2006 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, the "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

On February 1, 2005, the ISO began operation as a Regional Transmission Organization (RTO), assuming broader authority over the day-to-day 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 continues to work closely with regulators and stakeholders, including participants in the marketplace.

1.2 About Market Monitoring

The ISO's responsibility in overseeing the region's wholesale electricity marketplace is to ensure that the markets are fair, transparent, efficient, and competitive. As part of this responsibility, 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. Where design flaws are identified, the ISO works with market participants, state regulators, FERC, and other agencies to correct those imperfections.

To assess the operation of the markets, provide transparency, and meet Federal reporting guidelines, the ISO issues periodic market reports that describe the development and performance of New England's wholesale markets. The ISO seeks regular input from its Independent Market Monitoring Unit (IMMU), David B. Patton, Ph.D., to provide an additional, independent review of significant market developments.

This 2006 Second Quarter Quarterly 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 2006.

For a more complete discussion of wholesale markets, the reader is referred to the ISO's 2005 Annual Markets report, which is available on the ISO's web site[1].

[1] Annual Report from 2005

2. 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, 2006 to June 30, 2006 (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 were six mitigation events in the Net Commitment Period Compensation Credits and one mitigation event in the Real-Time Energy Market, during the Reporting Period.

- **Weather** — New England's average temperature was seasonal during the second quarter.

- **Peak Load** — On June 19th, a regional peak demand of 24,046 MW was set for the quarter.

- **Electric energy prices** — The system average Real-Time and Day Ahead electric energy prices for the Reporting Period were $57.33 and $58.52. The average hub Real-Time price and Day Ahead price in April were $62.33 and $60.88, in May were $56.05 and $56.34 and in June were $53.67 and $58.41, respectively.

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- **Boston Area OP4 —** On June 19, 2006, the ISO declared an OP4 event for Boston area. This was due to a transformer trip in Boston area, which caused limits on power flow on a certain interface.

- **Ancillary Service Market Phase II Project Update** – On May 12 2006, the Federal Energy Regulatory Commission (FERC) issued an order approving ISO New England's proposal for Phase II of the Ancillary Services Market project, paving the way for the associated package of market enhancements to become effective October 1, 2006. The most significant changes to the market will be the addition of a locational component to the Forward Reserve Market (FRM) and the co-optimized dispatch and pricing of energy and reserves in real time.

3. Electric Energy Markets

Key factors that influence the market price for electric energy are supply and demand, fuel prices, and transmission constraints.

3.1 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).[2] NEL supplied to the system in the second quarter of 2006 decreased by 1.6% relative to the second quarter of 2005. Since NEL is modestly influenced by weather, to allow for more accurate comparisons of load growth across years the ISO calculates the weather-normalized NEL that is, the NEL that would have been observed if weather were normal. The quarter showed a weather-normalized decrease in NEL in 2006 compared to 2005 values of -0.8%, as shown in Table 1.[3] Figure 1shows demand for each load zone.

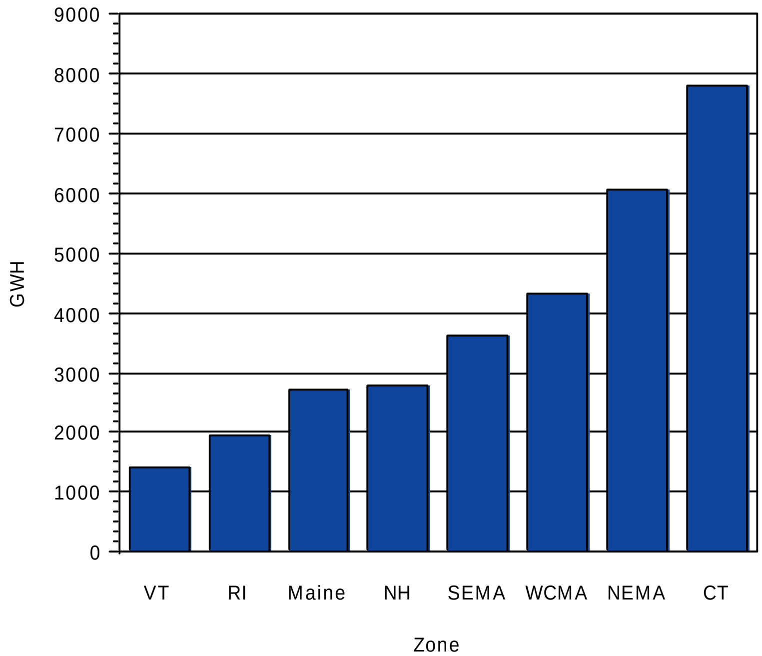
Table 1 – Net Energy For Load

Net Energy For Load	(GWh)			
	2006	2005	Diff.	%Chg.
Q2 Recorded	31,215	31,712	-497	-1.6%
Q2 Weather Normalized	31,056	31,297	-241	-0.8%

[2] 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.

[3] 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, and upward adjustment is made. Summer months also account for the effect of humidity on consumption levels.

Figure 1 – Demand by Load Zone, Q2 2006



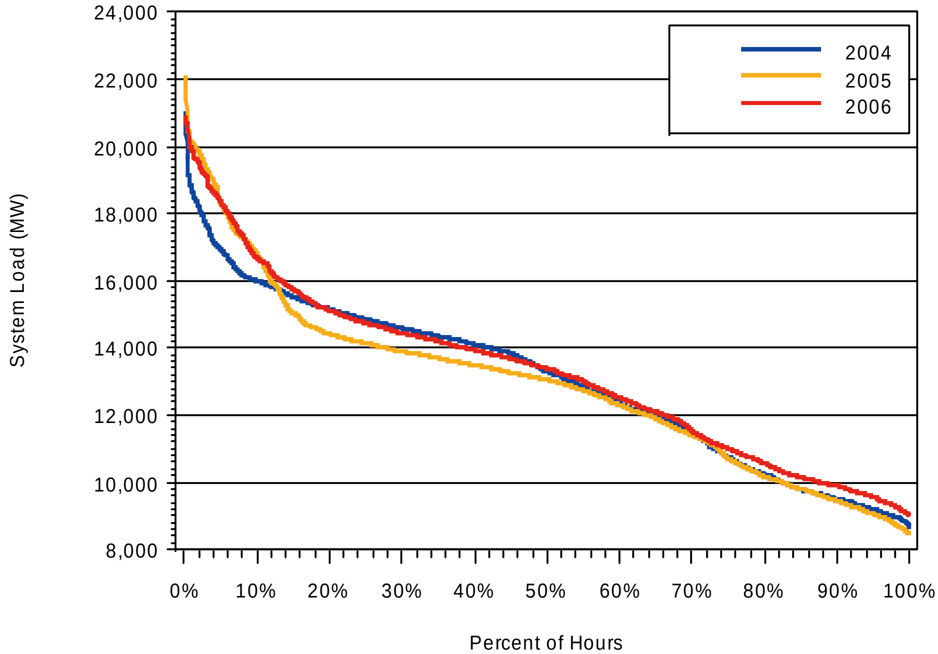
The second quarter system peak hourly load of 24,046 MW occurred on June 19, 2006. As shown in Table 2, this was 9.5% below the peak of 25,251 MW in the second quarter of 2005.

Table 2 – Q2 Peak Load Statistics

Peak Hourly Load	2006	2005	Change	% Chg.
Recorded Actual (MW)	24,046	25,251	-1,205	-9.5%

Figure 2 shows load levels for the second quarters of the past three years as load-duration curves, with the 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.

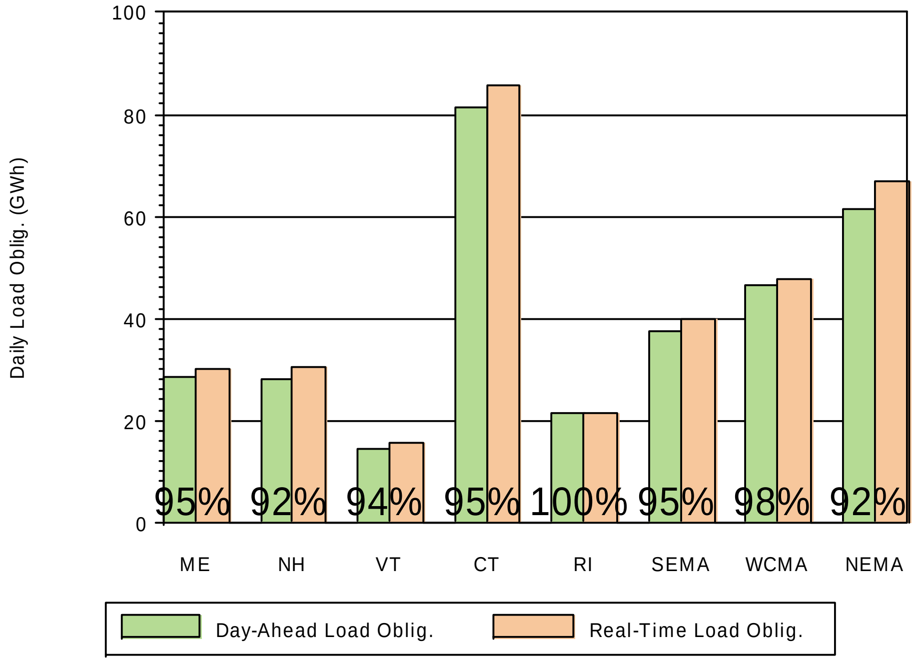
Figure 2 – New England Hourly Load Curves
Q2, 2004- 2006



3.1.1 Load Obligation

During all Reporting Period hours, the day-ahead load obligation averaged about 96% of the real-time load obligation. This percentage varied across zones. Figure 3 presents the statistics for the Reporting Period by zone. The Rhode Island and WCMA load zones cleared the highest percentage of load, 100% and 98%, respectively.

Figure 3 – Average Day-Ahead Load Obligation vs. Real-Time Load Obligation by Zone, 2006 Q2



3.1.2 Day-Ahead Demand and Virtual Trading Trends

Figure 4 shows the average hourly submitted and cleared quantities of demand, virtual demand, and virtual supply for the Reporting Period. Around 61% of cleared demand bids were fixed demand bids, insensitive to price, while approximately 34% were price-sensitive demand bids. The remaining 5% of cleared day-ahead demand was virtual demand bids, representing day-ahead locational purchases of electric energy.

Figure 4 – Average Hourly Submitted and Cleared Demand, Virtual Demand, and Virtual Supply Day Ahead Market, 2006 Q2

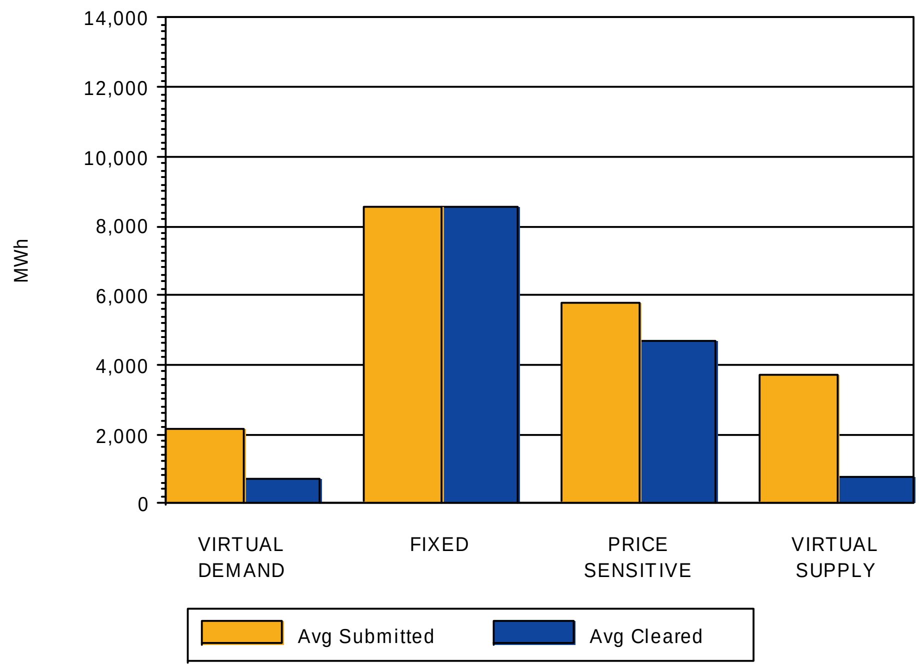


Figure 5 and Figure 6 show the daily total of the hourly submitted and cleared virtual transactions over the three-month Reporting Period. Submitted quantities of virtual transactions varied more than cleared volumes during the period. About 17,137 MWh of virtual demand bids and about 18,139 MWh of virtual supply offers cleared on average per day during the period.

Figure 5 – Submitted and Cleared Virtual Demand Daily Totals, 2006 Q2

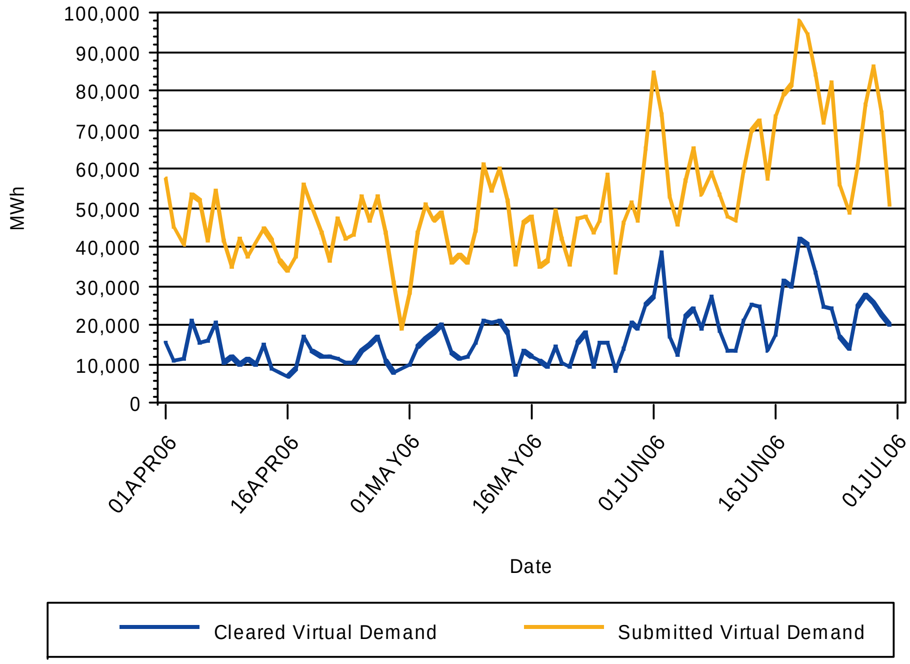
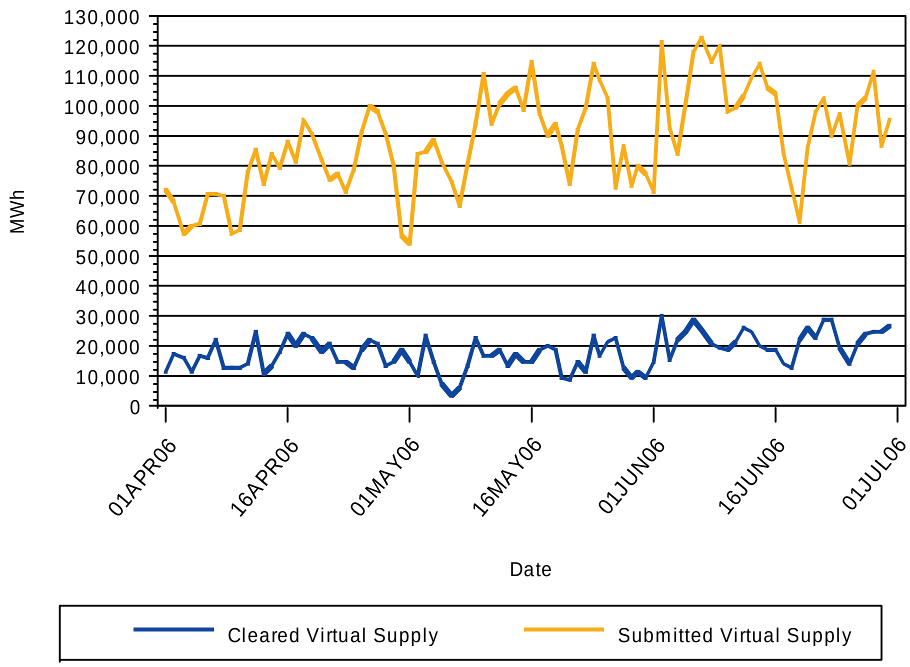


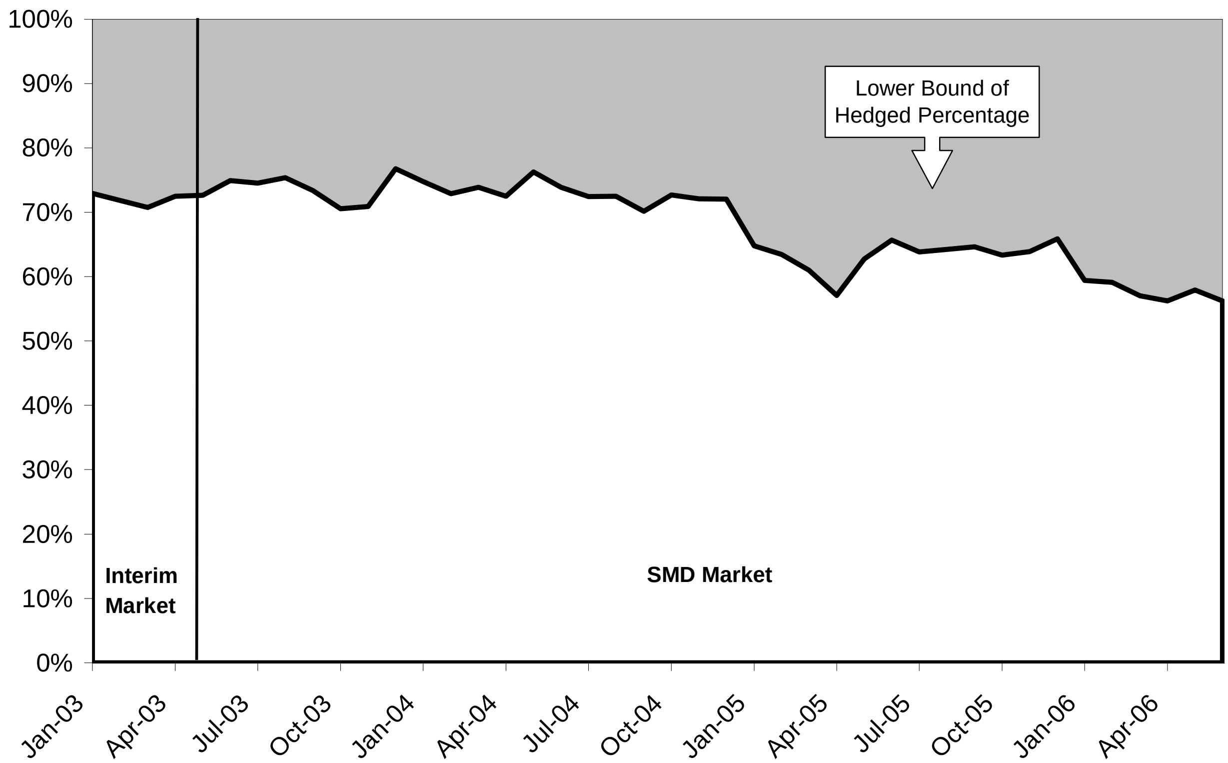
Figure 6 – Submitted and Cleared Virtual Supply Daily Totals, 2006 Q2



3.1.3 Forward Contracting

As shown in Figure 7, calculations for April 2006 through June 2006 show that, on average, about 61.9% of the total real-time load obligation was either forward contracted or covered by a physical hedge. This is approximately the same percentage as was seen during the same period last year, when the degree of forward contracting was at least 62% of real-time load obligation in each month. The information shown in Figure 7 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.

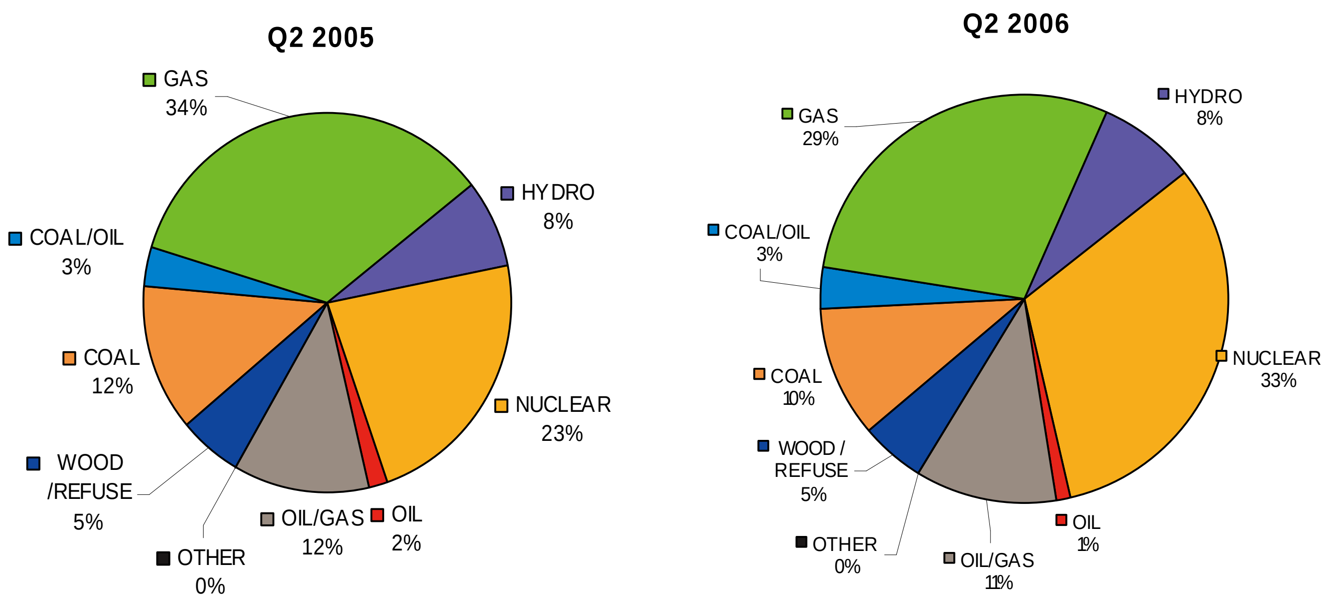
Figure 7 – Q2 Lower Bound of Real-Time Load as Hedged through ISO Settlement System



3.2 Supply

Figure 8 shows generation by fuel type as a percentage of total generation for the second quarters of 2005 and 2006. The percentages are relatively constant from 2005 to 2006 except for oil, gas and nuclear fuels. The increase in gas generation, the fuel of choice, and hydro generation is a reflection of the increase in oil prices during the second quarter of 2006. All the region's nuclear units were online during the quarter. Overall, second quarter generation decreased by 1.0% year-over-year, from 33,541 GWh in 2005 to 32,122 GWh in 2006, while non-weather normalized NEL decreased by 0.8%. Net interchange with other control areas decreased from 1,176 GWh in the second quarter of 2005 to 1,021 GWh of net imports in the second quarter of 2006. Generation used to support pumping at pumped storage hydro generators is not included in NEL.

Figure 8 – Actual Generation by Fuel Type



New England was a net importer from Canada but a net exporter to New York during the Reporting Period, with net imports accounting for 3.3% of the quarterly NEL in New England. Figure 9 shows total interregional power flows for the second quarters of 2001 through 2006. Figure 10 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 9 – New England Imports, Exports and Net Interchange
All Interfaces: Q2, 2001 – 2006

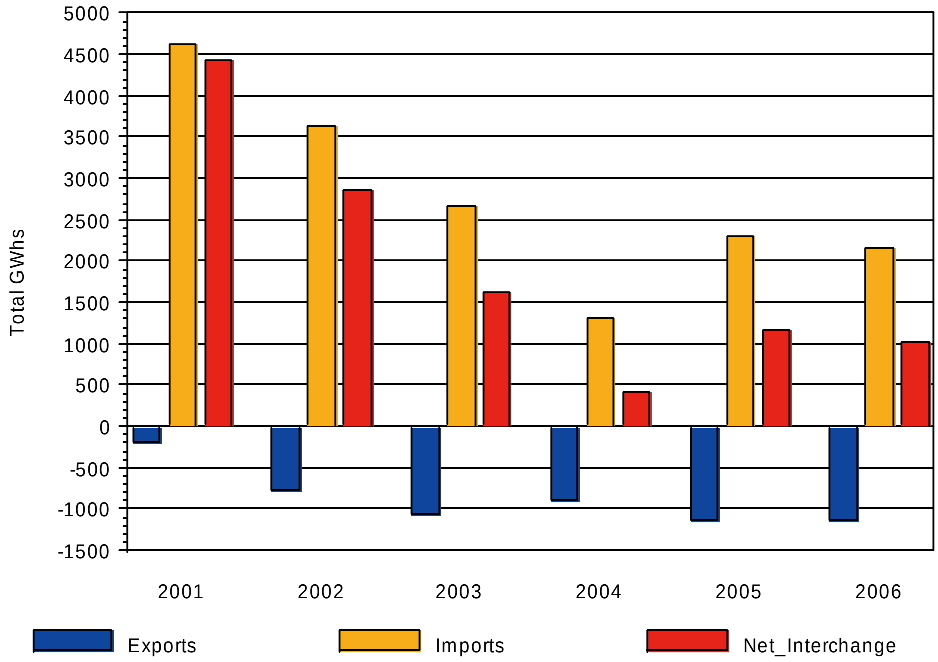
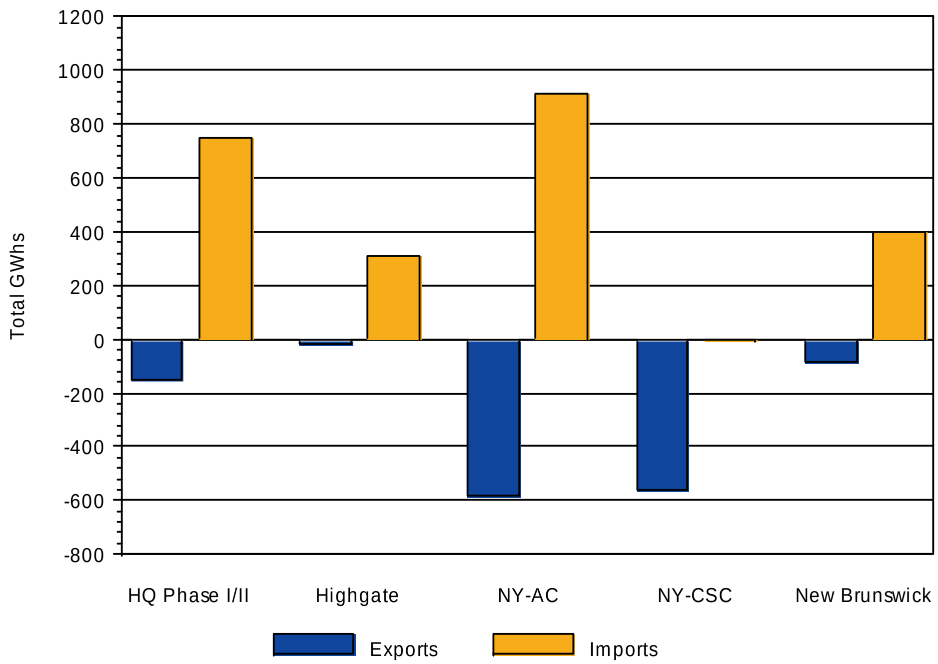


Figure 10 – New England Imports, Exports by Interface
Q2 2006

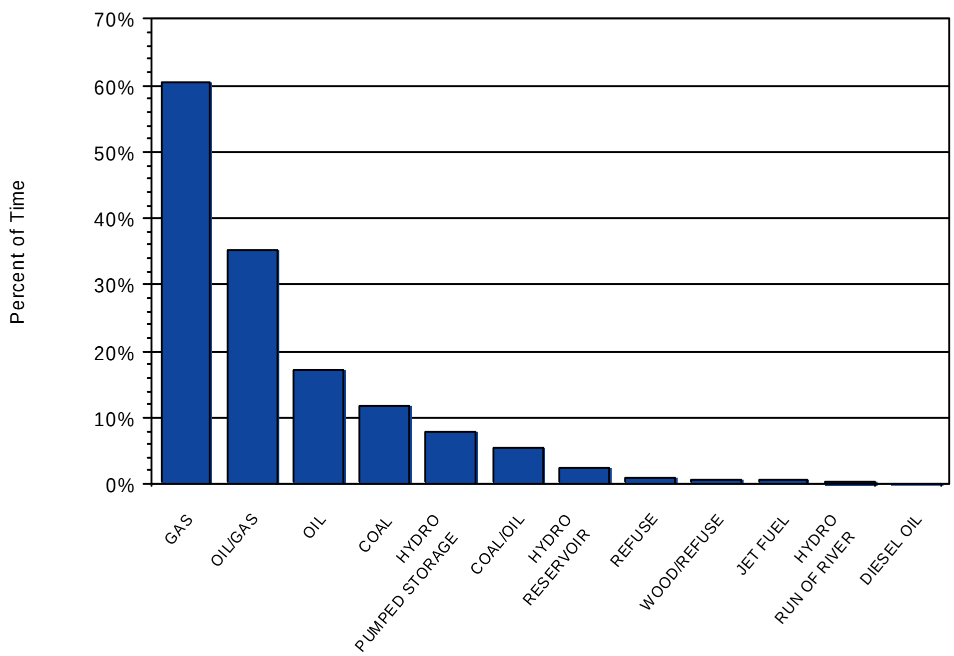


3.3 Electric Energy Prices

3.3.1 Marginal Input Fuel Types

Figure 11 shows the real-time marginal, or price-setting, input fuels during the Reporting Period as a percentage of pricing intervals in the period. 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 61% of the time during the period. Oil/Gas units, many which burn gas as their primary fuel, were marginal about 35% of the hours. These results show the extent to which New England power prices are dependent on gas unit offers.

Figure 11 – Marginal Units by Unit Type
2006 Q2



3.3.2 Electric Energy Prices and Fuel Prices

Natural gas spot prices, a primary driver of electric energy prices in New England, were between $6.06/MMBtu and $8.50/MMBtu and averaged $7.02/MMBtu during the Reporting Period. No6 oil ranged from $8.20/MMBtu to $9.17/MMBtu with an averaged $8.65/MMBtu. Low sulfur coal ranged from $2.17/MMBtu to $2.41/MMBtu with an average of $2.27/MMBtu. High sulfur coal ranged from $1.75/MMBtu to $1.96/MMBtu with an average of $1.82/MMBtu. Figure 12 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 12 – Daily Avg. Real-Time System Price of Energy vs. Variable Production Costs, 2006 Q2

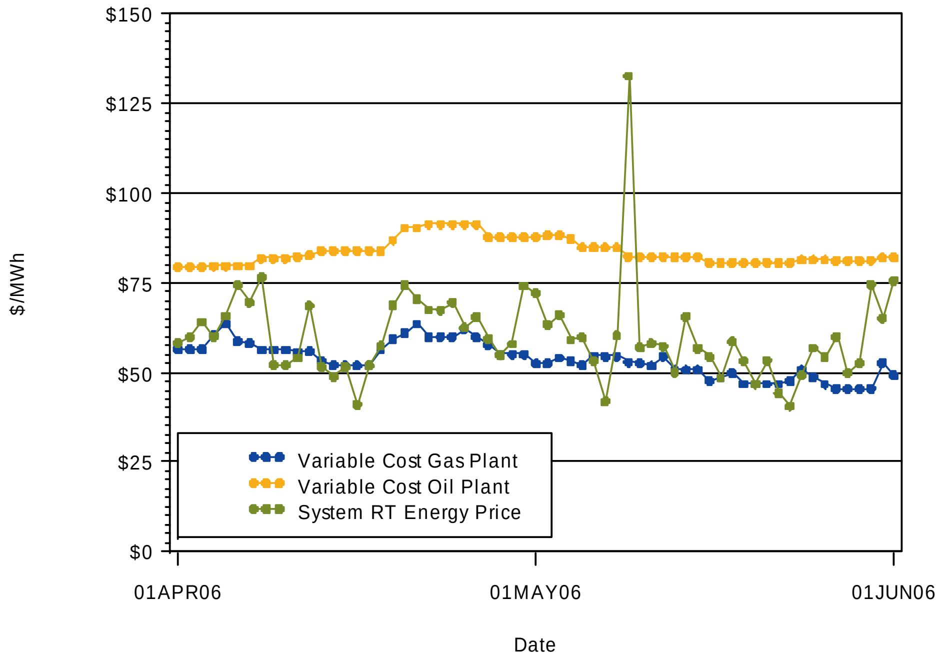


Table 3 shows average annual fuel prices for natural gas and No6 fuel oil for the second quarter of each of the last six years, indexed to its value in the year 2000. These two fuels are shown because they are on the margin for a majority of the time in New England, as was shown in Figure 11. Natural gas prices during the second quarter of 2006 were about 6.0% lower than those during the second quarter of 2005, while No6 oil prices increased by about 17%. Coal increased by 12%.

Table 3 – Fuel Price Index for Second Quarters, Year 2000 Basis

Fuel	2000	2001	2002	2003	2004	2005	2006
Natural Gas	1.00	1.21	0.93	1.55	1.70	1.93	1.85
No6 Oil	1.00	0.92	0.94	1.01	1.18	1.61	2.06

3.3.3 Electric Energy Prices Throughout the Quarter

Figure 13 and Figure 14 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. 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 2006 were considerably higher than those during the second quarter of 2004 but generally lower than the second quarter of 2005. This pattern is consistent with the fuel prices. There was one hour in 2006 with a price above $200/MWh in the Real-Time Price Duration Curve. To make the graph more readable, this hour was not included Figure 15 shows average quarterly prices since the introduction of LMPs, with those in the second quarter of 2006 higher than the preceding quarters.

Figure 13 – New England Hourly DA System Price Duration Curves Q2, 2004 - 2006, Prices <$150

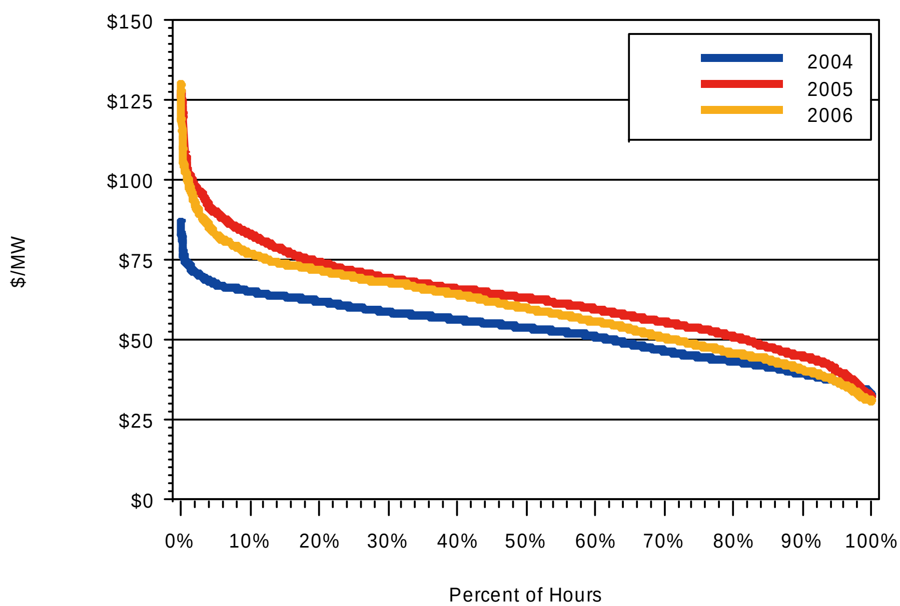


Figure 14 – New England Hourly RT System Price Duration Curves
Q2, 2004- 2006, Prices < $200

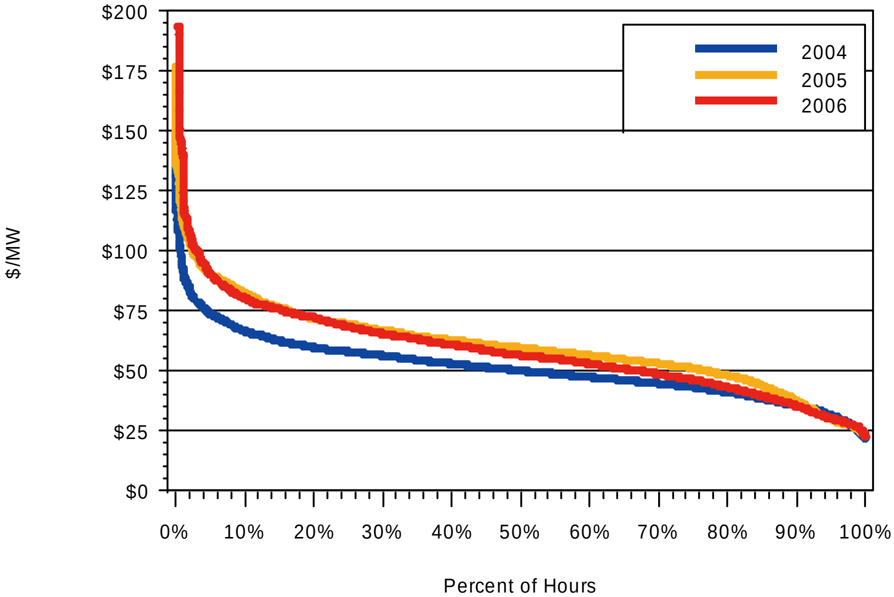


Figure 15 – Average Quarterly Load-Weighted System Day-Ahead and Real-Time LMPs
2004 Q2 – 2006 Q2

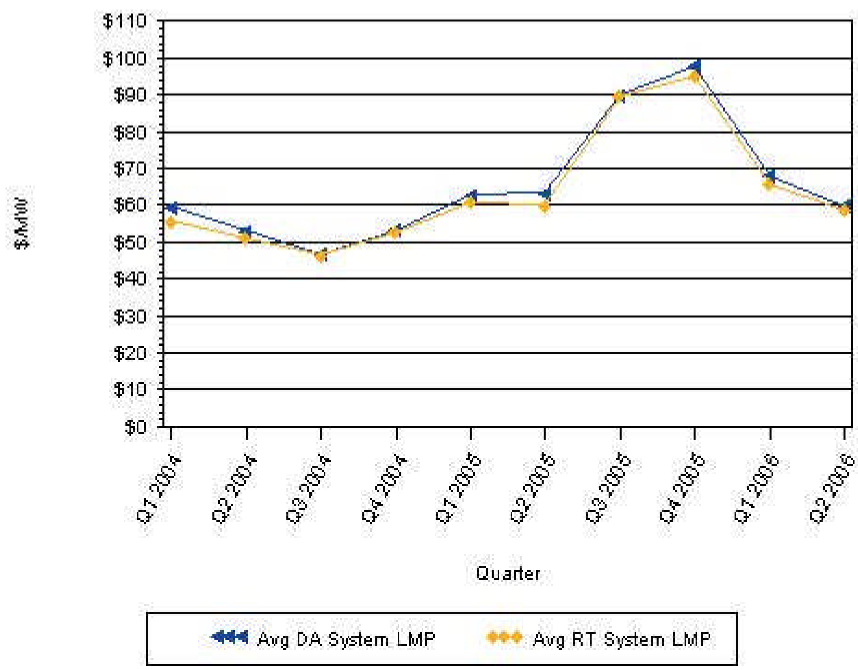


Table 4 shows the quarterly average, minimum and maximum LMP values as well as the minimum and maximum values at the Hub, eight load zones, and the five external nodes that are priced in New England. Export constraints and negative marginal losses resulted in the Maine load zone having the lowest average prices. Import constraints caused higher prices in Connecticut and Vermont, particularly in the Day-Ahead Energy Market. Average day-ahead and real-time prices were highest in Connecticut.

Average day-ahead LMPs were higher than average real-time LMPs for all the zones except for NEMA/Boston. The mild spring contributed to price differences between the Day-Ahead and Real-Time Energy Markets that average about $1.93. The largest difference was in Connecticut at $2.97 and the smallest in New Hampshire at $0.59. NEMA/Boston was the only zone where the average real-time LMP was lower than the average day-ahead LMP.

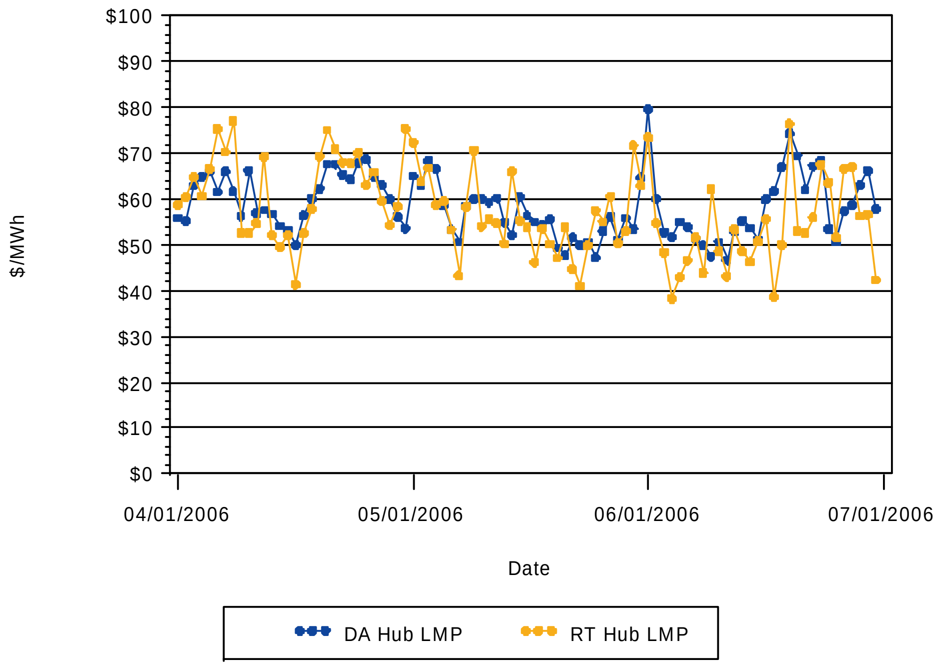
Over the quarter, the day-ahead Hub price averaged $58.52/MWh, while the real-time price averaged $57.33/MWh, a $1.18/MWh, or 2.1%, difference during the quarter. Hourly Hub LMPs over the three-month period were between $24.36/MWh and $108.87/MWh in the Day-Ahead Energy Market and between $0.00/MWh and $195.12/MWh in the Real-Time Energy Market. Hub LMPs were below $100.00/MWh in 56% of hours in the Day-Ahead and 55% in the Real-Time Energy Markets. Sixty-four percent of the 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 $28.20/MWh.

Table 4 – Summary Hourly LMP Statistics by Location, Q2 2006, All Hours

Location/Zone	LMP ($/MWh)					
	Avg DA	Avg RT	Min DA	Min RT	Max DA	Max RT
Internal Hub	$58.52	$57.33	$24.36	$0.00	$108.87	$195.12
Maine Load Zone	$55.34	$54.55	$23.61	$0.00	$88.98	$192.27
New Hampshire Load Zone	$57.19	$56.60	$23.92	$0.00	$94.80	$286.78
Vermont Load Zone	$58.27	$57.44	$23.92	$0.00	$99.77	$193.93
Connecticut Load Zone	$64.08	$61.10	$23.85	$0.00	$197.62	$225.49
Rhode Island Load Zone	$57.12	$56.15	$23.79	$0.00	$91.58	$192.21
SEMASS Load Zone	$57.29	$56.29	$23.97	$0.00	$91.80	$191.17
WCMASS Load Zone	$58.72	$57.99	$24.35	$0.00	$110.00	$196.06
NEMA/Boston Load Zone	$60.37	$61.77	$24.20	$0.00	$247.50	$999.28
NB-NE External Node	$53.44	$52.14	$23.00	$0.00	$84.71	$184.43
NY-NE AC External Node	$57.97	$57.02	$23.48	$0.00	$122.13	$194.48
HQ Phase I/II External Node	$56.70	$55.64	$23.93	$0.00	$91.10	$191.97
Highgate External Node	$55.36	$54.52	$22.65	$0.00	$98.27	$186.22
Cross Sound Cable External Node	$60.83	$58.58	$23.96	$0.00	$199.41	$228.62

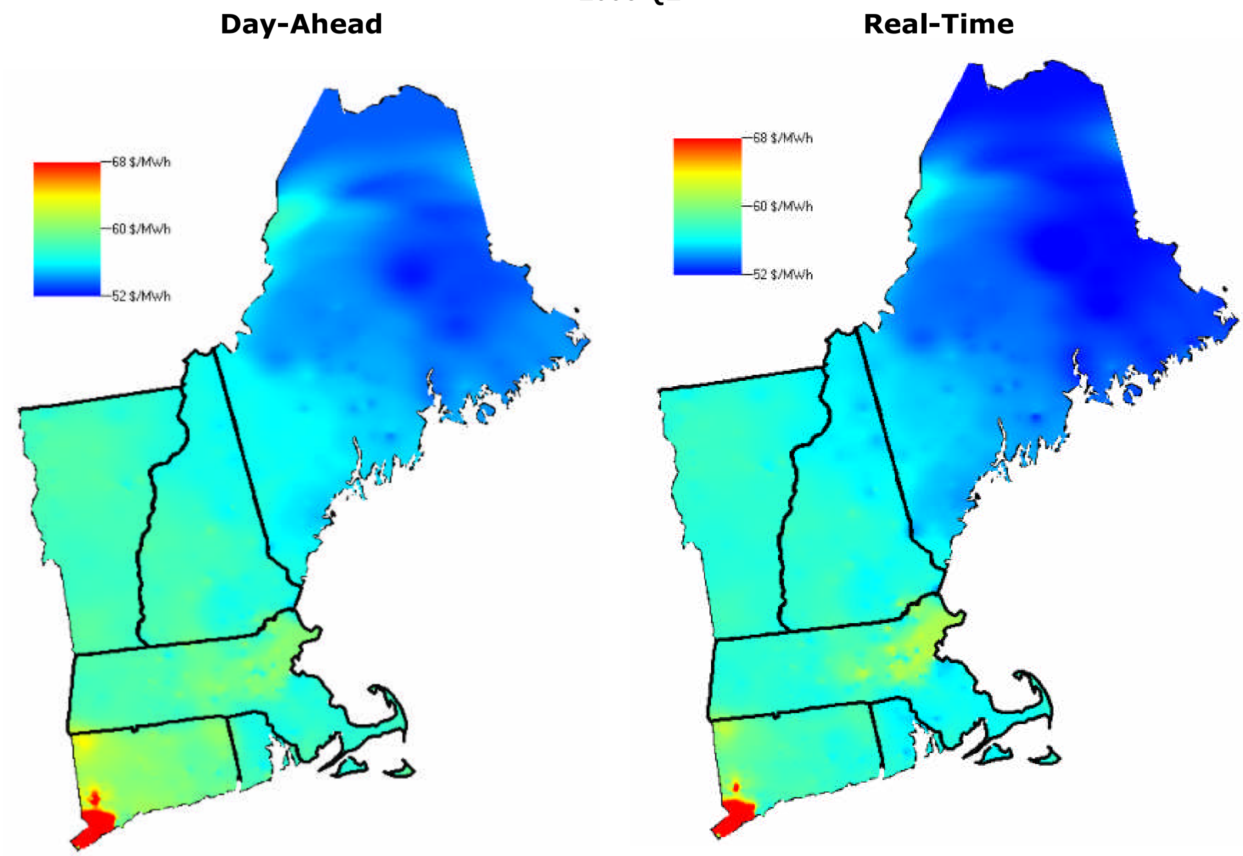
Figure 16 shows daily average Hub LMPs. Hourly prices were at times higher or lower than these daily average values

Figure 16 – Daily Average Hub LMP
2006 Q2



On the maps in Figure 17, average quarterly nodal LMPs are shown in color gradations from blue (representing $52/MWh) to red (representing $68/MWh).

Figure 17 – Average Nodal Prices,
2006 Q2



3.3.4 Wholesale Prices in Other Northeastern Pools

Comparing price levels among interconnected power pools provides a context for evaluation of price levels in New England. Table 5 shows quarterly average system prices for the three Northeast ISOs: PJM, NYISO, and ISO-NE. 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.[4]

Table 5 – NE, NY, and PJM Average Electric Energy Prices
2006 Q2

Control Area	Day-Ahead ($/MWh)			Real-Time ($/MWh)		
	All Hours	On-Peak	Off-Peak	All Hours	On-Peak	Off-Peak
NE	$59.68	$69.83	$50.43	$58.73	$69.10	$49.30
NY	$62.28	$73.65	$51.91	$62.74	$77.59	$49.21
PJM	$45.45	$57.21	$34.76	$45.70	$58.84	$33.74

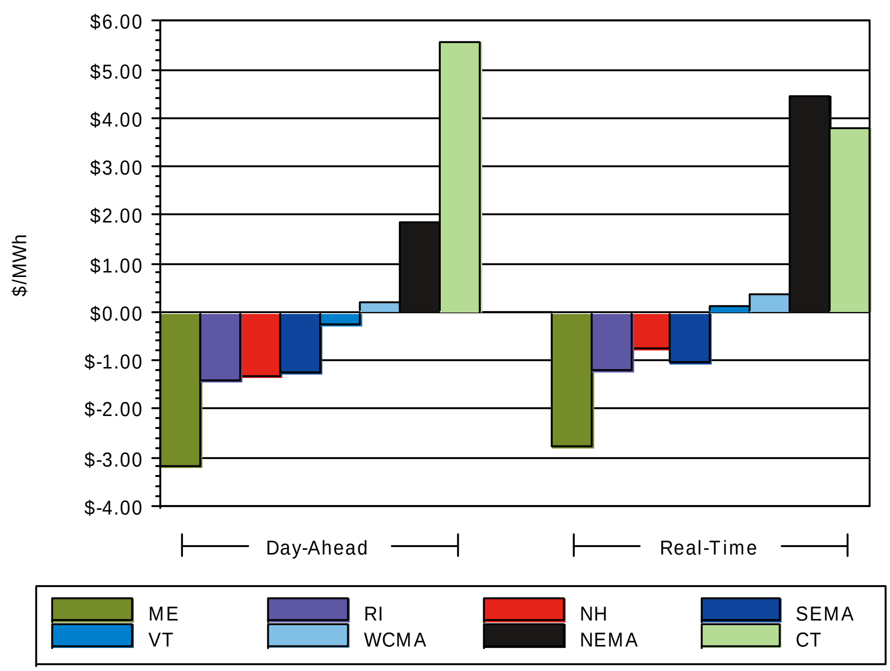
[4] PJM's web site is available at <http://www.pjm.com>. NYISO's web site is available at <http://www.nyiso.com>. Quarterly average system prices are not load-weighted.

New England's average prices were lower than those in NY and higher than PJM in both the Day-Ahead and Real-Time Energy Markets. Variations in average prices among the power pools are affected by transmission congestion, daily and seasonal load patterns, load concentration in congested areas, and the differences in generator efficiency and fuel mix.

3.3.5 Effects of Transmission Congestion and Marginal Losses on LMP

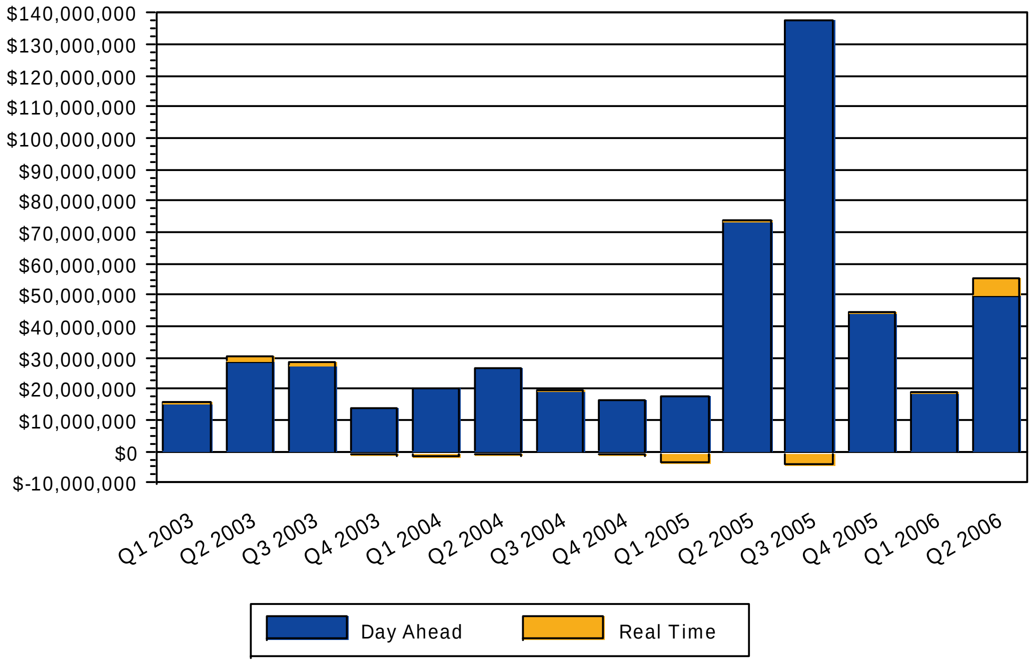
In addition to energy production costs, LMPs reflect the costs of transmission congestion and losses. The inclusion of these costs in the energy price and the resulting price separation between locations are key elements of efficient pricing. Figure 18 shows the average hourly differences between the LMPs in each zone and the LMPs at the Hub for the Reporting Period. The differences are due to the joint impact of congestion and losses in the Day-Ahead and Real-Time Energy Markets. Notable in the figure are the negative average differences in LMP in the Maine, Rhode Island, New Hampshire, SEMA and Vermont load zones (compared to the Hub) and the positive average differences in the WCMA, NEMA and Connecticut load zones (compared to the hub).

Figure 18 – Average Hourly LMP Difference from Hub
2006 Q2



Congestion revenues, which are collected in the congestion revenue fund and used to pay FTR holders, were higher than the previous quarter. Congestion revenue was almost 300% greater than the first quarter of 2006 but 25% lower then the second quarter of 2005. Figure 19 shows total congestion revenue by quarter since the implementation of SMD in March 2003.

Figure 19 – 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, a total of $18 million was returned to load-serving entities from the Marginal Loss Revenue Fund.

3.4 Electric Energy Market Conclusions

Energy market operations were normal during the Reporting Period, with Hub LMPs that averaged $58.52/MWh in the Day-Ahead Energy Market and $57.33/MWh in the Real-Time Energy Market. Prices were highest in Connecticut and lowest in Maine. Congestion and price separation were similar to what was observed in the second quarter of 2005.

4. Forward Reserve Market

The Forward Reserve Market (FRM), which was implemented in December 2003, is a market-based method for acquiring generating resources to satisfy the 10- and 30-minute nonsynchronized reserve requirements for New England. 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.

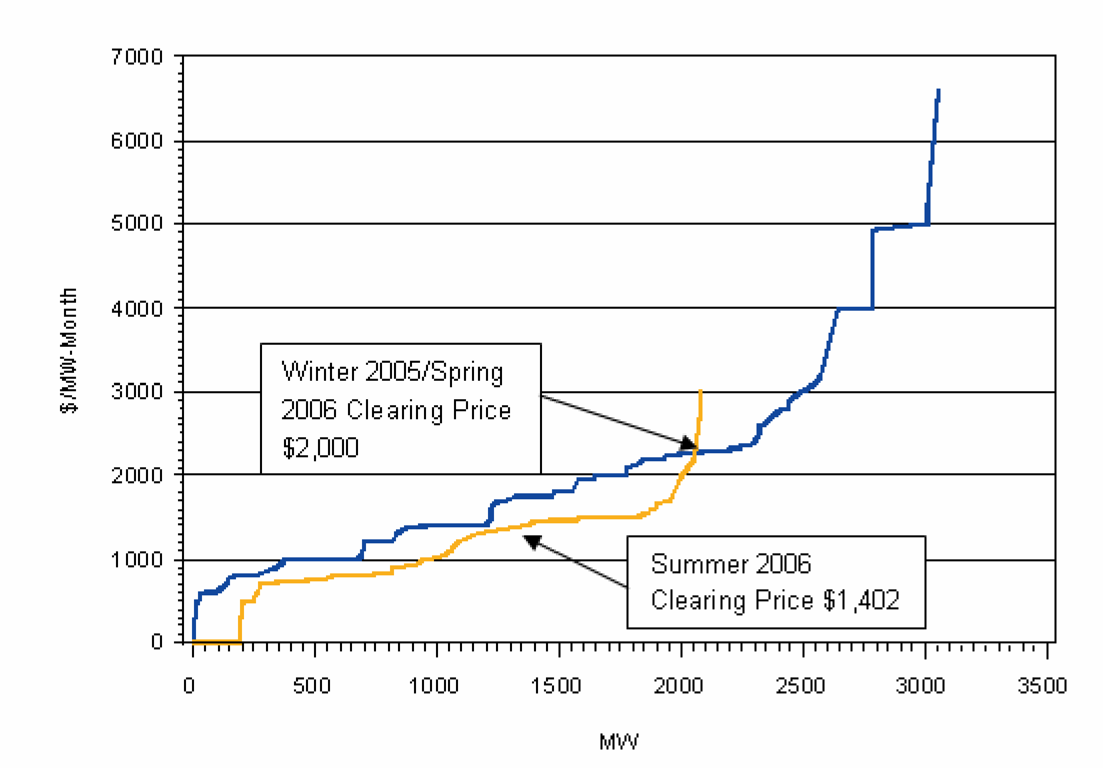
4.1 Forward Reserve Market Auction Results

On August 31, 2005, the fifth FRM auction cleared for the service period Oct 1, 2005 through May 31, 2006. A total of 1,449 MW cleared at a price of $2,000 per MW-month. On April 28, 2006, the sixth FRM auction cleared for the service period June 1, 2006 through September 30, 2006. A total of 1,184 MW cleared at a price of $1,402 per MW-month. The auction results are shown in Table 6. Figure 20 shows the 10-minute supply stack the auction.

Table 6 – Results Summary For Forward Reserve Auction

Auction Period	10-Minute Forward Reserve			30-Minute Forward Reserve		
	Total Supply Offers (MW)	Cleared MW	Clearing Price ($/MW-Month)	Total Supply Offers (MW)	Cleared MW	Clearing Price ($/MW-Month)
Winter Oct 1, 2005 – May 31, 2006	3,054	1,449	$2,000	1,534	736	$2,000
Summer Jun1, 2006 – Sept 30, 2006	2,081	1,181	$1,402	1,011	441	$1,402

Figure 20 – Supply Stack: 10-Minute Forward Reserve Auction Winter 2005/Spring 2006 and Summer 2006



4.2 *Forward Reserve Market Results*

FRM resources are required to offer above a monthly strike price, set using expected gas prices and a heat rate representative of an inefficient peaking unit. Table 7 shows the strike price for each month in the Reporting Period and the percentage of hours in which the real-time Hub LMP was above it. In most hours, LMPs were below the strike price, consistent with the design of the FRM.

Table 7 – 2006 Percentage of On-Peak Hours with Real-Time Hub LMPs Greater than Monthly FRM Strike Price

Month	Strike Price ($/MWh)	Real-Time LMPs > Strike Price
April 2006	$105.40	2.5%
May 2006	$105.40	1.4%
June 2006	$ 91.99	6.0%

Table 8 summarizes total payments, penalties, and net dollars for all forward reserve resources by month. Payments are determined by prorating the $/MW-month clearing price over all on-peak hours in the month. Generators that fail to provide energy when given dispatch instructions by the ISO incur penalties based on the cost of replacement energy.

Table 8 – Monthly Total Forward Reserve Market Payments and Penalties

Month	Total Payments	Total Penalties	Net Dollars
April 2006	$4,050,809	$ -385	$4,050,424
May 2006	$4,099,830	$ -10,276	$4.089,554
June 2006	$2,134,084	$ -68,561	$2,065,523

4.3 Forward Reserve Market Conclusions

When comparing the winter 2005-2006 auction period to the summer 2006 auction period the total supply offers have decreased by 32% and cleared MW have decreased by 18%. Clearing prices, in contrast, have decreased by 30%. A more dramatic decrease can be seen by comparing the winter 2004-2005 auction period clearing price to the winter 2005-2006 action period clearing price. The early auction clearing price was $3,690, while the latest auction period clearing price was $2,000, a change of 44%.

LMPs exceeded the strike price during the Reporting Period so forward reserve units were called to provide energy in few hours.

5. Capacity Market

In the Installed Capacity, or ICAP, Market, generators receive compensation for their investment in generating capacity in New England. Load-serving entities, the market participants with load obligations, make ICAP payments to generators across New England to ensure the availability of sufficient generation capacity for the reliable operation of the bulk power grid.

Table 9 shows the clearing prices and cleared quantities for the ICAP Market auctions during the Reporting Period. The quantities clearing the supply auction are greater than the market requirements met through the supply auction shown in Figure 23 because at times there are excess sales by participants into the supply auction. When a participant sells capacity that it does not own into the supply auction, it creates an obligation for itself to purchase capacity in the deficiency auction or through a bilateral transaction.

Table 9 – ICAP Market Summary, 2006 Q2

Obligation Month	Supply Auction		Deficiency Auction	
	Cleared (MW)	Clearing Price ($/MW-Month)	Cleared (MW)	Clearing Price ($/MW-Month)
Apr 2006	3,746	$10	2,975	$0
May 2006	4,879	$0	3,713	$77
Jun 2006	5,022	$100	2,528	$2,500

Figure 21 and Figure 22 show ICAP Supply and Deficiency Auction cleared quantities and prices. Cleared quantities in the Supply Auction reached the highest level since the implementation of SMD, but clearing prices declined from the preceding quarter.

Figure 21 – ICAP Supply Auction: Cleared MW and Cleared Prices

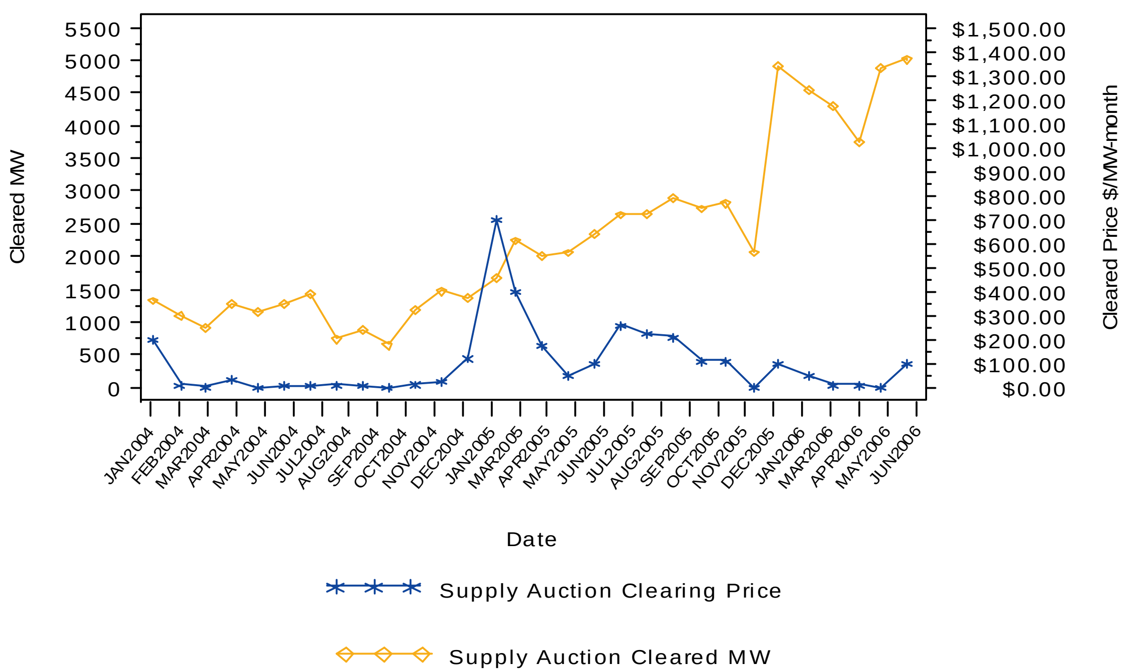
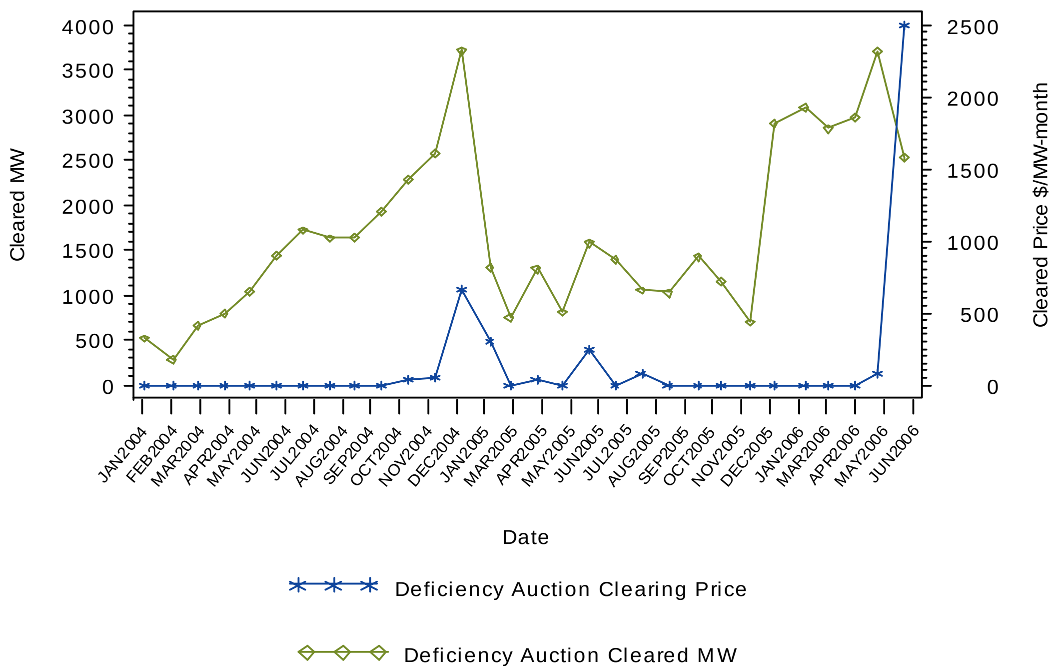
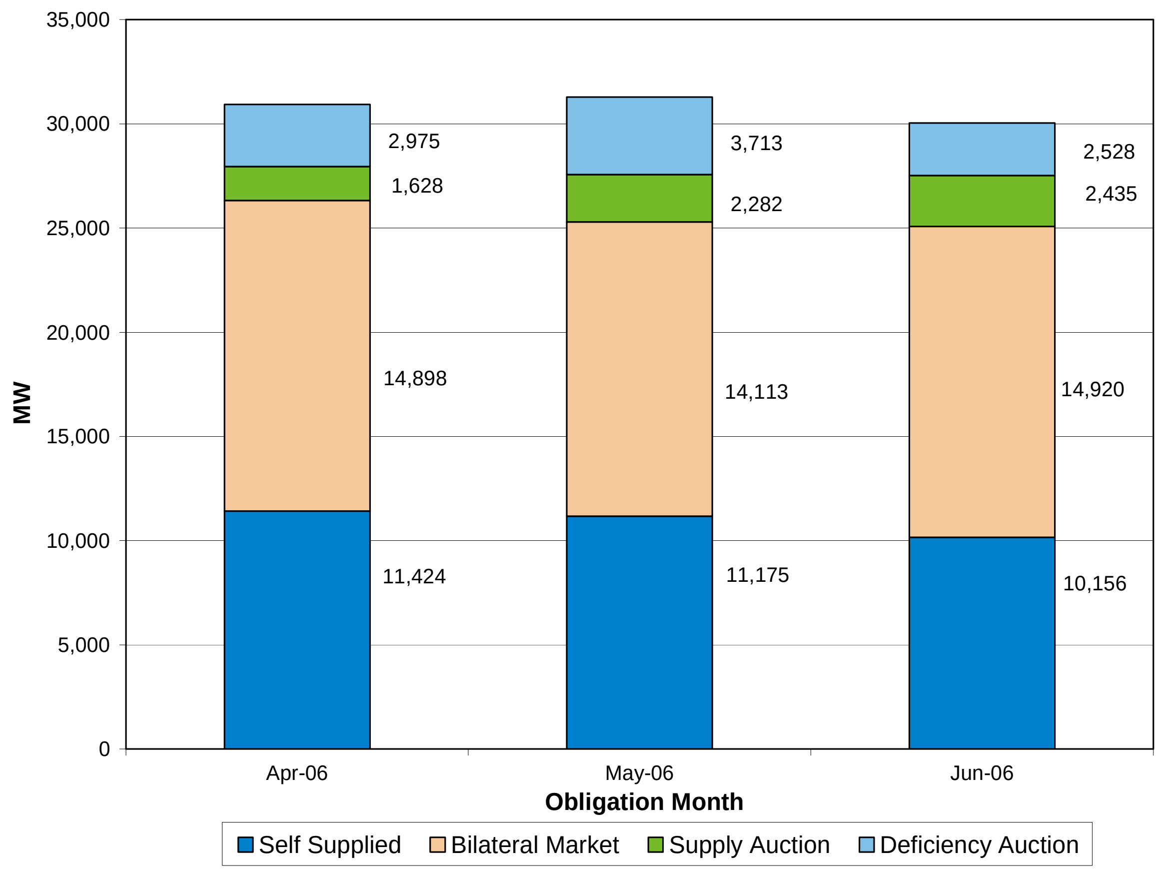


Figure 22 – ICAP Deficiency Auction: Cleared MW and Cleared Prices



Most ICAP Market requirements are met through self-supply or bilateral contracts, with relatively small amounts traded through the supply and deficiency auctions. Over the April through June 2006 obligation months, approximately 83% of the Pool Capability was met by participants who owned entitlement to capacity or procured it bilaterally. A MW-month quantity equivalent to about 7% of the Pool Capability transacted in the supply auction, with the remaining 10% obtained in the deficiency auction. Figure 23 shows sources of capacity in the ICAP market.

Figure 23 – Q2 Sources of Capacity (MW) in ICAP Market



6. Regulation Market

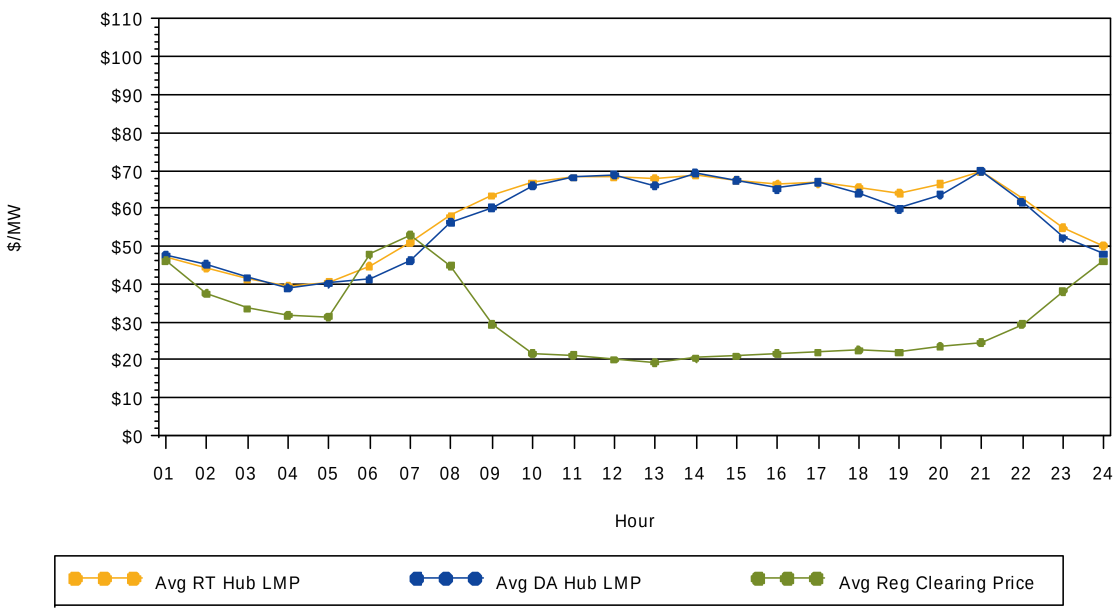
Regulation is necessary to balance supply levels with the second-to-second variations in demand. To respond to these slight changes on the system, specially equipped generators are sent signals to increase or decrease generation output every four seconds. This system balancing maintains proper power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

The hourly Regulation Market clearing price averaged $30.41/MWh during the Reporting Period. Total Regulation Market payments were $13.5 million, including $2.4 million in real-time opportunity cost payments. Table 10 shows summary information about clearing prices in the Regulation Market during the Reporting Period. Regulation prices were highest in the late evening and early morning, as Figure 24 illustrates.

Table 10 – Regulation Market Clearing Prices Summary Statistics ($/MWh)

$/MWh	Average	Median	Minimum	Maximum
April 2006	$36.96	$31.29	$0.00	$95.04
May 2006	$30.66	$27.00	$0.00	$76.90
June 2006	$23.61	$20.00	$0.00	$86.60

Figure 24 – Average Hourly Regulation Clearing Prices and Hub DA & RT LMPs 2006 Q2



7. 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.[5] The ISO commits some generation outside of the market-clearing process to maintain power system reliability and meet these requirements. Figure 25 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.

Figure 25 – Total Monthly Energy Output from Reliability Commitments Day-Ahead, RAA, and Real-Time, 2006 Q2

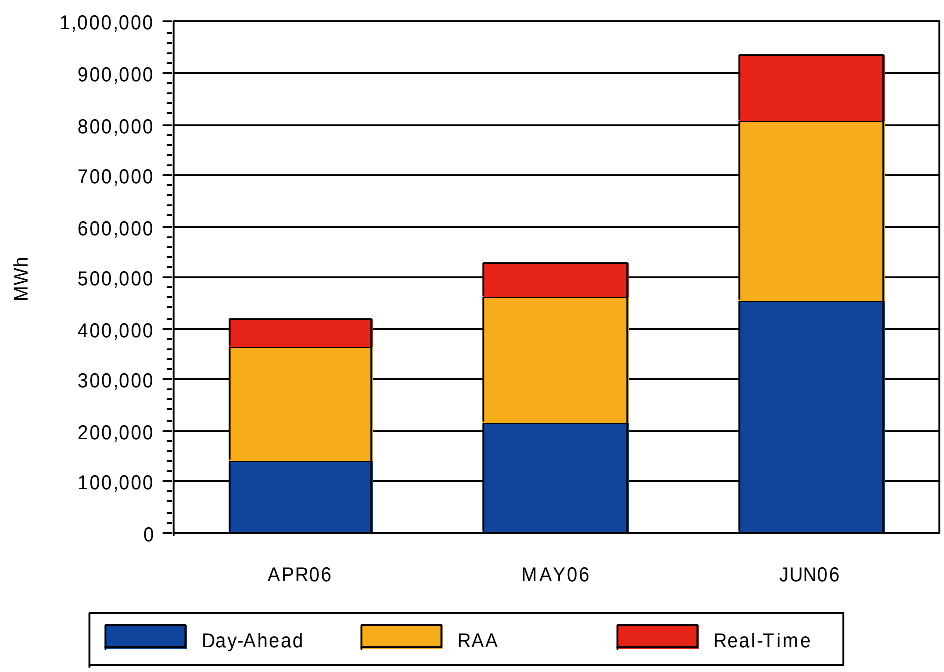


Table 11 shows total energy output from supplemental commitments made to supply local second contingency reserves[6] by month and load zone. Almost all second contingency commitments were made in the SEMA and Connecticut Zones. Norwalk-Stamford Connecticut, Southwest Connecticut, and the rest of Connecticut 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

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

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

the larger area. Energy output from second contingency commitments totaled about 1.0 million MWh during the Reporting Period.

Table 11 – 2006 Q2 Energy Output from Second Contingency Commitments by Month and Load Zone, MWh

		April 2006	May 2006	June 2006	Quarter Total
Connecticut	Day-Ahead	90,677	94,245	324,647	509,569
	RAA/Real-Time	31,638	38,732	90,186	160,556
	Total Second Contingency Commitments	122,314	132,977	414,833	670,124
SEMASS	Day-Ahead	39,210	480	2,300	41,990
	RAA/Real-Time	76.800	46,235	111,053	234,088
	Total Second Contingency Commitments	116,010	46,715	113,353	276,078
WCMASS	Day-Ahead	0	0	0	0
	RAA/Real-Time	0	0	3,225	3,225
	Total Second Contingency Commitments	0	0	3,255	3,225
NEMASS	Day-Ahead	0	90,840	108,990	199,830
	RAA/Real-Time	0	87,790	72,483	160,273
	Total Second Contingency Commitments	0	178,630	181,473	360,103

Table 12 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 132,561 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 12 – 2006 Q2 Energy Output from Voltage Commitments by Load Zone, MWh

		April 2006	May 2006	June 2006	Quarter Total
Connecticut	Day-Ahead	0	0	2,465	2,465
	RAA/Real-Time	740	0	4,790	5,530
	Total Voltage Commitments	740	0	7,255	7,995
SEMASS	Day-Ahead	0	0	840	840
	RAA/Real-Time	42,952	0	660	43,612
	Total Voltage Commitments	42,952	0	1,500	44,452
WCMASS	Day-Ahead	0	0	17,330	17,330
	RAA/Real-Time	0	864	4,559	5,423
	Total Voltage Commitments	0	864	21,889	22,753
NEMASS	Day-Ahead	11,700	27,420	0	39,120
	RAA/Real-Time	2,521	7,560	8,160	18,241
	Total Voltage Commitments	14,221	34,980	8,160	57,361

8. Net Commitment Period Compensation

NCPC can be viewed as the bulk power system's insurance policy. They provide a margin of additional supply above what is otherwise needed to meet real-time system demand. NCPC allows the ISO to respond to significant, unexpected imbalances between supply and demand without interrupting load. Providers of these reserves are paid through NCPC. Generators eligible for compensation are those whose output the ISO has constrained above or below the economic level, as determined by the LMP and in relation to their offers. 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 $73.5 million during the Reporting Period. Figure 26 provides quarterly totals for NCPC payments, and Table 13 shows second contingency payments by load zone.

Figure 26 – NCPC Payments by Quarter, 2003- 2006

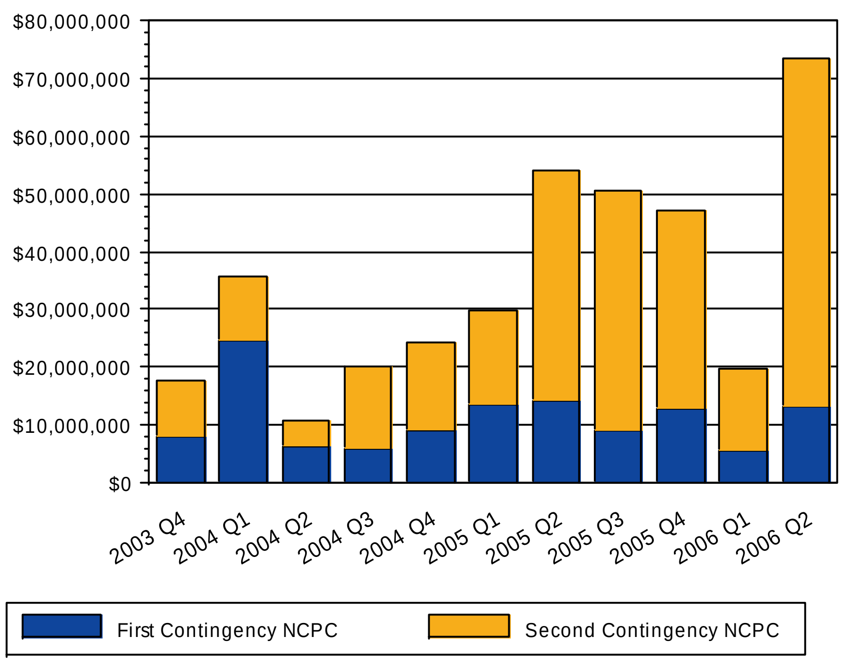


Table 13 – Total Second Contingency NCPC by Load Zone, 2006 Q2

Load Zone	Day-Ahead Payments	Real-Time Payments
Connecticut Load Zone	$769,201	$12,694,028
NEMA/Boston Load Zone	$562,869	$11,460,442
SEMASS Load Zone	$2,728,586	$23,897,305

Table 14 and Table 15 show the average allocation of NCPC by month for the Reporting Period. Average charges are calculated based only on days with charges.

Table 14 – 2006 Q2 First Contingency Net Commitment Period Compensation Allocations for Days with Charges, $/MWh

Month	Day-Ahead First Contingency	Real-Time First Contingency
April 2006	$ 0.02	$ 0.51
May 2006	$ 0.01	$ 0.69
June 2006	$0.01	$1.36

Table 15 – 2006 Q2 Second Contingency Net Commitment Period Compensation Charge Allocations for Days with Charges by Load Zone, $/MWh

Month	CT Day-Ahead Second Contingency	CT Real-Time Second Contingency	NEMA Day-Ahead Second Contingency	NEMA Real-Time Second Contingency	SEMASS Day-Ahead Second Contingency	SEMASS Real-Time Second Contingency
April 2006	$ 0.36	$ 1.98	$ 0.00	$ 0.00	$7.99	$7.67
May 2006	$ 0.36	$ 1.99	$ 0.00	$ 0.00	$2.89	$6.97
June 2006	$ 0.42	$2.20	$ 0.34	$ 5.51	3.94	$6.88

9. Voltage and Distribution Tariff Charges

Generators providing voltage or distribution[7] service are compensated for shortfalls between their energy revenues and energy offers in the same way as generators receiving Second Contingency or Second Contingency NCPCs. Figure 27 shows voltage or distribution payments for second quarter of 2003 through the second quarter of 2006. Total voltage payments in the

[7] Distribution service was formerly 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.

Reporting Period were $4.8 million while distribution payments amounted to $1.1 million. The majority of the payments, in both categories, came from real-time payments. Table 16 shows voltage payments by load zone. Voltage payments are shared by all New England transmission owners based upon network load, while distribution payments are assigned directly to the transmission owner requesting that the generator be committed.

Figure 27 – Tariff Payments by Quarter, 2003 - 2006

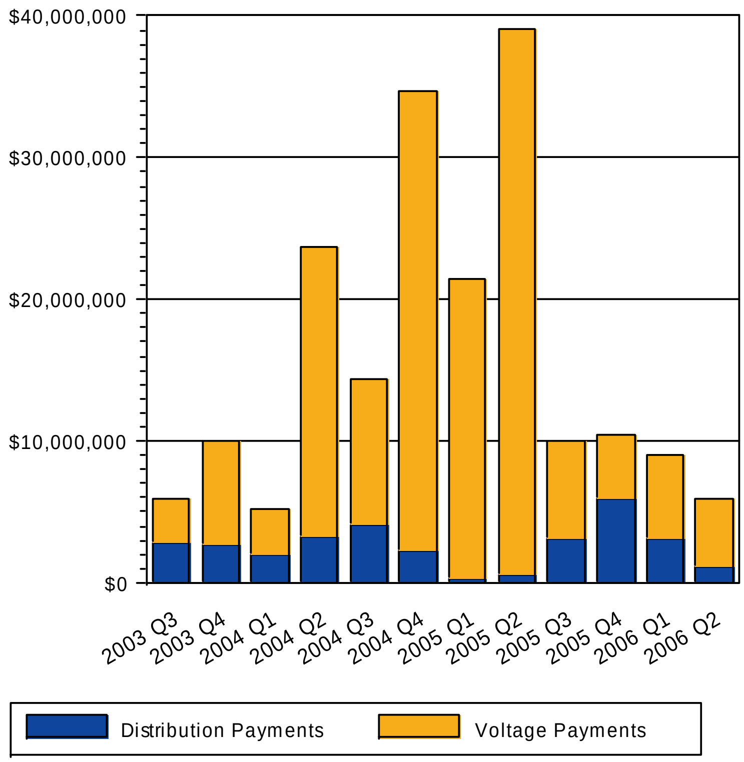


Table 16 – Total Voltage Payments by Load Zone, 2006 Q2

Load Zone	Day-Ahead Payments	Real-Time Payments
Connecticut Load Zone	$54,174	$116,608
SEMASS Load Zone	$246,503	$114,595
WCMASS Load Zone	$646,422	$94,387
NEMA Load Zone	$2,661,174	$905,012

10. 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 in which the generating units are located, with the exception of one agreement in the Boston area that is paid for by a specific participant.

During the Reporting Period, Reliability Agreements were in effect or were subsequently made effective retroactively for 11 generating stations, with a total of 24 units and 3,659MW[8] . Agreements covered the Devon, Middletown, Montville, Milford, New Haven Harbor, Bridgeport Harbor 2, and Bridgeport Energy stations in Connecticut, the New Boston 1 and Kendall Stations in Boston, and the West Springfield 3 unit and Berkshire Power in Western Massachusetts.[9]

The cost of Reliability Agreements to load during the Reporting Period was $151.9 million.

11. Managing Congestion Risk – FTRs

Financial Transmission Rights 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.

11.1 Auction Results

The April, May and June monthly auctions included previously awarded FTRs from the January 2006 through December 2006 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. When a long-term auction is held, 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 33 and 38 bidders participated in each monthly auction during the Reporting Period. This is consistent with levels of participation in auctions in prior months. Bids to buy FTRs total $803.2 million. Bids to buy FTRs with positive prices

[8] 2005 CELT Report, Summer Capacity

[9] 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 >.

totaled $17.0 million and negative prices totaling $3.1 million cleared, resulting in a net of $13.9 million in FTRs awarded.

Participants can sell FTRs awarded in the long-term auction into the monthly auctions. Bids to sell FTRs totaled $6.8 million. Bids to sell FTRs positive price totaling $340,169 and negative prices totaled $132,655 cleared in the monthly auctions, resulting in a net of $207,514 in FTRs sold.

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. 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 17 shows ARR distribution by category. The monthly revenues include monthly-normalized long-term auction revenues.

Table 17 – 2006 Q2 ARR Allocations

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 2006	3,811,888	5,619	38,680	3,754,590	0	3,798,889	12,999	3,811,888
May 2006	3,323,911	2,894	21,403	3,214,596	0	3,238,893	85,018	3,323,911
Jun 2006	6,560,720	8,410	120,135	6,249,867	0	6,378,412	182,308	6,560,720

Table 18 displays the total distribution of ARR dollars to the various zones for each month.

Table 18 2006 Q2 ARR Award Allocation by Zone ($)

Month	NEMA	CT	WCMA	SEMA	NH	VT	RI	ME
Apr 2006	615,263	2,459,089	324,299	79,573	120,122	150,822	43,501	6,219
May 2006	334,054	2,343,403	277,714	58,904	76,003	111,604	35,123	2,087
Jun 2006	2,763,543	2,621,992	592,583	166,505	254,440	335,178	18,428	7,479

Analysis of the on-peak auction results (the hours when power flows are heaviest) indicates that market participants had expectations that were consistent with historical patterns of congestion on the New England system. Figure 28 presents the overall pattern of inter-zonal FTR purchases (in MW-Months) for each of the on-peak auctions during the Reporting Period. Zone-to-zone FTR purchases were decomposed into their zone-to-Hub and Hub-to-zone components so that the analysis could be presented in relationship to the Hub. 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 28 – On-Peak Zonal FTR Awards by Month Relative to Hub 2006 Q2

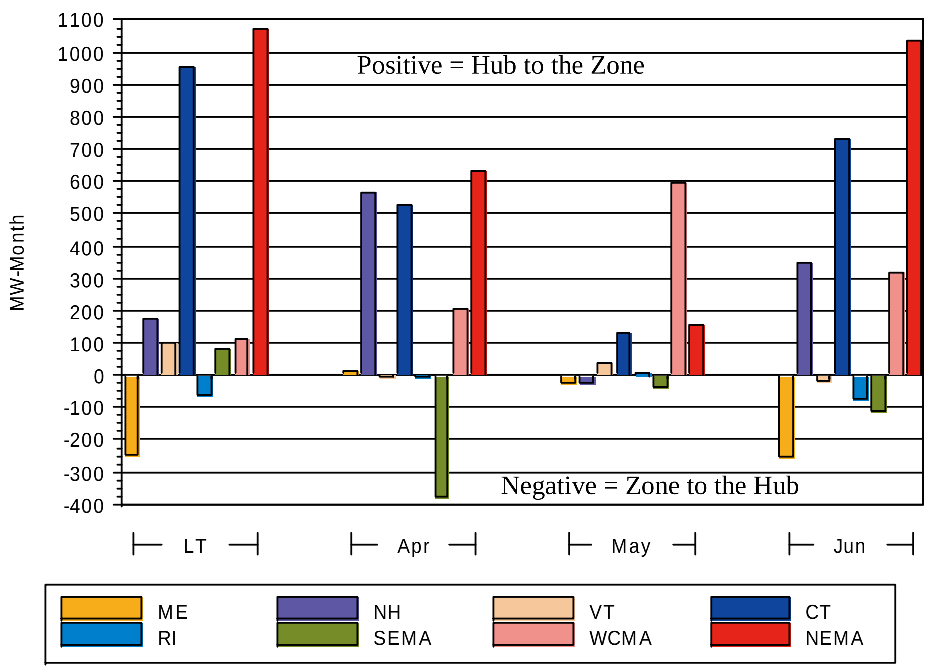


Figure 29 and Figure 30 present the relationship (on an equivalent $/MWh basis) of the cost to procure an FTR with the actual day-ahead and real-time congestion costs over the Reporting Period. The figures incorporate both the monthly and long-term auction results in the presentation of the cost of an FTR.

Day-ahead congestion costs and FTR auction prices were directionally consistent in the Maine and New Hampshire zones (export-constrained and negative), and the NEMA/Boston and

Connecticut zones (import constrained and positive). While day-ahead congestion costs and FTR prices were directionally consistent in Connecticut, FTR prices were disproportionately high. In other areas, FTR prices were lower than day-ahead congestion costs.

Figure 29 – FTR Auction Prices vs. Day-Ahead and Real-Time Congestion
2006 Q2, On Peak

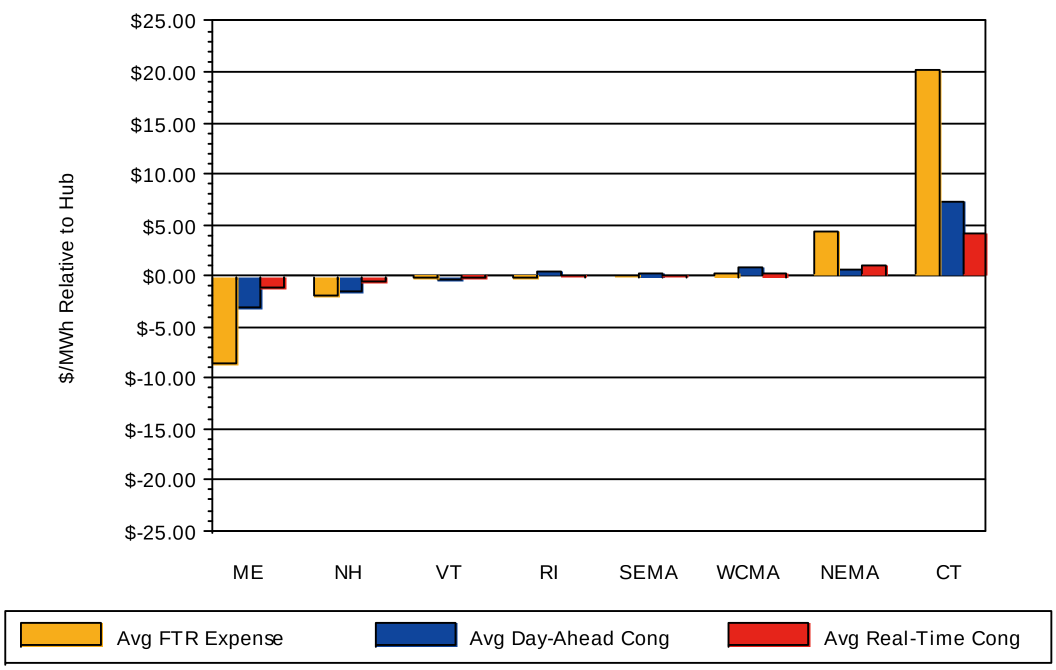
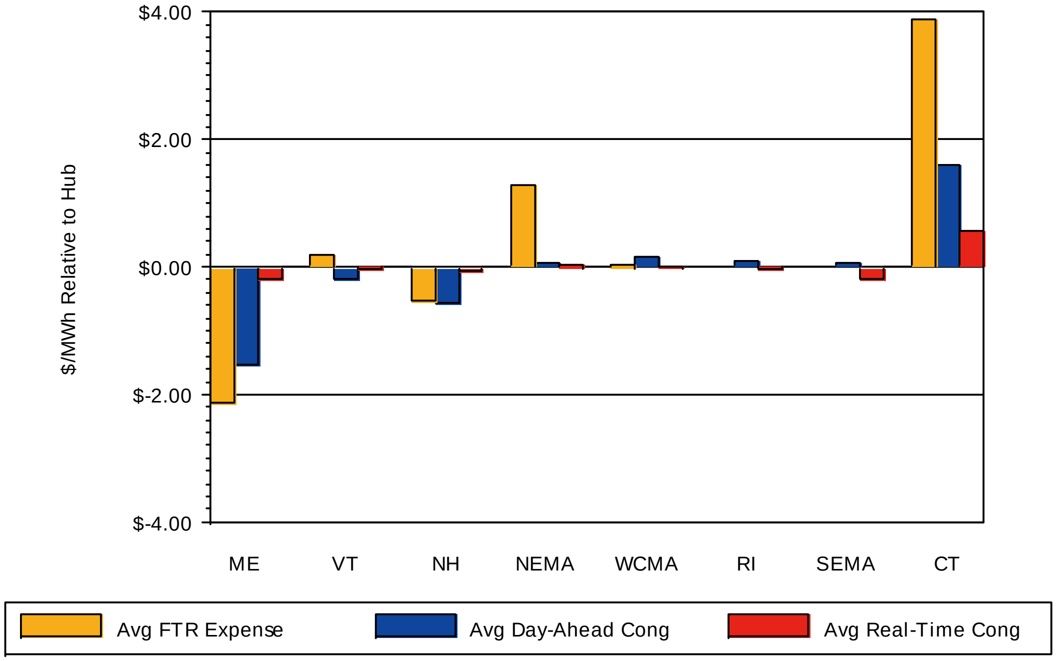


Figure 30 – FTR Auction Prices vs. Day-Ahead and Real-Time Congestion
2006 Q2, Off Peak



11.2 Financial Transmission Rights Clearing Prices

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

Table 19 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 19– 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 2006 LT	889.02	495.84	1324.18	170,185.12	-29,357.04	24,052.46	-9,426.95
Apr 2006	147.95	305.28	-4.31	3,932.24	-879.84	712.18	-523.32
May 2006	185.63	352.06	17.06	6,698.75	-682.19	1,001.60	-375.88
Jun 2006	381.69	378.30	389.68	11,366.96	-1,049.56	1,790.65	-102.06

Table 20 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 the Connecticut and NEMA/Boston zones. Many of the highest revenue-producing sources were nodes.

Table 20– Top Five Highest Priced FTR Sink-Source Combinations, Monthly Auction

Auction	On-Peak Auction		
	Source	Sink	Award Price
Apr 2006	UN.BUCKSPRT115 CHAM	LD.OLD_TOWN13.8	$4,808.45
Apr 2006	UN.ENFLD_ME115 IND5	LD.TOMAC115	$4,808.29
Apr 2006	UN.ENFLD_ME115 IND5	LD.WATERSDE115	$4,808.29
Apr 2006	LD.ELLSWRTH34.5	LD.FLAX_HL115	$4,808.26
Apr 2006	LD.GRAHAM46	LD.TOMAC115	$4,808.26
May 2006	UN.BPT_RESC14 BPTR	UN.NORWALKH17.1NRW1	$5,448.11
May 2006	UN.BRIDGEPT115 BHCC	UN.NORWALKH115 NRW3	$5,448.05
May 2006	LD.TRIANGLE115	LDRIDGEFLD115 2x LD	$5,447.70
MAy 2006	UN.BPT_RESC14 BPTR	LD.ASHCREEK115	$5,447.36
May 2006	LD.BRIDGET115	LD.ASHCREEK 115	$5,447.30
Jun 2006	UN.DEVON 115 DV11	LD.WESTON 27.6	$9,848.42
Jun 2006	LD.MIDLE_RV115	LD.WESTON 27.6	$9,844.69
Jun 2006	LD.TRIANGLE115	LD.WESTON 27.6	$9,844.69
Jun 2006	UN.BRIDGEPT115 BHCC	UN.NORWALKH115 NRW3	$9,841.45
Jun 2006	LD.MIDLE_RV115	LD.COSCOB 115	$9,838.20

11.3 Financial Transmission Rights Payment Results

FTR holders are paid through the Transmission Congestion Revenue Fund. Monthly revenues, allocations, and allocations paid are shown in Table 21. The second five columns of Table 21 show the amount each component (including FTRs with negative allocations) contributed to the Congestion Revenue for each month of the Reporting Period. The next three columns show the positive target allocations that were paid from the fund to FTR holders, the monthly surplus or deficiency of congestion revenue, and the fund’s ending balance, which is carried forward from month to month. Months with shortfalls result in FTR holders being paid a reduced percentage of their monthly entitlement. Months with surplus funds result in FTR holders being paid their full allocation. The last column shows the percent of positive allocations that FTR holders received in each month.

Table 21 – Congestion Revenue Fund, 2006 Q2

Month	Beginning Balance	Fund Adjustment	Day Ahead Congestion Revenue	Real Time Congestion Revenue	Negative Target Allocation	Positive Target Allocation	Monthly Fund Surplus or Shortfall	Ending Balance	Percent Positive Allocation Paid
Apr 2006	$0	$-421,869	$2,477,238	$-13,436	$-804,468	$2,846,401	$0	$0	100%
May 2006	$0	$-3,998,539	$18,191,348	$5,064,030	$-3,569,219	$22,826,059	$0	$0	100%
Jun 2006	$0	$26,623	$28,873,231	$652,375	$-5,628,188	$35,180,417	$0	$0	100%

11.4 Financial Transmission Rights Conclusions

Net FTR auction revenues of the Second Quarter were about $13.7 million. The total of all FTR auction revenues for the quarter were $30.1 million, which included the quarter's share of the Jan-Dec 2006 long term auction (1/4 of $103 million). FTR holders had positive target allocations totaling $60.9 million and negative target allocations of $10.0 million. The Congestion Revenue Fund did not have adequate moneys to pay 100% of the positive allocations.

12. Demand Response

Demand response in wholesale electricity markets refers to resources[10] that reduce their electricity consumption in response to either high wholesale prices or system reliability events in exchange for compensation based on wholesale market prices. The ISO administers the Load Response Program for the New England wholesale electricity market. During the second quarter 2006, the ISO administered several programs. These included:

- Day-Ahead Load Response Program
- Real-Time Demand Response Program (30-minute and two-hour response)
- Real-Time Price Response Program
- Real-Time Profiled Response Program

12.1 Demand Response Results

In the Reporting Period, 1,196 assets were enrolled in demand response programs, comprising over 658 MW of potential demand interruption or curtailment. There were 159.6 MW enrolled in the Real-Time Price Response Program,481.3 MW enrolled in Real-Time 30 Minute Demand Response Program, 0.8 MW enrolled in the Real-Time 2 Hour Demand Response Program and 16.9 MW enrolled in the Real-Time Profiled Response Program. Table 22 reports the assets that

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

were both "ready to respond" and "pending" in demand response program during the Reporting Period. Over 678.7 MW were under contract at this time, with 431.9 MW of the total in the Connecticut load zone. Enrollment increased by 225 assets and 58.6 MW from the first quarter of 2006.

Table 22 – Demand Response Program Enrollments

Zone	Ready to Respond Assets (MW) 1196 Assets 658.7 MW					Approved Assets (MW) 58 Assets 20.0 MW				
	No. of Assets	RT Price Response	Demand Response 30 min.	Demand Response 2 Hr	Profiled	No. of Assets	RT Price Response	Demand Response 30 min.	Demand Response 2 Hr	Profiled
CT	608	15.5	401.3	0.0	0.0	40	0.0	15.1	0.0	0.0
SWCT*	405	0.9	272.2	0.0	0.0	9	0.0	1.3	0.0	0.0
ME	15	10.0	25.6	0.0	11.0	0	0.0	0.0	0.0	0.0
NEMA	159	65.9	25.7	0.8	0.0	2	0.2	0.0	0.0	0.0
NH	13	15.8	2.5	0.0	0.0	0	0.0	0.0	0.0	0.0
RI	125	16.0	0.9	0.0	0.0	3	0.3	0.0	0.0	0.0
SEMA	107	10.7	6.1	0.0	0.0	7	0.1	3.8	0.0	0.0
VT	23	7.6	5.4	0.0	5.9	0	0.0	0.0	0.0	0.0
WCMA	146	18.3	13.8	0.0	0.0	6	0.6	0.0	0.0	0.0
Total	1196	159.6	481.3	0.8	16.9	58.0	1.2	18.8	0.0	0.0

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

Load response programs provided 658.7 MW of demand reduction during the Reporting Period. Of this total, 159.6 MW were from the Real-Time Demand Response Program and the rest were from the Real-Time Price Response Program. Payments to resources providing demand reduction totaled about $575,470 during the Reporting Period. These results are preliminary and may be revised after all curtailments are reported for 90-day resettlements.

13. 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 Markets and NCPC payments. Six NCPC Credit mitigation events and one Real-Time mitigation event were triggered during the Reporting Period.

14. 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 23 illustrates the monthly Weighted Equivalent Availability Factor (WEAF) of New England generating during the first and second quarters of 2006. As shown, the year began with generating units in New England experiencing a system monthly average WEAF of 95% then gradually declining.

Table 23 – New England 2006 Monthly Weighted Equivalent Availability Factors (%) by Unit Type

	Jan-06	Feb 06	Mar 06	Apr 06	May 06	Jun 06
System Average	95	94	90	79	77	88
Fossil Steam	98	97	91	78	65	88
Coal	95	91	79	62	56	88
Coal/Oil	97	96	97	75	86	88
Oil	99	99	96	92	70	83
Oil/Gas	100	99	95	73	55	94
Wood/Refuse	94	95	91	83	88	92
Nuclear	99	98	98	94	100	100
Jet Engine	95	97	95	89	94	97
Combustion Turbine	96	95	95	94	95	96
Combined Cycle	92	89	83	69	71	82
Pre-1999 Combined Cycle	91	99	98	88	82	99
New (Installed 1999-2005) Combined Cycle	92	87	80	65	68	80
Hydro	97	96	97	99	99	97
Pumped Storage	97	97	96	81	93	96
Diesel	99	100	100	100	97	100

Figure 31 shows total outages in megawatts for April 2005 through June 2006 and the amount of capacity on outages 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. October 2005 and April 2005 experienced the greatest amount of unit outages over the 15-month period. This can be attributed to the high amount of maintenance that is performed during these months when electrical demand is typically at its lowest in the year. The typical summer peak demand month of August had the lowest amount of outages during the peak.

Figure 31 –Average Generator Outages on Peak Demand Day of Month

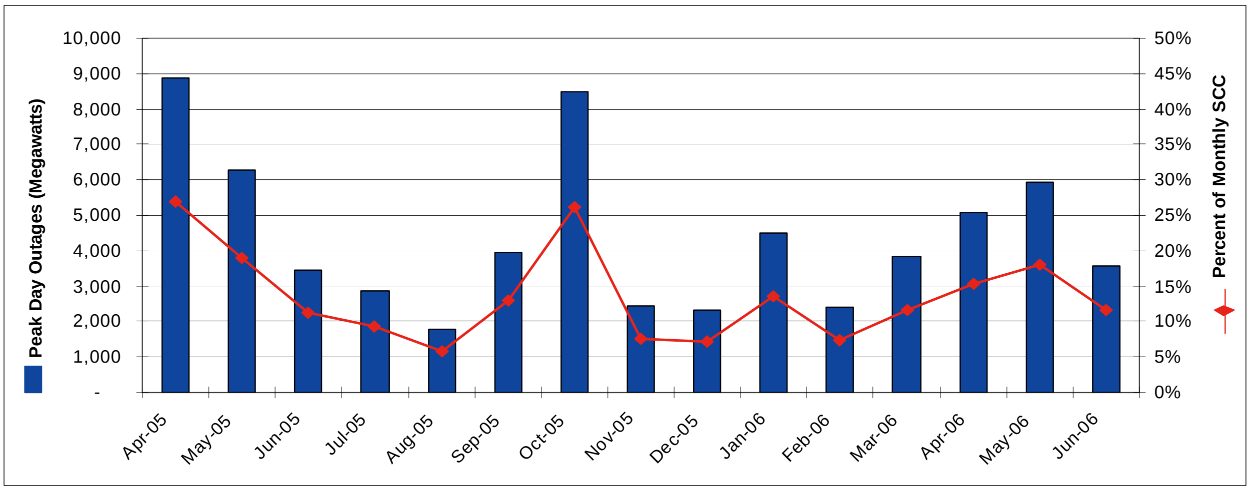
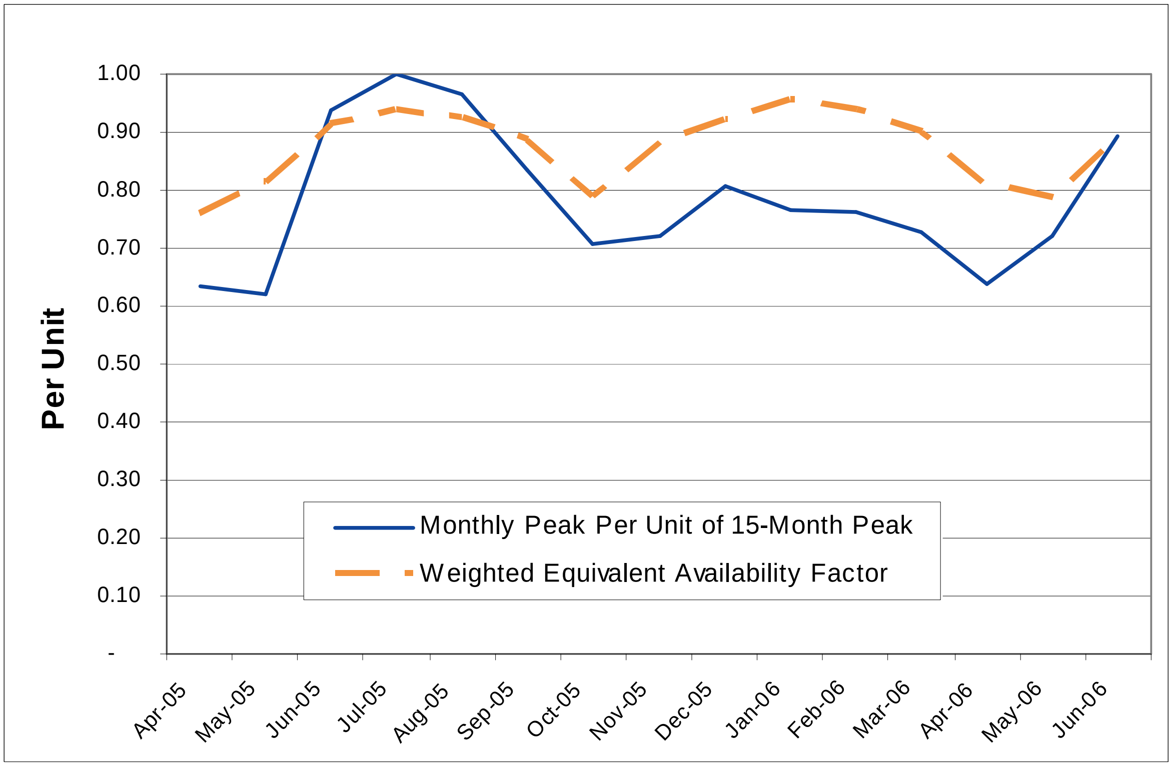


Figure 32 illustrates how the availability of the New England generating units tracks the monthly demand. Specifically, in Figure 32 the monthly WEAF is compared to the monthly peak demand as a percentage of the 15-month period peak demand. For the 15-month period of April 2005 through June 2006, this peak occurred in July 2005 with an hourly peak load of 26,885 MW. Similar to the information portrayed in Figure 31, 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 32 – 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.

Real-time LMPs were corrected in 45 hours during the Reporting Period. Figure 33 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 33 – Real-Time Energy Market LMP Corrections by Month