Monthly Market Operations Report
February 2014

ISO New England Inc.
Market Analysis and Settlements
March 29, 2017

1. Introduction

1.1 About ISO New England

Created in 1997, ISO New England Inc. (the ISO) is the not-for-profit regional transmission organization (RTO) responsible for the day-to-day reliable operation of New England's bulk power generation and transmission system, oversight and administration of the region's wholesale electricity markets, and management of a comprehensive regional bulk power system planning process.

1.2 Market Reporting

The ISO's FERC Electric Tariff No. 3, Section III – Market Rule 1 – Standard Market Design, Appendix A – Market Monitoring, Reporting and Market Power Mitigation Section III.A.11.2.1 requires the ISO to publish a monthly report, "which will be available to the public...containing an overview of the market's performance in the most recent period."

The ISO produces many reports that summarize the operations of New England's wholesale electricity markets. The weekly report provides summaries of key market activities for the trading week encompassing Monday-Sunday. This report, generally posted on Wednesdays, can be found on the ISO's web site here. This report is also supplemented by a Mid-Week Market Update, generally posted on Fridays, that reports pricing and congestion highlights from Monday through Thursday. This update may be accessed here.

Monthly summaries of certain wholesale market concepts are reported monthly by the ISO's Chief Operating Officer at the NEPOOL Participants Committee Meeting. These summaries are posted on the ISO's web site here, under the link entitled "Materials."

Additionally, in compliance with federal requirements, the ISO issues quarterly reports of key statistics for the region's wholesale electric power markets. These reports can be found on the ISO's web site here.

1.3 About This Report

This report summarizes aspects of New England's wholesale electricity markets that are generally not discussed in the first two reports noted above. There are many interrelationships between the various markets that the ISO administers – each of the concepts presented in this report may interact with others, and second order effects cannot be included here. Additional information can be found on the ISO's web site here.

2. Table of Contents

3. Monthly Summary

Day-ahead and real-time LMPs at the New England Hub averaged $156.02/MWh and $152.84/MWh, respectively, during February 2014. Day-ahead and real-time prices at the Hub and in the Load Zones averaged from 8% lower to 5% higher than January 2014 averages. In the aggregate, February 2014 day-ahead and real-time LMPs were approximately 34% higher during February 2014 than in February 2013. Average natural gas prices were 20% above the prior year's average prices, while residual fuel prices were down 1% from a year ago.

Overall, the average of the hourly real-time LMPs at the Hub and in the Load Zones ranged between 3.5% lower than day-ahead in the Vermont (VT) Load Zone to 1.8% lower than its day-ahead counterpart in the Southeastern Massachusetts (SEMA) Load Zone. In the Day-Ahead Market, Load Zone average LMPs ranged between 4.2% lower than the Hub average LMPs in the Maine (ME) Load Zone to 0.2% higher than the Hub in the Rhode Island (RI) Load Zone. In the Real-Time Market, Load Zone average LMPs ranged between 5.0% lower than the Hub average LMPs in the ME Load Zone to 0.4% higher than the Hub in the Northeastern Massachusetts (NEMA) Load Zone. Price differentials between on-peak and off-peak hours at the Hub and in the Load Zones ranged between 37% and 40% in both the Day-Ahead and Real-Time Markets.

The New England Control Area was a net importer of electricity in the Real-Time Market during February. In the Day-Ahead Energy Market, there were approximately 134,000 MWh of total exports and 2,416,000 MWh of imports, yielding a net import of approximately 2,282,000 MWh. In the Real-Time Energy Market, there were approximately 206,000 MWh of total exports and 2,479,000 MWh of imports, yielding a net import of approximately 2,272,000 MWh. This was about 224,000 MW higher than a year ago.

The Monthly FTR Auction (February 2014) had 31 participants and the awarded value of FTRs in the auction totaled $1.4 million. This represented a decline of $1.5 million from the previous month and an addition of about $973K over the prior year's monthly FTR auction. The allocation of FTR Auction Revenue for February 2014 resulted in $2.7 million awarded to eligible entities, with $148K allocated to Incremental Auction Revenue Rights (IARR).

The Marginal Loss Revenue Fund totaled $15.5 million for February, down $14.1 million from its January 2014 total.

Total Forward Reserve Credits to eligible assets of $10.4 million were reduced by $964K in Failure to Reserve Penalties and $0 in Failure to Activate Penalties during February 2014. The net Forward Reserve Payment of $9.9 million represented 86% of the maximum possible payment of $11.5 million. Real-Time Reserve Prices occurred in 69 separate hours during the month, and those yielded real-time payments to designated assets of $5.4 million. These payments were reduced by Forward Reserve Energy Obligation Charges totaling $727K yielding a net compensation of $4.7 million during the month.

Regulation Market Payments totaled $4.5 million during the month, a decrease of $1.7 million from the January 2014 value of $6.2 million.

For the month of February 2014, Forward Capacity payments were made to a total of 32,827 MW of capacity and totaled $85.2 million.

The Transitional Demand Response program is the method through which demand assets can participate in the Energy Market. Payments during February 2014 totaled $658,000 for interruptions associated with Day Ahead, $181,000 for interruptions associated with the Real Time, and $657 associated with FCM/Audit. Total Transitional Demand Response payments for the month, $839,000, were down approximately $633,000 from their January levels.

Winter 2013/14 Reliability Program Update – The Winter 2013/14 Reliability Program ended on Friday, February 28, 2014. The total program oil burned was approximately 2.7 million barrels, or the equivalent of 1.6 million MWh[1]. For more information on the Winter Reliability Program, see Appendix K to Market Rule 1 located here.

[1] Based on an average heat content of 6,000,000 Btu/Barrel and proxy heat rate of 10,000,000 Btu/MWh

4. Locational Marginal Prices (LMPs)

Under Standard Market Design (SMD), the LMP is the cost of supplying an increment of load at a particular location. LMPs are calculated for each Internal and External Node as well as the eight Load Zones and the internal Hub in both the Day-Ahead and Real-Time Markets. LMPs are made up of three components: energy, congestion and marginal loss. The energy component of an LMP is the cost of providing an additional MW of energy to the distributed market reference bus. In any hour, the energy component is the same for all locations, while the congestion and marginal loss components vary among locations. If there were no congestion and losses, LMPs would be the same for all locations. Although the three components of the LMP are separated in some stages of the accounting process, the cost of energy at a location is the total LMP.

The following tables summarize Hub, zonal, and external node LMPs during the month on an overall, on-peak, and off-peak basis. On-peak hours are weekdays between 7:00 a.m. and 11:00 p.m. Off-peak hours are weekdays between 11:00 p.m. and 7:00 a.m., Saturdays, Sundays, and North American Electric Reliability Council (NERC) holidays.

4.1 LMP Summary Statistics

The following tables show summary statistics for LMPs for the Hub, eight internal Load Zones, and five external nodes for both the Day-Ahead and Real-Time Markets:

4.1.1 All Hours, February 2014

Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$156.02	$152.84	$43.17	$0.00	$332.47	$578.89	128%	141%	98.0%	$55.88	$79.68	1.43
ME	$149.43	$145.24	$41.66	$0.00	$321.82	$550.30	122%	134%	97.2%	$53.50	$75.82	1.42
NH	$154.96	$150.61	$42.90	$0.00	$333.49	$571.06	127%	139%	97.2%	$55.70	$78.60	1.41
VT	$155.30	$149.82	$42.53	$0.00	$391.55	$565.49	127%	138%	96.5%	$56.39	$78.06	1.38
CT	$153.89	$150.80	$43.24	$0.00	$325.47	$567.83	126%	139%	98.0%	$54.84	$78.37	1.43
RI	$156.41	$152.87	$43.22	$0.00	$330.09	$587.18	128%	141%	97.7%	$56.48	$79.65	1.41
SEMA	$155.63	$152.88	$43.10	$0.00	$328.60	$591.08	127%	141%	98.2%	$55.46	$79.72	1.44
WCMA	$156.15	$152.64	$43.45	$0.00	$331.31	$575.60	128%	141%	97.7%	$55.81	$79.45	1.42
NEMA	$156.24	$153.39	$43.27	$0.00	$333.62	$583.97	128%	142%	98.2%	$56.03	$80.09	1.43
NB Ext	$139.85	$139.48	$38.65	$0.00	$298.86	$528.93	114%	129%	100%	$49.81	$73.03	1.47
NYN Ext	$151.19	$148.24	$42.48	$0.00	$318.28	$552.76	124%	137%	98%	$53.76	$76.88	1.43
HQ Ext	$152.94	$150.40	$42.41	$0.00	$326.26	$568.74	125%	139%	98%	$54.73	$78.42	1.43
HG Ext	$144.41	$139.04	$38.98	$0.00	$463.21	$531.93	118%	128%	96%	$53.42	$72.71	1.36
CSC Ext	$153.21	$150.62	$43.31	$0.00	$321.77	$569.68	125%	139%	98%	$54.17	$78.17	1.44
NNC Ext	$152.32	$149.16	$42.88	$0.00	$321.83	$567.46	125%	138%	98%	$54.30	$77.61	1.43

4.1.2 On-Peak Hours, February 2014

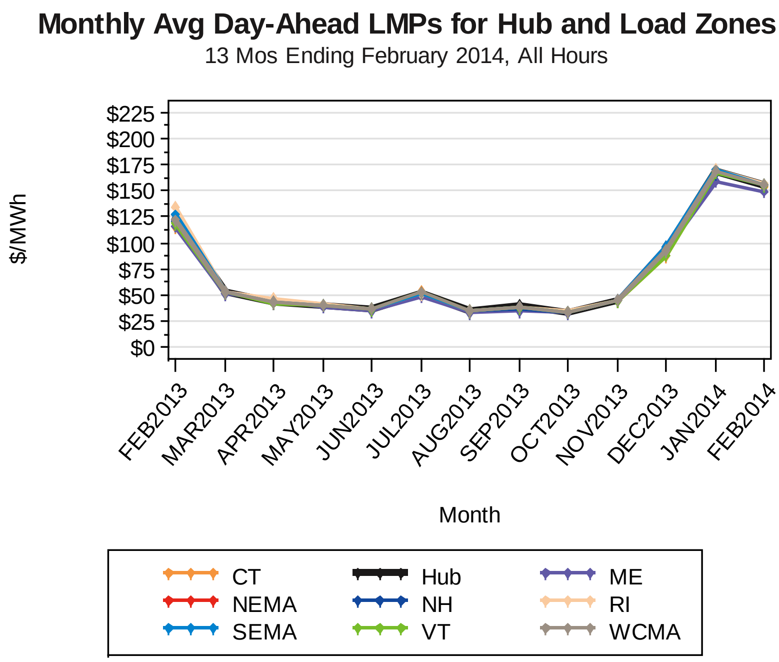
Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$182.09	$179.58	$66.87	$31.90	$332.47	$534.89	135%	152%	99%	$48.41	$65.40	1.35
ME	$174.53	$170.14	$66.52	$31.33	$321.82	$499.92	129%	144%	97%	$45.97	$62.08	1.35
NH	$181.26	$177.17	$67.16	$31.81	$333.49	$524.22	134%	150%	98%	$48.14	$64.38	1.34
VT	$181.84	$176.25	$66.12	$31.46	$391.55	$530.04	134%	149%	97%	$49.47	$64.05	1.29
CT	$179.52	$177.04	$66.19	$31.77	$325.47	$531.48	133%	150%	99%	$47.75	$64.40	1.35
RI	$182.74	$179.23	$66.99	$32.01	$330.09	$532.14	135%	152%	98%	$49.52	$65.20	1.32
SEMA	$181.46	$179.51	$66.95	$31.84	$328.60	$531.11	134%	152%	99%	$47.81	$65.20	1.36
WCMA	$182.21	$179.24	$66.98	$31.93	$331.31	$534.14	135%	152%	98%	$48.39	$65.22	1.35
NEMA	$182.37	$180.32	$66.81	$31.89	$333.62	$532.42	135%	153%	99%	$48.42	$65.66	1.36
NB Ext	$162.76	$163.28	$62.79	$30.09	$298.86	$487.09	120%	138%	100%	$42.72	$59.96	1.40
NYN Ext	$176.11	$173.75	$64.28	$31.18	$318.28	$524.15	130%	147%	99%	$46.92	$63.25	1.35
HQ Ext	$178.43	$176.69	$65.64	$31.43	$326.26	$523.52	132%	150%	99%	$47.35	$64.33	1.36
HG Ext	$169.24	$163.59	$61.11	$29.26	$463.21	$498.55	125%	138%	97%	$47.68	$59.50	1.25
CSC Ext	$178.51	$176.71	$66.31	$31.98	$321.77	$529.18	132%	150%	99%	$46.91	$64.00	1.36
NNC Ext	$177.58	$174.92	$65.08	$31.38	$321.83	$530.85	131%	148%	99%	$47.38	$63.83	1.35

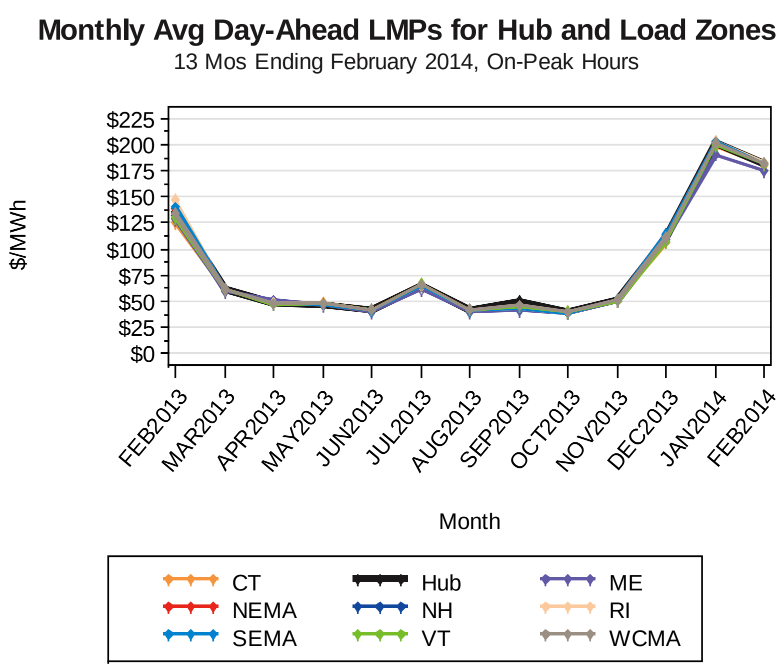
4.1.3 Off-Peak Hours, February 2014

Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$132.32	$128.54	$43.17	$0.00	$308.83	$578.89	120%	130%	97%	$51.54	$83.70	1.62
ME	$126.61	$122.60	$41.66	$0.00	$300.52	$550.30	115%	124%	97%	$49.54	$80.04	1.62
NH	$131.06	$126.47	$42.90	$0.00	$310.89	$571.06	119%	127%	96%	$51.20	$82.55	1.61
VT	$131.18	$125.79	$42.53	$0.00	$304.53	$565.49	119%	127%	96%	$51.27	$81.87	1.60
CT	$130.60	$126.95	$43.24	$0.00	$300.28	$567.83	118%	128%	97%	$50.33	$82.30	1.64
RI	$132.47	$128.90	$43.22	$0.00	$307.14	$587.18	120%	130%	97%	$51.59	$83.98	1.63
SEMA	$132.15	$128.67	$43.10	$0.00	$295.60	$591.08	120%	130%	97%	$51.39	$83.98	1.63
WCMA	$132.47	$128.46	$43.45	$0.00	$307.69	$575.60	120%	129%	97%	$51.44	$83.48	1.62
NEMA	$132.49	$128.90	$43.27	$0.00	$311.07	$583.97	120%	130%	97%	$51.79	$84.15	1.62
NB Ext	$119.01	$117.85	$38.65	$0.00	$279.04	$528.93	108%	119%	99%	$46.58	$77.09	1.66
NYN Ext	$128.54	$125.06	$42.48	$0.00	$293.34	$552.76	116%	126%	97%	$49.43	$80.81	1.64
HQ Ext	$129.77	$126.50	$42.41	$0.00	$304.01	$568.74	117%	127%	97%	$50.59	$82.40	1.63
HG Ext	$121.83	$116.72	$38.98	$0.00	$284.33	$531.93	110%	118%	96%	$48.13	$76.42	1.59
CSC Ext	$130.21	$126.90	$43.31	$0.00	$299.25	$569.68	118%	128%	97%	$49.95	$82.31	1.65
NNC Ext	$129.36	$125.74	$42.88	$0.00	$295.06	$567.46	117%	127%	97%	$49.86	$81.59	1.64

4.2 LMP Graphs, Day-Ahead Market, 13 Months Ending February 2014

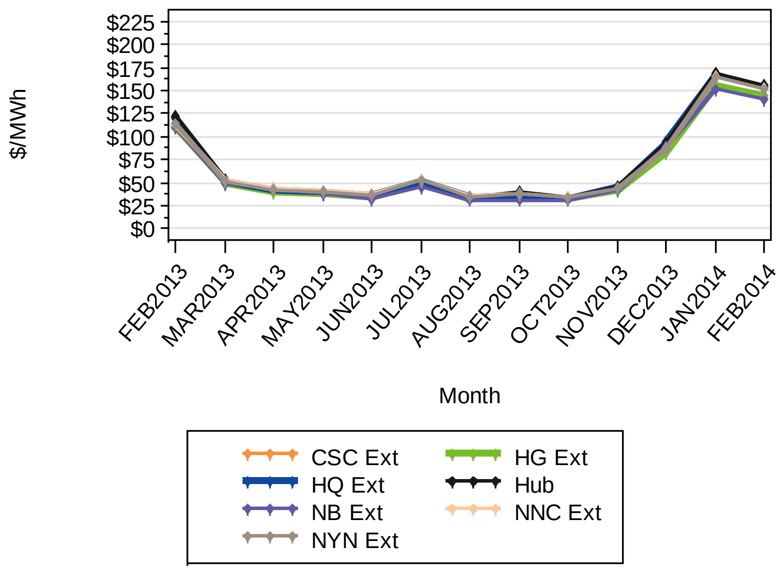
The following four graphs show the 13 month history of average hourly Day-Ahead LMPs for the Hub, Load Zones, and External Nodes on an overall and on-peak basis.





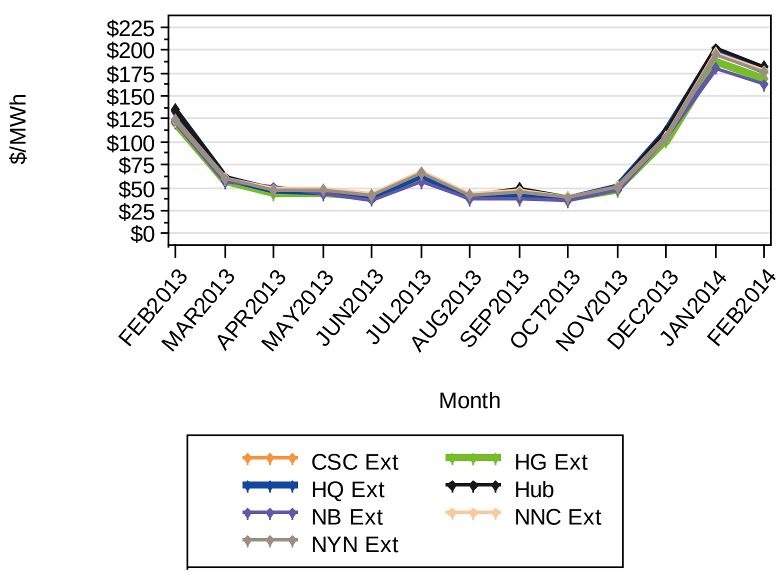
Monthly Avg Day-Ahead LMPs for Hub and External Nodes

13 Mos Ending February 2014, All Hours



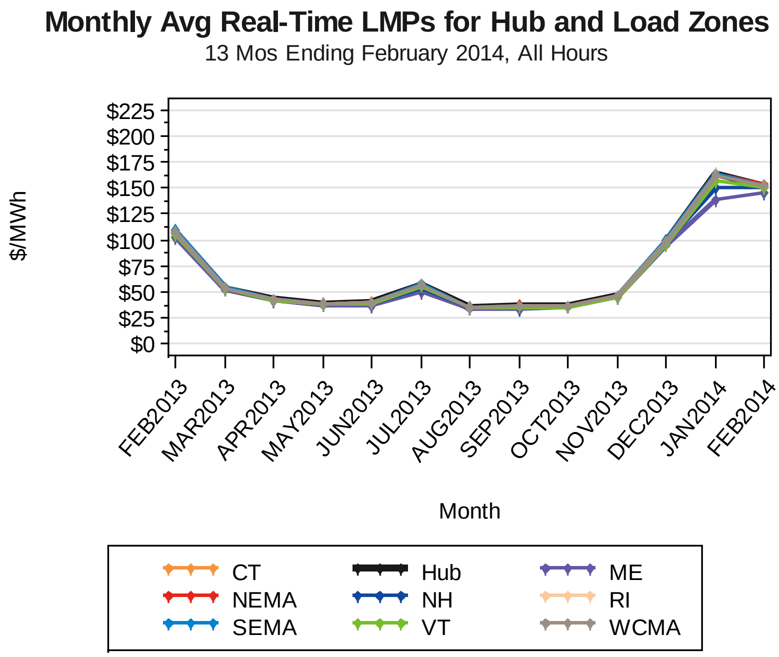
Monthly Avg Day-Ahead LMPs for Hub and External Nodes

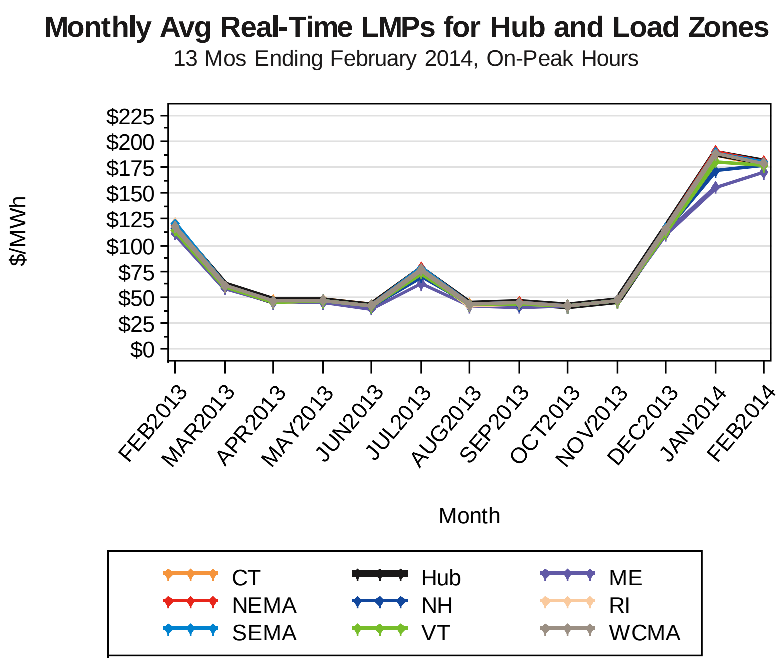
13 Mos Ending February 2014, On-Peak Hours



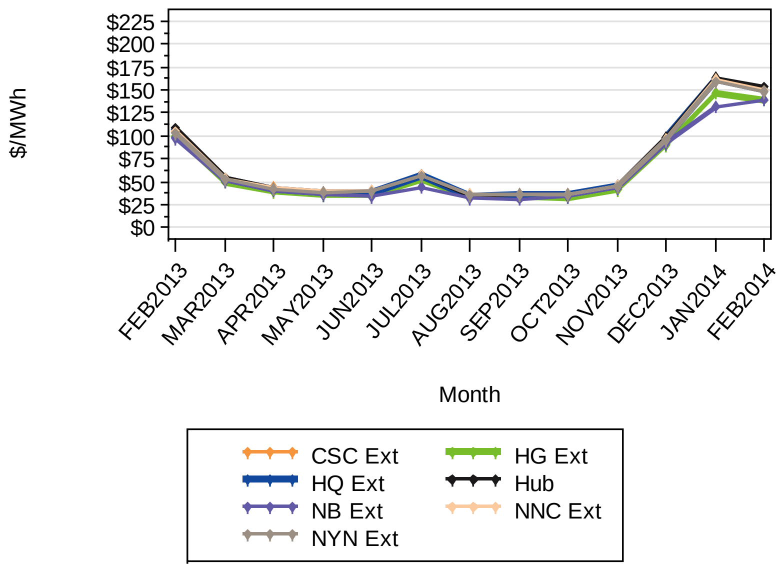
4.3 LMP Graphs, Real-Time Market, 13 Months Ending February 2014

The following four graphs show the 13 month history of average hourly Real-Time LMPs for the Hub, Load Zones, and External Nodes on an overall and on-peak basis.

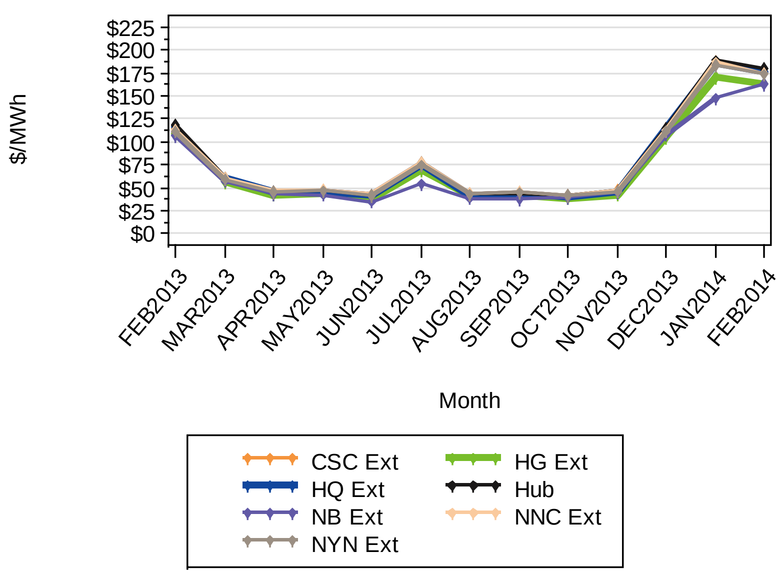




Monthly Avg Real-Time LMPs for Hub and External Nodes
13 Mos Ending February 2014, All Hours



Monthly Avg Real-Time LMPs for Hub and External Nodes
13 Mos Ending February 2014, On-Peak Hours



4.4 For More Information

The ISO provides a discussion of LMP results on a weekly basis in its Weekly Market Performance Report, located here.

The ISO also provides a discussion of LMP results on an annual basis in its Annual Market Performance Reports, located here.

Downloadable Hub and Load Zone weekly and monthly LMP indices are located here.

Customizable downloads of Day-Ahead and Real-Time Hourly LMPs can be performed here.

Current Day-Ahead and Real-Time LMPs for the Hub and Load Zones can be monitored here.

A discussion of the calculation of LMPs can be found in the ISO's Market Rule 1 located here.

5. Imports and Exports

Market Participants can submit hourly Fixed External Transaction quantities for which they commit to import at Day-Ahead LMPs for delivery in the next Operating Day. They can also submit hourly Fixed External Transaction quantities for which they commit to import at Real-Time LMPs for physical delivery within the Operating Day. There are also several types of price-dependent transactions that can be submitted.

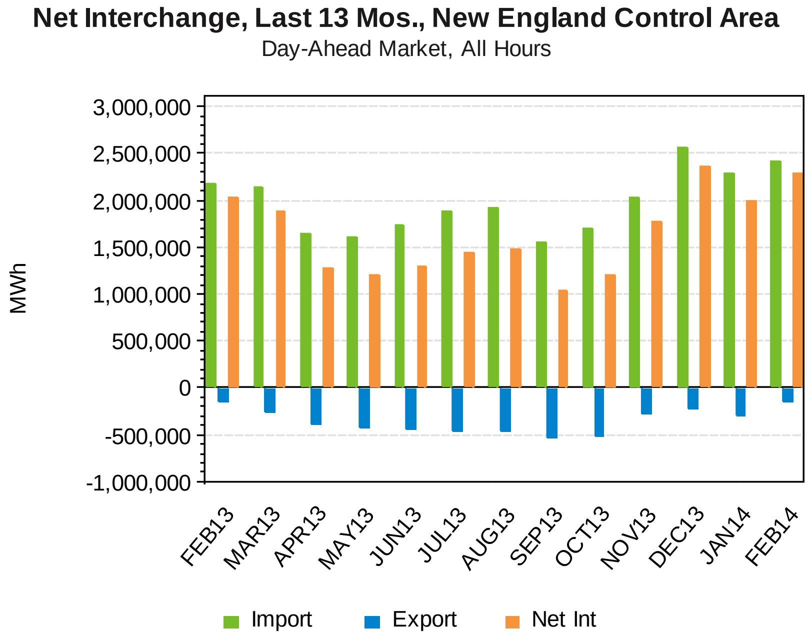
5.1 Net Interchange Summary, February 2014

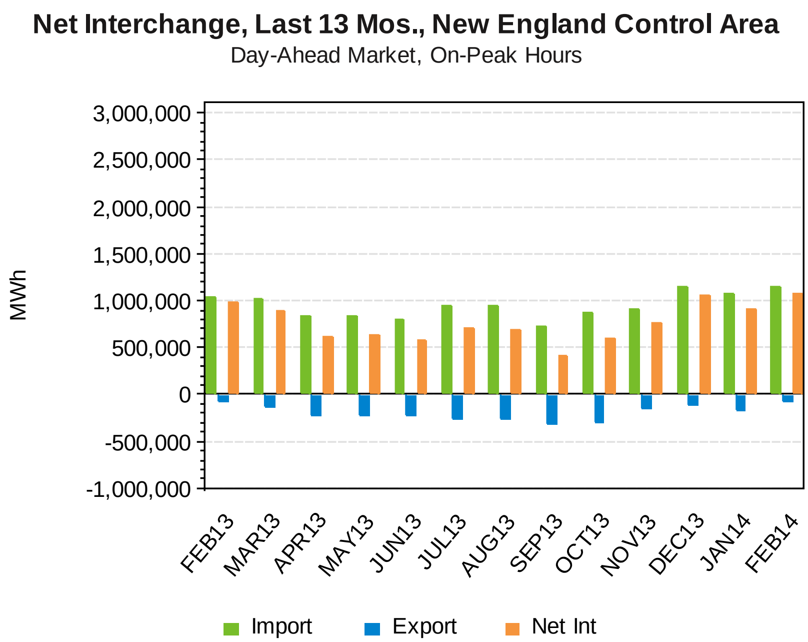
The following tables show summary statistics for imports and exports on the six external interfaces for both the Day-Ahead and Real-Time Markets:

5.1.1 Day-Ahead and Real-Time Market Summary by Interface

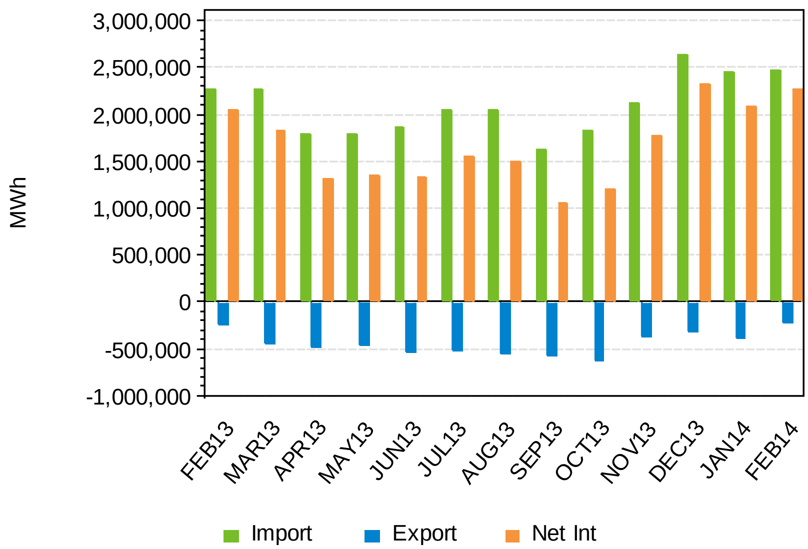
On/Off Peak	Interface	DA Total Exports (MWh)	DA Total Imports (MWh)	DA Net Int (MWh)	RT Total Exports (MWh)	RT Total Imports (MWh)	RT Net Int (MWh)
All Hours	NNC	-13,108	43,892	30,784	-18,203	55,520	37,317
	NY-CSC	-51,975	0	-51,975	-56,442	1,901	-54,541
	HQ HG	-436	146,496	146,060	-436	146,446	146,010
	HQ I/II	-358	876,492	876,134	-359	886,472	886,113
	NY-N AC	-67,674	874,444	806,770	-123,045	927,743	804,698
	NB	-200	474,872	474,672	-7,842	460,567	452,725
Total	**All Hours**	**-133,751**	**2,416,196**	**2,282,445**	**-206,327**	**2,478,649**	**2,272,322**
Off-Peak	NNC	-9,020	24,975	15,955	-10,728	29,576	18,848
	NY-CSC	-21,495	0	-21,495	-22,088	1,901	-20,187
	HQ HG	-218	76,736	76,518	-218	76,686	76,468
	HQ I/II	-179	458,452	458,273	-179	459,601	459,422
	NY-N AC	-30,437	459,869	429,432	-61,820	491,574	429,754
	NB	-100	247,516	247,416	-5,075	240,773	235,698
Total	**Off-Peak**	**-61,449**	**1,267,547**	**1,206,098**	**-100,108**	**1,300,111**	**1,200,003**
On-Peak	NNC	-4,087	18,917	14,830	-7,475	25,944	18,469
	NY-CSC	-30,480	0	-30,480	-34,354	0	-34,354
	HQ HG	-218	69,760	69,542	-218	69,760	69,542
	HQ I/II	-179	418,040	417,861	-180	426,871	426,691
	NY-N AC	-37,237	414,576	377,339	-61,225	436,169	374,944
	NB	-100	227,356	227,256	-2,767	219,794	217,027
Total	**On-Peak**	**-72,302**	**1,148,649**	**1,076,347**	**-106,219**	**1,178,538**	**1,072,319**

5.2 Day-Ahead and Real-Time Net Interchange Summary, Last 13 Months

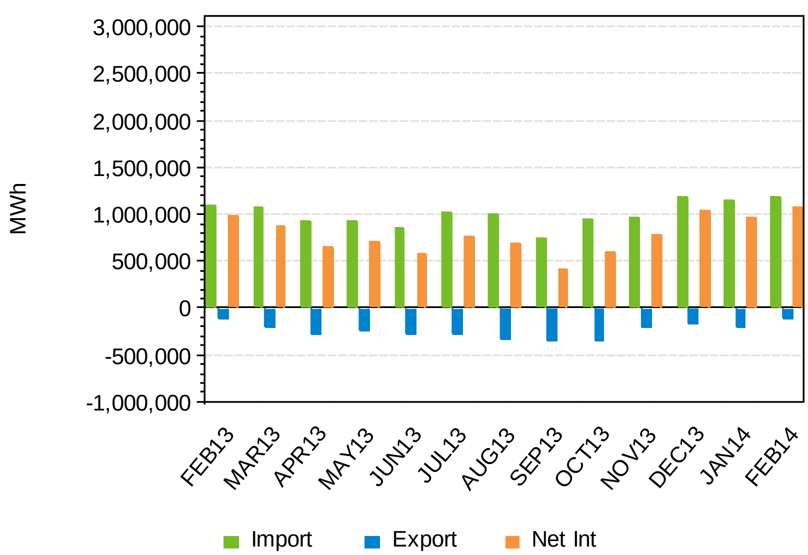




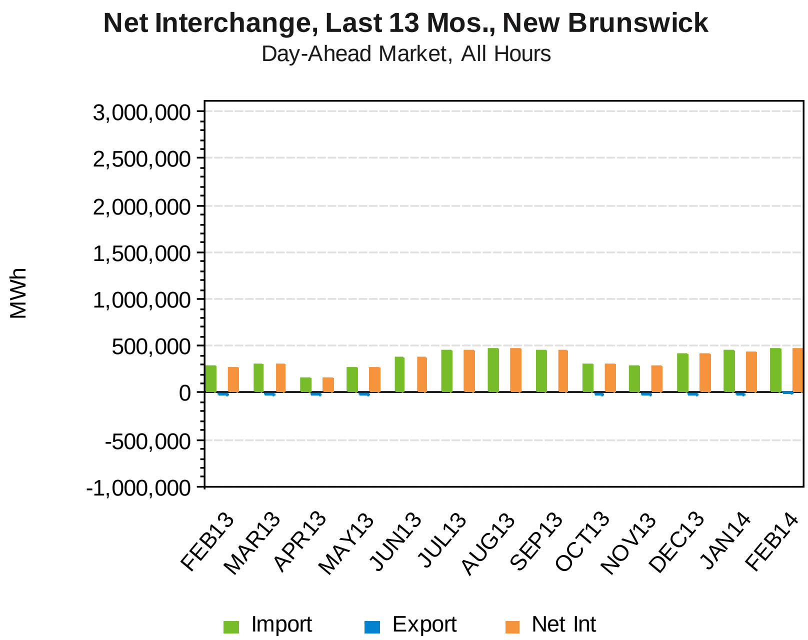
Net Interchange, Last 13 Mos., New England Control Area
Real-Time Market, All Hours

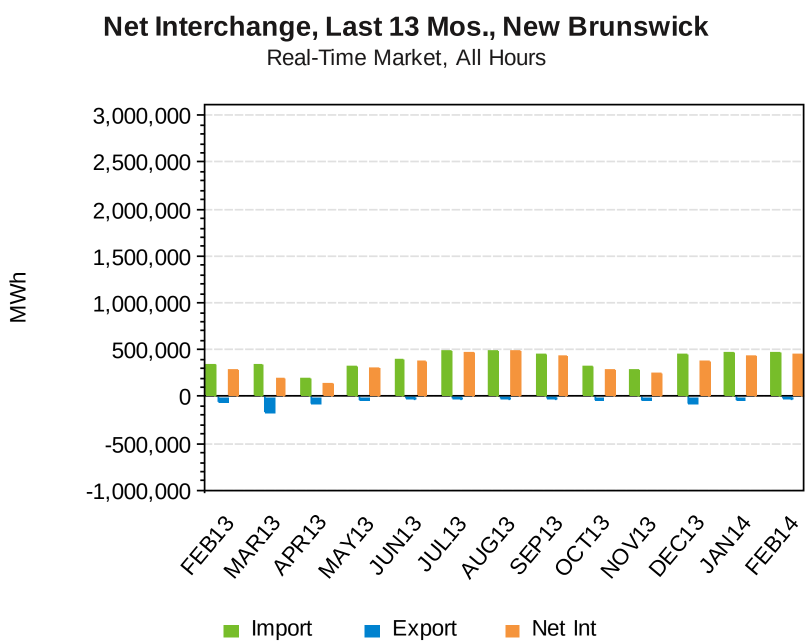


Net Interchange, Last 13 Mos., New England Control Area
Real-Time Market, On-Peak Hours



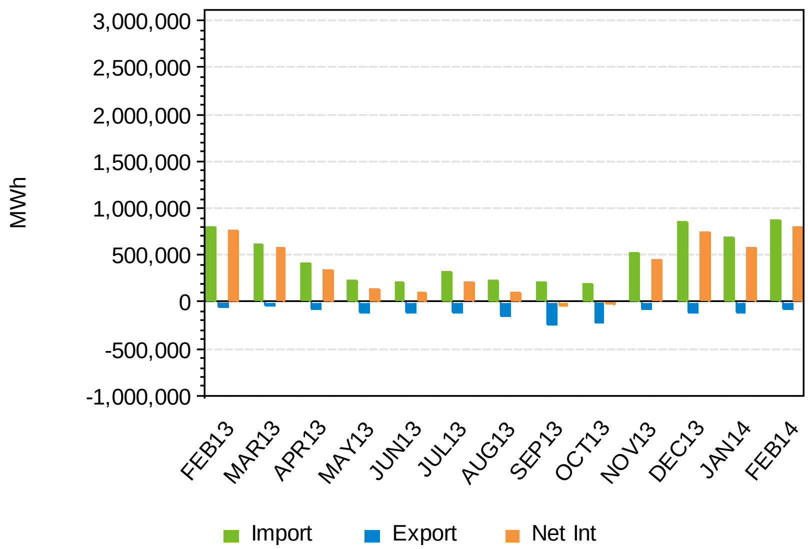
5.3 Net Interchange Summary by Interface, Last 13 Months





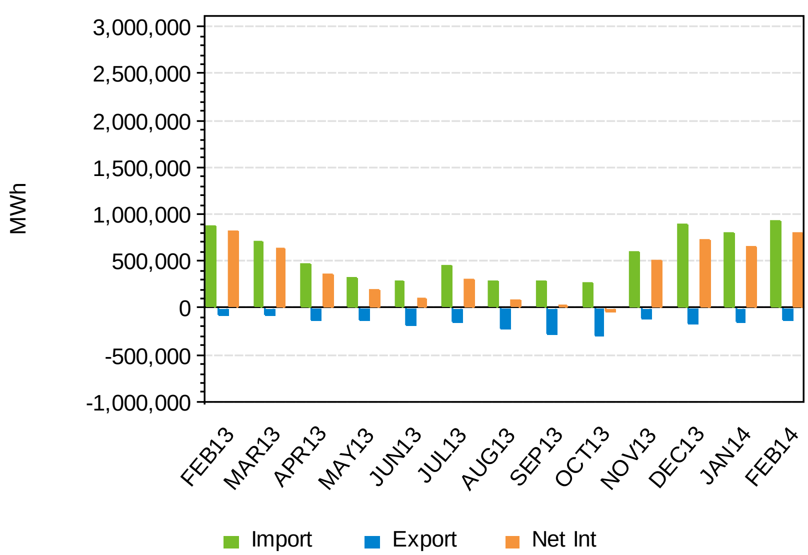
Net Interchange, Last 13 Mos., New York N-AC Ties

Day-Ahead Market, All Hours



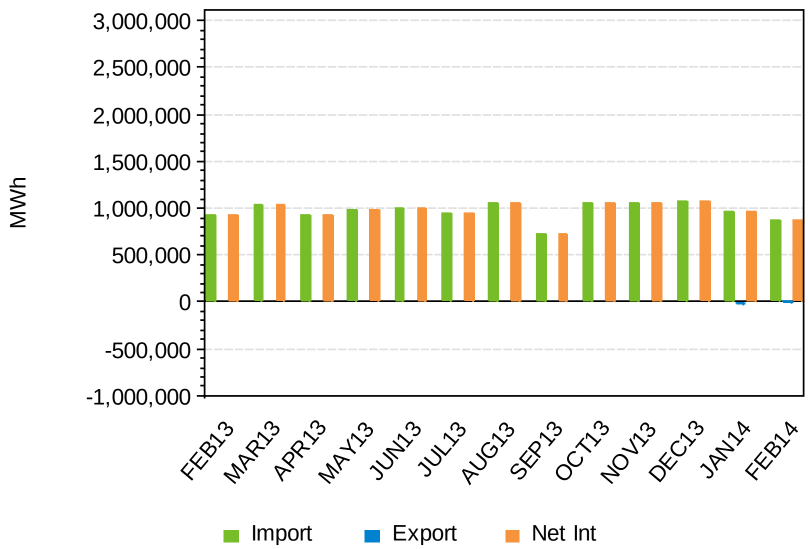
Net Interchange, Last 13 Mos., New York N-AC Ties

Real-Time Market, All Hours



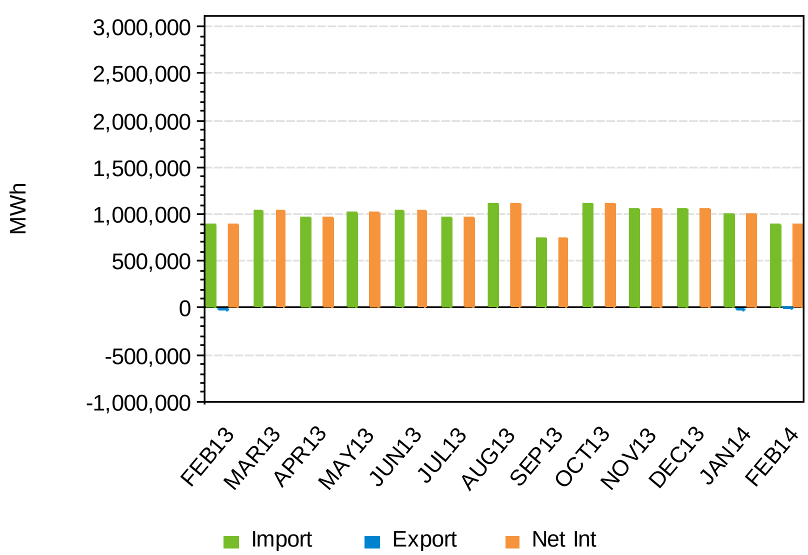
Net Interchange, Last 13 Mos., Hydro-Quebec Phase I/II

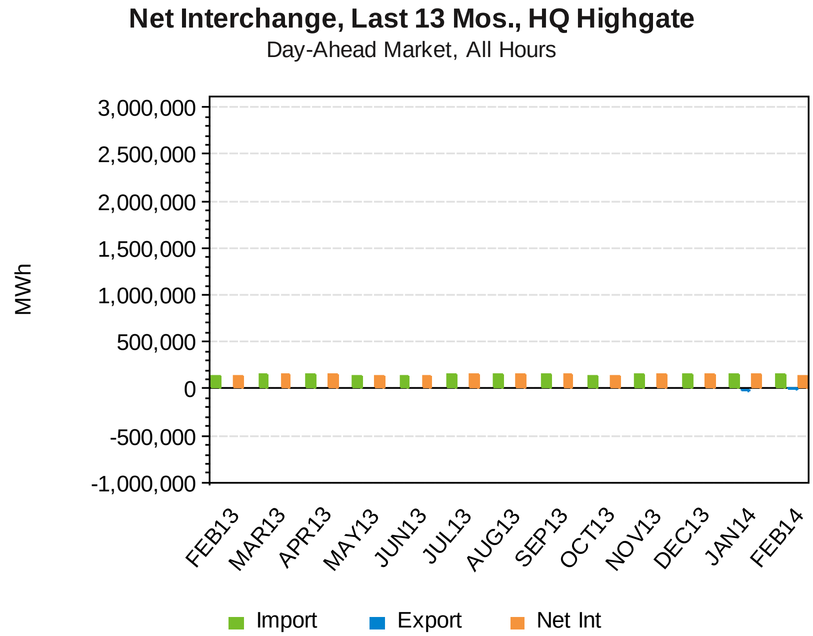
Day-Ahead Market, All Hours

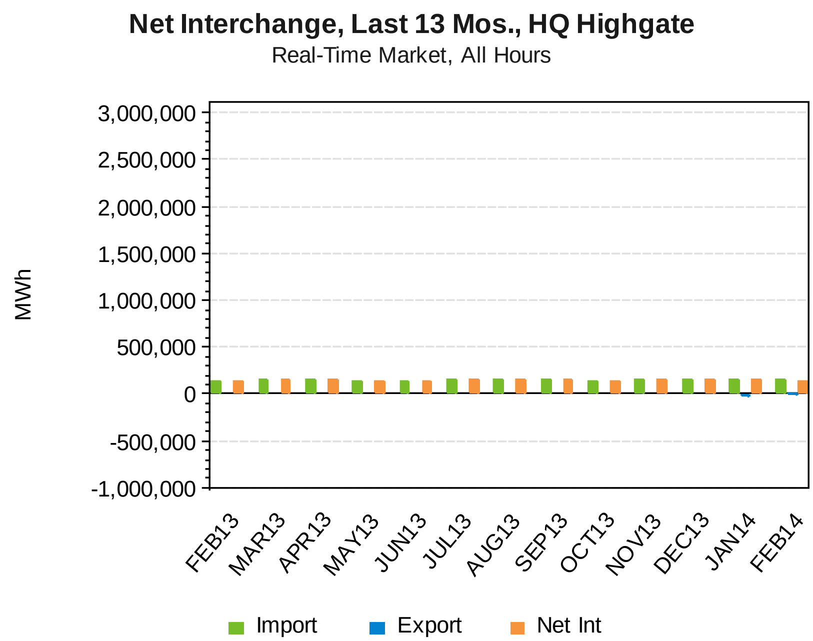


Net Interchange, Last 13 Mos., Hydro-Quebec Phase I/II

Real-Time Market, All Hours

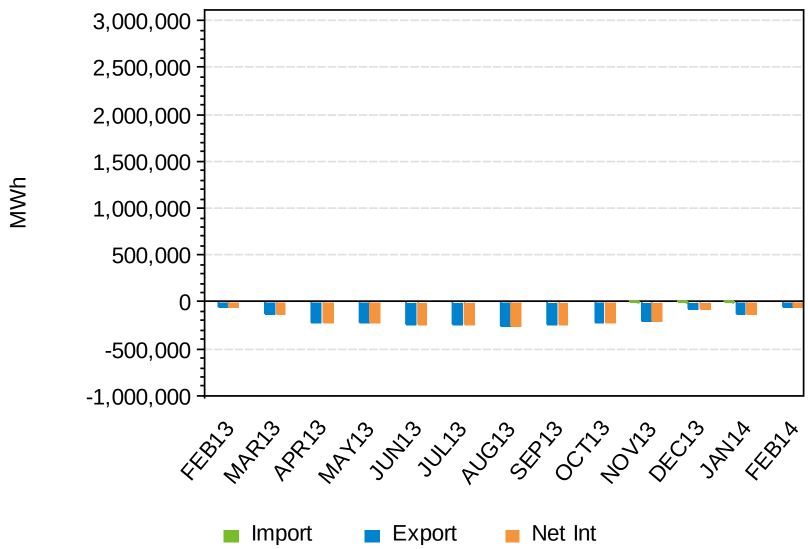



Net Interchange, Last 13 Mos., HQ Highgate
Day-Ahead Market, All Hours
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
FEB13
MAR13
APR13
MAY13
JUN13
JUL13
AUG13
SEP13
OCT13
NOV13
DEC13
JAN14
FEB14
Import
Export
Net Int


Net Interchange, Last 13 Mos., HQ Highgate
Real-Time Market, All Hours
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
FEB13
MAR13
APR13
MAY13
JUN13
JUL13
AUG13
SEP13
OCT13
NOV13
DEC13
JAN14
FEB14
Import
Export
Net Int

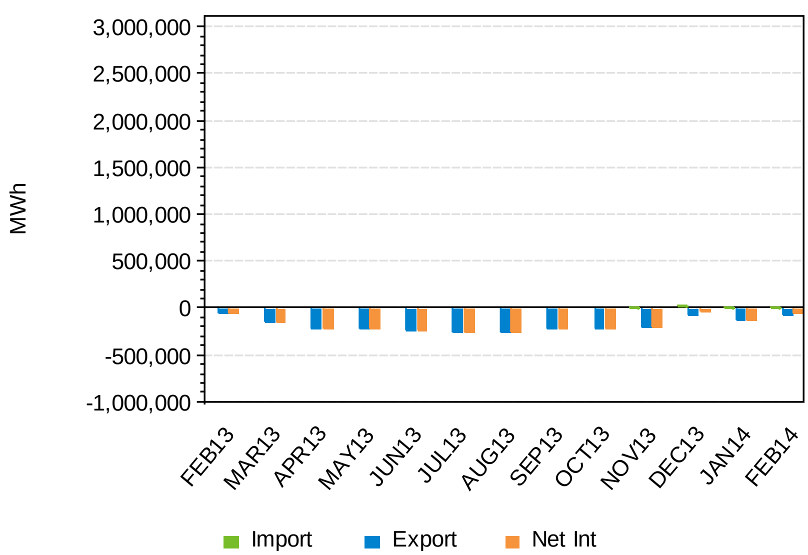
Net Interchange, Last 13 Mos., NY Cross Sound Cable

Day-Ahead Market, All Hours

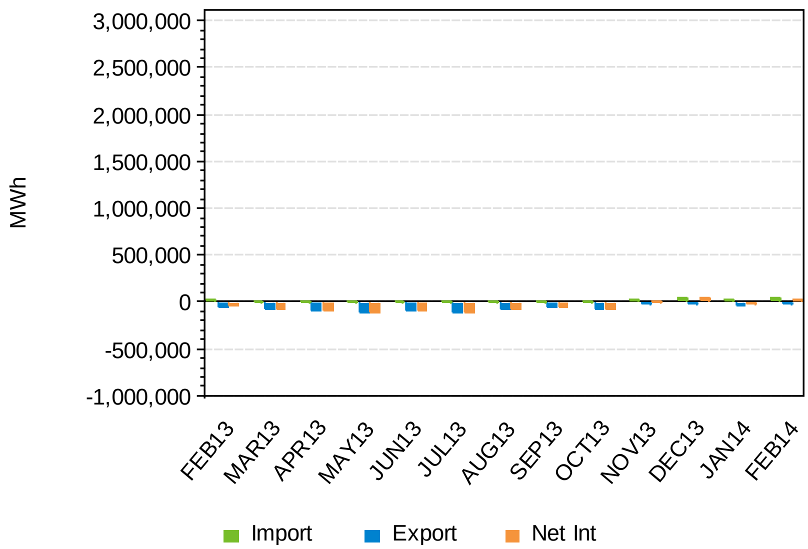


Net Interchange, Last 13 Mos., NY Cross Sound Cable

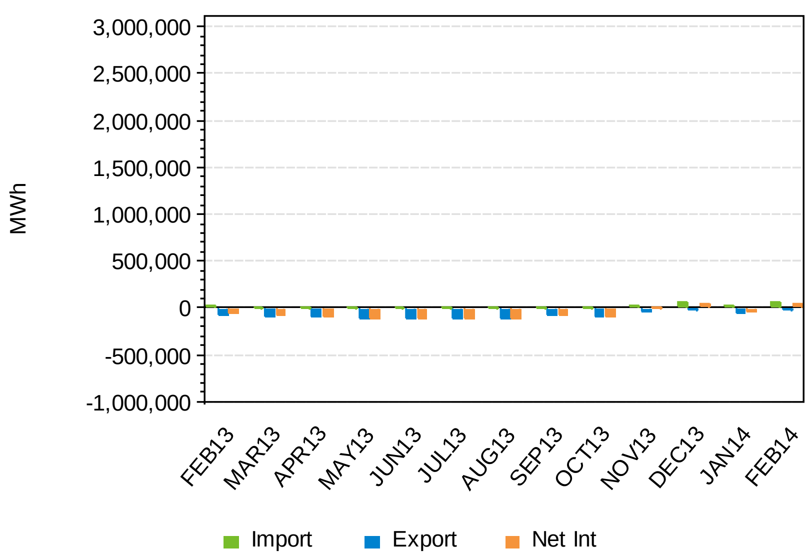
Real-Time Market, All Hours



Net Interchange, Last 13 Mos., Northport-Norwalk Cable
Day-Ahead Market, All Hours



Net Interchange, Last 13 Mos., Northport-Norwalk Cable
Real-Time Market, All Hours



5.4 For More Information

Selectable historical hourly net interchange for the New England Control can be found on the ISO's website (select 'Interchange' in the drop-down under 'Step 1') here.

Monthly, daily, and hourly summaries of New England Control Area net interchange can be found on the ISO's web site here.

The market rules governing the scheduling of external transactions can be found in Section III.1.10 "Scheduling" of the ISO's Market Rule 1 located here.

The business rules and procedures for external transactions can be found in Section 6.5, "External Transactions" in the ISO's Manual 11 – Market Operations located here.

A history of emergency purchases and sales from and to neighboring control areas can be found here.

6. Financial Transmission Rights (FTR) Auctions

FTRs are financial instruments that entitle the holder to a share of congestion collections in the Day-Ahead Market. The difference in prices (excluding losses) along a path or between any two locations on the system in the Day-Ahead Market reflects the marginal cost of transmission along that path. An FTR allows its purchaser to collect up to the full value of such congestion as consistent with the FTR's specified path and MW value.

FTRs can be acquired in three ways:

- FTR Auction – the ISO conducts periodic auctions to allow bidders to acquire and sell monthly and long-term FTRs. The bidders in the FTR auction initially define all FTRs.
- Secondary Market – The FTR secondary market is an ISO-administered bulletin board where existing FTRs are electronically bought or sold on a bilateral basis.
- Unregistered Trades – FTRs can be exchanged bilaterally outside of the ISO-administered process. However, the ISO compensates only FTR holders of record and does not recognize business done in this manner for day-ahead congestion settlement purposes.

6.1 FTR Auction Results

The results of the monthly FTR auction and any applicable long-term FTR auction are shown below.

6.1.1 Monthly Auction Summary, February 2014

Bids to Buy or Offers to Sell	On-Peak or Off-Peak	No. of Bids or Offers	Bid or Offered MW-Mos.	Bid or Offered Dollars	No. of Awards	Awarded MW-Mos.	Awarded Dollars
Buy	Off	17,839	97,842	$599,615	6,514	25,284	$492,469
Buy	On	16,490	115,929	-$2,361,674	5,178	26,190	$912,025
Buy	Buy Total	34,329	213,770	-$1,762,059	11,692	51,473	$1,404,494
Sell	Off	4,038	7,096	$6,448,650	117	257	-$50,968
Sell	On	4,106	8,091	$7,245,581	206	504	$44,593
Sell	Sell Total	8,144	15,188	$13,694,231	323	761	-$6,374
Grand Total	Grand Total	42,473	228,958	$11,932,172	12,015	52,234	$1,398,120

6.1.2 Number of Auction Participants, February 2014

Auction Period	Monthly or Long-Term	No. of Bidders
Feb 2014	MO	31

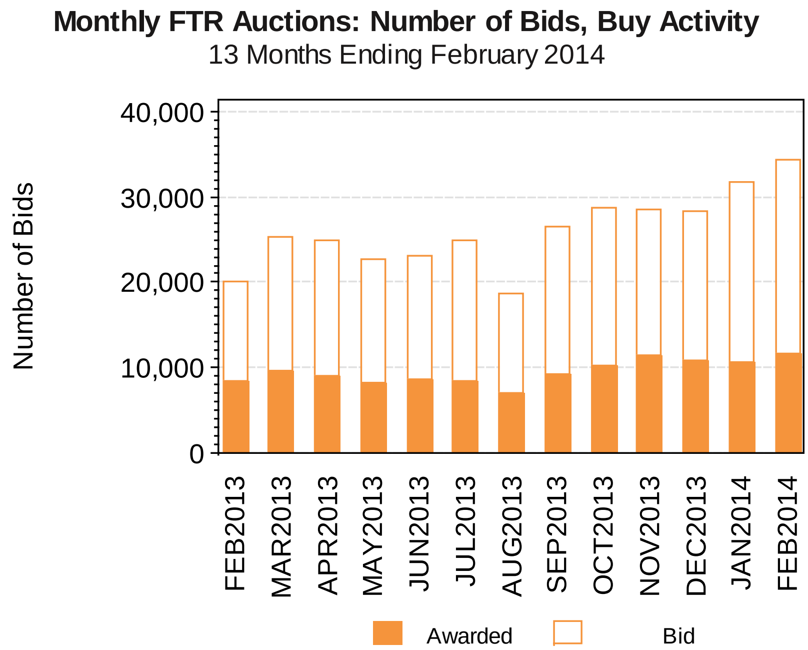
6.1.3 Monthly FTR Auction Results, Last 13 Months

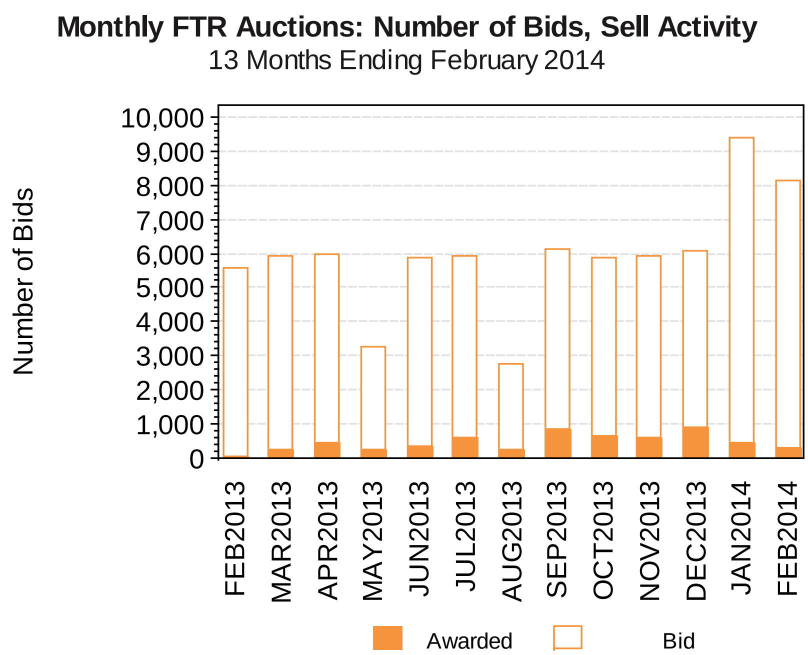
Auction Month	Bids to Buy or Offers to Sell	No. of Bids or Offers	Bid or Offered MW-Mos.	Bid or Offered Dollars	No. of Awards	Awarded MW-Mos.	Awarded Dollars
FEB 2013	Buy	20,017	138,409	-$5,309,132	8,440	43,578	$387,345
FEB 2013	Sell	5,552	10,469	$1,741,271	50	386	$37,419
FEB 2013	Tot	25,569	148,878	-$3,567,861	8,490	43,964	$424,764
MAR 2013	Buy	25,262	148,141	-$7,889,283	9,666	41,945	$857,323
MAR 2013	Sell	5,929	10,847	$3,766,561	265	997	$9,421
MAR 2013	Tot	31,191	158,987	-$4,122,722	9,931	42,942	$866,744
APR 2013	Buy	24,920	142,316	-$6,433,530	9,017	36,947	$587,672

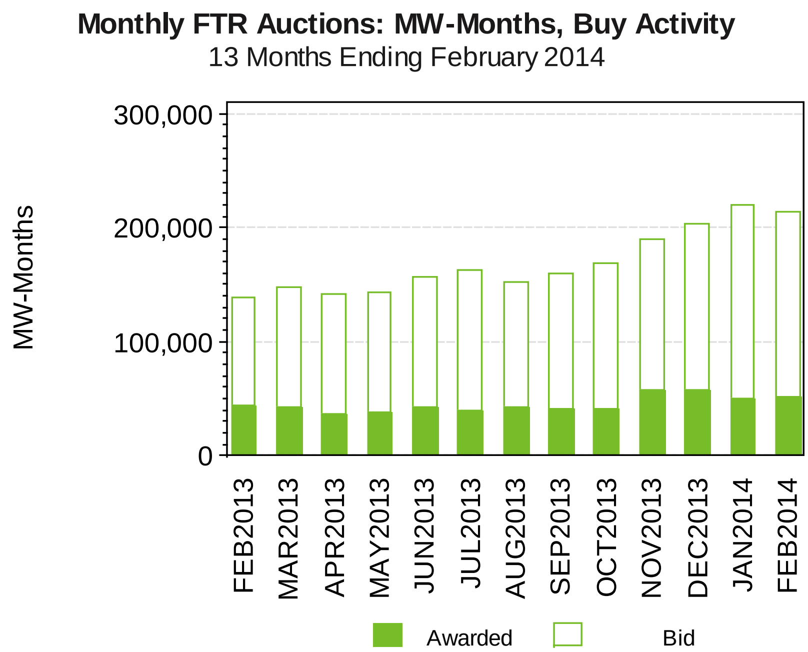
Auction Month	Bids to Buy or Offers to Sell	No. of Bids or Offers	Bid or Offered MW-Mos.	Bid or Offered Dollars	No. of Awards	Awarded MW-Mos.	Awarded Dollars
APR 2013	Sell	5,965	10,077	$3,260,657	473	1,146	-$10,085
APR 2013	Tot	30,885	152,392	-$3,172,873	9,490	38,093	$577,588
MAY 2013	Buy	22,614	143,919	-$4,286,670	8,306	37,921	$866,980
MAY 2013	Sell	3,271	8,737	$3,030,102	244	1,158	$20,776
MAY 2013	Tot	25,885	152,656	-$1,256,569	8,550	39,079	$887,756
JUN 2013	Buy	23,080	157,174	-$5,612,733	8,639	42,266	$812,663
JUN 2013	Sell	5,855	9,622	$2,989,609	381	959	-$86,030
JUN 2013	Tot	28,935	166,796	-$2,623,125	9,020	43,226	$726,634
JUL 2013	Buy	24,885	163,244	-$5,791,144	8,526	39,885	$742,559
JUL 2013	Sell	5,916	10,065	$3,281,166	616	1,260	-$54,186
JUL 2013	Tot	30,801	173,308	-$2,509,979	9,142	41,145	$688,373
AUG 2013	Buy	18,640	151,964	$2,138,361	7,000	42,476	$650,974
AUG 2013	Sell	2,764	7,499	$2,604,753	253	1,070	-$13,011
AUG 2013	Tot	21,404	159,464	$4,743,114	7,253	43,546	$637,963
SEP 2013	Buy	26,457	159,953	-$5,844,986	9,332	41,537	$606,395
SEP 2013	Sell	6,125	10,570	$2,991,914	859	1,672	-$41,171
SEP 2013	Tot	32,582	170,523	-$2,853,072	10,191	43,208	$565,224
OCT 2013	Buy	28,794	169,050	-$5,727,804	10,209	40,337	$818,036
OCT 2013	Sell	5,879	10,008	$3,202,743	662	1,703	-$54,686
OCT 2013	Tot	34,673	179,058	-$2,525,061	10,871	42,040	$763,350
NOV 2013	Buy	28,592	190,551	-$5,890,403	11,413	57,248	$1,104,161
NOV 2013	Sell	5,918	10,282	$3,137,958	633	1,616	-$54,043
NOV 2013	Tot	34,510	200,832	-$2,752,445	12,046	58,864	$1,050,119
DEC 2013	Buy	28,402	203,903	-$2,705,630	10,871	57,081	$1,483,248
DEC 2013	Sell	6,071	10,418	$3,189,192	891	2,058	-$94,804
DEC 2013	Tot	34,473	214,321	$483,562	11,762	59,139	$1,388,444
JAN 2014	Buy	31,703	220,120	$4,482,765	10,686	49,696	$3,143,026
JAN 2014	Sell	9,409	20,381	$12,042,842	443	1,331	-$274,050
JAN 2014	Tot	41,112	240,502	$16,525,607	11,129	51,027	$2,868,976
FEB 2014	Buy	34,329	213,770	-$1,762,059	11,692	51,473	$1,404,494
FEB 2014	Sell	8,144	15,188	$13,694,231	323	761	-$6,374
FEB 2014	Tot	42,473	228,958	$11,932,172	12,015	52,234	$1,398,120

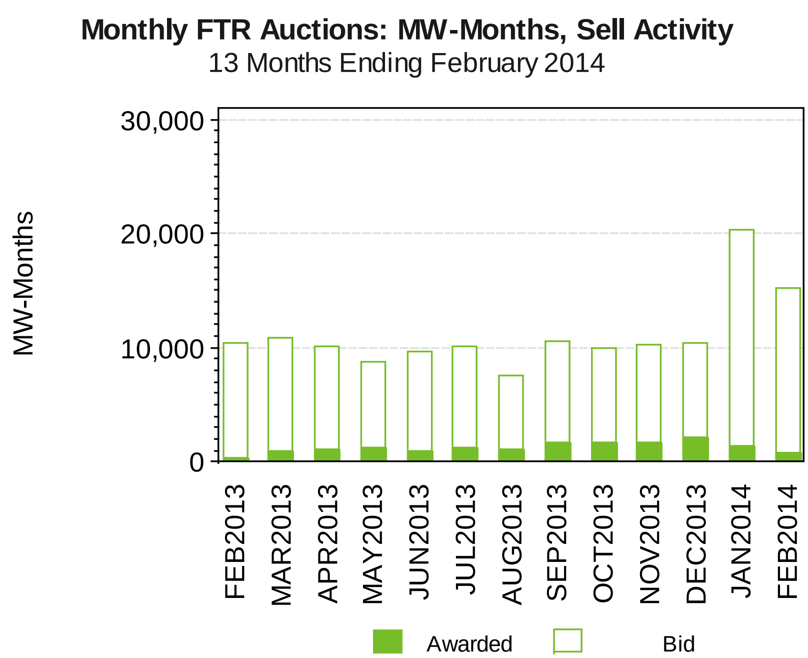
6.2 Monthly FTR Auction Results, Last 13 Months

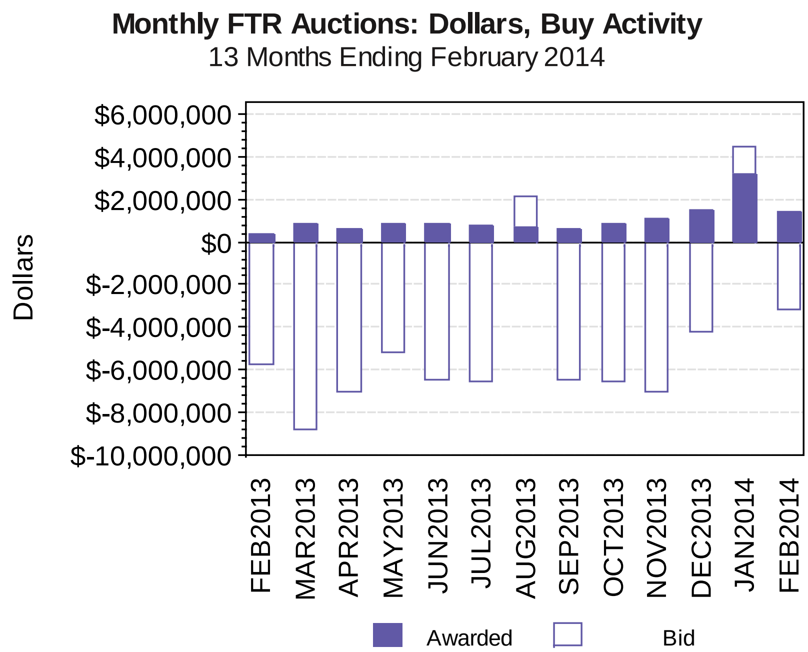
The next series of graphs show summaries of FTR Auction activity over the last 13 months, including bids to buy monthly FTRs and offers to sell long-term FTRs into each monthly auction.

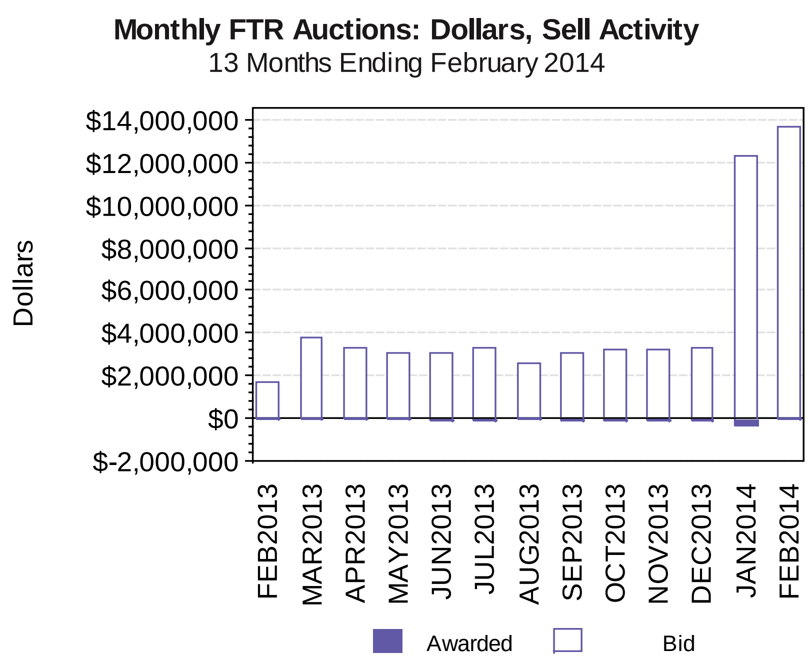

Monthly FTR Auctions: Number of Bids, Buy Activity
13 Months Ending February 2014
Number of Bids
40,000
30,000
20,000
10,000
0
FEB2013
MAR2013
APR2013
MAY2013
JUN2013
JUL2013
AUG2013
SEP2013
OCT2013
NOV2013
DEC2013
JAN2014
FEB2014
Awarded
Bid


Monthly FTR Auctions: Number of Bids, Sell Activity
13 Months Ending February 2014
Number of Bids
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
FEB2013
MAR2013
APR2013
MAY2013
JUN2013
JUL2013
AUG2013
SEP2013
OCT2013
NOV2013
DEC2013
JAN2014
FEB2014
Awarded
Bid


Monthly FTR Auctions: MW-Months, Buy Activity
13 Months Ending February 2014
300,000
200,000
100,000
0
MW-Months
FEB2013
MAR2013
APR2013
MAY2013
JUN2013
JUL2013
AUG2013
SEP2013
OCT2013
NOV2013
DEC2013
JAN2014
FEB2014
Awarded
Bid

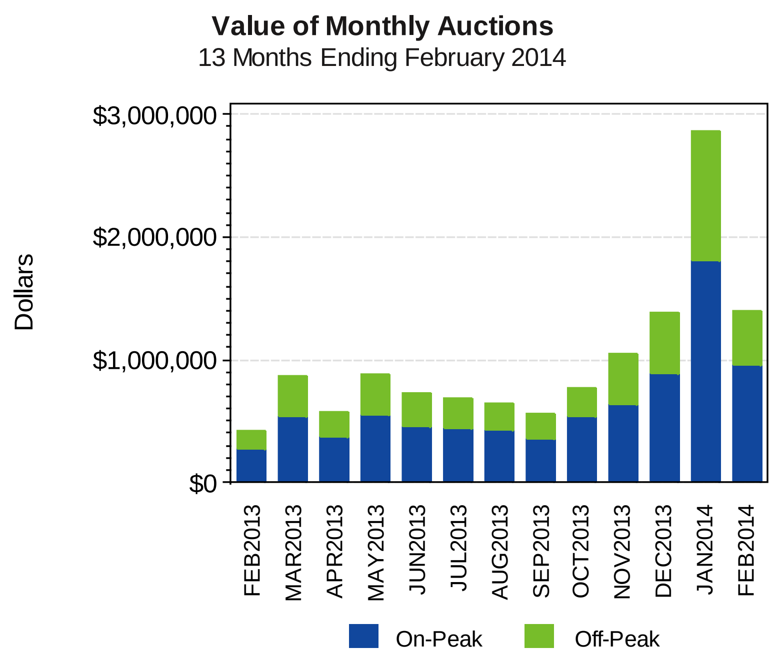

Monthly FTR Auctions: MW-Months, Sell Activity
13 Months Ending February 2014
30,000
20,000
10,000
0
MW-Months
FEB2013
MAR2013
APR2013
MAY2013
JUN2013
JUL2013
AUG2013
SEP2013
OCT2013
NOV2013
DEC2013
JAN2014
FEB2014
Awarded
Bid

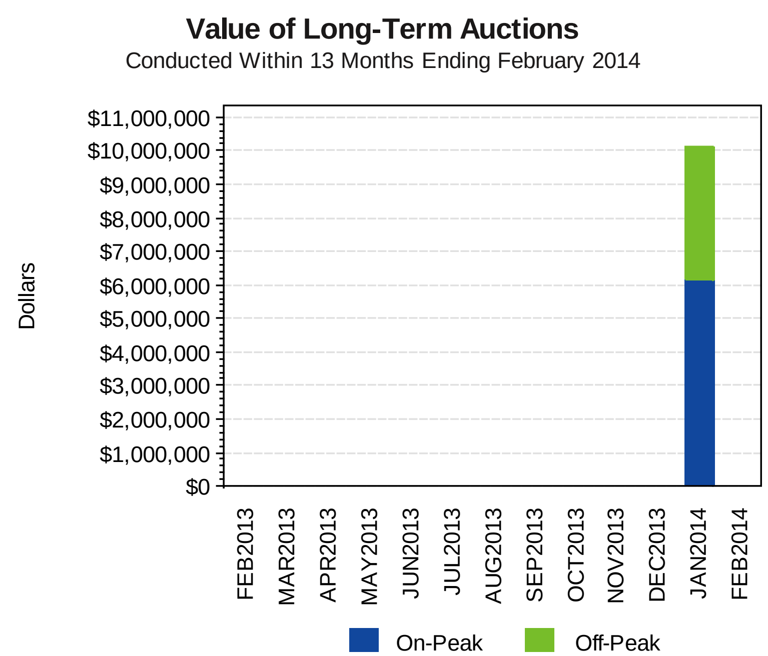

Monthly FTR Auctions: Dollars, Buy Activity
13 Months Ending February 2014
Dollars
$6,000,000
$4,000,000
$2,000,000
$0
$-2,000,000
$-4,000,000
$-6,000,000
$-8,000,000
$-10,000,000
FEB2013
MAR2013
APR2013
MAY2013
JUN2013
JUL2013
AUG2013
SEP2013
OCT2013
NOV2013
DEC2013
JAN2014
FEB2014
Awarded
Bid

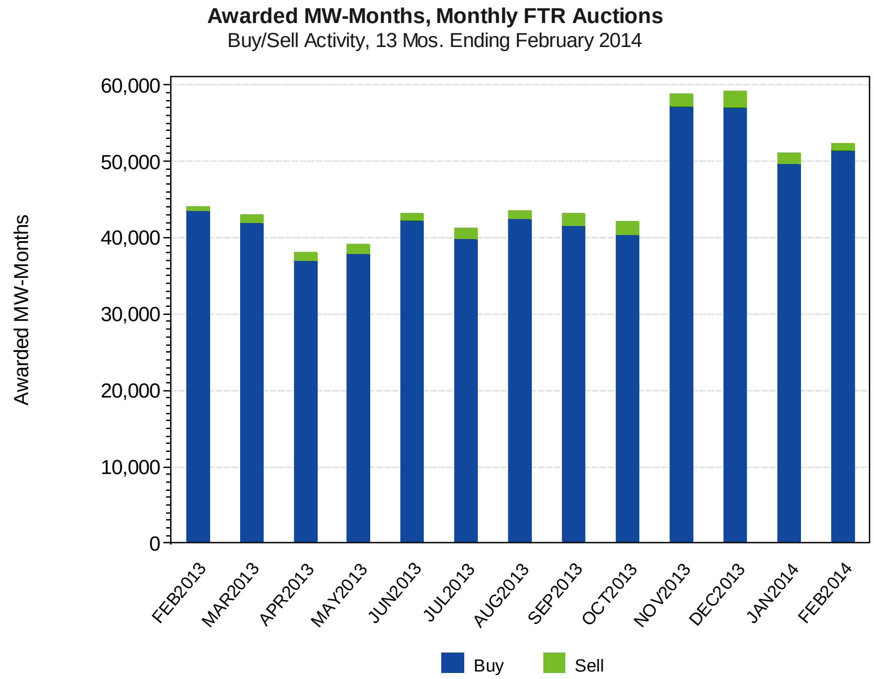

Monthly FTR Auctions: Dollars, Sell Activity
13 Months Ending February 2014
Dollars
$14,000,000
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$0
$-2,000,000
FEB2013
MAR2013
APR2013
MAY2013
JUN2013
JUL2013
AUG2013
SEP2013
OCT2013
NOV2013
DEC2013
JAN2014
FEB2014
Awarded
Bid

6.3 Auction Value, Last 13 Months

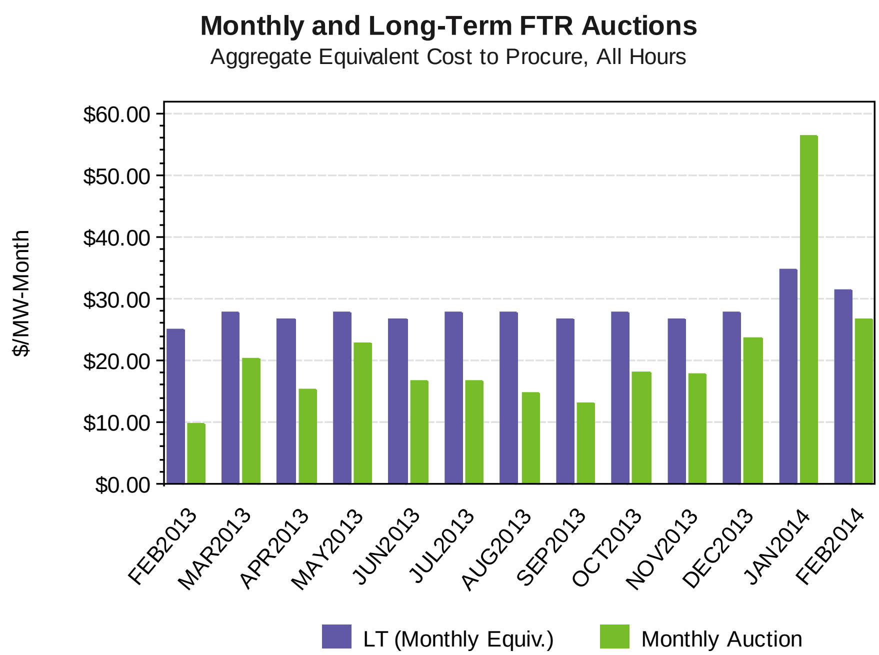
The next series of graphs show summaries of FTR Auction value and on/off-peak activity over the last 13 months.



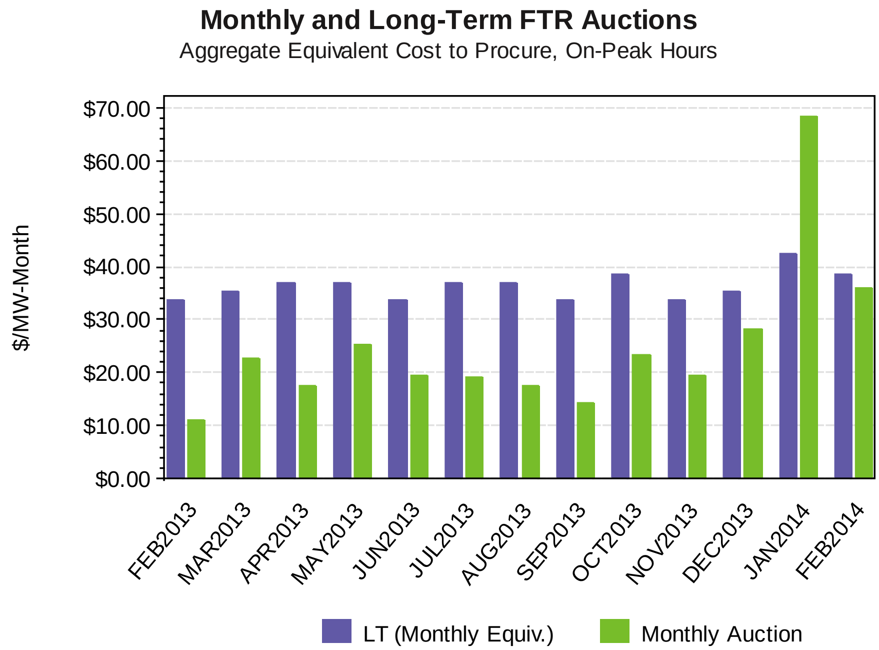


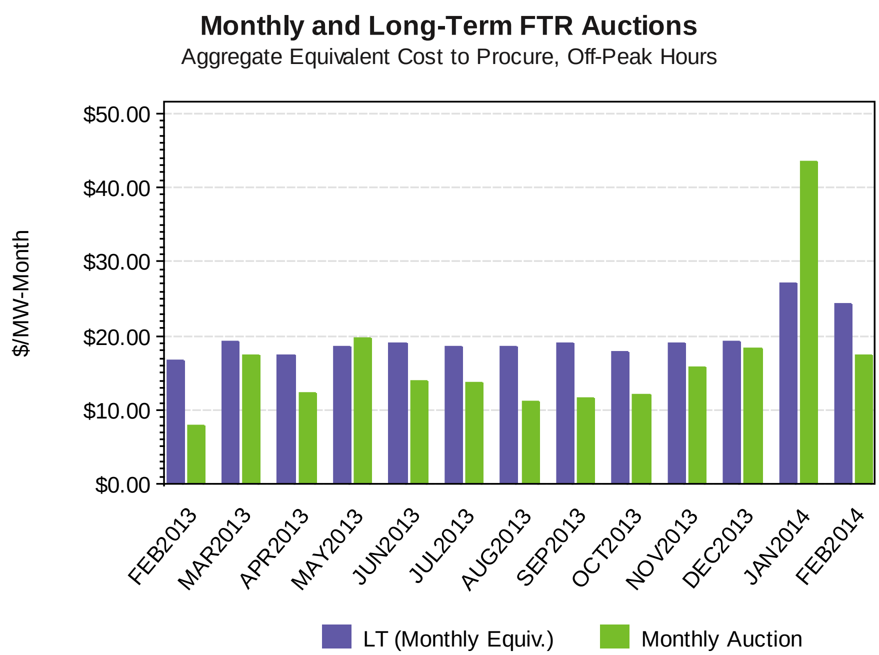


Awarded MW-Months, Monthly FTR Auctions
Buy/Sell Activity, 13 Mos. Ending February 2014
Awarded MW-Months
60,000
50,000
40,000
30,000
20,000
10,000
0
FEB2013
MAR2013
APR2013
MAY2013
JUN2013
JUL2013
AUG2013
SEP2013
OCT2013
NOV2013
DEC2013
JAN2014
FEB2014
Buy
Sell



Monthly and Long-Term FTR Auctions
Aggregate Equivalent Cost to Procure, All Hours
$/MW-Month
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
FEB2013
MAR2013
APR2013
MAY2013
JUN2013
JUL2013
AUG2013
SEP2013
OCT2013
NOV2013
DEC2013
JAN2014
FEB2014
LT (Monthly Equiv.)
Monthly Auction


Monthly and Long-Term FTR Auctions
Aggregate Equivalent Cost to Procure, On-Peak Hours
$/MW-Month
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
FEB2013
MAR2013
APR2013
MAY2013
JUN2013
JUL2013
AUG2013
SEP2013
OCT2013
NOV2013
DEC2013
JAN2014
FEB2014
LT (Monthly Equiv.)
Monthly Auction


Monthly and Long-Term FTR Auctions
Aggregate Equivalent Cost to Procure, Off-Peak Hours
$/MW-Month
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
FEB2013
MAR2013
APR2013
MAY2013
JUN2013
JUL2013
AUG2013
SEP2013
OCT2013
NOV2013
DEC2013
JAN2014
FEB2014
LT (Monthly Equiv.)
Monthly Auction

6.4 For More Information

The market rules governing the FTR auctions can be found in Section III.7 "Financial Transmission Rights Auctions" of the ISO's Market Rule 1 located here.

The business rules and procedures for FTRs can be found in Section 6.5, "External Transactions" in the ISO's Manual 6 – Financial Transmission Rights located here.

Information about the monthly and long-term FTR auctions can be found on the ISO's web site here.

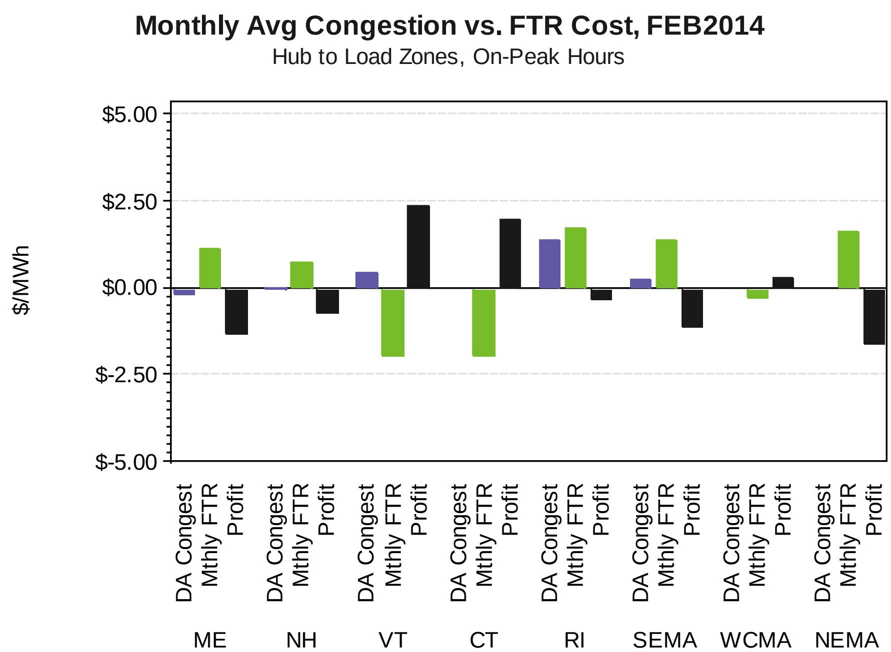
7. Effectiveness of FTRs

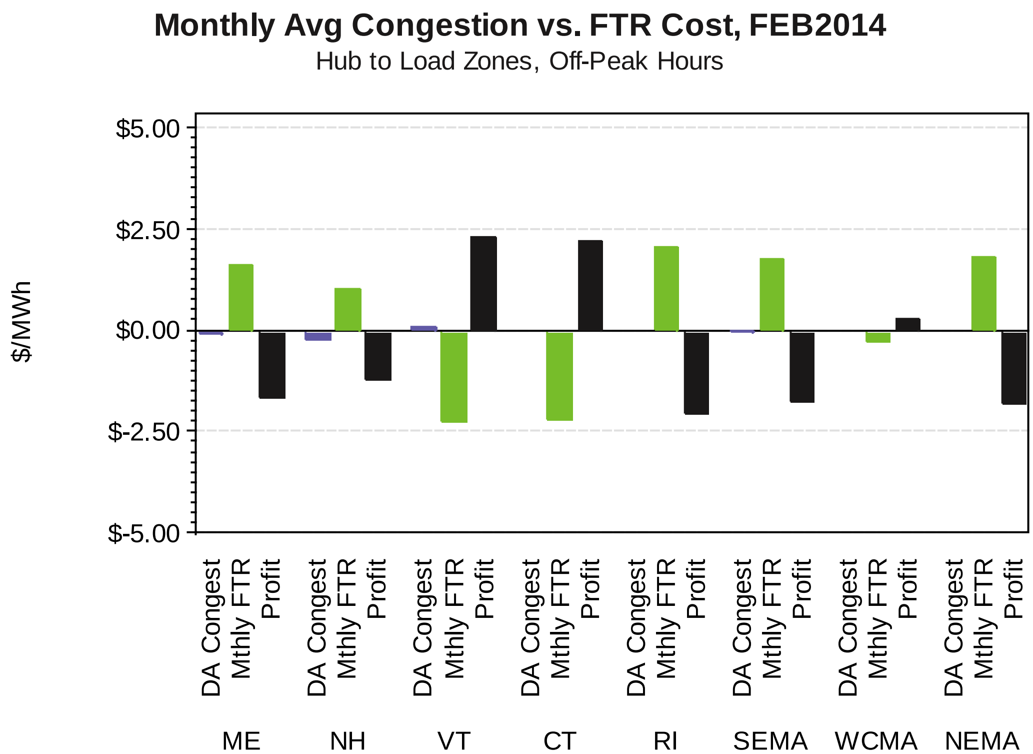
7.1 FTRs as a Congestion Hedging Instrument

Congestion costs occur in the Day-Ahead and Real-Time Markets between locations on the system when the most economic power cannot be transferred to needed load areas without violating transmission limits. These costs are embedded in the congestion component of LMP and its difference between locations. Customers who wish to protect against these real-time costs can do so by scheduling in the Day-Ahead Market. In turn, to hedge against day-ahead congestion costs, customers can obtain FTRs.

To analyze congestion and the effectiveness of the FTR market in managing the costs of congestion in New England, day-ahead congestion costs are examined in relation to FTR auction path clearing prices. Transmission paths from the Hub to the various New England Load Zones are examined in this section. In the following exhibits, monthly on-peak auction clearing prices are compared to the average day-ahead congestion components of prices for the month for each Hub-to-zone path. All units are presented in $/MWh equivalents.

Note that the exhibits are for illustration only, and do not indicate whether FTRs were actually owned by any market participant for the paths shown.





7.2 Profitability of Monthly FTRs, 13 Mos. Ending February 2014, On-Peak Hours, in $/MWh, from Hub to Load Zones

A comparison of the "profitability" or the success of the hedge that the illustrated FTRs provided over the last thirteen months is presented below.

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
ME	Feb-13	-$0.64	$0.56	-$1.20
ME	Mar-13	-$0.27	$0.48	-$0.76
ME	Apr-13	$4.32	$0.28	$4.04
ME	May-13	$0.01	$0.40	-$0.40
ME	Jun-13	-$0.52	-$0.03	-$0.49
ME	Jul-13	-$0.13	$0.01	-$0.15
ME	Aug-13	-$0.12	-$0.01	-$0.11
ME	Sep-13	-$6.11	$0.03	-$6.14
ME	Oct-13	$0.15	-$0.02	$0.17
ME	Nov-13	-$0.05	-$0.10	$0.06
ME	Dec-13	$2.16	-$0.11	$2.27
ME	Jan-14	$1.32	$1.89	-$0.56
ME	Feb-14	-$0.17	$1.11	-$1.28

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
NH	Feb-13	-$0.39	-$0.02	-$0.38
NH	Mar-13	$0.03	-$0.03	$0.07
NH	Apr-13	-$0.02	-$0.04	$0.02
NH	May-13	$0.00	$0.00	$0.00
NH	Jun-13	-$0.46	-$0.02	-$0.44
NH	Jul-13	$0.01	$0.01	-$0.01
NH	Aug-13	$0.06	-$0.01	$0.07
NH	Sep-13	-$5.60	-$0.15	-$5.45
NH	Oct-13	-$0.01	-$0.29	$0.28
NH	Nov-13	-$0.21	-$0.09	-$0.12
NH	Dec-13	$1.41	-$0.10	$1.51
NH	Jan-14	$1.17	$0.80	$0.37
NH	Feb-14	-$0.03	$0.71	-$0.73

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
VT	Feb-13	-$1.65	-$0.01	-$1.65
VT	Mar-13	-$0.08	-$0.01	-$0.07
VT	Apr-13	$0.00	-$0.01	$0.01
VT	May-13	$0.00	$0.02	-$0.02
VT	Jun-13	-$0.46	$0.01	-$0.47
VT	Jul-13	$0.01	$0.02	-$0.01
VT	Aug-13	$0.05	$0.00	$0.04
VT	Sep-13	-$4.99	-$0.01	-$4.97
VT	Oct-13	$0.04	-$0.09	$0.13
VT	Nov-13	-$0.09	-$0.04	-$0.05
VT	Dec-13	-$2.46	-$0.07	-$2.39
VT	Jan-14	-$2.82	-$2.02	-$0.81
VT	Feb-14	$0.41	-$1.93	$2.34

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
CT	Feb-13	-$7.69	$0.19	-$7.88
CT	Mar-13	-$0.12	$0.07	-$0.19
CT	Apr-13	$0.43	$0.28	$0.15
CT	May-13	$0.01	$0.50	-$0.49
CT	Jun-13	-$0.46	$0.37	-$0.83
CT	Jul-13	-$0.01	$0.23	-$0.25
CT	Aug-13	-$0.01	$0.20	-$0.21
CT	Sep-13	-$4.72	$0.24	-$4.96
CT	Oct-13	$0.59	$0.14	$0.45
CT	Nov-13	$0.03	$0.14	-$0.11
CT	Dec-13	-$3.17	$0.05	-$3.22
CT	Jan-14	-$2.92	-$2.05	-$0.87
CT	Feb-14	$0.00	-$1.94	$1.94

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
RI	Feb-13	$9.95	$0.07	$9.88
RI	Mar-13	$0.45	$1.33	-$0.88
RI	Apr-13	$2.01	$0.68	$1.33
RI	May-13	$1.45	$0.81	$0.64
RI	Jun-13	-$0.25	$2.04	-$2.29
RI	Jul-13	-$0.04	$1.09	-$1.13
RI	Aug-13	$0.18	$0.81	-$0.63
RI	Sep-13	-$5.49	$0.86	-$6.34
RI	Oct-13	$0.58	$0.66	-$0.08
RI	Nov-13	$0.05	$0.92	-$0.87
RI	Dec-13	$1.04	$1.11	-$0.07
RI	Jan-14	$2.34	$2.05	$0.29
RI	Feb-14	$1.35	$1.69	-$0.33

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
SEMA	Feb-13	$2.13	$0.02	$2.11
SEMA	Mar-13	$0.13	$0.26	-$0.13
SEMA	Apr-13	$0.35	$0.14	$0.21
SEMA	May-13	$0.28	$0.16	$0.12
SEMA	Jun-13	-$0.42	$0.39	-$0.81
SEMA	Jul-13	-$0.07	$0.25	-$0.32
SEMA	Aug-13	-$0.01	$0.15	-$0.16
SEMA	Sep-13	-$5.44	$0.16	-$5.60
SEMA	Oct-13	$0.10	$0.16	-$0.05
SEMA	Nov-13	$0.20	$0.15	$0.05
SEMA	Dec-13	$2.35	$0.22	$2.13
SEMA	Jan-14	$2.01	$1.61	$0.39
SEMA	Feb-14	$0.24	$1.35	-$1.11

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
WCMA	Feb-13	-$0.90	$0.10	-$1.01
WCMA	Mar-13	-$0.01	$0.10	-$0.11
WCMA	Apr-13	$0.04	$0.05	$0.00
WCMA	May-13	$0.01	$0.07	-$0.06
WCMA	Jun-13	-$0.38	$0.07	-$0.45
WCMA	Jul-13	$0.02	$0.12	-$0.10
WCMA	Aug-13	$0.03	$0.07	-$0.05
WCMA	Sep-13	-$4.32	$0.06	-$4.38
WCMA	Oct-13	-$0.01	$0.07	-$0.07
WCMA	Nov-13	-$0.01	$0.05	-$0.06
WCMA	Dec-13	-$0.31	$0.00	-$0.32
WCMA	Jan-14	-$0.34	-$0.24	-$0.10
WCMA	Feb-14	$0.00	-$0.25	$0.25

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
NEMA	Feb-13	$2.22	$0.06	$2.16
NEMA	Mar-13	$0.06	$0.17	-$0.11
NEMA	Apr-13	-$0.02	$0.18	-$0.20
NEMA	May-13	$0.00	$0.13	-$0.13
NEMA	Jun-13	-$0.27	$0.17	-$0.43
NEMA	Jul-13	$0.21	$0.80	-$0.60
NEMA	Aug-13	$0.20	$0.24	-$0.04
NEMA	Sep-13	-$4.92	$0.30	-$5.22
NEMA	Oct-13	-$0.01	$0.24	-$0.25
NEMA	Nov-13	$0.00	$0.16	-$0.16
NEMA	Dec-13	$2.49	$0.50	$1.99
NEMA	Jan-14	$2.12	$2.26	-$0.13
NEMA	Feb-14	$0.00	$1.60	-$1.60

8. Auction Revenue Rights

Auction Revenue is allocated to two main categories. First, it is allocated in the form of Incremental Auction Revenue Rights (IARRs) to entities, which, by paying for transmission upgrades, have increased the transfer capability of the NEPOOL transmission system and have enabled more FTRs to be available in the FTR auction. Second, it is allocated through the Auction Revenue Rights (ARR) process, where it is primarily received by congestion paying load-serving entities (LSEs). The majority of auction revenue is allocated through the ARR process.

The ARR process allocates dollars to:

- *Excepted Transactions* – special grandfathered transactions (listed in Attachment G of NEPOOL Tariff)
- *NEMA Contracts* – other long-term contracts having delivery in Northeastern Massachusetts.
- *Long-Term Firm Through or Out Service*.
- *Load Share* – the proportional Real-Time Load Obligation share of Congestion paying entities at the time of the pool's coincident peak for the month.

The following table provides a more detailed view of how auction revenues are allocated through the ARR and IARR process by including the dollars allocated to each component of the ARR process for each of the last 13 months.

Month	Net FTR Auction Revenue	Excepted Transactions	NEMA Contracts	Load Share	Total ARR Allocation	IARR Allocation	Total Auction Distribution
Feb-13	-$1,260,361	$0	$16,897	$1,159,290	$1,176,187	$84,174	$1,260,361
Mar-13	-$1,791,869	$0	$22,848	$1,673,627	$1,696,475	$95,394	$1,791,869
Apr-13	-$1,472,870	$0	$21,593	$1,347,999	$1,369,592	$103,278	$1,472,870
May-13	-$1,812,881	$0	$21,351	$1,685,038	$1,706,389	$106,492	$1,812,881
Jun-13	-$1,621,915	$0	$19,330	$1,500,786	$1,520,116	$101,800	$1,621,915
Jul-13	-$1,613,498	$0	$40,381	$1,465,642	$1,506,023	$107,475	$1,613,498
Aug-13	-$1,563,088	$0	$26,250	$1,434,483	$1,460,733	$102,355	$1,563,088
Sep-13	-$1,460,506	$0	$27,886	$1,340,162	$1,368,047	$92,458	$1,460,506
Oct-13	-$1,688,474	$0	$34,113	$1,527,590	$1,561,703	$126,771	$1,688,474
Nov-13	-$1,945,400	$0	$27,438	$1,817,061	$1,844,498	$100,902	$1,945,400
Dec-13	-$2,313,569	$0	$47,949	$2,149,383	$2,197,332	$116,237	$2,313,569
Jan-14	-$4,472,577	$0	$263,024	$4,034,504	$4,297,528	$175,049	$4,472,577
Feb-14	-$2,846,534	$0	$153,843	$2,544,648	$2,698,491	$148,043	$2,846,534

The following tables display the total distribution of On- and Off-Peak ARR dollars to the various Load Zones for each of the last 13 months. The sum across zones totals to the ‘Total ARR Allocation’ column in the preceding table.

On Peak								
Month	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Feb-13	$301,583	$7,137	$7,417	$85,350	$34,884	$33,190	$186,010	$119,436
Mar-13	$291,004	$7,522	$8,357	$113,689	$198,132	$90,072	$205,156	$171,572
Apr-13	$236,492	$6,649	$7,607	$166,220	$97,020	$52,987	$174,939	$158,936
May-13	$267,794	$8,679	$8,882	$269,459	$127,752	$60,441	$192,619	$160,130
Jun-13	$182,666	$8,102	$8,393	$161,225	$209,953	$90,019	$180,600	$144,112
Jul-13	$189,247	$9,018	$8,018	$121,060	$117,921	$61,744	$192,534	$285,555
Aug-13	$194,973	$13,012	$9,943	$153,026	$127,134	$70,650	$192,926	$205,593
Sep-13	$192,106	$8,785	$8,732	$164,994	$109,225	$58,324	$179,618	$162,217
Oct-13	$221,762	$14,640	$12,376	$186,710	$132,888	$87,411	$210,875	$193,932
Nov-13	$196,822	$21,466	$16,664	$166,345	$223,615	$118,718	$214,041	$204,707
Dec-13	$209,750	$28,308	$18,623	$184,649	$214,865	$129,908	$222,109	$409,163
Jan-14	$333,001	$166,662	$9,943	$120,209	$392,233	$346,607	$196,531	$1,079,838
Feb-14	$170,219	$110,256	$8,427	$103,665	$282,388	$224,705	$140,373	$686,419

Off Peak								
Month	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Feb-13	$175,661	$2,629	$2,789	$59,396	$43,666	$24,490	$53,775	$38,775
Mar-13	$185,344	$2,554	$3,129	$74,219	$150,782	$62,310	$58,986	$73,646
Apr-13	$127,515	$2,474	$2,995	$75,138	$106,879	$46,062	$48,021	$59,657
May-13	$146,460	$3,399	$3,347	$83,163	$192,361	$70,571	$54,043	$57,287
Jun-13	$108,015	$3,598	$3,238	$75,453	$178,219	$70,099	$49,336	$47,088
Jul-13	$110,863	$3,199	$3,193	$70,628	$96,478	$43,210	$54,137	$139,218
Aug-13	$112,864	$4,440	$3,790	$81,397	$119,851	$53,857	$53,973	$63,302
Sep-13	$113,177	$3,976	$3,643	$103,112	$104,008	$47,677	$52,524	$55,930
Oct-13	$127,346	$3,976	$4,556	$81,600	$101,863	$50,885	$60,539	$70,342
Nov-13	$112,538	$8,298	$7,093	$95,438	$214,055	$93,743	$66,182	$84,773
Dec-13	$126,613	$7,290	$5,415	$86,249	$198,202	$85,384	$58,220	$212,586
Jan-14	$194,991	$114,006	$2,010	$36,920	$327,446	$254,496	$113,568	$609,066
Feb-14	$94,618	$51,529	$1,716	$26,649	$242,661	$146,236	$59,034	$349,594

8.1 For More Information

The market rules governing the FTR auctions can be found in Section III.7 “Financial Transmission Rights Auctions” of the ISO’s Market Rule 1 located here.

The business rules and procedures for FTR Auction Revenue Settlement for September can be found in Section 7 and the Qualified Upgrade Award procedures can be found in Section 8 of the ISO’s Manual 6 – Financial Transmission Rights located here.

The methodology for and details of ARR Contracts can be found here.

9. Reserve Markets

The fourteenth Forward Reserve Market Auction, covering the Winter 2013-2014 Procurement Period (October-May) cleared on August 29, 2013. The results may be found on the ISO's website here.

Participants must meet their cleared portfolio-based obligations by assigning them to eligible generating or dispatchable asset related demand through offering or bidding them into the Energy Market at a $/MWh rate that is greater than or equal to the Forward Reserve Threshold Price. For the month of February 2014, the threshold price ranged from $128.17 to $417.25 and averaged $283.35.

9.1 Forward Reserve Market Results

Each month, the ISO calculates an individual hourly Forward Reserve Payment Rate for each reserve product and reserve zone by reducing (on a $/MWh basis) their auction clearing price by the Forward Capacity Auction clearing price for the capacity zone associated to the reserve zone in effect for that month, adjusted pursuant to Section III.13.2.7.3(b)[2]. Payments will be further reduced by any Failure-to-Reserve or Failure-to-Activate Penalties. FRM payments by reserve zone made during the month are shown in the following table. These figures are preliminary and subject to revision during the Settlement process.

9.1.1 FRM Payment Summary by Reserve Zone, February 2014

Reserve Zone	Reserve Product	Max FRM Payment	Final FRM Credits	Failure to Reserve Penalties	Failure to Activate Penalties	Total FRM Performance	Pct. of Max.
SYSTEM	TMNSR	$8,427,226	$7,984,860	-$710,488	$0	$7,274,372	86%
SYSTEM	TMOR	$3,053,904	$2,901,706	-$253,389	$0	$2,648,317	87%
SYSTEM	TOTAL	$11,481,130	$10,886,566	-$963,877	$0	$9,922,689	86%
ROS	TMNSR	$6,087,152	$5,754,044	-$530,214	$0	$5,223,830	86%
ROS	TMOR	$840,074	$789,203	-$77,291	$0	$711,911	85%
ROS	TOTAL	$6,927,226	$6,543,247	-$607,505	$0	$5,935,742	86%
SWCT	TMNSR	$0	$0	$0	$0	$0	n/a
SWCT	TMOR	$656,506	$614,647	-$75,784	$0	$538,862	82%
SWCT	TOTAL	$656,506	$614,647	-$75,784	$0	$538,862	82%
CT	TMNSR	$2,340,073	$2,230,816	-$180,275	$0	$2,050,542	88%
CT	TMOR	$1,557,324	$1,497,857	-$100,314	$0	$1,397,543	90%
CT	TOTAL	$3,897,397	$3,728,673	-$280,588	$0	$3,448,085	88%
NEMABSTN	TMNSR	$0	$0	$0	$0	$0	n/a
NEMABSTN	TMOR	$0	$0	$0	$0	$0	n/a
NEMABSTN	TOTAL	$0	$0	$0	$0	$0	n/a

[2] Prior to the start of the Forward Capactiy Market on June 1, 2010, the auction clearing price was reduced by the ICAP Transition Rate for Unforced Capacity in effect for that month.

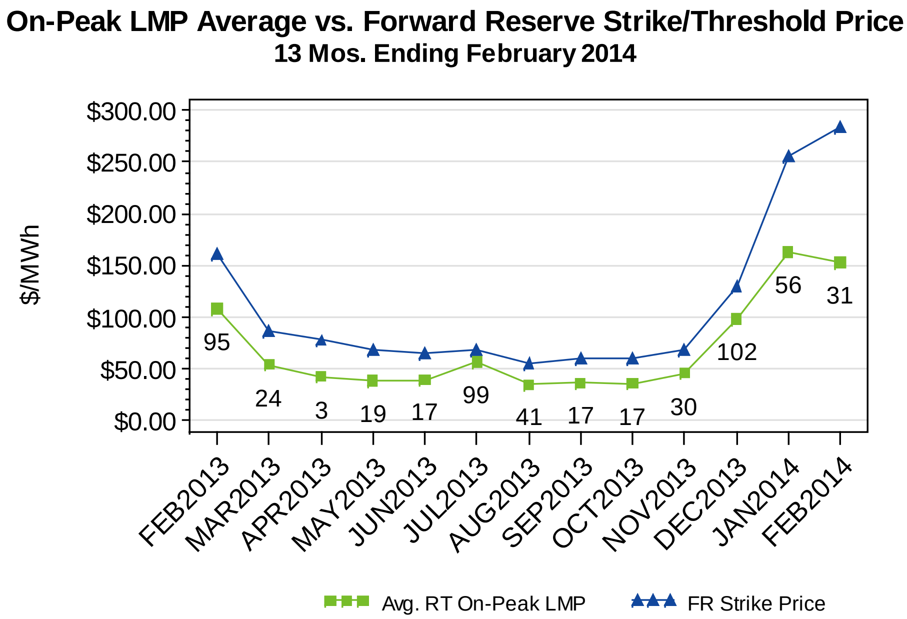
The ISO allocates Forward Reserve Credits, net of Forward Reserve Failure-to-Reserve Penalties and Forward Reserve Failure-to-Activate Penalties, to each Load Zone. The Forward Reserve charge allocation method changed on June 1, 2011. Under the new Forward Reserve Cost Allocation, the Forward Reserves Credits for TMNSR and TMOR are not allocated separately. Instead, the Forward Reserve Credits are allocated based upon System Requirements (Step 1) and Remaining Forward Reserve Credit (Step 2), if applicable. The System Requirements include the cost of procuring TMNSR and TMOR to meet the minimum requirements for the New England Control Area (Market Rule 1, Section III.9.2.1). The remaining Forward Reserve Credit includes the Incremental Cost associated with procuring Forward Reserves above the System Requirements. See Market Rule 1, Section III.9.9 Forward Reserve Charges and Manual 28, Section 2.6.2 Forward Reserve Charges for details on the two-step cost allocation approach.

FRM charges allocated to each Load Zone during the prior week are shown in the following table. These figures are also preliminary and subject to revision during the Settlement process.

9.1.2 FRM Charge Summary by Load Zone, February 2014

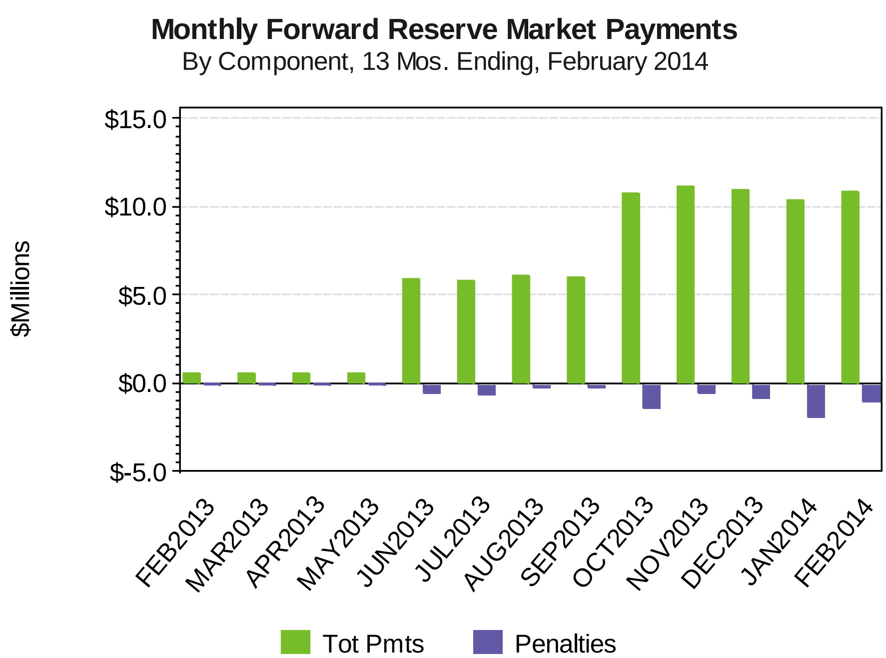
Load Zone	FRM Charge
ME	$883,333
NH	$927,407
VT	$452,329
CT	$2,487,743
RI	$637,854
SEMA	$1,146,746
WCMA	$1,397,078
NEMA	$1,990,198
ALL	$9,922,689

9.2 Real-Time On-Peak LMP vs. Forward Reserve Threshold Price, Last 13 Mos.



Number of times hourly RT LMP exceeded strike/threshold price during on-peak hours noted

9.3 Composition of Forward Reserve Market Payments, Last 13 Mos.



9.4 Real-Time Reserve Markets

Resources that are providing Real-Time Reserves are designated in the ISO's Energy Management System. When reserves are ample, the Real-Time Reserve price is $0. However, if there is a shortage of available reserves in a reserve zone or system-wide or reserve requirements are met through a re-dispatch of the system, non-zero Real-Time Reserve prices can result.

During the month, there were non-zero real-time reserve prices in 69 separate hours. On a reserve zone basis, non-zero prices occurred thus: CT-69 hours; NEMABSTN-69 hours; ROS-69 hours; SWCT-69 hours. The total compensation paid to assets providing real-time reserves during February 2014, and reductions in those payments for the Forward Reserve Obligation Charge are shown in the following table:

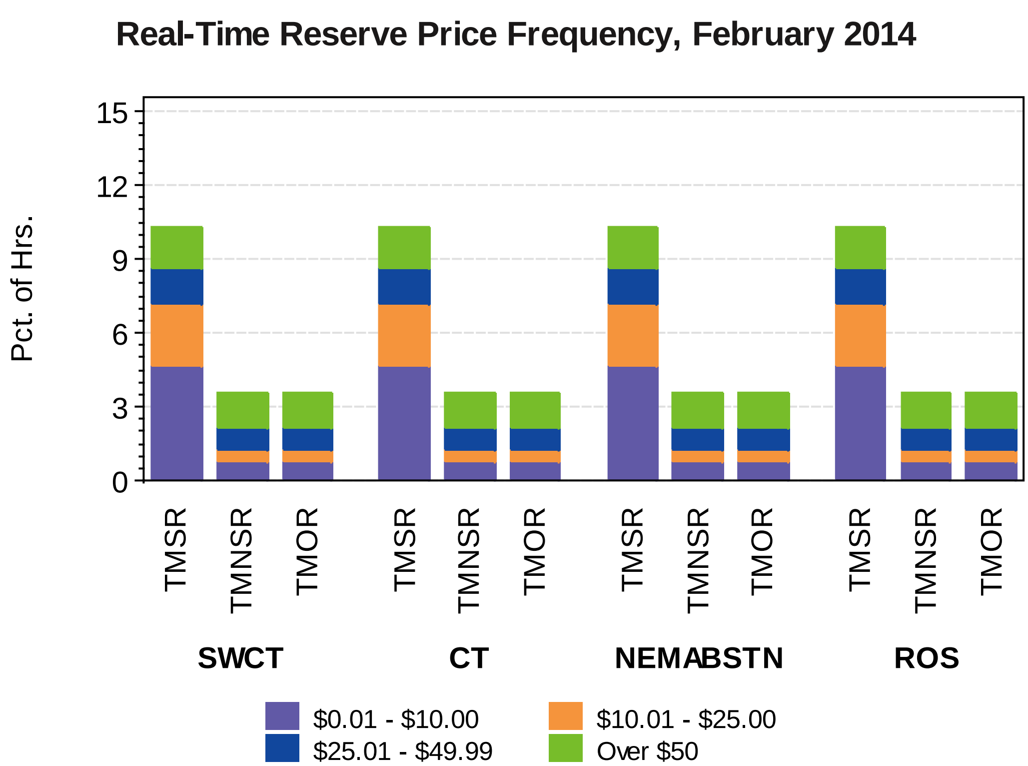
Reserve Zone	Real-Time Reserve Credits	Fwd Reserve Obligation Charges	Net Real-Time Reserve Payments
SYSTEM	$5,392,571	($727,283)	$4,665,288
ROS	$2,990,414	($538,543)	$2,451,871
SWCT	$1,315,607	($68,625)	$1,246,982
CT	$901,656	($120,115)	$781,540
NEMABSTN	$184,894	$0	$184,894

The ISO allocates Real Time Reserve Credits, net of Forward Reserve Energy Obligation Charges, to each Load Zone. The Real Time Reserve charges allocated to each Load Zone during the month are shown in the following table. These figures are also preliminary and subject to revision during the Settlement process.

Load Zone	Reserve Product	RT Reserve Charge
ME	TMSR	$142,536
ME	TMNSR	$198,623
ME	TMOR	$79,549
ME	ALL	$420,708
NH	TMSR	$145,862
NH	TMNSR	$200,798
NH	TMOR	$80,538
NH	ALL	$427,198
VT	TMSR	$71,959
VT	TMNSR	$99,505
VT	TMOR	$39,922
VT	ALL	$211,386
CT	TMSR	$397,902
CT	TMNSR	$549,588
CT	TMOR	$220,222
CT	ALL	$1,167,713
RI	TMSR	$99,041
RI	TMNSR	$137,265

Load Zone	Reserve Product	RT Reserve Charge
RI	TMOR	$54,804
RI	ALL	$291,110
SEMA	TMSR	$182,733
SEMA	TMNSR	$253,960
SEMA	TMOR	$101,334
SEMA	ALL	$538,028
WCMA	TMSR	$230,958
WCMA	TMNSR	$334,117
WCMA	TMOR	$133,138
WCMA	ALL	$698,213
NEMA	TMSR	$310,513
NEMA	TMNSR	$428,639
NEMA	TMOR	$171,780
NEMA	ALL	$910,931

The following chart shows the frequency (in percent of total hours in the month) that there were non-zero reserve market prices by reserve zone and market product.



9.5 For More Information

The market rules governing the Forward Reserve Market can be found in Section III.9 “Forward Reserve Market” of the ISO’s Market Rule 1 located here.

The market rules governing Real-Time Reserve can be found in Section III.10 “Real-Time Reserve” of the ISO’s Market Rule 1 located here.

The business rules and procedures for forward and real-time reserve can be found in the ISO’s Manual 28 –Market Rule 1 Accounting located here.

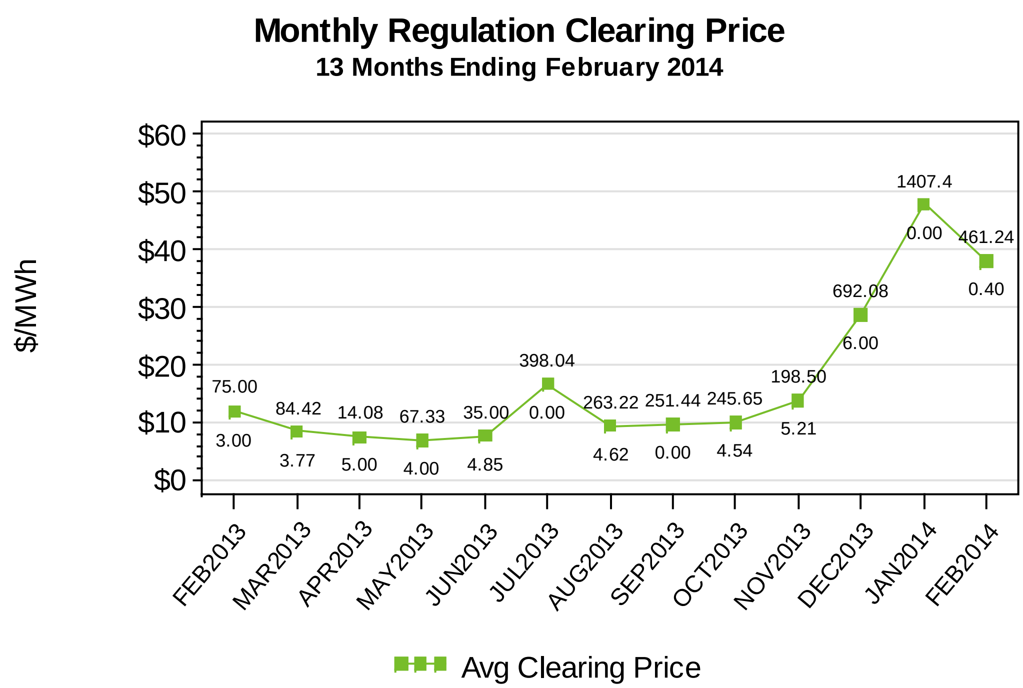
Information about the monthly forward reserve auctions and assumptions can be found on the ISO’s web site located here.

10. Regulation Market

Regulation, or Automatic Generation Control (AGC), is necessary to balance supply levels against second-to-second variations in demand.

On July 1, 2013, the ISO implemented changes to the Regulation market design. The new design reflects lost opportunity costs of regulating generators within the Regulation clearing price, rather than in a separate payment. Additionally, to ensure that total regulation costs are compensated through the clearing price, a 'make-whole cost' payment category was added.

10.1 Monthly Average of Hourly Regulation Market Clearing Price, Last 13 Months



Value of monthly maximum and minimum clearing price also shown

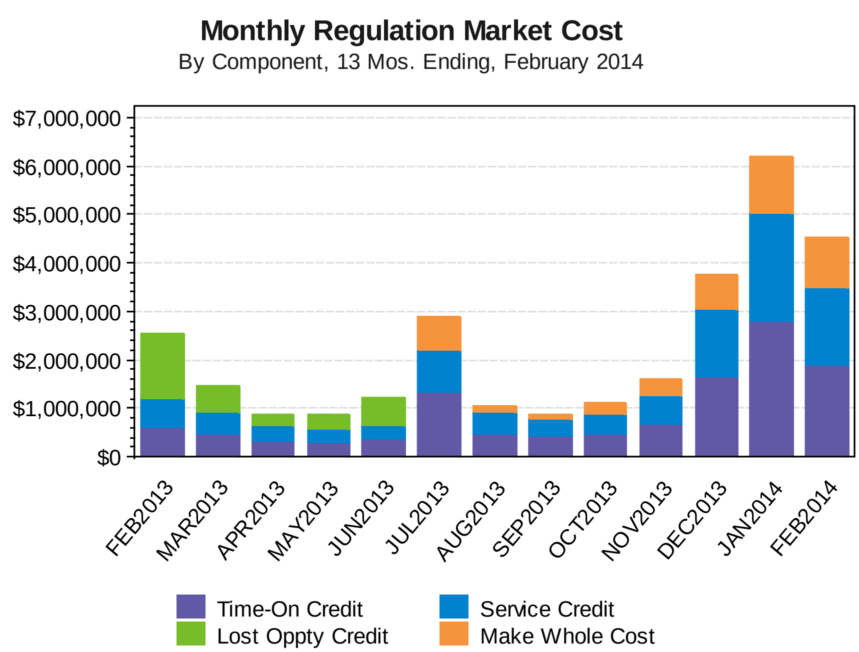
10.2 Monthly Regulation Market Clearing Price Statistics, Last 13 Months

Month	On-Peak Clearing Price Statistics			
	Mean	Max	Min	StdDev
Feb-13	$12.15	$75.00	$4.00	$10.57
Mar-13	$8.37	$26.29	$3.77	$4.02
Apr-13	$7.67	$13.00	$5.00	$1.65
May-13	$7.19	$67.33	$4.83	$3.57
Jun-13	$7.52	$35.00	$5.00	$2.61
Jul-13	$23.25	$398.04	$4.94	$49.72
Aug-13	$10.64	$263.22	$5.07	$14.83
Sep-13	$11.02	$251.44	$0.00	$21.64
Oct-13	$10.48	$245.65	$5.05	$14.95
Nov-13	$11.29	$141.27	$5.21	$11.26

Month	On-Peak Clearing Price Statistics			
	Mean	Max	Min	StdDev
Dec-13	$26.08	$360.53	$6.00	$29.71
Jan-14	$46.66	$1407.43	$0.00	$95.89
Feb-14	$30.53	$401.51	$0.40	$35.59

Month	Off-Peak Clearing Price Statistics			
	Mean	Max	Min	StdDev
Feb-13	$11.76	$75.00	$3.00	$8.37
Mar-13	$8.57	$84.42	$4.00	$5.14
Apr-13	$7.33	$14.08	$5.14	$1.36
May-13	$6.72	$11.37	$4.00	$1.01
Jun-13	$7.83	$26.65	$4.85	$2.53
Jul-13	$10.73	$99.17	$0.00	$7.08
Aug-13	$8.26	$41.14	$4.62	$3.06
Sep-13	$8.61	$38.46	$4.98	$3.95
Oct-13	$9.58	$163.73	$4.54	$12.17
Nov-13	$15.78	$198.50	$5.77	$18.03
Dec-13	$30.70	$692.08	$6.06	$45.62
Jan-14	$48.97	$1087.08	$6.99	$85.96
Feb-14	$44.81	$461.24	$3.46	$41.10

10.3 Components of Monthly Regulation Market Cost, Last 13 Months



Month	Time on Regulation Cost	Regulation Service Cost	Lost Opportunity Credit Cost	Regulation Make Whole Cost	Total Regulation Cost
Feb-13	$611,533	$578,276	$1,342,413	$0	$2,532,222
Mar-13	$460,641	$466,422	$552,763	$0	$1,479,827
Apr-13	$321,065	$319,488	$232,191	$0	$872,745
May-13	$298,723	$276,899	$293,893	$0	$869,516
Jun-13	$357,200	$290,787	$572,385	$0	$1,220,373
Jul-13	$1,322,914	$857,321	$0	$716,193	$2,896,428
Aug-13	$467,696	$432,491	$0	$139,265	$1,039,452
Sep-13	$417,076	$357,372	$0	$101,670	$876,118
Oct-13	$443,060	$416,506	$0	$252,085	$1,111,651
Nov-13	$661,195	$580,475	$0	$354,871	$1,596,541
Dec-13	$1,627,605	$1,401,506	$0	$742,532	$3,771,644
Jan-14	$2,780,202	$2,225,224	$0	$1,172,202	$6,177,628
Feb-14	$1,866,894	$1,621,270	$0	$1,029,588	$4,517,752

10.4 For More Information

The market rules governing the Regulation Market can be found in Section III.1.11.5 “Regulation” of the ISO’s Market Rule 1 located here.

The business rules and procedures for the Regulation Market can be found in the ISO’s Manual 11 – Market Operations located here:

Information about current regulation clearing prices can be found on the ISO’s web site here.

Selectable hourly historical regulation clearing prices can be found on the ISO’s web site here.

11. Marginal Loss Revenue Fund

The Marginal Loss Revenue Fund is allocated back to customers hourly in a pro-rata format based on customer share of the Pool's RT Adjusted Load Obligation. It consists of six components, as displayed in the following formula:

*Monthly Marginal Loss Revenue = (-1) * [Loss Revenue (DA+RT) + Energy Settlement (DA+RT) + RT Inadvertent Energy Cost + RT Emergency Energy Sales]*

The following table shows the contribution of each component to the Marginal Loss Revenue Fund and the fund total for last thirteen months.

11.1 Marginal Loss Revenue Fund by Month, 13 Mos. Ending February 2014

Month	Day-Ahead Energy Stlmnt	Real-Time Energy Stlmnt	Day-Ahead Loss Rev	Real-Time Loss Rev	Real-Time Inadvrt Energy	Real-Time Emergency Energy	Day-Ahead Marginal Loss Total	Real-Time Marginal Loss Total	Marg Loss Rev Fund Total
Feb-13	$20,622,852	$2,616,841	-$41,067,549	-$2,266,143	-$1,984,710	$0	$20,444,696	$1,634,013	$22,078,709
Mar-13	$8,203,310	$919,210	-$15,004,716	-$680,705	-$44,433	$0	$6,801,406	-$194,072	$6,607,334
Apr-13	$5,661,509	$1,041,406	-$10,316,981	-$465,334	-$23,712	$0	$4,655,473	-$552,359	$4,103,113
May-13	$5,910,351	$343,425	-$11,137,654	-$585,531	$712,649	$0	$5,227,303	-$470,543	$4,756,760
Jun-13	$6,433,997	$134,750	-$12,145,177	-$908,698	$831,724	$0	$5,711,180	-$57,776	$5,653,404
Jul-13	$12,547,955	$353,351	-$24,147,858	-$1,491,276	$82,705	$0	$11,599,903	$1,055,220	$12,655,123
Aug-13	$6,512,984	$844,700	-$12,406,250	-$352,754	$204,756	$0	$5,893,266	-$696,701	$5,196,565
Sep-13	$7,055,924	$620,905	-$13,404,537	-$164,903	-$157,993	$0	$6,348,614	-$298,009	$6,050,604
Oct-13	$5,299,001	$815,360	-$10,180,581	$79,796	-$552,255	$0	$4,881,580	-$342,901	$4,538,679
Nov-13	$6,950,641	$1,061,391	-$10,414,367	-$480,962	-$770,934	$0	$3,463,726	$190,505	$3,654,231
Dec-13	$16,719,862	$2,139,120	-$24,565,784	-$1,768,048	-$2,929,551	$146,145	$7,845,922	$2,412,334	$10,258,256
Jan-14	$32,639,065	$1,315,767	-$56,296,254	-$3,997,644	-$1,988,418	-$1,346,925	$23,657,189	$6,017,220	$29,674,409
Feb-14	$24,890,337	$779,430	-$36,609,438	-$2,097,843	-$2,511,872	$0	$11,719,102	$3,830,286	$15,549,387

11.2 For More Information

Rules governing the calculation of the Marginal Loss Revenue Fund can be found in Section III.3.2.1 Accounting and Billing of the ISO's Market Rule 1 located here.

12. Forward Capacity Market

The Forward Capacity Market (FCM) is an auction based approach to meeting New England's forecasted capacity requirements for a future year. A portfolio of supply and demand resources is selected to provide this capacity through a competitive Forward Capacity Auction (FCA) process. Resources clearing in the FCA are paid the market clearing price for capacity and acquire a capacity supply obligation (CSO), a financially binding obligation to provide the cleared amount of capacity. FCM was implemented in June 2010, corresponding with the termination of the Forward Capacity Transition Period. For more information on the Forward Capacity Transition Period, see Section 12 of the Monthly Market Reports published prior to June 2011.

12.1 FCM Auction Results and Monthly Modifications

The outcome of the Forward Capacity Auction (FCA) determines the initial CSOs for Resources. In the event that the Capacity Clearing Price Floor condition is reached in the FCA, the ISO will adjust (prorate) the per-MW rate of each CSO to adjust the over-purchased capacity. After the FCA is finalized, Lead Participants of obligated Resources may have the option to leave the CSO of these resources based upon the default proration (full CSO with a reduced payment rate - referred to as 'price proration') or opt to prorate the CSO MWs and receive the full CCP (described as 'MW proration'). The proration elections chosen by resources will not have an effect on the total amount of charges to load. The following table shows the aggregated CSO values by resource type from FCA 4, the 2013-2014 commitment period, with prorated amounts and change from the FCA for each resource type.

2013-2014 Forward Capacity Auction

Resource Type	FCA CSO MW	Prorated CSO MW	Proration Change MW
Demand	3,349	3,015	-335
Generator	32,247	28,634	-3,613
Import	1,993	1,726	-266
Total	37,589	33,355	-4,235

Each month, CSO values can change for a variety of reasons, which are referred to below as CSO modifications. Typically, changes result from the monthly or annual Reconfiguration Auctions. Additional examples of CSO modifications include ISO participation in annual reconfiguration auctions and termination of resource supply obligations. The table below displays the CSO modifications for the current month.

CSO Modifications for February 2014

Capacity Zone	Resource Type	Balance Net CSO MW for Multiyear Offer MW	Existing Capacity Obligation MW	Multi-Year Existing Capacity Obligation MW	New Capacity Obligation MW	Retained for Reliability Capacity Obligation MW	Self-Supply Capacity Obligation MW	Total MW
Rest-of-Pool	Demand Resource	0.00	-15.94	-13.14	-0.07	0.00	0.00	-29.15
Maine	Demand Resource	0.00	-0.29	0.00	0.00	0.00	0.00	-0.29
Rest-of-Pool	Generator	0.00	-86.58	-11.15	-0.11	-5.92	0.00	-103.76
Maine	Generator	0.00	-2.67	0.00	-0.36	0.00	0.00	-3.03
Rest-of-Pool	Import	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maine	Import	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total	0.00	-105.49	-24.29	-0.54	-5.92	0.00	-136.23

The table below displays a summary of the prorated CSO MW and dollars from the FCA, along with the CSO modifications for the current month. The CSO modification MWs are totaled for each Resource and Capacity Zone from the table above. These CSO modifications are used in the calculation of the final CSO MW and Dollars.

Final CSO MW and Dollars for February 2014

Capacity Zone	Resource Type	CSO MW	CSO Dollars	CSO Modification MW	CSO Modification Dollars	Final CSO MW	Final CSO Dollars
Rest-of-Pool	Demand Resource	1,907	$6,732,568	-29.15	-$91,260	1,878.25	$6,641,308
Maine	Demand Resource	289	$1,027,854	-0.30	-$728	288.62	$1,027,126
Rest-of-Pool	Generator	28,126	$70,518,548	-708.15	-$1,777,740	27,417.77	$68,740,808
Maine	Generator	2,618	$7,326,111	-3.03	-$7,150	2,615.16	$7,318,961
Rest-of-Pool	Import	527	$2,230,506	0.00	$0	527.10	$2,230,506
Maine	Import	100	$635,405	0.00	$0	100.00	$635,405
	Total	33,568	$88,470,992	-740.62	-$1,876,877	32,826.90	$86,594,115

12.2 FCM Payments and Charges

Supply Credit is the total credit paid to customer resources for incurring a CSO and is the sum of the following types of CSO-related payments: Forward Capacity Auction (FCA) Credits, Bilateral Dollars, and Reconfiguration Auction (RA) Dollars. The following table shows total Supply Credit and its aforementioned components by Capacity Zone for the last thirteen months.

Month	Capacity Zone	FCA Credit	Bilateral Dollars	Reconfiguration Auction Dollars	Supply Credit
Feb-13	Rest-of-Pool	$79,704,149	$328,483	-$217,128	$79,815,504
Feb-13	Maine	$9,789,108	-$328,483	$205,952	$9,666,578
Mar-13	Rest-of-Pool	$79,704,149	$330,888	-$210,031	$79,825,006
Mar-13	Maine	$9,789,108	-$330,888	$198,855	$9,657,076
Apr-13	Rest-of-Pool	$79,664,936	$321,112	-$185,604	$79,800,445
Apr-13	Maine	$9,790,043	-$321,112	$174,372	$9,643,303
May-13	Rest-of-Pool	$79,664,936	$353,682	-$186,731	$79,831,887
May-13	Maine	$9,790,043	-$353,682	$175,499	$9,611,861
Jun-13	Rest-of-Pool	$76,547,624	$36,269	-$60,916	$76,522,977
Jun-13	Maine	$9,486,419	-$36,269	$60,916	$9,511,066
Jul-13	Rest-of-Pool	$76,547,624	$35,140	$198,721	$76,781,485
Jul-13	Maine	$9,486,419	-$35,140	-$216,506	$9,234,773
Aug-13	Rest-of-Pool	$76,547,624	$35,140	$230,534	$76,813,298
Aug-13	Maine	$9,486,419	-$35,140	-$242,316	$9,208,963
Sep-13	Rest-of-Pool	$76,547,624	$35,140	$83,546	$76,666,310
Sep-13	Maine	$9,486,419	-$35,140	-$83,546	$9,367,733
Oct-13	Rest-of-Pool	$76,884,183	$36,259	$97,450	$77,017,892
Oct-13	Maine	$9,676,613	-$36,259	-$97,450	$9,542,904
Nov-13	Rest-of-Pool	$76,861,676	$36,259	$100,125	$76,998,060
Nov-13	Maine	$9,676,613	-$36,259	-$100,125	$9,540,229

Month	Capacity Zone	FCA Credit	Bilateral Dollars	Reconfiguration Auction Dollars	Supply Credit
Dec-13	Rest-of-Pool	$76,915,997	$35,140	$64,471	$77,015,608
Dec-13	Maine	$9,678,117	-$35,140	-$64,471	$9,578,506
Jan-14	Rest-of-Pool	$76,915,997	$60,640	$331,589	$77,308,227
Jan-14	Maine	$9,678,117	-$60,640	-$331,589	$9,285,888
Feb-14	Rest-of-Pool	$76,915,997	$160,140	$696,625	$77,772,762
Feb-14	Maine	$9,678,117	-$160,140	-$696,625	$8,821,352

The initial supply credit paid for the CSO, as shown above, can be further adjusted based upon computed values for Peak Energy Rent (PER), the participation of the ISO in reconfiguration auctions, and actual resource performance. PER is a downward adjustment of FCM payments to reflect energy market revenues earned during high priced hours. In reconfiguration auctions, credits are reduced by the sale of excess CSO by the ISO or increased by the purchase of additional CSO. Resource availability during shortage events (generator and import resources) or performance during dispatch events and performance hours (demand resources) result in additional penalties and credits. The supply credit adjusted for reasons just stated results in the pool of money called the Net Regional Clearing Price (NRCP) Credit, which is the basis for charges for capacity allocated to real-time load obligation. Additional credits may be earned by resources retained for reliability and their cost is allocated to Regional Network Load through the Open-Access Transmission Tariff rather than to Capacity Load Obligation (CLO).

The following table shows the various credit adjustments and total payments in the FCM made over the last 13 obligation months.

Month	Capacity Zone	CSO MW	Supply Credit (A)	PER Adjustment (B)	Excess DR Penalties (C)	NRCP Credit (D=A+B+C)	Reliability Credit (E)	Total Payment (F=D+E)
Feb-13	Rest-of-Pool	29,381	$79,815,504	-$367,929	$0	$79,447,575	$1,623,350	$81,070,925
Feb-13	Maine	3,618	$9,666,578	-$34,587	$0	$9,631,991	$0	$9,631,991
Mar-13	Rest-of-Pool	29,417	$79,825,006	-$368,462	$0	$79,456,544	$1,623,350	$81,079,894
Mar-13	Maine	3,582	$9,657,076	-$34,037	$0	$9,623,039	$0	$9,623,039
Apr-13	Rest-of-Pool	29,508	$79,800,445	-$367,167	$0	$79,433,278	$1,623,350	$81,056,628
Apr-13	Maine	3,475	$9,643,303	-$32,334	$0	$9,610,969	$0	$9,610,969
May-13	Rest-of-Pool	29,503	$79,831,887	-$368,520	$0	$79,463,366	$1,623,350	$81,086,716
May-13	Maine	3,480	$9,611,861	-$31,926	$0	$9,579,935	$0	$9,579,935
Jun-13	Rest-of-Pool	29,255	$76,522,977	-$352,598	$0	$76,170,379	$1,459,945	$77,630,324
Jun-13	Maine	3,370	$9,511,066	-$34,251	$0	$9,476,815	$0	$9,476,815
Jul-13	Rest-of-Pool	29,490	$76,781,485	-$460,650	$0	$76,320,835	$1,459,945	$77,780,781
Jul-13	Maine	3,135	$9,234,773	-$31,715	$0	$9,203,058	$0	$9,203,058
Aug-13	Rest-of-Pool	29,442	$76,813,298	-$1,890,030	$0	$74,923,268	$1,459,945	$76,383,213
Aug-13	Maine	3,183	$9,208,963	-$32,231	$0	$9,176,732	$0	$9,176,732
Sep-13	Rest-of-Pool	29,357	$76,666,310	-$1,871,057	$0	$74,795,253	$1,459,945	$76,255,199
Sep-13	Maine	3,268	$9,367,733	-$33,172	$0	$9,334,561	$0	$9,334,561
Oct-13	Rest-of-Pool	29,581	$77,017,892	-$1,964,305	$0	$75,053,587	$1,459,945	$76,513,532
Oct-13	Maine	3,230	$9,542,904	-$32,712	$0	$9,510,192	$0	$9,510,192
Nov-13	Rest-of-Pool	29,624	$76,998,060	-$1,971,944	$0	$75,026,116	$1,459,945	$76,486,061

Month	Capacity Zone	CSO MW	Supply Credit (A)	PER Adjustment (B)	Excess DR Penalties (C)	NRCP Credit (D=A+B+C)	Reliability Credit (E)	Total Payment (F=D+E)
Nov-13	Maine	3,182	$9,540,229	-$32,176	$0	$9,508,053	$0	$9,508,053
Dec-13	Rest-of-Pool	29,573	$77,015,608	-$2,202,113	$0	$74,813,495	$1,459,945	$76,273,441
Dec-13	Maine	3,254	$9,578,506	-$59,975	$0	$9,518,532	$0	$9,518,532
Jan-14	Rest-of-Pool	29,794	$77,308,227	-$3,097,750	$0	$74,210,477	$1,459,945	$75,670,422
Jan-14	Maine	3,033	$9,285,888	-$143,810	$0	$9,142,078	$0	$9,142,078
Feb-14	Rest-of-Pool	29,823	$77,772,762	-$2,755,434	$0	$75,017,328	$1,459,945	$76,477,274
Feb-14	Maine	3,004	$8,821,352	-$109,568	$0	$8,711,784	$0	$8,711,784

For each month and Capacity Zone, Load Serving Entities (LSEs) have capacity requirements which are calculated as their share of the total CSO purchased, based on their contribution to the system peak load from the previous year. Customers pay for capacity based on CLO. A customer's CLO is equivalent to its capacity requirement, adjusted for any Hydro-Quebec Installed Capacity Credits (HQICC), self-supply MWs, and CLO bilateral contracts. CLO bilateral contracts provide a means of transferring a capacity load obligation between two customers. Note that any customer, not just LSEs, can take on or shed CLO through a CLO bilateral contract.

The Net Regional Clearing Price is the rate at which load pays for capacity. It is calculated as:

*NRCP ($/kW-month) = NRCP Credit / (CLO MW * 1000)*

Where: *CLO MW = CSO MW – Self Supply MW – Excess RTEG MW*

Excess RTEG MW is composed of the CSO MW of Real Time Emergency Generation purchased in the Forward Capacity Auction in excess of 600 MW.

Charges are calculated as the product of a customer's CLO and the NRCP.

The following table provides details on aggregate FCM charges to load.

Month	CSO MW (A)	CLO Bilat MW	HQICC MW (B)	Excess RTEG MW (C)	Self Supply MW (D)	Capacity Req MW (E=A+B-C)	Peak Contrib MW	CLO MW (F=A-C-D)	Net Regional Clearing Price ($/kW-month)	Capacity Load Obligation Charge
Feb-13	32,999	541	977	0	1,928	33,976	27,312	31,071	$2.867011	$89,228,444
Mar-13	32,999	541	977	0	1,928	33,976	27,312	31,071	$2.867011	$89,189,306
Apr-13	32,983	541	977	0	1,928	33,960	27,312	31,055	$2.867308	$89,046,833
May-13	32,983	541	977	0	1,928	33,960	27,312	31,055	$2.867278	$89,049,904
Jun-13	32,625	541	998	15	2,693	33,608	25,543	29,917	$2.862817	$85,686,382
Jul-13	32,625	566	998	0	2,693	33,623	25,543	29,932	$2.857278	$85,441,457
Aug-13	32,625	566	998	0	2,693	33,623	25,543	29,932	$2.809707	$84,017,280
Sep-13	32,625	566	998	0	2,693	33,623	25,543	29,932	$2.810703	$84,066,878
Oct-13	32,811	636	998	0	2,693	33,809	25,543	30,118	$2.807706	$84,416,622
Nov-13	32,806	646	998	0	2,693	33,804	25,543	30,113	$2.807251	$84,354,773
Dec-13	32,827	646	998	0	2,693	33,825	25,543	30,134	$2.798575	$84,190,970
Jan-14	32,827	656	998	0	2,693	33,825	25,543	30,134	$2.766071	$83,151,374
Feb-14	32,827	666	998	0	2,693	33,825	25,543	30,134	$2.778567	$83,602,387

The calculations below describe how the Capacity Requirement and the Capacity Load Obligations are calculated for each Capacity Zone.

Capacity Requirement $_{\text{Capacity Zone}}$ = (Peak Contribution MW (CCP-2) $_{\text{Capacity Zone}}$ / Peak Contribution (CCP-2) $_{\text{Pool}}$) * (CSO $_{\text{Pool}}$ + HQICC MW $_{\text{Capacity Zone}}$) * (-1)

CLO $_{\text{Capacity Zone}}$ = Capacity Requirement $_{\text{Capacity Zone}}$ - HQICC MW $_{\text{Capacity Zone}}$ - CLO Self-Supply MW $_{\text{Capacity Zone}}$

There are two sides to a self-supply agreement – the generator supplying the MW and the entity using the MW to reduce its capacity requirement. During the 2013/2014 commitment period, with multiple capacity zones, a generator in Maine can have self-supply designations in both the Rest-of-Pool (ROP) and Maine. The NRCP is the per MW cost of capacity in a capacity zone. Self-supply MW used in the NRCP calculation are based on where the generator supplying the MWs resides and is presented in that manner below.

The following table provides details on FCM charges to load at the Capacity Zone level.

Month	Capacity Zone	CSO MW	HQICC MW	Self Supply MW	Capacity Req MW	Peak Contrib MW	CLO MW	Net Regional Clearing Price ($/kW-month)	Capacity Load Obligation Charge
Feb-13	Rest-of-Pool	29,381	977	1,919	31,594	25,400	28,693	$2.881057	$82,665,837
Feb-13	Maine	3,618	0	9	2,382	1,913	2,378	$2.760122	$6,562,607
Mar-13	Rest-of-Pool	29,417	977	1,919	31,594	25,400	28,693	$2.877566	$82,565,683
Mar-13	Maine	3,582	0	9	2,382	1,913	2,378	$2.785784	$6,623,623
Apr-13	Rest-of-Pool	29,508	977	1,919	31,580	25,400	28,678	$2.867573	$82,237,508
Apr-13	Maine	3,475	0	9	2,381	1,913	2,377	$2.865200	$6,809,325
May-13	Rest-of-Pool	29,503	977	1,919	31,580	25,400	28,678	$2.867952	$82,248,375
May-13	Maine	3,480	0	9	2,381	1,913	2,377	$2.861920	$6,801,529
Jun-13	Rest-of-Pool	29,255	998	2,687	31,254	23,885	27,565	$2.867175	$79,032,958
Jun-13	Maine	3,370	0	6	2,354	1,658	2,352	$2.828415	$6,653,424
Jul-13	Rest-of-Pool	29,490	998	2,687	31,268	23,885	27,579	$2.846167	$78,493,177
Jul-13	Maine	3,135	0	6	2,355	1,658	2,353	$2.952455	$6,948,280
Aug-13	Rest-of-Pool	29,442	998	2,687	31,268	23,885	27,579	$2.799047	$77,193,686
Aug-13	Maine	3,183	0	6	2,355	1,658	2,353	$2.899473	$6,823,594
Sep-13	Rest-of-Pool	29,357	998	2,687	31,268	23,885	27,579	$2.803154	$77,306,941
Sep-13	Maine	3,268	0	6	2,355	1,658	2,353	$2.872424	$6,759,937
Oct-13	Rest-of-Pool	29,581	998	2,687	31,442	23,885	27,752	$2.789340	$77,409,772
Oct-13	Maine	3,230	0	6	2,368	1,658	2,366	$2.960909	$7,006,850
Nov-13	Rest-of-Pool	29,624	998	2,687	31,436	23,885	27,747	$2.783883	$77,243,661
Nov-13	Maine	3,182	0	6	2,367	1,658	2,366	$3.005471	$7,111,112
Dec-13	Rest-of-Pool	29,573	998	2,687	31,456	23,885	27,766	$2.781304	$77,226,769
Dec-13	Maine	3,254	0	6	2,369	1,658	2,368	$2.941540	$6,964,200
Jan-14	Rest-of-Pool	29,794	998	2,687	31,456	23,885	27,766	$2.735408	$75,952,409
Jan-14	Maine	3,033	0	6	2,369	1,658	2,368	$3.040700	$7,198,965
Feb-14	Rest-of-Pool	29,823	998	2,687	31,456	23,885	27,766	$2.758558	$76,595,200
Feb-14	Maine	3,004	0	6	2,369	1,658	2,368	$2.959697	$7,007,186

12.3 Capacity Transfer Rights (CTRs)

CTRs are a mechanism to distribute excess revenue that results from differences in payment rates between Capacity Zones; a CTR fund will be calculated for each constrained capacity zone. There are two types of CTRs: Specifically Allocated CTRs (defined in Market Rule 1 and always paid), and Residual CTRs (remaining funds or shortfall of funds after Specifically Allocated CTRs are paid). Residual CTRs will be allocated to the load serving entities with CLO on the import-constrained side of the interface. For the 2013/2014 Capacity Commitment Period (CCP), Maine is the export-constrained Capacity Zone, while Rest of Pool is on the import-constrained side of the interface. The Capacity Load Obligation Charge above can change depending on the CTRs associated with the Capacity Zone. The Capacity Transfer Rights Fund consists of the following:

- Pool Planned Unit CTRs for certain municipal utilities
- Maine Export Interface CTRs for Casco Bay
- Provisions for Transmission Upgrade CTRs

The following table provides detail, by month and capacity zone, of the Capacity Transfer Rights Dollars, the Specifically Allocated CTR MW and Dollars, along with the Residual CTR MW and Dollars.

Month	Export-constrained Capacity Zone (Charged)	Import-constrained Capacity Zone (Paid)	CTR Fund Dollars	Specifically Allocated CTR MW	Specifically Allocated CTR Dollars	Residual CTR MW	Residual CTR Dollars
Feb-13	Maine	Rest-of-Pool	$148,878.10	329.97	$23,097.89	-28,687.91	$125,780.21
Mar-13	Maine	Rest-of-Pool	$109,722.42	329.97	$23,097.89	-28,687.91	$86,624.53
Apr-13	Maine	Rest-of-Pool	$2,586.50	329.97	$23,097.89	-28,673.46	-$20,511.39
May-13	Maine	Rest-of-Pool	$6,601.97	329.97	$23,097.89	-28,673.46	-$16,495.92
Jun-13	Maine	Rest-of-Pool	$39,188.61	329.94	$59,388.95	-27,559.81	-$20,200.34
Jul-13	Maine	Rest-of-Pool	-$82,436.52	329.94	$59,388.95	-27,573.62	-$141,825.47
Aug-13	Maine	Rest-of-Pool	-$82,720.09	329.94	$59,388.95	-27,573.62	-$142,109.04
Sep-13	Maine	Rest-of-Pool	-$62,935.98	329.94	$59,388.95	-27,573.62	-$122,324.93
Oct-13	Maine	Rest-of-Pool	-$147,156.40	329.97	$59,394.60	-27,747.03	-$206,551.00
Nov-13	Maine	Rest-of-Pool	-$179,395.79	329.97	$59,394.60	-27,741.77	-$238,790.39
Dec-13	Maine	Rest-of-Pool	-$141,057.39	329.97	$59,394.60	-27,761.42	-$200,451.99
Jan-14	Maine	Rest-of-Pool	-$201,180.24	329.97	$59,394.60	-27,761.42	-$260,574.84
Feb-14	Maine	Rest-of-Pool	-$126,725.81	329.97	$59,394.60	-27,761.42	-$186,120.41

12.4 PER Adjustment

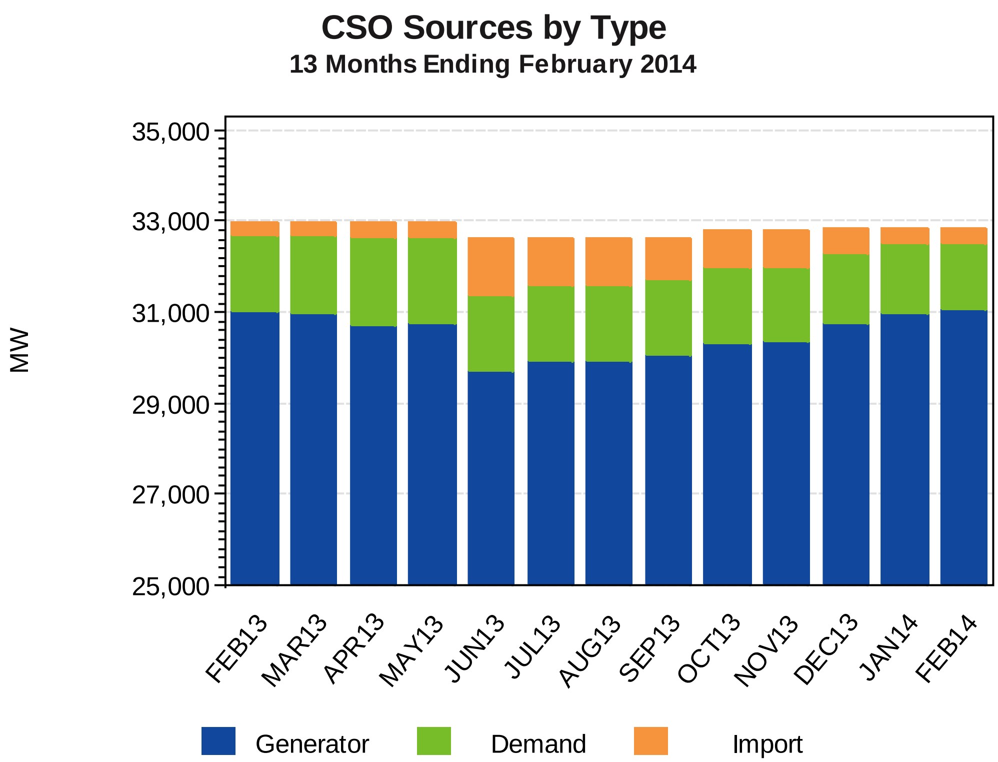
As stated above, PER is a payment adjustment made to reflect revenues earned by resources during high priced hours in the Energy markets. Generation and Import resources with a CSO are subject to PER adjustments (excluding self-supply CSO MWs). Demand resources are not subject to PER adjustments.

The following table provides detail, by month and capacity zone, of the CSO subject to PER, the rate at which these CSO are charged, and the total PER adjustment. It is important to note that individual resources are subject to an overall PER cap. Therefore, the product of the CSO and the rate in the table below will not necessarily equal the total PER adjustment.

Month	Capacity Zone	PER CSO MW	Average PER ($/kW-month)	Total PER Adjustment
Feb-13	Maine	3,144	0.011	$34,587
Feb-13	Rest-of-Pool	26,281	0.014	$367,929
Mar-13	Maine	3,094	0.011	$34,037
Mar-13	Rest-of-Pool	26,319	0.014	$368,462
Apr-13	Maine	2,939	0.011	$32,334
Apr-13	Rest-of-Pool	26,226	0.014	$367,167
May-13	Maine	2,902	0.011	$31,926
May-13	Rest-of-Pool	26,323	0.014	$368,520
Jun-13	Maine	3,114	0.011	$34,251
Jun-13	Rest-of-Pool	25,186	0.014	$352,598
Jul-13	Maine	2,883	0.011	$31,715
Jul-13	Rest-of-Pool	25,592	0.018	$460,650
Aug-13	Maine	2,930	0.011	$32,231
Aug-13	Rest-of-Pool	25,541	0.074	$1,890,030
Sep-13	Maine	3,016	0.011	$33,172
Sep-13	Rest-of-Pool	25,285	0.074	$1,871,057
Oct-13	Maine	2,974	0.011	$32,712
Oct-13	Rest-of-Pool	25,510	0.077	$1,964,305
Nov-13	Maine	2,925	0.011	$32,176
Nov-13	Rest-of-Pool	25,610	0.077	$1,971,944
Dec-13	Maine	2,999	0.020	$59,975
Dec-13	Rest-of-Pool	25,606	0.086	$2,202,113
Jan-14	Maine	2,766	0.052	$143,810
Jan-14	Rest-of-Pool	25,815	0.120	$3,097,750
Feb-14	Maine	2,672	0.041	$109,568
Feb-14	Rest-of-Pool	25,995	0.106	$2,755,434

12.5 Sources of Capacity

The following graph shows, in MW, the amount of capacity procured by type in New England for each of the last 13 months. The subsequent table displays the data underlying the graph.



Month	Demand Resource MW	Generation MW	Import MW	Total MW
Feb-13	1,675	30,987	337	32,999
Mar-13	1,687	30,975	337	32,999
Apr-13	1,919	30,702	362	32,983
May-13	1,888	30,734	362	32,983
Jun-13	1,665	29,702	1,258	32,625
Jul-13	1,655	29,931	1,039	32,625
Aug-13	1,658	29,927	1,039	32,625
Sep-13	1,663	30,046	917	32,625
Oct-13	1,640	30,314	858	32,811
Nov-13	1,604	30,344	858	32,806
Dec-13	1,535	30,740	552	32,827
Jan-14	1,560	30,950	317	32,827
Feb-14	1,473	31,037	317	32,827

12.6 Capacity Imports

The following table shows the monthly CSO MW resulting from imports for each of the last 13 months.

Month	Capacity Zone	NY AC Ties	New Brunswick	HQ Phase I/II	HQ Highgate	Total
Feb-13	Rest-of-Pool	104	0	40	193	337
Feb-13	Maine	0	0	0	0	0
Mar-13	Rest-of-Pool	104	0	40	193	337
Mar-13	Maine	0	0	0	0	0
Apr-13	Rest-of-Pool	104	0	65	193	362
Apr-13	Maine	0	0	0	0	0
May-13	Rest-of-Pool	104	0	65	193	362
May-13	Maine	0	0	0	0	0
Jun-13	Rest-of-Pool	459	0	396	194	1,049
Jun-13	Maine	0	209	0	0	209
Jul-13	Rest-of-Pool	234	0	402	194	830
Jul-13	Maine	0	209	0	0	209
Aug-13	Rest-of-Pool	234	0	402	194	830
Aug-13	Maine	0	209	0	0	209
Sep-13	Rest-of-Pool	134	0	380	194	708
Sep-13	Maine	0	209	0	0	209
Oct-13	Rest-of-Pool	84	0	380	194	658
Oct-13	Maine	0	200	0	0	200
Nov-13	Rest-of-Pool	84	0	380	194	658
Nov-13	Maine	0	200	0	0	200
Dec-13	Rest-of-Pool	84	0	274	194	552
Dec-13	Maine	0	0	0	0	0
Jan-14	Rest-of-Pool	84	0	39	194	317
Jan-14	Maine	0	0	0	0	0
Feb-14	Rest-of-Pool	84	0	39	194	317
Feb-14	Maine	0	0	0	0	0

12.7 Performance

All capacity resources with a CSO are subject to evaluation during each obligation month of a commitment period to ensure they can deliver the capacity for which they are paid. Generation and Import resources are evaluated for performance during shortage events. Demand resources are evaluated during dispatch events and performance hours.

12.7.1 Generation and Import Resource Availability

A shortage event reflects a shortage of operating reserves, as defined by 30 or more consecutive minutes of system Reserve Constraint Penalty Factor activation. Available MWs from Generation and Import resources are measured during shortage events, and availability scores are calculated based on this performance. Available MWs can be adjusted by Supplemental Availability Bilateral (SAB) agreements as well as exempt outage MWs. A resource's availability score is then used to compute the availability penalty associated with the shortage event.

Month	Hours with Shortage Events	Total Duration of Shortage Events (Hours)	Resource Type	SAB MW (Sold)	SAB MW (purchased)	Shortage Event Penalty
Feb-13	0	0.00	Generator	0	0	$0
Feb-13	0	0.00	Import	0	0	$0
Mar-13	0	0.00	Generator	0	0	$0
Mar-13	0	0.00	Import	0	0	$0
Apr-13	0	0.00	Generator	0	0	$0
Apr-13	0	0.00	Import	0	0	$0
May-13	0	0.00	Generator	0	0	$0
May-13	0	0.00	Import	0	0	$0
Jun-13	0	0.00	Generator	0	0	$0
Jun-13	0	0.00	Import	0	0	$0
Jul-13	0	0.00	Generator	0	0	$0
Jul-13	0	0.00	Import	0	0	$0
Aug-13	0	0.00	Generator	0	0	$0
Aug-13	0	0.00	Import	0	0	$0
Sep-13	0	0.00	Generator	0	0	$0
Sep-13	0	0.00	Import	0	0	$0
Oct-13	0	0.00	Generator	0	0	$0
Oct-13	0	0.00	Import	0	0	$0
Nov-13	0	0.00	Generator	0	0	$0
Nov-13	0	0.00	Import	0	0	$0
Dec-13	3	85.00	Generator	352	352	-$6,550,130
Dec-13	3	85.00	Import	0	0	-$45,439
Jan-14	0	0.00	Generator	0	0	$0
Jan-14	0	0.00	Import	0	0	$0
Feb-14	0	0.00	Generator	0	0	$0
Feb-14	0	0.00	Import	0	0	$0

12.7.2 Demand Resource Performance

Demand Resources are collections of assets which reduce their consumption of energy in order to provide capacity to the system. There are four types of Demand Resources: Real-Time Demand Response resources (RTDR), Real-Time Emergency Generation resources (RTEG), On-Peak resources, and Seasonal Peak resources. RTDR and RTEG are active demand resources, and are required to respond to dispatch instructions from ISO-NE. During these dispatch events, active resources are expected to curtail their energy consumption for the system by an amount equal to that requested by ISO-NE. On-Peak and Seasonal Peak resources, on the other hand, are passive demand resources, and do not receive dispatch instructions from ISO-NE. Instead, these resources curtail their electricity use at set times throughout the year. On-Peak resources must reduce consumption during summer peak hours (non-holiday weekdays, 1:00 p.m. to 5:00 p.m., during June, July, and August) and winter peak hours (non-holiday weekdays, 5:00 p.m. to 7:00 p.m., during December and January). Seasonal Peak resources must reduce consumption during the summer months of June, July, and August and during the winter months of December and January in hours on non-holiday weekdays when the Real-Time

System Hourly Load is equal to or greater than 90% of the most recent “50/50” System Peak Load Forecast.

Demand Resource performance is measured during hours with dispatch events for active resources, and during performance hours for passive resources. Resources with a capacity value less than their CSO will be assessed a penalty, while those with a capacity value greater than their CSO are eligible for a performance incentive. In the absence of a performance event during performance months, a resource’s capacity value and resulting variance will be based on its effective audit result; and in non-performance months, a resource’s capacity value and resulting variance will be based upon its Seasonal Demand Reduction Value.

The following table displays a pool-level summary of Demand Resource performance by type for the past 13 months.

Month	DR Type	Performance Hours	CSO MW	Capacity Value (MW)	Negative Capacity Variance (MW)	Positive Capacity Variance (MW)	Performance Penalty ($)	Performance Incentive ($)
Feb-13	ON_PEAK	0	726.98	1,153.53	-10.36	436.91	-$26,260	$74,426
Feb-13	REAL_TIME	0	401.89	424.78	-24.54	30.79	-$62,060	$4,744
Feb-13	REAL_TIME_EG	0	282.77	304.93	-11.18	33.35	-$26,977	$4,824
Feb-13	SEASONAL_PEAK	0	263.62	463.68	0.00	200.06	$0	$31,303
Mar-13	ON_PEAK	0	727.65	1,153.53	-10.18	436.06	-$25,794	$82,528
Mar-13	REAL_TIME	0	435.89	424.78	-33.18	22.07	-$83,921	$4,158
Mar-13	REAL_TIME_EG	0	260.07	291.21	-7.11	38.26	-$17,154	$6,111
Mar-13	SEASONAL_PEAK	0	263.62	463.68	0.00	200.06	$0	$34,071
Apr-13	ON_PEAK	0	724.06	862.38	-4.20	142.52	-$11,845	$8,065
Apr-13	REAL_TIME	0	578.80	622.48	-0.43	44.11	-$1,098	$2,075
Apr-13	REAL_TIME_EG	0	369.61	394.20	-0.09	24.68	-$208	$1,186
Apr-13	SEASONAL_PEAK	0	246.43	308.46	-0.57	62.61	-$1,455	$3,280
May-13	ON_PEAK	0	723.78	862.38	-4.20	142.81	-$11,845	$7,279
May-13	REAL_TIME	0	547.45	622.48	-0.43	75.46	-$1,098	$3,344
May-13	REAL_TIME_EG	0	369.45	394.20	-0.10	24.85	-$234	$1,072
May-13	SEASONAL_PEAK	0	246.93	308.46	-0.57	62.11	-$1,455	$2,937
Jun-13	ON_PEAK	80	822.18	1,043.32	-21.82	242.75	-$60,652	$96,230
Jun-13	REAL_TIME	0	355.32	429.33	-24.63	98.64	-$69,764	$21,987
Jun-13	REAL_TIME_EG	0	169.78	190.42	-6.95	27.58	-$15,240	$9,654
Jun-13	SEASONAL_PEAK	11	318.02	362.33	0.00	44.31	$0	$17,785
Jul-13	ON_PEAK	88	814.53	1,066.65	-8.92	260.83	-$22,964	$98,519
Jul-13	REAL_TIME	8	347.32	401.27	-37.60	91.55	-$95,889	$7,532
Jul-13	REAL_TIME_EG	0	164.70	190.86	-6.23	32.38	-$13,664	$10,793
Jul-13	SEASONAL_PEAK	64	328.02	367.85	0.00	39.83	$0	$15,674
Aug-13	ON_PEAK	88	814.89	1,078.65	-9.52	273.07	-$24,551	$132,177
Aug-13	REAL_TIME	0	352.08	369.09	-48.76	65.77	-$128,857	$14,347
Aug-13	REAL_TIME_EG	0	163.43	181.17	-11.77	29.50	-$25,768	$12,700
Aug-13	SEASONAL_PEAK	0	328.02	367.85	0.00	39.83	$0	$19,953

Month	DR Type	Performance Hours	CSO MW	Capacity Value (MW)	Negative Capacity Variance (MW)	Positive Capacity Variance (MW)	Performance Penalty ($)	Performance Incentive ($)
Sep-13	ON_PEAK	0	814.86	1,063.98	-9.29	258.20	-$23,483	$90,805
Sep-13	REAL_TIME	0	353.21	400.22	-30.55	77.56	-$79,640	$6,707
Sep-13	REAL_TIME_EG	0	166.47	187.48	-7.80	28.80	-$17,107	$8,927
Sep-13	SEASONAL_PEAK	0	328.02	366.01	0.00	37.99	$0	$13,790
Oct-13	ON_PEAK	0	811.69	1,063.98	-5.88	257.96	-$14,924	$51,556
Oct-13	REAL_TIME	0	340.54	400.63	-16.82	76.90	-$52,863	$4,058
Oct-13	REAL_TIME_EG	0	159.75	187.48	-0.33	28.06	-$728	$5,046
Oct-13	SEASONAL_PEAK	0	328.02	366.01	0.00	37.99	$0	$7,855
Nov-13	ON_PEAK	0	811.38	1,056.25	-9.75	254.41	-$25,087	$33,744
Nov-13	REAL_TIME	0	302.62	383.38	-7.14	87.90	-$18,114	$5,879
Nov-13	REAL_TIME_EG	0	161.97	178.83	-1.74	18.60	-$3,813	$2,212
Nov-13	SEASONAL_PEAK	0	328.02	366.01	0.00	37.99	$0	$5,180
Dec-13	ON_PEAK	42	811.88	1,425.38	-14.12	627.49	-$38,080	$205,842
Dec-13	REAL_TIME	4	268.42	218.00	-79.43	29.01	-$202,224	$9,282
Dec-13	REAL_TIME_EG	0	126.72	125.15	-16.38	14.80	-$35,339	$3,632
Dec-13	SEASONAL_PEAK	31	328.02	530.22	0.00	202.20	$0	$56,887
Jan-14	ON_PEAK	44	805.89	1,453.79	-27.82	675.57	-$99,041	$256,340
Jan-14	REAL_TIME	0	282.39	221.40	-91.03	30.04	-$233,506	$10,653
Jan-14	REAL_TIME_EG	0	143.26	158.08	-10.50	25.33	-$22,550	$8,088
Jan-14	SEASONAL_PEAK	62	328.02	546.50	0.00	218.48	$0	$80,015
Feb-14	ON_PEAK	0	808.76	1,441.24	-16.58	648.92	-$57,850	$84,055
Feb-14	REAL_TIME	0	208.73	221.06	-22.16	34.49	-$57,739	$3,613
Feb-14	REAL_TIME_EG	0	127.16	141.62	-1.20	15.65	-$2,626	$1,853
Feb-14	SEASONAL_PEAK	0	328.02	538.36	0.00	210.34	$0	$28,694

12.8 For More Information

Detailed information on the FCM, including information on the qualification process, auction results, and FERC filings and orders can be found here.

Detailed information about FCM Charge calculation summaries can be found here.

13. Energy Market Payments to Demand Assets

Energy Market payments to demand assets are administered through the Transitional Demand Response (TDR) program.

13.1 Transitional Demand Response

The Transitional Demand Response (TDR) program represents, in the aggregate, agreements between wholesale providers and retail customers to encourage reduction of their electricity consumption during periods of peak demand. Transitional Demand Response in New England is administered post the Day-Ahead Energy Market clearing and the scheduling of demand reductions by Market Participants in real-time based upon system conditions.

13.1.1 Transitional Demand Response Payments

- A Real-Time Demand Response Asset with an offer that clears in the post Day-Ahead Energy Market clearing will receive a payment for its Day-Ahead Demand Reduction Obligation at the applicable Day-Ahead Zonal Locational Marginal Price (LMP) and will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation in Real-Time at the applicable Real-Time Zonal LMP.

- A Real-Time Demand Response Asset with an offer that does not clear in the post Day-Ahead Energy Market clearing will be eligible to receive a payment for its Real-Time Demand Reduction Obligation at the applicable Real-Time Zonal LMP when the hourly provisional Real-Time Zonal LMP is greater than or equal to the its Demand Reduction Offer price.

- A Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that is associated to a Demand Resource in the Forward Capacity Market will receive a payment at the applicable Real-Time Zonal LMP, for its demand reduction, when the Demand Resource is dispatched or audited pursuant to Section III.13 of Market Rule 1.

13.1.2 Transitional Demand Response Charges

- The total credits associated with Transitional Demand Response are allocated proportionally on an hourly basis to Market Participants with Real-Time Load Obligations on a system-wide basis. Excluded are Real-Time Load Obligations incurred at all External Nodes or incurred by Dispatchable Asset Related Demand Postured by the ISO.

The following table includes Day-Ahead Demand Reduction Obligation megawatt-hours MWh (Day-Ahead Cleared MWh, plus average avoided peak distribution losses of 6.5%), Real-Time Demand Reduction MWh, Real-Time Demand Reduction Obligation MWh, RT Demand Reduction Deviation Set to Zero MWh, Real-Time Demand Reduction Deviation MWh, Average Pool Demand Response Charge Allocation MWh, and the FCM/Audit Demand Reduction MWh (Also adjusted for average avoided peak distribution losses of 6.5%).

*RT Demand Reduction Obligation MWh = Average Avoided Peak Distribution Losses (1.065) * RT Demand Reduction MWh*

RT Demand Reduction Deviation MW = RT Demand Reduction Obligation MWh - DA Demand Reduction Obligation MWh + RT Demand Reduction Deviation Set to Zero MWh

Month	Transitional Demand Response Settlement MW					Other Statistics	
	DA Demand Reduction Obligation MWh (A)	RT Demand Reduction MWh (B)	RT Demand Reduction Obligation MW (C)=(B)*1.065	RT Demand Reduction Deviation Set to Zero MWh (D)	RT Demand Reduction Deviation MWh (E)=(C)-(A)+(D)	Average Pool Demand Response Charge Allocation MWh	FCM/ Audit Demand Reduction MWh
Feb-13	2,918	3,722	3,964	-3	1,044	16,448	1
Mar-13	2,133	1,994	2,124	-12	-21	15,686	0
Apr-13	1,793	1,883	2,005	-13	198	14,484	0
May-13	2,484	2,917	3,106	-5	618	15,290	0
Jun-13	2,111	2,673	2,847	0	736	17,128	78
Jul-13	3,666	4,374	4,659	-7	986	20,693	1,515
Aug-13	3,283	4,516	4,810	-2	1,525	17,815	136
Sep-13	3,035	3,477	3,703	-59	609	15,902	9
Nov-13	2,817	3,687	3,927	0	1,111	15,521	0
Dec-13	3,002	3,809	4,057	0	1,054	16,916	506
Jan-14	4,354	5,842	6,222	-48	1,820	17,304	179
Feb-14	3,550	4,173	4,444	-3	892	16,577	2

In the above table the RT Demand Reduction Deviation Set to Zero MWh column is the difference between DA Demand Reduction Obligation MW and RT Demand Reduction Obligation MW when the RT Demand Reduction Deviation MWh has been set to zero in the settlement, which occurs when the following is true:

- Control Room denies interruption of an Asset
- DA Demand Reduction Obligation MW > 0, Load Zone Real-Time Net Benefit Hour Flag = N, and RT Demand Reduction MWh > DA Demand Reduction Obligation MW

The following table displays Day-Ahead payments, Real-Time Payment Dollars, Total Payment (sum of total Day-Ahead and Real-Time Payments), and the Charge per MWh.

Month	DA Payment Dollars	RT Payment Dollars	FCM Audit Demand Reduction Dollars	Total Payment (Charge) Dollars	Charge per MWh
Feb-13	$449,914	$166,771	$69	$616,754	$0.00
Mar-13	$125,943	$1,207	$0	$127,150	$0.00
Apr-13	$100,848	$12,772	$0	$113,620	$0.00
May-13	$127,273	$32,802	$0	$160,075	$0.00
Jun-13	$105,827	$44,809	$2,551	$153,187	$0.00
Jul-13	$329,350	$213,288	$522,247	$1,064,885	$0.00
Aug-13	$149,589	$81,289	$5,818	$236,695	$0.00
Sep-13	$148,319	$62,016	$465	$210,801	$0.00
Nov-13	$144,804	$65,018	$0	$209,822	$0.00
Dec-13	$443,245	$187,155	$169,991	$800,390	$0.00
Jan-14	$1,044,899	$393,853	$33,999	$1,472,751	$0.00
Feb-14	$657,926	$180,738	$657	$839,321	$0.10

13.2 For More Information:

Rules governing the calculation of the Transitional Demand Response can be found in Section III.13 Market Rule 1 and Section III, Appendix E located here.

14. Document History

Date	Version	Description
3/29/2017	Rev. 1	Table in “Section 12.6 Capacity Imports” updated with correct monthly CSO MW values. Please see the February Monthly Reports for 2013-2016 to view the complete series of revised CSO values.
3/17/2014	Original Posting	