2012 First Quarter
Quarterly Markets Report

Internal Market Monitor
May 18, 2012

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Preface

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

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

> The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this Appendix A and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy.

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

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

Underlying natural gas data furnished by:

ICE Global markets in clear view [3]

Oil prices are provided by Argus Media.

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

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

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

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Section 1 Executive Summary

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

1.1 First Quarter Findings

- The Internal Market Monitor has concluded that the energy market was competitive during the Reporting Period. System-wide concentration remains low. Energy market prices are consistent with costs (see Section 2.1).

- Low natural gas prices and low demand drove market outcomes in the Reporting Period.

    - Natural gas prices during the Reporting Period averaged \$3.90/MMBtu, a 41% drop from the first quarter of 2011 (see Section 2.3).

    - Peak load during the Reporting Period was 19,905 MW, and occurred on January 4. Net energy for load ("NEL") was 31,436 GWh, 4.2% lower than the 32,798 GWh load in the first quarter of 2011 (see Section 3.4).[4]

- Day-Ahead Energy Market prices during the Reporting Period averaged \$32.59/MWh at the Hub, and Real-Time prices averaged \$30.89/MWh (see Section 2.4). These are the lowest quarterly prices since the inception of Standard Market Design in 2003.

- Total Net Commitment Period Compensation ("NCPC") payments during the Reporting Period totaled \$10.2 million (see Section 2.4.4).

- There was one Day-Ahead Energy Market mitigation event and no Real-Time Energy Market mitigation events during the Reporting Period. There were eighteen Real-Time NCPC mitigation events and no Day-Ahead NCPC mitigation events during the Reporting Period.

- The IMM made three new non-public referrals to FERC in the Reporting Period. No referrals were closed in the Reporting Period. As of the end of the Reporting Period, there were seven open referrals made by the IMM before FERC.

[4] 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.

Section 2 Results

This section summarizes market outcomes and IMM analysis of market performance during the Reporting Period.

2.1 Assessment of Market Competitiveness

To assess the competitiveness of the wholesale electric energy markets in New England, the IMM examines two types of measures of market competitiveness: structural measures that look at market concentration, and price-based measures that compare price outcomes to the marginal cost of production.

2.2 Structural Measures

Market concentration considers the size of the market and the participant's respective market shares. Market share is estimated as the percentage of capacity megawatts controlled. The Herfindahl-Hirschman Index ("HHI"), 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.

Monthly system-wide HHIs for New England internal resources, based on summer capabilities and the resources' Lead Market Participants, averaged 635 in the Reporting Period. This value has been relatively constant over the past three years. The result indicates that the wholesale electric energy markets in New England are well within the "not concentrated" range.[5]

The Residual Supplier Index ("RSI") 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 may have pricing power. As RSIs rise, the ability of Market Participants to exert market power decreases.

Figure 2-1 shows RSIs for the entire New England market as a percentage of total hours for the Reporting Period. RSIs generally are lowest during periods of high demand, indicating a drop in the level of competition as the system approaches its capacity limit. Pivotal suppliers did not exist at the system level during the Reporting Period.

[5] HHI ignores transmission constraints and contractual entitlements to generator output, which would have the effect of increasing and decreasing concentration, respectively. The net effect has not been measured; however, given the low level of overall concentration even if these effects produced a net increase in concentration, the impact would not change our assessment.

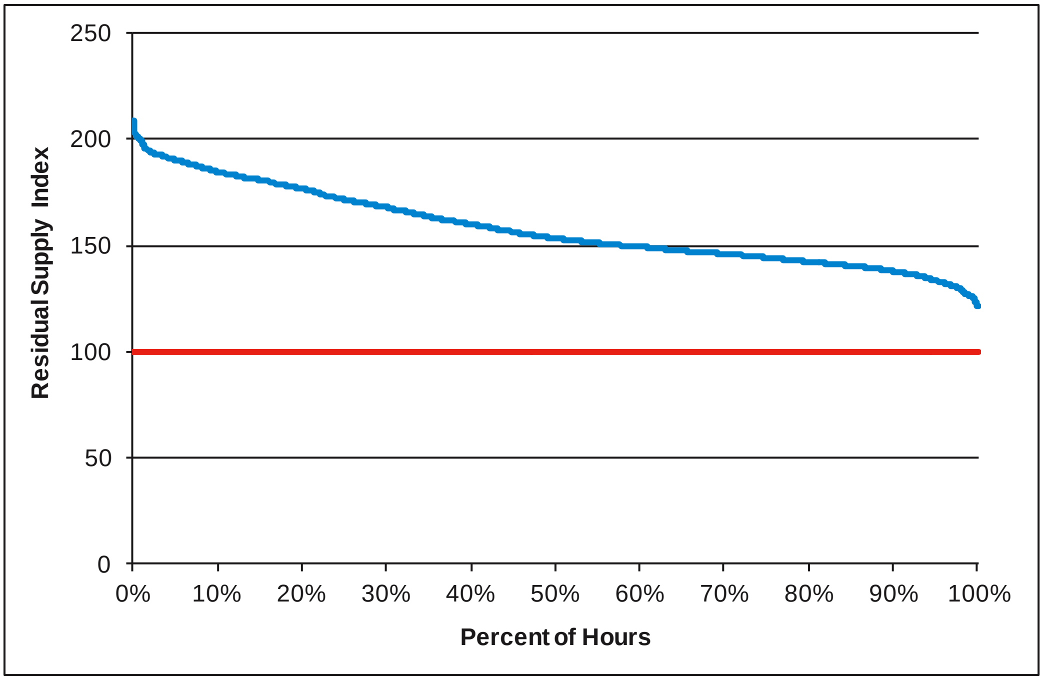


Figure 2-1: RSIs as a Percentage of Total Hours, Q1 2012.

2.3 Comparison of Fuel Prices and Electric Energy Prices

New England's most frequently marginal generation fuel, natural gas, declined over the last year from $6.61/MMBtu in Q1 of 2011 to $3.90/MMbtu in Q1 of 2012, a 41% drop. In a competitive market one would expect a corresponding drop in the electricity price.

In the Reporting Period, units burning natural gas were marginal for 80% of the pricing intervals, followed by pumped storage units, which were marginal in 13% of the pricing intervals. Generating resources burning fuel oil and other petroleum products were marginal 1.3% and coal generators were on the margin 3.1% of the time. See Figure 2-2, which shows the real-time marginal, or price-setting, input fuels during the Reporting Period as a percentage of all five minute pricing intervals.

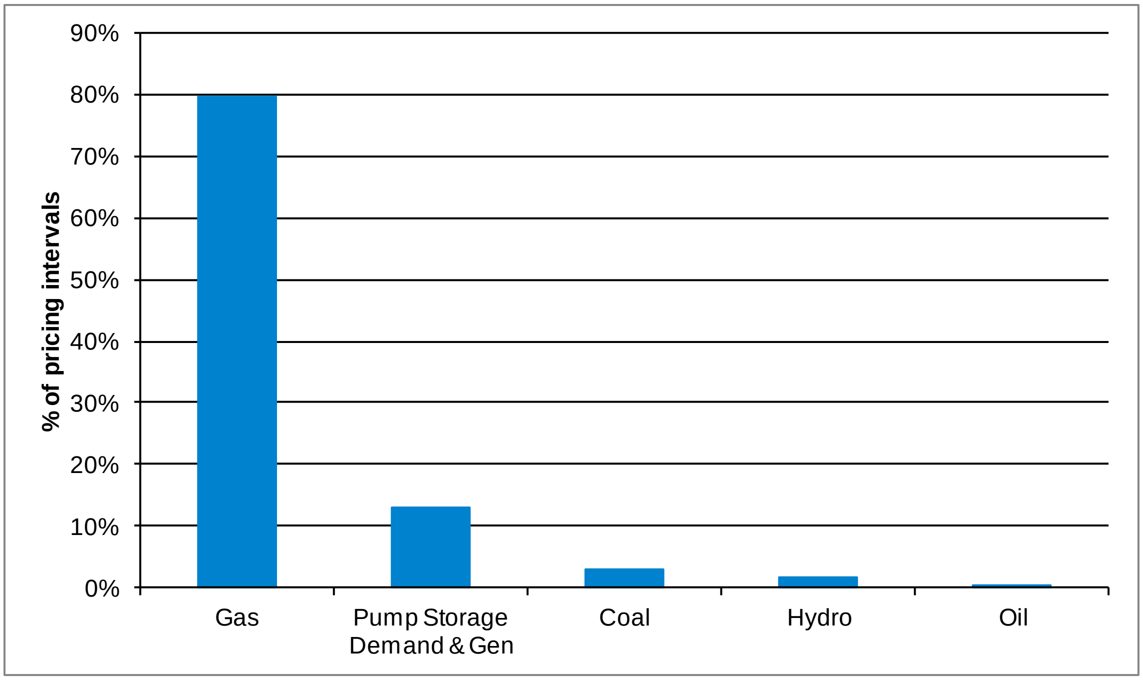


Figure 2-2: Marginal Units by Fuel Type, Q1 2012.

Figure 2-3 shows monthly average day-ahead and real-time electricity prices at the New England hub and monthly average natural gas and fuel oil prices. Wholesale electricity prices continue to move closely with input natural gas prices. Real-Time electricity prices dropped year-on-year from 57.91/MWh in Q1 2011 to $30.90/MWh in Q1 2012, a 47%drop. This supports the conclusion that the electricity market is competitive. Prices tend to deviate from cost only when unexpected system conditions, such as unplanned generator or transmission-line outages, cause short-term scarcity-related energy price spikes.

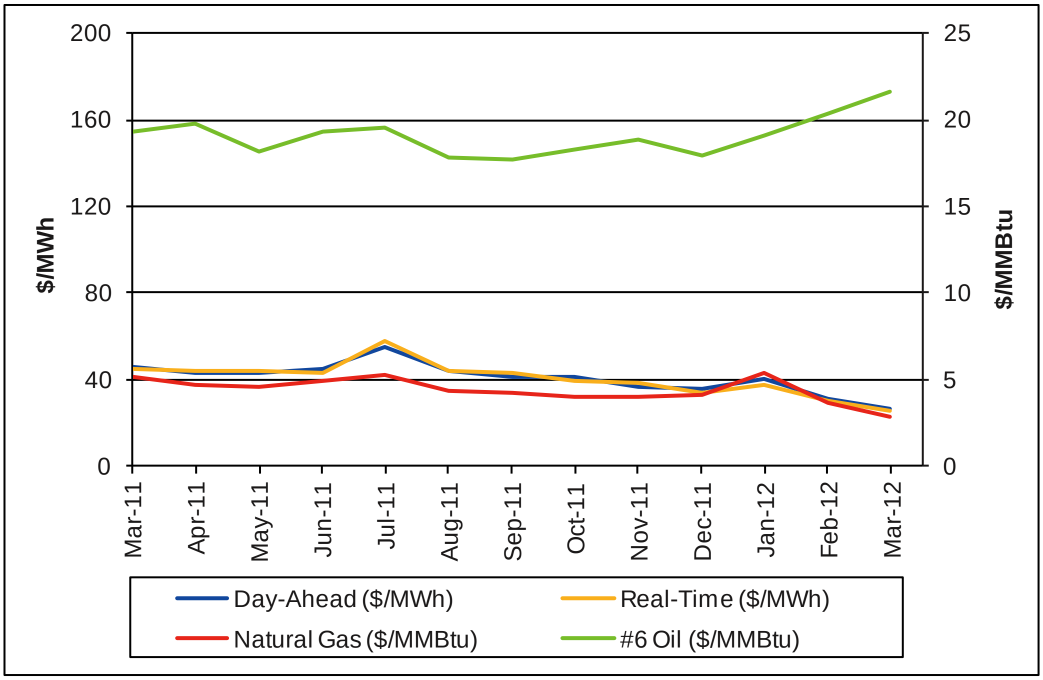


Figure 2-3: Monthly Average Day-Ahead and Real-Time Hub and Fuel Prices, March 2011-March 2012.

2.4 Day-Ahead and Real-Time Energy Market Outcomes

The average day-ahead energy price at the Hub for the Reporting Period was $32.59/MWh, 43.3% below the Q1 2011 level. The average real-time energy price at the Hub was $30.89/MWh, 46.6% below the Q1 2011 level. These are the lowest quarterly prices since the inception of Standard Market Design in 2003. Changes in Locational Marginal Prices ("LMPs") at the Hub are almost entirely due to changes in input fuel prices. In the Reporting Period, the difference between the average day-ahead and real-time prices was $1.70. See Figure 2-4, which shows daily average Day-Ahead and Real-Time Hub LMPs, and Section 3.1 in the statistical appendix for more information on average zonal LMPs.

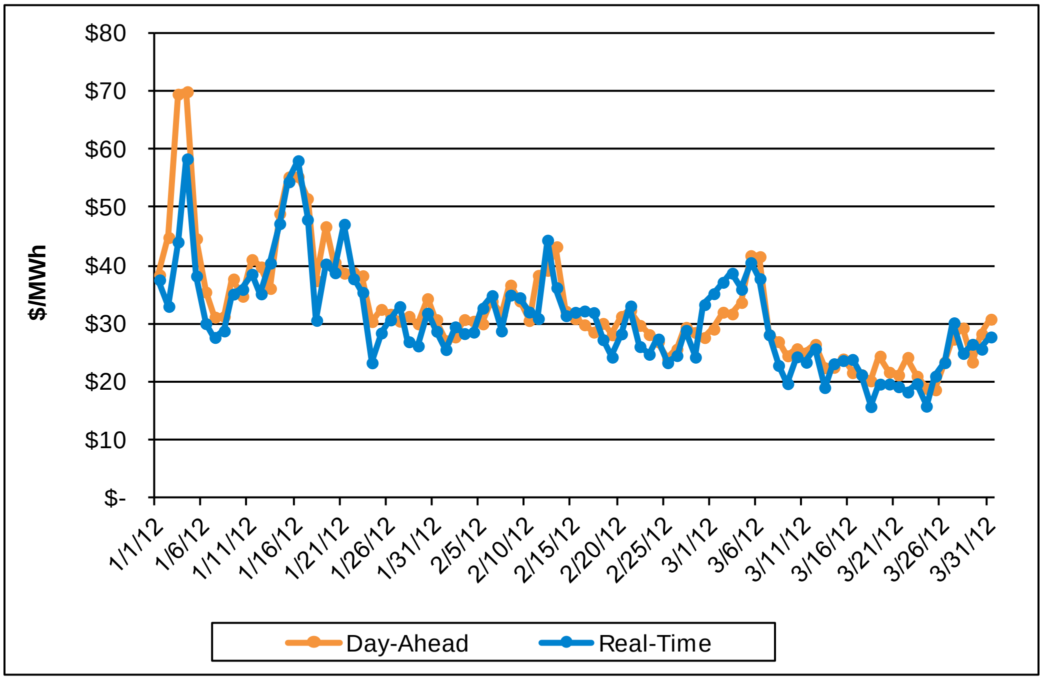


Figure 2-4: Average Day-Ahead and Real-Time LMPs, Q1 2012.

2.4.1 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 and technology. Figure 2-5 presents monthly estimated natural gas spark spreads based on the unweighted monthly average day-ahead and real-time Hub price for on-peak hours in \$/MMBtu from April 2011 through March 2012 and the estimated cost of a combined cycle gas turbine ("CCGT") unit with fuel costs that approximate those of the typical CCGT in New England, assuming the Algonquin gas price, 7,800 Btu/kWh heat rate, and 100% availability. The results suggest that a typical gas-fired combined-cycle plant is able to earn positive gross margin during on-peak hours. The day-ahead and real-time spark spreads averaged \$4.86/MWh (day-ahead market) and \$2.75/MWh (real-time market), respectively, in the past quarter.[6]

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

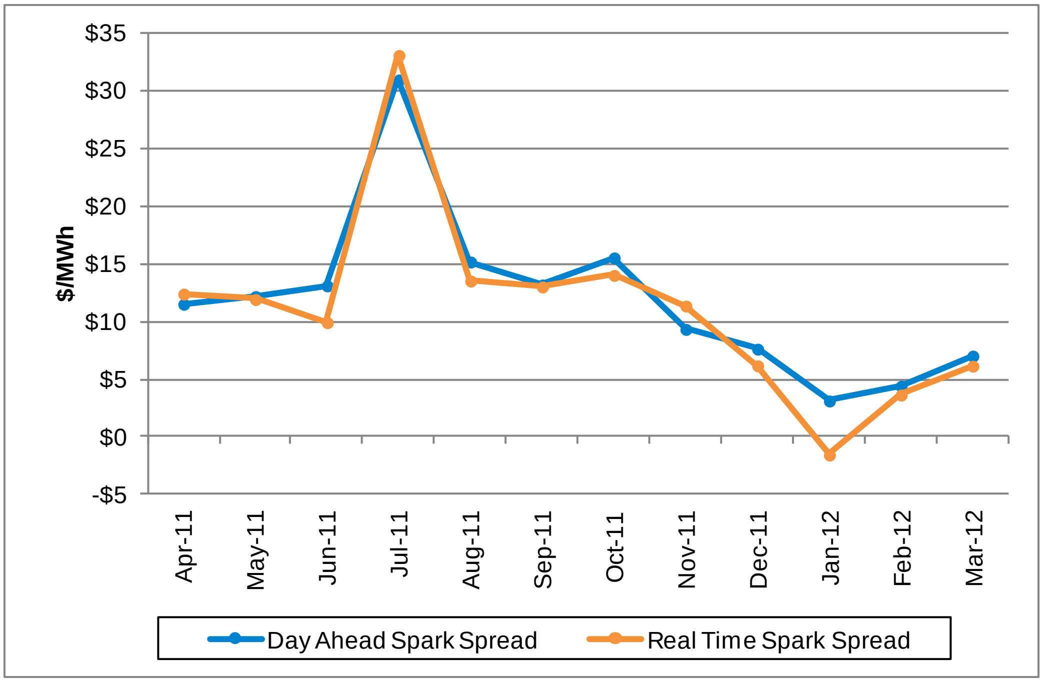


Figure 2-5: Estimated Spark Spreads, April 2011-March 2012.

2.4.2 Self-Scheduled Generation

Self-scheduled generators choose to sell specified quantities into the day-ahead market at the day-ahead market clearing price, rather than let the day-ahead market schedule the resource economically based on its supply offer. In the Reporting Period, day-ahead self-scheduled generation averaged 69.8% of day-ahead generation cleared. Day-ahead self-scheduled generation was up 11.5% when compared with Q4 2011. The increase in self-schedules in the Reporting Period compared with Q4 2011 is due, in part, to nuclear generation returning to service in the Reporting Period after being out of service for maintenance. Nuclear units typically self schedule in the day-ahead market. See Table 2-1.

Table 2-1
Day-Ahead Self Scheduled Generation as a Percent of Day-Ahead Generation Cleared, MWh

	Q1 2012	Q4 2011	% Change (Q4 2011 to Q1 2012)	Q1 2011	% Change (Q1 2011 to Q1 2012)
Day-Ahead Self Scheduled Generation	19,116,720	15,441,441	23.8%	20,457,915	-6.6%
Day-Ahead Cleared Physical Generation	27,390,580	26,478,620	3.4%	29,088,194	-5.8%
Percent	69.8%	58.3%	11.5%	70.3%	-0.5%

2.4.3 Virtual Transactions

In 2011, the IMM observed that the volume of submitted and cleared virtual transactions have stabilized, albeit at lower levels than those observed in 2010. Overall, the IMM has noted that a number of participants have reduced their volume of virtual trading activity, or changed their bidding strategies. See Table 2-2.

Table 2-2
Virtual Transaction Outcomes

	Q1 2012	Q4 2011	% Change (Q4 2011 to Q1 2012)	Q1 2011	% Change (Q1 2011 to Q1 2012)
Incs Submitted (MWh)	5,286,088	4,848,920	9%	5,141,285	3%
Incs Cleared (MWh)	668,293	669,290	0%	1,096,382	-39%
Decs Submitted (MWh)	2,294,916	2,800,537	-18%	3,221,203	-29%
Decs Cleared (MWh)	471,797	856,478	-45%	1,092,477	-57%

The decline in the cleared virtual bids and offers appears to have been caused by the changed composition of participants engaging in virtual transactions. The IMM has observed that the total number of participants has declined by close to 20%, compared to Q1 2011. The composition of participants has also changed. The IMM observed a decline in the purely financial players and an increase in the participants with physical assets in the energy market. The participants who engaged in hedging their physical energy positions lowered the average transaction size consistent with the lower load levels observed. There were fewer cleared virtual transactions (both bids and offers) at the Hub, which provides further evidence that the level of participation by financial participants has gone down.

2.4.3.1 Price Setting by Virtual Transactions

In the Reporting Period, virtual supply offers set price approximately 20% of the time, and virtual demand bids set price about 8% of the time in the Day-Ahead market. See Table 2-3.

Table 2-3
Virtual Transaction Price Setting in the Day-Ahead Market

	Q1 2012 (hours)	Q4 2011 (hours)	% Change (Q4 2011 to Q1 2012)	Q1 2011 (hours)	% Change (Q1 2011 to Q1 2012)
Virtual Supply Offers	431	221	95%	290	48%
Virtual Demand Bids	179	280	-36%	422	-58%

2.4.3.2 Virtual Transaction Gross Profitability

During the Reporting Period, the gross profitability of virtual positions totaled $783,870. See Table 2-4. Of the 40 participants submitting virtual transactions during the Reporting Period, 23 participants realized a gross profit on virtual instruments; the remaining 17 participants realized a gross loss. Of the participants which realized gross losses, 51% of the gross losses were attributable to one participant that serves physical load and uses virtual transactions as a financial hedging tool.

2.4.3.3 NCPC Charges to Virtual Transactions

During the Reporting Period, the gross profitability of virtual positions totaled $783,870 and the total allocation of real-time NCPC charges to these positions totaled $1.36 million. Net of real-time NCPC-related transaction costs, virtual positions realized a total loss of $575,425. See Table 2-4.

Table 2-4
Net Revenues and Real-Time NCPC Charges to Virtual Transactions by Quarter

Virtual Instrument	Revenues and Charges	Q1 2012	Q4 2011	Q1 2011
Demand	Net Revenue (before NCPC Charges)	-833,549	-686,233	-25,034
	Allocated Real-Time NCPC Charges	-567,082	-1,049,818	-2,700,323
	Revenue net of RT NCPC Charges	***-1,400,631***	***-1,736,051***	***-2,725,358***
Supply	Net Revenue (before NCPC Charges)	1,617,419	873,801	209,712
	Allocated Real-Time NCPC Charges	-792,213	-943,657	-3,109,490
	Revenue net of RT NCPC Charges	***825,206***	***-69,856***	***-2,899,779***
Total	Net Revenue(before NCPC Charges)	783,870	187,568	184,678
	Allocated Real-Time NCPC Charges	-1,359,295	-1,993,475	-5,809,814
	Revenue net of RT NCPC Charges	***-575,425***	***-1,805,907***	***-5,625,136***

Virtual transactions in the Day-Ahead Energy Market play an important function, generally increasing liquidity, improving commitment, and limiting market power. Virtual positions act to converge the day-ahead and real-time prices, and, in so doing, reduce the need for supplemental commitments in real-time and the NCPC costs associated with these positions. The IMM has recommended that the ISO consider revising the market rules that allocate Real-Time NCPC charges to virtual transactions. The ISO is evaluating this recommendation.

2.4.4 Reliability Commitments

Total Net Commitment Period Compensation (“NCPC”) payments during the Reporting Period totaled $10.2 million, as shown in Table 2-5. The majority of the NCPC incurred during the reporting period was economic (also called “first contingency”) NCPC. Economic NCPC is the difference between the cost of committing and operating a generating resource to meet capacity and energy needs in the day-ahead and real-time markets and the energy revenues the resource realizes during the market day. Most economic NCPC is associated with generating resource operation in real-time and is paid to resources that operate at Economic Minimum for some portion of their minimum run time.

Table 2-5
Total NCPC Payments by Quarter and Category

NCPC Category	Q1 2012	Q4 2011	Q1 2011
Economic and First Contingency Payments	$7,249,722	$9,219,489	$20,714,709
Second Contingency Payments	$1,041,519	$2,890,329	$1,386,323
Voltage Payments	$1,843,347	$2,034,155	$2,120,786
Distribution Payments	$57,918	$258,175	$137,322
Total	$10,192,506	$14,402,148	$24,359,140

In the Reporting Period, $1.0 million in NCPC payments were paid to "peaking" units with a minimum run time of one hour or less, down 67% from Q4 2011. Peaking units committed in real-time generally set price in the one or two pricing intervals during which they are needed to meet demand. During the balance of the hour, they may be dispatched down to their economic minimum, at which point they are ineligible to set price. Also, although the peaking resource is marginal and sets price during part of the hour, the hourly integrated price paid to the resource frequently is less than the cost of operating the resource across the hour, and the difference is paid as economic NCPC. See Figure 2-6.

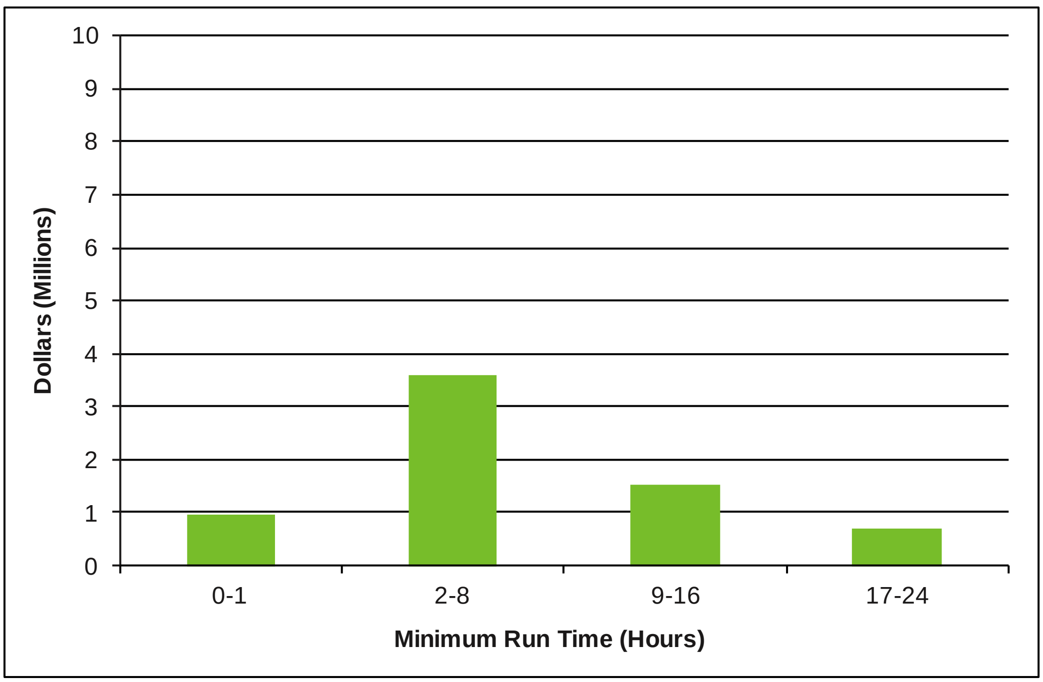


Figure 2-6: Economic NCPC Payments to Generators by Generator Minimum Run Time, Q1 2012.

2.4.5 Financial Transmission Rights

Thirty-four bidders participated in the January monthly auction, and 33 bidders participated in the February and March auctions. This is consistent with participant levels of participation in prior auctions. The three auctions combined totaled 109,802 MW of FTR transactions, worth a combined net value of $1.32 million. The amount distributed as Auction Revenue Rights ("ARRs") was $1.30 million.

2.5 Regulation Market

Total Regulation Market payments during the Reporting Period were $2.6 million. The average regulation price in the Reporting Period was $6.58/MWh, and the average hourly requirement was approximately 62 MW. See Table 2-6. The decline in regulation payments relative to Q4 2011 and Q1 2011 is attritutable to low natural gas prices in the Reporting Period.

Table 2-6
Regulation Market Outcomes

	Q1 2012	Q4 2011	% Change (Q4 2011 to Q1 2012)	Q1 2011	% Change (Q1 2011 to Q1 2012)
Capacity Credit	$973,588	$905,161	7.6%	$1,352,775	-28.0%
Opportunity Cost	$705,553	$940,034	-24.9%	$1,923,670	-63.3%
Service Credit	$931,231	$938,879	-0.8%	$1,365,406	-31.8%
Total Regulation Payments	$2,610,372	$2,784,074	-6.2%	$4,641,851	-43.8%

2.6 Forward Capacity Market

The net payments to resources with a Capacity Supply Obligation (“CSO”) totaled approximately $334.9 million in the Reporting Period. See Table 2-7. The total net payment is the sum of the following.

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

Table 2-7
FCM Payments and Charges, Q1 2012

Month	Capacity Zone	CSO MW	Supply Credit	PER Adjustment	Excess DR Penalties	Reliability Credit	Total Payment
January 2012	Rest-of-Pool	33,507	$111,618,814	$0	$0	$0	$111,618,814
February 2012	Rest-of-Pool	33,507	$111,618,814	$0	$0	$0	$111,618,814
March 2012	Rest-of-Pool	33,507	$111,618,814	$0	$0	$0	$111,618,814

2.6.1 Resource Performance

All capacity resources with a CSO are subject to performance evaluation during each obligation month of a commitment period. The performance of generation and import resources is evaluated during shortage events. There were no shortage events during the Reporting Period. The performance of demand resources is determined each month. The performance of active demand resources, such as Real-Time Demand Response, is determined based on the amount of load reduction achieved when the resource is dispatched during emergency actions (i.e., OP4) or audited. During the Reporting Period, there were no OP4 dispatch events and 34 audits. The performance of passive demand resources, such as On-Peak Demand Resources, is determined each month based on the amount of load reduction achieved in the month. See Table 3-8 in the Appendix for a system-wide summary of demand resource performance by type for the Reporting Period.

2.6.2 Reconfiguration Auctions and Bilateral Transactions

Participants can transfer and acquire capacity supply obligations through bilateral transactions and reconfiguration auctions.[7] Bilateral transactions and auction trades can be for either one month or the entire one-year capacity commitment period, and volumes exchanged in monthly bilateral trades and the monthly reconfiguration auctions vary from month to month.

An annual reconfiguration auction yielded 623 MW of cleared CSO at a price of $0.55/kW-Month; there were 3,117 MW of Annual Bilateral Trades for the 2012/2013 Capacity Commitment Period, with an average trade price of $2.32/kW-Month. See Table 2-8.

Table 2-8
Annual Reconfiguration Auction Results

Auction	Annual Reconfiguration Auction		Annual Bilateral Trades (Capacity Period 2012/2013)	
	Demand Bids and Supply Offers Cleared (MW)	Clearing Price ($/kW-month) *	Trades (MW)	Average Trade Price ($/kW-Month)
Third ARA Bilateral Period 1	622.99	$0.55	3117	$2.32

Table 2-9 shows the results of monthly reconfiguration auctions and bilateral transactions that occurred during the Reporting Period, for the capacity delivery periods indicated in the table. Reconfiguration auctions have not yet taken place for all months in the capacity period.

[7] RTEGs cannot participate in reconfiguration auctions. RTEGs can only acquire CSOs from other RTEGs (not from any other resource types) in bilateral trades. Capacity imports can only acquire CSOs from other imports on the same path.

Table 2-9
Monthly Reconfiguration Auctions and Bilateral Trades

Obligation Month	Monthly Reconfiguration Auctions		Bilateral Transactions	
	Cleared CSO MW	Auction Clearing Price ($/kW-Month)	Traded CSO MW	Average Trade Price ($/kW-Month)
March-12	0	$0.20	540	$0.72
April-12	1	$0.18	396	$0.78
May-12	71	$0.15	539	$0.91

2.7 Mitigation

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 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. There was one Day-Ahead Energy Market mitigation event and no Real-Time Energy Market mitigation events during the Reporting Period.[8] There were eighteen Real-Time NCPC mitigation events and no Day-Ahead NCPC mitigation events during the Reporting Period. There were no participants that had FTR revenues reduced pursuant to the FTR revenue capping provisions of Market Rule 1, Appendix A, Section III.A.8.4.

2.8 Behavior Requiring Referral to FERC

Market Rule 1, Appendix A, provides the IMM with a limited set of circumstances for applying mitigation without additional FERC involvement: energy market mitigation, NCPC mitigation, and FTR capping. When the IMM identifies other forms of potentially noncompetitive Market Participant behavior, Market Rule 1 requires the IMM to make a referral to the FERC.[9]

The IMM made three new non-public referrals to FERC in the Reporting Period. No referrals were closed in the Reporting Period. As of the end of the Reporting Period, there were seven open referrals made by the IMM before FERC.

[8] The process of NCPC mitigation relies on final settlements and therefore lags behind the market day when the mitigation thresholds were violated.

[9] More specifically, Section III.A19 of Appendix A to Market Rule 1 requires that the market monitor refer any "Market Violation," which includes any "tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies."

2.9 Administrative Price Corrections

Administrative price corrections were made in 11 occurrences in real-time during the Reporting Period. See Table 2-10. There were no revisions to day-ahead prices during the Reporting Period.

Table 2-10
Administrative Price Corrections

Reason	Number of Occurrences
Data error	0
Hardware/software scheduled outage	8
Hardware/software outage unscheduled	0
Software limitation	0
Software error	0
Dead bus logic	3

Section 3 Statistical Appendix

This section provides additional data supporting the analyses, conclusions and recommendations contained in this report.

3.1 Day-Ahead and Real-Time Energy Markets

Table 3-1 shows the quarterly average, minimum, and maximum hourly LMP values for the Reporting Period for the Hub, eight load zones, and the six external nodes that are priced in New England.

Table 3-1
Hourly LMP Statistics by Location, Q1 2012, All Hours

Location/Zone	LMP ($/MWh)					
	Avg. DA	Min. DA	Max. DA	Avg. RT	Min. RT	Max. RT
Internal Hub	$32.59	$11.02	$124.29	$30.90	$0.00	$209.86
Maine Load Zone	$32.57	$10.00	$121.14	$30.09	$0.00	$194.31
New Hampshire Load Zone	$32.13	$10.75	$122.02	$30.44	$0.00	$204.26
Vermont Load Zone	$32.44	$11.01	$118.76	$30.64	$0.00	$207.34
Connecticut Load Zone	$32.98	$11.12	$123.99	$31.15	$0.00	$213.65
Rhode Island Load Zone	$32.62	$11.12	$122.32	$30.89	$0.00	$209.61
SEMASS Load Zone	$32.55	$11.03	$124.14	$30.92	$0.00	$210.39
WCMASS Load Zone	$33.07	$11.11	$124.17	$31.08	$0.00	$210.42
NEMA/Boston Load Zone	$32.37	$10.97	$123.80	$30.76	$0.00	$209.15
NB-NE External Node	$32.17	$9.85	$117.20	$29.84	$0.00	$181.52
NY-NE AC External Node	$32.53	$11.11	$121.16	$30.58	$0.00	$207.95
HQ Phase I/II External Node	$31.65	$10.76	$120.53	$30.07	$0.00	$204.05
Highgate External Node	$30.08	$10.38	$108.20	$28.58	$0.00	$192.03
Cross Sound Cable External Node	$32.94	$11.11	$123.96	$31.49	$0.00	$216.69
Norwalk Harbor - Northport Cable External Node	$32.96	$11.14	$123.96	$31.19	$0.00	$215.32

Figure 3-1 and Figure 3-2 show the day-ahead and real-time system electric energy prices for New England during the first quarters of 2011 and 2012 as duration curves, with prices ordered from highest to lowest.[10]

[10] 2012 data has an extra 24 hours because of February 29.

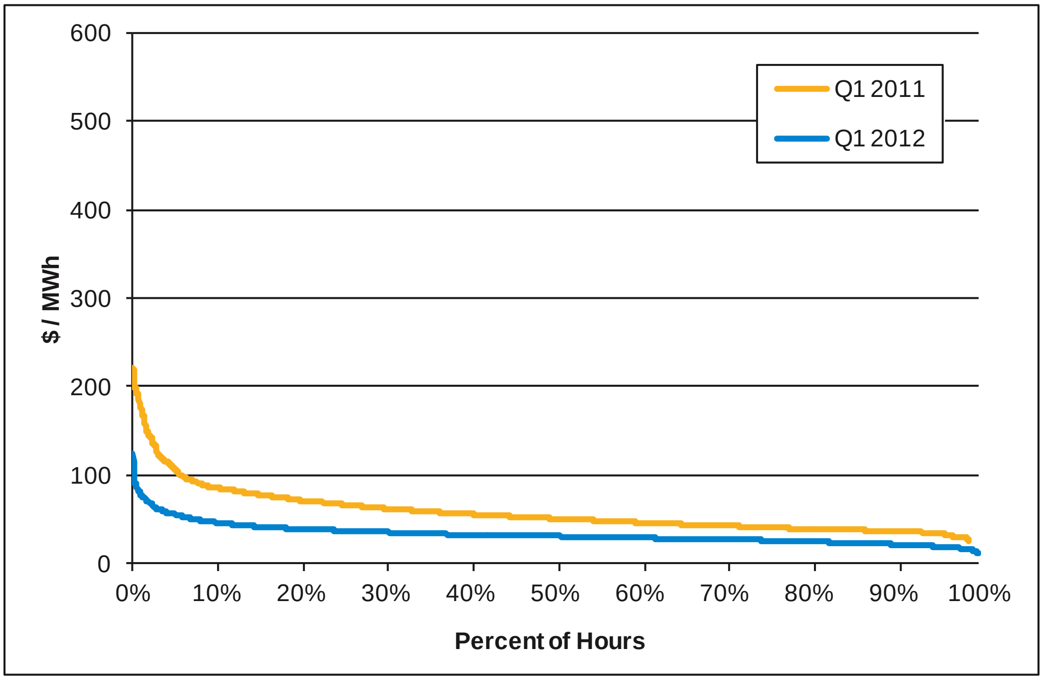


Figure 3-1: New England Hourly Day-Ahead System Price Duration Curves, Q1 2012 and Q1 2011.

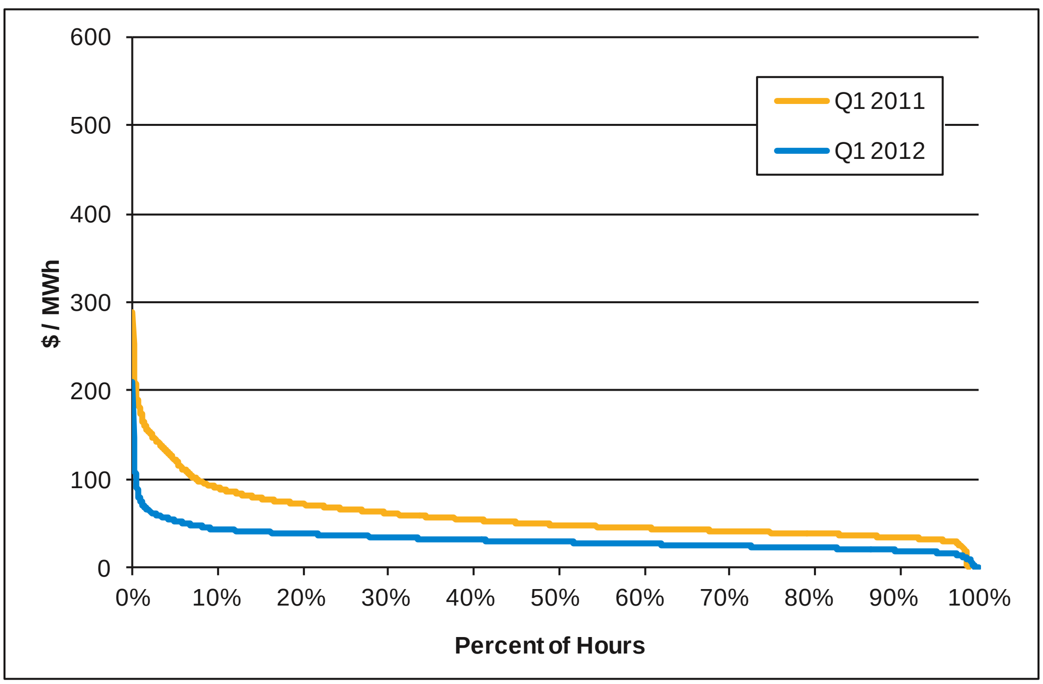


Figure 3-2: New England Hourly Real-Time System Price Duration Curves Q1 2012, and Q1 2011.

Table 3-2 below compares day-ahead self-scheduled generation as a percentage of Day-Ahead Load Obligation (or "DALO") for the Reporting Period, Q4 2011 and Q1 2011. In the Reporting Period, day-ahead self-scheduled generation averaged 61% of DALO. Day-ahead self-scheduled generation in the Reporting Period was up 25% when compared with Q4 2011.

Table 3-2
Day-Ahead Self Scheduled Generation as a Percent of Day-Ahead Load Obligation, MWh

	Q1 2012	Q4 2011	% Change (Q4 2011 to Q1 2012)	Q1 2011	% Change (Q1 2011 to Q1 2012)
Day-Ahead Self Schedules	19,378,857	15,451,958	25%	20,753,072	-7%
Day-Ahead Load Obligation	31,782,130	30,805,850	3%	33,974,272	-6%
Percent	61%	50%	22%	61%	0%

Over all Reporting Period hours, the average DALO was approximately 96% of RTLO for all zonal load obligations. This percentage varied across zones. All load zones cleared at least 89% of RTLO in the Day-Ahead Energy Market. See Figure 3-3.

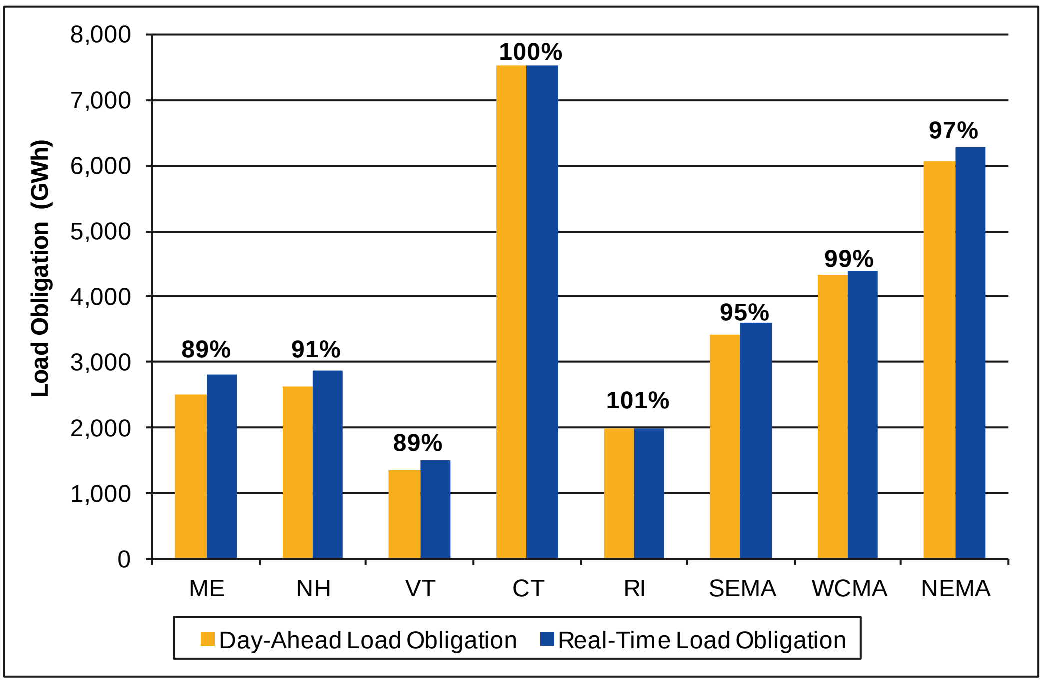


Figure 3-3: Zonal Load Obligation, Day-Ahead vs. Real-Time, Q1 2012.

Virtual profit (gross of NCPC charges) and the average Day-Ahead premium at the hub is presented in Figure 3-4 below.

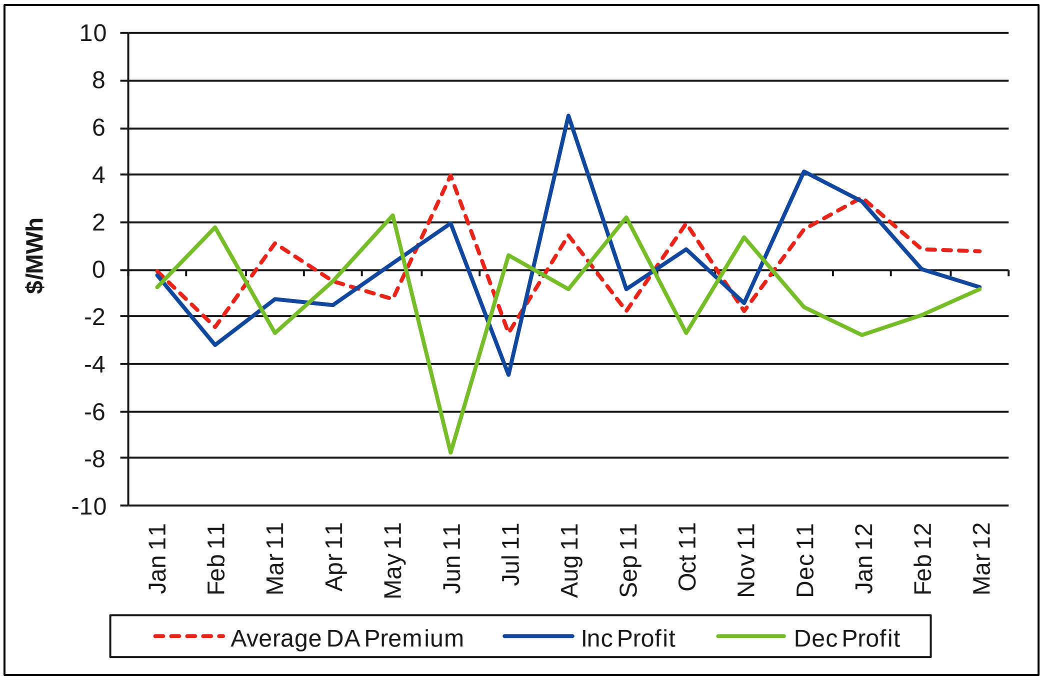


Figure 3-4: Virtual Profit and Average Day-Ahead Premium at the Hub (all hours), January 2011-March 2012.

Figure 3-5 and Figure 3-6 show the daily total of the hourly submitted and cleared virtual transactions over the Reporting Period.

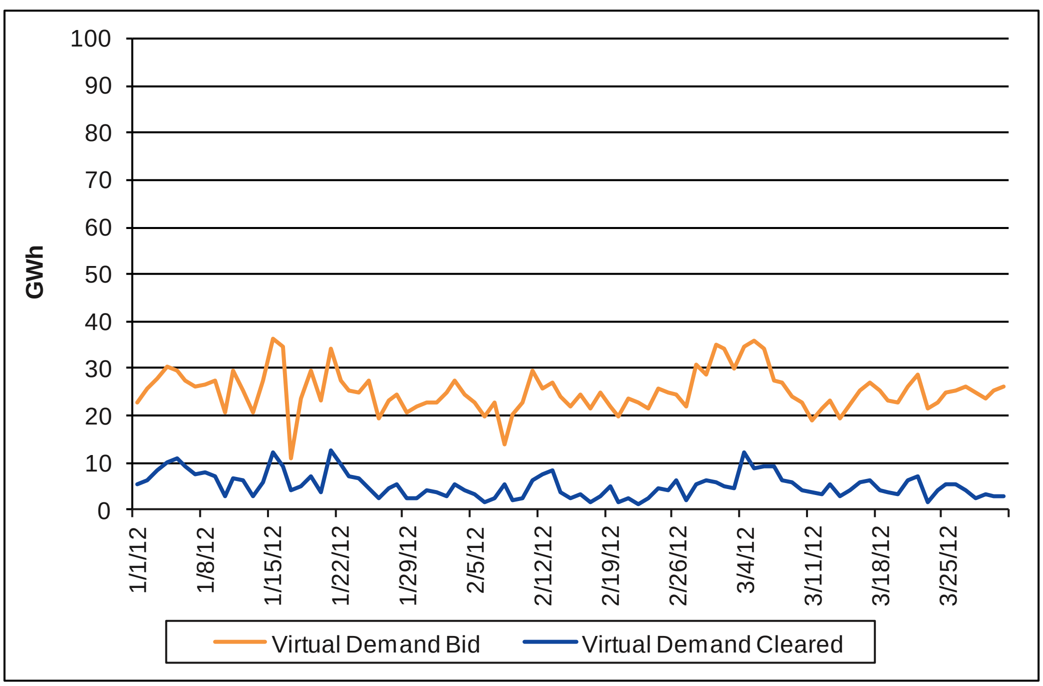


Figure 3-5: Submitted and Cleared Virtual Demand Daily Totals, Q1 2012.

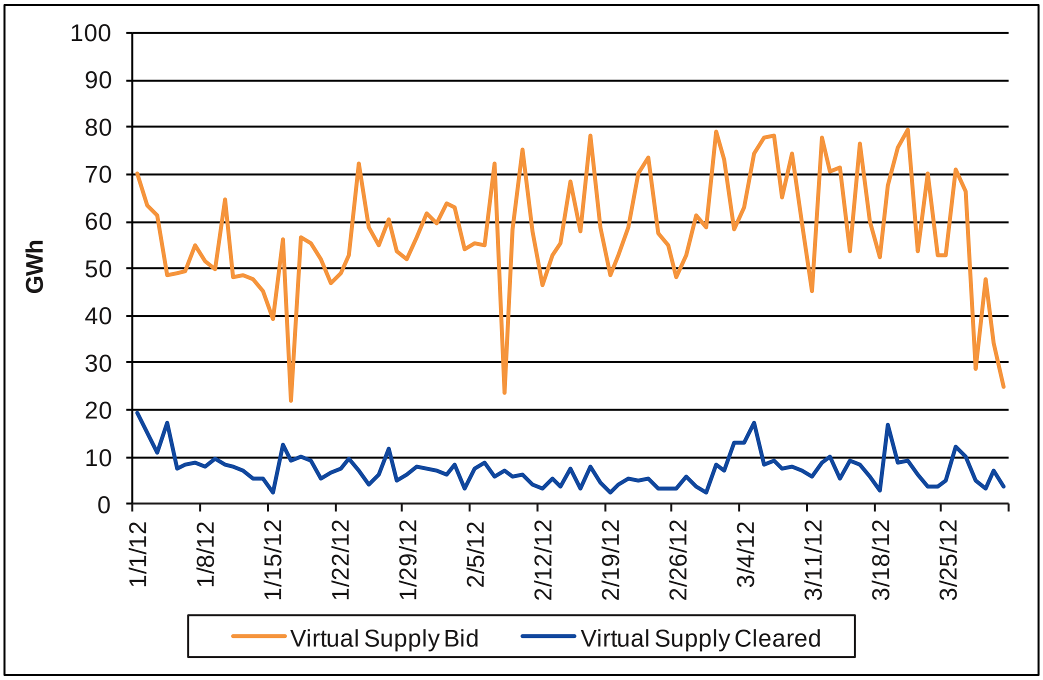


Figure 3-6: Submitted and Cleared Virtual Supply Daily Totals, Q1 2012.

Figure 3-7 below shows submitted and cleared virtual supply offer volumes.

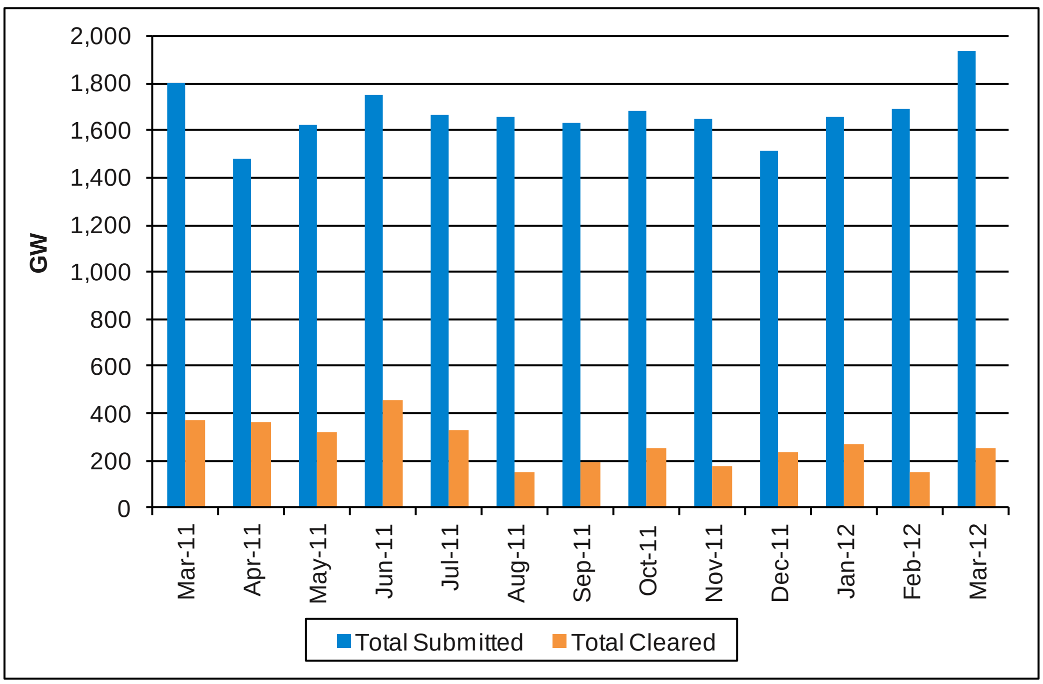


Figure 3-7: Submitted and Cleared Virtual Supply Offer Volumes, March 2011 – March 2012.

Figure 3-8 below presents submitted and cleared virtual demand bids.

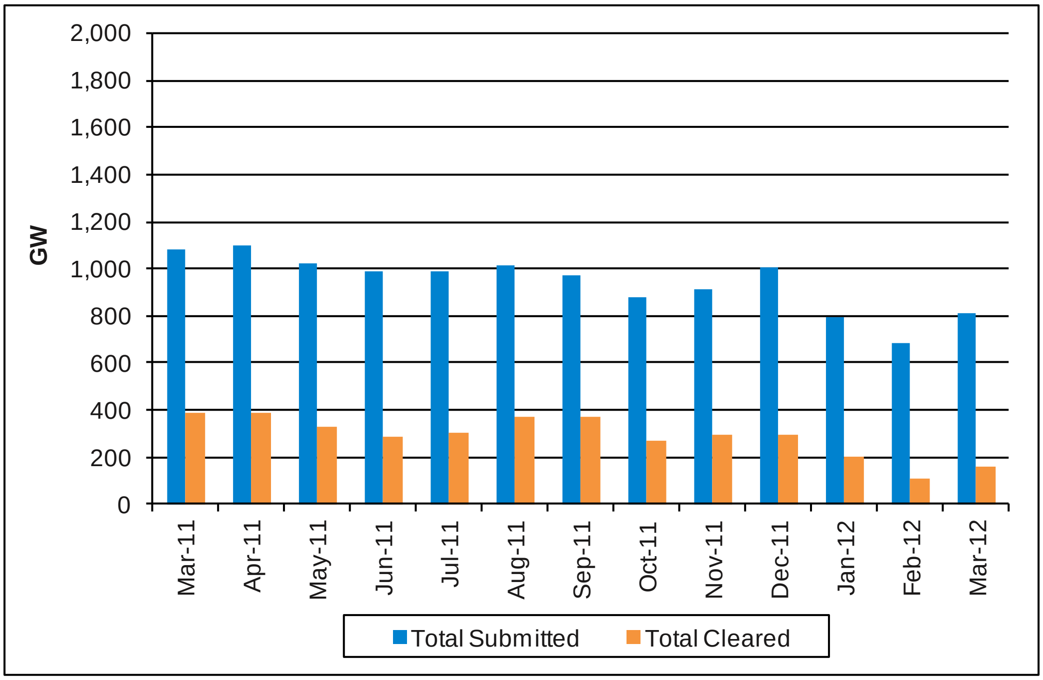


Figure 3-8: Submitted and Cleared Virtual Demand Bids, March 2011 – March 2012.

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. Table 3-3 shows real-time self-scheduled generation as a percentage of total electric energy for minimum generation hours.

Table 3-3
Real-Time Self-Schedules and Total Energy for Minimum Generation Emergency Hours, MWh

	Q1 2012	Q4 2011	% Change (Q4 2011 to Q1 2012)	Q1 2011	% Change (Q1 2011 to Q1 2012)
Real-Time Min Gen Self Schedules	168,231	163,489	3%	84,098	100%
NEL, Min Gen Hours Only	210,608	223,097	-6%	100,153	110%
Percent	80%	73%	9%	84%	-5%

3.2 Fuel Prices

Table 3-4 shows summary price statistics for selected fuels over the Reporting Period.

Table 3-4
Fuel Price Statistics for Q1 2012, $/MMBtu

Fuel Type	Average Daily Price	Minimum Daily Price	Maximum Daily Price
Natural Gas	$3.90	$2.16	$9.83
No. 6 Oil 1%	$17.86	$15.92	$19.34
No.2 Oil	$22.68	$21.15	$23.85
Low Sulfur Coal	$2.59	$2.34	$2.80
High Sulfur Coal	$2.46	$2.28	$2.64

3.3 Weather

Figure 3-9 shows statewide ranks for temperature for the Reporting Period, obtained from the National Oceanographic and Atmospheric Administration ("NOAA").[11]

[11] http://www.ncdc.noaa.gov/sotc/service/national/Statewidetrank/201201-201203.gif

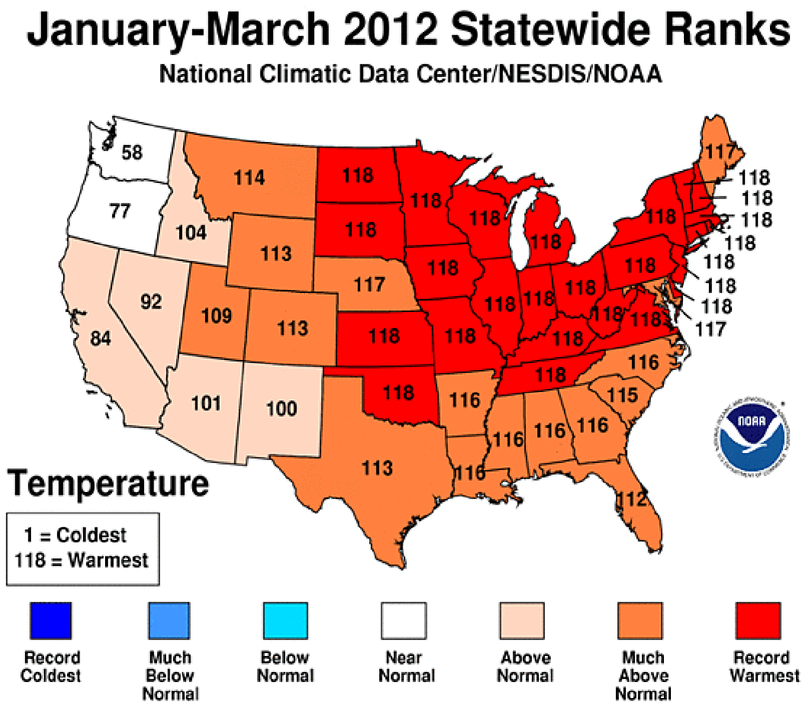


Figure 3-9: Statewide Ranks for Temperature, Reporting Period 2012.
(**Source:** NOAA)

3.4 Demand for Electricity

Table 3-5 shows that actual net energy for load (or "NEL," a measure of total energy use in New England) decreased by 4.2% in the Reporting Period, while weather normalized NEL decreased by 1.0% when compared to the first quarter of 2011. The peak demand for the Reporting Period occurred on January 4, hour ending 18. Peak demand was 5.5% below the peak of 21,053 MW for the first quarter 2011.

Table 3-5
Net Energy for Load

	(GWh)			
	Q1 2012	Q1 2011	Diff.	%Chg.
Recorded NEL (GWh)	31,436	32,798	-1,362	-4.2%
Normalized NEL (GWh)	32,187	32,523	-336	-1.0%
Recorded peak demand (MW)	19,905	21,053	-1,148	-5.5%

Figure 3-10 presents New England hourly load duration curves for Q1 2012 and Q1 2011.

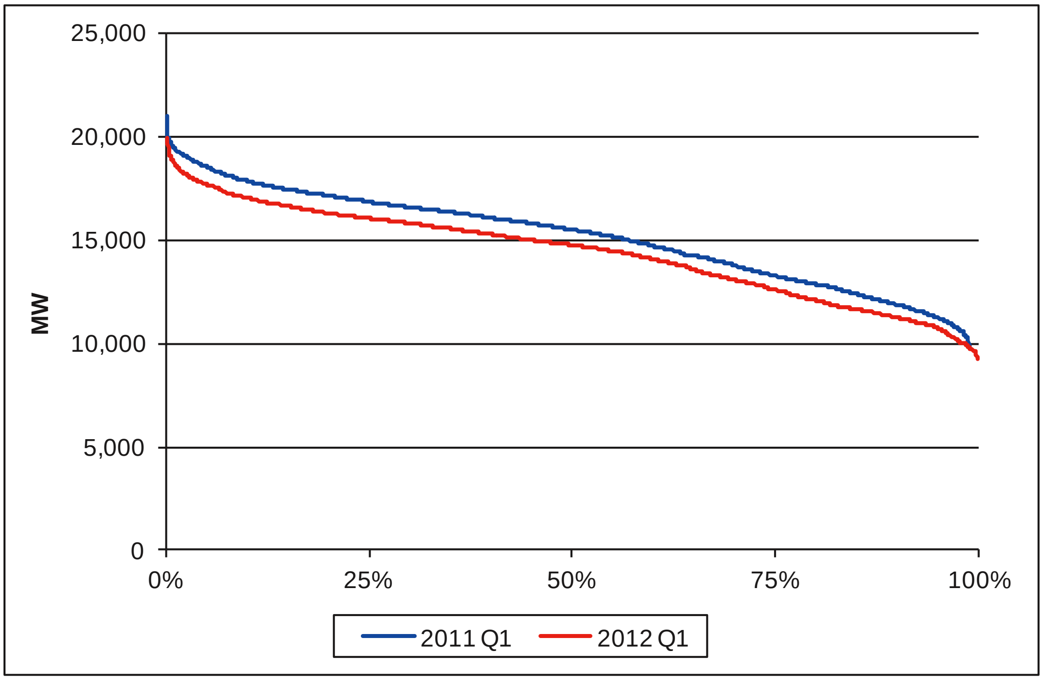
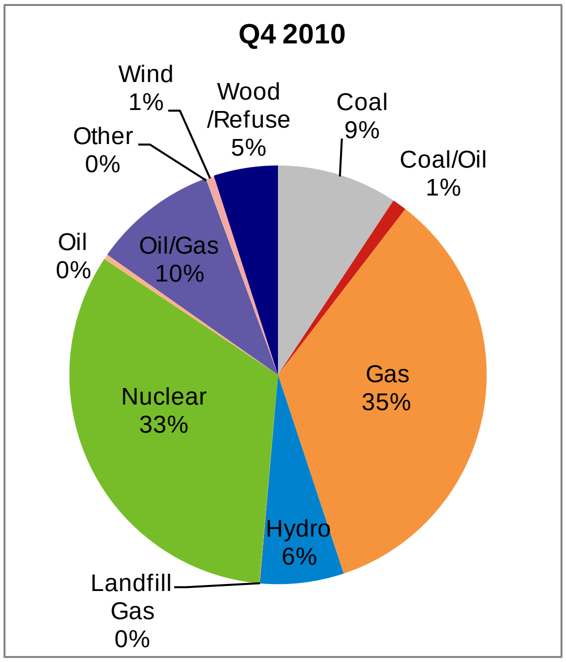


Figure 3-10: New England Hourly Load Duration Curves, Q1 2011 and Q1 2012.

3.5 Supply of Electricity

Figure 3-11 compares generation by fuel type as a percentage of total generation for Q1 2011 and Q1 2012.



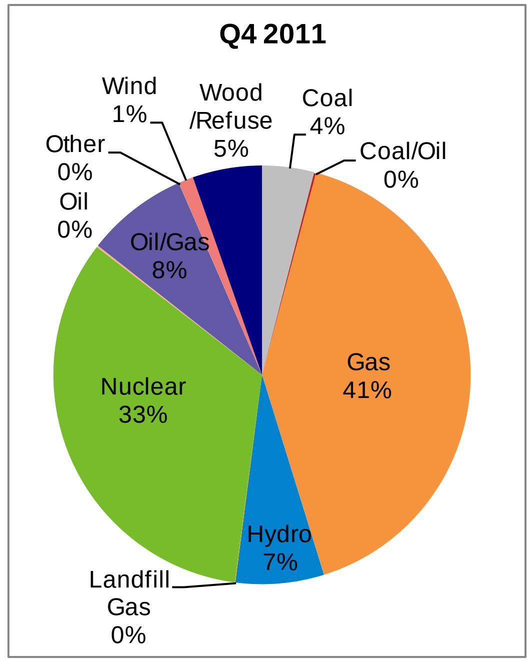


Figure 3-11: Percent of Generation by Fuel Type, Q1 2011 and Q1 2012.

3.6 Demand Response Program and Demand Resource Enrollments

Table 3-6 and Table 3-7 present enrollment in demand response programs by zone and by program under the Forward Capacity Market. Table 3-8 presents demand response performance for the Reporting Period.

Table 3-6
Demand Resource Asset Enrollment
by Demand Resource Type and Load Zone (as of April 1, 2012)

Zone	April 1, 2012 – Enrolled Amount (MW)				
	Real-Time Demand Response Resource	Real-Time Emergency Generation Resource	On-peak demand resource	Seasonal Peak Demand Resource	Grand Total
ME	356.1	24.4	66.5	0.0	447.0
NH	74.3	40.7	58.2	0.0	173.2
VT	84.8	15.4	46.2	0.0	146.4
CT	265.2	296.5	98.8	316.8	977.3
RI	54.7	39.8	47.3	0.8	142.6
SEMA	70.8	47.4	65.1	3.3	186.6
WCMA	162.5	68.1	74.1	38.5	343.2
NEMA	90.8	82.7	107.8	0.0	281.3
Total	1159.2	615.0	564.0	359.4	2697.6

Table 3-7
Real-Time Price Response Program* (“RTPR”) and
Day-Ahead Load Response Program (“DALRP”) Enrollment (as of April 1, 2012)**

Zone	April 1, 2012 – Enrolled (MW)	
	RTPR	DALRP
ME	0.0	115.2
NH	4.1	8.1
VT	1.8	12.1
CT	2.3	45.5
RI	11.9	11.7
SEMA	7.6	13.8
WCMA	13.5	18.5
NEMA	17.1	15.1
Total	58.3	240.0

* Displayed data is the enrolled amount of assets in the RTPR.

**Displayed data is the Day-Ahead Maximum Interruptible Capacity of assets that are active in the DALRP.

Table 3-8
Demand Response Performance, Q1 2012

Month	DR Type	Perf. Hrs	CSO MW	Capacity Value[12] (MW)	Negative Capacity Variance [13] (MW)	Positive Capacity Variance[14] (MW)	Perf. Penalty ($)	Perf. Incentive ($)
Jan 12	On peak	42	616.98	1,256.41	-2.13	641.56	-6,650	576,922
Jan 12	Real time	0	648.62	547.58	-167.76	66.72	-523,240	53,429
Jan 12	Real time EG	0	435.66	338.57	-109.34	12.26	-269,752	7,767
Jan 12	Seasonal peak	7	259.38	461.06	0	201.69	0	161,524
Feb 12	On peak	0	616.9	1,219.66	-2.96	605.71	-9,358	356,587
Feb 12	Real time	0	625.71	556.24	-103.24	33.76	-321,996	17,632
Feb 12	Real time EG	0	419.87	384.66	-55.55	20.33	-137,030	8,398
Feb 12	Seasonal peak	0	259.38	433.27	-1.94	175.84	-6,063	91,831
Mar 12	On peak	0	616.15	1,219.66	-2.75	605.79	-8,727	339,269
Mar 12	Real time	0	616.2	556.24	-96.62	36.65	-301,352	18,210
Mar 12	Real time EG	0	422.7	384.66	-54.85	16.8	-135,305	6,603
Mar 12	Seasonal peak	0	259.38	433.27	-1.94	175.84	-6,063	87,365

[12] The *Capacity Value* is the value, in MW, of the monthly demand response value, times the reserve factor, times a Transmission and Distribution Loss factor.

[13] A *Capacity Variance* is defined as the Capacity Value minus the CSO. A *Negative Capacity Variance* occurs when a resources capacity value is less than its CSO, resulting in a penalty.

[14] A *Capacity Variance* is defined as the Capacity Value minus the CSO. A *Positive Capacity Variance* occurs when a resources capacity is more than its CSO, resulting in an incentive payment.

3.7 Financial Transmission Rights

Table 3-9 compares maximum, minimum and average clearing price statistics for auctions in the Reporting Period. On-peak, off-peak and combined calculations are shown. Annual auction values have been converted to $/MW-Month for comparison.

Table 3-9
FTR Auction Clearing Price Statistics

	Auction Clearing Price ($/MW-Month)						
Auction Name	**Avg. Combined**	**Avg. On-Peak**	**Avg. Off-Peak**	**Max On-Peak**	**Min On-Peak**	**Max Off-Peak**	**Min Off-Peak**
Jan-Dec 2012 LT	$64.58	$87.80	$41.36	$706.80	$-291.90	$179.20	$-57.19
January 2012	$59.91	$61.91	$57.90	$560.80	$-381.02	$294.94	$-140.71
February 2012	$51.29	$57.80	$44.78	$327.52	$-352.95	$214.54	$-105.26
March 2012	$35.95	$35.20	$36.69	$513.83	$-249.22	$187.33	$-99.34

FTR clearing price statistics are based on actual FTR awards. A negative price indicates that the awardees were paid to take the FTR obligation. This occurs when participants purchase FTRs in the opposite direction of expected congestion, such as from Connecticut (import-constrained) to Maine (export-constrained).

Table 3-10 shows the total distribution of ARR dollars to the various zones for each month. The annual auction revenue presented for comparison is the annual value divided by 12 for a monthly value.

Table 3-10
ARR Award Allocation by Zone ($), Q1 2012

Month	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
January 2012	$324,967	$20,814	$31,405	$657,782	$12,324	$25,994	$166,706	$124,407
February 2012	$245,958	$20,977	$33,142	$594,872	$10,966	$25,563	$144,496	$97,079
March 2012	$168,590	$19,534	$31,051	$533,889	$10,723	$24,353	$160,383	$96,194

Table 3-11 lists the highest priced sink-source combinations as purchased in the monthly auctions during the Reporting Period.

Table 3-11
Top Five Highest Priced FTR Sink-Source Combinations, Monthly Auctions

Auction	On-Peak Auction		
	Source	Sink	Award Price
January 2012	LD.E_SPRFLD115	LD.BRECKWOD115	$941.82
	LD.E_SPRFLD115	LD.PIPER 115	$619.80
	LD.HAWKINS 115 110A LD	LD.CLINTON 115	$544.57
	LD.HAWKINS 115 110A LD	LD.W_SPRFLD13.8	$544.57
	LD.HAWKINS 115 110A LD	UN.W_SPRFLD13.8SPRF	$544.57
February 2012	LD.E_SPRFLD115	LD.BRECKWOD115	$680.47
	LD.E_SPRFLD115	UN.W_SPRFLD13.8WS10	$604.13
	LD.E_SPRFLD115	UN.W_SPRFLD13.8WSP3	$604.13
	LD.ORCHARD 115	LD.BRECKWOD115	$552.00
	LD.E_SPRFLD115	UN.SHAWINGN13.8MPWR	$397.94
March 2012	LD.E_SPRFLD115	LD.BRECKWOD115	$613.61
	LD.ORCHARD 115	LD.BRECKWOD115	$558.66
	LD.E_SPRFLD115	UN.W_SPRFLD13.8WS10	$554.00
	LD.E_SPRFLD115	UN.W_SPRFLD13.8WSP3	$554.00
	LD.ORCHARD 115	UN.W_SPRFLD13.8WS10	$499.05

Table 3-12 shows auction revenue distributed by category. The annual auction revenue presented for comparison is the annual value divided by 12 for a monthly value.[15]

[15] Starting January 2012, 'Qualified Upgrade Awards' have been converted to 'Incremental Auction Revenue Rights' (IARR.)

Table 3-12
ARR Allocations, Q1 2012

Month	Net FTR Auction Revenue	ARR Allocation ($)						
		Excepted Trans. Dollars	NEMA Contract Dollars	Load Share Dollars	Annual Firm Trans. Svc. Dollars	Total ARR Allocation	IARR Dollars	Total Auction Revenue Distrib. (IARR+ QUA)
January 2012	$-1,455,573	$36	$7,096	$1,357,268	$0	$1,364,400	$91,174	$1,455,573
February 2012	$-1,243,645	$19	$3,396	$1,169,639	$0	$1,173,054	$70,590	$1,243,645
March 2012	$-1,112,905	$0	$6,027	$1,038,690	$0	$1,044,717	$68,187	$1,112,905

FTR holders are paid through the Transmission Congestion Revenue Balancing Fund. Monthly revenues, target allocations, and actual allocations paid for the Reporting Period are shown in Table 3-13. The first four columns show the sources of revenue paid into the fund for each month of the Reporting Period. The next two columns show the positive target allocations that are owed to FTR holders and the shortfall or surplus for the month. The final column shows the percentage of the target allocation that is actually paid in each month.

Table 3-13
Congestion Revenue Fund, Q1 2012

Month	Fund Adjustment	Day-Ahead Congestion Revenue	Real-Time Congestion Revenue	Negative Target Allocation	Positive Target Allocation	Monthly Fund Surplus or Shortfall	Percent Positive Allocation Paid
January 2012	($68.13)	$342,201.61	($2,735.57)	$89,342.56	($437,993.71)	($9,253.24)	97.89%
February 2012	$187.25	$601,009.77	$54,299.01	$205,247.16	($1,237,398.34)	($376,655.15)	69.56%
March 2012	$542.57	$749,330.56	$8,543.91	$797,833.70	($1,595,361.50)	($39,110.76)	97.55%

3.8 Forward Reserve Market

Table 3-14 summarizes forward reserve credit, penalties, and net forward credit for all forward reserve resources, as well as all real-time reserve credit, by month for the Reporting Period. The total net forward reserve credit for the Reporting Period was $3.28 million, which includes $3.44 million in forward reserve credit and $156,523 in total failure to reserve and failure to activate penalties. The net Real-Time Reserve Credit for the Reporting Period was $916,273. No Forward Reserve Obligation Charges were reported in the Reporting Period.

Table 3-14
Monthly Total Forward Reserve Market Payments and Penalties, Q1 2012

Month	Forward Credit	Total Penalties	Net Forward Credit	Real-Time Credit	Forward Reserve Obligation Charge	Net Real-Time Credit
January 2012	$1,141,462	$-58,085	$1,083,376	$373,736	$0	$373,736
February 2012	$1,165,315	$-22,251	$1,143,064	$209,543	$0	$209,543
March 2012	$1,130,162	$-76,186	$1,053,976	$332,994	$0	$332,994
Total	*$3,436,939*	*$-156,523*	*$3,280,416*	*$916,273*	*$0*	*$916,273*

3.9 Real-Time Reserve Prices

Table 3-15 shows, by reserve zone, the average five-minute-interval Real-Time Reserve Clearing Prices during intervals with nonzero prices and the percentage of nonzero price intervals for the Reporting Period. Pricing and the amount of nonzero pricing intervals are quite similar across reserve zones and products for the Reporting Period; the relatively low frequency of nonzero pricing intervals indicates that there were few binding constraints during the review period.

Table 3-15
Real-Time Reserve Clearing Prices for Nonzero Price Intervals, Q1 2012

	TMSR		TMNSR		TMOR	
Reserve Zone	Price ($/MWh)	% Nonzero Intervals	Price ($/MWh)	% Nonzero Intervals	Price ($/MWh)	% Nonzero Intervals
CT	19.52	3.04%	100.82	0.03%	100.00	0.03%
NEMA/Boston	19.52	3.04%	100.82	0.03%	100.00	0.03%
ROS	19.52	3.04%	100.82	0.03%	100.00	0.03%
SWCT	19.52	3.04%	100.82	0.03%	100.00	0.03%

3.10 Supplemental Commitments

Figure 3-12 shows the monthly minimum, average, and maximum capacity scheduled after the clearing of the Day-Ahead Energy Market at economic minimum for the peak hour.

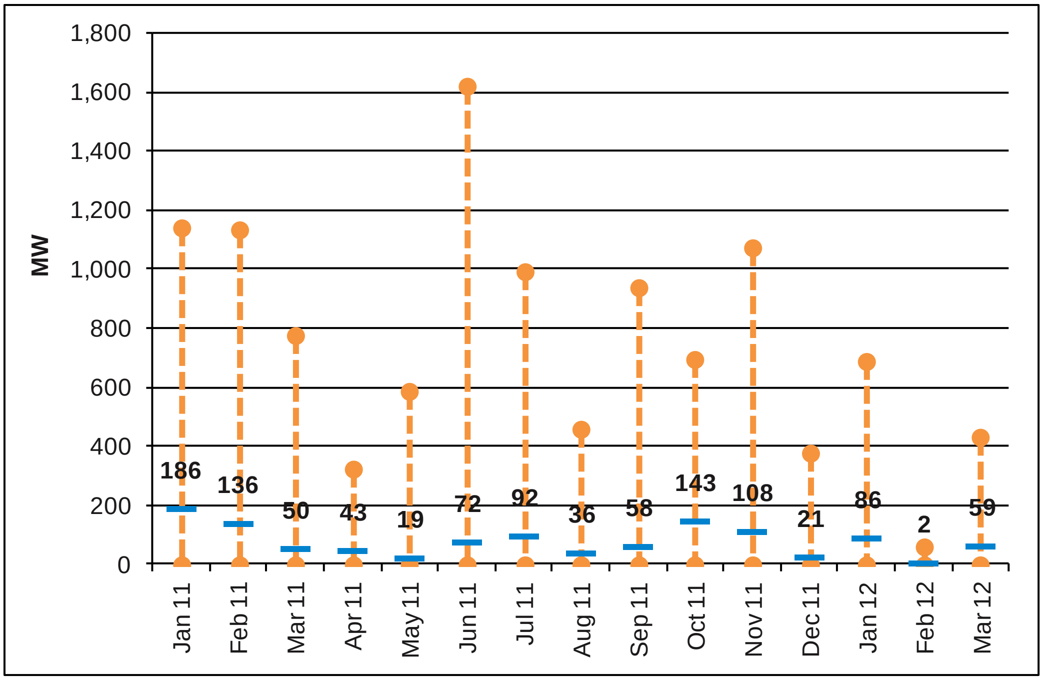


Figure 3-12: Minimum, Average, and Maximum Capacity Committed at Economic Minimum for the Peak Hour after Day-Ahead by month, January 2011 – March 2012.

Table 3-16 shows total generation from resources receiving supplemental commitments and NCPC as a percent of total net energy for load. Table 3-17 presents total local second contingency protection NCPC payments by load zone for the Reporting Period.

Table 3-16
Total Generation from Supplemental Reliability Commitments Paid NCPC, MWh, by Type

Month	Second Contingency	Voltage	Distribution	Economic and 1st Contingency	Total	New England Net Energy For Load	% of Total Energy
January 2012	3,959	10,257	15	49,443	63,674	11,255,123	0.6%
February 2012	1,947	2,159	221	14,123	18,450	10,089,369	0.2%
March 2012	29,193	0	0	70,497	99,690	10,092,191	1.0%
Quarter Total	*35,098*	*12,416*	*237*	*134,062*	*181,814*	*31,436,682*	*0.6%*

Table 3-17
Total Second Contingency NCPC Payments by Load Zone, Q1 2012

Load Zone	Day-Ahead	Real-Time	Total
Connecticut	$0	$173,964	$173,964
Maine	$0	$840,369	$840,369
NEMA/Boston	$0	$27,186	$27,186
Total	*$0*	*$1,041,519*	*$1,041,519*

3.11 Interregional Power Flows

New England was a net importer of electric energy during the Reporting Period. Net imports totaled 2,805 GWh in the Reporting Period. Figure 3-13 shows total interregional power flows by quarter from the first quarter of 2011 through the first quarter of 2012.

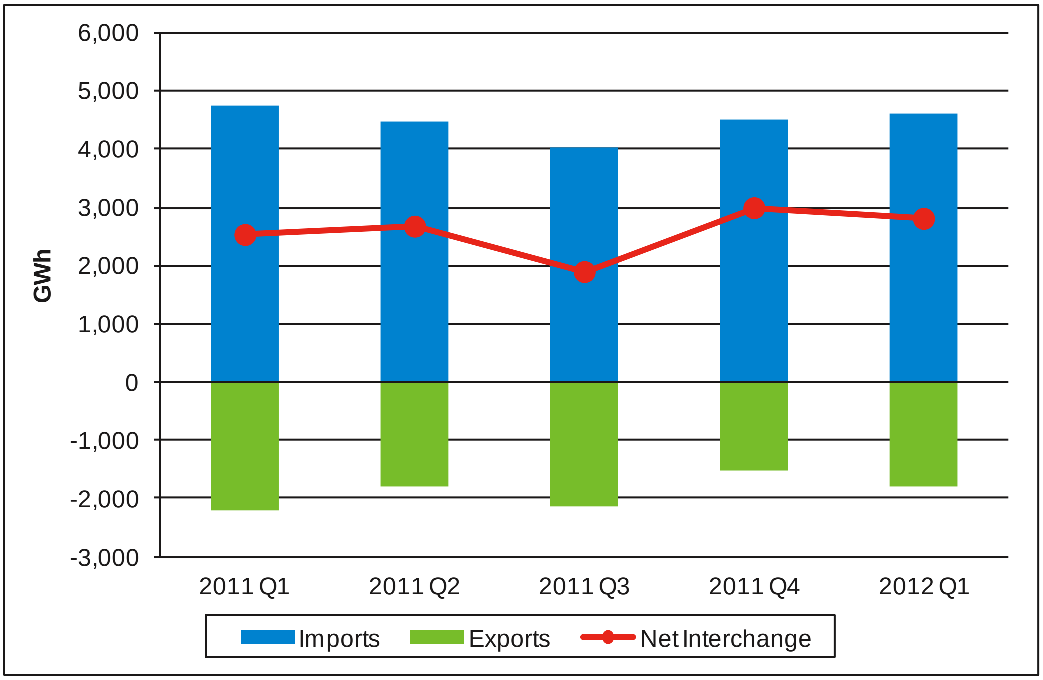


Figure 3-13: Quarterly New England Imports, Exports and Net Interchange, Q1 2011-Q1 2012.

Figure 3-14 shows interregional power flows during the Reporting Period by external node. The NY-AC interface is the collection of AC tie lines connected to New York through Connecticut, Massachusetts, and Vermont that are modeled as a single interface (which now includes the formerly-separate Norwalk-to-Northport 1385 line as well). The NY-CSC interface is the Cross-Sound Cable connecting Connecticut to Long Island.

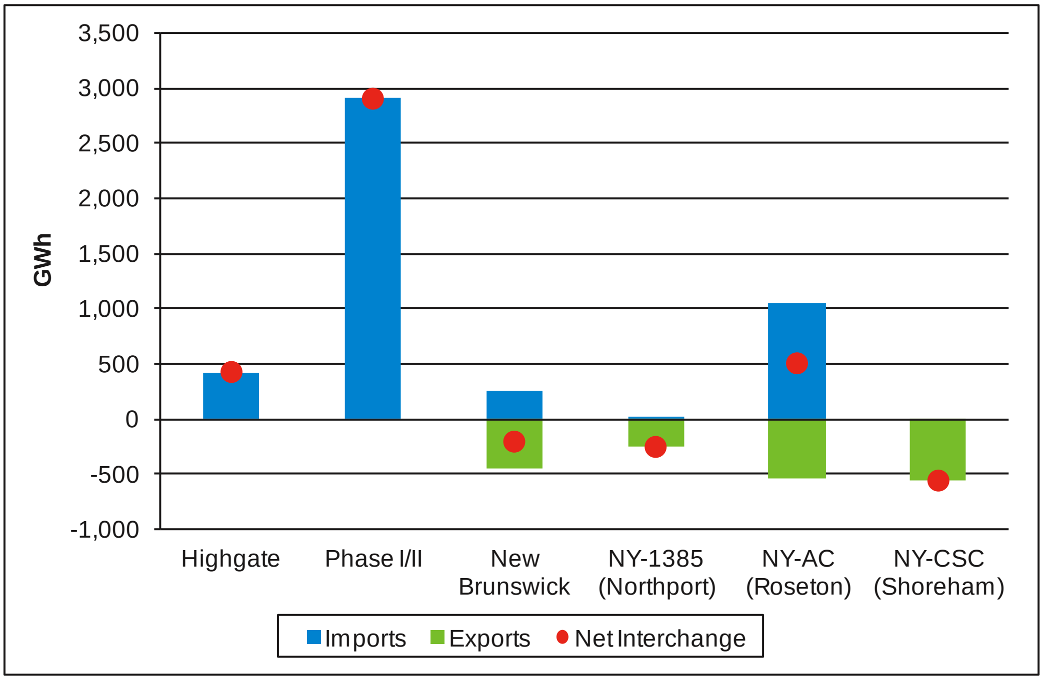


Figure 3-14: New England Imports and Exports by Interface, Q1 2012.