrates that the zonal creation and pricing aspect of the FCM design needs to be examined and improved. In the FCM Report, the IMM noted that in the absence of market power, ideally, all zones would be included in the auction. The report also stated that the potential efficiencies of this ideal approach are outweighed by market power concerns, particularly in concentrated, constrained zones. To move closer to this ideal, the FCM Report recommended that capacity from resources that submit permanent delist bids should be included in zonal modeling and the price setting process Thus, if clearing a permanent delist bid would result in a zone becoming capacity deficient, the zone would have a price at least as high as the permanent delist bid. Recent ISO-proposed changes moved the design even closer to the ideal by also including static delist bids from nonpivotal suppliers in zonal modeling and pricing. However, enabling zones to be modeled in the auctions and essentially all bids to affect zonal pricing and creation requires a comprehensive mitigation approach for all delist bids. Implementing the recommendation above to take into account whether a resource remains in the energy market would be part of a comprehensive mitigation approach and may further increase the ability of delist bids to affect zonal creation and pricing. Such an approach should also review the pricing rules from dynamic delist bids, which the IMM did not do in this report.

4.9 Recent Delist Bid Issues

In 2009, the Internal Market Monitor addressed three issues associated with delist bids:

- Delist bids from resources with common costs
- The appropriate period of depreciation
- The appropriateness of allowing static delist bids from nonpivotal suppliers to trigger modeling of, and price formation in, the capacity zones

The first two issues arose from static delist bids submitted for units at Salem Harbor station.[157] The bidder allocated the full common costs to each of the four units separately, in effect including the

[157] See the September 18, 2009 FERC Order, *ISO New England Inc.*, 128 FERC ¶ 61,266 (2009). A subsequent *Order Denying Rehearing and Granting Clarification* was issued on February 18, 2010.

same cost four times. The bidder also depreciated capital costs over three years on the grounds that the units would be taken out of service within three years after the service year.

The FERC order of September 18, 2009, accepted the IMM's revised stand-alone static delist bids for the Salem Harbor units. FERC also accepted the IMM's adjustments to the depreciation rates. The Internal Market Monitor also provided delist bid rates for circumstances in which more than one unit received a capacity supply obligation and the common costs could be shared among multiple units. FERC also accepted these combination rates for the Salem Harbor units.

The third issue arose in the FCM design changes proposed in the *FCM Design Basis Document*.[158] The effect of the proposed changes is to allow static delist bids, in addition to permanent delist bids, to create zones and set prices for the zones. The ISO limited the application to delist bids from nonpivotal suppliers. The restriction to nonpivotal suppliers alleviated the IMM's primary concern that participants could exercise market power in the capacity market. The IMM supports continued work on zonal creation and pricing.

4.10 Out-of-Market-Capacity, the Floor Price, and the Alternate Price Rule

The IMM concluded in a report to FERC that the results of FCA #3 are competitive.[159] The large amount of surplus capacity in FCA #3 indicates sufficient supply-side competition in the FCM. However, the conclusion of competition must be tempered by the fact that the surplus capacity includes 2,003 MW of out-of-market capacity. OOM capacity offered into the auction at prices below its estimated long-run costs would drive clearing prices lower absent the price floor. However, since the amount of surplus capacity in all three FCAs to date has exceeded the amount of OOM capacity, the floor price would have been reached even without the OOM capacity. Given the price collar, the results of the first three FCAs are consistent with the outcome of a competitive market.

After publication of the FCM Report in June 2009, the ISO and stakeholders in the FCM Working Group have included many of the report's recommendations in rule changes filed by the ISO in February 2010. The Internal Market Monitor generally supports these changes. These changes improve the FCA by enhancing the APR and by increasing the bids eligible to affect zonal pricing and creation. The changes extended the floor price for three years, in part to address the OOM capacity that cleared in the first three auctions. While the IMM knows that recognizing the 2,003 MW of OOM capacity and adjusting FCA outcomes in some way is needed, extending the floor price has adverse consequences. The floor price, and the large amount of OOM capacity, will prevent the FCA from determining a competitive price for capacity. FCM prices will be either too high because of the floor price or too low because of OOM capacity. The IMM supports elimination of the floor price as soon as possible and improvements to the APR to better address the impacts of large amounts of OOM capacity on the price from the FCA.

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[158] Forward Capacity Working Group "Design Basis Document" (FCM DBD), memorandum from David Doot and Michelle Gardner to NEPOOL Participants Committee Members and Alternates (November 5, 2009); http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2009/nov62009/addl_matls_nov_6_09_special_npc_mtg.pdf.

[159] Testimony of David LaPlante in *Forward Capacity Auction Results Filing*, Attachment C, FERC Docket No. ER10-186-000 (October 30, 2009); http://www.iso-ne.com/regulatory/ferc/filings/2009/oct/er10-___-000_10-29-09_fca_3_results_filing.pdf.

Section 5
Forward Reserve Market

As shown in this section, the results of the two forward-reserve auctions conducted in 2009—in April, for summer 2009, and in August, for winter 2009/2010—are consistent with competitive outcomes.[160] A description of the Forward Reserve Market mechanics is contained in Section 2.3.1. Section 3.3 has information on real-time reserve pricing. The data appendix, Section 8.3 contains additional information on the product offers for both forward-reserve auctions.

Table 5-1 shows the Connecticut reserve zone continues to have supply offer deficiencies; therefore, the clearing prices in CT and the nested Southwest Connecticut reserve zones were set administratively at the price cap of $14.00/kW-month. The NEMA/Boston TMOR clearing prices fell because of reduced local requirements attributable to transmission improvements.[161] With no binding constraint in the summer 2009 auction, the local TMOR price was zero. For the winter 2009/21010 auction, there is no NEMA/Boston requirement; therefore, there is no price for TMOR. The total amount paid for forward reserve in 2009 was $144.1 million, a decrease from $171.0 million in 2008.

Table 5-1
Forward Reserve Market Inputs and Results

Forward Reserve Period	Product		Local Second-Contingency Req. (MW)	External Reserve Support (MW)	Local Req. (MW)	MW Offered[(a)]	MW Cleared	Surplus/ Shortfall (MW)	Clearing Price ($/kW-month)
Summer 2009	Systemwide	TMNSR	N/A	N/A	850	1,457	850	607	6.30
	Systemwide	TMOR	N/A	N/A	700	1,401	999	701	0.00
	SWCT	TMOR	673	651	22	402	402	380	14.00
	CT	TMOR	1,145	0	1,145	999	999	−146	14.00
	NEMA/Boston	TMOR	1,200	1,610	0	50	25	50	0.00
Winter 2009/2010	Systemwide	TMNSR	N/A	N/A	850	1,305	850	455	6.08
	Systemwide	TMOR	N/A	N/A	750	1,414	1,170	664	0.00
	SWCT	TMOR	520	849	0	426	426	426	14.00
	CT	TMOR	1,225	0	1,225	1,170	1,170	−55	14.00
	NEMA/Boston	TMOR	1,050	1,310	0	68	0	68	0.00

(a) "MW Offered" is the sum of all offers that can meet the requirement, which allows a 25 MW TMNSR offer in a local area as an offer into both the system TMNSR requirement and the local TMOR requirement; a 402 MW TMOR offer in SWCT is included in the total CT offer.

Like assessing market concentration in the electric energy markets, concentration in the forward-reserve auctions is measured by the Residual Supply Index and the Herfindahl-Hirschman Index. The

[160] The outcome of clearing at the price cap is consistent with a competitive outcome because FERC has implicitly deemed that price just and reasonable through their approval of the Forward Reserve Market rules.

[161] The market rule defines the offer cap in $/MW-month units. Because reserves are a capacity concept, for consistency, this report uses $/kW-month throughout to represent all capacity measures.

RSI and HHI shown in Table 5-2 were calculated based on the total fast-start capability available to compete in the Forward Reserve Market but does not include any capability from on-line resources that may be assigned against a forward reserve obligation.

Table 5-2
Forward Reserve Market Measures of Competition

Forward Reserve Period	Product		RSI	HHI
Summer 2009	Systemwide	TMNSR	204	2,172
	Systemwide	TMOR	202	1,209
	SWCT	TMOR	2,810	2,228
	CT	TMOR	76	1,817
	NEMA/Boston	TMOR		4,586
Winter 2009/2010	Systemwide	TMNSR	206	2,146
	Systemwide	TMOR	199	1,180
	SWCT	TMOR		1,973
	CT	TMOR	77	1,656
	NEMA/Boston	TMOR		4,418

Based on the calculated HHI values, the market for all forward-reserve products is either moderately or highly concentrated. While the NEMA/Boston market for TMOR is extremely concentrated, as indicated by HHI values over 4,000, the lack of a local purchase requirement means that there are no pivotal suppliers. A similar situation existed in the SWCT zone for the winter 2009/2010 market, the exception being that the HHI does not indicate the same level of concentration.

For the CT zone, even though the HHI metric indicates moderate concentration, the supply deficiency makes all suppliers pivotal, and the RSI values are less than 100.

Section 6
Regulation

This section presents data concerning the participation, outcomes, and competitiveness of the Regulation Market in 2009. Section 2.4 summarizes the function and operation of this market.

6.1 Regulation Requirements and Compliance

NERC has set the Control Performance Standard 2 (CPS 2) at 90% for the New England Balancing Authority Area.[162] CPS 2 is the primary measure for evaluating control performance and area control error (see Section 2.4). 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 2009, the ISO achieved a minimum value of 94% and a maximum of 97%.

The ISO periodically evaluates the regulation requirements necessary to maintain CPS 2 compliance. The regulation requirements are determined by hour and vary by time of day, day of week, and month. The ISO has been able to reduce the requirements because unit performance has remained high. The average annual regulation requirement has been steadily decreasing from 181 MW in 2002 to 89 MW for 2009. The large drop between 2008 and 2009 is the result of software and operational enhancements made to the Regulation Market in 2008.

6.2 Regulation Capacity

The pool of resources available for regulation hourly is a subset of all active regulation-capable generators and depends on scheduled outages and other real-time conditions. On average, about 5.2%, or 89 MW, of all available regulation capability is required to provide regulation in real-time. Regulation capability is affected at the unit level by ambient temperature and at the system level by outage schedules. During 2009, monthly average regulation capability ranged from about 1,500 MW to about 1,800 MW, with an average quantity of about 1,700 MW. Gas units were the primary provider of regulation, providing approximately 65% of capability and 87% of capacity.

6.3 Regulation Market Costs, Prices, and Competitiveness

Payments to generators for providing regulation totaled $23.1 million in 2009, a decrease of $27.4 million from the 2008 costs of $50.5 million. The cost decrease was caused by two main factors. First, the regulation requirement has fallen, thereby reducing the regulation credit. Second, decreased energy prices have decreased the opportunity cost of providing regulation.

The competitiveness of the New England Regulation Market is evaluated using two analyses: HHI and RSI (see Section 3.1.1). The HHI for the New England Regulation Market is based on summer capabilities of regulation capacity to offer into the market. The values shown were developed from participant information collected by the Internal Market Monitor. The maximum eligible regulation capability (MW) over all hours in the month for each lead participant's portfolio of resources was used in the HHI and RSI analyses.

[162] More information on NERC's *Control Performance Standard 2* is available at http://www.nerc.com/files/BAL-001-0_1a.pdf.

Throughout 2009, the monthly HHI varied from a low of 784 to a high of 863, with an annual average of 835. Each of these outcomes is below the U.S. Department of Justice benchmark for an unconcentrated market.[163] The monthly RSIs exceeded 1,000 for every month in 2009. The results of the HHI and RSI analyses indicate that the Regulation Market is structurally competitive.

[163] The DOJ's guidelines for market concentration are available at http://www.usdoj.gov/atr/public/guidelines/horiz_book/15.html.

Section 7
Reliability and Operations Assessment

This section discusses the payments made to resource owners that do not recover their full as bid cost from energy market revenues. These payments are referred to as Net Commitment-Period Compensation (NCPC) (see Section 2.5.1). The section also contains information about the Reliability Agreements in place with generation owners for providing resources deemed necessary for reliability.

7.1 Daily Reliability Payments for 2009

Figure 7-1 presents total monthly reliability payments for 2008 and 2009 by financial settlement category. The fall in voltage payments that began in April 2008 was due to the transmission improvements in the Boston area that allowed the ISO to revise the operating guides. The overall decline in October 2008, most notably in economic and first-contingency NCPC payments, is a result of the decreasing price of No. 6 oil.[164] Reliability resources running No. 6 oil became increasingly less expensive as a result of the drop of their input fuel prices. Transmission improvements completed in June 2009 significantly reduced the need for out-of-market commitments in SEMA and reduced second-contingency payments for the remainder of the year.[165]

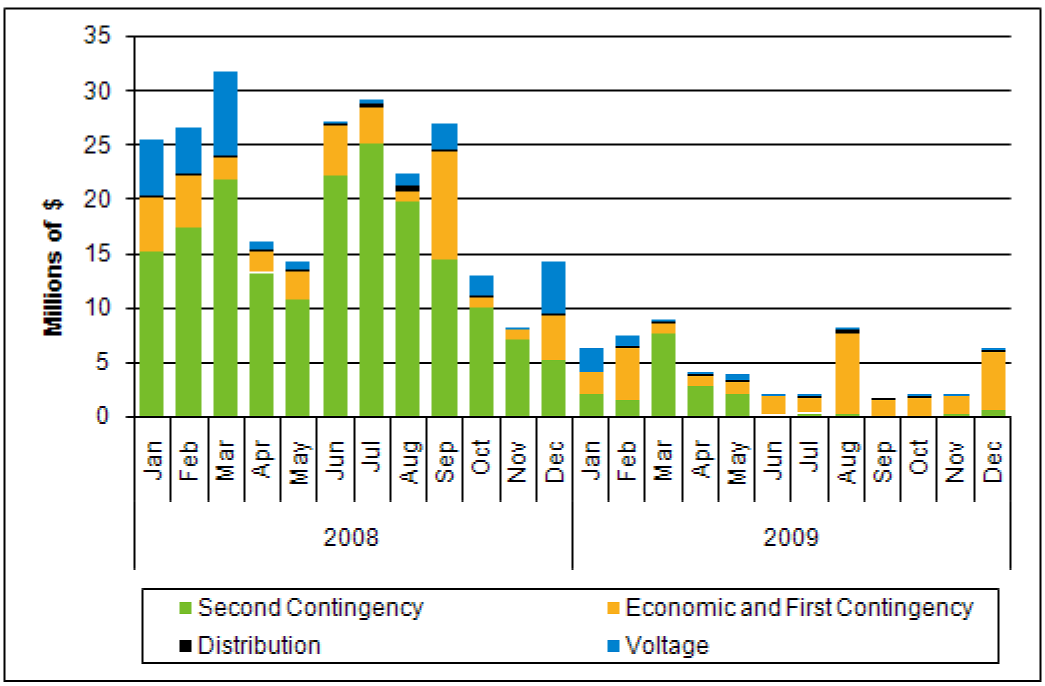

Figure 7-1: Daily reliability payments by month, January 2008 to December 2009.

[164] Economic and first-contingency NCPC payments are made to resource owners for days when the resources committed and dispatched by the ISO do not recover their bid-in costs, and the resources were not committed for local second-contingency protection, for voltage support or control, or as requested by a transmission owner to protect its distribution system.

[165] Second-contingency payments are NCPC payments made to resource owners that have resources dispatched out-of-market specifically to protect a local region from cascading outages if a local first- and second-contingency failure occurs. These payments are also known as local second-contingency-protection resource NCPC.

Table 7-1 shows the total daily reliability payments by category with the percentage change between years. The decrease in voltage payments by 83% can be attributed to new transmission infrastructure that allowed changes in operating-procedure requirements and resulted in a significant decrease in voltage payments made to the NEMA zone in April 2008. The decrease in second-contingency payments by 91% is attributable to transmission improvements completed in 2009 that significantly reduced the need for out-of-market commitments in SEMA.

Table 7-1
Total Daily Reliability Payments, 2008 and 2009, Million $

Payment Type	2008	2009	Difference	% Change
Economic and first-contingency payments	42.48	32.19	−10.29	−24%
Second-contingency reliability payments	182.49	17.22	−165.28	−91%
Distribution	1.47	0.59	−0.88	−60%
Voltage	29.39	5.03	−24.36	−83%
Total	**255.83**	**55.02**	**−200.81**	**−78%**

7.2 Reliability Agreements

As of February 2010, Reliability Agreements were in effect for eight generating stations in two load zones, comprising 2,711 MW of capacity, or 8.7% of the total systemwide generating capacity.[166] Table 7-2 shows each zone's 2009 seasonal claimed capability (SCC)—the claimed generating capability for summer—and the total capacity of resources in each zone with cost-of-service Reliability Agreements. Connecticut and WCMA are the only zones with generation resources that have Reliability Agreements. Of the two zones, CT has both a greater total capacity under Reliability Agreements, with a total of 2,172 MW under these agreements, and a higher percentage (28%) of its summer claimed capability accounted for by these agreements.

[166] These eight stations include West Springfield 3 and GTs, Berkshire Power, Middletown, Montville, New Haven Harbor, Bridgeport Harbor, Pittsfield/Altresco, and Norwalk Harbor 1 and 2.

Table 7-2
Percentage of Capacity under Reliability Agreements, Effective February 2010

Load Zone	2009 CELT Summer Seasonal Claimed Capability (MW)	2009 Capacity with Cost-of-Service Reliability Agreement	2009 Capacity under Reliability Agreements as % of 2009 SCC
Maine	3,265	0	0
New Hampshire	4,129	0	0
Vermont	915	0	0
Connecticut	7,747	2,172	28.0
Rhode Island	1,844	0	0
SEMA	6,038	0	0
WCMA	3,890	539	13.9
NEMA	3,296	0	
New England Total	**31,123**	**2,711**	**8.7**

Source: *RMR Agreements and Total Capacity by Reliability Region and New England Total*; http://www.iso-ne.com/genrtion_resrcs/reports/rmr/rmr_agreements_summary_with_fixed_costs.xls (February 19, 2010).

Figure 7-2 shows the total generating capacity with FERC-approved cost of service Reliability Agreements and net payments (net of revenues received in the ISO markets) to resource owners to maintain their full cost-of-service fixed payments. The variations in net payments shown in Figure 7-2 are the result of changes over time in capacity, the total fixed costs allowed under the agreements, and the revenues received by resource owners through participation in the ISO markets. In particular, 2007 was the first year of the FCM transition payments, which increased capacity revenues, and each year the transition rate has increased over time,thereby increasing the capacity revenues from the ISO markets.

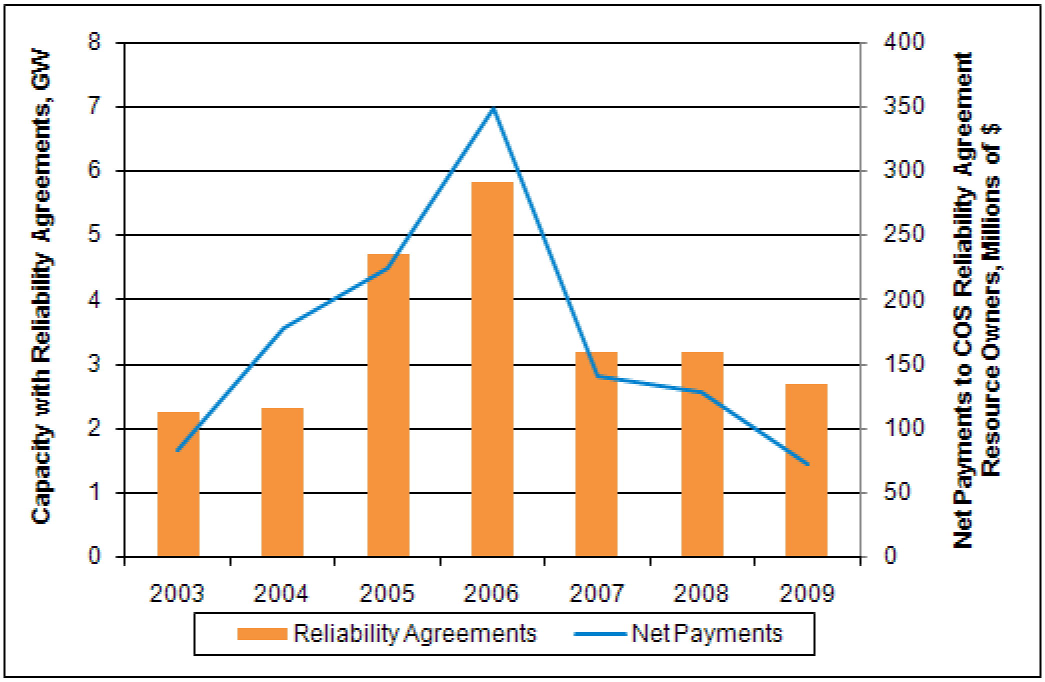

Figure 7-2: Generating capacity with FERC-approved Reliability Agreements.

From 2008 to 2009, the net payments for Reliability Agreements decreased by almost 44%, even though average energy prices and loads were lower than in previous years. Because fixed costs remain the same, lower revenues from the energy markets should result in higher net payments. The overall decrease is likely due to the October 2008 termination of the Reliability Agreement with the owners of the Milford Station. A total of 489 MW from two units at this station had a $12.36/kW-month annualized fixed-revenue requirement.

7.3 Internal ISO Market Operations Assessment

In 2009, the ISO undertook various internal initiatives to ensure transparency of the wholesale markets. These initiatives include reviews, audits, and administrative price corrections. This section highlights the 2009 initiatives.

7.3.1 Audits

The ISO participated in several audits during 2009. The following audits were conducted to ensure that the ISO had followed the approved market rules and procedures and to provide transparency to New England stakeholders:

- **Internal Market Monitoring Audit**—In 2009, the ISO Board of Directors retained KPMG to audit the policies, processes, and procedures of the IMM. This audit followed the discovery of an analytical error that resulted in incorrect statements being made in testimony submitted in a proceeding before FERC regarding capacity imports.[167] KPMG made detailed recommendations regarding revisions to IMM policies, processes, and procedures, with special attention to controls. The IMM committed to revise all its processes and procedures

[167] For additional information, see *Compliance Filing of ISO New England Inc.*, FERC Docket No. ER09-873-___ (July 13, 2009).

consistent with the KPMG recommendations by the end of the first quarter 2010 and has successfully completed this effort.

- **SAS 70 Type 2 Audit—**In November 2009, the ISO successfully passed a SAS 70 Type 2 Audit, which resulted in an "unqualified opinion" about the design and operating effectiveness of controls.[168] Developed by the American Institute of Certified Public Accountants, the SAS 70 Audit is used by service organizations to provide assurances regarding the validity and integrity of controls and systems used in the organizations' business processes. Entities such as Regional Transmission Organizations rely on SAS 70 Audits to provide assurance to the wholesale electricity marketplace regarding the validity and integrity of controls and systems used in the "bid-to-bill" business processes.

  The ISO's SAS 70 Type 2 Audit is a rigorous and detailed examination of the business processes and information technology used for activities related to bidding into the market, accounting, billing, and settling the market products of energy, regulation, transmission, capacity, demand response, and reserves. Conducted by the auditing firm KPMG LLP, the Type 2 Audit covered a 12-month period from October 1, 2008, through September 30, 2009. The SAS 70 Type 2 Audit includes the auditor's opinion on the effectiveness of controls tested, the fairness of the description of the controls contained in the audit report prepared by the ISO, and the suitability of the design of the controls for achieving the specified objectives.[169] The ISO conducts a SAS 70 Type 2 Audit annually. The 2009 SAS 70 Audit report is available to participants upon request through the ISO external Web site.

- **Review of the Forward Capacity Market Project**—The ISO internal audit department conducted a review of the Forward Capacity Market project including the auction and capacity supply obligation submission window. This review examines the systems development process, application test planning and results, the development of business and related control procedures, and the production migration process.

- **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. 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 analysis 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.

[168] A SAS 70, *unqualified audit opinion* is issued when three conditions are met as determined by the audit firm. First, the description of the controls in the ISO audit report (see footnote below) fairly presents the relevant aspects of the service organization's controls. Second, the overall design of the controls is sufficient to meet the specified control objectives. Third, the firm has collected and evaluated sufficient competent evidence through applied tests to specific controls and determines that the controls are operating with sufficient effectiveness to provide reasonable assurance that the control objectives were achieved during the test period.

[169] KPMG. *Report on Controls Placed in Operation Pertaining to the Market Operations and Settlements Processes and Systems of ISO New England Inc. and Tests of Operating Effectiveness for the Period October 1, 2008 to September 30, 2009, Prepared Pursuant to Statement on Auditing Standards No. 70, as Amended*. (October 5, 2007). This report is available to participants on request through the ISO external Web site: http://www.iso-ne.com/aboutiso/audit_rpts/index.html and http://www.iso-ne.com/aboutiso/audit_rpts/SAS70Request.do.

In 2009, PA Consulting issued the following certifications:[170]

- Regulation Clearing Price Market Software, January 9, 2009
- Simultaneous Feasibility Test Software, February 5, 2009
- Forward Capacity Reconfiguration Auction Clearing Engine Software, April 30, 2009
- Scheduling, Pricing and Dispatch—Day Ahead Market Software, October 5, 2009
- Scheduling, Pricing and Dispatch—Unit Dispatch System Market Software, October 5, 2009
- Locational Marginal Price Calculator Market Software, October 5, 2009
- Auction Revenue Rights Market Software, December 10, 2009
- Financial Transmission Rights Market Software, December 17, 2009

7.3.2 Administrative Price Corrections

Table 7-3 shows the ISO's administrative price corrections.

Table 7-3
Administrative Price Corrections

Location/Load Zone	Congestion Component
Data error	4
Hardware/software scheduled outage	5
Hardware/software outage unscheduled	0
Software limitation	13
Software error	0
Dead bus logic	37

[170] All certificates are available to participants upon request through the ISO external Web site: http://www.iso-ne.com/aboutiso/audit_rpts/index.

Section 8
Data Appendix

This appendix contains details on the energy, forward capacity, forward locational 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.

8.1 Energy Appendix

The energy appendix has additional information of the energy markets that may be interesting to readers but is not essential for evaluating the competitiveness and efficiency of the markets covered in this report.

8.1.1 Competitive Measures Supporting Information

Table 8-1 shows the average and minimum heat rates of generating resources in New England by generation technology type and input fuel.

Table 8-1
Average and Minimum
Heat Rates for New England Generators, 2009, Btu/MWh

Technology	Fuel Type	Average Heat Rate	Minimum Heat Rate
Combined cycle	Gas	7,800	6,900
	No. 6 oil (1%)	11,100	10,100
Combustion turbine	Diesel	12,200	11,400
	Gas	11,000	8,900
	Jet fuel	13,800	10,500
	No. 2 oil	16,100	15,500
Steam	Coal	9,700	8,700
	Gas	11,000	10,200
	No. 6 oil (1%)	10,500	9,000
	Other	10,300	10,000
	Wood	12,400	10,000

Table 8-2 presents yearly capacity factors by fuel type for 2007 to 2009.

Table 8-2
Yearly Capacity Factors by Fuel Type, 2007 to 2009, %

Fuel	2007	2008	2009 (descending sorted)	Change 2009 to 2008
Wood/propane	95.10	91.46	96.45	4.99
Other	97.06	101.15	93.68	−7.47
Nuclear	91.37	89.29	92.27	2.97
Refuse	85.39	85.78	86.07	0.30
Wood/coal	77.23	80.36	81.78	1.42
Refuse/natural gas	75.89	69.40	74.94	5.54
Wood	83.07	78.97	68.78	−10.19
Coal	76.15	70.97	58.87	−12.09
Hydroelectric	46.57	57.59	56.15	−1.44
Wood/natural gas	60.26	53.83	50.30	−3.53
Natural gas	42.55	37.11	38.99	1.88
Coal/oil	66.59	59.71	37.94	−21.77
Wind	—	47.19	29.34	−17.86
Natural gas/oil	22.35	24.69	18.62	−6.07
Oil/natural gas	7.46	3.72	3.74	0.02
Oil	2.26	1.39	0.72	−0.67

8.1.2 Day-Ahead Market

Table 8-3 and Table 8-4 show the breakdown of day-ahead supply and demand for 2007 to 2009.

Table 8-3
Day-Ahead Demand by Category, 2007, 2008, and 2009, MW

	2007	2008	2009
Fixed demand	82,229,629	82,760,527	83,580,944
Price-sensitive demand	40,498,597	42,600,688	37,677,821
Exports	6,768,957	7,867,334	6,608,331
Virtual demand	16,591,836	14,828,780	9,344,550
Total	**146,089,019**	**148,057,329**	**137,211,646**

Table 8-4
Day-Ahead Supply by Category, 2007, 2008, and 2009, MW

	2007	2008	2009
Fixed supply	86,144,395	92,192,213	94,982,116
Price-sensitive supply	31,284,184	23,961,596	18,763,024
Imports	12,000,486	17,381,466	15,185,951
Virtual supply	20,080,687	17,086,241	10,190,515
Total	**149,509,752**	**150,621,516**	**139,121,606**

8.1.3 Real-Time Market

This section provides additional information on real-time generation and the price difference between the Day-Ahead and Real-Time Energy Markets.

8.1.3.1 Real-Time Generation

Figure 8-1 shows the annual hydroelectric energy production from resources in New England for 2000 to 2009.

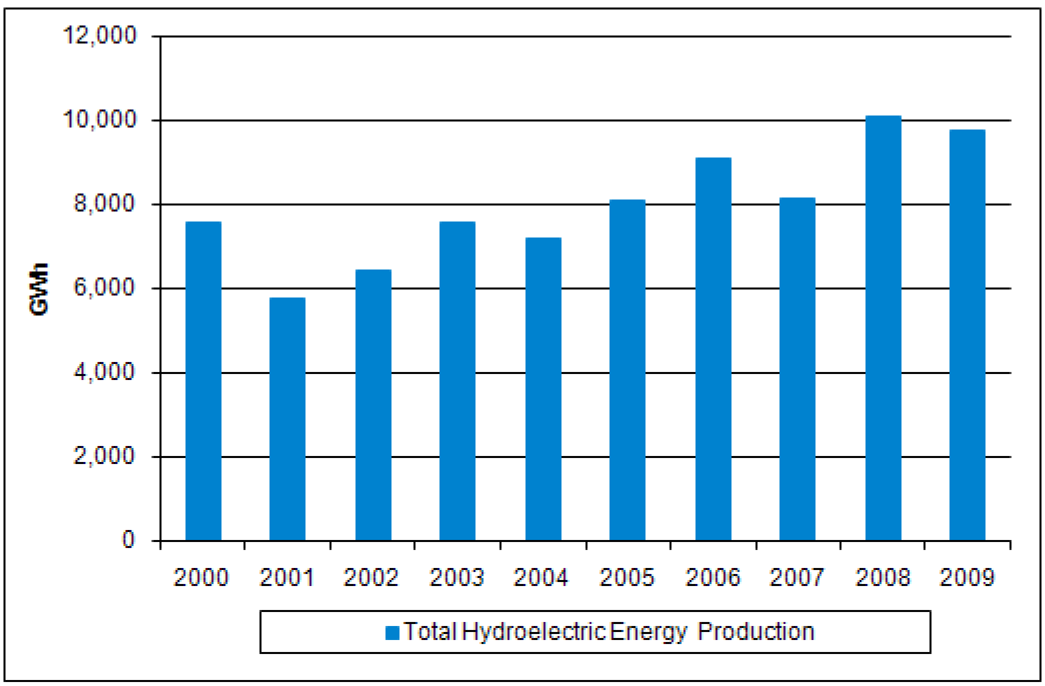

Figure 8-1: Annual hydroelectric energy production, 2000 to 2009.

Table 8-5 provides an annual breakdown of generation by fuel type with comparisons to 2009.

Table 8-5
Yearly Generation by Fuel Type, 2007 to 2009, MW

Fuel	2007	2008	2009 (descending sorted)	Change 2009 to 2008	% Change
Natural gas	41,260,671	39,579,449	32,389,381	−7,190,068	−18%
Nuclear	36,972,058	35,547,388	31,137,416	−4,409,972	−12%
Coal	16,624,166	15,325,726	10,665,456	−4,660,270	−30%
Natural gas/oil	12,186,747	10,861,323	8,250,110	−2,611,213	−24%
Hydroelectric	6,692,889	9,198,393	7,143,281	−2,055,112	−22%
Refuse	3,485,082	3,512,076	2,899,678	−612,398	−17%
Wood	2,251,478	2,219,776	1,561,675	−658,101	−30%
Coal/oil	3,145,629	3,270,322	1,257,738	−2,012,584	−62%
Oil	2,806,788	1,878,209	857,451	−1,020,758	−54%
Oil/natural gas	1,719,016	613,059	540,768	−72,291	−12%
Wood/coal	302,361	319,848	264,986	−54,862	−17%
Wood/natural gas	281,547	252,183	193,909	−58,274	−23%
Refuse/natural gas	227,098	195,297	169,666	−25,631	−13%
Wind		10,636	163,989	153,354	1,442%
Wood/propane	171,341	165,229	143,710	−21,519	−13%
Other	139,587	141,988	112,182	−29,806	−21%

The annual average day-ahead premium for the Hub and eight load zones is shown in Table 8-6.

Table 8-6
Average Day-Ahead Premium, 2007 to 2009 $/MWh

Location	2007	2008	2009
CT	−0.06	1.42	−0.16
Hub	1.25	−0.13	−0.47
ME	0.69	0.62	−0.38
NEMA	1.03	−0.55	−0.34
NH	0.84	−0.21	−0.47
RI	1.11	−0.20	−0.44
SEMA	1.76	1.11	−0.34
VT	1.24	−0.04	−0.49
WCMA	1.06	−0.15	−0.45

8.1.3.2 Marginal Resource Detail

This section provides exhibits identifying trends in the frequency with which different resource classes, including external transactions, set price in the ISO.

Table 8-7 shows the percentage of time that external transaction purchases set price for both the Day-Ahead and Real-Time Energy Markets.

Table 8-7
Price Setting by External Transactions, 2007 to 2009

	2007	2008	2009
Day-ahead imports	3.98%	5.29%	6.60%
Real-time imports	0.08%	0.14%	0.12%

Figure 8-2 and Figure 8-3 show the annual percentage of time that imports set price in the day-ahead and real-time markets, respectively, by on- and off-peak hours.

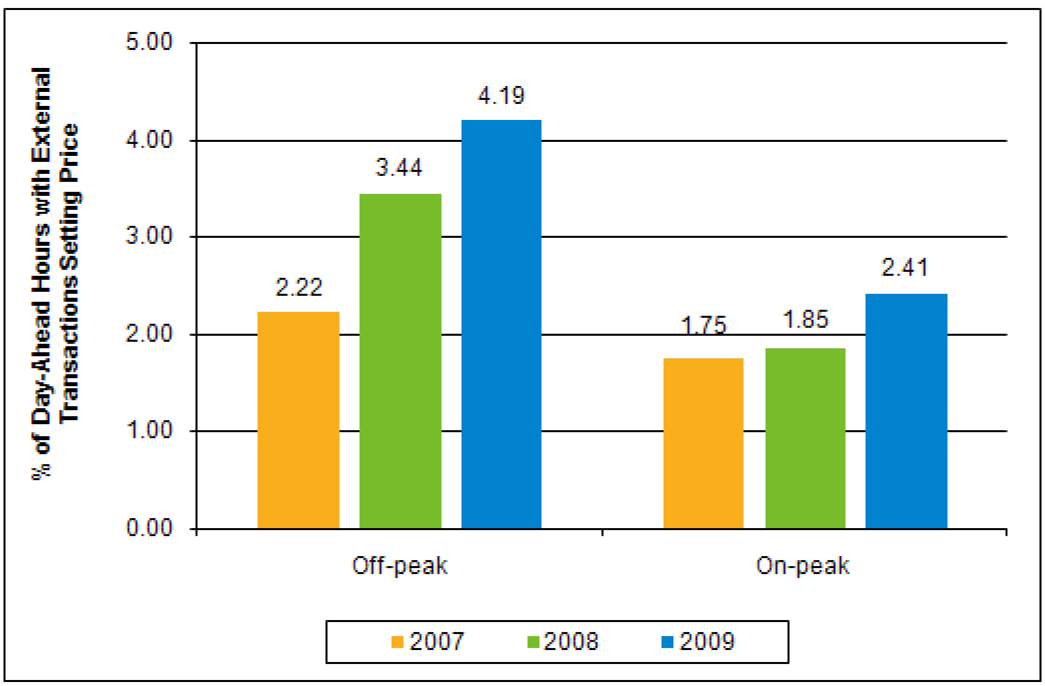

Figure 8-2: Day-ahead external transaction price setting by on- and off-peak, 2007 to 2009.

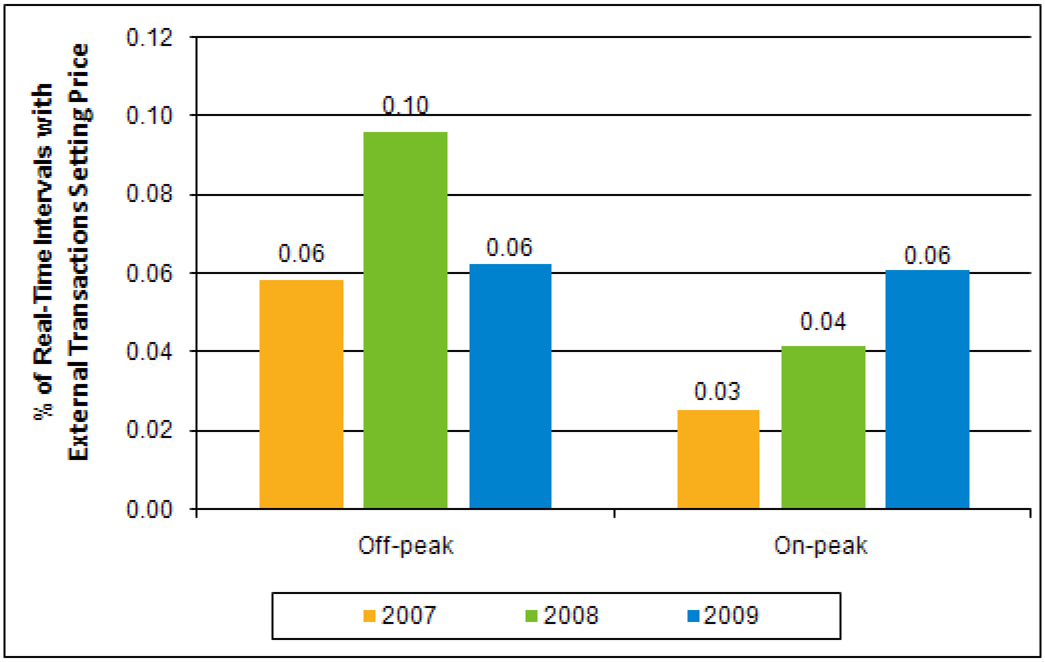

Figure 8-3: Real-time external transaction price setting by on- and off-peak, 2007 to 2009.

Figure 8-4 shows day-ahead price setting by resource type.

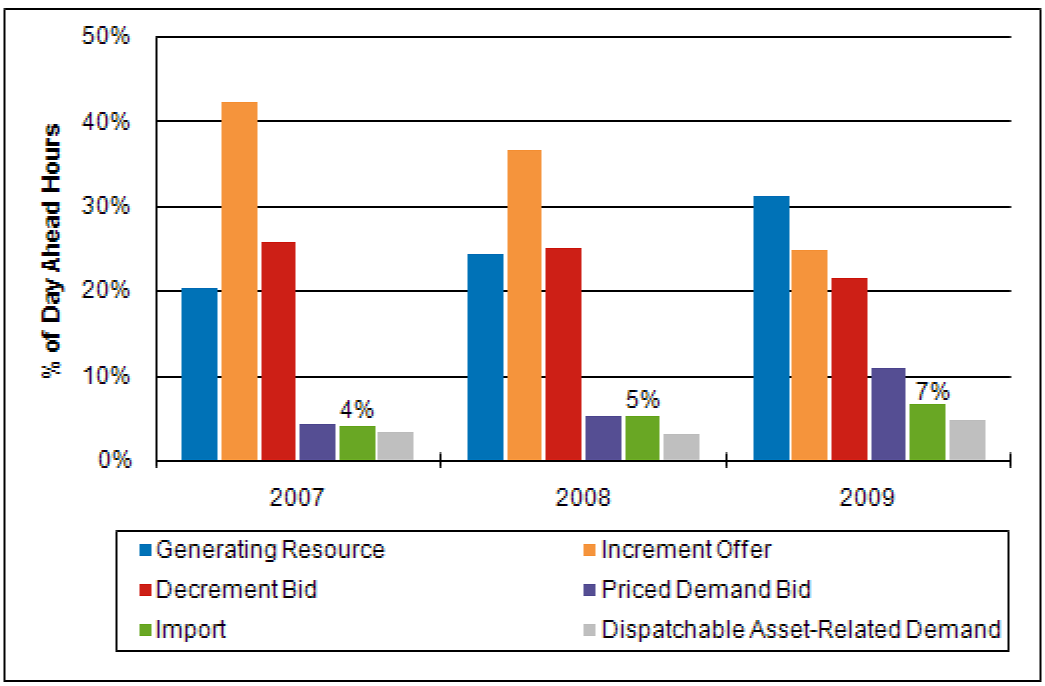

Figure 8-4: Day-ahead price setting by type, 2007 to 2009.

Figure 8-5 and Figure 8-6 show the amount of time that imports were marginal within an hour as a percentage of the total amount of time that all price setters were marginal within that hour for the Day-Ahead and Real-Time Energy Markets.

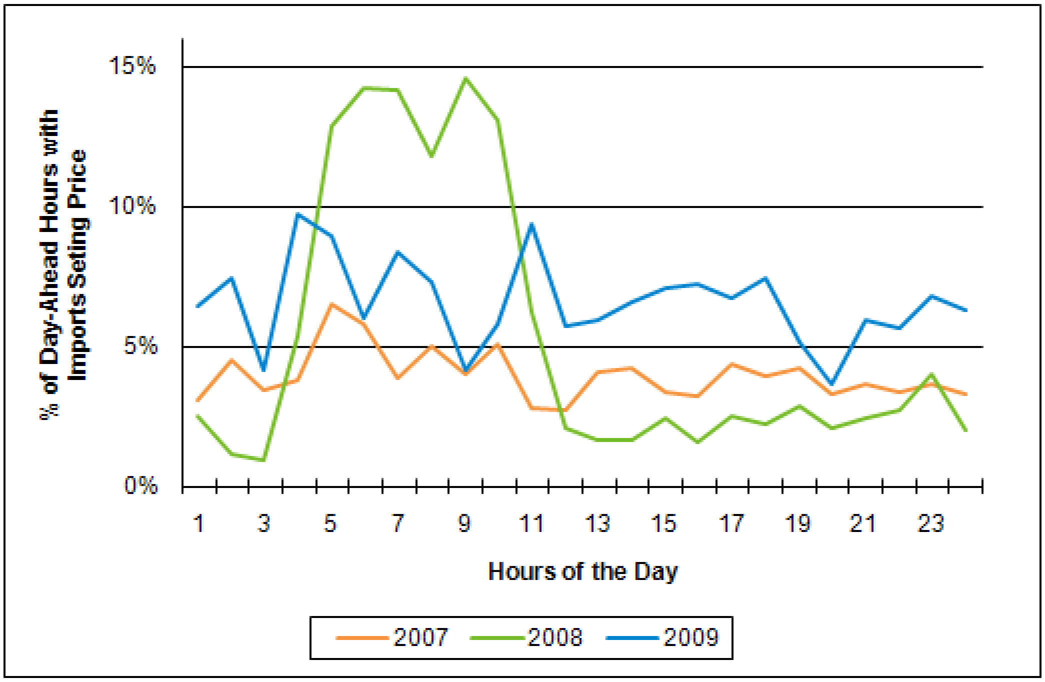

Figure 8-5: External transaction price setting by time of day, day-ahead market, 2007 to 2009.

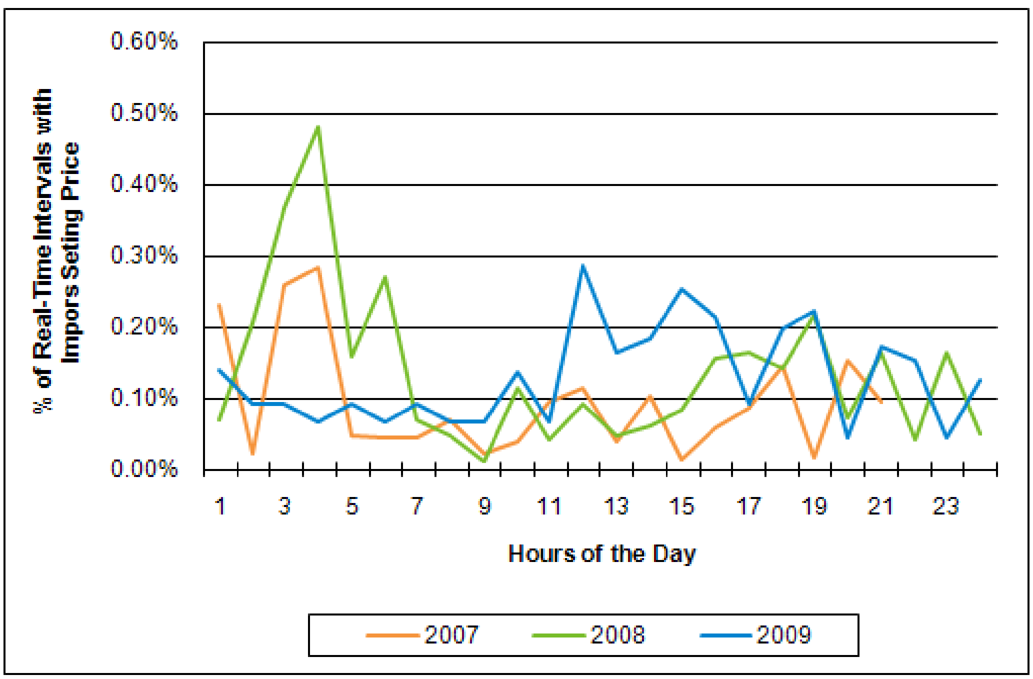

Figure 8-6: External transaction price setting by time of day, real-time market, 2007 to 2009.

8.1.3.3 Interchange Details

This section provides information on the transfer of energy between balancing authorities for 2007 to 2009, as well as average hourly flow levels by interface.

Figure 8-7 shows scheduled imports, exports, and net external energy flow for 2007 through 2009.

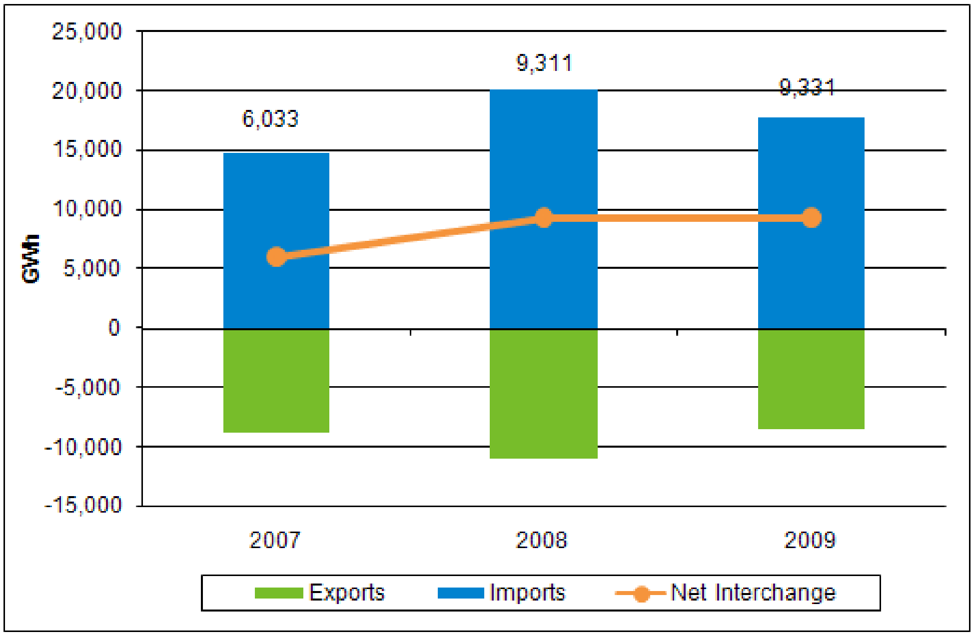

Figure 8-7: Scheduled imports and exports and net external energy flow, 2007 to 2009.

Figure 8-8 to Figure 8-11 present average metered flow by hour over the priced external interfaces with neighboring balancing authority areas.

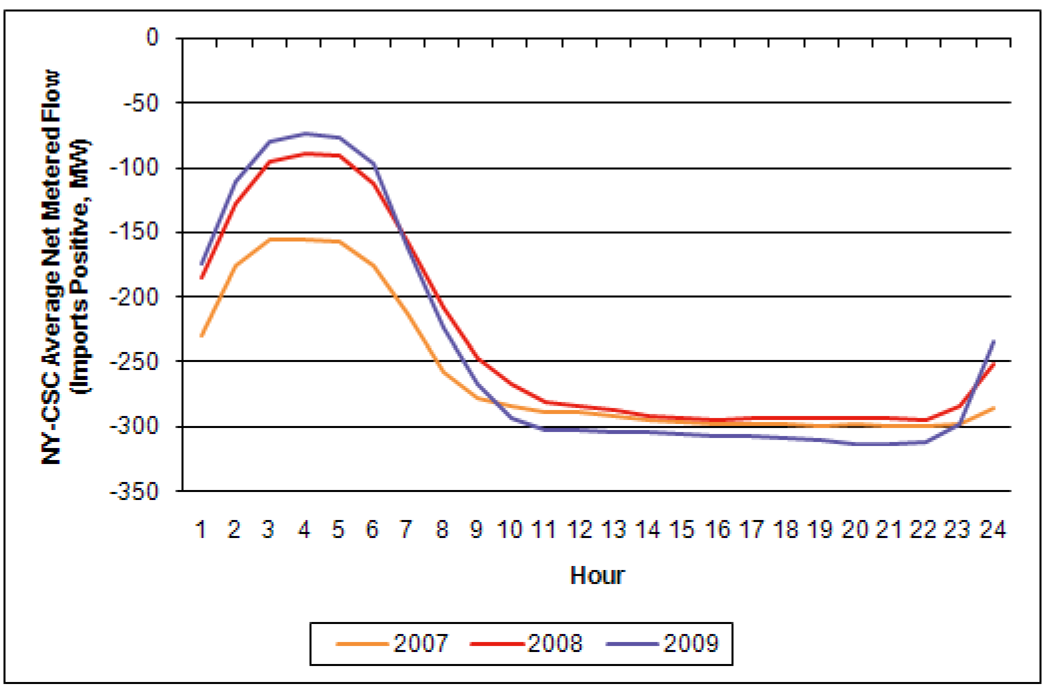

Figure 8-8: New York Cross-Sound Cable, average net metered flow by hour of the day, 2007 to 2009.

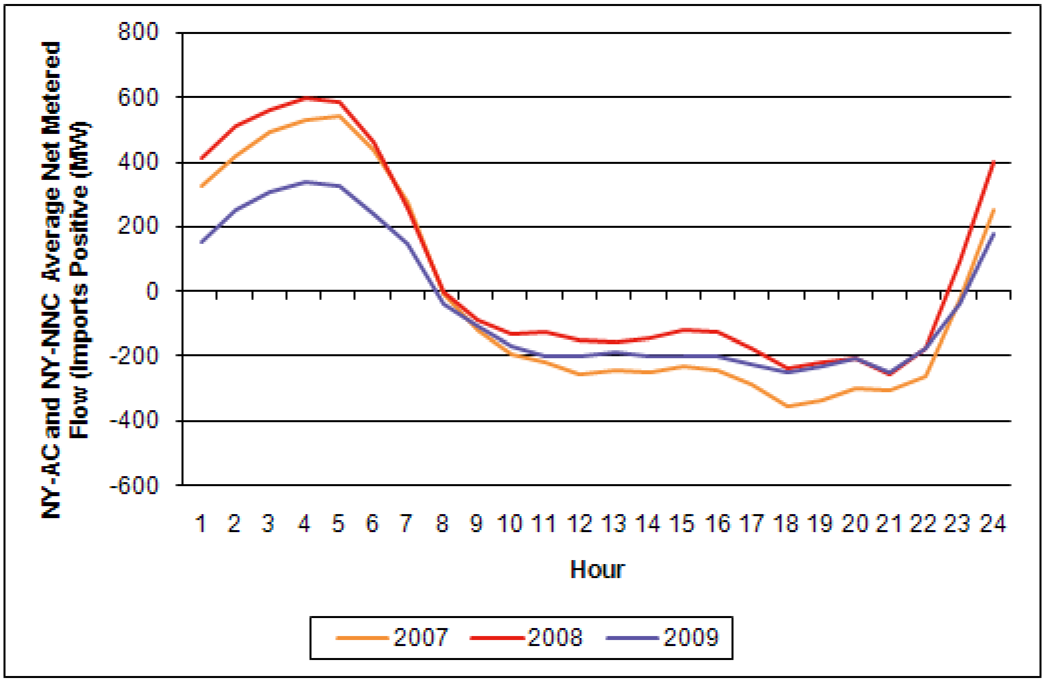

Figure 8-9: New York-AC ties, average net metered flow by hour of the day, 2007 to 2009.

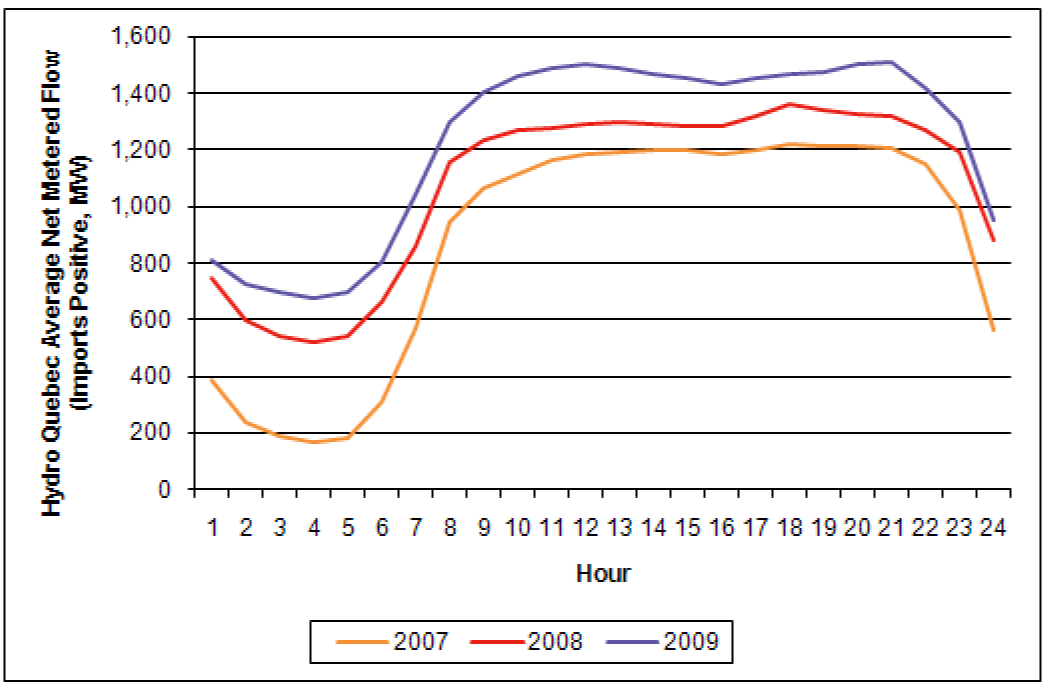

Figure 8-10: Hydro Québec (Phases 1 and 2 and Highgate), average net metered flow by hour of the day, 2007 to 2009.

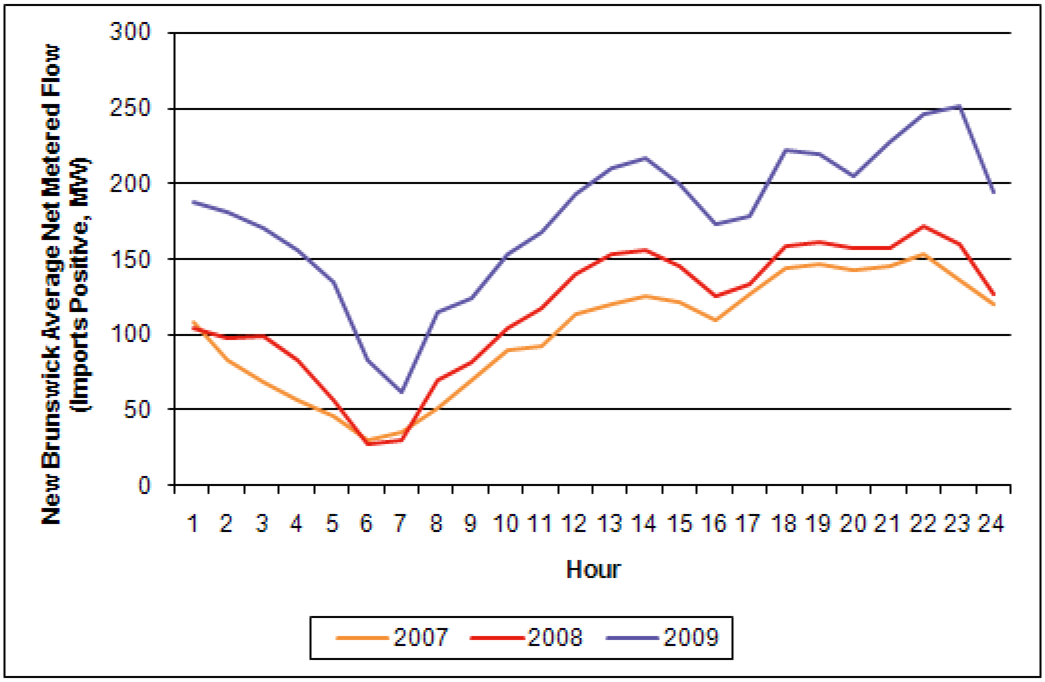

Figure 8-11: New Brunswick average net metered flow by hour of the day, 2007 to 2009.

8.1.4 Congestion and FTR

This section provides some details about the marginal cost of congestion and the marginal cost of losses by zone for the Day-Ahead and Real-Time Energy Markets, along with the Congestion Revenue Balancing Fund for 2009.

Table 8-8 and Table 8-9 show the annual average marginal congestion component and marginal loss component the Hub and eight load zones.

Table 8-8
Average Day-Ahead Marginal Congestion Component, Marginal Loss Component, and Combined, 2009, $/MWh

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−0.25	0.07	−0.18
Maine	−0.34	−1.77	−2.11
New Hampshire	−0.32	−0.53	-0.85
Vermont	−0.26	0.12	−0.13
Connecticut	0.32	0.71	1.03
Rhode Island	−0.27	−0.31	−0.57
SEMA	−0.00	−0.01	−0.01
WCMA	−0.13	0.32	0.18
NEMA	−0.09	−0.17	−0.27

Table 8-9
Average Real-Time Marginal Congestion Component, Marginal Loss Component, and Combined, 2009, $/MWh

Location/ Load Zone	Congestion Component	Marginal Loss Component	Congestion Component Plus Marginal Loss Component
Hub	−0.05	0.09	0.03
Maine	−0.17	−1.82	−1.99
New Hampshire	−0.13	−0.51	−0.64
Vermont	−0.04	0.14	0.10
Connecticut	0.11	0.82	0.93
Rhode Island	−0.08	−0.31	−0.39
SEMA	0.05	0.02	0.07
WCMA	0.03	0.35	0.37
NEMA	−0.02	−0.16	−0.18

Table 8-10 shows the monthly values of the different components of the Congestion Revenue Balancing Fund for 2009.

Table 8-10
Congestion Revenue Balancing Fund, 2009

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)	Amount Paid Out to Positive Target Allocations	Monthly Fund Surplus or Shortfall	Interest	FTR Capping	Ending Balance	Cumulative Balance for Year End	Percent Positive Allocation Paid
Jan	−1,354	1,196,935	−7,794	686,433	−1,750,394	−1,750,394	123,826	1,742	91,074	216,643	216,643	100
Feb	2,786	2,065,188	53,572	465,680	−2,363,344	−2,363,344	223,881	159	5,558	229,598	446,241	100
Mar	6,446	1,963,346	−63,245	1,431,151	−3,740,537	−3,337,697	−402,839	138	14,240	14,377	460,618	89
Apr	−64	3,374,746	−824,676	1,448,017	−5,320,331	−3,998,022	−1,322,308	84	1,224	84	460,702	75
May	−117	3,093,431	−101,571	1,277,109	−4,048,782	−4,048,782	220,070	259	4,729	220,328	681,030	100
Jun	1,334	2,487,261	−318,914	921,041	−3,390,930	−3,090,722	−300,208	88	0	88	681,119	91
Jul	−940	3,183,633	−3,882	1,836,031	−4,934,716	−4,934,716	80,126	589	0	80,715	761,833	100
Aug	−524	1,263,034	97,544	1,064,367	−2,364,716	−2,364,716	59,705	662	0	60,367	822,200	100
Sep	5,938	3,051,838	8,239	937,103	−3,987,636	−3,987,636	15,482	507	0	20,718	842,918	100
Oct	91	447,660	57,753	298,289	−855,359	−803,794	−51,566	215	5,426	215	843,133	94
Nov	116	1,740,324	−495,437	811,335	−2,499,695	−2,056,338	−443,357	208	0	208	843,133	82
Dec	−1,720	2,813,731	127	1,444,438	−3,729,438	−3,729,438	527,138	399	3,400	527,537	1,370,878	100

8.1.5 Demand Resources

Table 8-11 shows Day-Ahead Load-Response Program interruptions and payments for 2009. Table 8-12 shows the 2009 interruptions and payments for the Real-Time Load-Response Program.

Table 8-11
Day-Ahead Load-Response Program Interruptions and Payments, 2009

	Reliability Program Resources			Real-Time Price-Response Resources		
	Column A	Column B	Column C	Column A	Column B	Column C
	Day-Ahead Cleared (MWh)[(a)]	Actual Interruptions Produced by Day-Ahead Program Resources in Real Time (MWh)[(a)]	Day-Ahead Program Payments ($)[(a)]	Day-Ahead Cleared (MWh)[(a)]	Actual Interruptions Produced by Day-Ahead Program Resources in Real Time (MWh)[(a)]	Day-Ahead Program Payments ($)[(a)]
Jan	1,198.93	6,287.87	$573,062.73	23.4	128.70	$11,934.28
Feb	414.90	2,038.31	$153,407.11	8.8	3.72	$289.44
Mar	319.5	2,086.48	$146,187.66	8.4	5.68	481.61
Apr	28.8	262.05	$10,937.41	2.4	6.87	275.72
May	551.9	2,419.96	$112,588.76	14.5	20.46	$916.64
Jun	166.4	825.25	$39,713.62	6.5	29.49	$1,334.18
Jul	132.6	755.67	$35,318.88	4.5	74.85	$3,641.60
Aug	1014.8	8,143.87	$551,958.14	16.7	33.86	$1,682.30
Sep	597	2,872.39	$134,820.36	5.6	43.88	$2,961.23
Oct	692.7	3,303.04	$207,939.71	5.2	0.9	37.86
Nov	84.2	224.04	$15,234.01	0.7	0.1	−$13.17
Dec	1048.6	6,451.98	$562,377.55	7.4	3.49	$289.91
Total	**6,250.33**	**35,670.90**	**$2,543,545.94**	**104.1**	**351.995**	**$23,831.60**

(a) The day-ahead program payments [column C] are equal to the sum of two components—day-ahead cleared megawatt payments and real-time deviation payments:

Day-ahead cleared MW payments = day-ahead cleared MWh [column A] × day-ahead LMP.

Real-time deviation payments = real-time deviation MWh [column B – column A] × real-time LMP.

If the ISO activates a demand-response program, any megawatts in excess of the day-ahead cleared quantity interrupted by a resource in real time are counted as real-time interruptions and would not be included as a day-ahead program interruption.

Table 8-12
Real-Time Load-Response Program Interruptions and Payments, 2009

	Reliability Programs					Price-Response Program	
	Demand Response		Profiled Response		FCM Transition Payments		
	Real-Time Program Interruptions (MWh)	Real-Time Program Payments ($)[(a)]	Real-Time Program Interruptions (MWh)	Real-Time Program Payments ($)[(a)]	Total Transition Payments ($)	Real-Time Program Interruptions (MWh)	Real-Time Program Payments ($)[(a)]
Jan	-	-	-	-	8,946,342	1,472.76	149,588
Feb	-	-	-	-	9,069,553	676.87	67,687
Mar	-	-	-	-	9,117,421	411.27	41,127
Apr	-	-	-	-	9,305,785	115.64	11,564
May	-	-	-	-	9,595,740	711.35	71,693
Jun	-	-	-	-	7,772,179	684.96	71,241
Jul	-	-	-	-	7,834,267	6.19	622
Aug	3,345	1,608,159	59.60	5,990	7,848,410	1,080.47	117,977
Sep	-	-	-	-	7,159,759	98.92	9,892
Oct	-	-	-	-	9,519,138	93.933	9,532
Nov	-	-	-	-	10,237,029	13.181	1,318
Dec	-	-	-	-	10,369,756	435.122	45,214
Total	**3,345**	**1,608,159**	**59.601**	**5,990**	**106,775,377**	**5,800.66**	**597,455**

(a) Payments = MW x LMP.

8.2 FCM Appendix

This appendix shows cleared capacity by load zone for the first two forward capacity auctions.[171]

Figure 8-12 shows cleared capacity by load zone and type for FCA #2. Figure 8-13 shows the same information for FCA #1.The horizontal lines indicate the local sourcing requirement for the Connecticut and NEMA/Boston load zones, and the maximum capacity limit for the Maine load zone.

[171] More information about the first two FCAs is contained in the Internal Market Monitoring Unit report, *Review of the Forward Capacity Market Auction Results and Design Elements* (June 5, 2009); http://www.iso-ne.com/markets/mktmonmit/rpts/other/fcm_report_final.pdf.

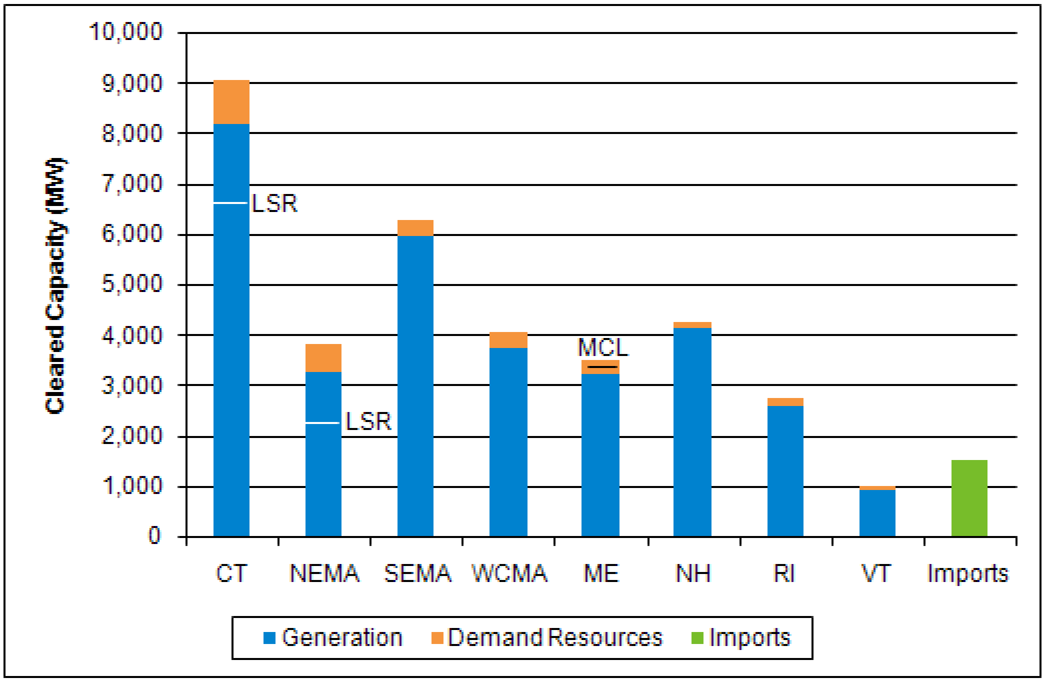

Figure 8-12: Capacity by load zone for FCA #2.

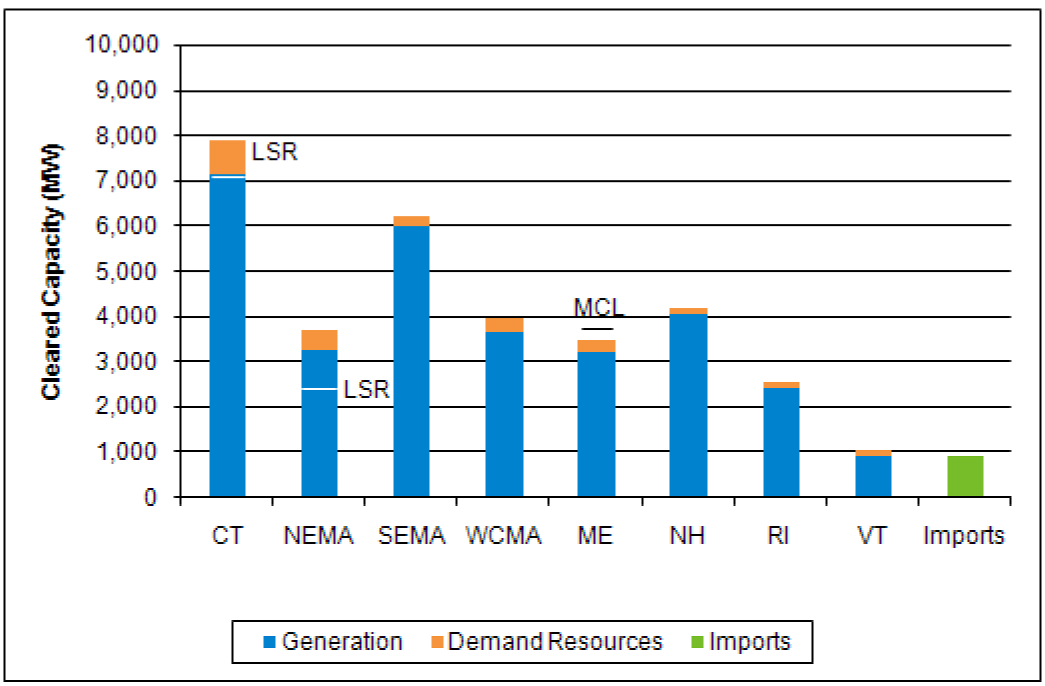

Figure 8-13: Capacity by load zone for FCA #1.

Figure 8-14 and Figure 8-15 show cleared new capacity by load zone and type for FCA #2 and FCA #1.

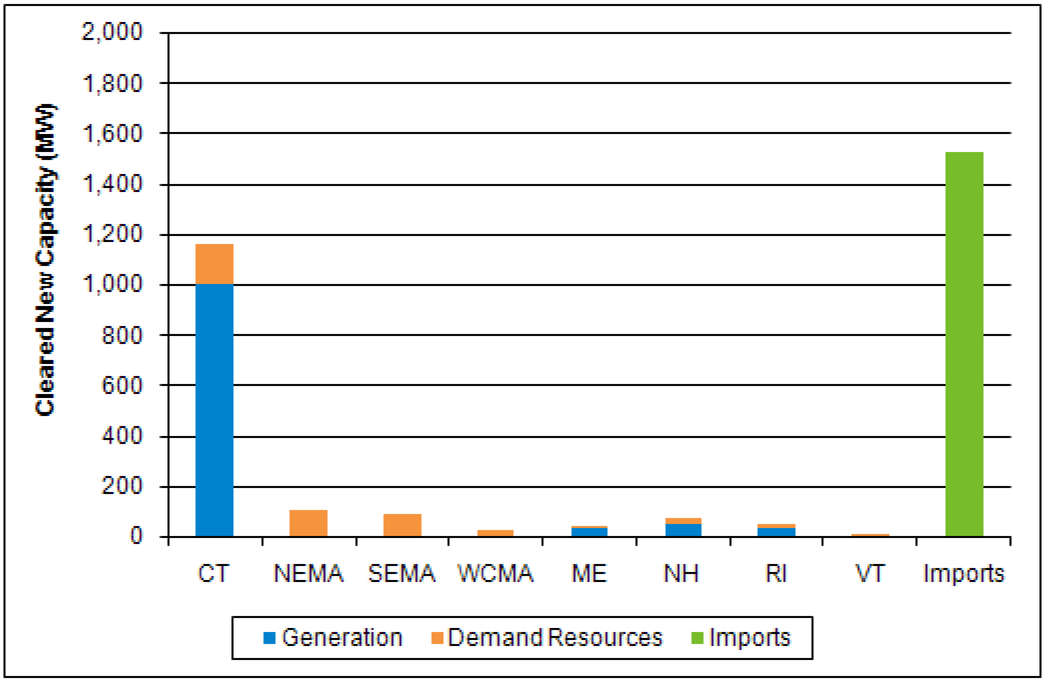

Figure 8-14: New capacity by load zone for FCA #2.

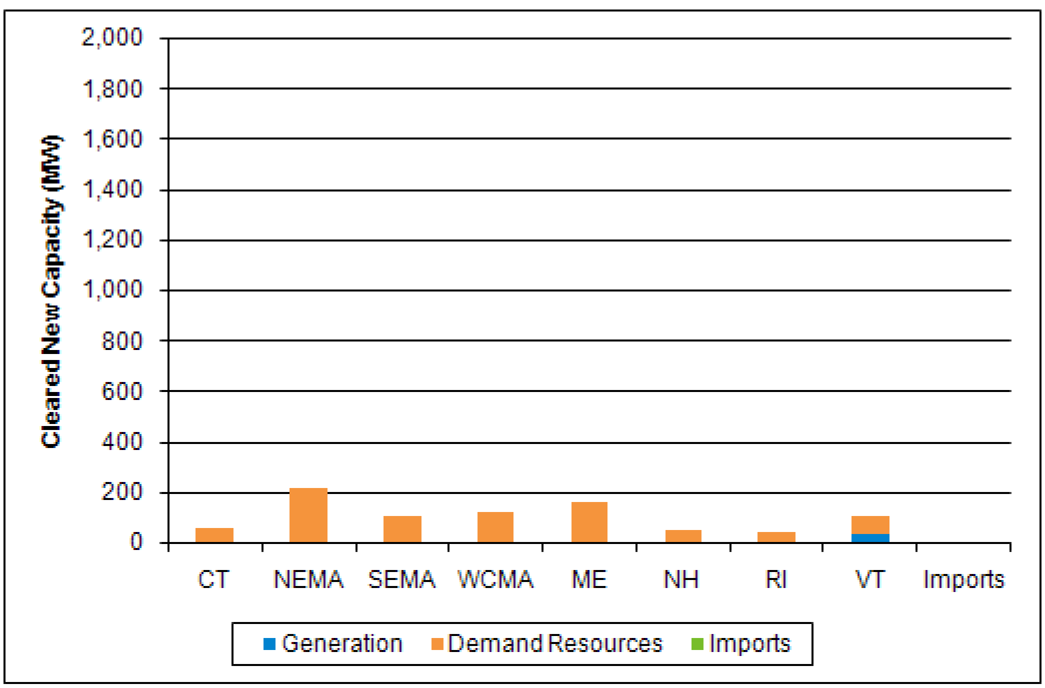

Figure 8-15: New capacity by load zone for FCA #1.

8.3 Reserves Appendix

This reserves appendix provides information on the outcome of the payments and charges associated the settlement of the Forward Reserve Market.

Table 8-13 shows the requirements, offers and cleared amounts for each product and zone combination that the market rules accept offers.

Table 8-13
Forward Reserve Market Requirements and Participant Offers by Product and Reserve Zone, MW

Forward Reserve Period	Reserve Zone Name	TMNSR			TMOR		
		Req.	Offered	Cleared	Req.	Offered	Cleared
Summer 2009	System	850	N/A	N/A	700	N/A	N/A
	ROS	N/A	1,432	825	798	378	0
	SWCT	N/A	0	0	22	402	402
	CT	N/A	0	0	1,145	597	597
	NEMA/Boston	N/A	25	25	0	25	0
Winter 2009/2010	System	850	N/A	N/A	750	N/A	N/A
	ROS	N/A	1,271	850	798	210	0
	SWCT	N/A	0	0	0	426	426
	CT	N/A	0	0	1,225	744	744
	NEMA/Boston	N/A	34	0	0	34	0

Table 8-14 shows forward-reserve megawatts designated to meet forward-reserve requirements in each reserve zone for 2007 to 2009 categorized by generator technology.[172]

Table 8-14
Forward Reserve Delivered, by Technology Type, 2007 to 2009

Technology Type	2007	2008	2009
Hydro	25.0%	23.0%	22.8%
Non-fast-start	4.8%	1.5%	2.7%
Fast-start	70.1%	75.5%	74.5%

Table 8-15 shows the monthly average bilateral trading volume of forward-reserve obligations for 2007 to 2009. The volumes shown do not include prearranged transactions among affiliates occurring at the start of the season.

[172] Forward-reserve auctions clear on a portfolio basis (i.e., without specifying resources). Resources are designated before the start of the operating day at 12:00 a.m. (midnight).

Table 8-15
Monthly Average Bilateral FRM Obligation Trading Volume, MW, 2007 to 2009

Year	Systemwide TMOR	Systemwide TMNSR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR
2007	0	3	0	0	5
2008	0	179	0	0	3
2009	3	214	69	0	0

Figure 8-16 shows monthly average peak-hour reserve margins for TMSR and TMNSR since 2008.

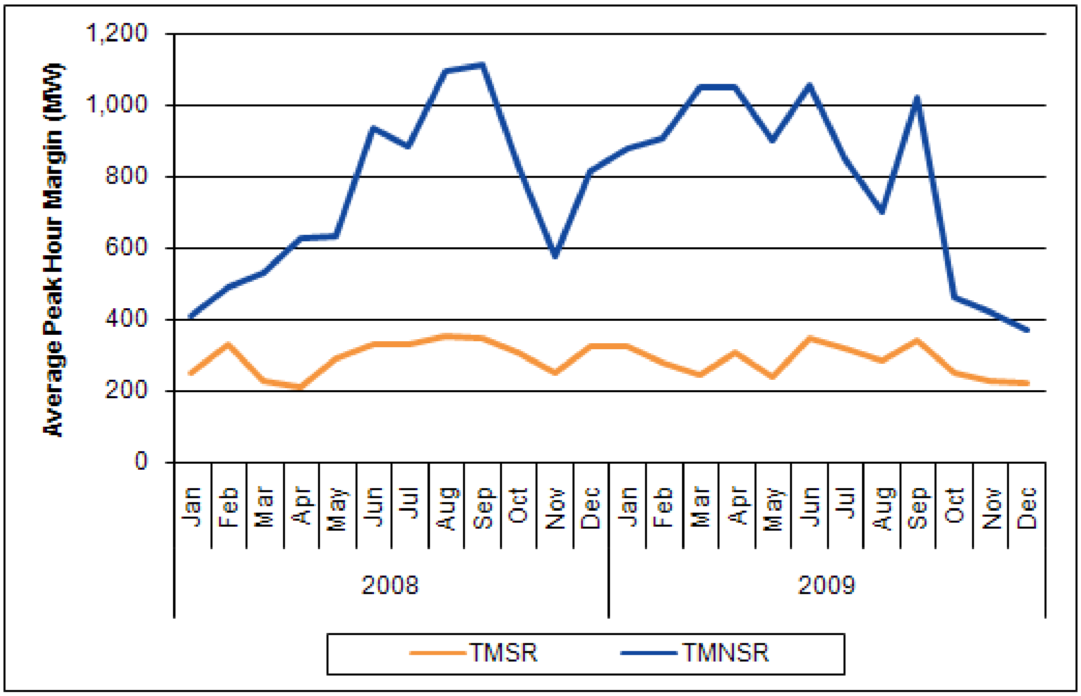

Figure 8-16: Real-time reserve margins, TMSR and TMNSR, peak hour, 2008 to 2009.

Table 8-16 shows the total failure-to-reserve penalties by participants with forward-reserve obligations during 2007 through 2009.

Table 8-16
Failure-to-Reserve Penalties, 2007 to 2009, $

Year	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR
2007	−3,251,943	−53,754	−1,108,773	−444,735	−1,542,000
2008	−3,517,805	−52,591	−1,664,859	−1,536,191	−911,575
2009	−1,426,316	−68,489	−2,082,158	−405,945	−61,431

Total forward- and real-time reserve payments and penalties are shown in Table 8-17. The net forward credit equals the forward-reserve payments minus penalties and forward-reserve energy obligation charges.

Table 8-17
Forward and Real-Time Reserve Payments and Penalties, 2007 to 2009, $

Year	Failure-to-Activate Penalties	Failure-to-Reserve Penalties	Forward Credit	Forward-Reserve Obligation Charge	Net Forward Credit	Real-Time Credit
2007	−3,537	−6,401,204	171,893,905	−1,680,469	163,808,694	6,568,714
2008	−10,752	−7,683,020	179,551,242	−1,543,901	171,049,377	16,799,082
2009	−8,367	−4,044,339	148,172,068	−1,432,877	144,119,362	7,852,066

Table 8-18 shows total reserve charges for the reporting period that are allocated real-time load obligation.

Table 8-18
Reserve Charges to Load, by Load Zone, 2009, $[a]

Market	Product	CT Load Zone	NEMA Load Zone	Rest-of-System
Forward reserves	TMNSR	−9,257,499	−3,621,754	−9,362,884
Forward reserves	TMOR	−95,102,881	−7,851,418	−18,922,914
Real-time reserves	TMNSR	−436,564	−380,148	−992,608
Real-time reserves	TMOR	−68,965	−106,003	−140,253
Real-time reserves	TMSR	−1,052,237	−875,686	−2,366,725

(a) The SWCT reserve zone does not have a separate allocation.

8.4 Regulation Appendix

This section presents additional detail on the requirements, payments, and compliance of the ISO New England Regulation Market during 2009.

Table 8-19 summarizes information about clearing prices in the Regulation Market by month for 2009.

Table 8-19
Monthly Regulation
Clearing Price Statistics, 2009, $

Month	Minimum	Average	Maximum
Jan	6.50	12.28	91.40
Feb	6.17	9.77	80.74
Mar	1.33	14.41	100.00
Apr	5.18	9.68	95.84
May	4.07	10.60	95.84
Jun	0.00	9.70	100.00
Jul	0.00	7.94	22.49
Aug	0.00	7.60	58.41
Sep	0.00	7.08	14.00
Oct	1.09	7.00	15.00
Nov	3.00	7.10	23.44
Dec	0.00	7.87	81.49

Figure 8-17 shows the NERC CPS 2 compliance requirement and the monthly ISO compliance levels for 2009.

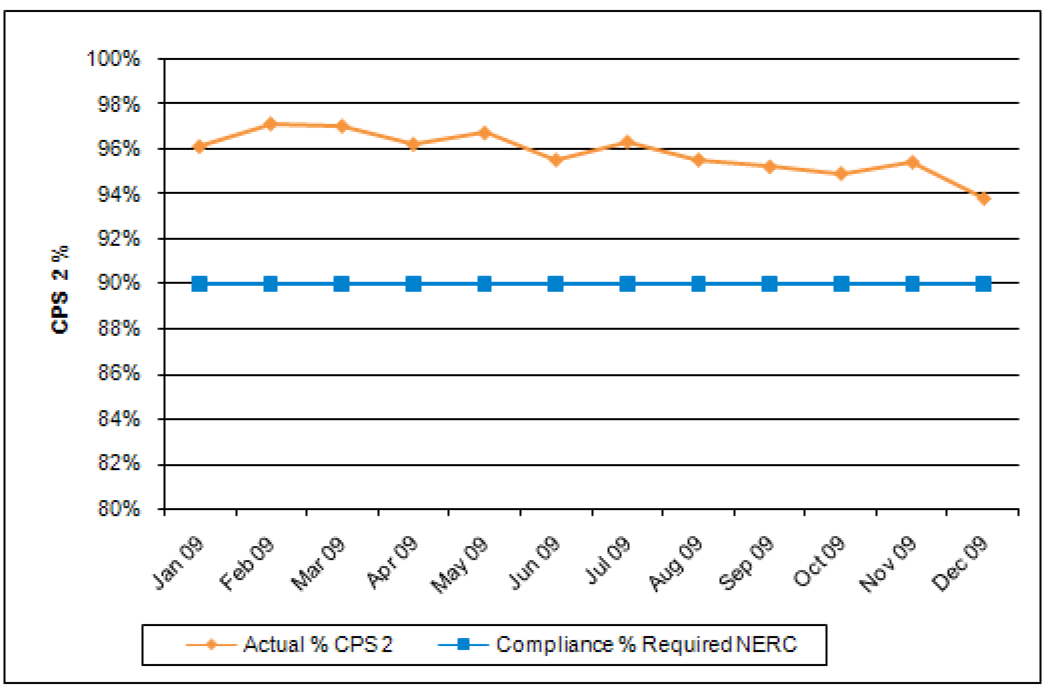

Figure 8-17: CPS 2 compliance, 2009.

Figure 8-18 shows the megawatt time-weighted monthly average of the regulation requirements for 2006 to 2009.

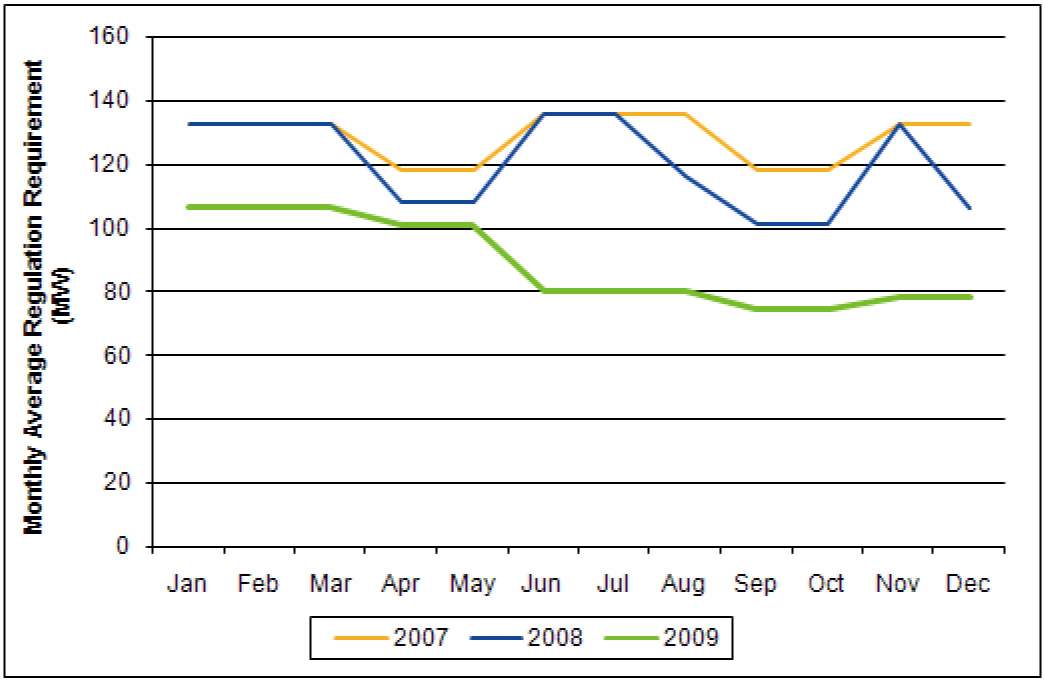

Figure 8-18: Monthly average regulation requirements, 2007 to 2009.

Figure 8-19 shows the annual average regulation requirement since 2002. Average regulation values have fallen from 181 to 89 MW during the last six years.

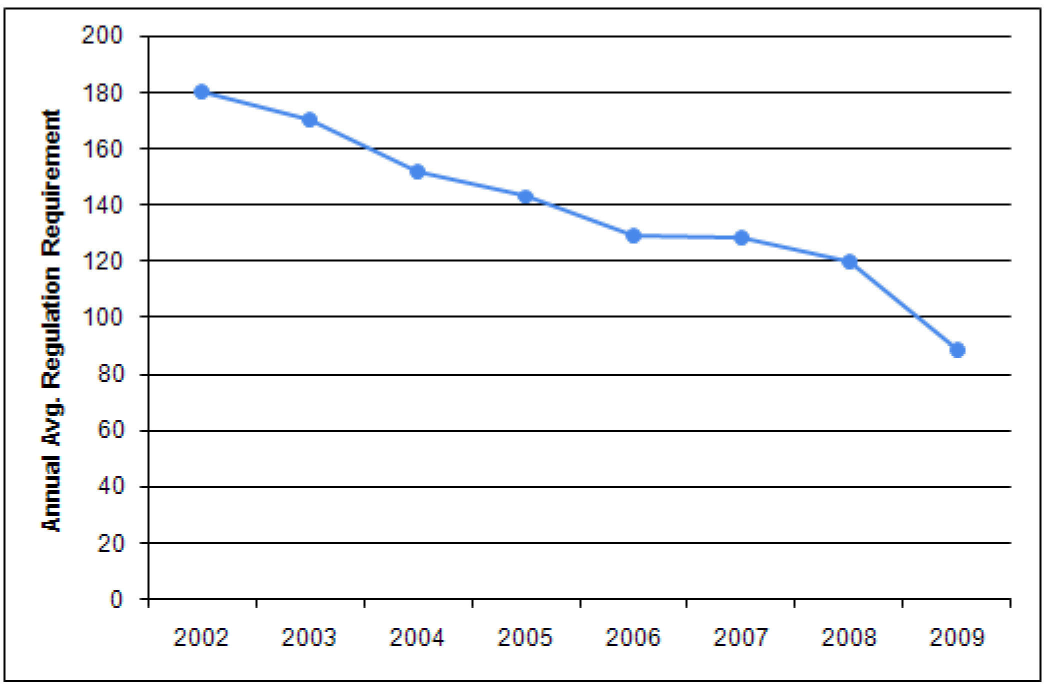

Figure 8-19: Annual average regulation requirement, 2002 to 2009.

Figure 8-20 shows the total 2009 Regulation Market payments by payment category.

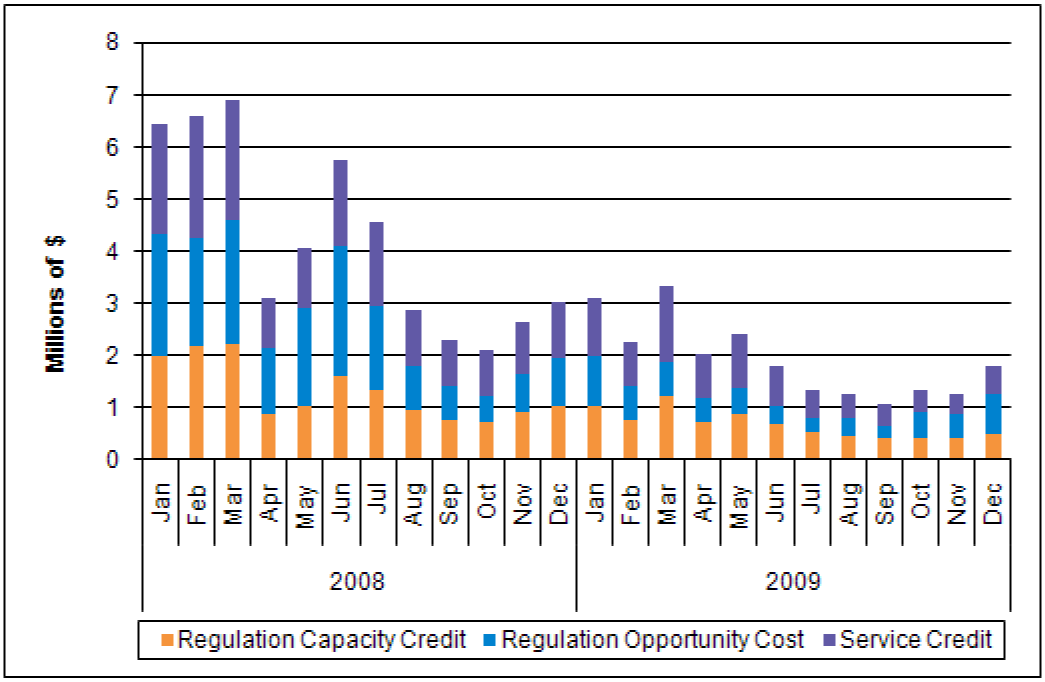

Figure 8-20: Total regulation payments by month, 2008 to 2009.

Figure 8-21 shows in-service regulation capability by month for 2009.

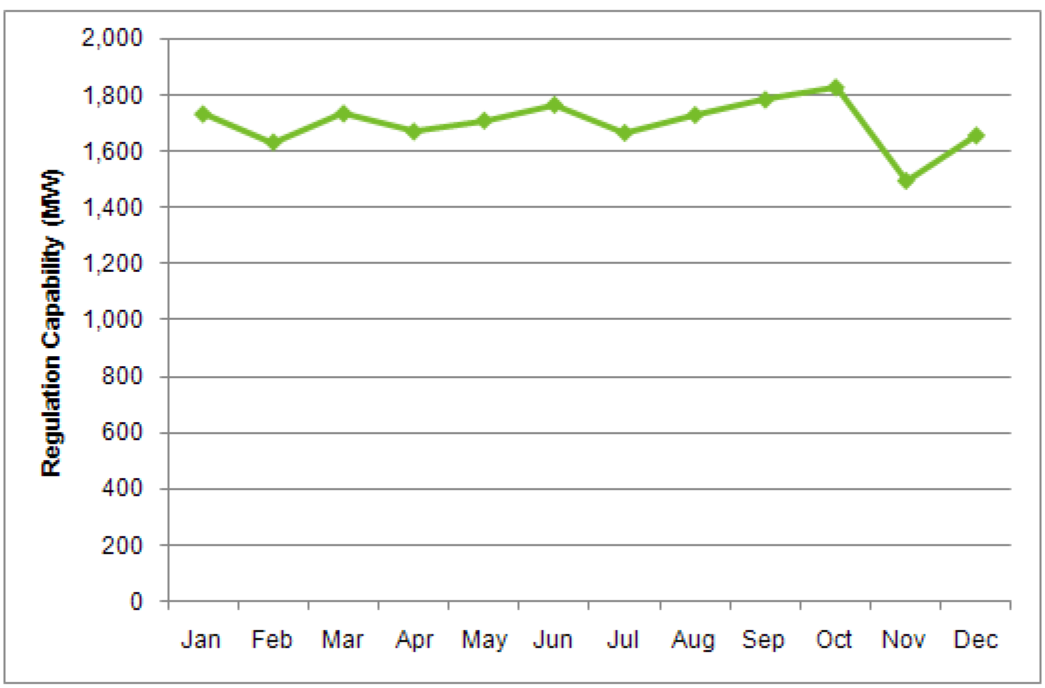

Figure 8-21: Total available in-service regulation capability, 2009.

Figure 8-22 shows regulation capacity and the amount of regulation provided by unit type for 2009.

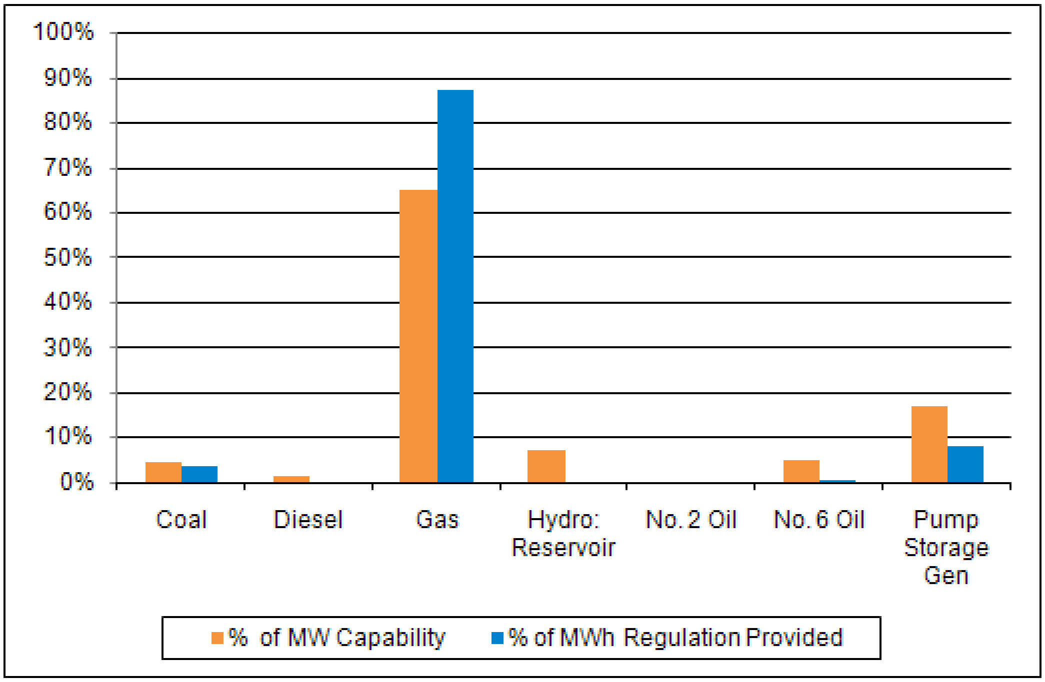

Figure 8-22: Regulation capability and regulation provided by fuel type, 2009.

8.5 Reliability and Operations Assessment Appendix

This section includes information on net Reliability Agreement and tariff charges, as well as a listing of hours the system was under Minimum Generation Emergency events or M/LCC2.

Table 8-20 shows the annual sum of monthly net payments for 2003 through 2009.

Table 8-20
Net Reliability Agreement Payments, System Total, Million $[a]

	2003	2004	2005	2006	2007	2008	2009
Payment	83.36	177.64	223.71	348.69	140.76	127.22	71.83

(a) The table shows restated values for previous years that account for the refunds to load associated with the FERC settlements.

Total payments under each ISO schedule are shown in Table 8-21.

Table 8-21
ISO Self-Funding Tariff Charges, $

Date	Schedule 1: Scheduling, System Control, and Dispatch Service	Schedule 2: Energy Administration Service	Schedule 3: Reliability Administration Service
2009 Total	24,992,702	53,660,899	38,398,312

Total payments under each OATT schedule are shown in Table 8-22.

Table 8-22
OATT Charges, $

Date	Schedule 1	Schedule 2: CC	Schedule 2: VAR	Schedule 8: TOUT	Schedule 9: RNS	Schedule 16: Black Start	Schedule 19: SCR
2009 Total	28,698,519	22,674,951	6,460,468	7,903,928	1,039,620,986	10,449,220	586,034

Table 8-23 and Table 8-24 summarize the periods when M/LCC2 and Minimum Generation Emergency events were declared in 2009 to maintain system reliability. No OP 4 actions were implemented during 2009.

Table 8-23
M/LCC2 Events, 2009

Date	Area effected
Jan 20	Public Service of New Hampshire (PSNH) only due to computer issues
Jan 26	System capacity issue due to Sable Island outage
May 15	PSNH only due to PSNH Energy Management System (EMS) computer problems
Jun 15	PSNH only due to PSNH EMS computer problems
Jun 30	The ISO due to capacity surplus problems
Aug 3	All of New England for capacity
Aug 5	All of New England for capacity
Aug 11	All of New England for capacity
Aug 14	All of New England for capacity
Aug 15	All of New England for capacity
Aug 21	All of New England for capacity
Sep 27	All of New England for capacity
Oct 3	All of New England for capacity
Oct 5	All of New England for capacity
Nov 1	All of New England for capacity
Nov 7	All of New England for capacity
Nov 21	All of New England for capacity
Nov 23	All of New England for capacity
Dec 5	All of New England for capacity
Dec 12	All of New England for capacity
Dec 18	All of New England for capacity
Dec 19	All of New England for capacity

Table 8-24
Minimum Generation Emergency Events, 2009

Date	Hours Declared
Feb 28	5:00 to 8:00
Mar 9	1:00 to 5:00
Apr 18	2:00 to 8:00
Apr 19	4:00 to 7:00
Apr 25	3:00 to 7:30
May 8	3:00 to 5:00
May 22	2:15 to 5:00
May 27	2:00 to 5:00
Jun 1	2:00 to 6:00
Jun 15	2:00 to 4:00
Jun 22	2:00 to 5:00
Jul 1	3:00 to 6:00
Jul 5	6:00 to 7:00
Jul 13	3:00 to 5:00
Aug 9	0:15 to 7:00
Aug 30	1:00 to 9:30
Sep 18	3:00 to 5:00
Sep 30	3:00 to 5:00
Oct 4	3:00 to 8:00
Oct 8	4:00 to 5:00
Oct 12	1:00 to 6:00
Oct 12–13	23:00 to 4:00
Oct 26	3:00 to 5:45

List of Acronyms and Abbreviations

Acronyms and Abbreviations	Description
AC	alternating current
ACE	area control error
AMR	Annual Markets Report
APR	Alternative Pricing Rule
ARR	Auction Revenue Rights
BAL -001-0	NERC's *Real Power Balancing Control Performance Standard*
Btu	British thermal unit
CONE	cost of new entry
COS	cost of service
CPS	NERC *Control Performance Standard*
CPS 2	NERC *Control Performance Standard 2*
CRBF	Congestion Revenue Balancing Fund
CSC	Cross-Sound Cable
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
DALRP	Day-Ahead Load Response Program
DARD	dispatchable asset-related demand
DBD	Design Basis Document
DG	distributed generation
DOJ	U.S. Department of Justice
EAS	Energy Administration Service
EE	energy efficiency
EMM	External Market Monitor
EMS	Energy Management System
EPAct	*Energy Policy Act of 2005*
ERCOT	Electric Reliability Council of Texas
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market

FTR	Financial Transmission Right
GW	gigawatt
GWh	gigawatt-hour
HE	hour ending
HHI	Herfindahl-Hirschman Index
Highgate	Vermont–Hydro Quebec Interconnection
HQICC	Hydro-Québec Phase I/II Interface
ICAP	installed capacity
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
IMM	Independent Market Monitor; Independent Market Monitoring Unit
ISO	Independent System Operator; ISO New England
kW	kilowatt
kWh	kilowatt-hour
kW-mo	kilowatt-month
L_{10}	Limit 10
LM	load management
LMP	locational marginal price
LOLE	loss-of-load expectation
LSCPR	local second-contingency protection resource
LSE	load-serving entity
LSR	local sourcing requirement
MCL	maximum capacity limit
ME	State of Maine and Maine load zone
MinGen Emergency	Minimum Generation Emergency
M/LCC	Master/Local Control Center
M/LCC2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
mo	month
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency

NCPC	Net Commitment-Period Compensation
NE	New England
NEL	net energy for load
NEMA	Northeast Massachusetts and Boston load zone
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	National Electric Reliability Corporation
NH	State of New Hampshire and New Hampshire load zone
NICR	net Installed Capacity Requirement (net of the HQ interconnection credits)
NNC	Norwalk Harbor–Northport, NY, Cable (formerly called the New York 1385 transmission line)
NPCC	Northeast Power Coordinating Council
NTA	negative target allocation
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
O&M	operations and maintenance
OATT	*Open Access Transmission Tariff*
ODR	other demand resources
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
PSNH	Public Service of New Hampshire
PTA	positive target allocation
PTF	pool transmission facility
QUA	Qualified Upgrade Award
QWLI	Quantity-Weighted Lerner Index

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 and Rhode Island load zone
RNS	Regional Network Service
ROS	Rest-of-System reserve zone
RSI	Residual Supply Index
RSP	Regional System Plan
RTEG	real-time emergency generation
RTLO	real-time load obligation
RTO	Regional Transmission Organization
SCC	seasonal claimed capability
SCR	special-constraint resource
SEMA	Southeast Massachusetts load zone
SMD	Standard Market Design
SOI	show of interest
SWCT	Southwest Connecticut
TMNSR	10-minute nonspinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TOUT	through-or-out service
UCAP	unforced capacity
VAR	voltage ampere reactive (voltage control)
VT	Vermont and Vermont load zone
WCMA	Western/Central Massachusetts
WEAF	Weighted Equivalent Availability Factors