2008 Second Quarter Markets Report

ISO New England Inc.

Market Monitoring

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1. Introduction

1.1 About ISO New England

Created in 1997, ISO New England (ISO) is the not-for-profit corporation responsible for three main functions:

- The day-to-day reliable operation of New England's bulk power generation and transmission system
- Oversight and fair administration of the region's wholesale electricity markets
- Management of a comprehensive regional bulk power system planning process

Since February 1, 2005, the ISO has operated as a Regional Transmission Organization (RTO), assuming broader authority over the daily operation of the region's transmission system and possessing greater independence to manage the region's bulk electric power system and competitive wholesale electricity markets. The ISO also continues to work closely with regulators and stakeholders, including participants in the marketplace. The ISO operates the Day-Ahead and Real-Time Energy Markets, the Forward Capacity Market (FCM), the Regulation Market, the reserve markets, and the annual and monthly auctions of Financial Transmission Rights (FTRs).

1.2 About This Report

The ISO's Internal Market Monitoring Unit (INTMMU) monitors the markets, publishes market results, analyzes market efficiency, and addresses any impediments to efficiency or competition. The INTMMU issues periodic reports, including this quarterly report and the annual report, as part of its monitoring responsibility. The quarterly report is required by Section III of the Transmission, Markets and Services Tariff (Market Rule 1), Appendix A, Section 11.2.2.

This 2008 Second Quarter Markets Report, as required by Section III of the Transmission, Markets and Services Tariff (Market Rule 1), Appendix A, Section 11.2.2, is an assessment of New England's wholesale electricity marketplace during the second quarter of 2008. This quarterly report includes a Special Topics report, detailing the trends between energy prices and the highly volatile prices of natural gas and oil during the 2008 year, to date.

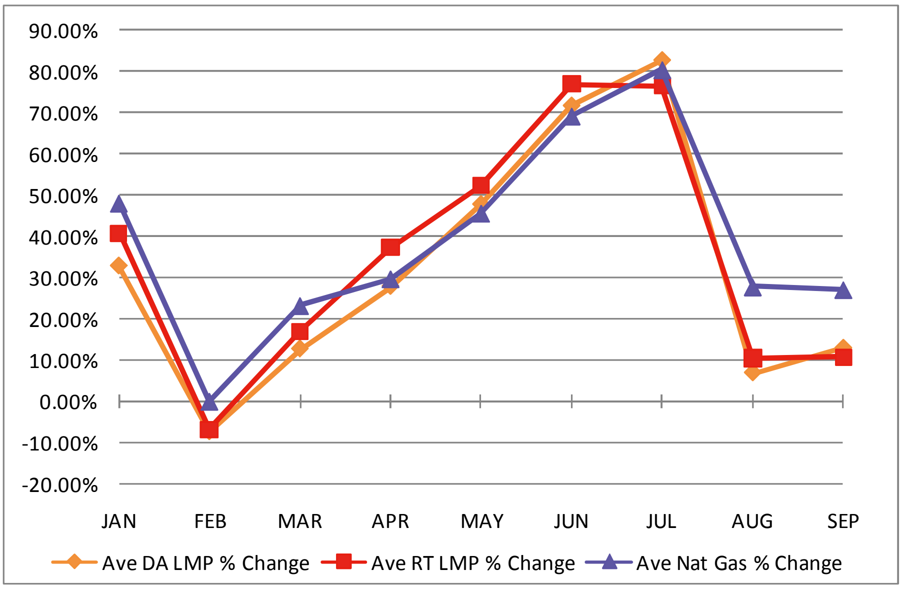
2. Special Topics: The Relationship between Fuel Prices and Wholesale Electricity Prices Q1-Q3 2008

Real-Time electricity prices were higher in 2008 than in 2007 and have shown great volatility. Average monthly prices were about 77% higher in June and July of 2008 than in June and July of 2007. To determine if increased fuel prices were causing the increase in energy costs, the Internal Market Monitoring Unit (INTMMU) conducted a mid-year review of the relationship between the price of fossil fuels and wholesale electricity prices.

The results show that changes in wholesale electricity prices tracked changes in the input fuel costs. Specifically, the electricity price tracked the cost of natural gas very closely, which is the fuel of the unit on the margin the vast majority of the time. This was true at the region-wide pricing hub and in typically congested load zones such as Connecticut and Southeast Massachusetts. The review also showed that load declined slightly in 2008 compared to 2007, indicating that the price changes were driven mainly by the fuel price increases rather than increases in demand.

Figure 1 shows the percent changes in the average Day-Ahead Hub LMP, average Real-Time Hub LMP and average Massachusetts natural gas prices. It shows that fuel price declines in February were accompanied by corresponding drops in wholesale electric prices. As the price of gas began to rise in March through July, so did the wholesale electric price. When the price of natural gas started to decline in August, energy prices dropped accordingly.

Figure 1 - Change in Average Day-Ahead LMP, Real-Time LMP & Average Natural Gas Prices, 2007-2008



The impetus for this review was a sharp increase in electricity prices in 2008. Table 1 compares average monthly real-time electricity prices for the first 9 months of 2007 and 2008. In all months except February, average monthly Real-Time LMPs have increased from the same month in 2007 while prices increased significantly in April through July of 2008.

Table 1 - Average Day-Ahead Hub LMPs

Month	2007 Ave Hub RT LMP	2008 Ave Hub RT LMP	Ave Hub RT LMP % Change
JAN	$60.75	$85.53	40.79%
FEB	$79.55	$74.25	-6.66%
MAR	$65.77	$76.95	17.00%
APR	$67.45	$92.61	37.30%
MAY	$67.47	$102.84	52.42%
JUN	$60.61	$107.20	76.87%
JUL	$61.18	$107.98	76.49%
AUG	$65.08	$71.92	10.52%
SEP	$60.74	$67.25	10.71%

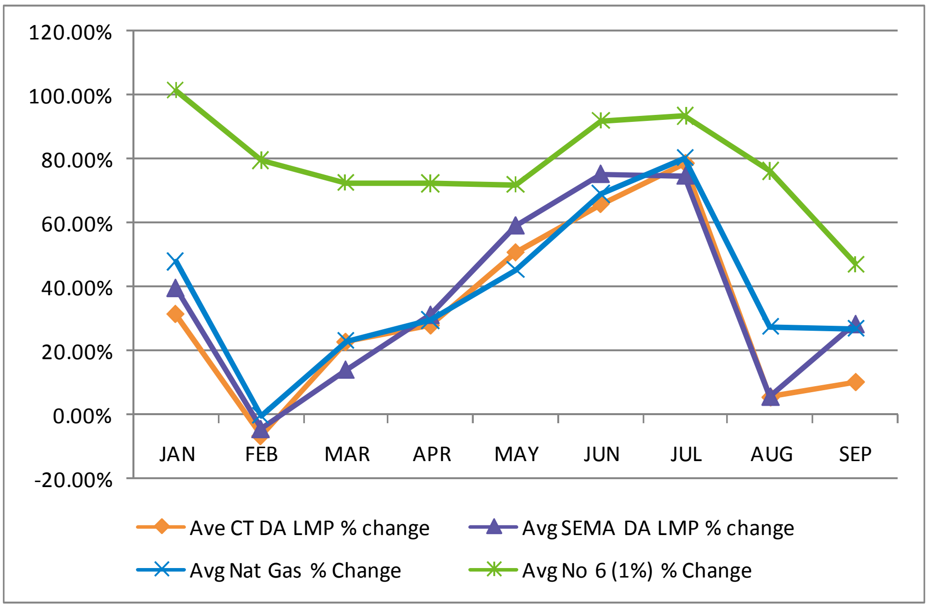
An increase in load could also cause electricity prices to rise. To examine whether load increases were contributing to the increase in electricity prices we compared monthly weather-normalized Net Energy for Load (NEL) for the first 9 months in 2008 to the first 9 months in 2007. As Table 2 shows, NEL remained relatively flat or declined from 2007 to 2008, indicating that load increases were not an important contributor to the increase in wholesale electricity prices.

Table 2 - Net Energy for Load (Weather-Normalized) (GWh), 2007 - 2008

Month	2007	2008	Change
Jan	11,874	11,887	0.11%
Feb	10,751	10,484	-2.48%
Mar	11,154	11,010	-1.29%
Apr	10,050	9,886	-1.63%
May	10,353	9,901	-4.37%
Jun	11,227	11,259	0.29%
Jul	12,474	12,608	1.08%
Aug	12,551	12,296	-2.03%
Sep	10,788	10,486	-2.80%

To examine whether the correlation of natural gas prices and electricity prices holds up in local areas, we examined two local areas that might diverge from the Hub price patterns. In SEMA, the large Canal station units run on No. 6 oil which is more expensive than natural gas. In Connecticut there is significant congestion causing prices to be higher than the Hub prices. For the most part, LMPs in these areas also follow the trend of natural gas prices.

Figure 2 - Changes in CT Day-Ahead LMP, SEMA Day-Ahead LMP, Ave Nat Gas, Avg No. 6 (1%), 2007 to 2008



3. Summary of Second Quarter Results

Each quarter, the ISO reports on the wholesale electricity markets that it administers. This report covers the period from April 1, 2008 to June 30, 2008 (the "Reporting Period"). The report contains the ISO analyses and summaries of market performance. Significant events and results during the Reporting Period included:

- **Market Monitoring** – The ISO monitors the market to ensure efficient and competitive market results. There was one mitigation event in the Real-Time Energy Markets and one mitigation event in the Day-Ahead Energy Market. There were no mitigation events in Day-Ahead or Real-Time Net Commitment Period Compensation payments during the Reporting Period.

- **OP-4 Events –** There was one OP-4 event during the Reporting Period. The event occurred on Tuesday, May 8, 2008 in the NEMA load zone and was caused by a major line tripping in the area.

- **Peak Load** – On June 27, 2008, the second quarter's peak was set at 26,138MW. This was 0.32% higher than the 2007 second quarter peak.

- **Electric energy prices** – The average Hub Day-Ahead and Real-Time electric energy prices for the Reporting Period were $99.61/MWh and $100.91/MWh, respectively. The average Hub system Day-Ahead and Real-Time price in April were 90.08/MWh and $92.61/MWh, in May were $99.43/MWh and $102.85/MWh, and in June were $109.32/MWh and $107.20/MWh, respectively.

4. Electric Energy Markets

Key factors that influence the market price for electric energy are supply and demand. Supply is influenced in turn by fuel prices and the frequency and location of transmission constraints.

4.1 Demand

The total energy needed to serve demand, including transmission losses, within the New England control area is referred to as the Net Energy for Load (NEL).[1] NEL supplied to the system in the second quarter of 2008 decreased by 2.2% relative to the second quarter of 2007. Since NEL is influenced by weather, to allow for more accurate comparisons of load growth across years, the ISO calculates the weather-normalized NEL (i.e., the NEL that would have been observed if weather were normal). The quarter showed a weather-normalized decrease by 1.8% in NEL in 2008 compared to 2007 values, as shown in Table 1.[2]

Table 3 – Net Energy for Load

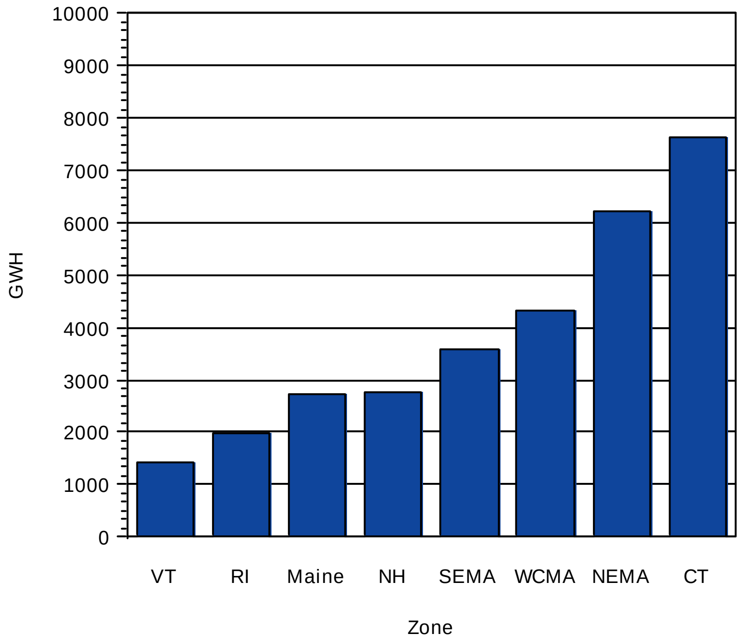
Net Energy For Load	(GWh)			
	2008	2007	Diff.	%Chg.
Q2 Recorded	31,028	31,731	-703	-2.2
Q2 Weather Normalized	31,046	31,630	-584	-1.8

[1] NEL is calculated as generation in New England (excluding generation used to support pumping at pumped storage hydro generators) plus net interchange with other control areas.

[2] To adjust for the effect of weather, the ISO adjusts energy consumption to reflect the departure of the experienced weather during a period from 20-year average, or "normal" levels using statistically derived factors. If temperatures are more severe than normal, consumption is adjusted downward; if milder than normal, an upward adjustment is made. Summer months also account for the effect of humidity on consumption levels.

Figure 3 shows the demand for each load zone during the Reporting Period. Unlike Net Energy for Load (NEL), Figure 3 shows total energy consumption, including net interchange and electric energy consumption used for pumping at certain hydro units.

Figure 3 – Demand by Load Zone, 2008 Q2



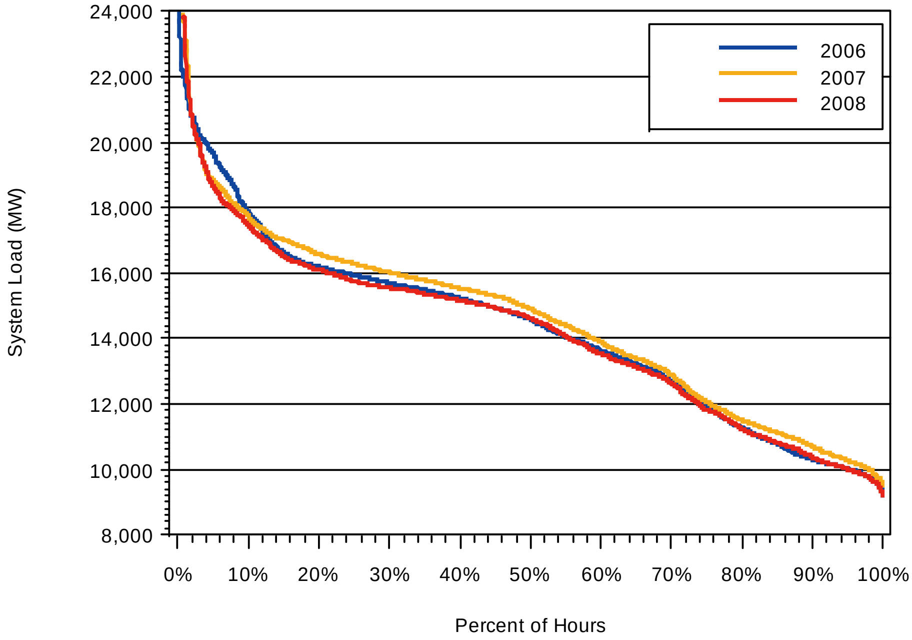
The second quarter system peak hourly load of 26,138 MW occurred on June 27, 2008. As shown in Table 4, this was 0.32% above the peak of 26,055 MW in the second quarter of 2007.

Table 4 – Peak Load Statistics, 2008 Q2

Peak Hourly Load	2008	2007	Change	% Chg.
Recorded Actual (MW)	26,138	26,055	83	0.32

Figure 2 shows load levels for the second quarters of the past three years as load-duration curves, with the hourly load levels ordered from highest to lowest. The duration curve shows, for each year, the percentage of time that the hourly load was at or above the load levels shown on the vertical axis.

Figure 4 – New England Hourly Load Curves
2006 – 2008 Q2

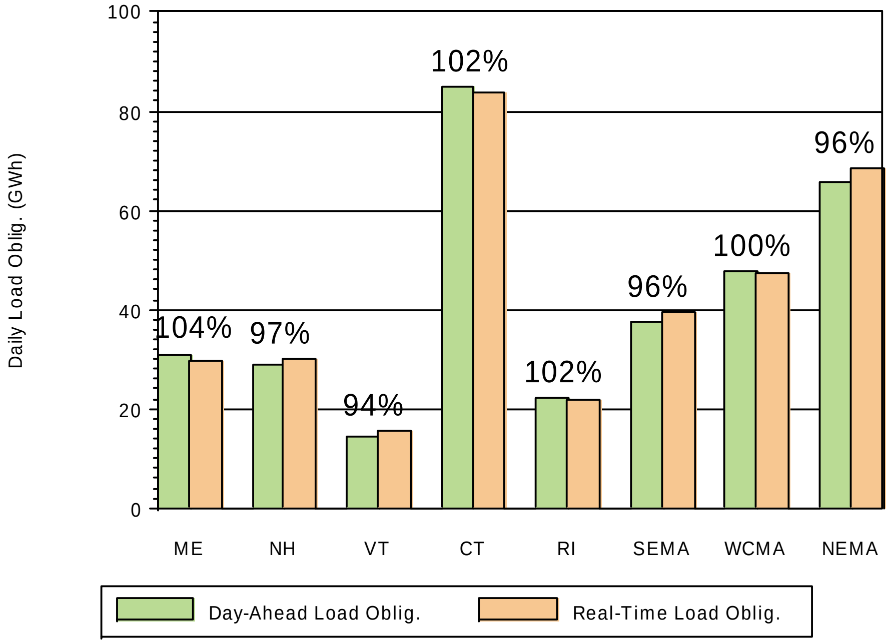


4.1.1 Load Obligation

During all Reporting Period hours, the day-ahead load obligation averaged about 99% of the real-time load obligation. This percentage varied across zones. Figure 5 presents the statistics for the Reporting Period by zone. The Maine, Connecticut, and Rhode Island load zones cleared the highest percentage, clearing 104%, 102% and 102% of real-time load obligation in the Day-Ahead Energy Market, respectively.

Cleared Day-Ahead load obligations for a zone can be higher than Real-Time load obligation due to forecasting errors by participants, or expectations of price differences that create opportunities for participants to arbitrage prices using virtual transactions. A cleared decrement bid is included in day-ahead load obligation while the real-time financial settlement of an increment bid is not included in real-time load obligation

Figure 5 – Average Day-Ahead Load Obligation vs. Real-Time Load Obligation by Zone, 2008 Q2



4.1.2 Day-Ahead Demand and Virtual Trading Trends

Figure 6 shows the average hourly submitted and cleared quantities of demand, virtual demand, and virtual supply for the Reporting Period. Around 59% of cleared demand bids were fixed demand bids, insensitive to price, while approximately 30% were price-sensitive demand bids. The remaining 11% of cleared day-ahead demand was virtual demand bids.

Figure 6 - Average Hourly Submitted and Cleared Demand, Virtual Demand, Q2

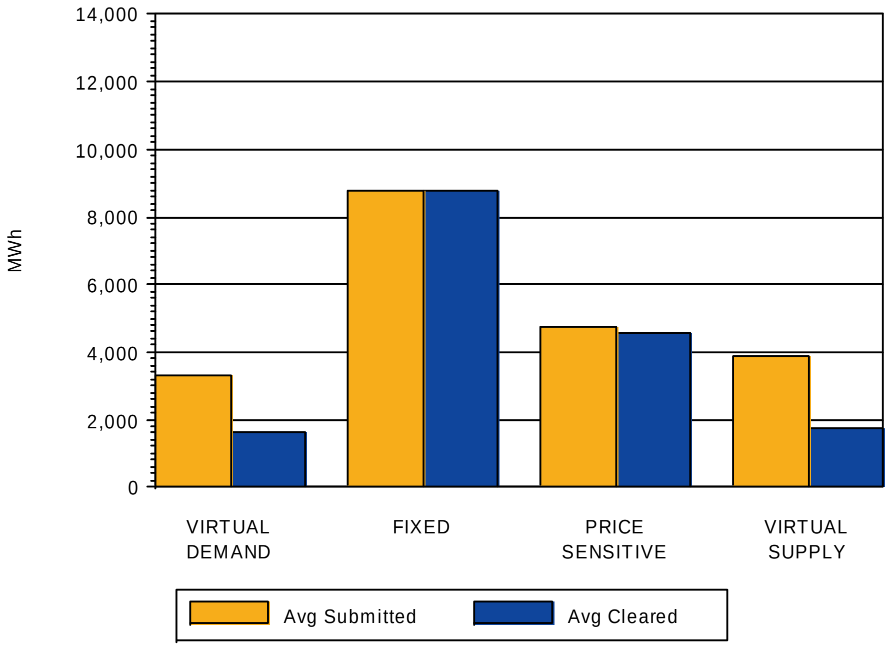


Figure 7 and Figure 8 show the daily total of the hourly submitted and cleared virtual transactions over the three-month Reporting Period. Submitted quantities of virtual transactions varied more than cleared volumes during the period. About 39,169 MWh of virtual demand bids and about 41,367 MWh of virtual supply offers cleared on average per day during the period.

Figure 7 – Submitted and Cleared Virtual Demand Daily Totals, 2008 Q2

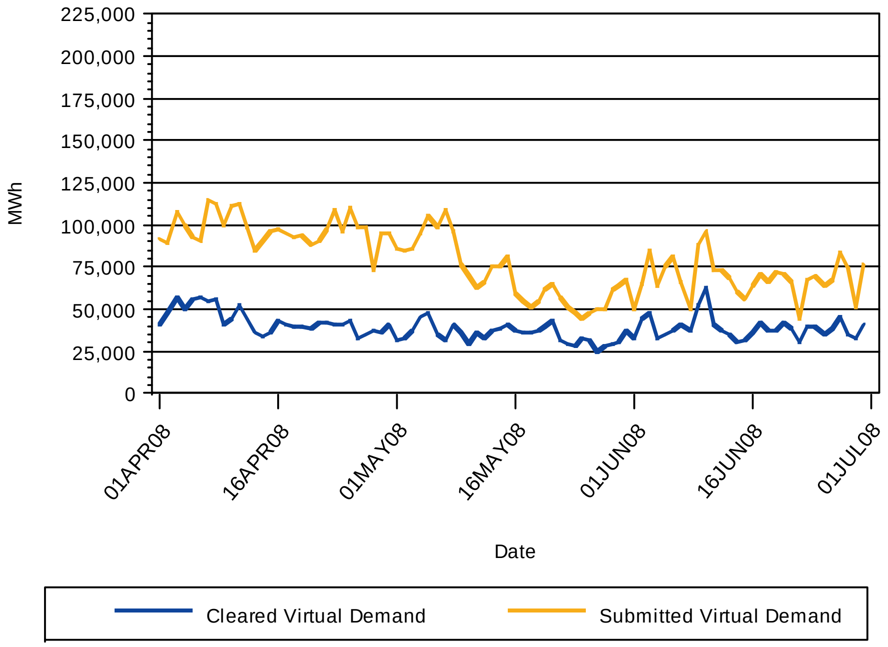
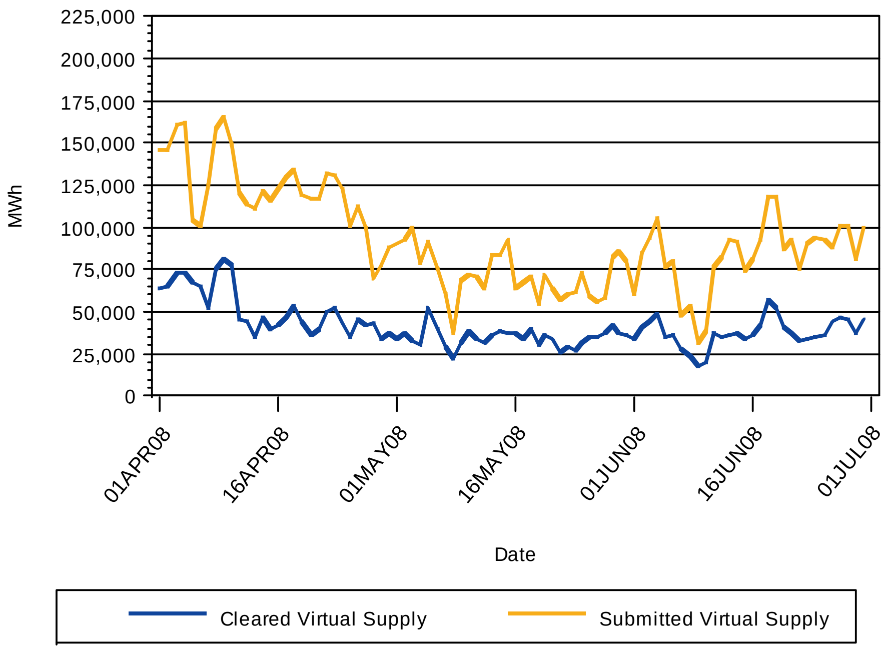


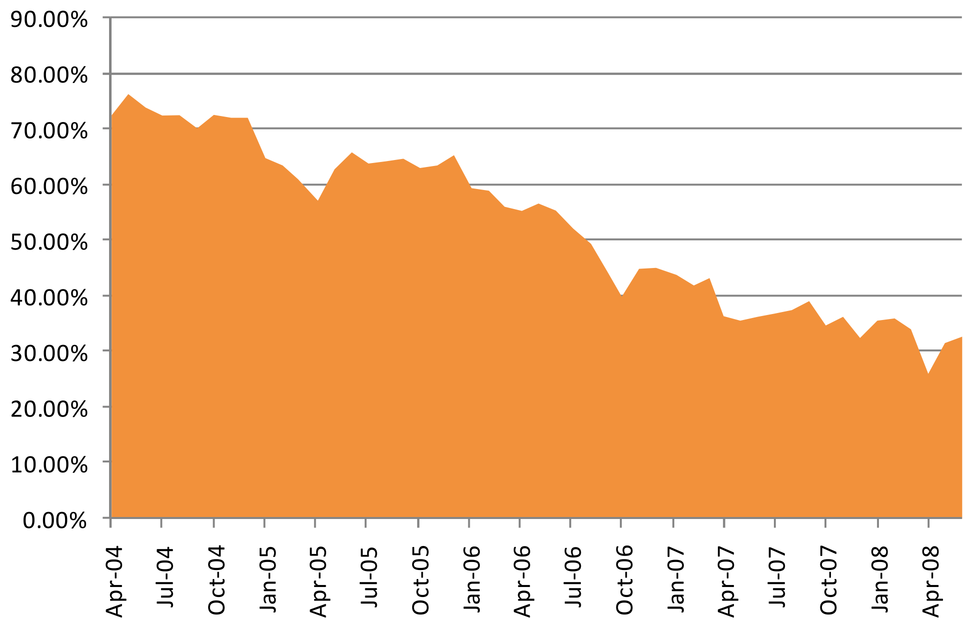
Figure 8 – Submitted and Cleared Virtual Supply Daily Totals, 2008 Q2



4.1.3 Forward Contracting

As shown in Figure 9, calculations for April 2004 through June 2008 averaged about 30% of the total real-time load obligation was either forward contracted or covered by a physical hedge. This is a decrease over what was seen during the same period last year, when the degree of forward contracting was 36% of real-time load obligation in each month. The information shown in Figure 9 tends to understate the degree of forward contracting that actually takes place to the extent that bilateral contracts exist but are not settled through the ISO's centralized settlement system. They also understate the physically hedged load to the extent that non-dispatched generators are available. Hence, while these numbers are useful, they are only indicative of the forward positions held by participants.

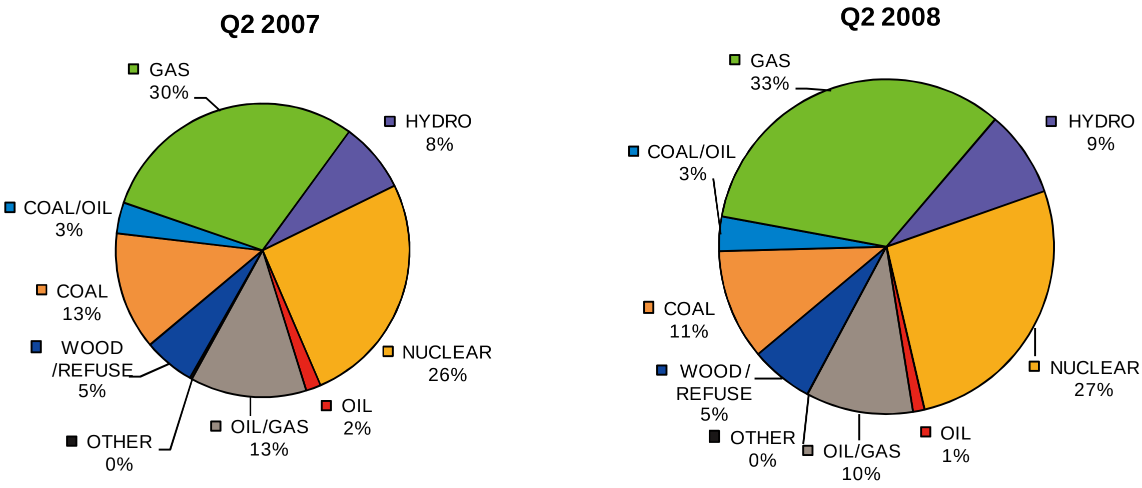
Figure 9 - 2008 Q2 Lower Bound of Real-Time Load as Hedged through ISO Settlement System



4.2 Supply

Figure 10 shows generation by fuel type as a percentage of total generation for the second quarters of 2007 and 2008. The percentages are relatively constant from 2007 to 2008. Overall, second quarter generation decreased by 1.8% year-over-year, from 31,630 GWh in 2007 to 31,028 GWh in 2008, while non-weather normalized NEL decreased by 2.2%. Net interchange with other control areas decreased from -1,959 GWh in the second quarter of 2007 to -2,572 GWh in the second quarter of 2008. Energy exported decreased by 477 GWh in the second quarter of 2008 from the same period in 2007, while energy imported increased by 135 GWh in the second quarter of 2008 from the same period in 2007. Generation used to support pumping at pumped storage hydro generators is not included in NEL.

Figure 10 – Actual Generation by Fuel Type



New England was a net importer from Canada and New York during the Reporting Period. Overall net imports were 8.2% of the quarterly NEL in New England.

Figure 11 shows total interregional power flows for the second quarters of 2001 through 2008. Figure 12 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. The NY-CSC interface is the Cross-Sound Cable.

Figure 11 – New England Imports, Exports and Net Interchange All Interfaces: 2001 – 2008 Q2

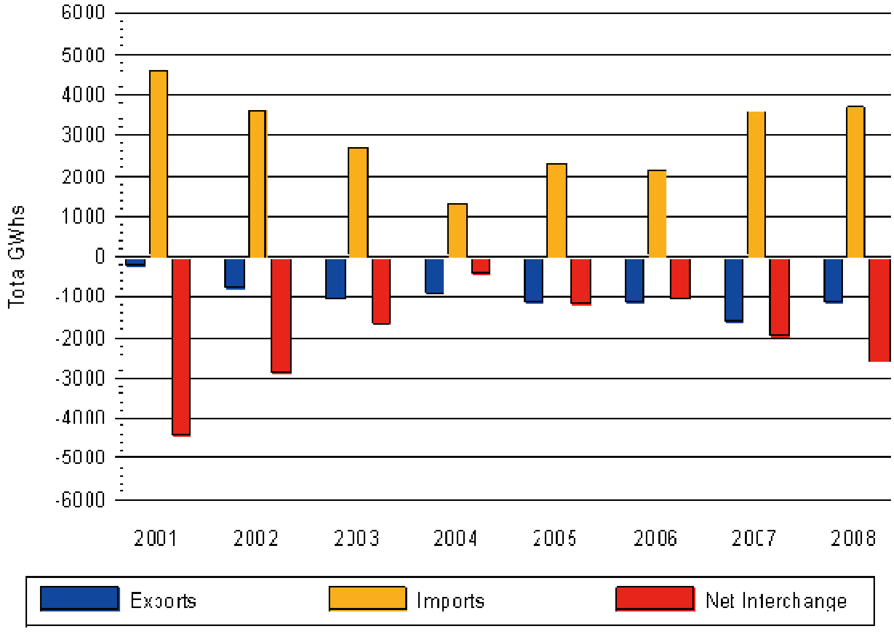
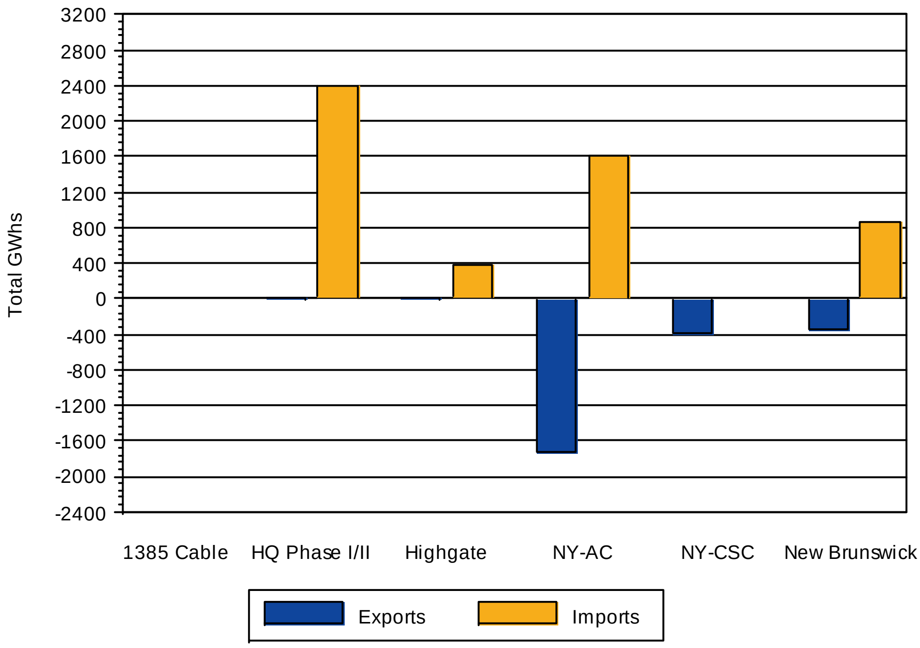


Figure 12 – New England Imports, Exports by Interface 2008 Q2

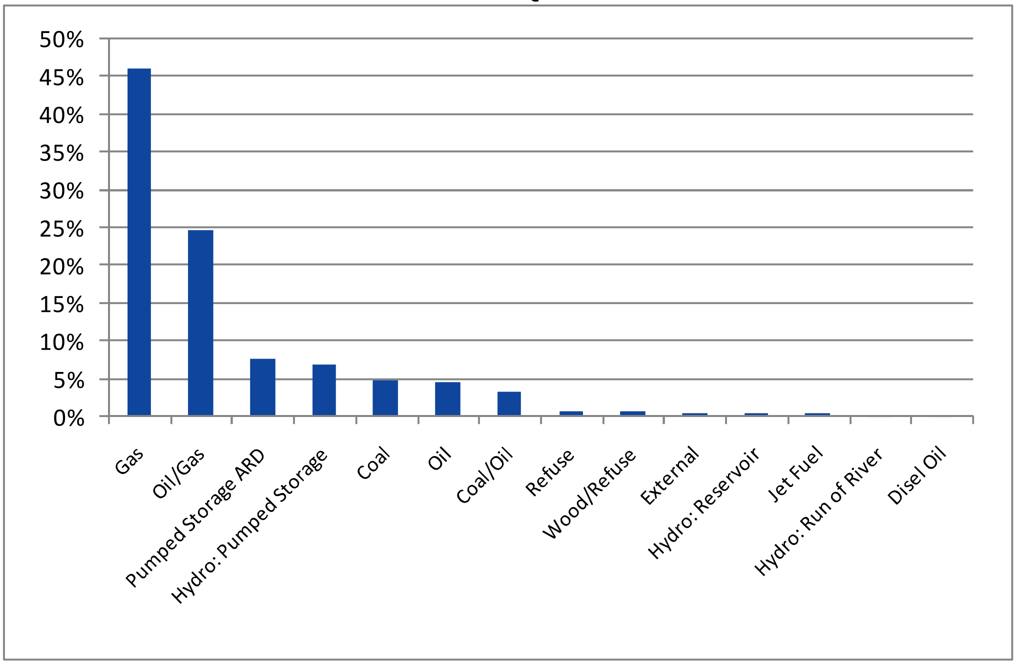


4.3 Electric Energy Prices

4.3.1 Marginal Input Fuel Types

Figure 13 shows the real-time marginal, or price-setting, input fuels during the Reporting Period as a percentage of pricing intervals. Binding real-time transmission constraints produce instances when there is more than one marginal generating unit on the system because there is a marginal unit on each side of a constraint; one setting price for the constrained area and one setting price for the unconstrained area. Since each marginal unit is included in the analysis, the percentages in the figure total more than 100%. Some types of generating units, such as nuclear power stations, were never marginal during the Reporting Period and are not included in the figure. The figure shows that units burning natural gas were marginal about 45.5% of the time during the period. Oil/Gas units, many of which burn gas as their primary fuel, were marginal about 24% of the hours. These results show the extent to which New England power prices are dependent on gas unit offers.

Figure 13 – Marginal Units by Unit Type
2008 Q2



4.3.2 Electric Energy Prices and Fuel Prices

Table 3 shows the price per MMBtu for the major fuels used during the Reporting Period.

Table 5 – Fuel Price Statistics for Q2 2008, $/MMBtu

Fuel Type	Average Price	Low Price	High Price
Natural Gas	12.10	10.16	14.25
No. 6 Oil 1%	14.60	11.70	17.42
Low Sulfur Coal	3.97	3.37	5.20
High Sulfur Coal	3.58	3.00	4.72

Figure 14 shows the daily average real-time system price plotted against the daily average variable production cost of hypothetical power plants burning either natural gas or oil. The gas plant production costs are based on a gas plant with a heat rate of approximately 7,000 Btu/kWh, while the oil plant production costs are based on a heat rate of approximately 10,500 Btu/kWh. The day-ahead spot prices for fuel are used to calculate each unit's variable costs. Unexpected system conditions, such as an unplanned generator or transmission-line outage, may cause energy-price spikes that are unrelated to fuel prices.

Figure 14 – Daily Avg. Real-Time System Price of Energy vs. Variable Production Costs 2008 Q2

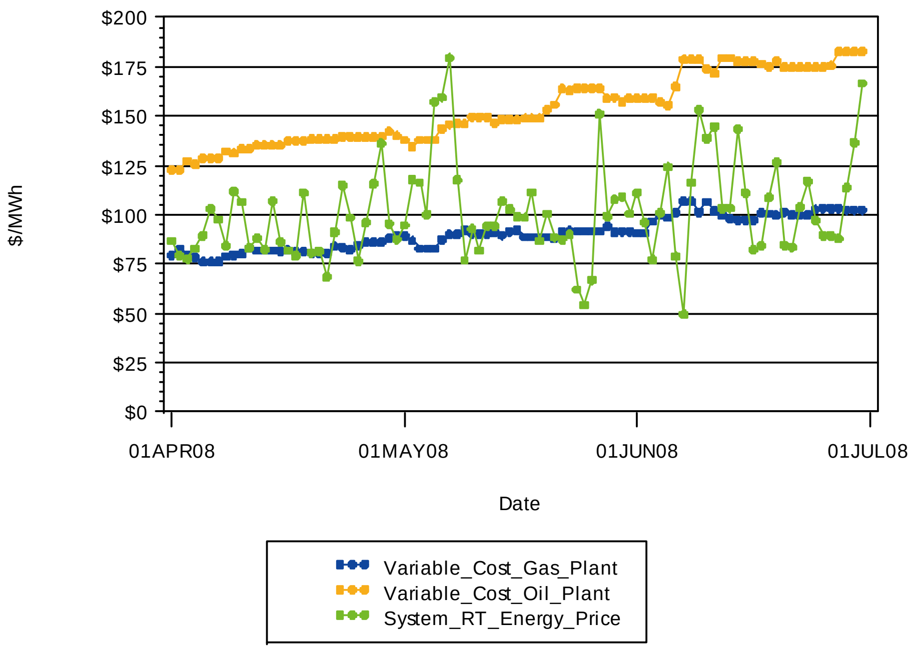


Table 6 shows average second quarter price indices for natural gas and No. 6 oil (1%), with each fuel indexed to its value in the year 2000. These two fuels are shown because they are on the margin for a majority of the time in New England, as was shown in Figure 13. The price of natural gas and No. 6 oil (1%) both increased in the second quarter of 2008 relative to the same period in 2006. Note that between 2007 and 2008, No. 6 oil (1%) prices increased at a higher rate than natural gas prices and oil has become the more expensive fuel on average. This change in relative prices alters the merit order dispatch with No. 6 oil units becoming more expensive, and dispatched less frequently, than natural gas units.

Table 6 – Fuel Price Index for Second quarters, Year 2000 Basis

Fuel	2000	2001	2002	2003	2004	2005	2006	2007	2008
Natural Gas	1.00	1.21	0.93	1.55	1.70	1.93	1.82	2.12	3.13
No. 6 Oil (1%)	1.00	0.92	0.94	1.01	1.18	1.61	2.04	2.10	3.77

4.3.3 Energy Prices Throughout the Quarter

Figure 15 and Figure 16 show the day-ahead and real-time system electric energy prices for New England during the second quarters of the most recent three years as duration curves, with prices ordered from highest to lowest.[3] For each second quarter, the duration curve shows the percentage of time that the system price was at or above the price levels shown on the vertical axis. The figures show that prices during the second quarter of 2008 were higher than those during the second quarter of 2007for all hours in both the Day Ahead and Real-Time Energy Markets.

[3] System price is the load-weighted average of the nodal LMPs

Figure 15 – New England Hourly DA System Price Duration Curves 2005- 2008 Q2

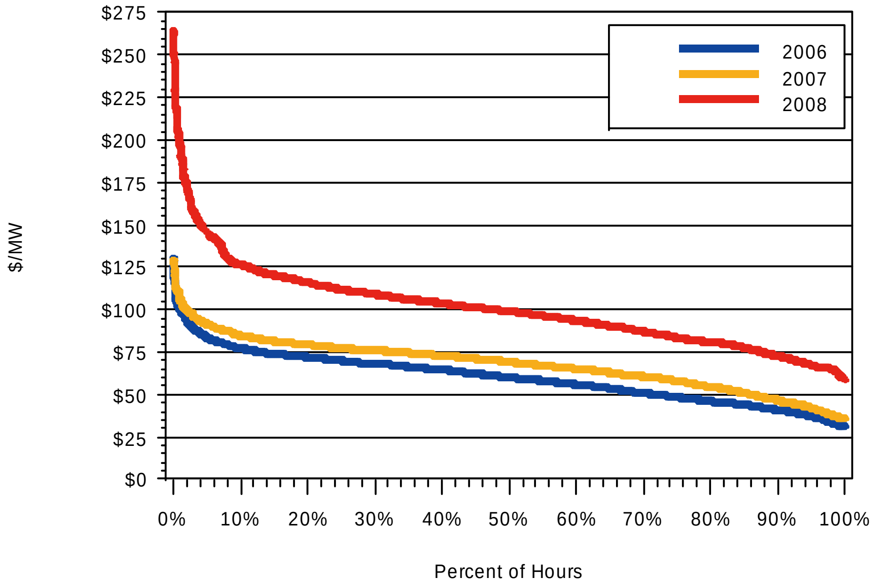


Figure 16 – New England Hourly RT System Price Duration Curves 2005- 2008, Q2 Prices < $275

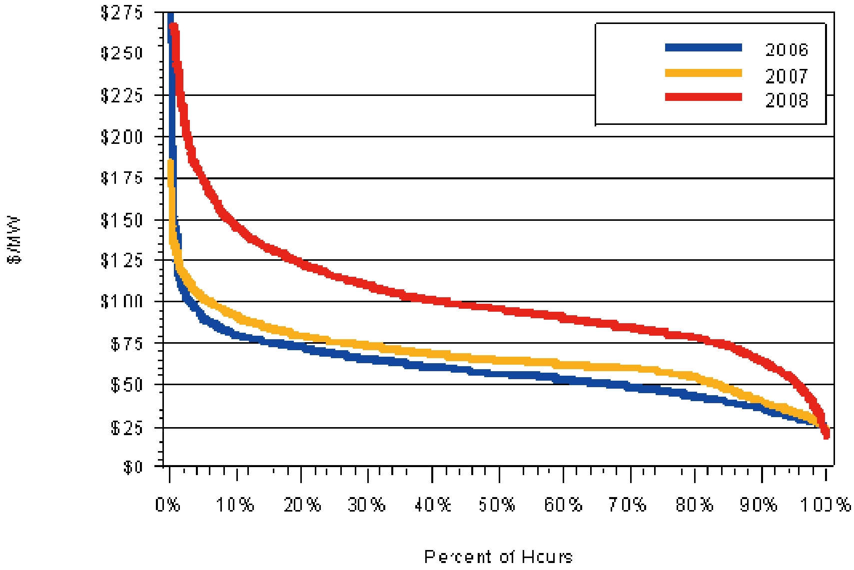


Figure 17 - Average Quarterly Load-Weighted System Day-Ahead and Real-Time LMPs

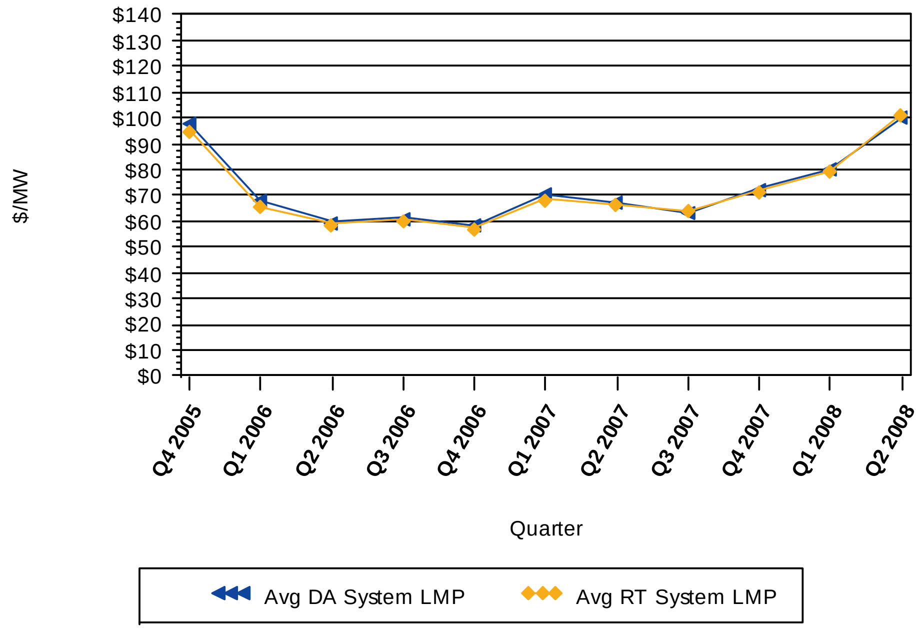


Figure 17 shows average quarterly prices from 2005 Q4 – 2008 Q2. Prices for the second quarter of 2008 were about $30-40/MW higher than the second quarters of 2007 and 2006. Table 7 shows the quarterly average, minimum and maximum LMP values at the Hub, eight load zones, and the five external nodes that are priced in New England.[4] Export constraints and negative marginal losses resulted in the Maine load zone having the lowest average prices of the load zones while import constraints caused Connecticut to have the highest average day-ahead and real-time load zone prices.

Average day-ahead LMPs were lower than average real-time LMPs in all zones. Zonal price differences between the Day-Ahead and Real-Time Energy Markets averaged about $1.31/MWh. The largest difference was in NEMA at $2.61/MWh and the smallest in Maine at $0.16/MWh.

Fifty-four percent of the 2,184 hours during the quarter had Day-Ahead prices that were higher than their real-time counterparts. The standard deviation of the differences between day-ahead and real-time hourly prices was $32.37/MWh.

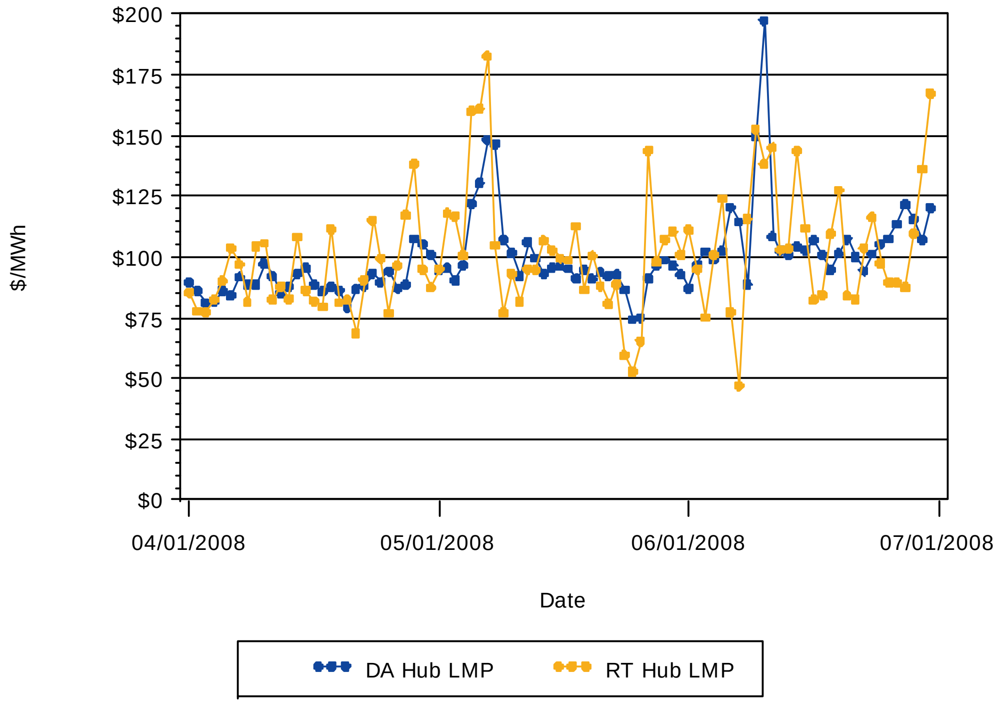
[4] On June 27, 2007, the 1385 cable was separated out from the NY –NE external interface and is now modeled as an individual external pricing node.

Table 7 – Summary Hourly LMP Statistics by Location, 2008 Q2, All Hours

Location/Zone	LMP ($/MWh)					
	Avg DA	Avg RT	Min DA	Min RT	Max DA	Max RT
Internal Hub	$99.61	$100.91	$35.33	$0.00	$367.19	$403.23
Maine Load Zone	$92.94	$92.78	$10.57	$0.00	$177.07	$359.85
New Hampshire Load Zone	$97.89	$99.46	$34.91	$0.00	$244.32	$397.76
Vermont Load Zone	$99.60	$101.09	$35.44	$0.00	$292.41	$399.99
Connecticut Load Zone	$105.57	$104.62	$36.08	$0.00	$300.00	$413.24
Rhode Island Load Zone	$97.48	$99.17	$34.82	$0.00	$240.15	$397.70
SEMA Load Zone	$103.23	$102.52	$34.85	$0.00	$295.12	$403.78
WCMA Load Zone	$100.30	$101.63	$35.47	$0.00	$378.68	$404.72
NEMA Load Zone	$98.77	$101.38	$34.99	$0.00	$255.00	$496.65
NB-NE External Node	$90.52	$89.33	$1.32	$0.00	$181.78	$359.92
NY-NE AC External Node	$99.94	$101.93	$35.76	$0.00	$266.96	$402.28
HQ Phase I/II External Node	$96.16	$98.21	$34.29	$0.00	$216.56	$393.89
Highgate External Node	$93.18	$94.66	$32.63	$0.00	$287.56	$369.36
Cross Sound Cable External Node	$104.56	$104.48	$36.11	$0.00	$301.14	$415.71
1385 Cable	$110.83	$106.97	$36.94	$0.00	$449.30	$412.11

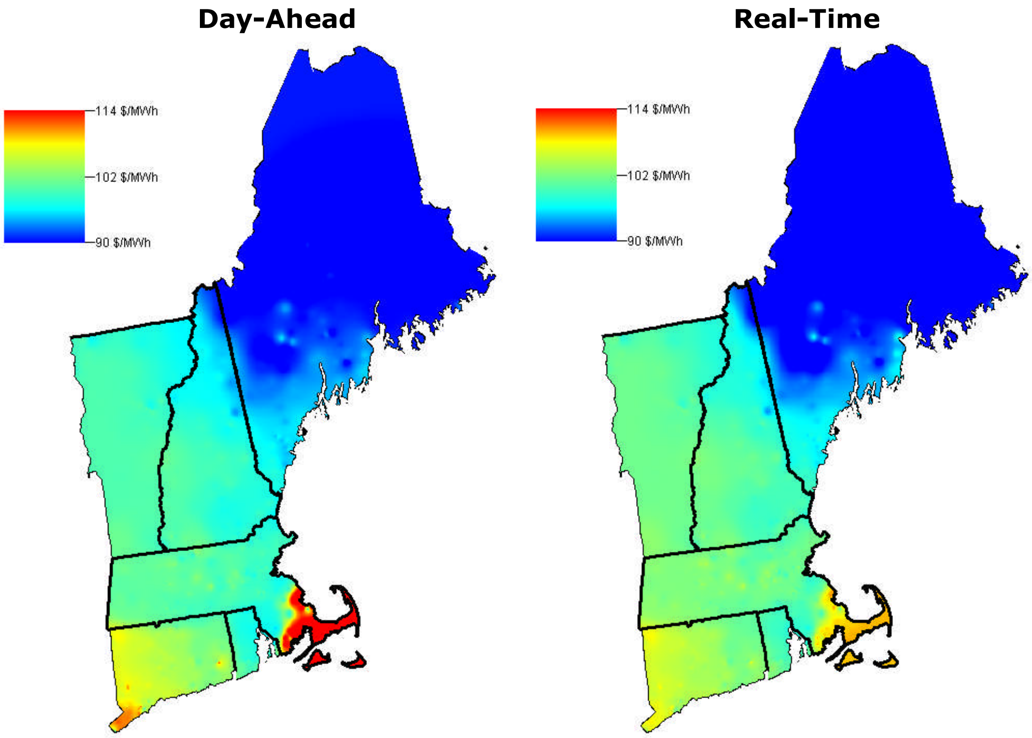
Figure 18 shows daily average Hub LMPs during the Reporting Period.

Figure 18 – Daily Average Hub LMP 2008 Q2



On the maps in Figure 19, average quarterly nodal LMPs are shown in color gradations from blue (representing $90/MWh) to red (representing $114/MWh).

Figure 19 – Average Nodal Prices
2008 Q2



4.3.4 Wholesale Prices in Other Northeastern Pools

Table 8 shows quarterly average system prices for the three Northeast ISOs: PJM, NYISO, and the ISO. Hourly system prices were calculated for New England and New York based on locational prices and locational loads, while prices for PJM are its published hourly system prices.[5]

[5] PJM's web site is available at <http://www.pjm.com>. NYISO's web site is available at <http://www.nyiso.com>. Quarterly average system prices are not load-weighted.

Table 8 – NE, NY, and PJM Average Electric Energy Prices
2008 Q2

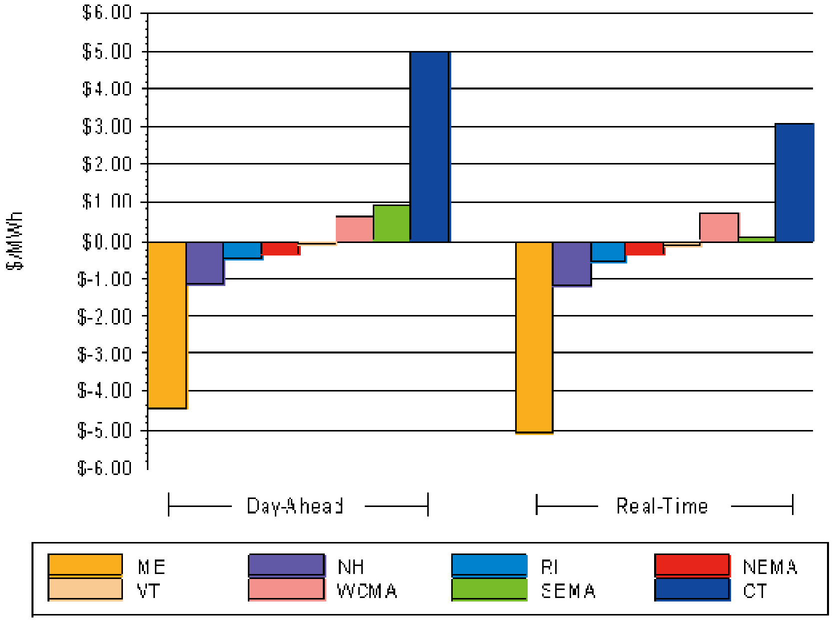
Control Area	Day-Ahead ($/MWh)			Real-Time ($/MWh)		
	All Hours	On-Peak	Off-Peak	All Hours	On-Peak	Off-Peak
NE	$100.53	$114.82	$87.54	$101.37	$116.33	$87.78
NY	$100.28	$118.72	$83.51	$101.41	$116.37	$87.81
PJM	$74.13	$94.30	$55.79	$73.69	$94.15	$55.08

New England's average Day-Ahead and Real-Time prices were similar to those in NY for all hour type categories. When compared to PJM, New England's average prices were higher in all hours. Variations in average prices among the power pools are affected by differences in generator fuel mix, transmission congestion, daily and seasonal load patterns, and load concentration in congested areas.

4.3.5 Effects of Transmission Congestion and Marginal Losses on LMP

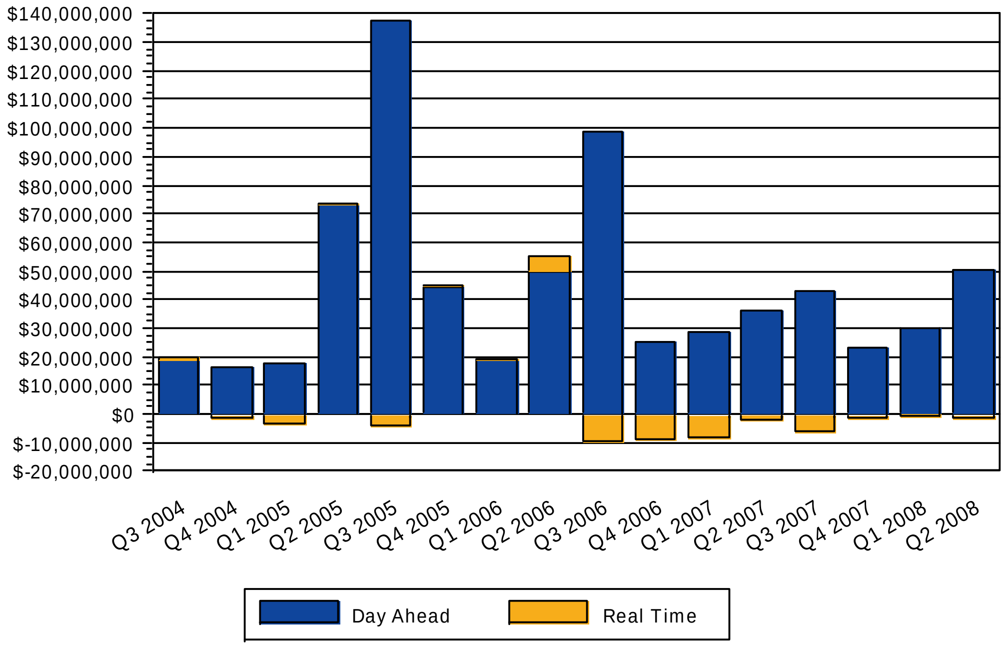
LMPs reflect the cost of delivering electric energy to a specific location on the grid including marginal production costs and the marginal costs of transmission congestion and losses. This can result in price separation between locations which is a key element of efficient pricing. Figure 20 shows the average hourly LMP differences between each zone and the hub for the Reporting Period. The differences are due to the joint impact of the marginal costs of congestion and losses. Notable in the figure are the negative average differences in LMP in the Maine, New Hampshire, Rhode Island, NEMA and VT load zones (compared to the Hub) and the positive average differences in the WCMA, SEMA and Connecticut load zones (compared to the Hub).

**Figure 20 – Average Hourly LMP Difference from Hub
2008 Q2**



Net congestion revenues are collected in the congestion revenue balancing fund and are used to pay FTR holders. Congestion revenue in the Day-Ahead Market was $50.2 million for the second quarter of 2008 and $36.1 million for the second quarter of 2007. The Real-Time revenue was -$1.2 million in the second quarter of 2008 and -$1.9 million in the second quarter of 2007. Figure 21 shows total congestion revenue by quarter since the third quarter of 2004.

Figure 21 – Total Congestion Revenue by Quarter



Excess energy and marginal loss revenue is collected in the Marginal Loss Revenue Fund and returned to load serving-entities according to each participant's monthly share of the real-time load obligation, net of bilateral trades. For the Reporting Period, the Marginal Loss Revenue Fund totaled $39.5 million.

4.4 Electric Energy Market Conclusions

Energy market operations were normal during the Reporting Period, with Hub LMPs that averaged $99.61/MWh in the Day-Ahead Energy Market and $100.91/MWh in the Real-Time Energy Market Prices were highest in Connecticut and lowest in Maine.

5. Locational Forward Reserve Market

ISO operating procedures require reserve capacity to be available (i.e., electrically synchronized to the system and at rated capability) within 10 minutes to meet the first-largest system contingency and within 30 minutes to meet one-half of the second-largest system contingency. In general, capacity equal to one-half of the 10 minute reserve requirement must be synchronized to the power system, or spinning (Ten-Minute Spinning Reserve (TMSR)), while the rest of the 10-minute requirement may be nonsynchronized. The entire 30-minute requirement may be nonsynchronized (including Ten-Minute Non-Spinning Reserve (TMNSR), and Thirty-Minute Operating Reserve (TMOR)) or the higher-quality TMSR. In addition to being able to meet system wide requirements, 30-minute reserves must be available to meet the local second contingency requirements for the constrained areas of NEMA/Boston, Connecticut, and Southwest Connecticut.[6] The Locational Forward Reserve Market (FRM), implemented as part of ASM II in October 2006, is a market-based method for compensating generating resources for providing operating reserves. FRM auctions are held twice a year, one month in advance of each of the semi-annual service periods of June 1 through September 30 and October 1 through May 31. Tables 7 and 8 pertain to the auction that ended in April 2008 regarding the Summer Period.

5.1 Forward Reserve Market Auction Results

The FRM requirements for each reserve zone (NEMA/Boston, CT, SWCT, and Rest-of-System) are shown in Table 9. Reserves that clear in SWCT count toward both SWCT and CT requirements. Reserves that clear in any of the local reserve zones (i.e., Rest-of-System, SWCT, CT, and NEMA/Boston) count toward the total system requirement in addition to the local requirement.

[6] The local areas of NEMA/Boston, CT, and SWCT have no 10-minute reserve requirements. Local first-contingency recovery requirements can be met by operating at the N-1 import-interface limit.

Table 9 – Summer 05/2008- 09/2008 Forward Reserve Auction Requirement by Reserve Zone

Location Name	Product Type	Total Reserve Requirement (MW)	Cleared Reserve Requirement (MW)	Shortfall Target-Cleared MW
Total System	TMNSR	800.0	800.0	0
Total System	TMOR/TMNSR	1,450.0	1,450.0	0
Rest of System (outside SWCT, CT, NEMA)	TMNSR	798.0	798.0	0
SWCT	TMOR	520.0	301.35	(218.65)
CT	TMOR	1,155.0	873.85	(281.15)
NEMA/Boston	TMOR	1,200.0	1,182.0	(18.0)

The TMNSR and TMOR requirements for the total system, Rest-of-System and NEMA reserve zones were met in the summer 2008 auction, while the TMOR requirements for SWCT, CT and NEMA/Boston were not met. In SWCT, all 301.35 MW of offers cleared. The cleared quantity was 218.65 MW short of the requirement of 520 MW. In the CT reserve zone, all 873.85 MW of offers cleared. The CT reserve zone was 281.15 MW short of its requirement. A total of 225 MW cleared in NEMA/Boston. The Total Reserve Requirement was reduced by 900 MW in NEMA/Boston due to external reserve support. NEMA/Boston fell short of its requirement by 18 MW.

Table 10 shows the quantity of reserve offered and cleared for each reserve location by product type along with clearing prices. Because the locational TMOR reserve requirements were not met in SWCT, CT, and NEMA/Boston the auction cleared at the administrative offer cap of $14,000/MW Month. While there are no locational TMNSR requirements, participants can offer TMNSR to meet the TMOR requirement.

Table 10 – Winter 10/2007- 05/2008 Offered and Cleared by Reserve Zone and Product Type

Reserve Zone	Product Type	Total Supply Offers (MW)	Cleared Supply (MW)	Clearing Price ($/MW-Month)
Rest of System (outside SWCT, CT, NEMA/Boston)	TMNSR	1,281.10	743.00	$8,888.00
Rest of System (outside SWCT, CT, NEMA/Boston)	TMOR	183.00	55.00	$6,500.00
SWCT	TMOR	301.35	301.35	$14,000.00
CT	TMOR	572.50	572.50	$14,000.00
NEMA/Boston	TMNSR	57.00	57.00	$14,000.00
NEMA/Boston	TMOR	225.00	225.00	$14,000.00

5.2 Forward Reserve Market Results

Resources designated to meet a Forward Reserve obligation are required to offer energy at or above a monthly threshold price. The monthly threshold price is set using a formula announced as part of the forward reserve auction notice. The formula includes a heat rate that is fixed for the duration of the service period and a fuel price index that varies monthly.

Table 11 shows the threshold price for each month in the Reporting Period and the percentage of hours in which the real-time LMP for the NEMA and Connecticut load zones and the Hub exceeded the threshold price. The target frequency is 2.5% or less. There was significant deviation from the design target during all the months in the second quarter.

Table 11 – 2008 Q2 Percentage of On-Peak Hours with Real-Time LMPs Greater than or Equal to FRM Threshold Price for the Hub, CT & NEMA Load Zones

Month	Hub (%)	CT (%)	NEMA (%)
Apr 2008	8%	13%	8%
May 2008	14%	17%	17%
Jun 2008	10%	11%	10%

The clearing prices from the forward-reserve auction are converted into an hourly payment rate based on on-peak hours.[7] Generating units designated to meet daily forward reserve obligations are paid the hourly price. A market participant is penalized if it does not meet its forward reserve obligation by designating resources and offering these resources into the Real-Time Energy Market at or above the threshold price. Participants are also penalized if an assigned resource is not able to provide energy within 10 or 30 minutes if called on during real-time operations.[8,9] The penalty for failing to designate a resource to meet a reserve obligation is 1.5 times the forward-reserve payment rate, in addition to the loss of the forward-reserve payment for the hour that the participant would otherwise have received.[10] The penalty rate for failing to activate when called on by the ISO is 2.25 times the forward-reserve payment rate or the hourly price for electric energy, whichever is higher. Table 12 summarizes total payments, penalties, and net dollars for all forward reserve resources, by month. Generators that fail to provide energy when given dispatch instructions by the ISO incur penalties based on the cost of replacement energy.

Table 12 – Monthly Total Forward Reserve Market Payments and Penalties, 2008 Q2

Month	Total Payments	Total Penalties	Net Dollars
Apr 2008	$15,687,549.17	-$570,013.84	$14,946,883.93
May 2008	$15,960,729.31	-$759,973.36	$15,118,440.63
Jun 2008	$15,323,282.14	-$742,261.40	$14,581,020.74

Table 13 – Real-Time Reserve Credits and Forward-Reserve Obligation Charges, 2008 Q2

Month	Real-Time Reserve Credit	Forward reserve Energy Obligation Charge
Apr 2008	$1,312,069.13	-$170,651.40
May 2008	$1,471,140.96	-$82,315.32
Jun 2008	$1,068,207.13	-$125,909.49
Total	$3,851,417.22	-$378,876.21

[7] Since ASM II implementation, the auction clearing prices are adjusted to reflect the FCM transition payment before being converted into an hourly rate.

[8] Since ASM II implementation, participants are not assessed the failure-to-reserve penalty for periods when the unavailability is due to an approved annual maintenance outage.

[9] Since ASM II implementation, failure-to-activate penalties are applied only when control room operators have approved a contingency unit-dispatch software case.

[10] The forward-reserve payment rate is the auction price for the applicable reserve product in the applicable reserve zone, measured in $/MW-month, divided by the number of on-peak hours in the applicable month.

5.3 Forward Reserve Market Conclusions

The Forward Reserve Market and real-time reserve pricing appear to be working as designed. The quantity of supply offered in local areas may increase in future auctions, as it did in the earlier system-wide auctions.

6. Forward Capacity Market (FCM)

In March 2006, a settlement was filed at FERC to replace the previous SMD ICAP Market with a Forward Capacity Market (FCM). Payment under the FCM will not begin until 2010, approximately two and one-half years after the first FCM auction that was completed in February 2008. The FERC settlement includes a transition payment mechanism, which began on December 1, 2006, that provides payment certainty until the auction commitment year and FCM payments begin. Table 14 shows the FCM transition payments made to capacity resources during the Reporting Period.

Table 14 – FCM Transition Period Payment Summary

Obligation Month	UCAP Supply MW	FCM Transition Payment	Transition Payment $/MW-Month
Apr 2008	38,123.15	$116,275,605.15	3,050
May 2008	36,909.19	$112,573,033.43	3,050
Jun 2008	34.341.59	$128,780,988.22	3,750

7. Regulation Market

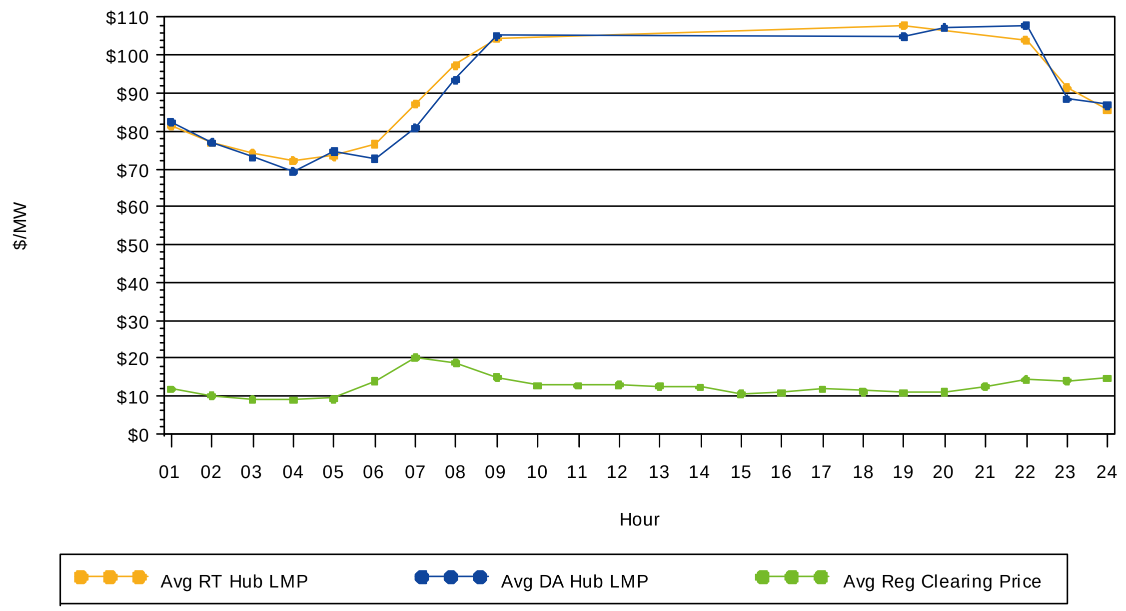
Regulation is necessary to balance supply levels with the second-to-second variations in demand. To respond to these slight changes on the system, specially equipped generators are sent signals to increase or decrease generation output every four seconds. This system balancing maintains proper power flows into and out of the New England Control Area.

The hourly Regulation Market clearing price averaged $12.68/MWh during the Reporting Period. Total Regulation Market payments were $9.45 million, including $5.67 million in real-time opportunity cost payments. Table 15 shows summary information about clearing prices in the Regulation Market during the Reporting Period.

Table 15 – Regulation Market Clearing Prices Summary ($/MWh), 2008 Q2

$/MWh	Average	Median	Minimum	Maximum
Apr 2008	$10.49	$10.00	$2.38	$30.00
May 2008	$11.76	$9.88	$2.02	$84.49
Jun 2008	$15.78	$12.00	$6.38	$100.00

Figure 22 – Average Hourly Regulation Clearing Prices and Hub DA & RT LMPs 2008 Q2



8. Supplemental Commitment of Generation

The requirements for the reliability of New England's bulk power system reflect standards developed by NERC and NPCC. These requirements are codified in the ISO's operating procedures.[11] The ISO commits some generation outside of the market-clearing process to maintain power system reliability and meet these requirements. Figure 23 shows the energy output that resulted from these supplemental commitments in the Day-Ahead Energy Market, RAA process, and Real-Time Energy Market during the Reporting Period.

[11] The system operating procedures are available on the ISO's Web site at <http://www.iso-ne.com/rules_proceds/operating/isone/index.html>.

Figure 23 – Total Monthly Energy Output from Reliability Commitments Day-Ahead, RAA, and Real-Time, 2008 Q2

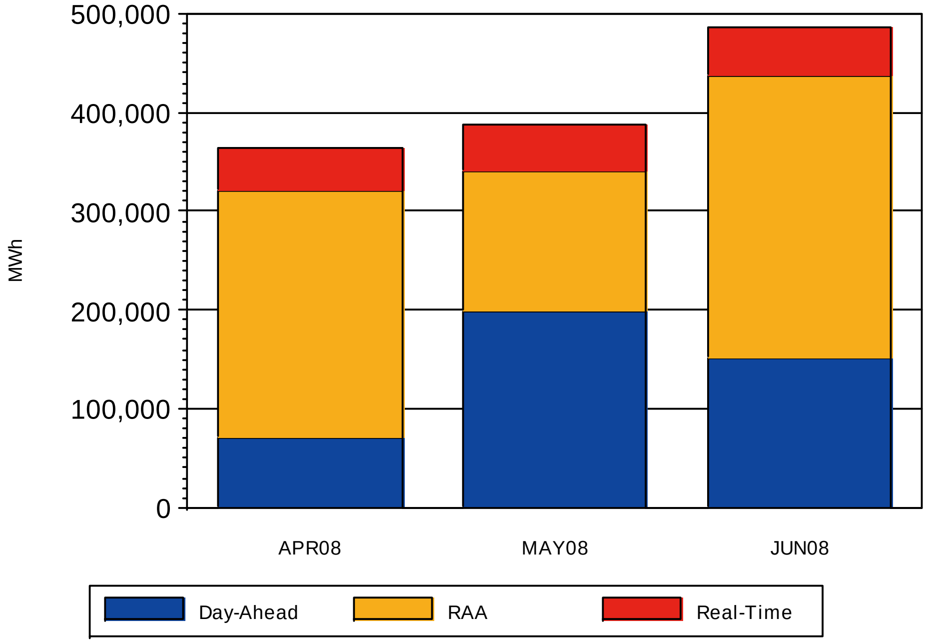


Table 16 shows total energy output from supplemental commitments made to supply local second contingency reserves by month and load zone.[12] Almost all second contingency commitments were made in the SEMA and Connecticut Zones. Norwalk-Stamford Connecticut, Southwest Connecticut, and the rest of Connecticut have local second-contingency reserve requirements on a regular basis. Within Connecticut, commitments are first made to solve constraints in the Norwalk/Stamford area, then Southwest Connecticut, and finally the rest of Connecticut, because commitments made in one of the sub-areas may also resolve constraints in the larger area. Energy output from second contingency commitments totaled 782,233 MWh during the Reporting Period.

[12] Local second contingency commitments were formerly called reliability must run (RMR) commitments.

Table 16– Energy Output from Second Contingency Commitments by Month and Load Zone, MWh, 2008 Q2

		Apr 2008	May 2008	Jun 2008	Quarter Total
ME	**Day-Ahead**	0	0	0	0
	RAA/Real-Time	0	0	8,220	8,220
	Total Second Contingency Commitments	0	0	8,220	8,220
CT	**Day-Ahead**	54,975	169,553	122,370	346,898
	RAA/Real-Time	29,003	33,131	44,233	106,367
	Total Second Contingency Commitments	83,978	202,685	166,603	453,265
SEMA	**Day-Ahead**	13,287	21,264	16,723	51,274
	RAA/Real-Time	61,387	41,621	123,339	226,348
	Total Second Contingency Commitments	74,674	62,885	140,062	277,622
WCMA	**Day-Ahead**	0	0	0	0
	RAA/Real-Time	0	8,001	4,260	12,261
	Total Second Contingency Commitments	0	8,001	4,260	12,261
NEMA	**Day-Ahead**	0	984	2,610	3,594
	RAA/Real-Time	15,500	0	3,420	18,920
	Total Second Contingency Commitments	15,500	984	6,030	22,514
RI	**Day-Ahead**	0	0	0	0
	RAA/Real-Time	0	8,351	0	8,351
	Total Second Contingency Commitments	0	8,351	0	8,351

Table 17 shows total energy output from commitments made during the Reporting Period to provide reactive power by month and load zone. These commitments provide high voltage control or low voltage support. Total energy from reactive power commitments was about 54,426 MWh during the Reporting Period. Voltage control commitments are generally driven by hours when load levels are low, while voltage support commitments are needed for contingency coverage during high load periods.

Table 17 – Energy Output from Voltage Commitments by Load Zone, MWh, 2008 Q2

		Apr 2008	May 2008	Jun 2008	Quarter Total
4001	Day-Ahead	2,530	0	0	2,530
	RAA/Real-Time	17,751	310	0	18,061
	Total Voltage	20,281	310	0	20,591
4004	Day-Ahead	0	0	0	0
	RAA/Real-Time	0	1,185	0	1,185
	Total Voltage	0	1,185	0	1,185
4005	Day-Ahead	0	0	0	0
	RAA/Real-Time	0	6,522	0	6,522
	Total Voltage	0	6,522	0	6,522
4006	Day-Ahead	0	0	4,800	4,800
	RAA/Real-Time	0	0	60	60
	Total Voltage	0	0	4,860	4,860
4007	Day-Ahead	0	7,080	4,800	11,880
	RAA/Real-Time	0	1,740	1,834	3,574
	Total Voltage	0	8,820	6,634	15,454
4008	Day-Ahead	0	0	0	0
	RAA/Real-Time	5,814	0	0	5,814
	Total Voltage	5,814	0	0	5,814

9. Net Commitment Period Compensation

Reliability commitments can be viewed as the bulk power system's insurance policy. It provides a margin of additional supply above what is otherwise needed to meet real-time system demand. Reliability commitments call on units that are not economic given the LMP, and thus must be paid their costs not covered by the LMP. This payment is called Net Commitment Period Compensation, or NCPC. This compensation is based on the generator's submitted costs for providing energy, including start-up and no-load costs.

First and Second Contingency NCPC payments totaled approximately $55.3 million during the Reporting Period. Figure 24 provides quarterly totals for NCPC payments. Table 18 shows second contingency payments by load zone.

Figure 24 – NCPC Payments by Quarter, 2003- 2008

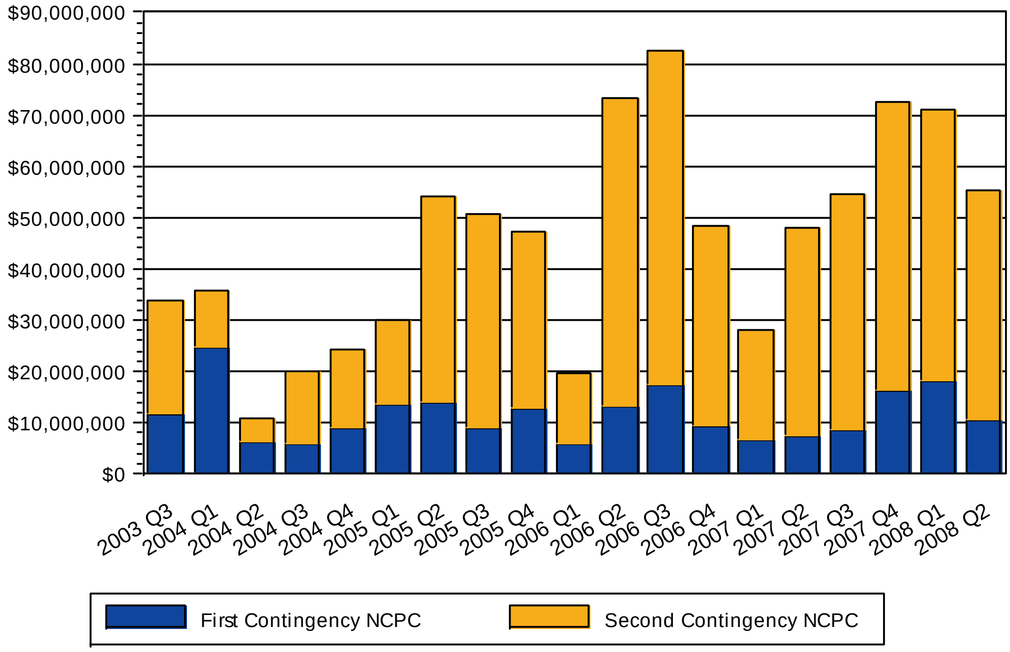


Table 18 – Total Second Contingency NCPC by Load Zone, 2008 Q2

Load Zone	Day-Ahead Payments	Real-Time Payments
Connecticut Load Zone	$401,242	$6,882,850
NEMA Load Zone	$171,730	$878,602
SEMA Load Zone	$759,732	$35,453,476
WCMA Load Zone	$0	$128,547

Table 19 and Table 20 show the average allocation of NCPC by month for the Reporting Period. Average charges are calculated based only on days with charges.

Table 19 – First Contingency Net Commitment Period Compensation Allocations for Days with Charges, $/MWh, 2008 Q2

Month	Day-Ahead First Contingency	Real-Time First Contingency
APR 2008	0.06	0.43
MAY 2008	0.05	0.55
JUN 2008	0.12	0.83

Table 20 – Second Contingency Net Commitment Period Compensation Charge Allocations for Days with Charges by Load Zone, $/MWh, 2008 Q2

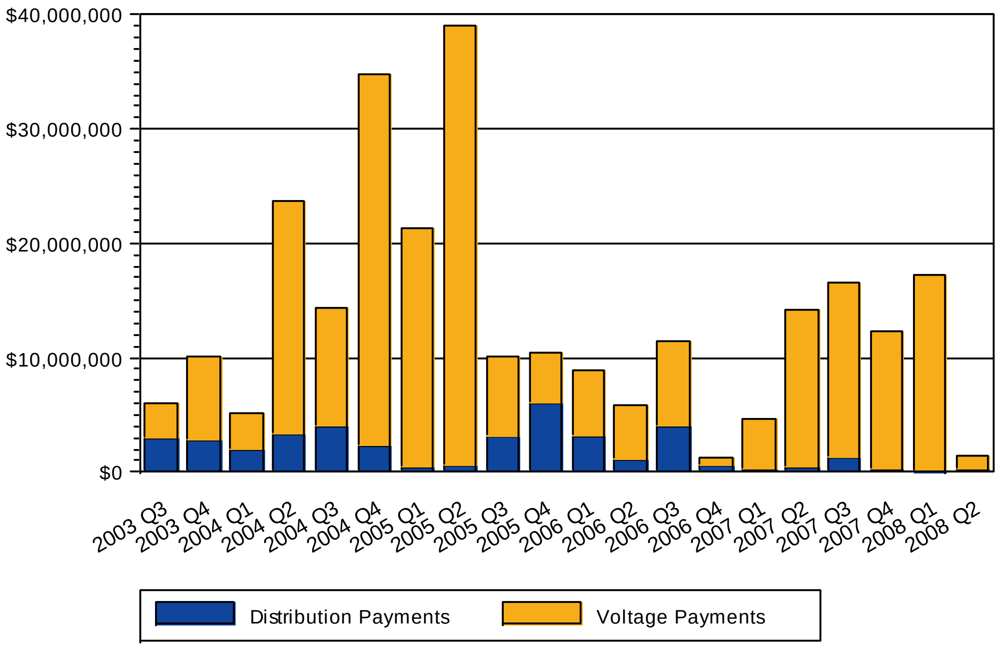
Month	CT Day-Ahead Second Contingency	CT Real-Time Second Contingency	NEMA Day-Ahead Second Contingency	NEMA Real-Time Second Contingency
APR 2008	0.00	0.00	0.00	0.00
MAY 2008	0.44	0.77	0.00	0.00
JUN 2008	0.13	0.97	2.28	0.69

Month	SEMA Day-Ahead Second Contingency	SEMA Real-Time Second Contingency	WCMA Day-Ahead Second Contingency	WCMA Real-Time Second Contingency
APR 2008	0.00	0.00	0.00	0.00
MAY 2008	1.42	7.69	0.00	0.59
JUN 2008	3.24	12.71	0.00	0.81

10. Voltage and Distribution Tariff Charges

Generators providing voltage or distribution service are compensated for shortfalls between their energy revenues and energy offers in the same way as generators flagged Second Contingency receive NCPC. [13] Figure 25 shows voltage and distribution payments for the second quarter of 2003 through the second quarter of 2008. Total voltage payments in the Reporting Period were $1,176,890 while distribution payments amounted to $285,675. The majority of the payments, in both categories, came from real-time commitments. Table 21 shows voltage payments by load zone. Voltage payments are allocated to all New England transmission users based upon network load, while distribution payments are assigned directly to the transmission owner requesting that the generator be committed.

Figure 25 – Tariff Payments by Quarter, 2003 - 2008



[13] Distribution service is called Special Constraint Resource service. Generators providing distribution service are called by the local transmission owner in an area to support the local transmission system.

Table 21 – Total Voltage Payments by Load Zone, 2008 Q2

Load Zone	Day-Ahead Payments	Real-Time Payments
Maine	$28	$34,889
Connecticut	$0	$15,829
Rhode Island	$0	$139,595
SEMA	$93,337	$13,981
WCMA	$634,126	$15,389
NEMA	$0	$229,717

11. Reliability Agreements

Reliability Agreements provide eligible generators with monthly fixed-cost payments for providing reliability service. Reliability Agreements are paid for by network load in the zone that benefits from the reliability support provided. During the Reporting Period, Reliability Agreements were in effect for 9 generating stations, with a total of 18 units and 3,389[14] MW. These 9 stations include West Springfield 1-3, Pittsfield/Altresco, and Berkshire Power in Western Massachusetts as well as Middletown, Montville, Milford, New Haven Harbor, Bridgeport Harbor, and Norwalk Harbor 1 and 2 in Connecticut.[15]

The net cost of Reliability Agreements to load during the Reporting Period was $33.7 million.

12. Managing Congestion Risk – FTRs

Financial Transmission Rights (FTRs) are financial instruments that entitle the holder to a share of the Day-Ahead Energy Market and Real-Time Energy Market congestion revenues. The holder of an FTR is entitled to receive, or required to make, payments based on the FTR-megawatt quantity and the difference between the congestion components of the day-ahead LMPs at the FTR's location of origin (source) and delivery (sink) points. The ISO pays FTR holders with positive target allocations from congestion revenues generated by the Day-Ahead and Real-Time Energy Markets and from FTR holders with negative target allocations.

12.1 Auction Results

The April, May, and June monthly auctions included previously awarded FTRs from the January 2008 through December 2008 long-term auction. Fifty-percent of the transmission capacity of the New England control area was auctioned in the long-term auction, and 95% of the remainder was available in each of the monthly auctions. The long-term awarded FTRs are held aside in the following monthly auctions, decreasing the volume of FTRs that can be awarded in those auctions. Between 40 and 44 bidders participated in each monthly auction during the Reporting Period. This is consistent with levels of participation in auctions in prior months. The value of the second quarter was about $9.42 million, the total value of all FTRs active in the quarter was about $28.04 million, which includes the quarterly share of the January-December 2008 auction value (91/366) of $74.7 million. Bids and offers cleared with negative prices that totaled to $4.13 million. The $9.42 million value for the second quarter monthly auctions is realized by netting $4.13 million in net payments to FTR holders with negative prices from $13.56 million in net collections from FTRs with positive prices.

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[14] 2007 CELT Report, Summer Capacity

[15] Additional information about Reliability Agreements is posted on the ISO's Web site at < http://www.iso-ne.com/genrtion_resrcs/reports/rmr/index.html >.

Market Rule 1 specifies that auction revenues must first be allocated to entities in the form of Qualified Upgrade Awards (QUAs). By paying for transmission upgrades, the entities have increased the transfer capability of the New England transmission system and enabled more FTRs to be available in the FTR auction. The remaining auction revenues are then allocated to entities through the Auction Revenue Rights (ARRs) process. During this process, auction revenues are awarded primarily to congestion-paying load-serving entities.

Table 22 shows auction revenue distribution by category. The monthly revenues include monthly-normalized long-term auction revenues.

Table 22 –ARR Allocations, 2008 Q2

Month	Net FTR Auction Revenue	ARR Allocation ($)					QUA Alloc. Dollars	Total Auction Revenue Distrib. (ARR + QUA)
		Excepted Trans. Dollars	NEMA Contract Dollars	Load Share Dollars	Long-Term Firm Trans. Svc. Dollars	Total ARR Allocation		
APR 2008	$-8,214,882	$10,349	$11,755	$7,086,142	$0	$7,108,245	$1,106,637	$8,214,882
MAY 2008	$-9,388,755	$9,837	$17,290	$8,959,609	$0	$8,986,737	$402,018	$9,388,755
JUN 2008	$-10,398,941	$9,245	$23,710	$9,405,602	$0	$9,438,557	$960,385	$10,398,941

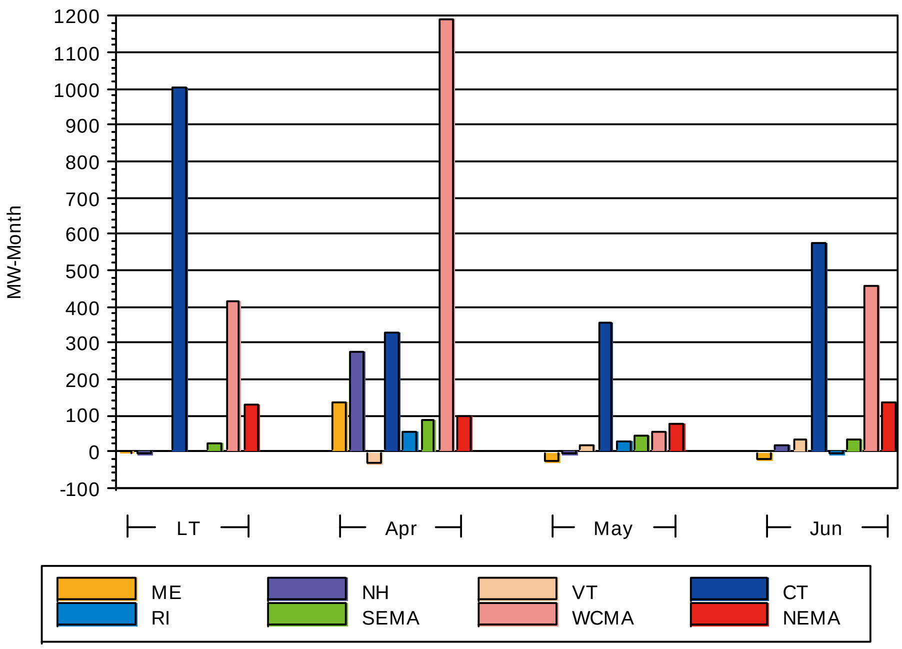
Table 23 displays the total distribution of ARR dollars to the various zones for each month including monthly-normalized long-term auction revenues.

Table 23 – ARR Award Allocation by Zone ($), 2008 Q2

Month	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
APR 2008	$145,831	$332,910	$343,026	$3,477,959	$51,033	$1,690,950	$607,267	$459,269
MAY 2008	$201,372	$513,026	$483,214	$3,500,634	$58,909	$2,539,566	$882,139	$807,877
JUN 2008	$165,553	$554,298	$469,459	$3,317,605	$55,008	$3,285,529	$880,290	$710,815

Figure 26 presents the overall pattern of inter-zonal FTR purchases (in MW-Months) for each of the on-peak auctions during the Reporting Period relative to the Hub. Zone-to-zone FTR purchases were decomposed into their zone-to-Hub and Hub-to-zone components. In the figure, negative values indicate that the net of all FTRs purchased between the Hub and the particular zone was toward the Hub (e.g., Maine), while positive values indicate net purchases from the Hub to the zone (e.g., NEMA and Connecticut, import-constrained areas).

Figure 26 – On-Peak Zonal FTR Awards by Month Relative to Hub 2008 Q2



Negative = Zone to the Hub Positive = Hub to the Zone

Figure 27 and Figure 28 present the relationship (on an equivalent $/MWh basis) of the cost to procure an FTR with the actual day-ahead and real-time congestion costs over the Reporting Period. The figures incorporate both the monthly and long-term auction results in the presentation of the cost of an FTR.

Figure 27 – FTR Auction Prices vs. Day-Ahead and Real-Time Congestion 2008 Q2, On Peak

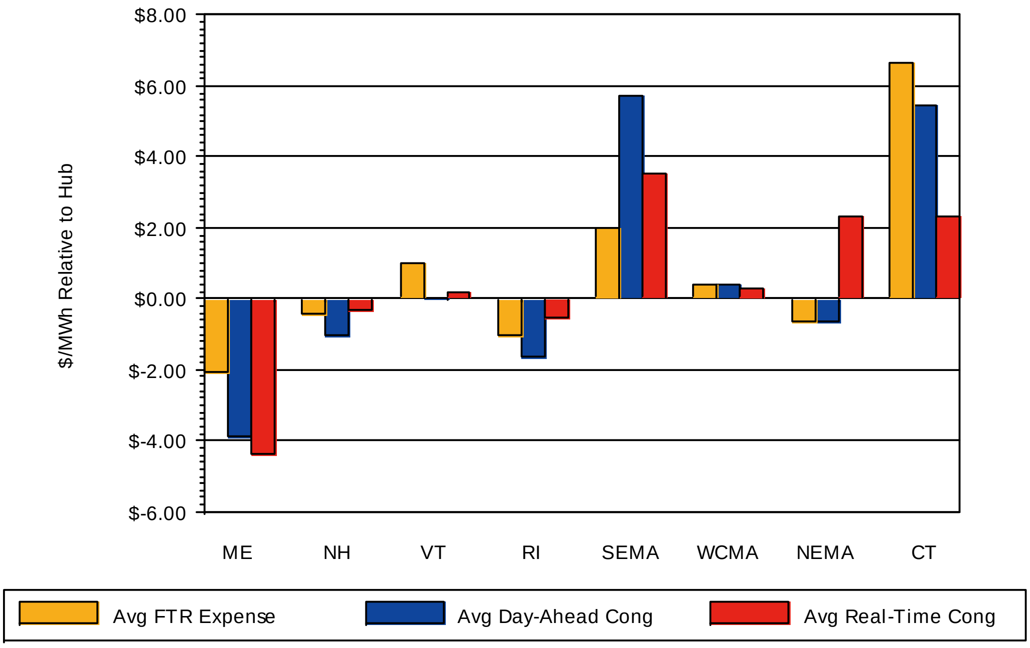
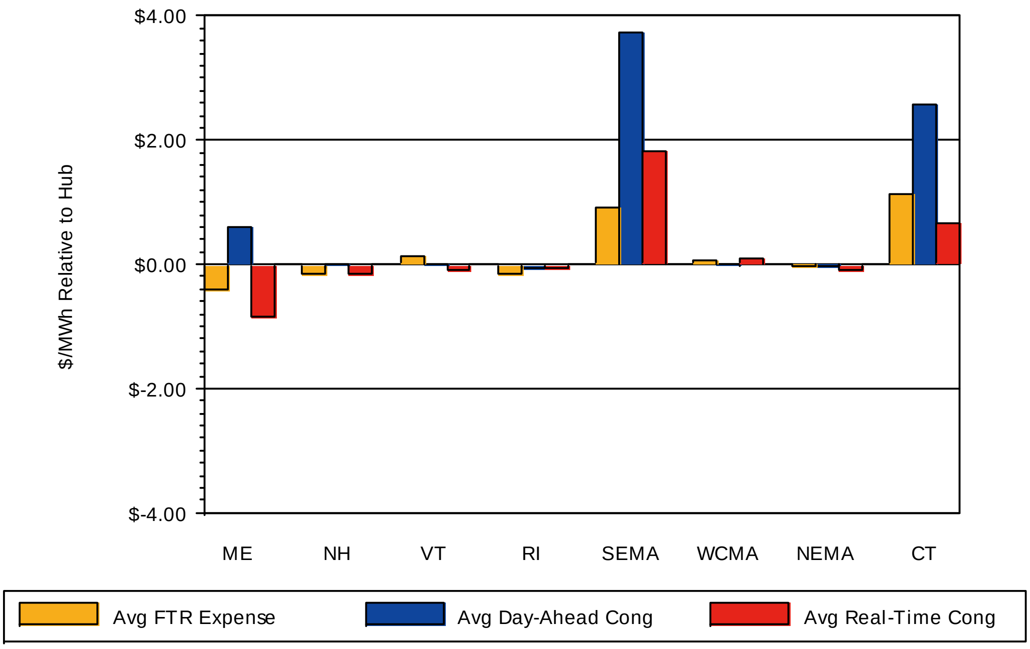


Figure 28 – FTR Auction Prices vs. Day-Ahead and Real-Time Congestion 2008 Q2, Off Peak



12.2 Financial Transmission Rights Clearing Prices

FTR clearing prices 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 24 compares maximum, minimum and average clearing price statistics for recent auctions. On-peak, off-peak and combined calculations are shown. Long-term auction values have been converted to $/MW-Month for comparison.

Table 24 - FTR Auction Clearing Price Statistics

	Auction Clearing Price ($/MW-Month)						
	Avg. Combined	**Avg. On-Peak**	**Avg. Off-Peak**	**Max On-Peak**	**Min On-Peak**	**Max Off-Peak**	**Min Off-Peak**
Jan-Dec 2008 LT	$4,788.78	$8,207.57	$1,471.15	$37,515.50	-$12,975.78	$13,362.52	-$4,279.26
Apr 2008	$585.58	$780.63	$404.48	$3,322.81	-$914.94	$1,203.85	-$29.72
May 2008	$502.27	$799.16	$211.87	$4,624.34	-$1,590.67	$1,629.49	-$328.27
Jun 2008	$727.20	$1,181.84	$289.08	$6,437.71	-$1,247.82	$2,832.38	-$224.77

Table 25 lists the highest priced sink-source combinations as purchased in the monthly auctions during the Reporting Period. In general, the table reflects the use of FTRs as a congestion hedge between generation-rich areas, such as Maine, and the most constrained areas on the system, such as the Connecticut and NEMA zones. Many of the highest revenue-producing sources were nodes.

Table 25 – Top Five Highest Priced FTR Sink-Source Combinations, Monthly Auction

Auction	On-Peak Auction		
	Source	Sink	Award Price
APR 2008	LD.E_BRGWTR13.8	LD.KINGSTON115	$3,218.69
APR 2008	LD.EASTON 115	LD.KINGSTON115	$3,190.47
APR 2008	LD.BATES_ST115	LD.CROSS_RD115 111X LD	$2,562.67
APR 2008	LD.TIVERTON115	LD.CROSS_RD115 111X LD	$2,562.32
APR 2008	LD.BATES_ST115	UN.DARTMTH 13.8DART	$2,556.97
MAY 2008	LD.E_BRGWTR13.8	LD.KINGSTON115	$3,218.69
MAY 2008	LD.EASTON 115	LD.KINGSTON115	$3,190.47
MAY 2008	LD.BATES_ST115	LD.CROSS_RD115 111X LD	$2,562.67
MAY 2008	LD.TIVERTON115	LD.CROSS_RD115 111X LD	$2,562.32
MAY 2008	LD.BATES_ST115	UN.DARTMTH 13.8DART	$2,556.97
JUN 2008	LD.E_BRGWTR13.8	LD.DUXBURY 115	$6,164.68
JUN 2008	LD.E_BRGWTR13.8	LD.MARSHFEL115	$6,164.68
JUN 2008	LD.MILL_ST 115	LD.KINGSTON115	$6,164.68
JUN 2008	LD.MILL_ST 115	LD.MARSHFEL115	$6,164.68
JUN 2008	LD.BELL_RK 34.5	LD.CROSS_RD115 109X LD	$6,161.77

12.3 Financial Transmission Rights Payment Results

FTR holders are paid through the Transmission Congestion Revenue Balancing Fund. Monthly revenues, target allocations, and allocations paid are shown in Table 26. 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 for each month.

Table 26 – Congestion Revenue Fund, 2008 Q2

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
APR 2008	$18,525	$12,030,178	$-754,256	$-5,708,416	$17,098,317	$-95,453	100.00%
MAY 2008	$11,113	$14,718,960	$-144,091	$-8,793,908	$23,484,496	$-104,605	98.21%
JUN 2008	$-88	$23,453,198	$-296,216	$-10,392,397	$31,732,442	$1,816,848	100.00%

12.4 Financial Transmission Rights Conclusions

Revenues from the FTR Auctions during the second quarter for 2008 totaled about $9.42 million. The total value of all FTRs active in the quarter was about $28.04 million, which included the quarterly share of the January-December 2008 auction value (91/366) of $74.7 million. Bids and offers cleared with negative prices that totaled to $4.13 million. The $9.42 million value for the auction is realized by netting $4.13 million in net payments to FTR holders with negative prices from $13.56 million in net collections from FTRs with positive prices.

13. Demand Response

Demand response in wholesale electricity markets refers to resources that reduce consumption of electric energy from the high-voltage transmission system in response to either high wholesale prices or system reliability events in exchange for compensation based on wholesale market prices. [16] The ISO administers the Demand Response Programs for the New England wholesale electricity market. During the second quarter of 2008, the ISO administered several demand response programs. Other demand resources such as energy efficiency, load management, and distributed generation 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. All types of demand resources may provide relief from capacity constraints, the activation of reserve, or promote more economically efficient uses of electrical energy. Along with adequate supply and robust transmission infrastructure, demand resources are an important component of a well-functioning wholesale market.

The ISO operates three reliability-activated and two price-activated demand-response programs for the New England wholesale electricity market. Another group of demand resources known as other demand resources (ODRs) came into being with the implementation of the FCM transition period. The reliability-activated demand-response programs and ODRs are considered capacity resources and are eligible to receive FCM transition payments.

Reliability Programs

The demand-response programs that help preserve system reliability 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 of this program include 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.

[16] Demand resources include sites enrolled individually and collections of multiple sites enrolled by one customer.

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

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

- **Real-Time Price-Response Program—**involves voluntary load reductions by program participants that are eligible for payment when the 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 RT LMP.

- **Day-Ahead Load-Response Program (DALRP)—**an optional program that allows a participant in any of the real-time programs 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. The participant is then charged or credited at the real-time LMP for any deviations in curtailment during real-time for the cleared interruptions.

Other Demand Resources:

- **Other Demand Resources (ODRs) —**other demand resources were established by the FCM Settlement Agreement and are eligible to receive FCM transition payments. These resources consist of energy efficiency, load management, and distributed generation projects implemented by market participants at retail customer facilities.

13.1 Demand Response Results

As of July 1, 2008, 2,838 assets were enrolled in the ISO's demand response programs, comprising 1,706.6 MW of potential demand interruption or curtailment. Table 25 displays enrollment by zone and by program, as well as the changes in each category from the same period in 2007. Figure 27 shows the amount of enrolled megawatts of Demand Response participation from January 2005 through June 2008.

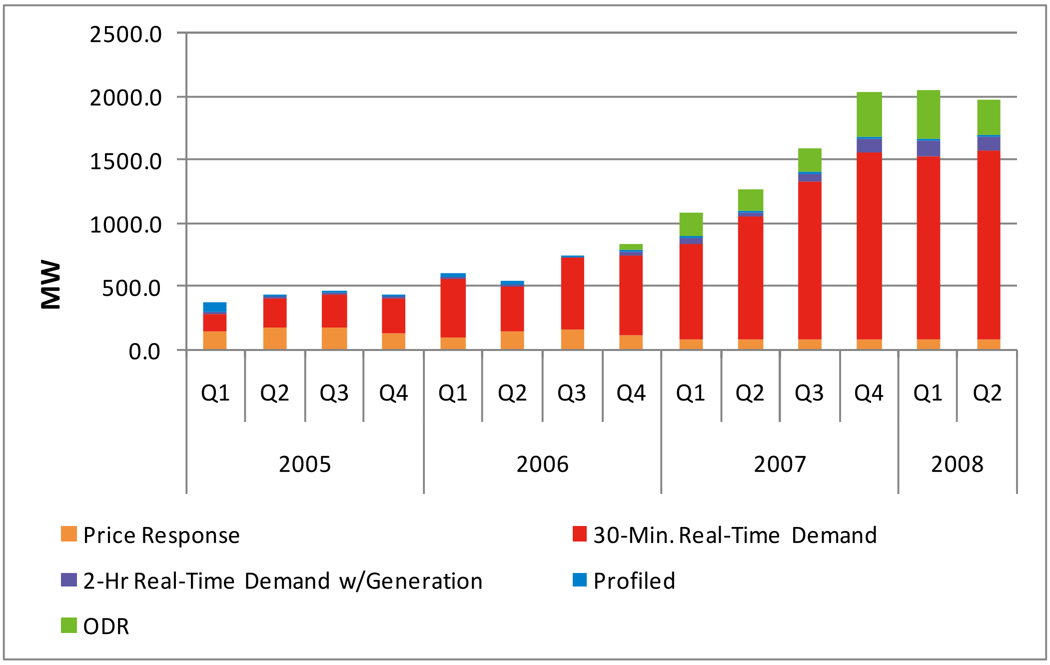
The quantity of enrolled MW has increased 85% since July 1, 2007, with the majority of the increases coming from greater participation in the Reliability based Real-Time 30-Minute and Real-Time 2 Hour Demand-Response Programs. In the Connecticut load zone, enrollment increased to 725 MW in the second quarter of 2008 from 607 MW during the same period in 2007.

Table 27 – Demand Response Program Enrollments

	July 2008					
	Assets	MW	Real-Time Price	Real-Time 30-Min	Real-Time 2-Hour	Profiled
CT	1,412	725.2	7.3	717.9	0.0	0.0
SWCT*	675	332.2	0.7	331.5	0.0	0.0
ME	59	404.8	0.0	321.0	72.7	11.0
NEMA	370	166.7	30.9	135.8	0.0	0.0
NH	107	62.4	4.5	56.8	1.1	0.0
RI	208	79.6	16.5	57.7	5.4	0.0
SEMA	275	83.4	9.5	66.3	7.5	0.0
VT	69	40.5	6.3	25.4	2.9	5.9
WCMA	338	144.1	22.0	102.9	19.1	0.0
Total	2,838	1,706.6	97.0	1,483.9	108.9	16.9
% Change from July 2007	43.0%	54.6%	0.03%	54.8%	213.8%	0%

*SWCT assets are included in CT values and are not included in total.

Figure 29 - Demand Response Enrollment by Program



Demand response programs provided 15,005 MWh of demand reductions during the Reporting Period. The majority of these reductions were from the two price-activated programs: Real-Time Price Response and the Day-Ahead Load Response Program. There were no reliability programs activated during the Reporting Period. Payments to resources providing demand reduction totaled $1.79 million during the Reporting Period.

14. Market Monitoring and Mitigation

Market Rule 1, Appendix A, regarding Market Monitoring, Reporting and Market Power Mitigation, provides for the monitoring and, in specifically defined circumstances, the mitigating of behavior that interferes with the competitiveness and efficiency of the Energy Market and NCPC payments. There was one mitigation event in the Real-Time Energy Markets and one mitigation event in the Day-Ahead Energy Market. There were no mitigation events in Day-Ahead or Real-Time Net Commitment Period Compensation payments during the Reporting Period.

15. Generating Unit Availability

In its continuing effort to monitor and analyze the availability of New England's generating units, the ISO's System Planning department routinely analyzes generating unit availability. This type of analysis is important in assessing whether the market is providing the proper incentives for availability, a key factor in maintaining both reliability and market competitiveness. Historical generator availability is presented below to provide a more encompassing view of trends in unit performance.

Table 28 illustrates the Weighted Equivalent Availability Factors[17] (WEAF) of New England generating units during the second quarter of 2008. As illustrated, the monthly system WEAF increased through the quarter with June 2008 having the highest WEAF (90%), as generator maintenance decreased and System Operators prepared for the summer peak load period.

Table 28 – New England 2008 Monthly
Weighted Equivalent Availability Factors (%) by Unit Type

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08
System Average	90	92	85	75	77	90
Fossil Steam	86	90	85	70	72	87
Coal	83	84	80	73	57	77
Coal/Oil	93	96	96	65	81	99
Oil	74	82	93	64	58	81
Oil/Gas	98	100	78	69	91	98
Wood/Refuse	94	94	90	87	90	92
Nuclear	100	100	100	56	75	97
Jet Engine	98	99	91	92	92	96
Combustion Turbine	93	95	95	92	83	96
Combined Cycle	87	90	76	75	72	86
Pre-1999 Combined Cycle	91	99	85	93	89	99
New (Installed 1999-2008) Combined Cycle	86	88	74	71	68	82
Hydro	97	98	100	99	98	98
Pumped Storage	99	90	81	96	98	99
Diesel	98	99	100	97	93	99

[17] The term "Weighted" means that averaging is proportional to unit size, so that a 100 MW unit counts ten times more than a 10 MW unit. "Equivalent" means that both deratings (partial outages) and full unit outages are counted, proportional to the megawatts that are unavailable.

Figure 30 shows total peak day outages in megawatts for 2nd quarter 2007 through 2nd quarter 2008 and the amount of capacity on outage as a percentage of total available capacity (seasonal claimed capability). This figure illustrates how both the spring and fall months have the largest number of outages, while the summer period has the smallest number. Peak day outages about the same in April and May 2008 compared to 2007, but higher in June 2008 compared to the same period in 2007.

Figure 30 – Average Generator Outages on Peak Demand Day of Month

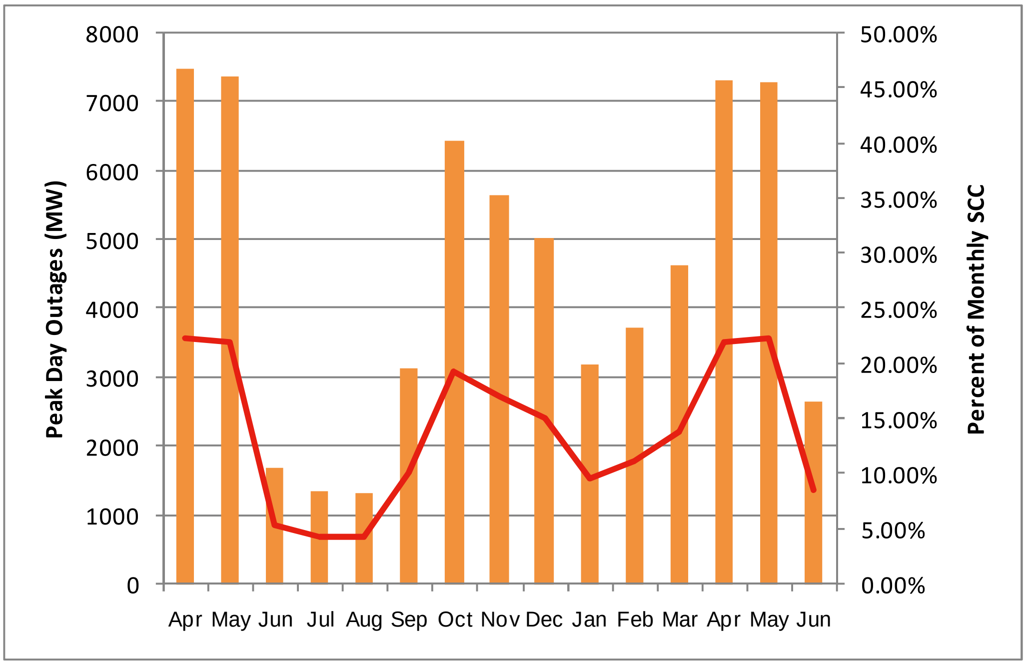
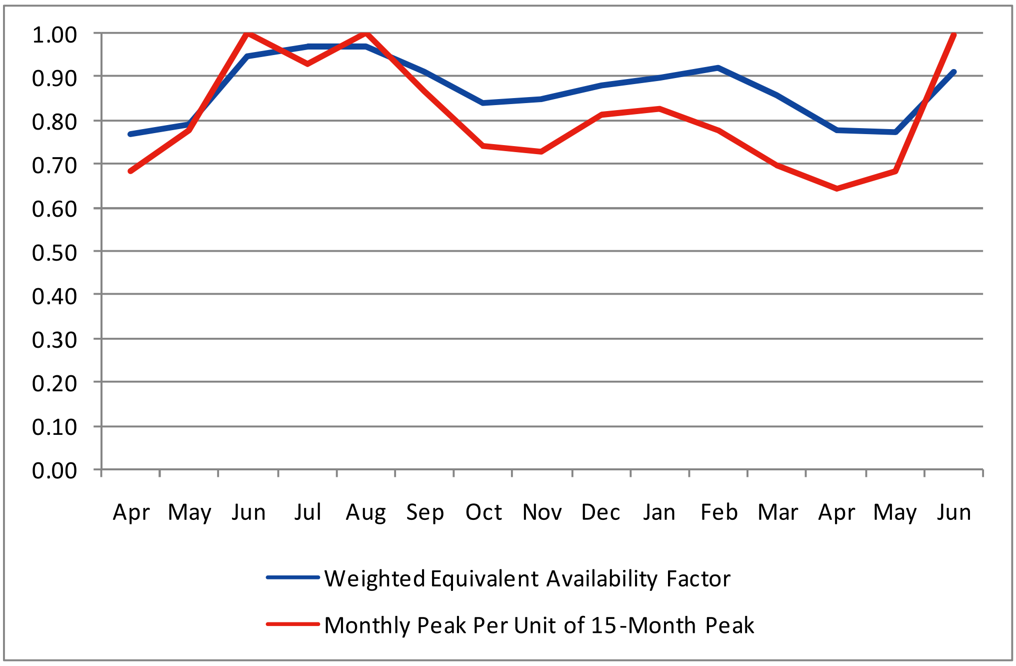


Figure 31 illustrates how the availability of the New England generating units tracks the monthly electrical demands. Specifically, Figure 31 illustrates the monthly WEAF compared to the monthly peak electricity demand as a percentage of the 15-month period peak demand. For the 15-month period of April 2008 through June 2008, the peak of 26,264 MW occurred in June 2007. Similar to the information portrayed in Figure 28, the average availability for the New England generating units is lowest during the months that have the lowest demand. In contrast, when New England experiences the highest demand, the average availability of New England generators is the greatest.

Figure 31 – Monthly Peak Demand and Average Availability (WEAF)



15. Administrative Price Corrections

The ISO continually monitors the processes associated with the calculation of LMPs. In the event of a data input failure, hardware or software failure or outage, program failure, or binding constraint errors, corrective actions may be taken to ensure that the resulting LMPs are as accurate as is reasonably possible.

Figure 32 shows the number of hours with real-time LMP corrections made during each month during the Reporting Period. In many cases, corrections affected LMPs at only a few individual nodes. Real-time nodal prices were unaffected.

There were no revisions to day-ahead prices during the Reporting Period.

Figure 32 – Real-Time Energy Market LMP Corrections by Month