Monthly Market Operations Report
March 2015

ISO New England Inc.
Market Analysis and Settlements
April 13, 2015

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[1]. 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[2].

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.

[1] Select "Weekly Markets Reports" from the document type filter on the left hand side of the page.

[2] Select "Quarterly Markets Reports" from the document type filter on the left hand side of the page.

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3. Monthly Summary

Day-ahead and real-time LMPs at the New England Hub averaged $64.25/MWh and $57.93/MWh, respectively, during March 2015. Day-ahead and real-time prices at the Hub and in the Load Zones averaged 46-55% lower than February 2015 averages. In the aggregate, March 2015 day-ahead and real-time LMPs were approximately 46% lower during March 2015 than in March 2014. Average natural gas prices were 48% below the prior year's average prices, while residual fuel prices were down 54% from a year ago.

Overall, the average of the hourly real-time LMPs at the Hub and in the Load Zones ranged between 12.6% lower than day-ahead in the Southeastern Massachusetts (SEMA) Load Zone to 7.8% lower than its day-ahead counterpart in the Connecticut (CT) Load Zone. In the Day-Ahead Market, Load Zone average LMPs ranged between 5.5% lower than the Hub average LMPs in the CT Load Zone to 3.3% higher than the Hub in the Rhode Island (SEMA) Load Zone. In the Real-Time Market, Load Zone average LMPs ranged between 4.6% lower than the Hub average LMPs in the Maine (ME) Load Zone to 0.7% higher than the Hub in the NEMA Load Zone. Price differentials between on-peak and off-peak hours at the Hub and in the Load Zones ranged between 4% and 25% 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 March. In the Day-Ahead Energy Market, there were approximately 143,000 MWh of total exports and 2,611,000 MWh of imports, yielding a net import of approximately 2,468,000 MWh. In the Real-Time Energy Market, there were approximately 257,000 MWh of total exports and 2,671,000 MWh of imports, yielding a net import of approximately 2,414,000 MWh. This was about 290,000 MW higher than a year ago.

The Monthly FTR Auction (March 2015) had 35 participants and the awarded value of FTRs in the auction totaled $950K. This represented an increase of $196K over the previous month and a decrease of about $150K from the prior year's monthly FTR auction. The allocation of FTR Auction Revenue for March 2015 resulted in $2.3 million awarded to eligible entities, with $194K allocated to Incremental Auction Revenue Rights (IARR).

The Marginal Loss Revenue Fund totaled $6.8 million for March, down $10.1 million from its February 2015 total.

Total Forward Reserve Credits to eligible assets of $13.5 million were reduced by $516K in Failure to Reserve Penalties and $0 in Failure to Activate Penalties during March 2015. The net Forward Reserve Payment of $13.0 million represented 94% of the maximum possible payment of $13.8 million. Real-Time Reserve Prices occurred in 124 separate hours during the month, and those yielded real-time payments to designated assets of $394K. These payments were not reduced by any Forward Reserve Energy Obligation Charges, yielding a net compensation of $394K during the month.

Regulation Market Payments totaled $2.1 million during the month, a decrease of $880K from the February 2015 value of $2.9 million. On March 31, the ISO implemented a change to the Regulation Market to enable the participation of alternative regulating resources, as required by the Federal Energy Regulatory Commission.

For the month of March 2015, Forward Capacity payments were made to a total of 32,981 MW of capacity and totaled $90.6 million.

The Transitional Demand Response program is the method through which demand assets can participate in the Energy Market. Payments during March 2015 totaled $126,000 for interruptions associated with Day Ahead, $28,000 for interruptions associated with the Real Time, and $0 associated with FCM/Audit. Total Transitional Demand Response payments for the month, $154,000, were down approximately $249,000 from their February levels.

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, March 2015

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	$64.25	$57.93	$9.98	-$129.33	$190.10	$241.82	58%	50%	90.2%	$32.88	$38.99	1.19
ME	$62.47	$55.24	$9.60	-$124.48	$186.59	$235.85	56%	48%	88.4%	$31.48	$38.79	1.23
NH	$64.56	$56.71	$9.91	-$127.32	$189.14	$239.22	58%	49%	87.8%	$32.75	$38.91	1.19
VT	$61.24	$56.08	$9.95	-$127.97	$188.40	$237.25	55%	48%	91.6%	$33.11	$38.23	1.15
CT	$60.69	$55.98	$9.98	-$128.90	$184.15	$238.26	55%	48%	92.2%	$32.63	$38.15	1.17
RI	$65.38	$57.73	$10.00	-$130.06	$188.18	$242.95	59%	50%	88.3%	$32.60	$38.74	1.19
SEMA	$66.36	$58.02	$9.89	-$129.69	$191.68	$242.54	60%	50%	87.4%	$33.67	$38.99	1.16
WCMA	$63.87	$57.48	$10.02	-$130.01	$190.16	$242.06	57%	49%	90.0%	$32.96	$38.71	1.17
NEMA	$66.28	$58.34	$9.94	-$129.81	$192.51	$244.12	60%	50%	88.0%	$33.66	$39.23	1.17
NB Ext	$56.93	$53.42	$9.26	-$119.97	$178.78	$231.09	51%	46%	94%	$30.38	$37.70	1.24
NYN Ext	$60.05	$55.20	$9.97	-$128.26	$181.55	$234.49	54%	48%	92%	$32.21	$37.56	1.17
HQ Ext	$64.89	$57.01	$9.79	-$126.99	$187.50	$239.17	58%	49%	88%	$32.73	$38.33	1.17
HG Ext	$55.22	$51.92	$9.42	-$116.78	$172.58	$221.08	50%	45%	94%	$29.15	$35.48	1.22
CSC Ext	$60.52	$56.84	$9.96	-$129.08	$182.68	$236.62	54%	49%	94%	$32.47	$38.33	1.18
NNC Ext	$59.98	$55.33	$9.98	-$128.40	$180.86	$234.39	54%	48%	92%	$32.19	$37.68	1.17

4.1.2 On-Peak Hours, March 2015

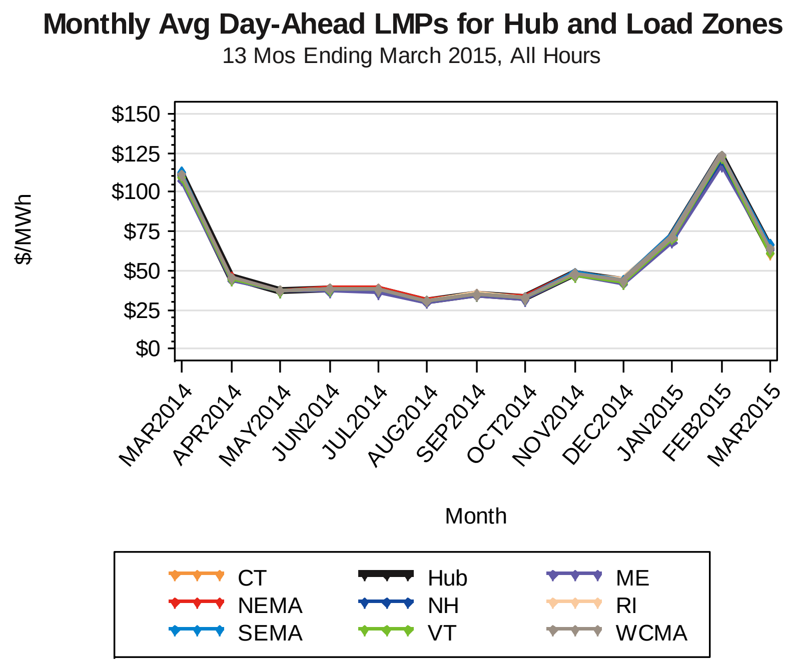
Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$69.86	$59.19	$26.25	-$58.79	$171.78	$201.77	55%	44%	85%	$32.70	$34.29	1.05
ME	$66.32	$57.12	$24.87	-$55.85	$159.42	$192.86	52%	43%	86%	$30.44	$32.86	1.08
NH	$69.35	$58.53	$26.03	-$57.91	$167.71	$200.71	54%	44%	84%	$32.33	$34.02	1.05
VT	$68.47	$57.95	$25.75	-$57.31	$169.18	$201.59	54%	43%	85%	$32.40	$34.02	1.05
CT	$67.94	$57.83	$25.84	-$58.05	$169.20	$201.09	53%	43%	85%	$32.21	$33.73	1.05
RI	$69.78	$58.81	$26.57	-$58.82	$171.61	$198.98	55%	44%	84%	$32.50	$34.04	1.05
SEMA	$70.67	$59.19	$26.25	-$58.61	$172.85	$202.93	55%	44%	84%	$33.33	$34.44	1.03
WCMA	$69.73	$58.93	$26.22	-$58.55	$171.77	$201.92	55%	44%	85%	$32.78	$34.26	1.05
NEMA	$70.62	$59.67	$26.33	-$58.92	$172.36	$204.20	55%	45%	84%	$33.04	$34.70	1.05
NB Ext	$60.69	$55.21	$18.89	-$52.43	$151.27	$186.54	47%	41%	91%	$29.23	$31.80	1.09
NYN Ext	$67.09	$56.95	$25.57	-$57.07	$165.56	$198.57	52%	43%	85%	$31.77	$33.31	1.05
HQ Ext	$69.14	$58.27	$25.85	-$57.60	$167.67	$199.29	54%	44%	84%	$32.22	$33.88	1.05
HG Ext	$60.71	$53.69	$24.20	-$52.80	$158.88	$187.83	47%	40%	88%	$27.60	$31.56	1.14
CSC Ext	$67.81	$58.91	$25.76	-$57.97	$168.30	$202.49	53%	44%	87%	$32.13	$34.28	1.07
NNC Ext	$67.10	$57.20	$25.68	-$57.43	$166.89	$200.86	52%	43%	85%	$31.75	$33.47	1.05

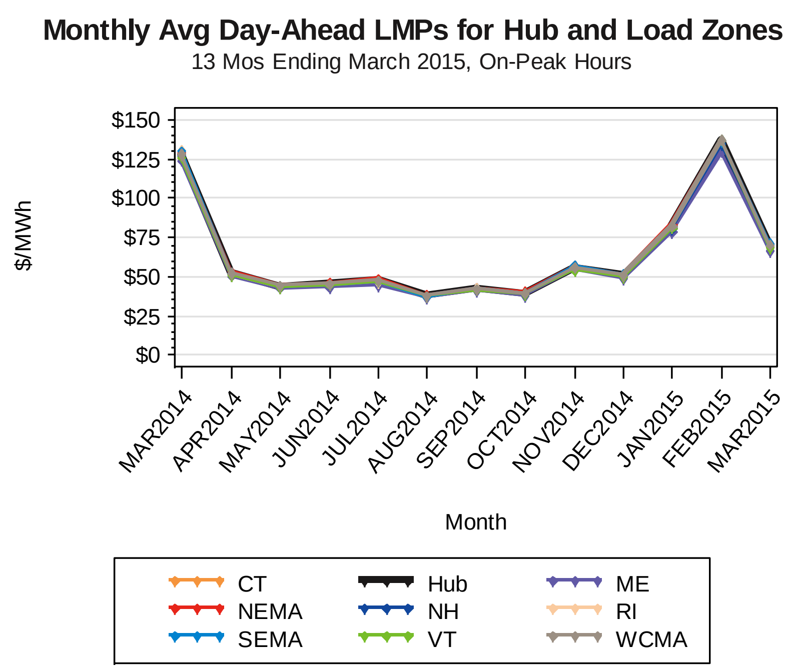
4.1.3 Off-Peak Hours, March 2015

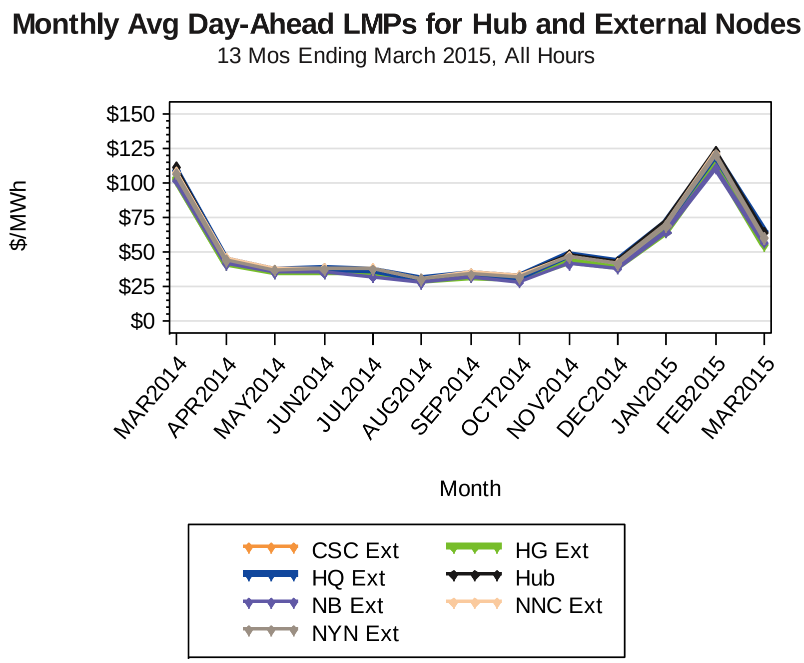
Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$59.19	$56.79	$9.98	-$129.33	$190.10	$241.82	61%	56%	96%	$32.25	$42.79	1.33
ME	$59.01	$53.56	$9.60	-$124.48	$186.59	$235.85	61%	53%	91%	$32.04	$43.41	1.35
NH	$60.24	$55.07	$9.91	-$127.32	$189.14	$239.22	62%	54%	91%	$32.58	$42.82	1.31
VT	$54.74	$54.39	$9.95	-$127.97	$188.40	$237.25	56%	53%	99%	$32.43	$41.63	1.28
CT	$54.17	$54.31	$9.98	-$128.90	$184.15	$238.26	56%	53%	100%	$31.64	$41.70	1.32
RI	$61.42	$56.76	$10.00	-$130.06	$188.18	$242.95	63%	56%	92%	$32.22	$42.55	1.32
SEMA	$62.48	$56.96	$9.89	-$129.69	$191.68	$242.54	64%	56%	91%	$33.53	$42.68	1.27
WCMA	$58.59	$56.17	$10.02	-$130.01	$190.16	$242.06	60%	55%	96%	$32.26	$42.33	1.31
NEMA	$62.38	$57.15	$9.94	-$129.81	$192.51	$244.12	64%	56%	92%	$33.76	$42.91	1.27
NB Ext	$53.55	$51.81	$9.26	-$119.97	$178.78	$231.09	55%	51%	97%	$31.03	$42.29	1.36
NYN Ext	$53.72	$53.63	$9.97	-$128.26	$181.55	$234.49	55%	53%	100%	$31.33	$40.99	1.31
HQ Ext	$61.08	$55.87	$9.79	-$126.99	$187.50	$239.17	63%	55%	91%	$32.76	$41.95	1.28
HG Ext	$50.28	$50.32	$9.42	-$116.78	$172.58	$221.08	52%	49%	100%	$29.66	$38.64	1.30
CSC Ext	$53.95	$54.98	$9.96	-$129.08	$182.68	$236.62	55%	54%	102%	$31.38	$41.60	1.33
NNC Ext	$53.57	$53.65	$9.98	-$128.40	$180.86	$234.39	55%	53%	100%	$31.26	$41.06	1.31

4.2 LMP Graphs, Day-Ahead Market, 13 Months Ending March 2015

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 March 2015, All Hours
$/MWh
$150
$125
$100
$75
$50
$25
$0
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
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JAN2015
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MAR2015
Month
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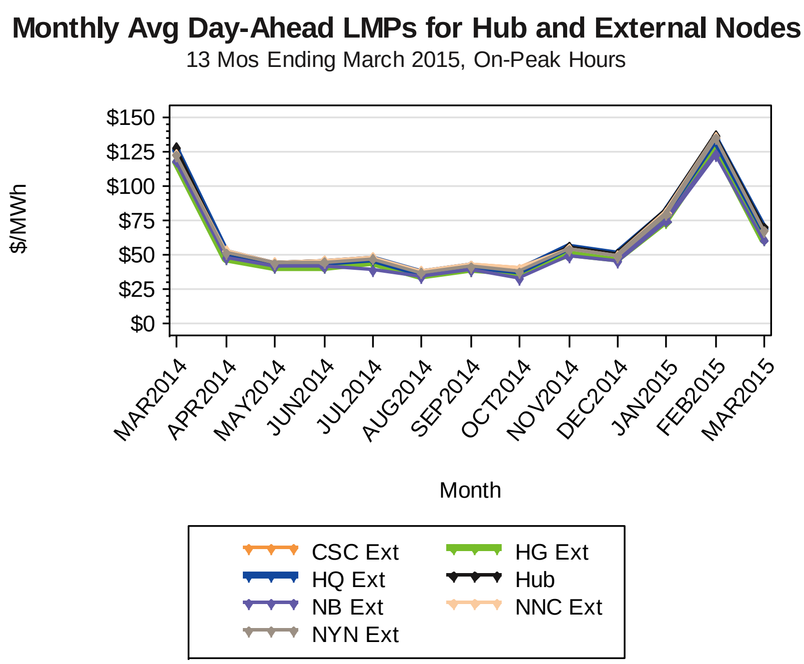
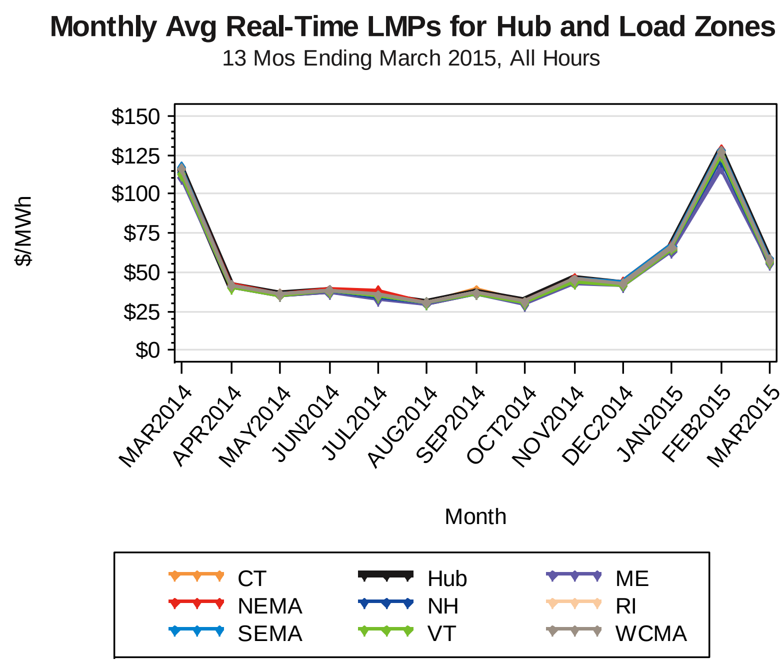
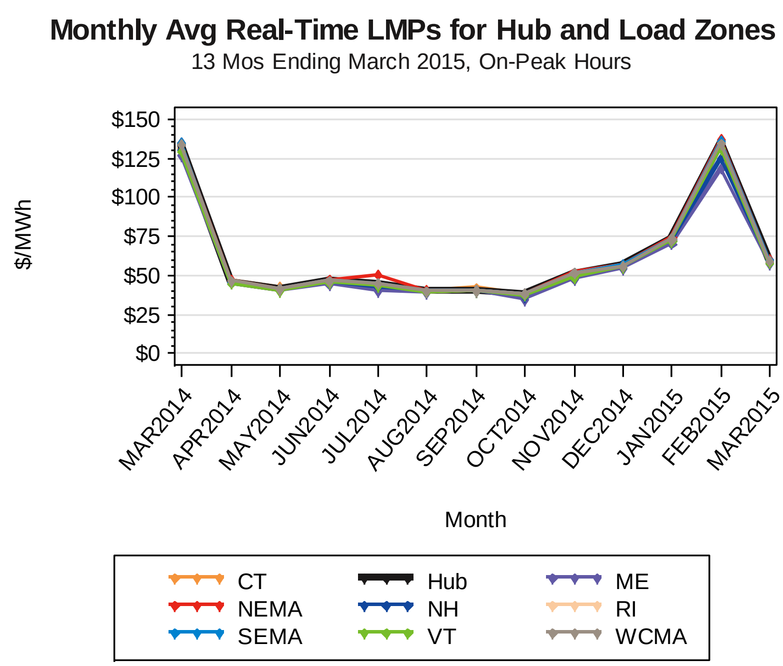
HG Ext
HQ Ext
Hub
NB Ext
NNC Ext
NYN Ext

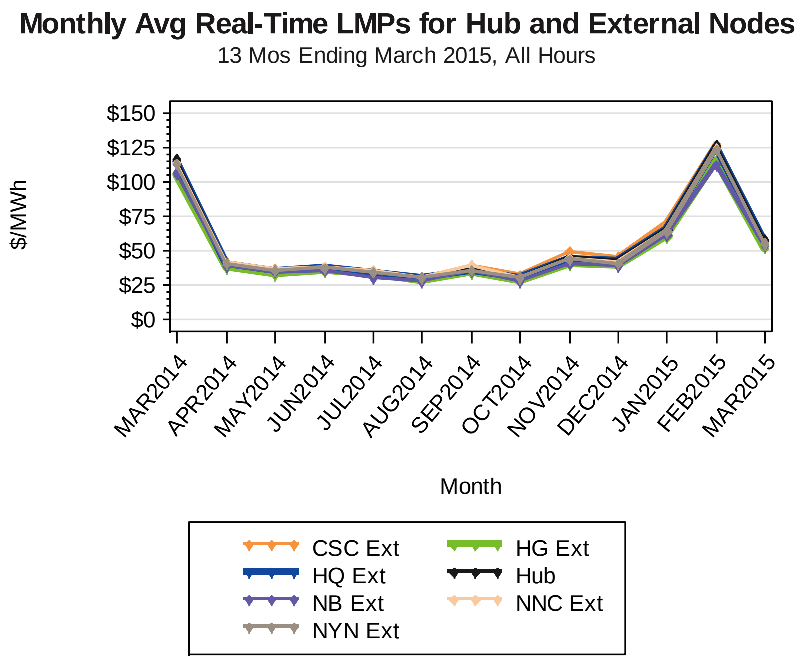

Monthly Avg Day-Ahead LMPs for Hub and External Nodes
13 Mos Ending March 2015, On-Peak Hours
$/MWh
$150
$125
$100
$75
$50
$25
$0
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
Month
CSC Ext
HG Ext
HQ Ext
Hub
NB Ext
NNC Ext
NYN Ext

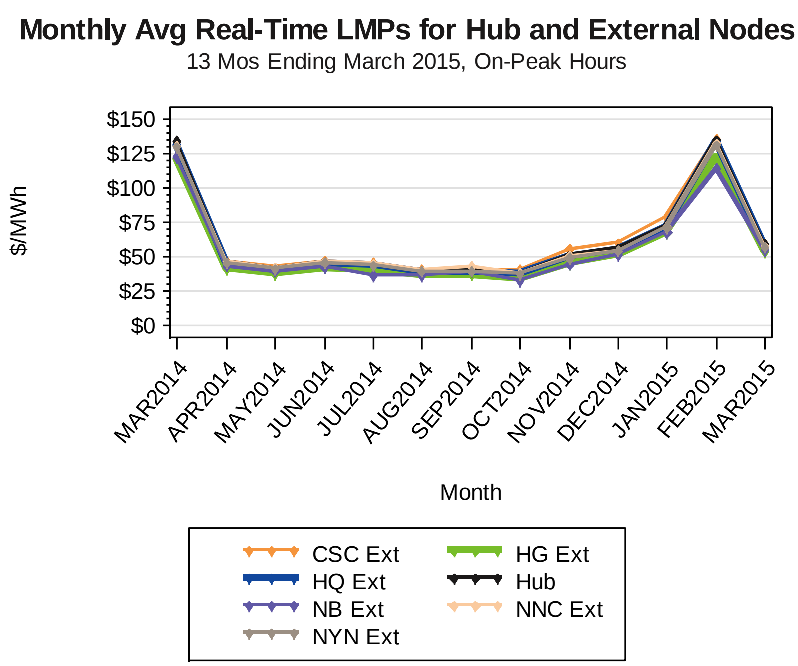
4.3 LMP Graphs, Real-Time Market, 13 Months Ending March 2015

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 March 2015, All Hours
$/MWh
$150
$125
$100
$75
$50
$25
$0
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
Month
CSC Ext
HG Ext
HQ Ext
Hub
NB Ext
NNC Ext
NYN Ext


Monthly Avg Real-Time LMPs for Hub and External Nodes
13 Mos Ending March 2015, On-Peak Hours
$/MWh
$150
$125
$100
$75
$50
$25
$0
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
Month
CSC Ext
HG Ext
HQ Ext
Hub
NB Ext
NNC Ext
NYN Ext

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[3].

The ISO also provides a discussion of LMP results on an annual basis in its Annual Market Performance Reports, located here[4].

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.

[3] Select "Weekly Markets Reports" from the document type filter on the left hand side of the page

[4] Select "Annual Markets Reports" from the document type filter on the left hand side of the page

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.

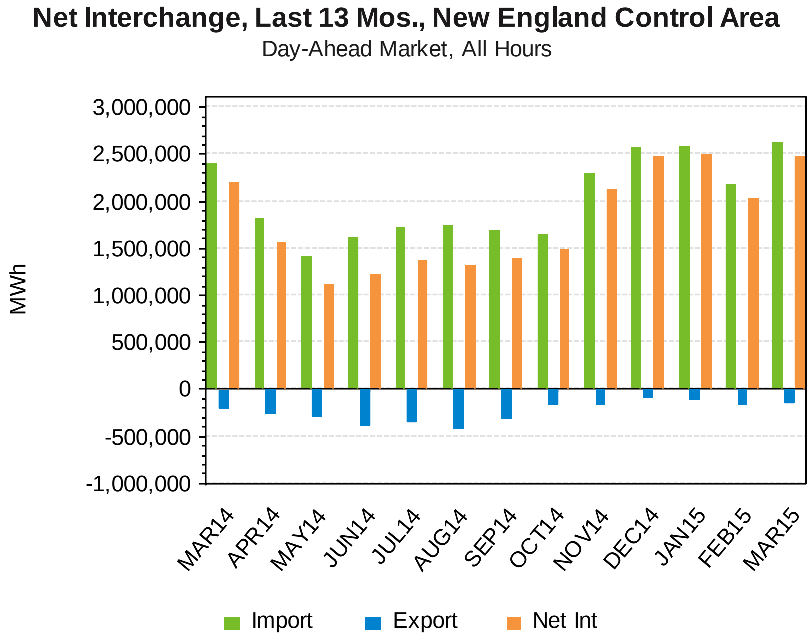
5.1 Net Interchange Summary, March 2015

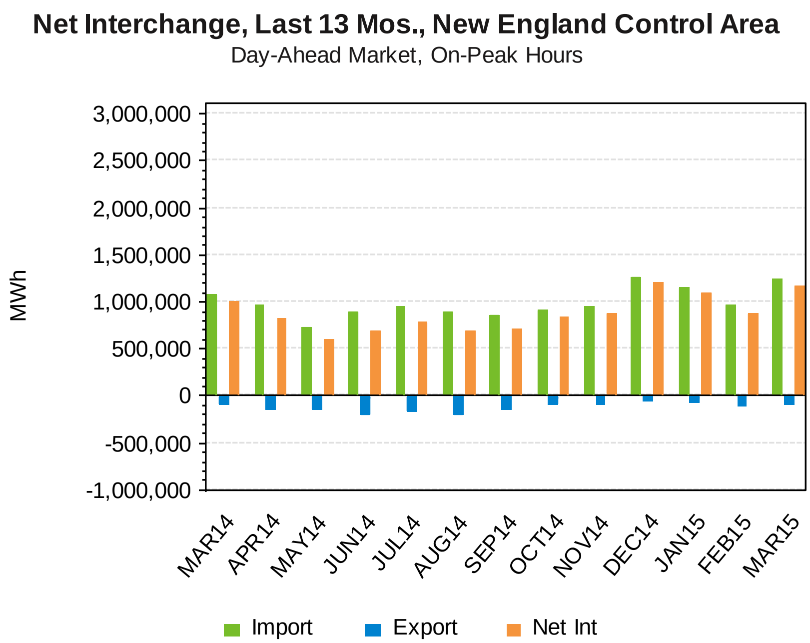
The following tables show summary statistics for imports and exports on the six external interfaces for both the Day-Ahead and Real-Time Markets:

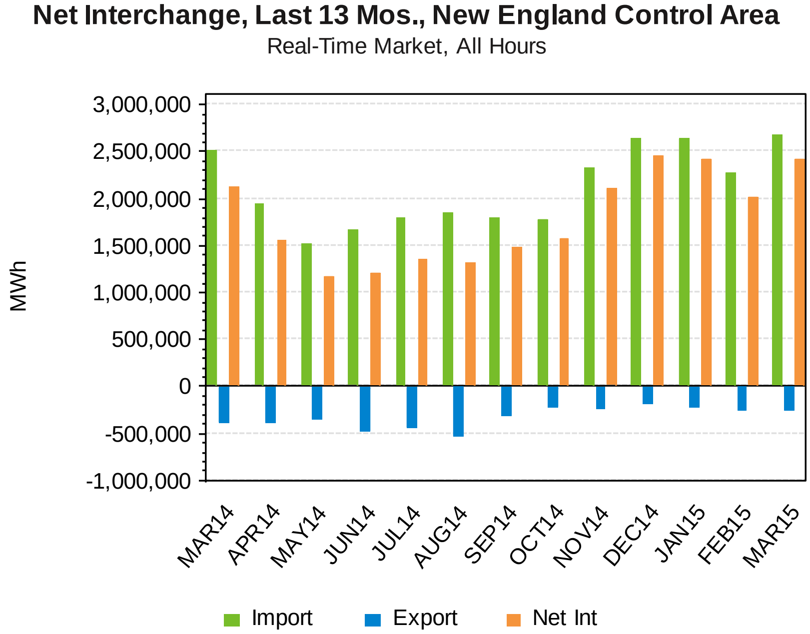
5.1.1 Day-Ahead and Real-Time Market Summary by Interface

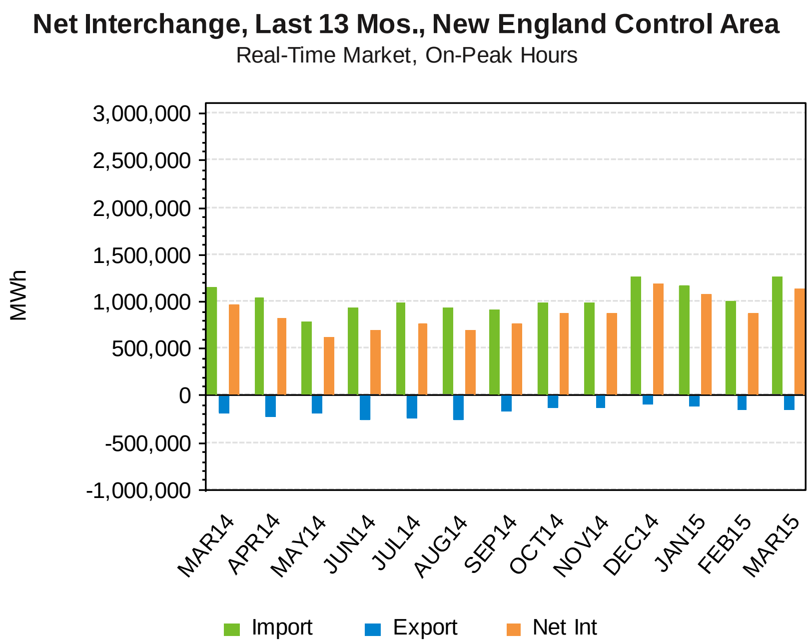
On/Off Peak	Interface	DA Total Exports (MWh)	DA Total Imports (MWh)	DA Net Int (MWh)	RT Total Exports (MWh)	RT Total Imports (MWh)	RT Net Int (MWh)
All Hours	NNC	-18,446	53,428	34,983	-25,632	66,638	41,006
	NY-CSC	-37,910	3,964	-33,946	-37,905	8,975	-28,930
	HQ HG	0	160,833	160,833	0	161,257	161,257
	HQ I/II	-6,358	1,078,600	1,072,242	0	1,071,953	1,071,953
	NY-N AC	-55,058	963,406	908,348	-132,125	1,028,783	896,658
	NB	-25,621	351,033	325,412	-61,703	333,560	271,857
Total	**All Hours**	**-143,393**	**2,611,264**	**2,467,871**	**-257,365**	**2,671,166**	**2,413,801**
Off-Peak	NNC	-8,713	25,000	16,287	-11,597	36,699	25,102
	NY-CSC	-13,610	3,164	-10,446	-13,605	8,550	-5,055
	HQ HG	0	84,097	84,097	0	84,521	84,521
	HQ I/II	-2,870	568,041	565,171	0	561,497	561,497
	NY-N AC	-30,473	507,571	477,098	-65,515	544,801	479,286
	NB	-12,619	181,613	168,994	-33,053	175,085	142,032
Total	Off-Peak	-68,285	1,369,486	1,301,200	-123,770	1,411,153	1,287,383
On-Peak	NNC	-9,733	28,428	18,696	-14,035	29,939	15,904
	NY-CSC	-24,300	800	-23,500	-24,300	425	-23,875
	HQ HG	0	76,736	76,736	0	76,736	76,736
	HQ I/II	-3,488	510,559	507,071	0	510,456	510,456
	NY-N AC	-24,585	455,835	431,250	-66,610	483,982	417,372
	NB	-13,002	169,420	156,418	-28,650	158,475	129,825
Total	On-Peak	-75,108	1,241,778	1,166,670	-133,595	1,260,013	1,126,418

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

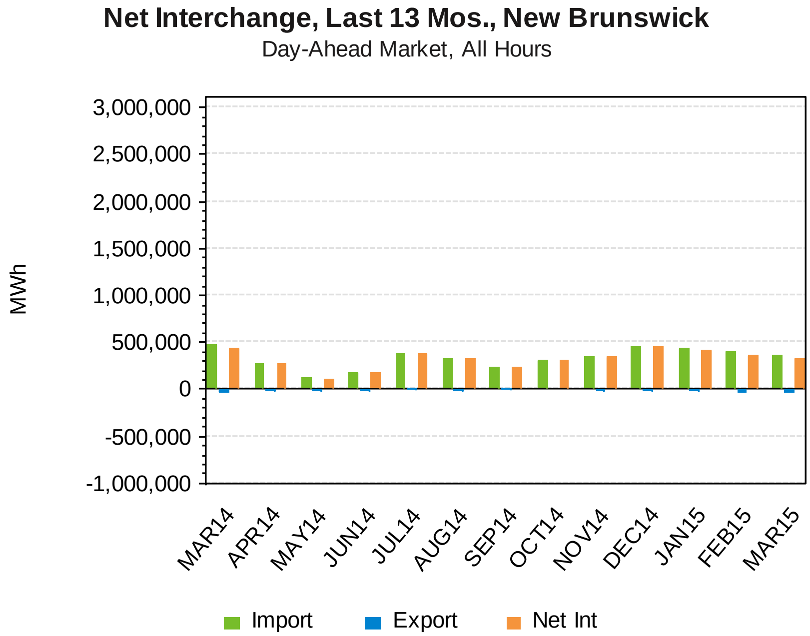


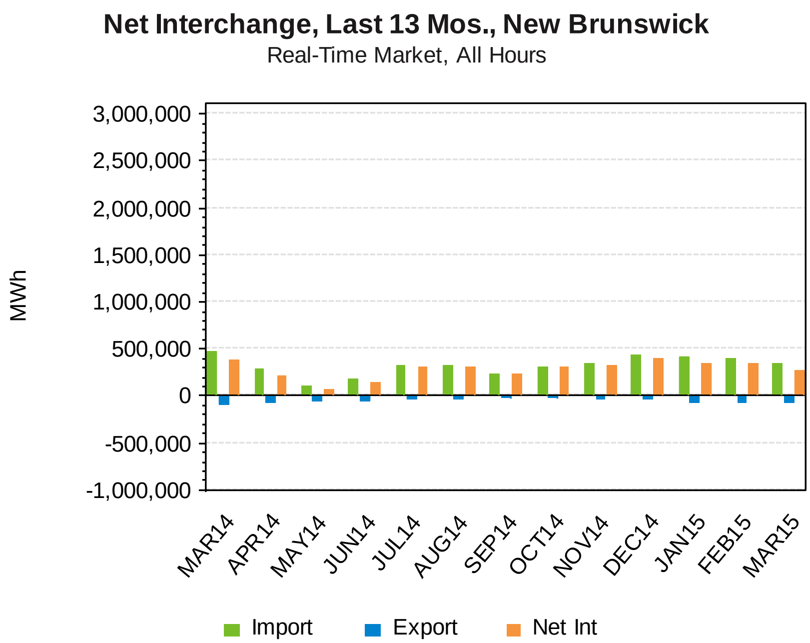


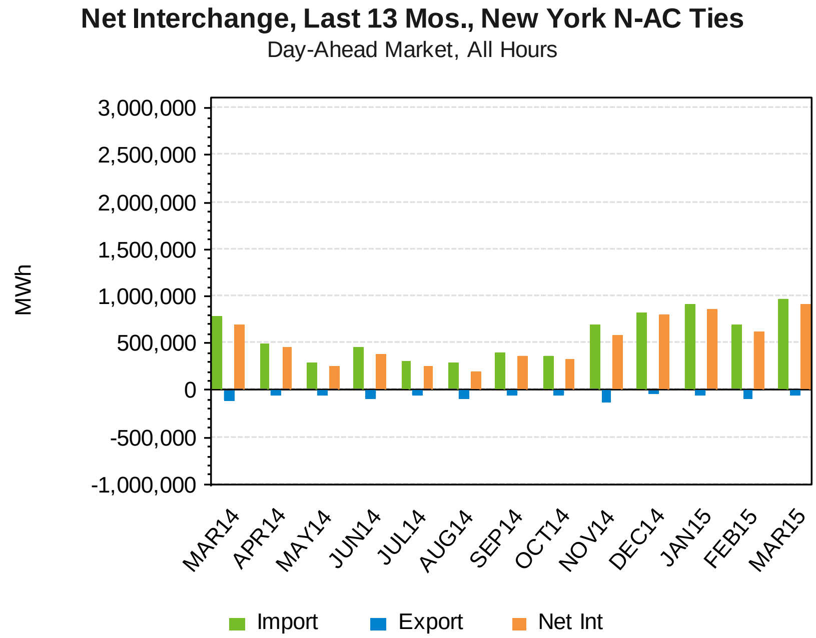

Net Interchange, Last 13 Mos., New England Control Area
Real-Time Market, All Hours
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MAR14
APR14
MAY14
JUN14
JUL14
AUG14
SEP14
OCT14
NOV14
DEC14
JAN15
FEB15
MAR15
Import
Export
Net Int

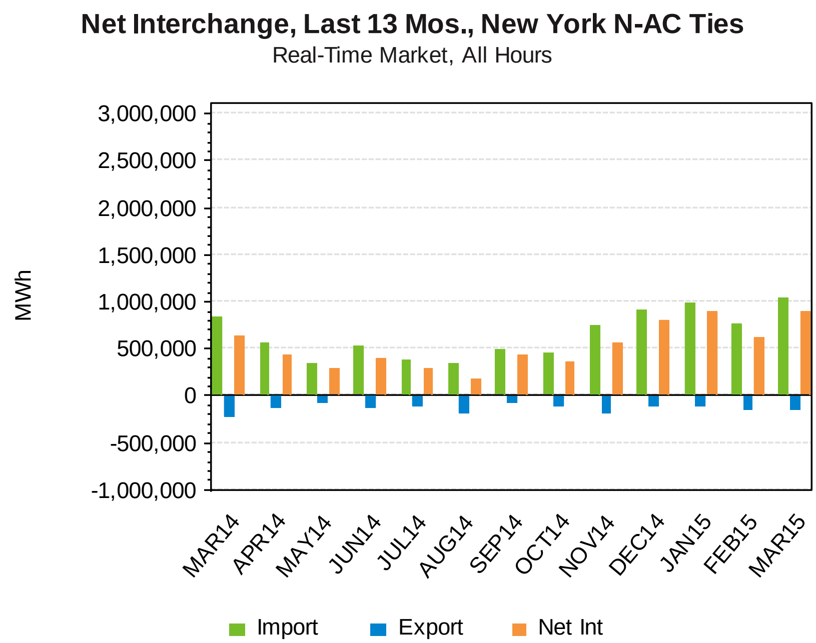

Net Interchange, Last 13 Mos., New England Control Area
Real-Time Market, On-Peak Hours
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MAR14
APR14
MAY14
JUN14
JUL14
AUG14
SEP14
OCT14
NOV14
DEC14
JAN15
FEB15
MAR15
Import
Export
Net Int

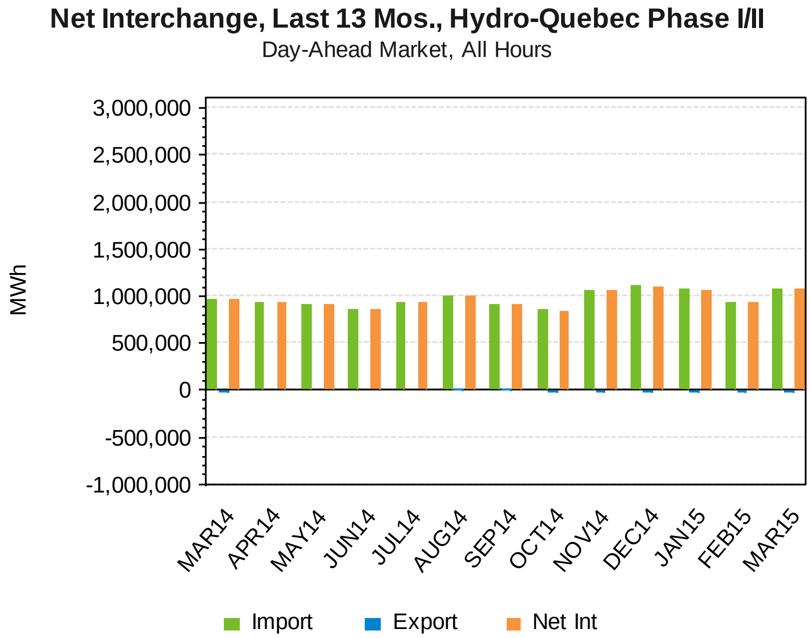
5.3 Net Interchange Summary by Interface, Last 13 Months

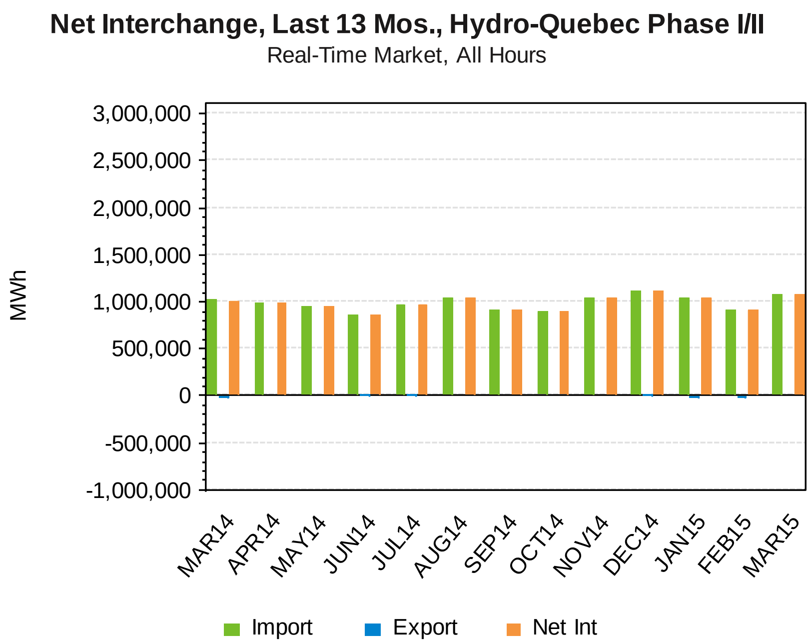


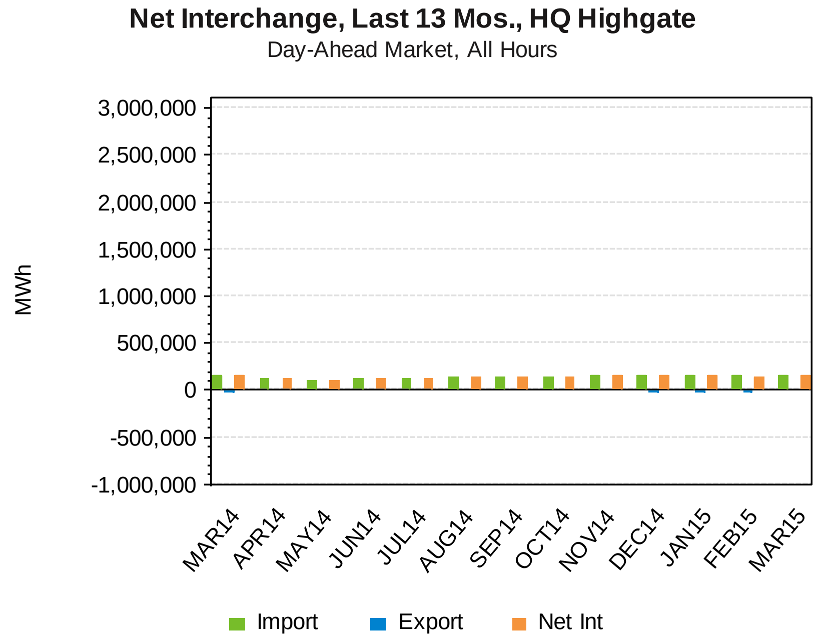


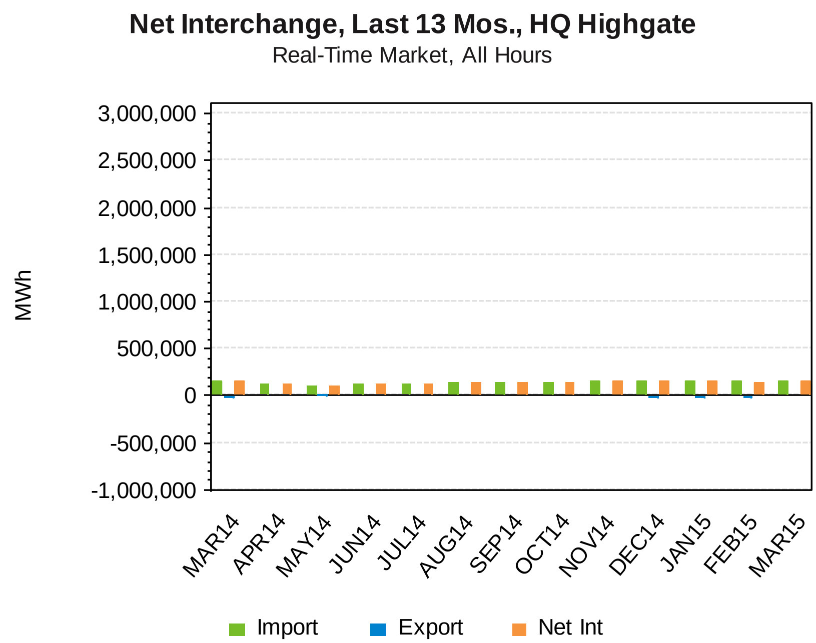

Net Interchange, Last 13 Mos., New York N-AC Ties
Day-Ahead Market, All Hours
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MAR14
APR14
MAY14
JUN14
JUL14
AUG14
SEP14
OCT14
NOV14
DEC14
JAN15
FEB15
MAR15
Import
Export
Net Int

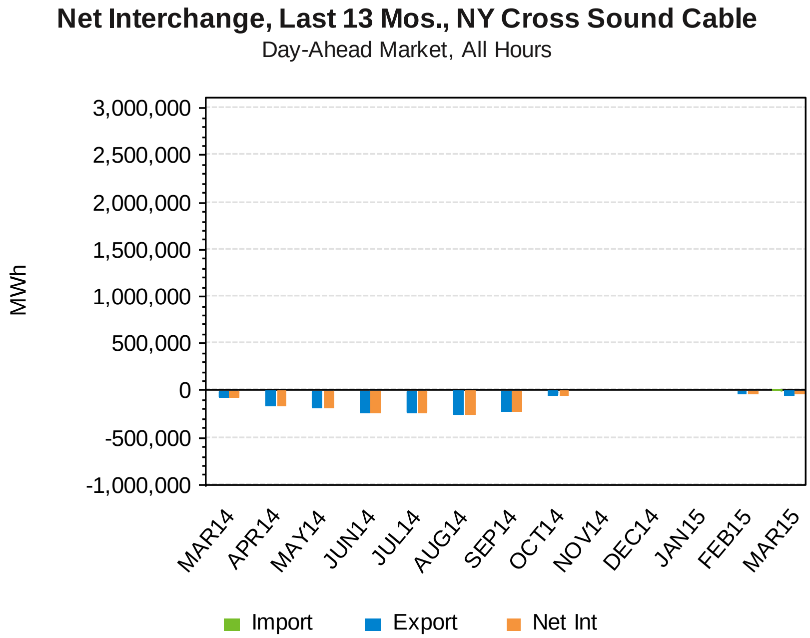

Net Interchange, Last 13 Mos., New York N-AC Ties
Real-Time Market, All Hours
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MAR14
APR14
MAY14
JUN14
JUL14
AUG14
SEP14
OCT14
NOV14
DEC14
JAN15
FEB15
MAR15
Import
Export
Net Int

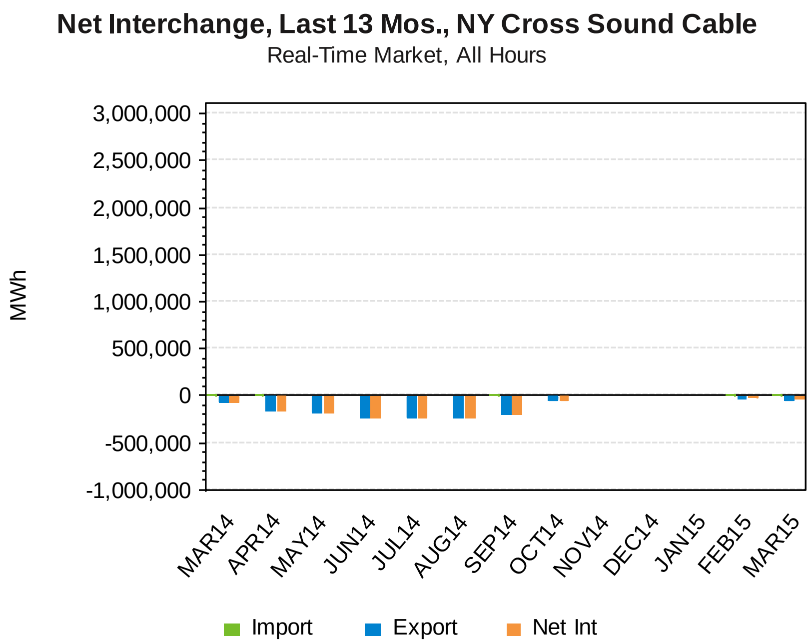

Net Interchange, Last 13 Mos., Hydro-Quebec Phase I/II
Day-Ahead Market, All Hours
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MAR14
APR14
MAY14
JUN14
JUL14
AUG14
SEP14
OCT14
NOV14
DEC14
JAN15
FEB15
MAR15
Import
Export
Net Int


Net Interchange, Last 13 Mos., Hydro-Quebec Phase I/II
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
MAR14
APR14
MAY14
JUN14
JUL14
AUG14
SEP14
OCT14
NOV14
DEC14
JAN15
FEB15
MAR15
Import
Export
Net Int


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
MAR14
APR14
MAY14
JUN14
JUL14
AUG14
SEP14
OCT14
NOV14
DEC14
JAN15
FEB15
MAR15
Import
Export
Net Int

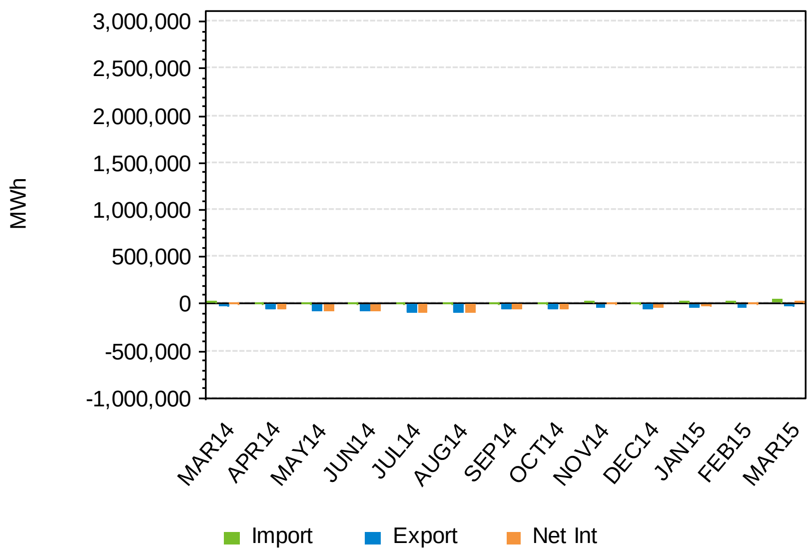

Net Interchange, Last 13 Mos., HQ Highgate
Real-Time Market, All Hours
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MAR14
APR14
MAY14
JUN14
JUL14
AUG14
SEP14
OCT14
NOV14
DEC14
JAN15
FEB15
MAR15
Import
Export
Net Int


Net Interchange, Last 13 Mos., NY Cross Sound Cable
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
MAR14
APR14
MAY14
JUN14
JUL14
AUG14
SEP14
OCT14
NOV14
DEC14
JAN15
FEB15
MAR15
Import
Export
Net Int


Net Interchange, Last 13 Mos., NY Cross Sound Cable
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
MAR14
APR14
MAY14
JUN14
JUL14
AUG14
SEP14
OCT14
NOV14
DEC14
JAN15
FEB15
MAR15
Import
Export
Net Int

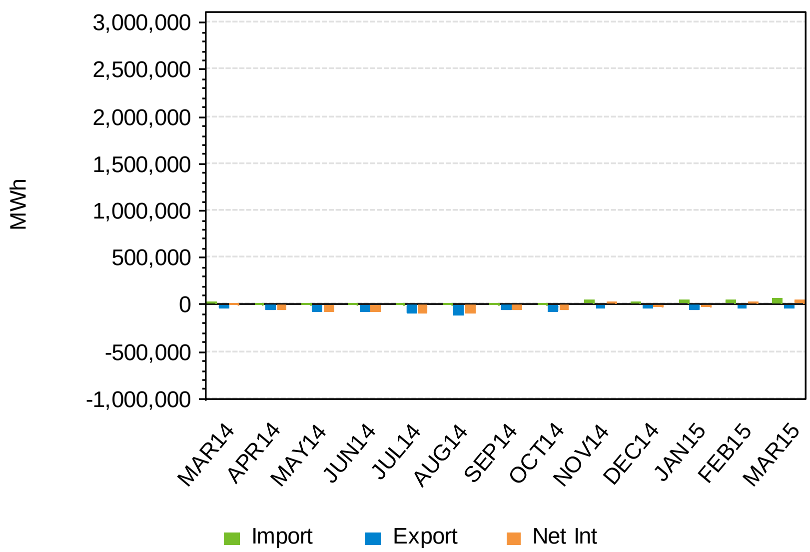
Net Interchange, Last 13 Mos., Northport-Norwalk Cable

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 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, March 2015

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	6,620	40,545	$2,569,838	2,818	18,676	$458,289
Buy	On	7,087	42,193	$2,916,830	3,102	19,483	$678,864
Buy	Buy Total	13,707	82,739	$5,486,668	5,920	38,159	$1,137,153
Sell	Off	4,526	8,132	$1,072,508	166	415	-$94,099
Sell	On	3,478	6,261	$1,441,687	254	376	-$93,383
Sell	Sell Total	8,004	14,393	$2,514,195	420	791	-$187,482
Grand Total	Grand Total	21,711	97,132	$8,000,863	6,340	38,950	$949,670

6.1.2 Number of Auction Participants, March 2015

Auction Period	Monthly or Long-Term	No. of Bidders
Mar 2015	MO	35

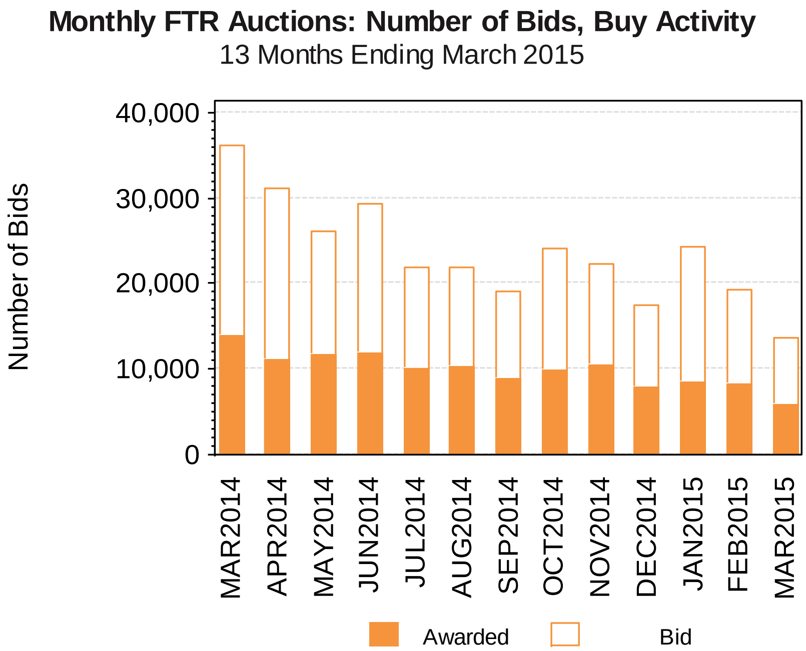
6.1.3 Monthly FTR Auction Results, Last 13 Months

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
MAR 2014	Buy	36,168	213,771	$1,556,725	13,844	56,380	$1,061,545
MAR 2014	Sell	10,633	19,741	$11,649,581	314	1,012	$38,524
MAR 2014	Tot	46,801	233,513	$13,206,306	14,158	57,392	$1,100,069
APR 2014	Buy	31,176	208,832	$2,229,922	11,028	48,663	$981,324
APR 2014	Sell	8,364	16,450	$8,801,843	471	1,439	-$43,018
APR 2014	Tot	39,540	225,282	$11,031,765	11,499	50,102	$938,305
MAY 2014	Buy	26,074	104,097	$1,256,257	11,623	37,803	$843,517
MAY 2014	Sell	4,045	10,808	$4,938,699	214	1,110	-$37,462

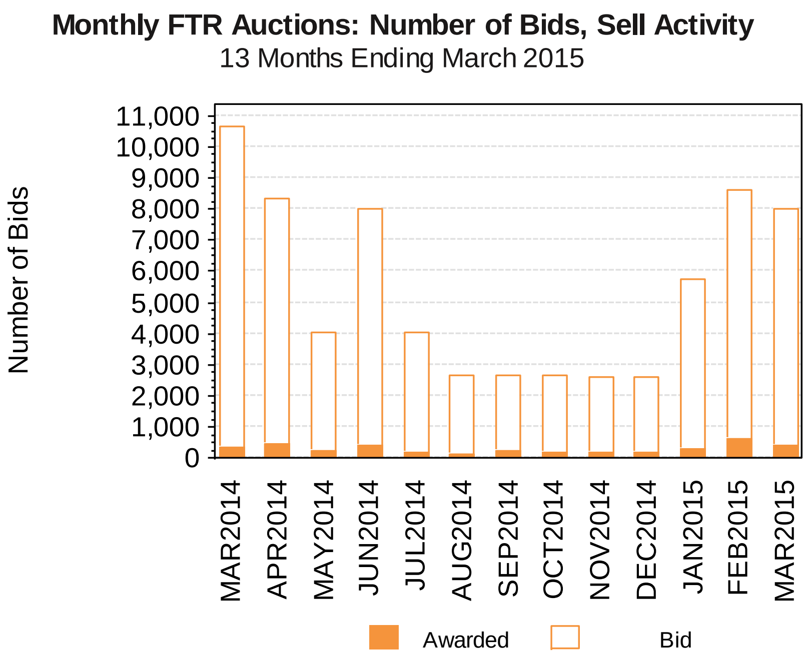
Auction Month	Bids to Buy or Offers to Sell	No. of Bids or Offers	Bid or Offered MW-Mos.	Bid or Offered Dollars	No. of Awards	Awarded MW-Mos.	Awarded Dollars
MAY 2014	Tot	30,119	114,905	$6,194,957	11,837	38,913	$806,055
JUN 2014	Buy	29,414	137,535	$2,128,457	11,788	44,695	$926,982
JUN 2014	Sell	8,032	15,058	$5,805,574	375	1,146	-$38,976
JUN 2014	Tot	37,446	152,593	$7,934,031	12,163	45,841	$888,006
JUL 2014	Buy	21,904	117,538	$2,033,681	10,017	46,262	$800,435
JUL 2014	Sell	4,035	10,656	$6,117,024	173	934	-$10,355
JUL 2014	Tot	25,939	128,194	$8,150,705	10,190	47,197	$790,080
AUG 2014	Buy	21,926	118,474	$2,772,628	10,317	46,888	$707,115
AUG 2014	Sell	2,642	8,002	$4,998,797	129	666	-$2,658
AUG 2014	Tot	24,568	126,476	$7,771,425	10,446	47,553	$704,457
SEP 2014	Buy	19,031	103,585	$3,568,041	8,878	35,259	$836,319
SEP 2014	Sell	2,630	8,038	$4,251,738	213	921	-$141,488
SEP 2014	Tot	21,661	111,622	$7,819,780	9,091	36,180	$694,832
OCT 2014	Buy	24,149	117,230	$3,465,038	9,801	40,854	$811,820
OCT 2014	Sell	2,631	8,053	$4,493,595	158	942	-$16,650
OCT 2014	Tot	26,780	125,282	$7,958,633	9,959	41,796	$795,170
NOV 2014	Buy	22,362	107,363	$3,727,035	10,508	43,353	$762,294
NOV 2014	Sell	2,623	7,962	$5,179,905	148	992	-$50,141
NOV 2014	Tot	24,985	115,325	$8,906,939	10,656	44,345	$712,153
DEC 2014	Buy	17,420	104,104	$6,609,853	7,917	41,381	$1,067,697
DEC 2014	Sell	2,610	8,048	$5,884,632	192	1,276	-$28,225
DEC 2014	Tot	20,030	112,151	$12,494,484	8,109	42,658	$1,039,472
JAN 2015	Buy	24,298	107,259	$5,026,171	8,451	40,478	$1,077,749
JAN 2015	Sell	5,730	12,109	$3,708,788	280	608	-$91,414
JAN 2015	Tot	30,028	119,368	$8,734,959	8,731	41,085	$986,334
FEB 2015	Buy	19,316	107,144	$4,270,459	8,162	42,310	$860,822
FEB 2015	Sell	8,615	13,924	$3,160,446	616	908	-$107,383
FEB 2015	Tot	27,931	121,068	$7,430,906	8,778	43,218	$753,438
MAR 2015	Buy	13,707	82,739	$5,486,668	5,920	38,159	$1,137,153
MAR 2015	Sell	8,004	14,393	$2,514,195	420	791	-$187,482
MAR 2015	Tot	21,711	97,132	$8,000,863	6,340	38,950	$949,670

6.2 Monthly FTR Auction Results, Last 13 Months

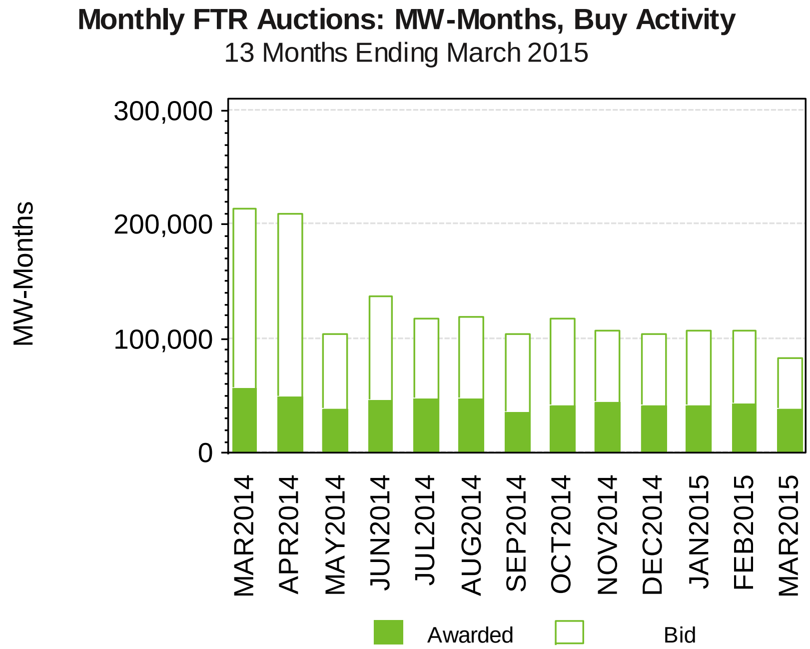
The next series of graphs show summaries of FTR Auction activity over the last 13 months, including bids to buy monthly FTRs and offers to sell long-term FTRs into each monthly auction.

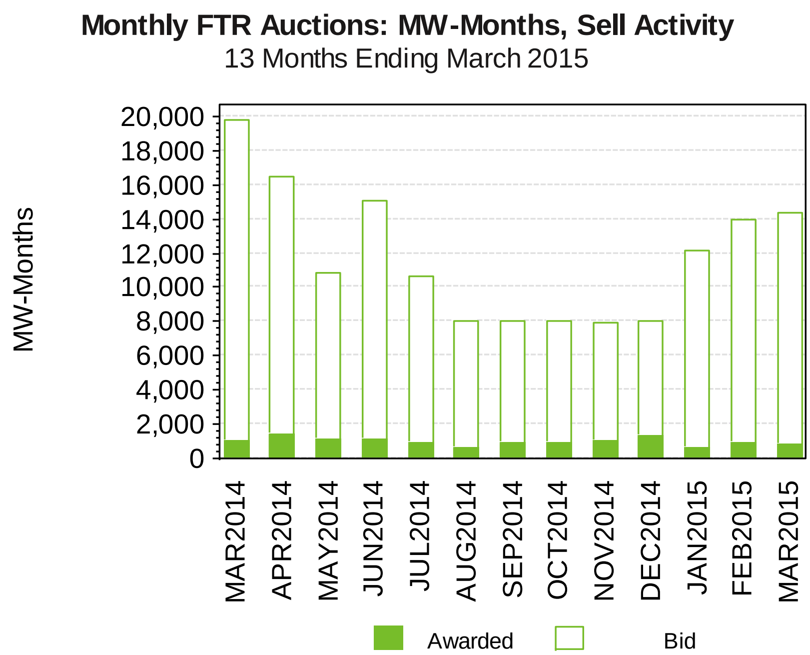


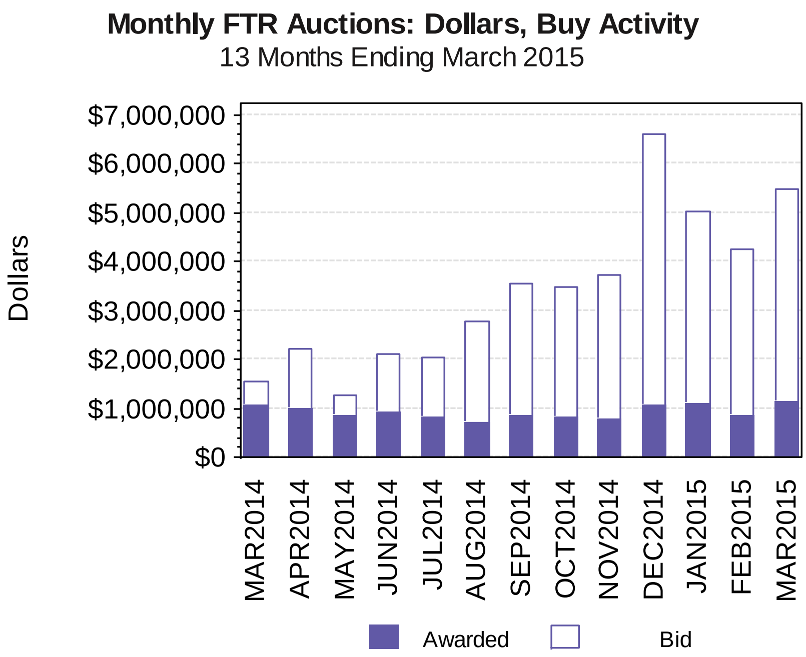
Monthly FTR Auctions: Number of Bids, Buy Activity
13 Months Ending March 2015
40,000
30,000
20,000
10,000
0
Number of Bids
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
Awarded
Bid

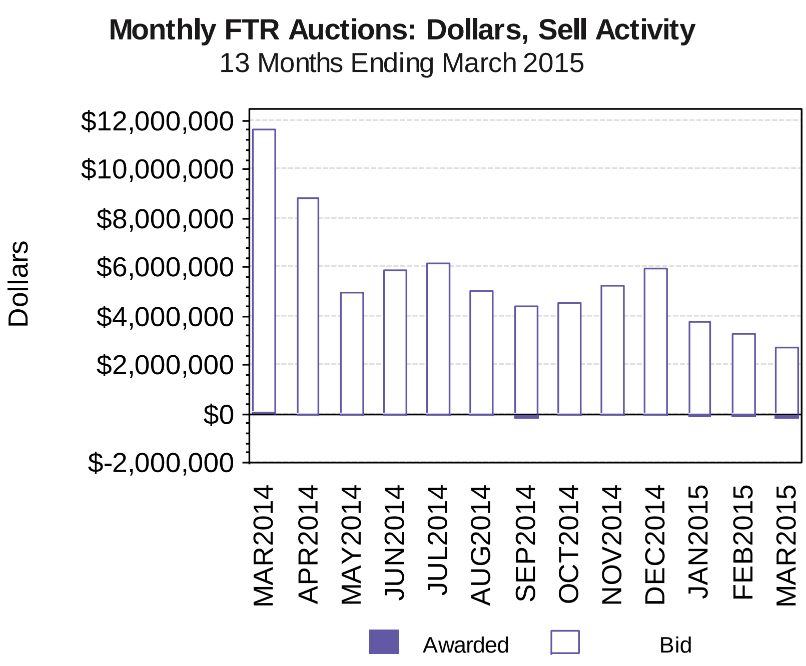


Monthly FTR Auctions: Number of Bids, Sell Activity
13 Months Ending March 2015
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Number of Bids
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
Awarded
Bid


Monthly FTR Auctions: MW-Months, Buy Activity
13 Months Ending March 2015
MW-Months
300,000
200,000
100,000
0
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
Awarded
Bid

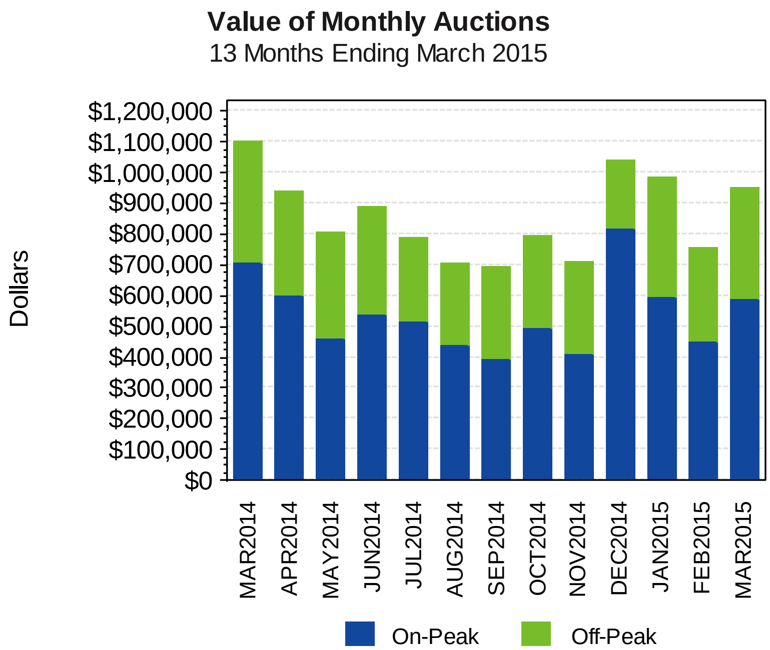

Monthly FTR Auctions: MW-Months, Sell Activity
13 Months Ending March 2015
MW-Months
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
Awarded
Bid

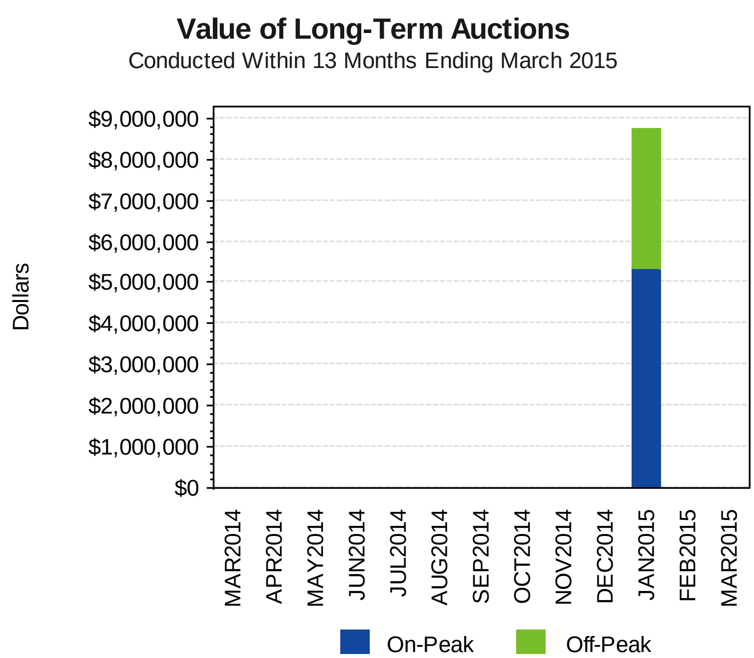

Monthly FTR Auctions: Dollars, Buy Activity
13 Months Ending March 2015
Dollars
$7,000,000
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000
$0
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
Awarded
Bid

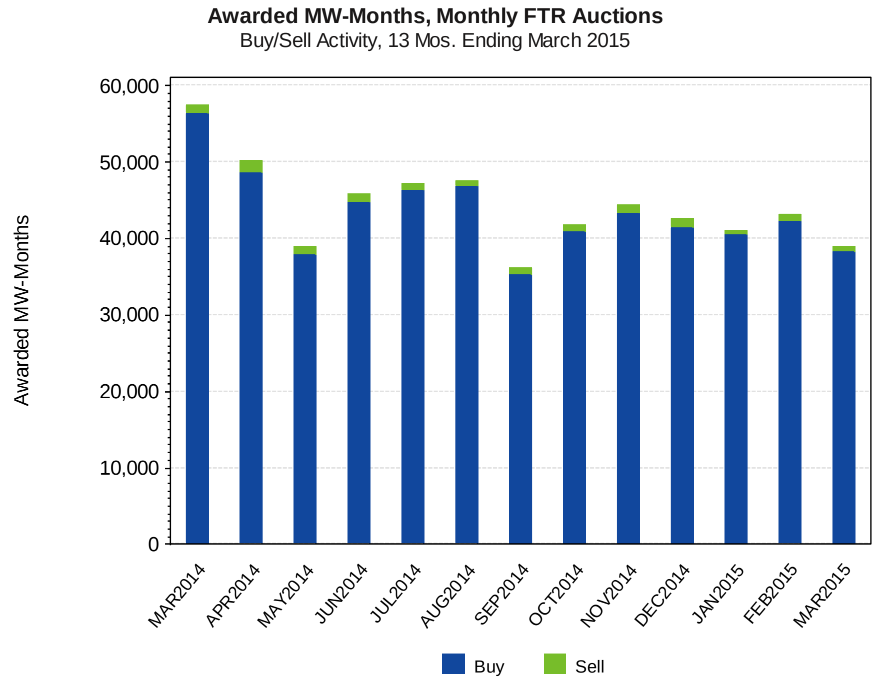

Monthly FTR Auctions: Dollars, Sell Activity
13 Months Ending March 2015
Dollars
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$0
$-2,000,000
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
Awarded
Bid

6.3 Auction Value, Last 13 Months

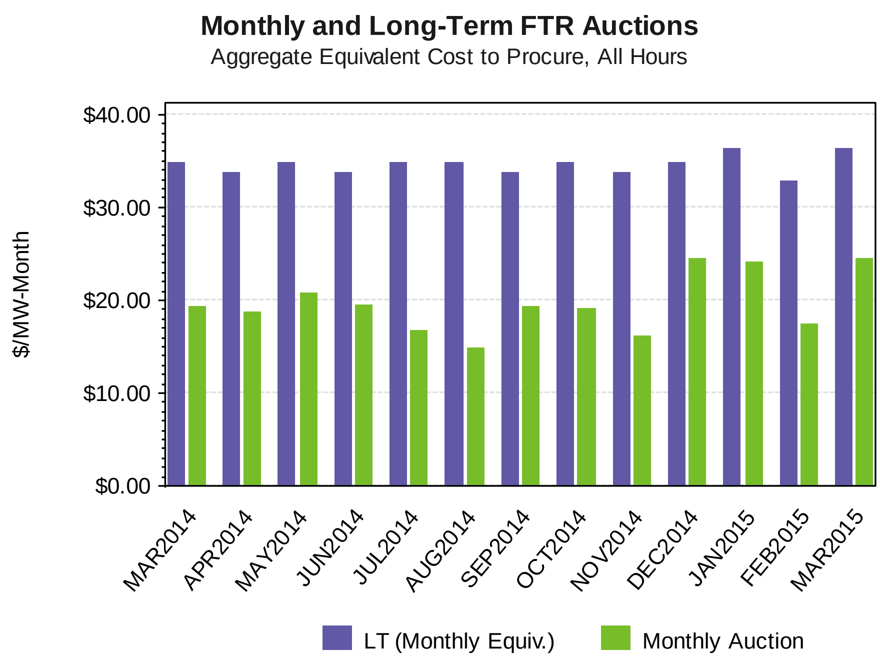
The next series of graphs show summaries of FTR Auction value and on/off-peak activity over the last 13 months.



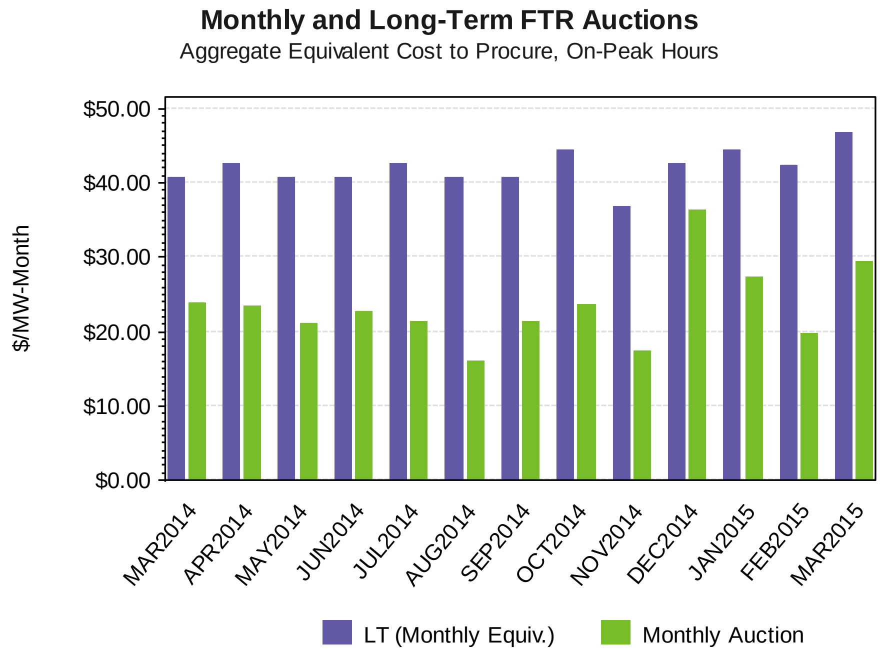


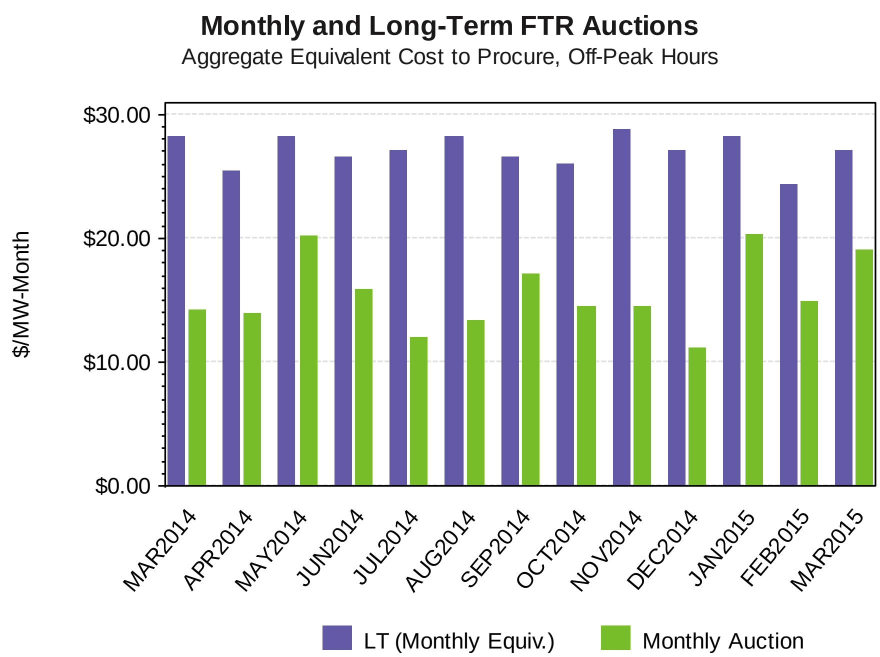


Awarded MW-Months, Monthly FTR Auctions
Buy/Sell Activity, 13 Mos. Ending March 2015
Awarded MW-Months
60,000
50,000
40,000
30,000
20,000
10,000
0
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
Buy
Sell



Monthly and Long-Term FTR Auctions
Aggregate Equivalent Cost to Procure, All Hours
$/MW-Month
$40.00
$30.00
$20.00
$10.00
$0.00
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
LT (Monthly Equiv.)
Monthly Auction


Monthly and Long-Term FTR Auctions
Aggregate Equivalent Cost to Procure, On-Peak Hours
$/MW-Month
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
LT (Monthly Equiv.)
Monthly Auction


Monthly and Long-Term FTR Auctions
Aggregate Equivalent Cost to Procure, Off-Peak Hours
$/MW-Month
$30.00
$20.00
$10.00
$0.00
MAR2014
APR2014
MAY2014
JUN2014
JUL2014
AUG2014
SEP2014
OCT2014
NOV2014
DEC2014
JAN2015
FEB2015
MAR2015
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.

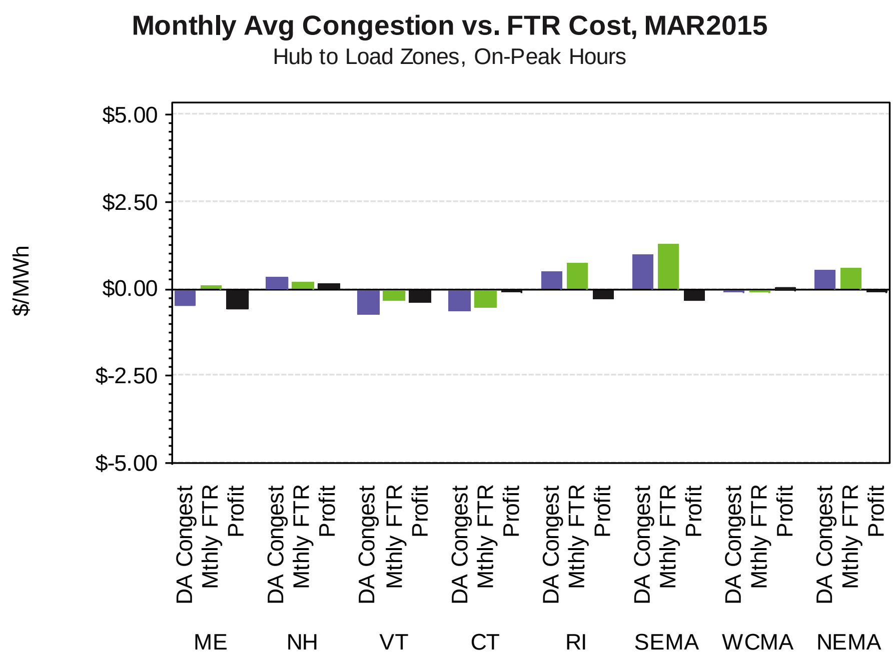
7. Effectiveness of FTRs

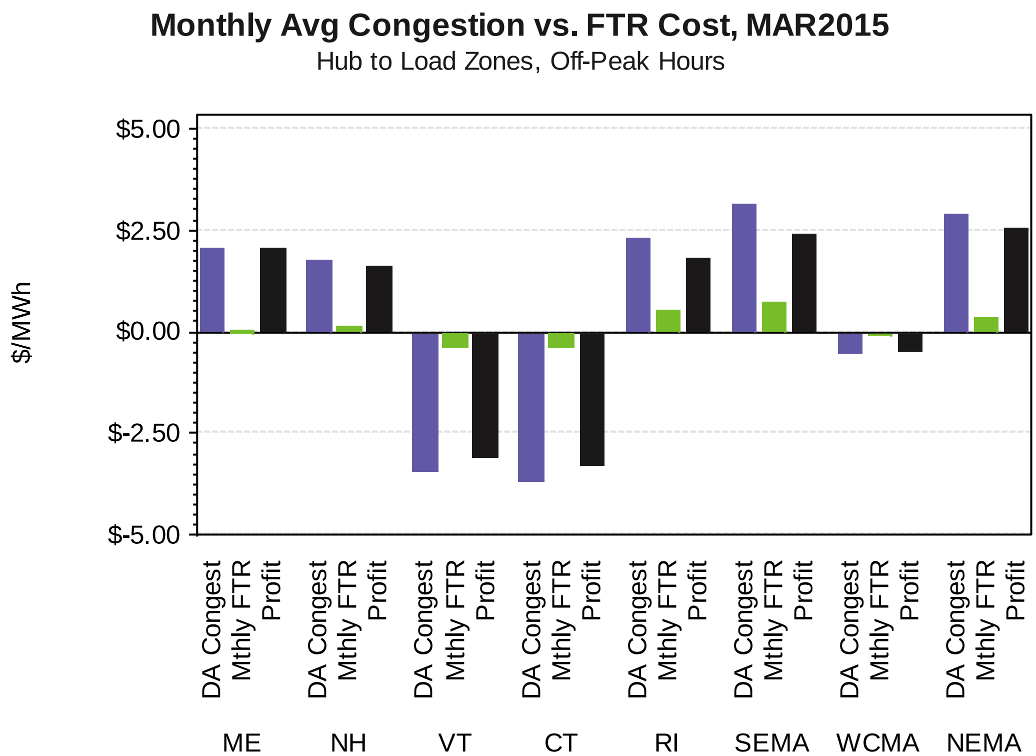
7.1 FTRs as a Congestion Hedging Instrument

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 March 2015, 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	Mar-14	$0.81	$0.50	$0.31
ME	Apr-14	-$0.17	$0.58	-$0.75
ME	May-14	-$0.02	$1.00	-$1.02
ME	Jun-14	-$0.04	$0.46	-$0.50
ME	Jul-14	-$0.25	-$0.04	-$0.21
ME	Aug-14	-$0.05	$0.10	-$0.15
ME	Sep-14	-$0.07	$0.05	-$0.12
ME	Oct-14	-$0.49	$0.07	-$0.56
ME	Nov-14	$0.14	$0.16	-$0.02
ME	Dec-14	-$0.50	$0.09	-$0.59
ME	Jan-15	-$0.11	$0.75	-$0.87
ME	Feb-15	-$0.36	$0.38	-$0.74
ME	Mar-15	-$0.49	$0.08	-$0.57

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
NH	Mar-14	-$0.03	$0.14	-$0.17
NH	Apr-14	-$0.05	$0.03	-$0.08
NH	May-14	$0.00	-$0.03	$0.03
NH	Jun-14	-$0.01	-$0.07	$0.06
NH	Jul-14	-$0.01	-$0.05	$0.04
NH	Aug-14	-$0.02	-$0.02	$0.01
NH	Sep-14	$0.00	$0.04	-$0.03
NH	Oct-14	-$0.04	-$0.04	$0.00
NH	Nov-14	$0.36	-$0.02	$0.38
NH	Dec-14	-$0.02	$0.17	-$0.19
NH	Jan-15	-$0.02	$0.57	-$0.59
NH	Feb-15	-$0.10	$0.35	-$0.46
NH	Mar-15	$0.30	$0.20	$0.10

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
VT	Mar-14	-$0.33	-$0.49	$0.16
VT	Apr-14	-$0.04	-$0.19	$0.15
VT	May-14	-$0.01	$0.01	-$0.01
VT	Jun-14	-$0.03	-$0.05	$0.01
VT	Jul-14	-$0.03	-$0.05	$0.02
VT	Aug-14	-$0.07	-$0.01	-$0.05
VT	Sep-14	-$0.01	$0.03	-$0.05
VT	Oct-14	-$0.11	-$0.01	-$0.10
VT	Nov-14	-$0.51	-$0.03	-$0.48
VT	Dec-14	-$0.06	-$0.55	$0.48
VT	Jan-15	-$0.17	-$1.24	$1.08
VT	Feb-15	-$0.04	-$0.34	$0.30
VT	Mar-15	-$0.71	-$0.34	-$0.37

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
CT	Mar-14	-$0.70	-$0.54	-$0.17
CT	Apr-14	$0.43	-$0.22	$0.64
CT	May-14	$0.00	$0.06	-$0.06
CT	Jun-14	$0.01	-$0.03	$0.04
CT	Jul-14	$0.24	$0.09	$0.15
CT	Aug-14	$0.00	$0.04	-$0.04
CT	Sep-14	$0.05	$0.01	$0.04
CT	Oct-14	$0.28	$0.15	$0.13
CT	Nov-14	-$0.68	$0.06	-$0.74
CT	Dec-14	-$0.08	-$0.39	$0.31
CT	Jan-15	$0.00	-$1.07	$1.07
CT	Feb-15	$0.03	-$0.66	$0.69
CT	Mar-15	-$0.60	-$0.52	-$0.08

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
RI	Mar-14	$2.01	$0.72	$1.29
RI	Apr-14	-$0.13	$1.03	-$1.17
RI	May-14	$0.12	$0.48	-$0.36
RI	Jun-14	-$0.02	$0.38	-$0.39
RI	Jul-14	$0.00	$0.28	-$0.27
RI	Aug-14	$0.05	$0.29	-$0.23
RI	Sep-14	$0.94	$0.43	$0.51
RI	Oct-14	$0.45	$1.09	-$0.64
RI	Nov-14	$0.17	$0.41	-$0.24
RI	Dec-14	$0.58	$0.48	$0.10
RI	Jan-15	$0.01	$1.27	-$1.26
RI	Feb-15	$0.10	$0.94	-$0.84
RI	Mar-15	$0.47	$0.73	-$0.26

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
SEMA	Mar-14	$0.86	$0.43	$0.43
SEMA	Apr-14	-$0.03	$0.28	-$0.32
SEMA	May-14	$0.02	$0.12	-$0.10
SEMA	Jun-14	-$0.01	$0.10	-$0.10
SEMA	Jul-14	$0.00	$0.05	-$0.05
SEMA	Aug-14	$0.01	$0.05	-$0.05
SEMA	Sep-14	$0.20	$0.25	-$0.05
SEMA	Oct-14	$0.13	$0.26	-$0.12
SEMA	Nov-14	$0.79	$0.10	$0.69
SEMA	Dec-14	$0.19	$0.44	-$0.25
SEMA	Jan-15	$0.01	$1.20	-$1.19
SEMA	Feb-15	$0.24	$0.79	-$0.56
SEMA	Mar-15	$0.94	$1.25	-$0.31

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
WCMA	Mar-14	-$0.36	-$0.08	-$0.28
WCMA	Apr-14	-$0.02	$0.00	-$0.02
WCMA	May-14	$0.00	$0.01	-$0.01
WCMA	Jun-14	$0.00	$0.00	$0.00
WCMA	Jul-14	$0.02	$0.03	-$0.01
WCMA	Aug-14	$0.00	$0.03	-$0.02
WCMA	Sep-14	-$0.01	$0.02	-$0.04
WCMA	Oct-14	$0.00	$0.02	-$0.02
WCMA	Nov-14	-$0.06	$0.00	-$0.06
WCMA	Dec-14	-$0.04	-$0.06	$0.02
WCMA	Jan-15	$0.00	-$0.15	$0.15
WCMA	Feb-15	-$0.01	-$0.10	$0.08
WCMA	Mar-15	-$0.08	-$0.09	$0.01

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
NEMA	Mar-14	$0.46	$0.54	-$0.08
NEMA	Apr-14	-$0.01	$1.03	-$1.04
NEMA	May-14	$0.00	$0.23	-$0.23
NEMA	Jun-14	$0.01	$1.28	-$1.27
NEMA	Jul-14	$0.99	$1.94	-$0.95
NEMA	Aug-14	$0.06	$0.98	-$0.92
NEMA	Sep-14	$0.03	$1.03	-$1.00
NEMA	Oct-14	$0.92	$0.68	$0.23
NEMA	Nov-14	$0.62	$0.23	$0.38
NEMA	Dec-14	$0.09	$1.35	-$1.26
NEMA	Jan-15	$0.19	$1.42	-$1.23
NEMA	Feb-15	$0.00	$0.91	-$0.91
NEMA	Mar-15	$0.51	$0.57	-$0.06

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	NEMA Contracts	Load Share	Total ARR Allocation	IARR Allocation	Total Auction Distribution
Mar-14	-$2,703,670	$123,945	$2,431,098	$2,555,043	$148,627	$2,703,670
Apr-14	-$2,490,177	$116,083	$2,224,532	$2,340,616	$149,562	$2,490,177
May-14	-$2,409,656	$76,895	$2,213,293	$2,290,189	$119,468	$2,409,656
Jun-14	-$2,439,878	$107,285	$2,176,815	$2,284,100	$155,778	$2,439,878
Jul-14	-$2,393,681	$110,080	$2,147,411	$2,257,492	$136,190	$2,393,681
Aug-14	-$2,308,058	$96,662	$2,068,024	$2,164,686	$143,372	$2,308,058
Sep-14	-$2,246,704	$78,153	$2,033,859	$2,112,012	$134,691	$2,246,704
Oct-14	-$2,398,771	$89,733	$2,175,481	$2,265,214	$133,557	$2,398,771
Nov-14	-$2,264,025	$77,198	$2,057,662	$2,134,860	$129,165	$2,264,025
Dec-14	-$2,643,073	$107,284	$2,351,379	$2,458,663	$184,410	$2,643,073
Jan-15	-$2,444,423	$165,417	$2,106,829	$2,272,246	$172,177	$2,444,423
Feb-15	-$2,070,422	$137,701	$1,785,635	$1,923,336	$147,086	$2,070,422
Mar-15	-$2,514,028	$143,192	$2,176,677	$2,319,870	$194,158	$2,514,028

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**
Mar-14	$176,289	$62,265	$10,584	$121,643	$296,390	$188,485	$102,413	$611,509
Apr-14	$153,443	$28,801	$11,231	$126,645	$284,714	$129,567	$75,530	$619,039
May-14	$240,865	$16,001	$11,696	$156,466	$270,854	$119,508	$61,735	$467,207
Jun-14	$117,875	$14,681	$9,361	$119,219	$228,408	$107,017	$60,688	$703,069
Jul-14	$67,393	$14,908	$9,028	$140,745	$222,590	$99,863	$62,427	$772,064
Aug-14	$88,319	$16,739	$9,950	$126,396	$226,791	$101,072	$60,979	$668,141
Sep-14	$78,161	$26,225	$13,306	$138,432	$227,029	$151,373	$65,375	$528,007
Oct-14	$87,107	$17,459	$11,526	$170,223	$292,659	$135,139	$61,857	$587,134
Nov-14	$146,850	$29,500	$15,993	$161,572	$244,357	$120,042	$70,980	$473,992
Dec-14	$168,868	$64,940	$16,023	$173,628	$249,971	$161,924	$105,836	$714,559
Jan-15	$116,140	$101,849	$3,874	$59,778	$147,463	$208,512	$84,423	$648,141
Feb-15	$99,110	$86,768	$11,552	$57,138	$127,831	$166,625	$65,371	$537,665
Mar-15	$105,223	$90,752	$15,018	$109,133	$146,789	$261,148	$86,707	$603,665

Off Peak								
Month	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Mar-14	$121,357	$34,163	$1,990	$33,091	$265,951	$138,212	$46,351	$344,349
Apr-14	$108,358	$17,286	$2,553	$32,266	$279,534	$117,747	$32,283	$321,616
May-14	$205,255	$8,422	$2,631	$30,435	$303,244	$114,591	$22,813	$258,465
Jun-14	$135,824	$7,631	$2,240	$30,614	$248,729	$100,496	$24,120	$374,126
Jul-14	$45,684	$6,073	$2,208	$37,741	$250,739	$96,799	$22,806	$406,426
Aug-14	$55,015	$7,370	$2,880	$38,226	$257,807	$99,791	$23,301	$381,910
Sep-14	$61,353	$14,986	$5,887	$53,824	$253,704	$106,459	$31,023	$356,870
Oct-14	$62,679	$8,045	$3,640	$56,658	$296,594	$117,621	$23,320	$333,552
Nov-14	$92,134	$23,647	$4,823	$45,279	$262,677	$116,911	$35,072	$291,031
Dec-14	$70,408	$23,104	$2,298	$32,411	$233,978	$110,667	$33,913	$296,135
Jan-15	$77,240	$69,646	$1,649	$21,037	$108,819	$138,797	$50,671	$434,206
Feb-15	$58,419	$54,310	$2,563	$25,003	$102,217	$121,651	$42,815	$364,297
Mar-15	$62,923	$56,295	$6,612	$53,440	$106,431	$162,404	$51,794	$401,535

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 can be found in Section 7 and the Incremental Auction Revenue Rights 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 fifteenth Forward Reserve Market Auction, covering the Winter 2014-2015 Procurement Period (October-May) cleared on August 28, 2014. 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 March 2015, the threshold price ranged from $56.35 to $246.65 and averaged $86.87.

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)[5]. 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, March 2015

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	$9,295,659	$9,235,139	-$90,771	$0	$9,144,368	98%
SYSTEM	TMOR	$4,535,498	$4,251,823	-$425,507	$0	$3,826,316	84%
SYSTEM	TOTAL	$13,831,157	$13,486,962	-$516,278	$0	$12,970,684	94%
ROS	TMNSR	$5,463,105	$5,431,842	-$46,888	$0	$5,384,954	99%
ROS	TMOR	$2,139,639	$2,064,987	-$111,976	$0	$1,953,011	91%
ROS	TOTAL	$7,602,744	$7,496,829	-$158,864	$0	$7,337,965	97%
SWCT	TMNSR	$0	$0	$0	$0	$0	n/a
SWCT	TMOR	$1,113,775	$1,035,350	-$117,637	$0	$917,713	82%
SWCT	TOTAL	$1,113,775	$1,035,350	-$117,637	$0	$917,713	82%
CT	TMNSR	$3,832,554	$3,803,297	-$43,883	$0	$3,759,414	98%
CT	TMOR	$1,282,084	$1,151,486	-$195,894	$0	$955,592	75%
CT	TOTAL	$5,114,638	$4,954,783	-$239,777	$0	$4,715,006	92%
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

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

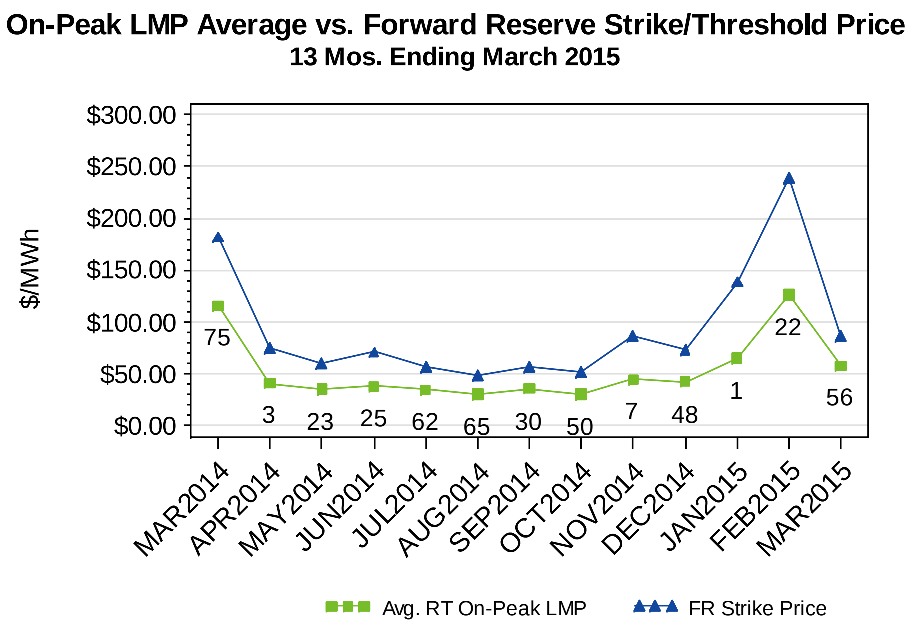
The ISO allocates Forward Reserve Credits, net of Forward Reserve Failure-to-Reserve Penalties and Forward Reserve Failure-to-Activate Penalties, to each Load Zone. The Forward Reserve charge allocation method changed on June 1, 2011. Under the new Forward Reserve Cost Allocation, the Forward Reserves 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, March 2015

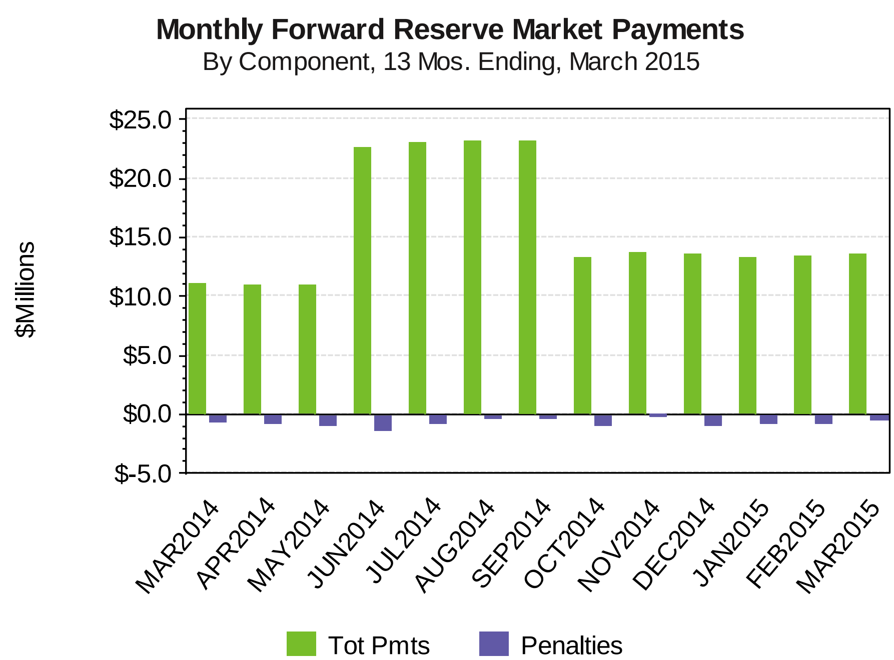
Load Zone	FRM Charge
ME	$1,181,989
NH	$1,209,989
VT	$599,282
CT	$3,106,073
RI	$803,963
SEMA	$1,479,945
WCMA	$1,759,408
NEMA	$2,524,241
ALL	$12,664,891

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 124 separate hours. On a reserve zone basis, non-zero prices occurred thus: CT-124 hours; NEMABSTN-124 hours; ROS-124 hours; SWCT-124 hours. The total compensation paid to assets providing real-time reserves during March 2015, and reductions in those payments for the Forward Reserve Obligation Charge are shown in the following table:

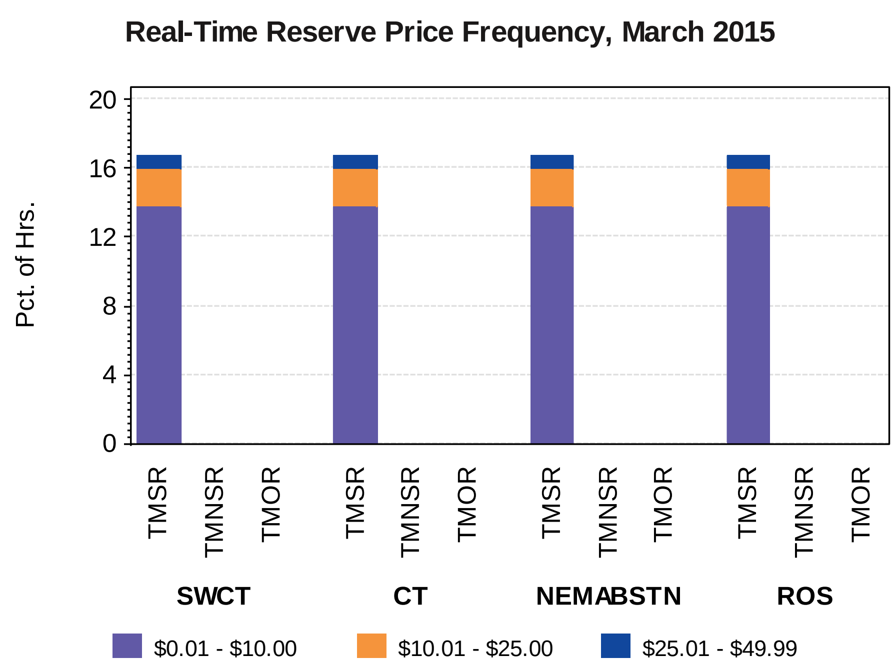
Reserve Zone	Real-Time Reserve Credits	Fwd Reserve Obligation Charges	Net Real-Time Reserve Payments
SYSTEM	$393,653	$0	$393,653
ROS	$381,721	$0	$381,721
SWCT	$8,134	$0	$8,134
CT	$520	$0	$520
NEMABSTN	$3,277	$0	$3,277

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	$36,473
ME	TMNSR	$0
ME	TMOR	$0
ME	ALL	$36,473
NH	TMSR	$36,478
NH	TMNSR	$0
NH	TMOR	$0
NH	ALL	$36,478
VT	TMSR	$18,042
VT	TMNSR	$0
VT	TMOR	$0
VT	ALL	$18,042
CT	TMSR	$98,482
CT	TMNSR	$0
CT	TMOR	$0
CT	ALL	$98,482
RI	TMSR	$24,847
RI	TMNSR	$0

Load Zone	Reserve Product	RT Reserve Charge
RI	TMOR	$0
RI	ALL	$24,847
SEMA	TMSR	$46,140
SEMA	TMNSR	$0
SEMA	TMOR	$0
SEMA	ALL	$46,140
WCMA	TMSR	$54,524
WCMA	TMNSR	$0
WCMA	TMOR	$0
WCMA	ALL	$54,524
NEMA	TMSR	$78,666
NEMA	TMNSR	$0
NEMA	TMOR	$0
NEMA	ALL	$78,666

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.

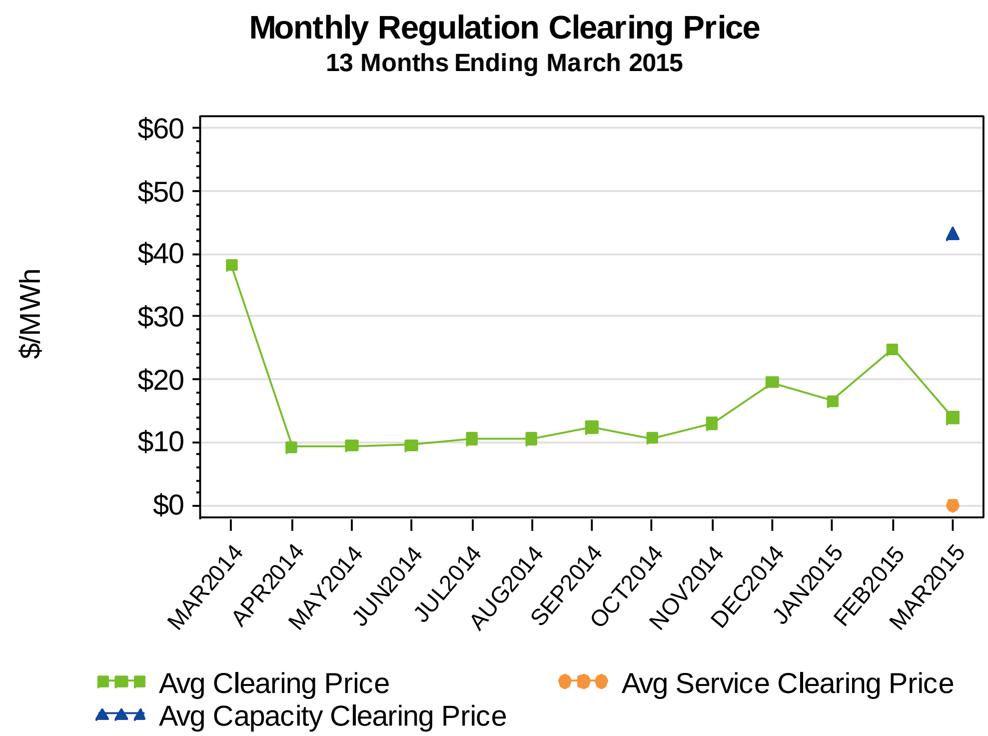
The business rules and procedures for forward and real-time reserve can be found in the ISO's Manual 28 –Market Rule 1 Accounting located here.

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. Beginning on March 31, 2015, the Regulation Clearing price was split into two components, a Regulation Service Clearing price and a Regulation Capacity Clearing price. The market change was implemented to enable the participation of alternative resources in this market, and to improve compensation for resources providing regulation services in New England. The exhibit below shows the 30-day average of the expiring, singular clearing price, and the average of the two new component prices on March 31.

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



10.2 Monthly Regulation Market Clearing Price Statistics, Last 13 Months

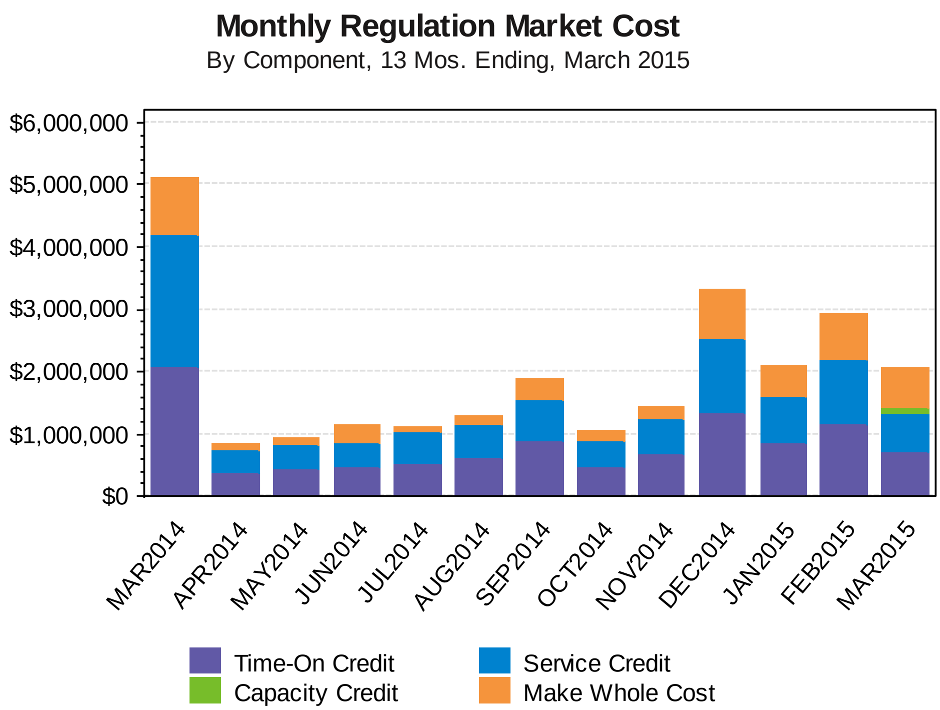
Month	On-Peak Clearing Price Statistics				Off-Peak Clearing Price Statistics			
	Mean	Max	Min	StdDev	Mean	Max	Min	StdDev
Mar-14	$31.51	$406.13	$3.84	$36.72	$43.85	$416.61	$3.76	$54.66
Apr-14	$9.57	$97.32	$2.37	$6.48	$9.03	$54.05	$1.34	$4.66
May-14	$9.28	$27.29	$4.27	$3.65	$9.66	$80.04	$4.08	$5.01
Jun-14	$9.52	$82.43	$1.36	$6.49	$9.58	$33.89	$3.62	$4.70
Jul-14	$11.72	$209.76	$0.00	$15.91	$9.60	$97.19	$4.77	$6.00
Aug-14	$12.75	$258.29	$5.05	$20.20	$8.86	$85.50	$5.28	$4.84
Sep-14	$13.11	$281.11	$1.15	$22.98	$11.76	$304.65	$2.55	$19.41
Oct-14	$12.06	$158.02	$3.27	$13.42	$9.38	$51.15	$4.08	$4.12
Nov-14	$11.20	$64.07	$3.52	$6.32	$14.32	$184.87	$4.11	$15.05
Dec-14	$17.32	$579.91	$3.86	$45.95	$21.51	$170.60	$2.47	$27.66
Jan-15	$15.54	$381.13	$4.09	$22.36	$17.39	$136.99	$4.08	$16.32

Month	On-Peak Clearing Price Statistics				Off-Peak Clearing Price Statistics			
	Mean	Max	Min	StdDev	Mean	Max	Min	StdDev
Feb-15	$20.39	$222.55	$4.00	$20.09	$28.80	$214.05	$4.19	$27.23
Mar-15	$11.46	$66.82	$3.67	$8.51	$16.13	$167.32	$2.86	$17.25

Month	On-Peak Service Clearing Price Statistics[6]				Off-Peak Service Clearing Price Statistics			
	Mean	Max	Min	StdDev	Mean	Max	Min	StdDev
Mar-15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Month	On-Peak Capacity Clearing Price Statistics[6]				Off-Peak Capacity Clearing Price Statistics			
	Mean	Max	Min	StdDev	Mean	Max	Min	StdDev
Mar-15	$25.95	$38.94	$11.63	$10.67	$77.63	$103.66	$47.98	$16.66

10.3 Components of Monthly Regulation Market Cost, Last 13 Months



[6] The average shown is for March 31, 2015 – the one day that the new construct was in effect during March.

Month	Time on Regulation Cost	Regulation Service Cost	Regulation Capacity Cost	Regulation Make Whole Cost	Total Regulation Cost
Mar-14	$2,063,986	$2,111,287	$0	$933,748	$5,109,021
Apr-14	$378,182	$335,829	$0	$122,752	$836,764
May-14	$410,282	$389,681	$0	$122,189	$922,152
Jun-14	$453,526	$392,651	$0	$286,533	$1,132,711
Jul-14	$519,996	$485,231	$0	$115,938	$1,121,165
Aug-14	$589,500	$552,390	$0	$149,791	$1,291,680
Sep-14	$881,456	$629,990	$0	$364,440	$1,875,886
Oct-14	$458,573	$422,192	$0	$160,886	$1,041,651
Nov-14	$653,848	$570,958	$0	$225,358	$1,450,163
Dec-14	$1,306,281	$1,193,306	$0	$818,725	$3,318,313
Jan-15	$831,261	$755,841	$0	$507,157	$2,094,259
Feb-15	$1,125,593	$1,066,715	$0	$742,775	$2,935,082
Mar-15	$677,989	$635,039	$87,609	$654,288	$2,054,925

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 March 2015

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
Mar-14	$18,531,368	-$1,131,246	-$27,360,822	-$1,385,618	$1,197,949	$389	$8,829,453	$1,318,525	$10,147,978
Apr-14	$6,379,049	-$490,077	-$9,260,234	-$187,793	$602,894	$0	$2,881,185	$74,976	$2,956,160
May-14	$4,651,854	$168,674	-$6,508,952	-$353,230	$517,959	$0	$1,857,098	-$333,403	$1,523,695
Jun-14	$5,888,834	-$192,838	-$8,491,304	-$182,531	$729,014	$0	$2,602,470	-$353,646	$2,248,824
Jul-14	$7,783,949	$56,517	-$11,351,650	$1,967	-$150,084	$0	$3,567,701	$91,600	$3,659,301
Aug-14	$5,279,961	$23,843	-$7,660,346	-$159,119	$275,806	$0	$2,380,386	-$140,530	$2,239,855
Sep-14	$5,308,812	$312,475	-$7,681,422	-$346,327	-$28,275	$0	$2,372,609	$62,127	$2,434,736
Oct-14	$4,669,220	$212,085	-$6,498,290	-$168,288	-$28,459	$0	$1,829,070	-$15,337	$1,813,733
Nov-14	$7,082,927	$378,564	-$10,080,608	-$261,353	-$183,382	$0	$2,997,681	$66,172	$3,063,853
Dec-14	$7,518,915	$1,197,657	-$11,030,579	-$685,973	-$551,721	-$946,159	$3,511,664	$986,197	$4,497,861
Jan-15	$13,875,915	$100,499	-$20,183,921	-$342,108	-$1,467,924	$0	$6,308,006	$1,709,533	$8,017,539
Feb-15	$22,956,432	-$3,788,381	-$33,705,474	-$731,062	-$1,655,564	$0	$10,749,042	$6,175,007	$16,924,049
Mar-15	$12,121,748	-$1,529,021	-$16,153,401	-$270,823	-$983,977	$24,355	$4,031,654	$2,759,466	$6,791,120

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 5, the 2014-2015 commitment period, with prorated amounts and change from the FCA for each resource type.

2014-2015 Forward Capacity Auction

Resource Type	FCA CSO MW	Prorated CSO MW	Proration Change MW
Demand	3,350	3,399	-191
Generator	31,439	29,165	-2,274
Import	2,011	1,831	-180
Total	37,040	34,395	-2,645

In the event where proration is rejected for reliability reasons, the resource will be still be paid consistent with the proration method. The difference between the resources actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected, will result in an FCM Proration Denial for Reliability Charge (PDFR) to cover this cost. This charge shall be allocated to Regional Network Load within the affected Reliability Region.

FCM Proration Denial for Reliability Charge

Month	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Jun-14	$0	$0	$0	$0	$0	$0	$0	$987,345
Jul-14	$0	$0	$0	$0	$0	$0	$0	$987,345
Aug-14	$0	$0	$0	$0	$0	$0	$0	$987,345
Sep-14	$0	$0	$0	$0	$0	$0	$0	$987,345
Oct-14	$0	$0	$0	$0	$0	$0	$0	$988,468
Nov-14	$0	$0	$0	$0	$0	$0	$0	$988,468
Dec-14	$0	$0	$0	$0	$0	$0	$0	$984,410
Jan-15	$0	$0	$0	$0	$0	$0	$0	$984,410
Feb-15	$0	$0	$0	$0	$0	$0	$0	$984,410
Mar-15	$0	$0	$0	$0	$0	$0	$0	$984,410

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 March 2015

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	-250.69	-130.70	0.00	0.00	0.00	-381.39
Rest-of-Pool	Generator	0.00	-221.64	-11.00	-10.66	-604.25	-10.22	-857.76
Rest-of-Pool	Import	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total	0.00	-472.33	-141.70	-10.66	-604.25	-10.22	-1,239.15

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 March 2015

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	2,621	$8,957,730	-381.39	-$1,156,282	2,240.02	$7,801,449
Rest-of-Pool	Generator	30,873	$85,633,524	-857.25	-$2,457,789	30,015.75	$83,175,736
Rest-of-Pool	Import	725	$2,284,185	0.00	$0	725.28	$2,284,185
	Total	34,220	$96,875,440	-1,238.64	-$3,614,070	32,981.06	$93,261,370

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
Mar-14	Rest-of-Pool	$76,915,997	$41,700	$124,424	$77,082,122
Mar-14	Maine	$9,678,117	-$41,700	-$124,424	$9,511,993
Apr-14	Rest-of-Pool	$76,861,369	$35,140	$15,390	$76,911,899
Apr-14	Maine	$9,676,920	-$35,140	-$15,390	$9,626,389
May-14	Rest-of-Pool	$76,861,369	$35,140	$195,214	$77,091,723
May-14	Maine	$9,676,920	-$35,140	-$195,214	$9,446,565

Month	Capacity Zone	FCA Credit	Bilateral Dollars	Reconfiguration Auction Dollars	Supply Credit
Jun-14	Rest-of-Pool	$93,392,258	$0	-$773,582	$92,618,676
Jul-14	Rest-of-Pool	$93,380,677	$0	-$773,582	$92,607,094
Aug-14	Rest-of-Pool	$93,380,677	$0	-$773,582	$92,607,094
Sep-14	Rest-of-Pool	$93,380,677	$0	-$773,582	$92,607,094
Oct-14	Rest-of-Pool	$93,757,644	$0	-$767,700	$92,989,944
Nov-14	Rest-of-Pool	$93,751,080	$0	-$767,700	$92,983,380
Dec-14	Rest-of-Pool	$94,029,070	$0	-$767,700	$93,261,370
Jan-15	Rest-of-Pool	$94,029,070	$0	-$767,700	$93,261,370
Feb-15	Rest-of-Pool	$94,029,070	$0	-$767,700	$93,261,370
Mar-15	Rest-of-Pool	$94,029,070	$0	-$767,700	$93,261,370

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)
Mar-14	Rest-of-Pool	29,603	$77,082,122	-$2,722,784	$0	$74,359,338	$0	$74,359,338
Mar-14	Maine	3,224	$9,511,993	-$122,568	$0	$9,389,424	$0	$9,389,424
Apr-14	Rest-of-Pool	29,378	$76,911,899	-$2,685,191	$0	$74,226,708	$0	$74,226,708
Apr-14	Maine	3,427	$9,626,389	-$130,009	$0	$9,496,380	$0	$9,496,380
May-14	Rest-of-Pool	29,583	$77,091,723	-$2,707,204	$0	$74,384,520	$0	$74,384,520
May-14	Maine	3,223	$9,446,565	-$121,636	$0	$9,324,930	$0	$9,324,930
Jun-14	Rest-of-Pool	32,759	$92,618,676	-$2,938,667	$0	$89,680,008	$0	$89,680,008
Jul-14	Rest-of-Pool	32,755	$92,607,094	-$2,828,007	$0	$89,779,087	$0	$89,779,087
Aug-14	Rest-of-Pool	32,755	$92,607,094	-$1,273,419	$0	$91,333,676	$0	$91,333,676
Sep-14	Rest-of-Pool	32,755	$92,607,094	-$1,274,201	$0	$91,332,894	$0	$91,332,894
Oct-14	Rest-of-Pool	32,878	$92,989,944	-$1,311,029	$0	$91,678,914	$0	$91,678,914
Nov-14	Rest-of-Pool	32,876	$92,983,380	-$1,310,313	$0	$91,673,067	$0	$91,673,067
Dec-14	Rest-of-Pool	32,981	$93,261,370	-$1,064,892	$0	$92,196,478	$0	$92,196,478
Jan-15	Rest-of-Pool	32,981	$93,261,370	-$2,380,343	$0	$90,881,026	$0	$90,881,026
Feb-15	Rest-of-Pool	32,981	$93,261,370	-$2,548,451	$0	$90,712,918	$0	$90,712,918
Mar-15	Rest-of-Pool	32,981	$93,261,370	-$2,692,864	$0	$90,568,506	$0	$90,568,506

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
Mar-14	32,827	671	998	0	2,693	33,825	25,543	30,134	$2.779219	$83,604,456
Apr-14	32,806	371	998	0	2,693	33,804	25,543	30,113	$2.780316	$83,716,319
May-14	32,806	388	998	0	2,693	33,804	25,543	30,113	$2.779863	$83,585,779
Jun-14	32,759	414	996	0	3,166	33,755	26,911	29,593	$3.030468	$89,680,008
Jul-14	32,755	418	996	0	3,166	33,751	26,911	29,589	$3.034186	$89,779,087
Aug-14	32,755	418	996	0	3,166	33,751	26,911	29,589	$3.086725	$91,333,676
Sep-14	32,755	444	996	0	3,166	33,751	26,911	29,589	$3.086699	$91,332,894
Oct-14	32,878	454	996	0	3,166	33,874	26,911	29,712	$3.085591	$91,678,914
Nov-14	32,876	454	996	0	3,166	33,872	26,911	29,710	$3.085633	$91,673,067
Dec-14	32,981	454	996	0	3,166	33,977	26,911	29,815	$3.092281	$92,196,478
Jan-15	32,981	454	996	0	3,166	33,977	26,911	29,815	$3.048160	$90,881,026
Feb-15	32,981	454	996	0	3,166	33,977	26,911	29,815	$3.042522	$90,712,918
Mar-15	32,981	454	996	0	3,166	33,977	26,911	29,815	$3.037678	$90,568,506

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 $_{\text{pool}}$ - Excess RTEG MW $_{\text{pool}}$) * (-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
Mar-14	Rest-of-Pool	29,603	998	2,687	31,456	23,885	27,766	$2.761098	$76,665,711
Mar-14	Maine	3,224	0	6	2,369	1,658	2,368	$2.930788	$6,938,745
Apr-14	Rest-of-Pool	29,378	998	2,687	31,436	23,885	27,747	$2.779587	$77,124,481
Apr-14	Maine	3,427	0	6	2,367	1,658	2,366	$2.786003	$6,591,838
May-14	Rest-of-Pool	29,583	998	2,687	31,436	23,885	27,747	$2.764335	$76,701,285
May-14	Maine	3,223	0	6	2,367	1,658	2,366	$2.909692	$6,884,494
Jun-14	Rest-of-Pool	32,759	996	3,166	33,755	26,911	29,593	$3.030468	$89,680,008
Jul-14	Rest-of-Pool	32,755	996	3,166	33,751	26,911	29,589	$3.034186	$89,779,087
Aug-14	Rest-of-Pool	32,755	996	3,166	33,751	26,911	29,589	$3.086725	$91,333,676
Sep-14	Rest-of-Pool	32,755	996	3,166	33,751	26,911	29,589	$3.086699	$91,332,894
Oct-14	Rest-of-Pool	32,878	996	3,166	33,874	26,911	29,712	$3.085591	$91,678,914
Nov-14	Rest-of-Pool	32,876	996	3,166	33,872	26,911	29,710	$3.085633	$91,673,067
Dec-14	Rest-of-Pool	32,981	996	3,166	33,977	26,911	29,815	$3.092281	$92,196,478
Jan-15	Rest-of-Pool	32,981	996	3,166	33,977	26,911	29,815	$3.048160	$90,881,026
Feb-15	Rest-of-Pool	32,981	996	3,166	33,977	26,911	29,815	$3.042522	$90,712,918
Mar-15	Rest-of-Pool	32,981	996	3,166	33,977	26,911	29,815	$3.037678	$90,568,506

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
Mar-14	Maine	Rest-of-Pool	-$144,306.96	329.97	$59,394.60	-27,761.42	-$203,701.56
Apr-14	Maine	Rest-of-Pool	-$6,769.51	329.97	$59,394.60	-27,741.77	-$66,164.11
May-14	Maine	Rest-of-Pool	-$123,670.25	329.97	$59,394.60	-27,741.77	-$183,064.85

12.4 PER Adjustment

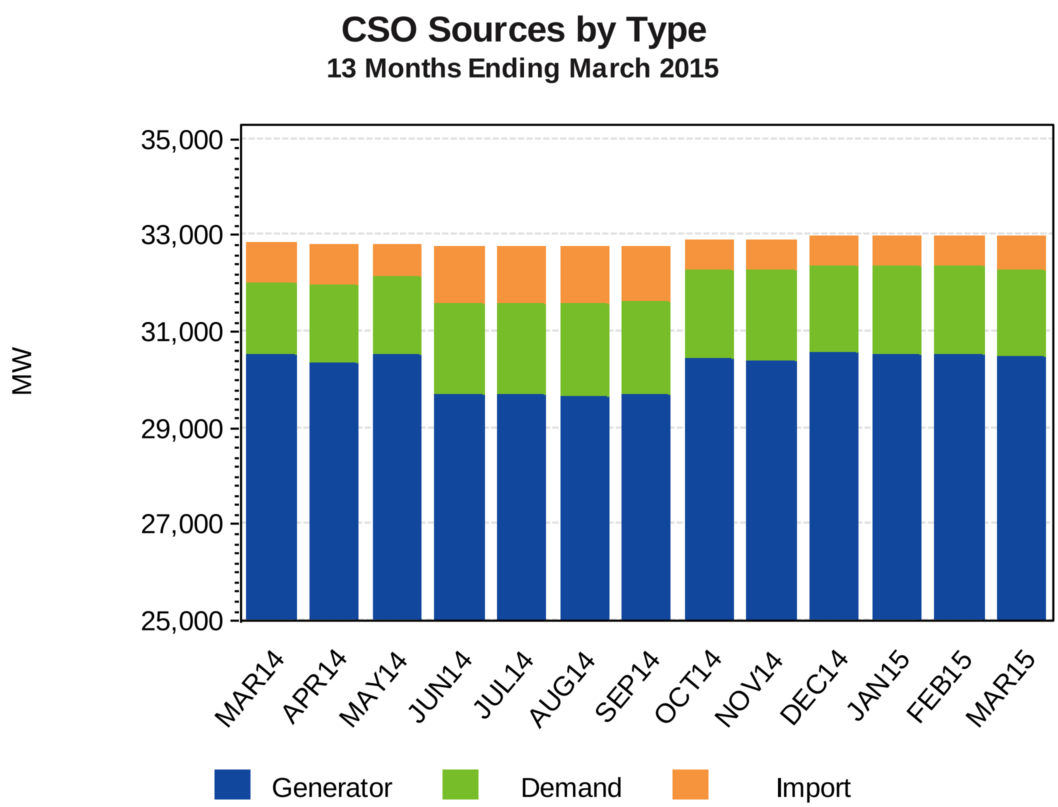
As stated above, PER is a payment adjustment made to reflect revenues earned by resources during high priced hours in the Energy markets. Generation and Import resources with a CSO are subject to PER adjustments (excluding self-supply CSO MWs). Demand resources are not subject to PER adjustments.

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
Mar-14	Maine	2,989	0.041	$122,568
Mar-14	Rest-of-Pool	25,687	0.106	$2,722,784
Apr-14	Maine	3,171	0.041	$130,009
Apr-14	Rest-of-Pool	25,332	0.106	$2,685,191
May-14	Maine	2,967	0.041	$121,636
May-14	Rest-of-Pool	25,540	0.106	$2,707,204
Jun-14	Rest-of-Pool	27,723	0.106	$2,938,667
Jul-14	Rest-of-Pool	27,726	0.102	$2,828,007
Aug-14	Rest-of-Pool	27,683	0.046	$1,273,419
Sep-14	Rest-of-Pool	27,700	0.046	$1,274,201
Oct-14	Rest-of-Pool	27,894	0.047	$1,311,029
Nov-14	Rest-of-Pool	27,879	0.047	$1,310,313
Dec-14	Rest-of-Pool	28,023	0.038	$1,064,892
Jan-15	Rest-of-Pool	28,004	0.085	$2,380,343
Feb-15	Rest-of-Pool	28,005	0.091	$2,548,451
Mar-15	Rest-of-Pool	28,051	0.096	$2,692,864

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
Mar-14	1,467	30,543	817	32,827
Apr-14	1,619	30,330	857	32,806
May-14	1,616	30,530	660	32,806
Jun-14	1,888	29,704	1,167	32,759
Jul-14	1,910	29,679	1,166	32,755
Aug-14	1,952	29,637	1,166	32,755
Sep-14	1,922	29,710	1,123	32,755
Oct-14	1,848	30,419	612	32,878
Nov-14	1,861	30,403	612	32,876
Dec-14	1,821	30,548	612	32,981
Jan-15	1,842	30,528	612	32,981
Feb-15	1,840	30,529	612	32,981
Mar-15	1,794	30,461	725	32,981

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
Mar-14	Rest-of-Pool	84	0	39	194	317
Mar-14	Maine	0	0	0	0	0
Apr-14	Rest-of-Pool	84	0	79	194	357
Apr-14	Maine	0	0	0	0	0
May-14	Rest-of-Pool	84	0	82	194	360
May-14	Maine	0	0	0	0	0
Jun-14	Rest-of-Pool	80	0	82	194	356
Jul-14	Rest-of-Pool	80	0	80	194	354
Aug-14	Rest-of-Pool	80	0	80	194	354
Sep-14	Rest-of-Pool	80	0	80	194	354
Oct-14	Rest-of-Pool	80	0	39	194	313
Nov-14	Rest-of-Pool	80	0	39	194	313
Dec-14	Rest-of-Pool	80	0	39	194	313
Jan-15	Rest-of-Pool	80	0	39	194	313
Feb-15	Rest-of-Pool	80	0	39	194	313
Mar-15	Rest-of-Pool	150	0	39	194	383

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
Mar-14	0	0.00	Generator	0	0	$0
Mar-14	0	0.00	Import	0	0	$0
Apr-14	0	0.00	Generator	0	0	$0
Apr-14	0	0.00	Import	0	0	$0
May-14	0	0.00	Generator	0	0	$0
May-14	0	0.00	Import	0	0	$0
Jun-14	0	0.00	Generator	0	0	$0

Month	Hours with Shortage Events	Total Duration of Shortage Events (Hours)	Resource Type	SAB MW (Sold)	SAB MW (purchased)	Shortage Event Penalty
Jun-14	0	0.00	Import	0	0	$0
Jul-14	0	0.00	Generator	0	0	$0
Jul-14	0	0.00	Import	0	0	$0
Aug-14	0	0.00	Generator	0	0	$0
Aug-14	0	0.00	Import	0	0	$0
Sep-14	0	0.00	Generator	0	0	$0
Sep-14	0	0.00	Import	0	0	$0
Oct-14	0	0.00	Generator	0	0	$0
Oct-14	0	0.00	Import	0	0	$0
Nov-14	0	0.00	Generator	0	0	$0
Nov-14	0	0.00	Import	0	0	$0
Dec-14	0	0.00	Generator	0	0	$0
Dec-14	0	0.00	Import	0	0	$0
Jan-15	0	0.00	Generator	0	0	$0
Jan-15	0	0.00	Import	0	0	$0
Feb-15	0	0.00	Generator	0	0	$0
Feb-15	0	0.00	Import	0	0	$0
Mar-15	0	0.00	Generator	0	0	$0
Mar-15	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 ($)	Performance Incentive ($)
Mar-14	ON_PEAK	0	807.75	1,437.46	-6.62	636.19	-$16,663	$31,672
Mar-14	REAL_TIME	0	206.13	222.66	-7.99	24.52	-$25,238	$936
Mar-14	REAL_TIME_EG	0	124.97	149.57	-0.94	25.54	-$2,060	$1,112
Mar-14	SEASONAL_PEAK	0	328.02	531.84	0.00	203.82	$0	$10,242
Apr-14	ON_PEAK	0	813.60	1,063.98	-6.62	256.78	-$16,775	$20,472
Apr-14	REAL_TIME	0	314.01	400.24	-4.20	90.44	-$11,382	$3,530
Apr-14	REAL_TIME_EG	0	163.32	187.48	-0.33	24.48	-$724	$1,756
Apr-14	SEASONAL_PEAK	0	328.02	366.01	0.00	37.99	$0	$3,124
May-14	ON_PEAK	0	814.20	1,063.86	-5.33	254.79	-$13,547	$18,514
May-14	REAL_TIME	0	309.97	397.69	-4.37	92.09	-$11,704	$2,993
May-14	REAL_TIME_EG	0	163.32	187.48	-0.33	24.48	-$724	$1,608
May-14	SEASONAL_PEAK	0	328.02	366.01	0.00	37.99	$0	$2,861
Jun-14	ON_PEAK	84	1,032.86	1,219.54	-10.70	197.38	-$30,731	$58,955
Jun-14	REAL_TIME	0	345.20	393.62	-20.44	68.86	-$57,990	$20,221
Jun-14	REAL_TIME_EG	0	162.28	181.47	-5.83	25.02	-$13,845	$5,875
Jun-14	SEASONAL_PEAK	0	347.18	409.21	0.00	62.03	$0	$17,516
Jul-14	ON_PEAK	88	1,036.33	1,234.30	-10.98	208.95	-$33,026	$119,978
Jul-14	REAL_TIME	0	358.87	381.76	-43.68	66.57	-$125,692	$37,606
Jul-14	REAL_TIME_EG	0	167.50	174.44	-19.53	26.48	-$46,371	$11,966
Jul-14	SEASONAL_PEAK	7	347.18	412.57	0.00	65.39	$0	$35,540
Aug-14	ON_PEAK	84	1,029.63	1,244.96	-3.13	218.46	-$8,965	$156,862
Aug-14	REAL_TIME	0	360.21	374.02	-40.16	53.97	-$116,014	$38,078
Aug-14	REAL_TIME_EG	0	205.41	175.50	-50.09	20.19	-$118,921	$11,389
Aug-14	SEASONAL_PEAK	0	357.18	412.57	0.00	55.39	$0	$37,571
Sep-14	ON_PEAK	0	1,034.87	1,234.25	-8.59	207.97	-$24,536	$104,998
Sep-14	REAL_TIME	0	331.64	382.17	-10.16	60.69	-$28,951	$29,681
Sep-14	REAL_TIME_EG	0	207.98	177.14	-50.33	19.48	-$119,474	$7,708
Sep-14	SEASONAL_PEAK	0	347.18	411.45	0.00	64.27	$0	$30,574
Oct-14	ON_PEAK	0	1,027.94	1,234.25	-2.96	209.12	-$8,442	$7,418
Oct-14	REAL_TIME	0	323.04	382.17	-1.10	57.12	-$3,193	$1,937
Oct-14	REAL_TIME_EG	0	149.48	177.14	-0.27	27.93	-$646	$777
Oct-14	SEASONAL_PEAK	0	347.18	411.45	0.00	64.27	$0	$2,149
Nov-14	ON_PEAK	0	1,027.55	1,234.25	-2.75	209.45	-$7,854	$17,673
Nov-14	REAL_TIME	0	347.62	400.06	-5.33	57.77	-$18,393	$4,689
Nov-14	REAL_TIME_EG	0	138.23	159.32	-1.14	22.24	-$2,697	$1,471
Nov-14	SEASONAL_PEAK	0	347.18	411.45	0.00	64.27	$0	$5,112

Month	DR Type	Performance Hours	CSO MW	Capacity Value (MW)	Negative Capacity Variance (MW)	Positive Capacity Variance (MW)	Performance Penalty ($)	Performance Incentive ($)
Dec-14	ON_PEAK	44	1,032.94	1,607.34	-13.00	587.40	-$37,228	$153,081
Dec-14	REAL_TIME	0	296.15	318.48	-43.01	65.34	-$123,285	$16,135
Dec-14	REAL_TIME_EG	0	145.22	128.92	-29.47	13.17	-$69,967	$2,620
Dec-14	SEASONAL_PEAK	4	347.18	592.22	0.00	245.04	$0	$58,643
Jan-15	ON_PEAK	42	1,033.04	1,647.27	-11.99	626.22	-$34,391	$222,026
Jan-15	REAL_TIME	0	282.64	321.99	-45.82	85.16	-$144,028	$28,024
Jan-15	REAL_TIME_EG	0	179.03	131.90	-60.14	13.01	-$142,772	$3,538
Jan-15	SEASONAL_PEAK	30	347.18	553.83	0.00	206.65	$0	$67,603
Feb-15	ON_PEAK	0	1,032.24	1,628.38	-9.77	605.91	-$27,947	$134,885
Feb-15	REAL_TIME	0	274.02	316.86	-0.09	42.93	-$243	$9,007
Feb-15	REAL_TIME_EG	0	186.59	130.41	-69.19	13.01	-$164,259	$2,219
Feb-15	SEASONAL_PEAK	0	347.18	573.03	0.00	225.84	$0	$46,337
Mar-15	ON_PEAK	0	1,040.29	1,627.72	-10.61	598.04	-$30,365	$40,208
Mar-15	REAL_TIME	0	280.69	320.26	-2.28	41.86	-$6,513	$2,668
Mar-15	REAL_TIME_EG	0	126.14	130.41	-8.74	13.01	-$20,742	$674
Mar-15	SEASONAL_PEAK	0	347.18	573.03	0.00	225.84	$0	$14,069

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.

Detailed information about charges to Network Load 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

Transitional Demand Response Settlement MW						Other Statistics	
Month	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
Mar-14	2,244	2,496	2,659	-25	389	16,534	0
Apr-14	404	562	599	-66	129	14,615	0
May-14	2,085	2,439	2,597	0	513	14,401	3
Jun-14	2,423	2,714	2,891	-56	412	16,705	105
Jul-14	2,661	2,619	2,789	-55	73	19,258	331
Aug-14	2,187	2,905	3,094	-125	782	17,723	48
Sep-14	2,451	3,033	3,230	-75	704	15,934	0
Oct-14	2,208	2,469	2,629	-65	357	14,627	0
Nov-14	1,648	1,919	2,044	0	397	15,143	0
Dec-14	1,912	2,546	2,711	0	799	16,394	329
Jan-15	2,845	3,770	4,015	0	1,171	17,416	50
Feb-15	2,472	2,688	2,863	0	390	17,601	0
Mar-15	1,362	1,608	1,712	0	351	16,160	0

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
Mar-14	$378,457	$75,420	$0	$453,877	$0.00
Apr-14	$24,075	$9,361	$0	$33,436	$0.00
May-14	$96,423	$24,095	$191	$120,708	$0.00
Jun-14	$119,970	$32,466	$5,061	$157,497	$0.00
Jul-14	$150,444	$14,945	$9,735	$175,124	$0.00
Aug-14	$94,746	$47,518	$1,261	$143,525	$0.00
Sep-14	$115,589	$43,980	$0	$159,569	$0.00
Oct-14	$90,613	$17,615	$0	$108,229	$0.00
Nov-14	$100,941	$22,935	$0	$123,876	$0.00
Dec-14	$108,880	$57,356	$12,669	$178,904	$0.00
Jan-15	$256,865	$110,223	$3,647	$370,735	$0.00
Feb-15	$346,410	$56,898	$0	$403,308	$0.00
Mar-15	$125,681	$28,436	$0	$154,116	$0.01

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
4/13/2015	Original Posting	