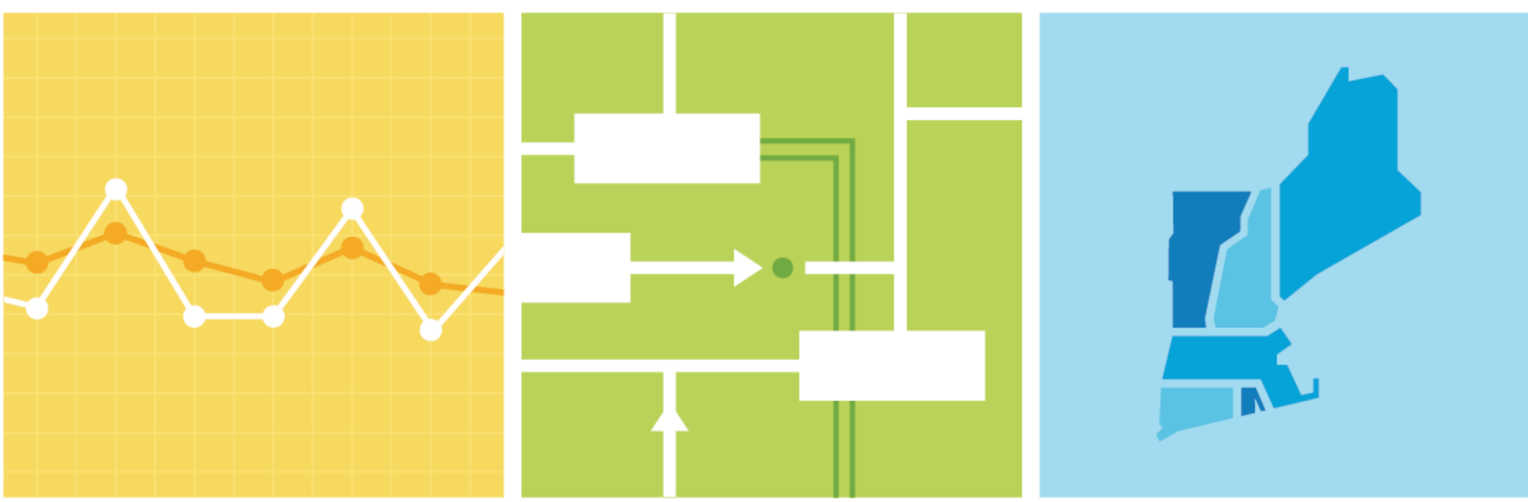
Monthly Market Operations Report December 2015

Market Analysis and Settlements

JANUARY 12, 2016

ISO-NE PUBLIC



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. There is also a summary of weekly Net Commitment Period Compensation (NCPC) credits posted 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.

2. Table of Contents

3. Monthly Summary

Day-ahead and real-time LMPs at the New England Hub averaged $22.42/MWh and $21.35/MWh, respectively, during December 2015. Day-ahead and real-time prices at the Hub and in the Load Zones averaged 17-28% lower than November 2015 averages. In the aggregate, December 2015 day-ahead and real-time LMPs were approximately 49% lower during December 2015 than in December 2014. Average natural gas prices were 63% below the prior year's average prices, while residual fuel prices were down 52% from a year ago.

Overall, the average of the hourly real-time LMPs at the Hub and in the Load Zones ranged between 5.7% lower than day-ahead in the Vermont (VT) Load Zone to 3.9% lower than its day-ahead counterpart in the Southeastern Massachusetts (SEMA) Load Zone. In the Day-Ahead Market, Load Zone average LMPs ranged between 2.0% lower than the Hub average LMPs in the Maine (ME) Load Zone to 0.3% higher than the Hub in the Rhode Island (RI) Load Zone. In the Real-Time Market, Load Zone average LMPs ranged between 2.4% lower than the Hub average LMPs in the ME Load Zone to 1.2% higher than the Hub in the SEMA Load Zone. Price differentials between on-peak and off-peak hours at the Hub and in the Load Zones ranged between 60% and 91% 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 December. In the Day-Ahead Energy Market, there were approximately 252,000 MWh of total exports and 2,018,000 MWh of imports, yielding a net import of approximately 1,766,000 MWh. In the Real-Time Energy Market, there were approximately 309,000 MWh of total exports and 1,895,000 MWh of imports, yielding a net import of approximately 1,585,000 MWh. This was about 873,000 MW lower than a year ago. On December 15, 2015, ISO New England and the New York ISO implemented a new scheduling protocol on the New York Northern AC ties. Coordinated Transaction Scheduling (CTS) moves Real-Time scheduling and settlement to a 15-minute level on this interface *only*. Read more about CTS here.

The Monthly FTR Auction (December 2015) had 32 participants and the awarded value of FTRs in the auction totaled $697K. This represented a decline of $21K from the previous month and a decrease of about $342K from the prior year's monthly FTR auction. The allocation of FTR Auction Revenue for December 2015 resulted in $2.1 million awarded to eligible entities, with $124K allocated to Incremental Auction Revenue Rights (IARR).

The Marginal Loss Revenue Fund totaled $1.9 million for December, down $1.3 million from its November 2015 total.

Total Forward Reserve Credits to eligible assets of $4.1 million were reduced by $34K in Failure to Reserve Penalties and $2K in Failure to Activate Penalties during December 2015. The net Forward Reserve Payment of $4.1 million represented 99% of the maximum possible payment of $4.2 million. Real-Time Reserve Prices occurred in 56 separate hours during the month, and those yielded real-time payments to designated assets of $720K. These payments were reduced by Forward Reserve Energy Obligation Charges totaling $231K yielding a net compensation of $491K during the month.

Regulation Market Payments totaled $1.6 million during the month, a decrease of $70K from the November 2015 value of $1.7 million.

For the month of December 2015, Forward Capacity payments were made to a total of 33,662 MW of eligible capacity and totaled $93.5 million.

The Transitional Demand Response program is the method through which demand assets can participate in the Energy Market. Payments during December 2015 totaled $57K for interruptions associated with Day Ahead, $40K for interruptions associated with the Real Time, and $7K associated with FCM/Audit. Total Transitional Demand Response payments for the month, $104K, were down approximately $3K from their November 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, December 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	$22.42	$21.35	$0.00	-$118.74	$68.71	$350.03	52%	50%	95.2%	$10.18	$21.05	2.07
ME	$21.97	$20.83	$0.00	-$113.15	$67.63	$348.08	51%	49%	94.8%	$9.93	$20.65	2.08
NH	$22.33	$21.18	-$0.31	-$115.81	$68.50	$350.49	52%	50%	94.8%	$10.13	$20.92	2.06
VT	$22.32	$21.04	$0.00	-$115.58	$66.94	$340.98	52%	50%	94.3%	$10.03	$20.59	2.05
CT	$22.26	$21.26	$0.00	-$118.86	$67.00	$348.14	52%	50%	95.5%	$10.02	$20.90	2.08
RI	$22.34	$21.40	$0.00	-$119.26	$68.16	$348.62	52%	50%	95.8%	$10.08	$21.05	2.09
SEMA	$22.47	$21.60	$0.00	-$118.78	$69.62	$350.52	52%	51%	96.1%	$10.25	$21.24	2.07
WCMA	$22.47	$21.38	$0.00	-$118.83	$68.53	$350.47	52%	50%	95.2%	$10.18	$21.06	2.07
NEMA	$22.48	$21.54	$0.00	-$118.40	$69.74	$355.02	52%	51%	95.8%	$10.29	$21.30	2.07
NB Ext	$20.90	$19.93	$0.00	-$108.95	$63.61	$339.75	49%	47%	95%	$9.32	$19.90	2.13
NYN Ext[3]	$21.93	$20.21	$0.00	-$138.99	$60.42	$337.46	51%	48%	92%	$9.60	$20.89	2.18
HQ Ext	$21.98	$21.01	$0.00	-$116.15	$67.82	$347.25	51%	49%	96%	$10.00	$20.78	2.08
HG Ext	$20.71	$19.41	$0.00	-$107.11	$62.23	$315.71	48%	46%	94%	$9.28	$19.11	2.06
CSC Ext	$22.28	$21.95	$0.00	-$119.10	$66.71	$352.35	52%	52%	99%	$10.03	$21.52	2.15
NNC Ext	$22.24	$21.25	$0.00	-$119.53	$66.23	$348.11	52%	50%	96%	$9.93	$20.85	2.10

[3] CTS has changed settlement to a 15-minute level on this interface in the Real-Time Market. The values shown here are computed over all of the hours (pre-CTS) and 15-minute intervals (post-CTS implementation) during the month.

4.1.2 *On-Peak Hours, December 2015*

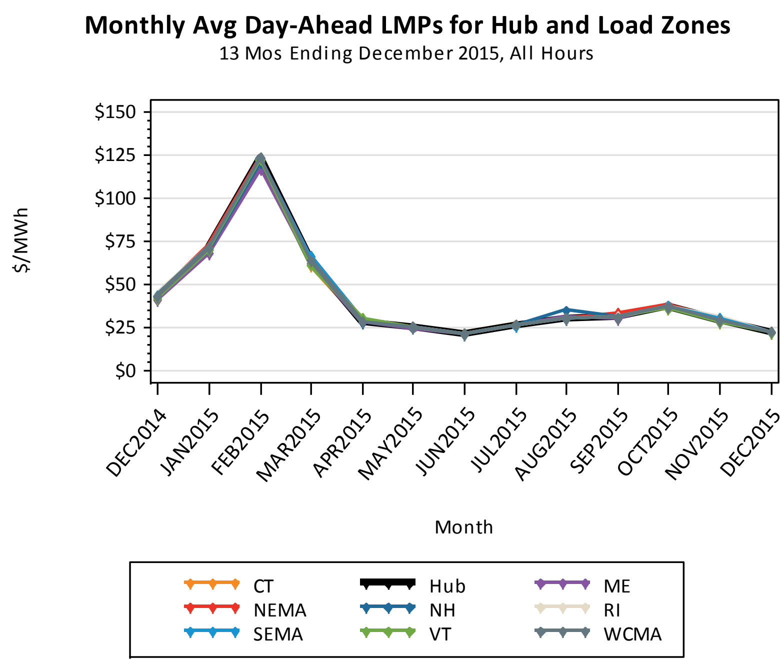
Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$28.02	$28.33	$12.63	$0.02	$68.71	$350.03	55%	51%	101%	$9.15	$22.33	2.44
ME	$27.56	$27.81	$12.27	$0.02	$67.63	$348.08	55%	50%	101%	$8.87	$22.11	2.49
NH	$27.97	$28.22	$12.29	$0.02	$68.50	$350.49	55%	50%	101%	$9.07	$22.31	2.46
VT	$27.93	$27.95	$12.35	$0.02	$66.94	$340.98	55%	50%	100%	$8.90	$21.74	2.44
CT	$27.84	$28.25	$12.72	$0.02	$67.00	$348.14	55%	50%	101%	$8.92	$22.10	2.48
RI	$27.82	$28.36	$12.72	$0.02	$68.16	$348.62	55%	51%	102%	$9.10	$22.27	2.45
SEMA	$28.05	$28.74	$12.71	$0.02	$69.62	$350.52	55%	51%	102%	$9.30	$22.53	2.42
WCMA	$28.09	$28.39	$12.66	$0.02	$68.53	$350.47	56%	51%	101%	$9.13	$22.33	2.45
NEMA	$28.14	$28.68	$12.72	$0.02	$69.74	$355.02	56%	51%	102%	$9.31	$22.70	2.44
NB Ext	$26.17	$26.69	$11.74	$0.02	$63.61	$339.75	52%	48%	102%	$8.28	$21.42	2.59
NYN Ext	$27.25	$26.30	$12.49	-$138.99	$60.42	$337.46	54%	47%	97%	$8.32	$22.74	2.73
HQ Ext	$27.48	$27.91	$12.42	$0.02	$67.82	$347.25	54%	50%	102%	$9.02	$22.11	2.45
HG Ext	$25.89	$25.79	$11.27	$0.02	$62.23	$315.71	51%	46%	100%	$8.31	$20.15	2.42
CSC Ext	$27.90	$28.93	$12.78	$0.02	$66.71	$352.35	55%	52%	104%	$8.88	$22.83	2.57
NNC Ext	$27.81	$28.22	$12.75	$0.02	$66.23	$348.11	55%	50%	102%	$8.76	$21.99	2.51

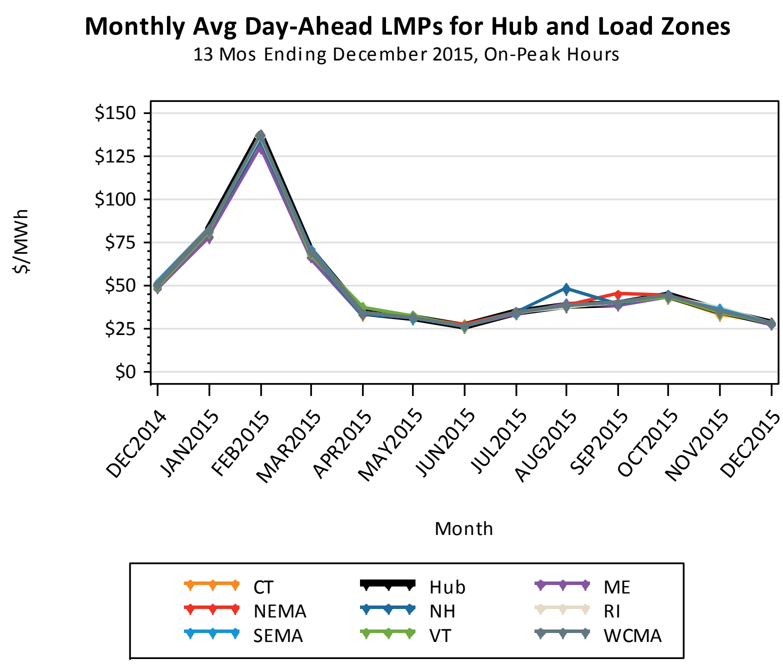
4.1.3 *Off-Peak Hours, December 2015*

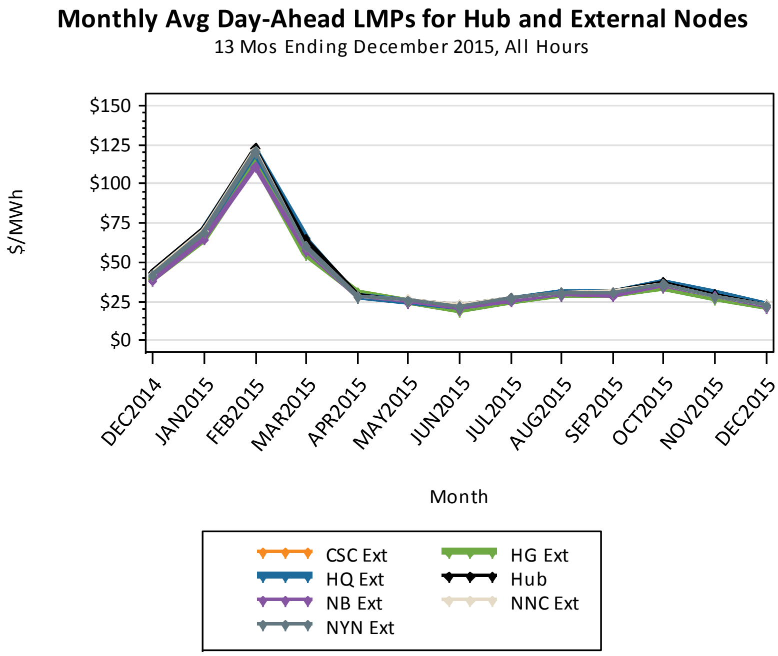
Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$17.40	$15.07	$0.00	-$118.74	$47.90	$106.18	48%	50%	87%	$8.25	$17.64	2.14
ME	$16.95	$14.56	$0.00	-$113.15	$46.13	$101.02	47%	48%	86%	$7.97	$16.97	2.13
NH	$17.27	$14.86	-$0.31	-$115.81	$47.47	$104.17	48%	49%	86%	$8.18	$17.32	2.12
VT	$17.28	$14.83	$0.00	-$115.58	$47.63	$104.06	48%	49%	86%	$8.13	$17.30	2.13
CT	$17.24	$14.98	$0.00	-$118.86	$47.47	$105.49	48%	49%	87%	$8.13	$17.54	2.16
RI	$17.41	$15.14	$0.00	-$119.26	$47.35	$106.85	48%	50%	87%	$8.21	$17.72	2.16
SEMA	$17.45	$15.18	$0.00	-$118.78	$47.78	$106.99	48%	50%	87%	$8.28	$17.73	2.14
WCMA	$17.42	$15.09	$0.00	-$118.83	$48.00	$106.19	48%	50%	87%	$8.25	$17.65	2.14
NEMA	$17.41	$15.13	$0.00	-$118.40	$48.08	$106.36	48%	50%	87%	$8.30	$17.68	2.13
NB Ext	$16.17	$13.87	$0.00	-$108.95	$43.72	$94.57	45%	46%	86%	$7.49	$16.21	2.16
NYN Ext	$17.15	$14.74	$0.00	-$118.21	$47.06	$104.08	47%	49%	86%	$8.05	$17.38	2.16
HQ Ext	$17.04	$14.81	$0.00	-$116.15	$46.91	$104.29	47%	49%	87%	$8.09	$17.33	2.14
HG Ext	$16.06	$13.68	$0.00	-$107.11	$44.52	$95.12	44%	45%	85%	$7.48	$16.12	2.16
CSC Ext	$17.23	$15.69	$0.00	-$119.10	$48.60	$105.90	48%	52%	91%	$8.14	$18.15	2.23
NNC Ext	$17.25	$15.00	$0.00	-$119.53	$47.39	$105.07	48%	49%	87%	$8.09	$17.57	2.17

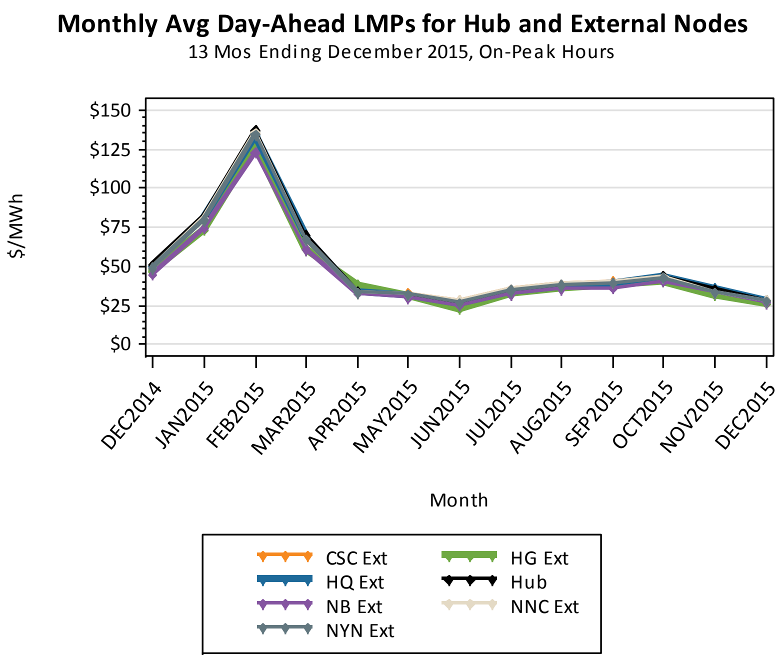
4.2 LMP Graphs, Day-Ahead Market, 13 Months Ending December 2015

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.



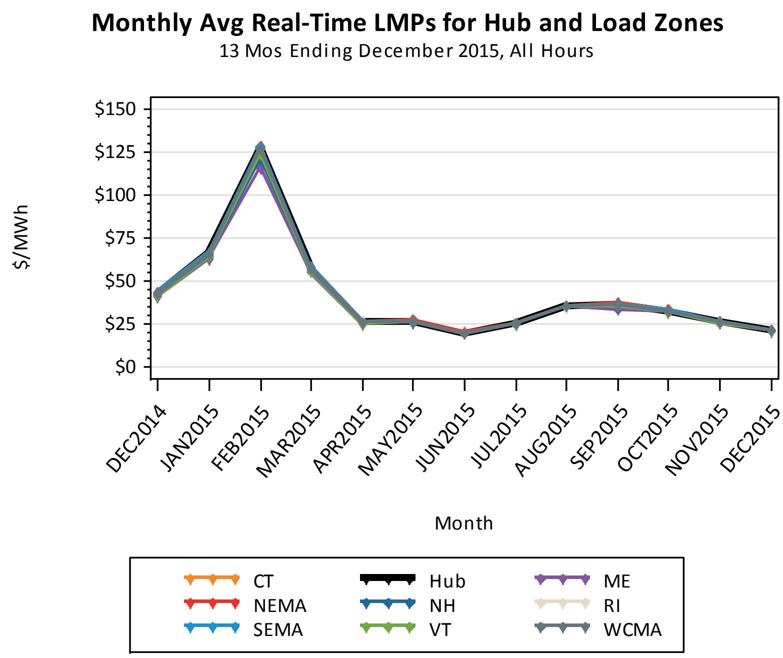


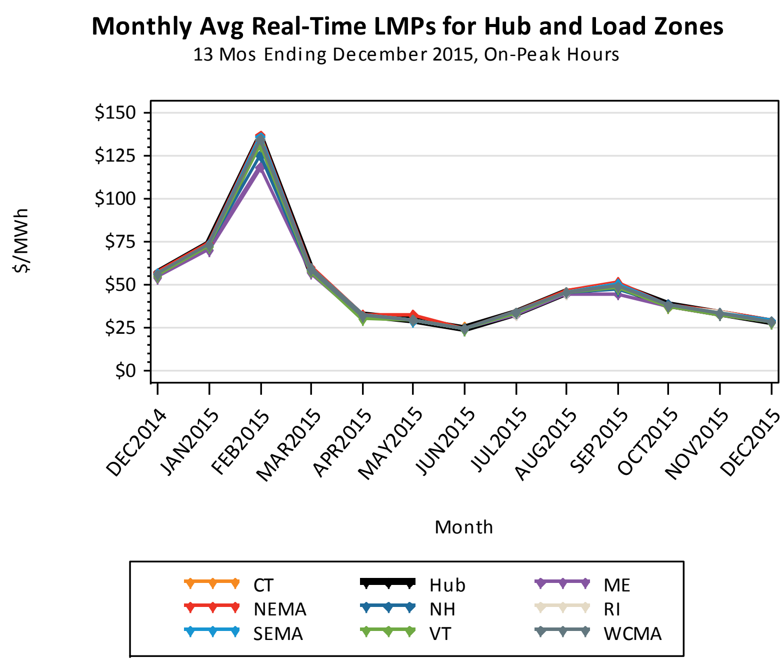

Monthly Avg Day-Ahead LMPs for Hub and External Nodes
13 Mos Ending December 2015, All Hours
$/MWh
$150
$125
$100
$75
$50
$25
$0
DEC2014
JAN2015
FEB2015
MAR2015
APR2015
MAY2015
JUN2015
JUL2015
AUG2015
SEP2015
OCT2015
NOV2015
DEC2015
Month
CSC Ext
HQ Ext
NB Ext
NYN Ext
HG Ext
Hub
NNC Ext


Monthly Avg Day-Ahead LMPs for Hub and External Nodes
13 Mos Ending December 2015, On-Peak Hours
$/MWh
$150
$125
$100
$75
$50
$25
$0
DEC2014
JAN2015
FEB2015
MAR2015
APR2015
MAY2015
JUN2015
JUL2015
AUG2015
SEP2015
OCT2015
NOV2015
DEC2015
Month
CSC Ext
HQ Ext
NB Ext
NYN Ext
HG Ext
Hub
NNC Ext

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

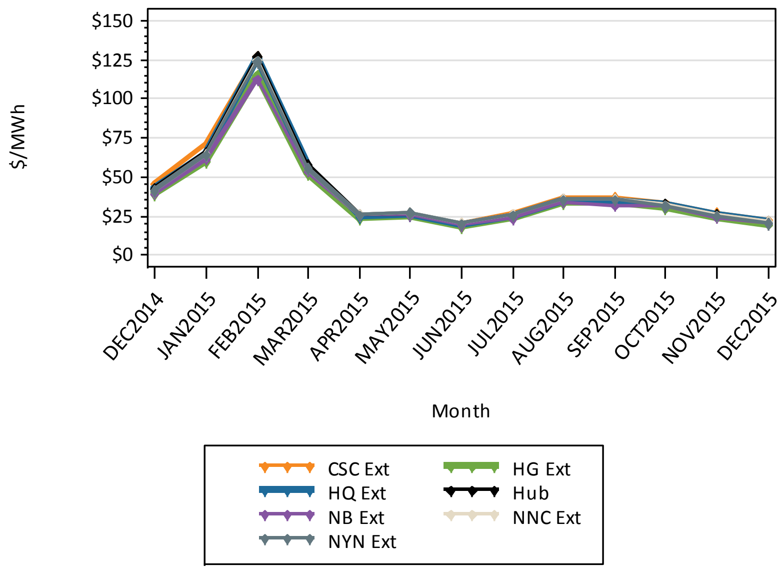
The following four graphs show the 13 month history of average hourly Real-Time LMPs for the Hub, Load Zones, and External Nodes on an overall and on-peak basis.





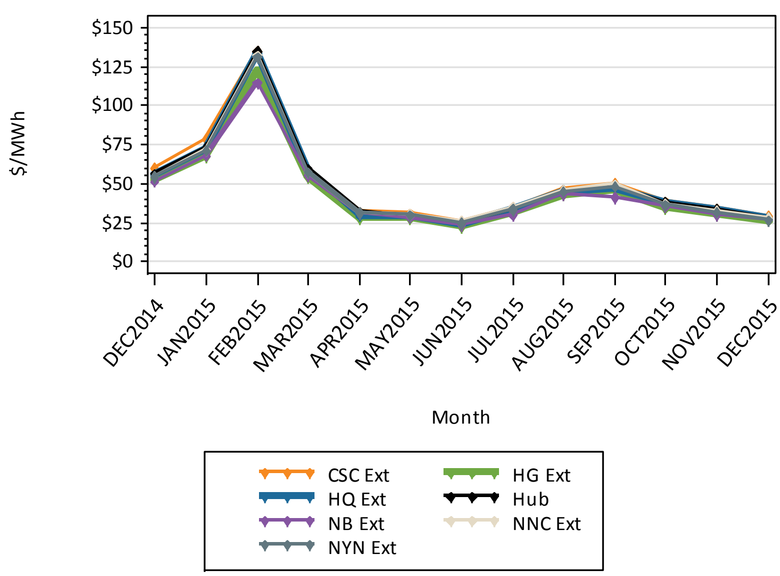
Monthly Avg Real-Time LMPs for Hub and External Nodes

13 Mos Ending December 2015, All Hours



Monthly Avg Real-Time LMPs for Hub and External Nodes

13 Mos Ending December 2015, 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[4].

The ISO also provides a discussion of LMP results on an annual basis in its Annual Market Performance Reports, located here[5].

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.

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

[5] 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.

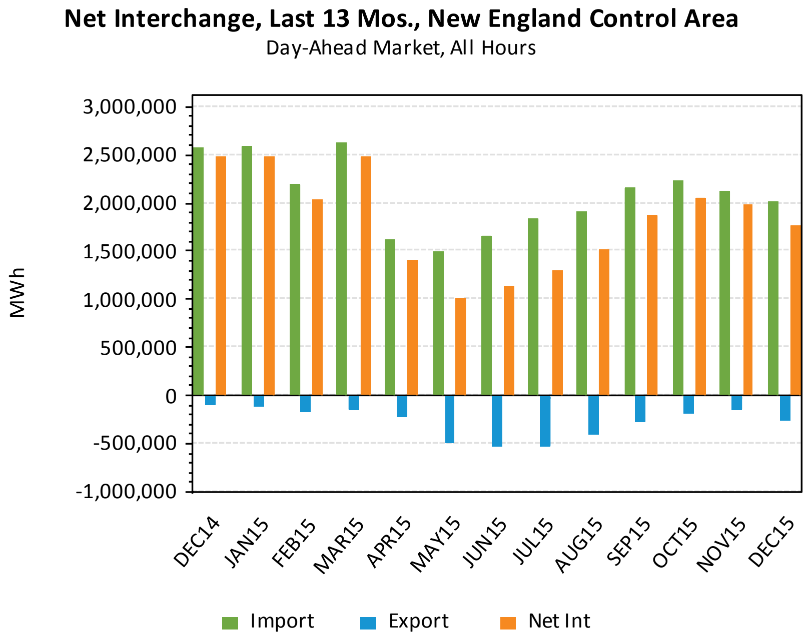
5.1 Net Interchange Summary, December 2015

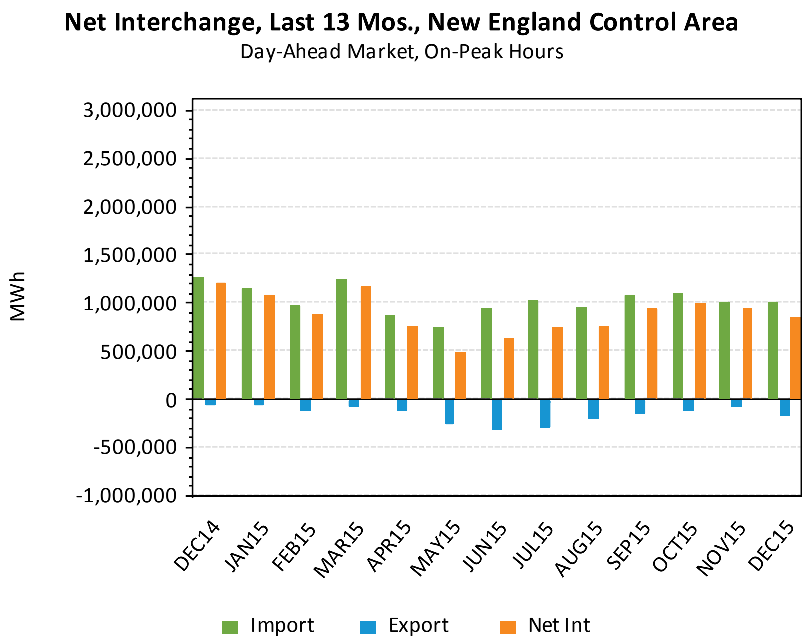
The following tables show summary statistics for imports and exports on the six external interfaces for both the Day-Ahead and Real-Time Markets:

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	-41,272	14,108	-27,164	-51,539	14,920	-36,619
	NY-CSC	-109,740	0	-109,740	-110,368	0	-110,368
	HQ HG	0	148,753	148,753	0	149,408	149,408
	HQ I/II	-1,175	1,007,246	1,006,071	-1,692	1,004,959	1,003,267
	NY-N AC	-99,678	419,073	319,395	-201,366	486,416	285,050
	NB	-251	429,295	429,044	-17,370	442,525	425,155
Total	**All Hours**	**-252,116**	**2,018,475**	**1,766,359**	**-382,335**	**2,098,228**	**1,715,893**
Off-Peak	NNC	-18,854	6,514	-12,340	-25,534	5,754	-19,780
	NY-CSC	-34,180	0	-34,180	-34,258	0	-34,258
	HQ HG	0	72,162	72,162	0	72,799	72,799
	HQ I/II	-400	524,096	523,696	-1,692	519,668	517,976
	NY-N AC	-40,068	196,670	156,602	-103,545	223,815	120,269
	NB	-82	216,335	216,253	-2,489	229,904	227,415
Total	Off-Peak	-93,583	1,015,777	922,194	-167,518	1,051,940	884,421
On-Peak	NNC	-22,418	7,594	-14,824	-26,005	9,166	-16,839
	NY-CSC	-75,560	0	-75,560	-76,110	0	-76,110
	HQ HG	0	76,591	76,591	0	76,609	76,609
	HQ I/II	-775	483,150	482,375	0	485,291	485,291
	NY-N AC	-59,611	222,403	162,792	-97,821	262,602	164,781
	NB	-169	212,960	212,791	-14,881	212,621	197,740
Total	On-Peak	-158,533	1,002,698	844,166	-214,817	1,046,289	831,472

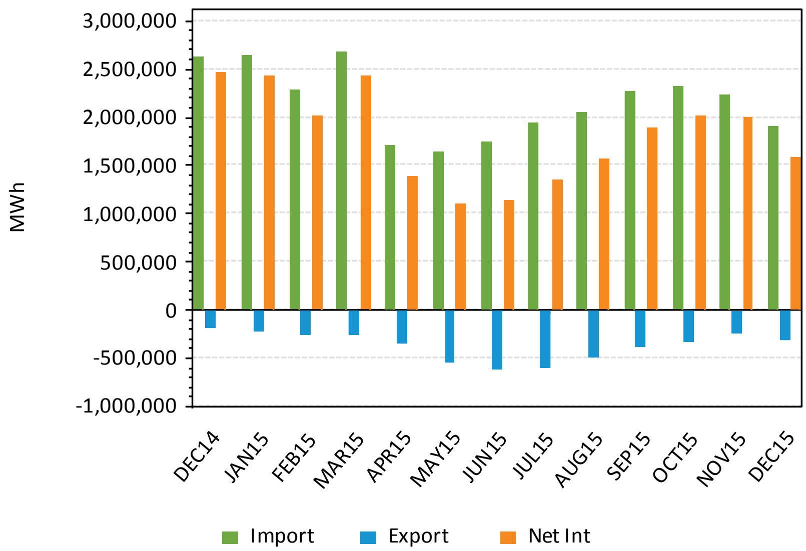
5.2 Day-Ahead and Real-Time Net Interchange Summary, Last 13 Months





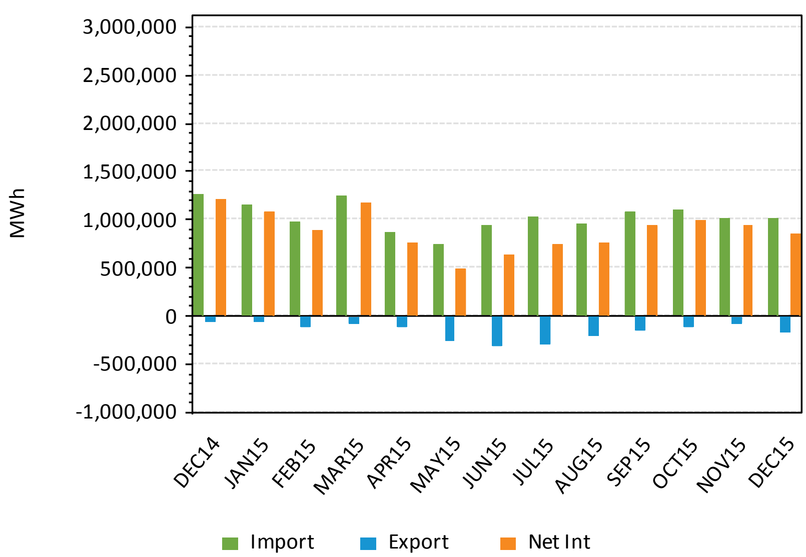
Net Interchange, Last 13 Mos., New England Control Area

Real-Time Market, All Hours

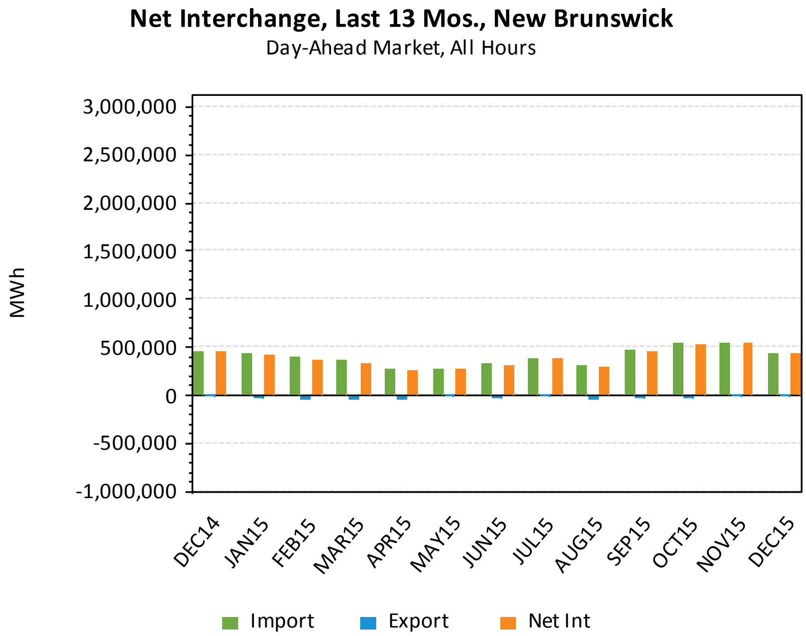


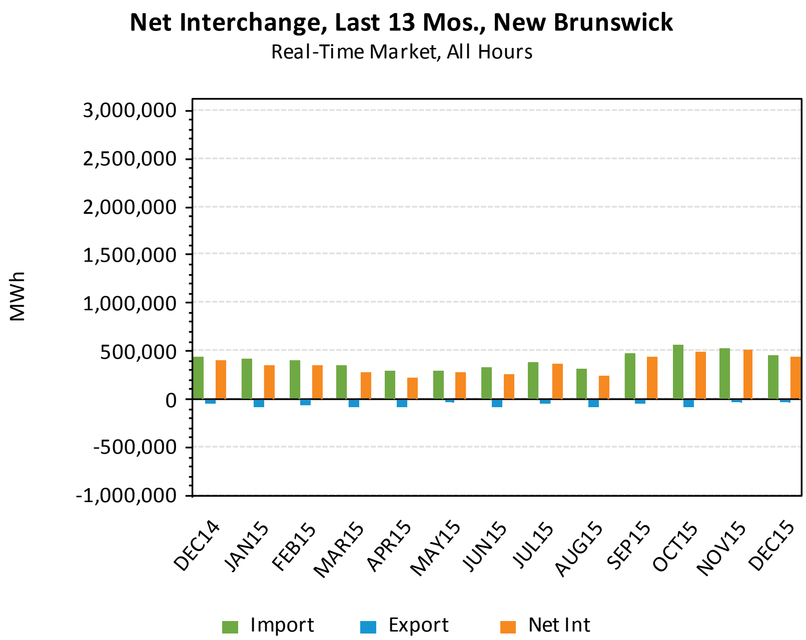
Net Interchange, Last 13 Mos., New England Control Area

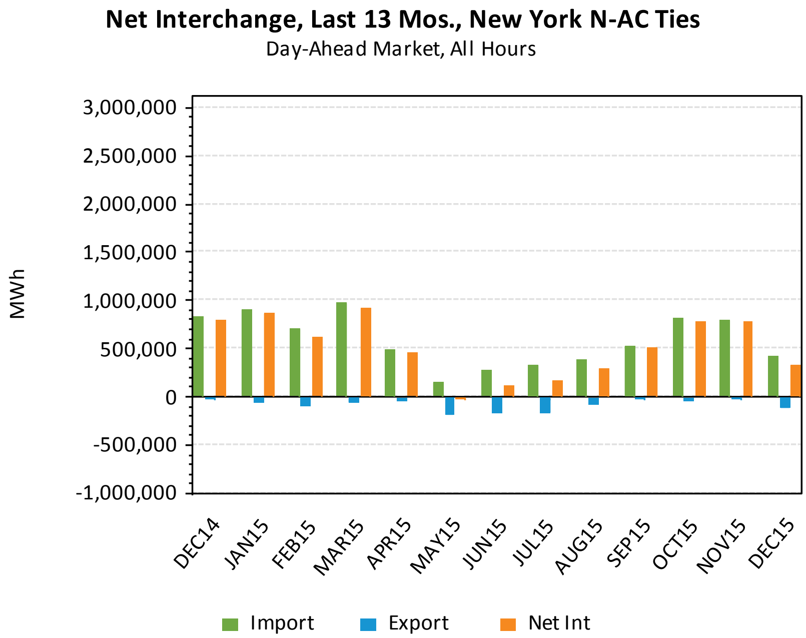
Day-Ahead Market, On-Peak Hours

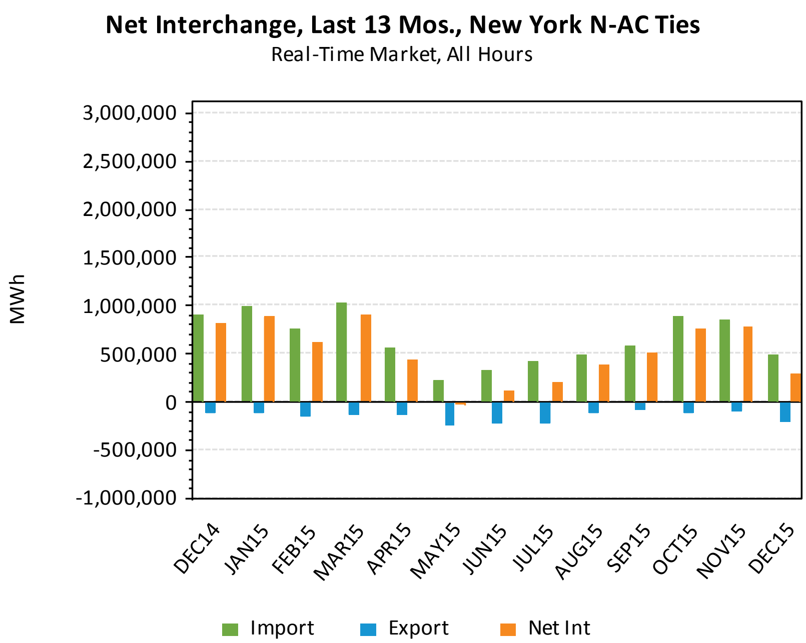


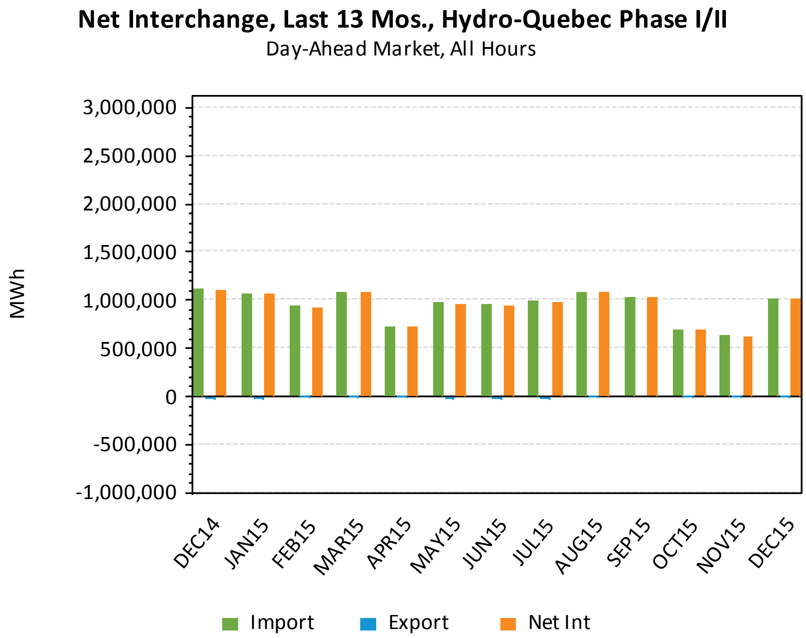
5.3 Net Interchange Summary by Interface, Last 13 Months

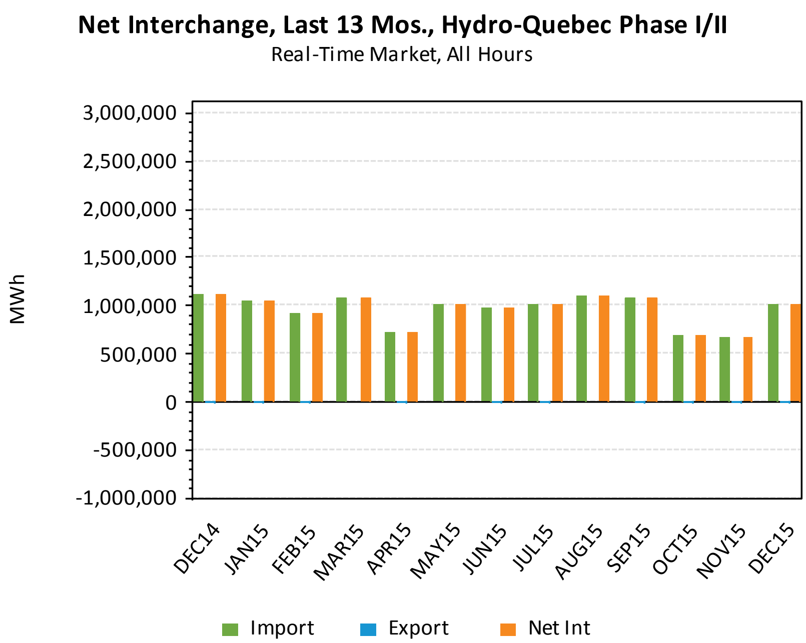


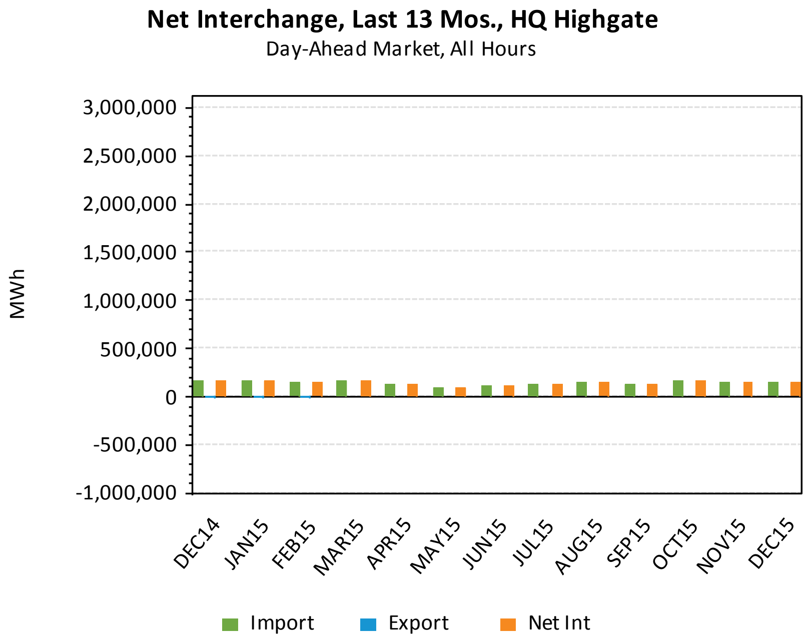


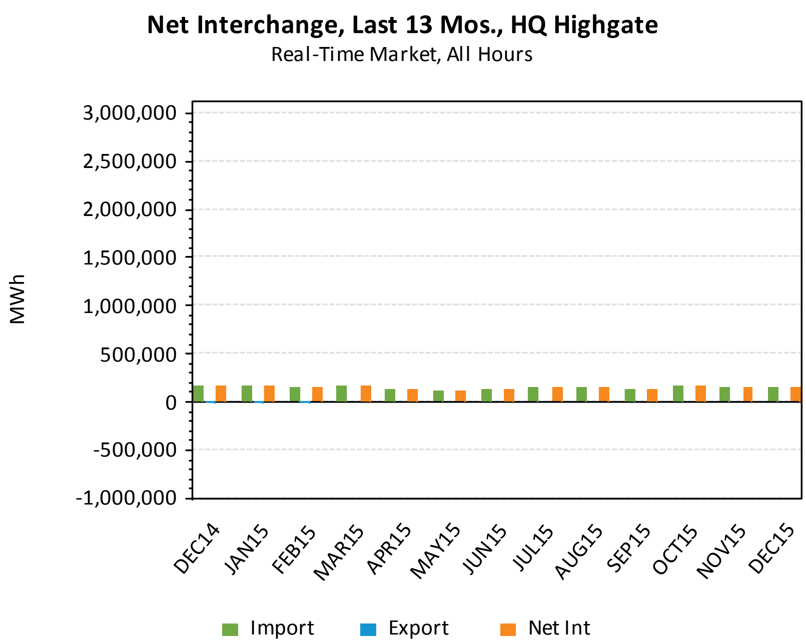

Net Interchange, Last 13 Mos., New York N-AC Ties
Day-Ahead Market, All Hours
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MWh
DEC14
JAN15
FEB15
MAR15
APR15
MAY15
JUN15
JUL15
AUG15
SEP15
OCT15
NOV15
DEC15
Import
Export
Net Int

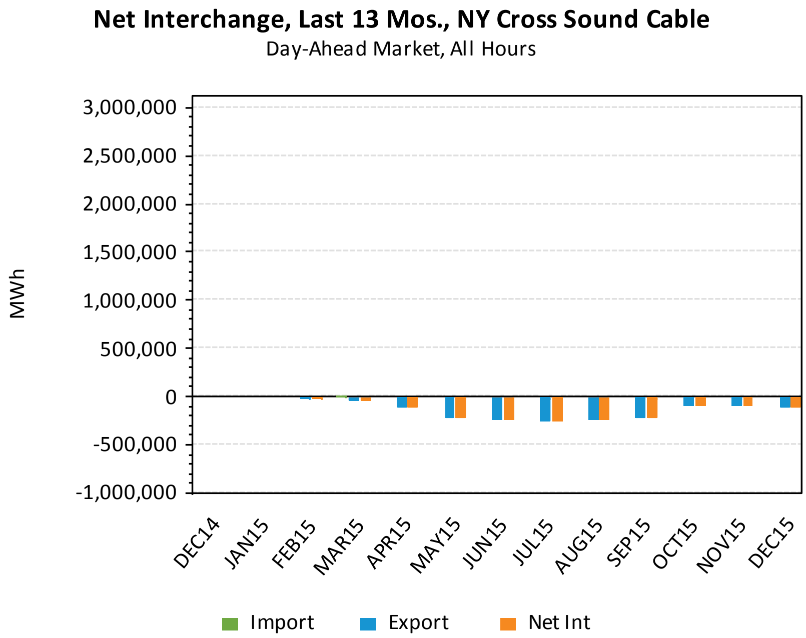

Net Interchange, Last 13 Mos., New York N-AC Ties
Real-Time Market, All Hours
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MWh
DEC14
JAN15
FEB15
MAR15
APR15
MAY15
JUN15
JUL15
AUG15
SEP15
OCT15
NOV15
DEC15
Import
Export
Net Int

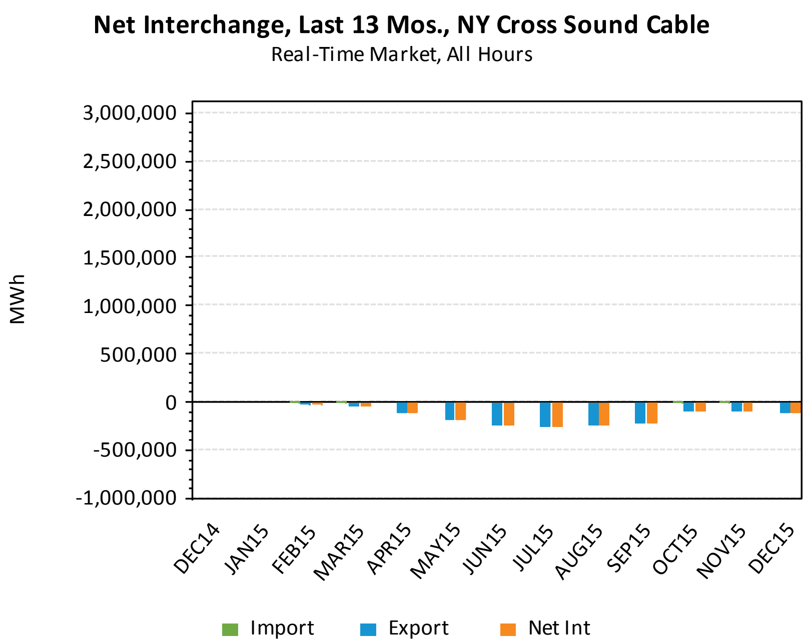

Net Interchange, Last 13 Mos., Hydro-Quebec Phase I/II
Day-Ahead Market, All Hours
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
DEC14
JAN15
FEB15
MAR15
APR15
MAY15
JUN15
JUL15
AUG15
SEP15
OCT15
NOV15
DEC15
Import
Export
Net Int


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
DEC14
JAN15
FEB15
MAR15
APR15
MAY15
JUN15
JUL15
AUG15
SEP15
OCT15
NOV15
DEC15
Import
Export
Net Int

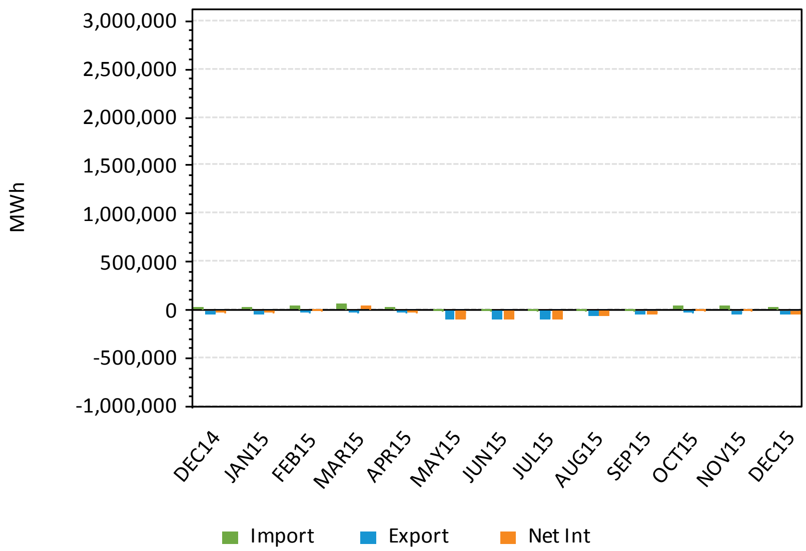

Net Interchange, Last 13 Mos., HQ Highgate
Day-Ahead Market, All Hours
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
DEC14
JAN15
FEB15
MAR15
APR15
MAY15
JUN15
JUL15
AUG15
SEP15
OCT15
NOV15
DEC15
Import
Export
Net Int


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
DEC14
JAN15
FEB15
MAR15
APR15
MAY15
JUN15
JUL15
AUG15
SEP15
OCT15
NOV15
DEC15
Import
Export
Net Int

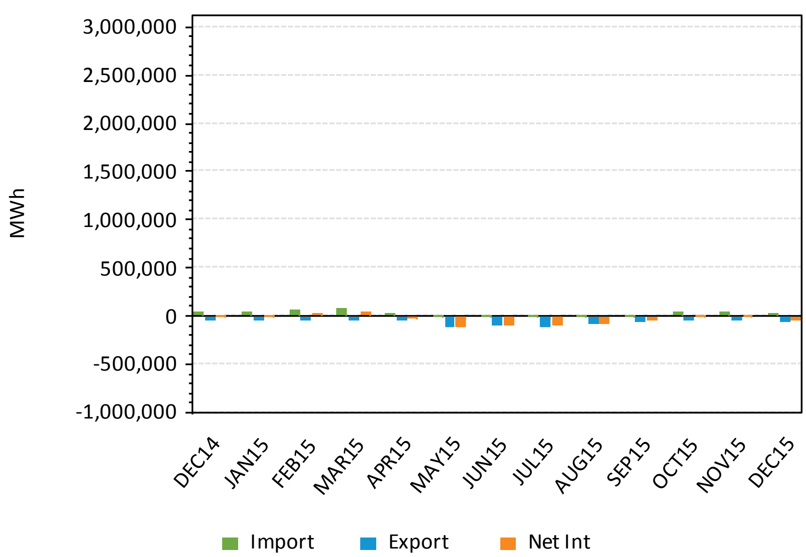

Net Interchange, Last 13 Mos., NY Cross Sound Cable
Day-Ahead Market, All Hours
MWh
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
DEC14
JAN15
FEB15
MAR15
APR15
MAY15
JUN15
JUL15
AUG15
SEP15
OCT15
NOV15
DEC15
Import
Export
Net Int


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
DEC14
JAN15
FEB15
MAR15
APR15
MAY15
JUN15
JUL15
AUG15
SEP15
OCT15
NOV15
DEC15
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, December 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	4,534	33,463	$1,404,318	2,068	15,100	$314,665
Buy	On	4,532	35,130	$1,760,805	2,096	15,536	$409,205
Buy	Buy Total	9,066	68,593	$3,165,123	4,164	30,636	$723,870
Sell	Off	1,230	4,247	$680,471	132	271	-$19,762
Sell	On	360	3,171	$809,120	69	201	-$6,931
Sell	Sell Total	1,590	7,418	$1,489,591	201	472	-$26,693
Grand Total	Grand Total	10,656	76,011	$4,654,714	4,365	31,108	$697,178

6.1.2 *Number of Auction Participants, December 2015*

Auction Period	Monthly or Long-Term	No. of Bidders
Dec 2015	MO	32

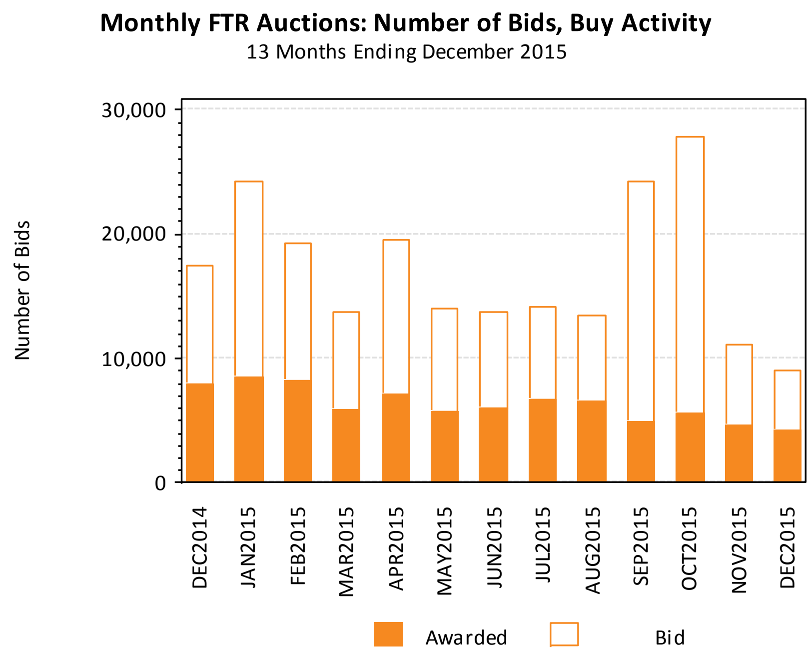
6.1.3 *Monthly FTR Auction Results, Last 13 Months*

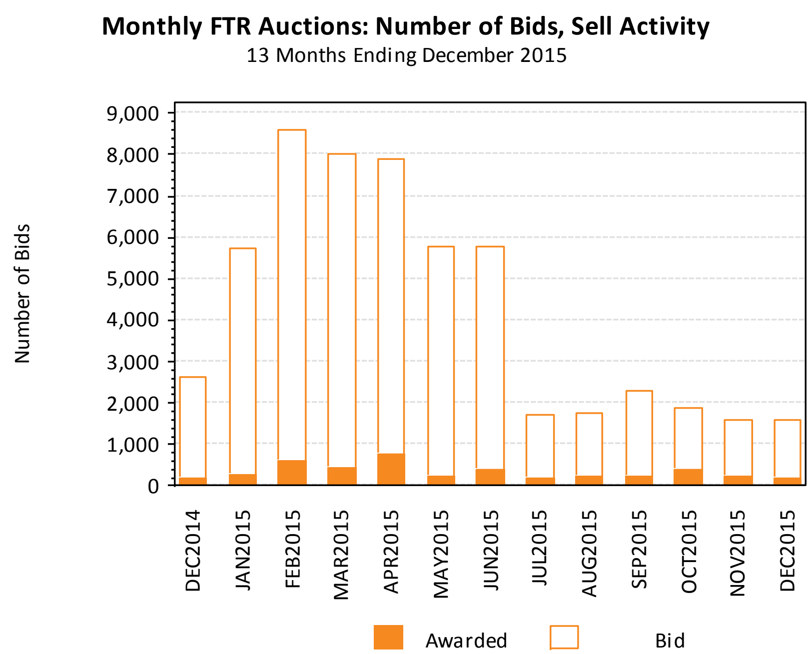
Auction Month	Bids to Buy or Offers to Sell	No. of Bids or Offers	Bid or Offered MW-Mos.	Bid or Offered Dollars	No. of Awards	Awarded MW-Mos.	Awarded Dollars
DEC 2014	Buy	17,420	104,104	$6,609,853	7,917	41,381	$1,067,697
DEC 2014	Sell	2,610	8,048	$5,884,632	192	1,276	-$28,225
DEC 2014	Tot	20,030	112,151	$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

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
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
APR 2015	Buy	19,544	96,391	$4,475,393	7,129	33,196	$1,066,026
APR 2015	Sell	7,876	14,020	$2,245,905	757	1,433	-$162,220
APR 2015	Tot	27,420	110,411	$6,721,298	7,886	34,628	$903,806
MAY 2015	Buy	13,989	80,167	$2,976,157	5,755	34,385	$685,661
MAY 2015	Sell	5,772	10,606	$1,465,011	245	606	-$52,461
MAY 2015	Tot	19,761	90,774	$4,441,168	6,000	34,990	$633,200
JUN 2015	Buy	13,738	74,509	$2,661,192	6,021	35,661	$552,630
JUN 2015	Sell	5,788	10,998	$1,970,657	389	561	-$44,765
JUN 2015	Tot	19,526	85,507	$4,631,849	6,410	36,222	$507,865
JUL 2015	Buy	14,138	81,160	$3,151,391	6,651	40,048	$709,150
JUL 2015	Sell	1,718	8,147	$919,873	183	395	-$28,761
JUL 2015	Tot	15,856	89,307	$4,071,263	6,834	40,442	$680,389
AUG 2015	Buy	13,511	80,138	$2,533,786	6,611	36,553	$623,353
AUG 2015	Sell	1,742	8,287	$907,884	211	788	-$42,725
AUG 2015	Tot	15,253	88,425	$3,441,671	6,822	37,342	$580,629
SEP 2015	Buy	24,278	65,486	$1,856,339	4,845	32,997	$461,001
SEP 2015	Sell	2,314	8,803	$801,635	232	1,017	-$33,569
SEP 2015	Tot	26,592	74,289	$2,657,974	5,077	34,013	$427,432
OCT 2015	Buy	27,816	78,732	$3,352,157	5,591	27,435	$834,747
OCT 2015	Sell	1,902	9,525	$1,167,039	411	1,957	-$103,006
OCT 2015	Tot	29,718	88,256	$4,519,196	6,002	29,393	$731,741
NOV 2015	Buy	11,167	62,231	$3,002,938	4,668	26,057	$754,575
NOV 2015	Sell	1,594	7,480	$1,052,590	232	527	-$35,999
NOV 2015	Tot	12,761	69,711	$4,055,528	4,900	26,584	$718,576
DEC 2015	Buy	9,066	68,593	$3,165,123	4,164	30,636	$723,870
DEC 2015	Sell	1,590	7,418	$1,489,591	201	472	-$26,693
DEC 2015	Tot	10,656	76,011	$4,654,714	4,365	31,108	$697,178

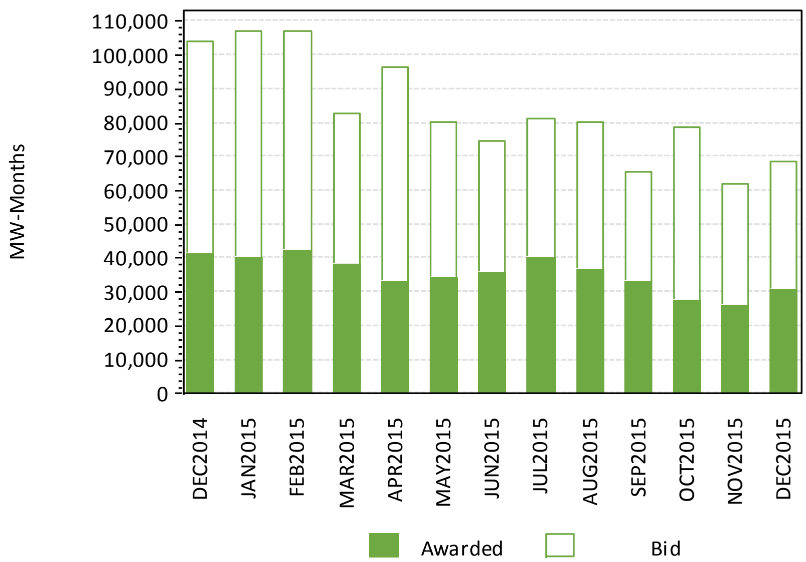
6.2 Monthly FTR Auction Results, Last 13 Months

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.

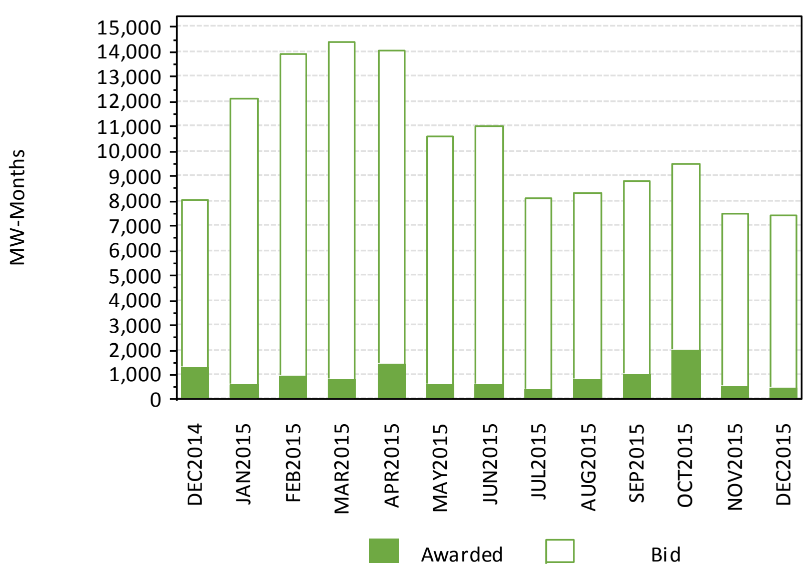

Monthly FTR Auctions: Number of Bids, Buy Activity
13 Months Ending December 2015
Number of Bids
30,000
20,000
10,000
0
DEC2014
JAN2015
FEB2015
MAR2015
APR2015
MAY2015
JUN2015
JUL2015
AUG2015
SEP2015
OCT2015
NOV2015
DEC2015
Awarded
Bid


Monthly FTR Auctions: Number of Bids, Sell Activity
13 Months Ending December 2015
Number of Bids
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
DEC2014
JAN2015
FEB2015
MAR2015
APR2015
MAY2015
JUN2015
JUL2015
AUG2015
SEP2015
OCT2015
NOV2015
DEC2015
Awarded
Bid

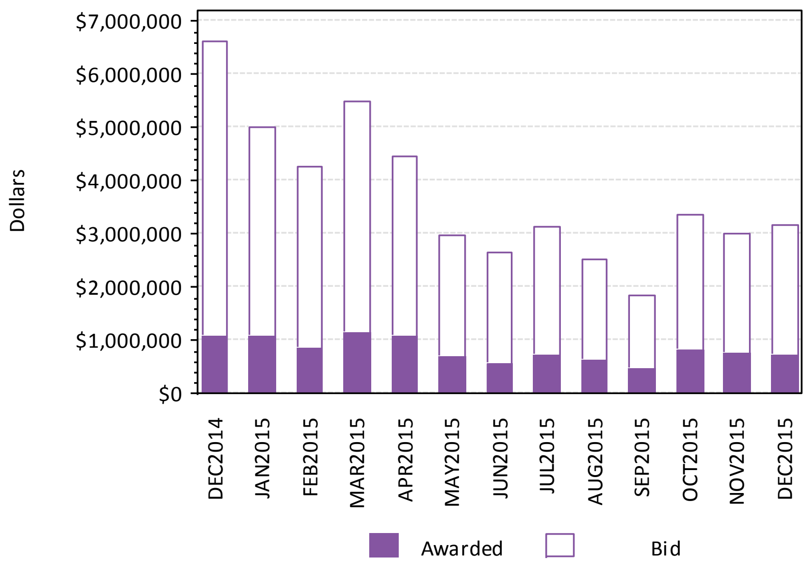
Monthly FTR Auctions: MW-Months, Buy Activity
13 Months Ending December 2015



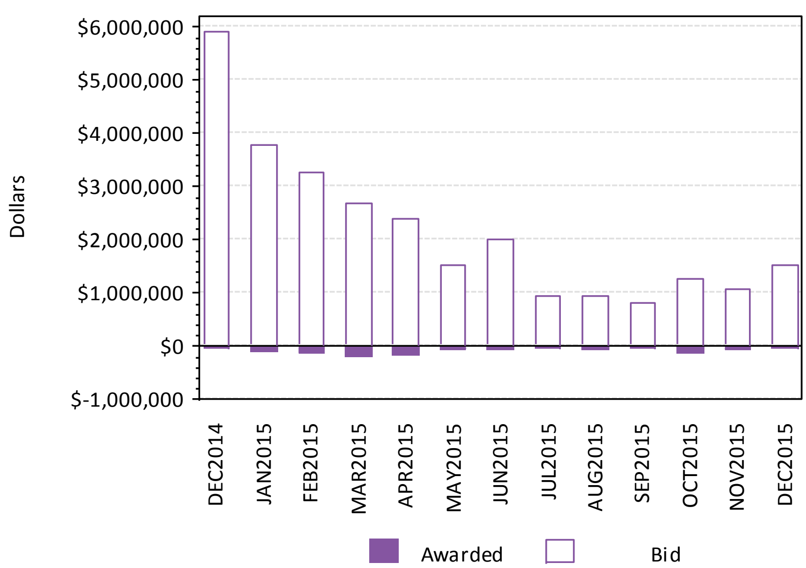
Monthly FTR Auctions: MW-Months, Sell Activity
13 Months Ending December 2015



Monthly FTR Auctions: Dollars, Buy Activity
13 Months Ending December 2015

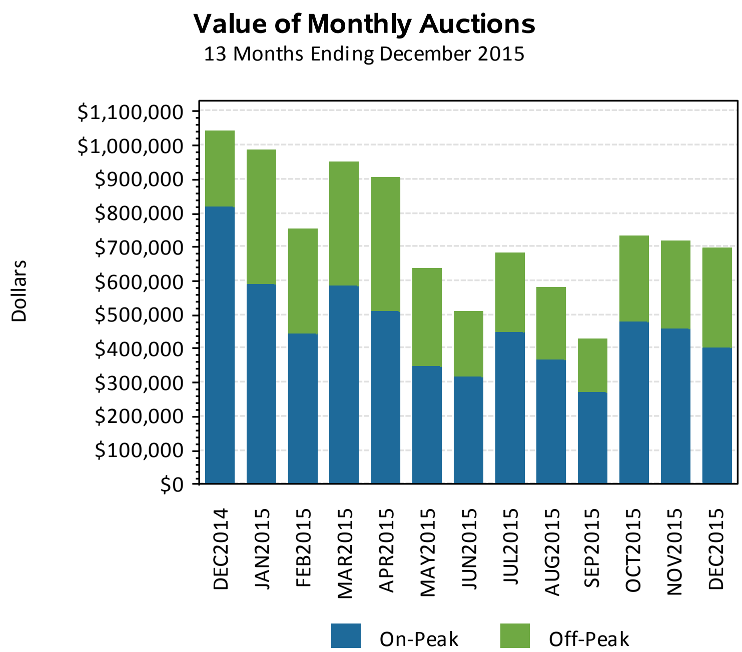


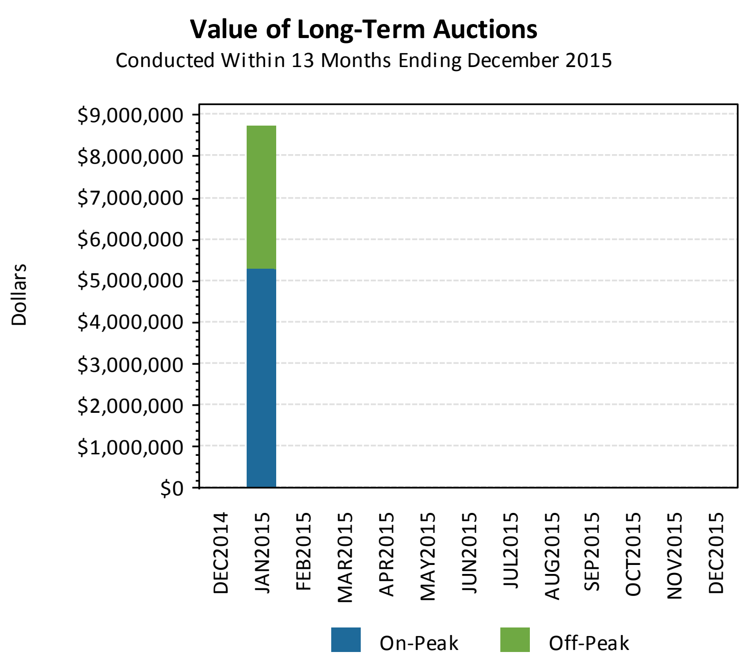
Monthly FTR Auctions: Dollars, Sell Activity
13 Months Ending December 2015

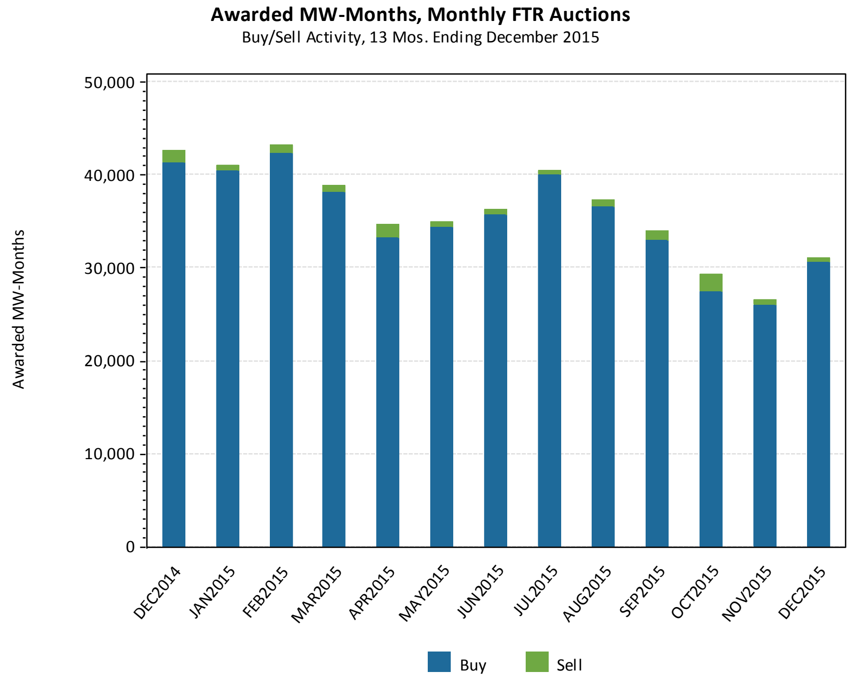


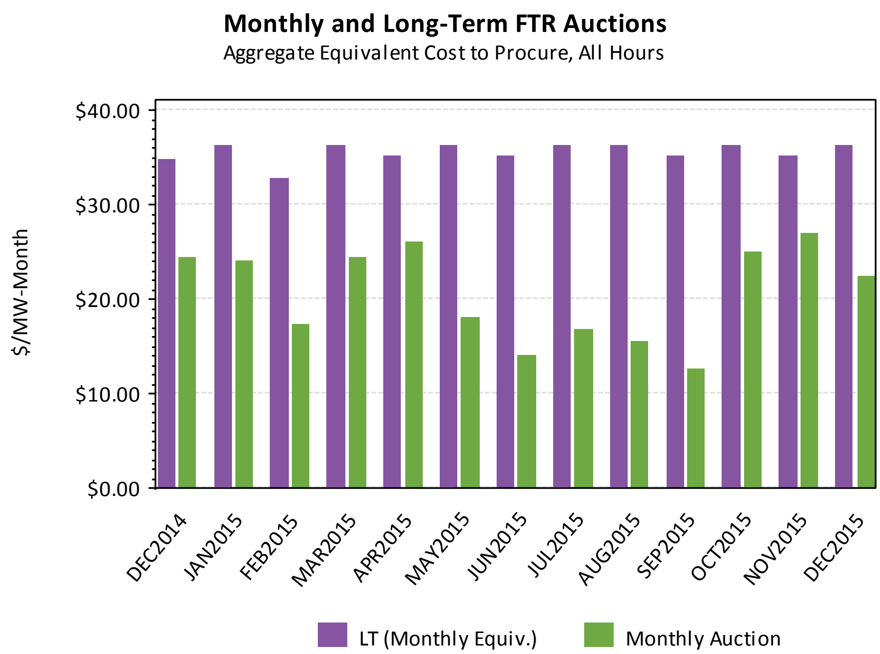
6.3 Auction Value, Last 13 Months

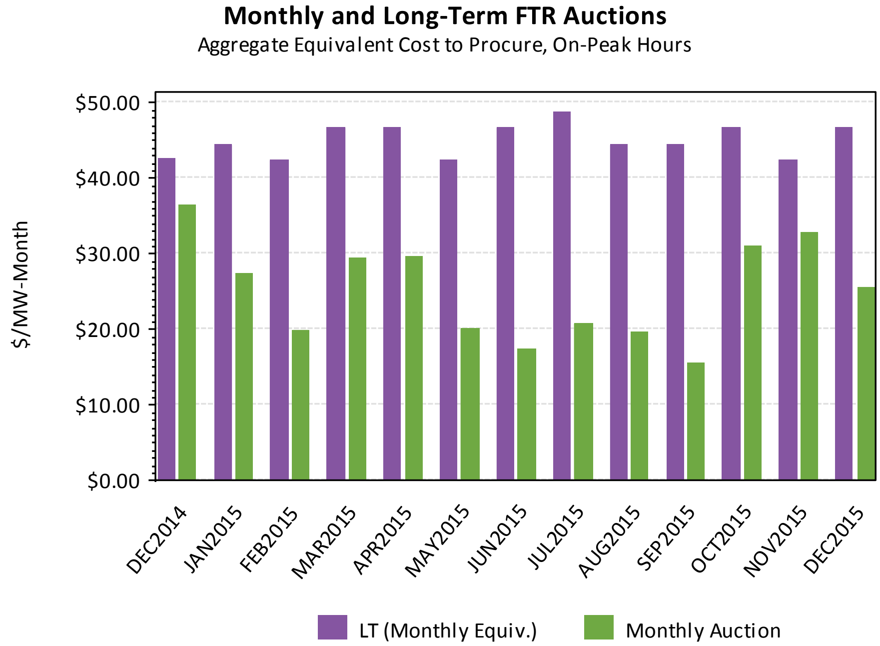
The next series of graphs show summaries of FTR Auction value and on/off-peak activity over the last 13 months.



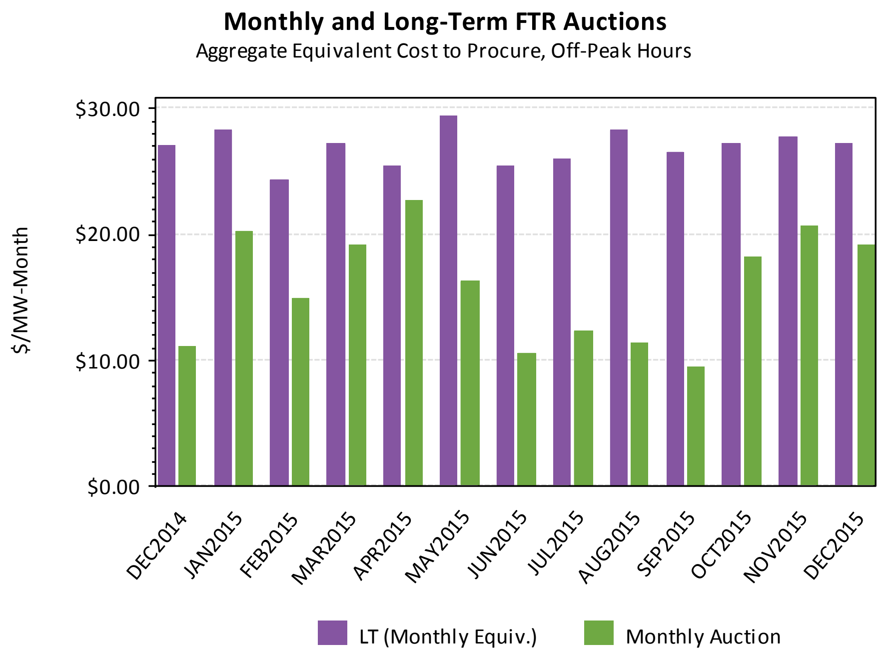



Awarded MW-Months, Monthly FTR Auctions
Buy/Sell Activity, 13 Mos. Ending December 2015
Awarded MW-Months
50,000
40,000
30,000
20,000
10,000
0
DEC2014
JAN2015
FEB2015
MAR2015
APR2015
MAY2015
JUN2015
JUL2015
AUG2015
SEP2015
OCT2015
NOV2015
DEC2015
Buy
Sell


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
DEC2014
JAN2015
FEB2015
MAR2015
APR2015
MAY2015
JUN2015
JUL2015
AUG2015
SEP2015
OCT2015
NOV2015
DEC2015
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
DEC2014
JAN2015
FEB2015
MAR2015
APR2015
MAY2015
JUN2015
JUL2015
AUG2015
SEP2015
OCT2015
NOV2015
DEC2015
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
DEC2014
JAN2015
FEB2015
MAR2015
APR2015
MAY2015
JUN2015
JUL2015
AUG2015
SEP2015
OCT2015
NOV2015
DEC2015
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.

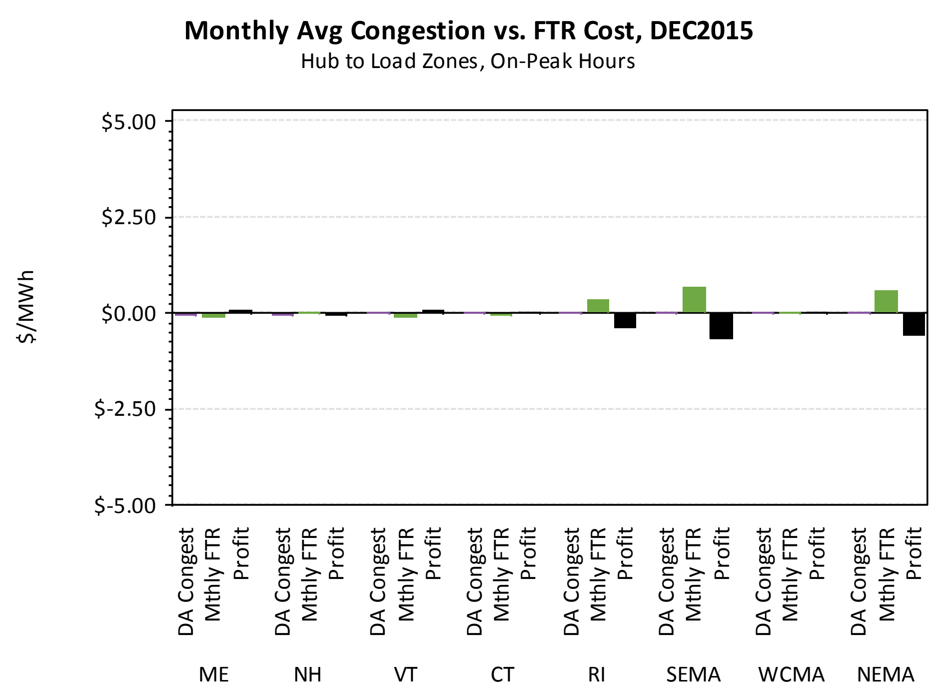
7. Effectiveness of FTRs

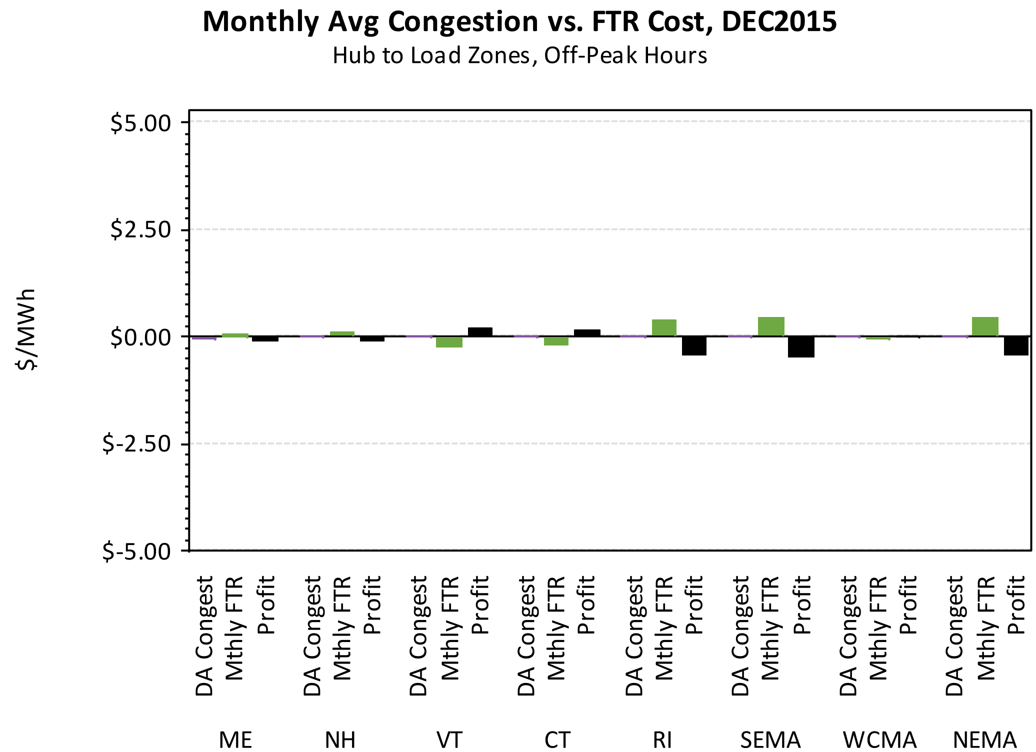
7.1 FTRs as a Congestion Hedging Instrument

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 December 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	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
ME	Apr-15	$0.09	-$0.09	$0.18
ME	May-15	$0.00	-$0.11	$0.11
ME	Jun-15	$0.00	-$0.05	$0.06
ME	Jul-15	$0.00	-$0.03	$0.03
ME	Aug-15	$2.28	$0.01	$2.27
ME	Sep-15	-$0.30	-$0.06	-$0.24
ME	Oct-15	$0.01	-$0.04	$0.05
ME	Nov-15	$0.58	-$0.04	$0.62
ME	Dec-15	-$0.01	-$0.07	$0.06

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
NH	Apr-15	-$0.05	$0.04	-$0.08
NH	May-15	-$0.02	-$0.02	$0.00
NH	Jun-15	-$0.01	-$0.03	$0.02
NH	Jul-15	$0.13	-$0.01	$0.14
NH	Aug-15	$10.01	$0.02	$9.99
NH	Sep-15	-$0.21	$0.03	-$0.25
NH	Oct-15	$0.02	$0.07	-$0.05
NH	Nov-15	$0.34	$0.05	$0.29
NH	Dec-15	-$0.01	$0.00	-$0.01

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
VT	Apr-15	$4.27	-$0.17	$4.44
VT	May-15	$0.36	$0.47	-$0.10
VT	Jun-15	-$0.10	$0.31	-$0.40
VT	Jul-15	$0.00	$0.00	-$0.01
VT	Aug-15	-$0.02	$0.02	-$0.04
VT	Sep-15	-$0.12	$0.01	-$0.13
VT	Oct-15	-$0.06	-$0.11	$0.06
VT	Nov-15	-$0.77	$0.07	-$0.84
VT	Dec-15	-$0.01	-$0.06	$0.06

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
CT	Apr-15	-$0.25	$0.04	-$0.29
CT	May-15	$0.07	$0.01	$0.05
CT	Jun-15	$0.89	$0.05	$0.84
CT	Jul-15	$0.00	$0.23	-$0.23
CT	Aug-15	$0.01	$0.20	-$0.19
CT	Sep-15	-$0.01	$0.14	-$0.16
CT	Oct-15	$0.01	$0.36	-$0.35
CT	Nov-15	-$1.02	$0.26	-$1.28
CT	Dec-15	$0.00	-$0.02	$0.02

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
RI	Apr-15	$0.60	$0.72	-$0.11
RI	May-15	-$0.02	$0.52	-$0.54
RI	Jun-15	$0.03	$0.48	-$0.45
RI	Jul-15	$0.02	$0.35	-$0.32
RI	Aug-15	$0.05	$0.45	-$0.40
RI	Sep-15	$0.58	$0.38	$0.20
RI	Oct-15	$0.06	$0.31	-$0.25
RI	Nov-15	$1.75	$0.44	$1.31
RI	Dec-15	$0.00	$0.36	-$0.36

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
SEMA	Apr-15	$0.23	$1.25	-$1.02
SEMA	May-15	-$0.03	$0.85	-$0.88
SEMA	Jun-15	$0.01	$0.69	-$0.68
SEMA	Jul-15	$0.01	$0.57	-$0.56
SEMA	Aug-15	$0.11	$0.45	-$0.33
SEMA	Sep-15	$0.14	$0.49	-$0.35
SEMA	Oct-15	$0.04	$0.76	-$0.71
SEMA	Nov-15	$0.81	$0.84	-$0.03
SEMA	Dec-15	$0.01	$0.65	-$0.64

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
WCMA	Apr-15	-$0.05	-$0.02	-$0.03
WCMA	May-15	$0.01	$0.01	$0.00
WCMA	Jun-15	$0.02	$0.01	$0.01
WCMA	Jul-15	$0.00	$0.01	-$0.01
WCMA	Aug-15	$0.01	$0.01	$0.00
WCMA	Sep-15	$0.02	$0.00	$0.02
WCMA	Oct-15	-$0.01	$0.01	-$0.01
WCMA	Nov-15	-$0.08	$0.00	-$0.08
WCMA	Dec-15	$0.00	-$0.01	$0.01

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
NEMA	Apr-15	$0.14	$0.56	-$0.42
NEMA	May-15	$0.07	$0.22	-$0.15
NEMA	Jun-15	$0.45	$0.27	$0.18
NEMA	Jul-15	$0.01	$0.29	-$0.28
NEMA	Aug-15	$0.02	$0.27	-$0.26
NEMA	Sep-15	$4.99	$0.15	$4.84
NEMA	Oct-15	$0.10	$1.37	-$1.27
NEMA	Nov-15	$0.59	$0.51	$0.08
NEMA	Dec-15	$0.00	$0.55	-$0.55

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
Dec-14	-$2,643,073	$107,284	$2,351,379	$2,458,663	$184,410	$2,643,073
Jan-15	-$2,550,692	$173,745	$2,204,769	$2,378,514	$172,177	$2,550,692
Feb-15	-$2,166,406	$145,223	$1,874,097	$2,019,320	$147,086	$2,166,406
Mar-15	-$2,514,028	$143,192	$2,176,677	$2,319,870	$194,158	$2,514,028
Apr-15	-$2,417,700	$136,857	$2,064,398	$2,201,255	$216,445	$2,417,700
May-15	-$2,197,557	$125,555	$1,912,888	$2,038,443	$159,114	$2,197,557
Jun-15	-$2,021,759	$122,082	$1,780,654	$1,902,736	$119,023	$2,021,759
Jul-15	-$2,244,746	$130,422	$2,007,525	$2,137,947	$106,799	$2,244,746
Aug-15	-$2,144,986	$128,899	$1,901,459	$2,030,358	$114,628	$2,144,986
Sep-15	-$1,941,326	$119,421	$1,732,040	$1,851,461	$89,865	$1,941,326
Oct-15	-$2,296,098	$145,650	$2,026,129	$2,171,779	$124,319	$2,296,098
Nov-15	-$2,232,470	$129,334	$1,993,071	$2,122,406	$110,064	$2,232,470
Dec-15	-$2,261,535	$135,105	$2,002,370	$2,137,475	$124,060	$2,261,535

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
Dec-14	$168,868	$64,940	$16,023	$173,628	$249,971	$161,924	$105,836	$714,559
Jan-15	$120,582	$105,351	$4,157	$63,151	$154,627	$217,542	$87,377	$683,897
Feb-15	$103,122	$89,931	$11,807	$60,185	$134,302	$174,781	$68,039	$569,961
Mar-15	$105,223	$90,752	$15,018	$109,133	$146,789	$261,148	$86,707	$603,665
Apr-15	$79,888	$67,221	$10,070	$98,070	$141,832	$280,684	$63,525	$564,530
May-15	$69,189	$60,429	$36,413	$73,990	$134,728	$226,954	$56,765	$534,279
Jun-15	$64,336	$54,729	$22,825	$70,630	$134,434	$222,044	$49,667	$535,597
Jul-15	$69,481	$60,740	$11,050	$96,817	$144,218	$276,784	$58,493	$603,794
Aug-15	$71,162	$65,176	$10,212	$99,689	$137,116	$215,461	$51,590	$587,400
Sep-15	$65,528	$69,911	$10,142	$81,719	$124,279	$198,297	$49,641	$525,890
Oct-15	$69,523	$66,762	$7,549	$92,653	$111,904	$194,700	$51,857	$745,946
Nov-15	$67,164	$62,795	$11,331	$121,603	$132,348	$258,533	$52,510	$598,698
Dec-15	$72,492	$65,266	$9,350	$87,667	$130,605	$223,969	$61,021	$624,576

Off Peak								
Month	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Dec-14	$70,408	$23,104	$2,298	$32,411	$233,978	$110,667	$33,913	$296,135
Jan-15	$79,400	$71,504	$1,710	$21,900	$113,880	$144,743	$52,146	$456,547
Feb-15	$60,370	$55,988	$2,618	$25,783	$106,787	$127,022	$44,147	$384,476
Mar-15	$62,923	$56,295	$6,612	$53,440	$106,431	$162,404	$51,794	$401,535
Apr-15	$53,948	$47,425	$4,816	$55,303	$109,411	$192,570	$43,419	$388,544
May-15	$42,314	$39,129	$7,294	$41,144	$119,038	$193,988	$35,713	$367,076
Jun-15	$35,343	$31,027	$5,328	$24,769	$104,954	$160,643	$27,408	$359,002
Jul-15	$37,882	$34,550	$3,554	$37,191	$108,363	$181,052	$30,528	$383,451
Aug-15	$38,110	$40,884	$3,269	$29,905	$113,866	$165,884	$30,259	$370,375
Sep-15	$37,148	$42,006	$1,801	$25,370	$98,289	$151,276	$25,490	$344,675
Oct-15	$40,123	$40,063	$3,247	$60,337	$90,382	$128,523	$30,221	$437,990
Nov-15	$44,435	$42,624	$2,139	$38,584	$105,657	$166,967	$32,637	$384,382
Dec-15	$53,014	$49,061	$3,522	$38,313	$105,883	$146,699	$41,511	$424,526

Section 8

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 sixteenth Forward Reserve Market Auction, covering the Winter 2015-2016 Procurement Period (October-May) cleared on September 9, 2015. 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 December 2015, the threshold price ranged from $16.20 to $43.88 and averaged $31.19.

Section 9

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)[6]. 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, December 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	$2,862,024	$2,856,203	-$8,824	-$1,876	$2,845,503	99%
SYSTEM	TMOR	$1,286,648	$1,272,069	-$24,806	$0	$1,247,263	97%
SYSTEM	TOTAL	$4,148,672	$4,128,272	-$33,630	-$1,876	$4,092,766	99%
ROS	TMNSR	$1,537,488	$1,535,461	-$3,134	-$1,500	$1,530,827	100%
ROS	TMOR	$492,242	$484,272	-$14,892	$0	$469,380	95%
ROS	TOTAL	$2,029,730	$2,019,732	-$18,026	-$1,500	$2,000,206	99%
SWCT	TMNSR	$0	$0	$0	-$376	-$376	n/a
SWCT	TMOR	$367,282	$363,816	-$5,201	$0	$358,616	98%
SWCT	TOTAL	$367,282	$363,816	-$5,201	-$376	$358,240	98%
CT	TMNSR	$1,324,536	$1,320,742	-$5,690	$0	$1,315,053	99%
CT	TMOR	$427,123	$423,981	-$4,714	$0	$419,267	98%
CT	TOTAL	$1,751,659	$1,744,723	-$10,403	$0	$1,734,320	99%
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

[6] 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.

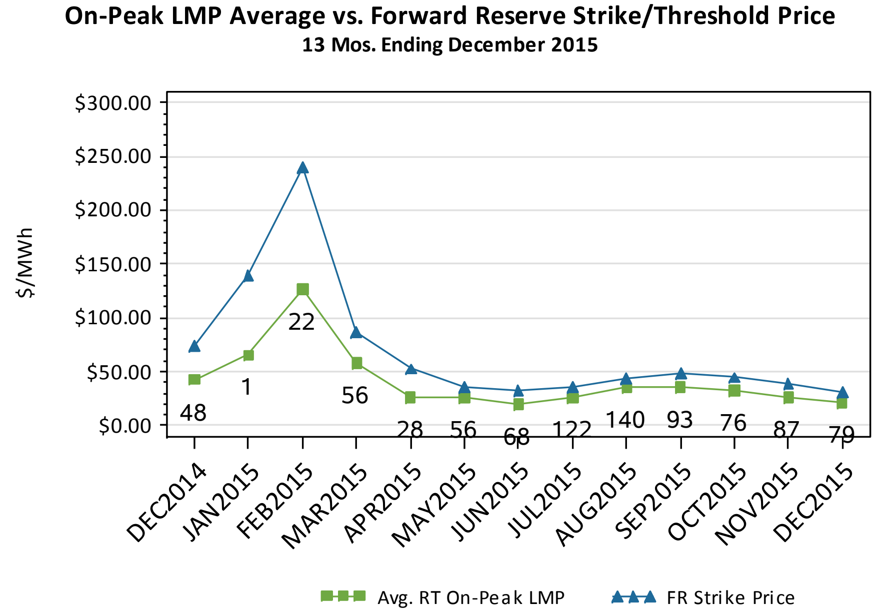
The ISO allocates Forward Reserve Credits, net of Forward Reserve Failure-to-Reserve Penalties and Forward Reserve Failure-to-Activate Penalties, to each Load Zone. The Forward Reserve charge allocation method changed on June 1, 2011. Under the new Forward Reserve Cost Allocation, the Forward Reserves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

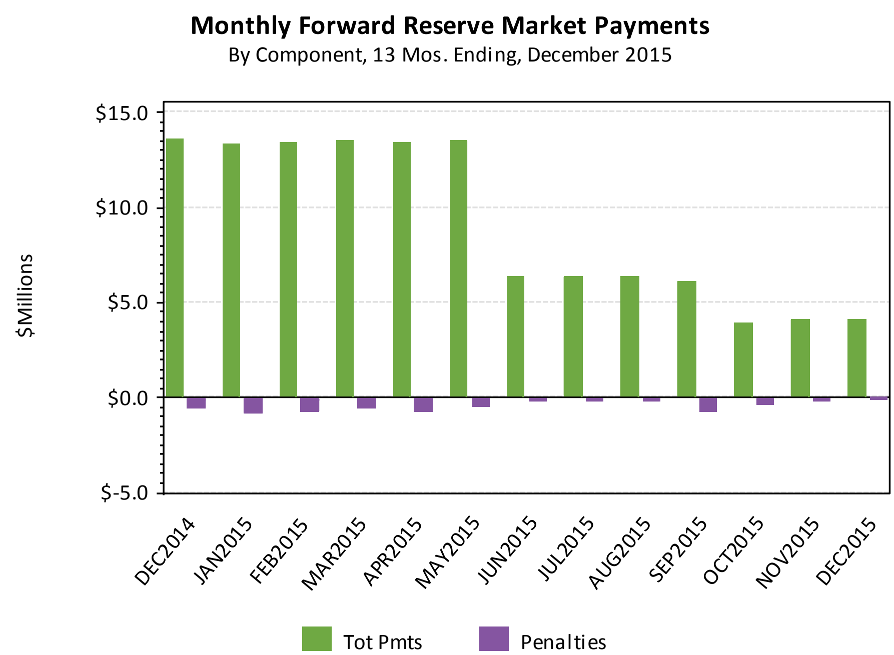
Load Zone	FRM Charge
ME	$390,766
NH	$392,919
VT	$192,263
CT	$1,005,020
RI	$259,056
SEMA	$475,966
WCMA	$558,365
NEMA	$818,411
ALL	$4,092,766

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 56 separate hours. On a reserve zone basis, non-zero prices occurred thus: CT-56 hours; NEMABSTN-56 hours; ROS-56 hours; SWCT-56 hours. The total compensation paid to assets providing real-time reserves during December 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	$721,686	($231,134)	$490,552
ROS	$350,834	($103,278)	$247,556
SWCT	$191,169	($16,288)	$174,882
CT	$154,875	($111,568)	$43,306
NEMABSTN	$24,808	$0	$24,808

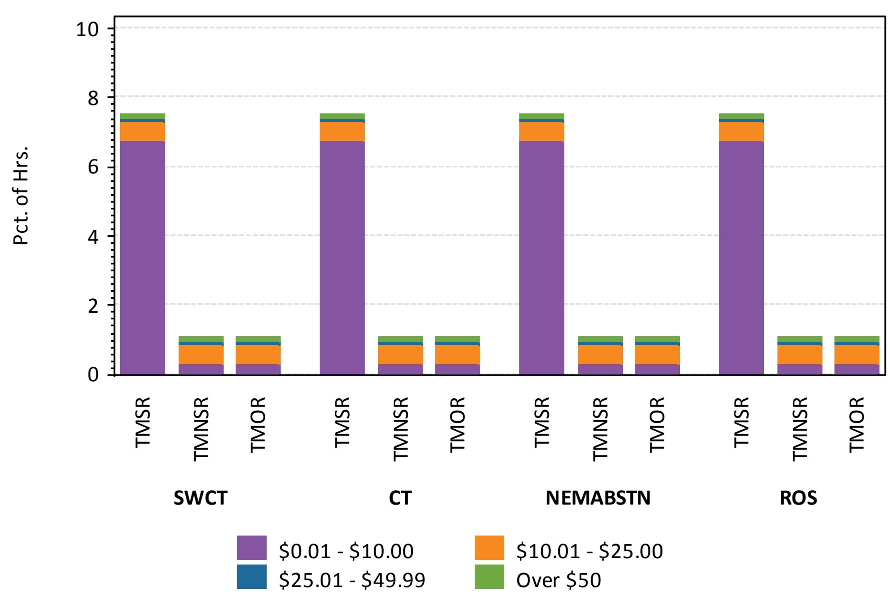
The ISO allocates Real Time Reserve Credits, net of Forward Reserve Energy Obligation Charges, to each Load Zone. The Real Time Reserve charges allocated to each Load Zone during the month are shown in the following table. These figures are also preliminary and subject to revision during the Settlement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

Load Zone	Reserve Product	RT Reserve Charge
ME	TMSR	$15,579
ME	TMNSR	$24,899
ME	TMOR	$7,462
ME	ALL	$47,940
NH	TMSR	$15,515
NH	TMNSR	$24,523
NH	TMOR	$7,298
NH	ALL	$47,336
VT	TMSR	$7,492
VT	TMNSR	$11,888
VT	TMOR	$3,555
VT	ALL	$22,935
CT	TMSR	$38,899
CT	TMNSR	$61,079
CT	TMOR	$18,176
CT	ALL	$118,154
RI	TMSR	$10,273

Load Zone	Reserve Product	RT Reserve Charge
RI	TMNSR	$16,307
RI	TMOR	$4,854
RI	ALL	$31,434
SEMA	TMSR	$19,326
SEMA	TMNSR	$30,850
SEMA	TMOR	$9,185
SEMA	ALL	$59,361
WCMA	TMSR	$21,960
WCMA	TMNSR	$34,622
WCMA	TMOR	$10,271
WCMA	ALL	$66,853
NEMA	TMSR	$31,649
NEMA	TMNSR	$50,029
NEMA	TMOR	$14,861
NEMA	ALL	$96,538

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.

Real-Time Reserve Price Frequency, December 2015



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.

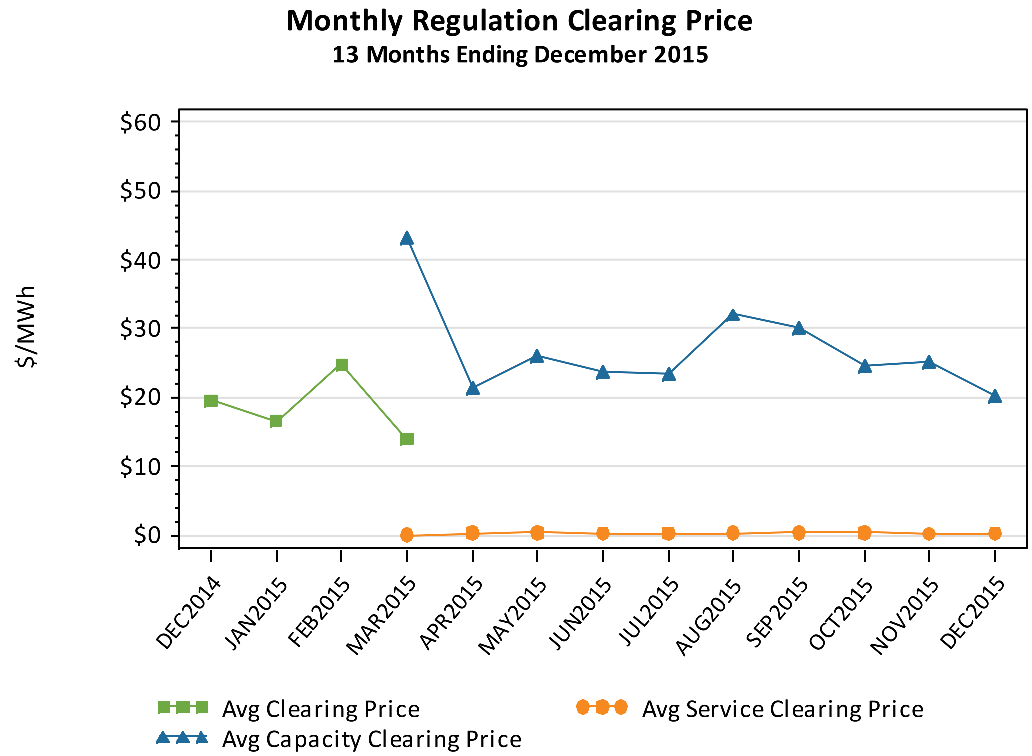
The business rules and procedures for forward and real-time reserve can be found in the ISO’s Manual 28 –Market Rule 1 Accounting located here.

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.

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
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
Feb-15	$20.39	$222.55	$4.00	$20.09	$28.80	$214.05	$4.19	$27.23
Mar-15[7]	$11.46	$66.82	$3.67	$8.51	$16.13	$167.32	$2.86	$17.25

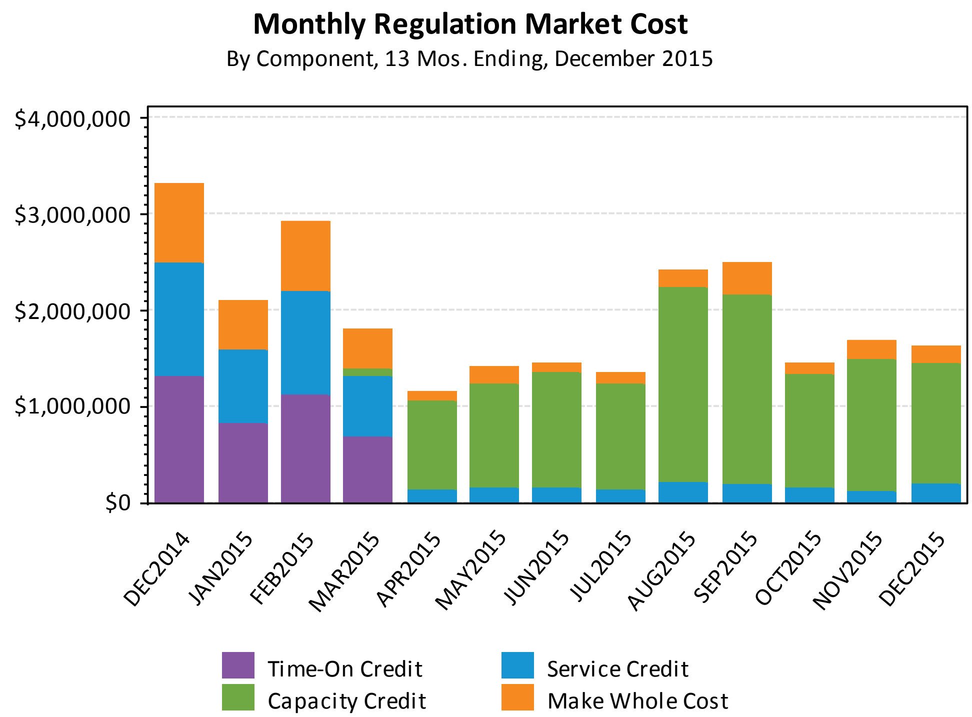
[7] March 1-30, 2015

Month	On-Peak Service Clearing Price Statistics				Off-Peak Service Clearing Price Statistics			
	Mean	Max	Min	StdDev	Mean	Max	Min	StdDev
Mar-15[8]	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-15	$0.16	$8.33	$0.00	$0.51	$0.44	$10.00	$0.00	$1.07
May-15	$0.28	$10.00	$0.00	$0.70	$0.39	$5.00	$0.00	$0.63
Jun-15	$0.13	$1.63	$0.00	$0.23	$0.41	$9.32	$0.00	$1.09
Jul-15	$0.30	$9.32	$0.00	$0.75	$0.27	$4.21	$0.00	$0.35
Aug-15	$0.43	$10.00	$0.00	$1.11	$0.21	$1.58	$0.00	$0.32
Sep-15	$0.40	$6.69	$0.00	$0.83	$0.27	$2.58	$0.00	$0.33
Oct-15	$0.34	$3.00	$0.00	$0.40	$0.31	$3.00	$0.00	$0.44
Nov-15	$0.26	$3.25	$0.00	$0.41	$0.21	$3.00	$0.00	$0.34
Dec-15	$0.27	$5.00	$0.00	$0.54	$0.27	$2.58	$0.00	$0.34

Month	On-Peak Capacity Clearing Price Statistics				Off-Peak Capacity Clearing Price Statistics			
	Mean	Max	Min	StdDev	Mean	Max	Min	StdDev
Mar-15[7]	$25.95	$38.94	$11.63	$10.67	$77.63	$103.66	$47.98	$16.66
Apr-15	$21.17	$311.42	$5.20	$19.30	$21.61	$123.38	$2.51	$16.97
May-15	$22.71	$103.94	$5.69	$12.92	$28.46	$1172.47	$3.80	$79.10
Jun-15	$23.49	$167.02	$5.03	$17.56	$23.96	$158.94	$4.48	$21.02
Jul-15	$27.23	$238.79	$2.44	$26.57	$19.77	$157.95	$3.67	$16.79
Aug-15	$42.56	$406.99	$5.71	$50.55	$23.40	$633.04	$4.43	$35.71
Sep-15	$39.82	$452.31	$4.70	$53.68	$21.65	$361.07	$2.53	$24.74
Oct-15	$25.02	$107.33	$6.16	$15.82	$24.41	$179.50	$2.93	$21.64
Nov-15	$23.71	$278.26	$4.83	$25.12	$26.20	$165.23	$4.26	$22.53
Dec-15	$19.91	$247.86	$3.24	$19.97	$20.47	$221.93	$4.65	$19.43

[8] March 31, 2015 only.

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
Dec-14	$1,306,281	$1,193,306	$0	$818,771	$3,318,359
Jan-15	$831,261	$755,841	$0	$507,000	$2,094,103
Feb-15	$1,125,593	$1,066,715	$0	$742,775	$2,935,082
Mar-15	$677,989	$635,039	$87,609	$408,462	$1,809,099
Apr-15	$0	$129,914	$929,817	$91,276	$1,151,008
May-15	$0	$148,482	$1,092,814	$166,408	$1,407,704
Jun-15	$0	$151,530	$1,193,435	$105,423	$1,450,389
Jul-15	$0	$143,908	$1,100,080	$115,006	$1,358,994
Aug-15	$0	$214,678	$2,021,950	$175,425	$2,412,052
Sep-15	$0	$197,877	$1,967,593	$327,013	$2,492,483
Oct-15	$0	$160,852	$1,172,225	$122,919	$1,455,996
Nov-15	$0	$123,363	$1,365,937	$202,282	$1,691,582
Dec-15	$0	$189,570	$1,260,422	$171,565	$1,621,557

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 December 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
Dec-14	$7,518,915	$1,212,899	-$11,030,579	-$684,082	$440,617	-$946,159	$3,511,664	-$23,274	$3,488,390
Jan-15	$13,875,915	$14,178	-$20,183,921	-$338,889	-$227,633	$0	$6,308,006	$552,345	$6,860,351
Feb-15	$22,956,432	-$3,861,822	-$33,705,474	-$734,152	$244,780	$0	$10,749,042	$4,351,193	$15,100,235
Mar-15	$12,121,748	-$1,510,441	-$16,153,401	-$269,579	$132,431	$24,355	$4,031,654	$1,623,233	$5,654,887
Apr-15	$4,197,773	-$550,028	-$5,356,046	-$169,550	$227,176	$0	$1,158,273	$492,402	$1,650,675
May-15	$3,904,558	-$173,692	-$5,504,937	-$231,966	$430,497	$0	$1,600,379	-$24,839	$1,575,540
Jun-15	$3,400,051	$211,921	-$4,788,499	-$213,246	$19,880	$0	$1,388,448	-$18,554	$1,369,894
Jul-15	$5,211,688	-$323,313	-$7,254,239	-$330,707	$251,997	$0	$2,042,550	$402,023	$2,444,574
Aug-15	$5,419,485	-$414,471	-$7,296,585	-$336,211	$131,657	$0	$1,877,101	$619,025	$2,496,126
Sep-15	$5,405,792	-$909,051	-$7,536,274	-$426,821	-$860,980	$0	$2,130,482	$2,196,851	$4,327,333
Oct-15	$5,944,699	-$784,609	-$8,593,712	-$180,481	-$742,207	$0	$2,649,013	$1,707,297	$4,356,310
Nov-15	$4,892,954	-$160,964	-$7,171,370	-$166,601	-$557,704	$0	$2,278,416	$885,269	$3,163,684
Dec-15	$3,588,631	$512,481	-$5,110,770	-$142,560	-$719,172	$0	$1,522,139	$349,252	$1,871,391

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 6, the 2015-2016 commitment period, with prorated amounts and change from the FCA for each resource type.

2015-2016 Forward Capacity Auction

Resource Type	FCA CSO MW	Prorated CSO MW	Proration Change MW
Demand	3,645	3,472	-173
Generator	30,757	28,798	-1,959
Import	1,924	1,768	-156
Total	36,326	34,038	-2,288

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
Dec-14	$0	$0	$0	$0	$0	$0	$0	$984,410
Jan-15	$0	$0	$0	$0	$0	$0	$0	$984,410
Feb-14	$0	$0	$0	$0	$0	$0	$0	$984,410
Mar-14	$0	$0	$0	$0	$0	$0	$0	$984,410
Apr-15	$0	$0	$0	$0	$0	$0	$0	$988,468
May-15	$0	$0	$0	$0	$0	$0	$0	$988,468

Month	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Jun-15	$0	$0	$0	$0	$0	$0	$96	$861,481
Jul-15	$0	$0	$0	$0	$0	$0	$96	$861,481
Aug-15	$0	$0	$0	$0	$0	$0	$96	$861,481
Sep-15	$0	$0	$0	$0	$0	$0	$96	$861,481
Oct-15	$0	$0	$0	$0	$0	$0	$167	$862,385
Nov-15	$0	$0	$0	$0	$0	$0	$167	$862,385
Dec-15	$0	$0	$0	$0	$0	$0	$167	$858,698

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 December 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	-229.18	-115.43	-6.37	-51.23	0.00	-402.22
Rest-of-Pool	Generator	0.00	-52.86	-13.50	-48.37	-27.38	-0.21	-142.31
Rest-of-Pool	Import	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total	0.00	-282.04	-128.93	-54.74	-78.61	-0.21	-544.53

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 December 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	2,887	$8,894,458	-401.69	-$1,354,148	2,485.34	$7,540,310
Rest-of-Pool	Generator	30,203	$87,340,944	-149.82	-$476,630	30,053.46	$86,864,315
Rest-of-Pool	Import	1,124	$4,576,206	0.00	$0	1,123.59	$4,576,206
	Total	34,214	$100,811,608	-551.51	-$1,830,777	33,662.39	$98,980,830

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
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
Apr-15	Rest-of-Pool	$93,732,433	$0	-$767,700	$92,964,733
May-15	Rest-of-Pool	$93,732,433	$0	-$767,700	$92,964,733
Jun-15	Rest-of-Pool	$98,950,067	$0	-$878,406	$98,071,661
Jul-15	Rest-of-Pool	$98,947,696	$0	-$885,249	$98,062,447
Aug-15	Rest-of-Pool	$98,934,393	$0	-$885,249	$98,049,145
Sep-15	Rest-of-Pool	$98,930,901	$0	-$885,249	$98,045,652
Oct-15	Rest-of-Pool	$99,585,324	$0	-$868,837	$98,716,488
Nov-15	Rest-of-Pool	$99,585,324	$0	-$869,569	$98,715,755
Dec-15	Rest-of-Pool	$99,854,666	$0	-$873,836	$98,980,830

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)
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
Apr-15	Rest-of-Pool	32,870	$92,964,733	-$2,677,728	$0	$90,287,005	$0	$90,287,005
May-15	Rest-of-Pool	32,870	$92,964,733	-$2,685,472	$0	$90,279,260	$0	$90,279,260
Jun-15	Rest-of-Pool	33,388	$98,071,661	-$3,572,771	$0	$94,498,890	$0	$94,498,890
Jul-15	Rest-of-Pool	33,382	$98,062,447	-$3,571,826	$0	$94,490,621	$0	$94,490,621
Aug-15	Rest-of-Pool	33,378	$98,049,145	-$3,568,844	$0	$94,480,301	$0	$94,480,301
Sep-15	Rest-of-Pool	33,377	$98,045,652	-$4,691,033	$0	$93,354,619	$0	$93,354,619

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)
Oct-15	Rest-of-Pool	33,580	$98,716,488	-$5,379,309	$0	$93,337,178	$0	$93,337,178
Nov-15	Rest-of-Pool	33,579	$98,715,755	-$5,394,379	$0	$93,321,376	$0	$93,321,376
Dec-15	Rest-of-Pool	33,662	$98,980,830	-$5,445,629	$0	$93,535,202	$0	$93,535,202

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
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
Apr-15	32,870	204	996	0	3,166	33,866	26,911	29,704	$3.039607	$90,287,005
May-15	32,870	204	996	0	3,166	33,866	26,911	29,704	$3.039346	$90,279,260
Jun-15	33,388	115	1,042	0	4,164	34,430	24,068	29,225	$3.233514	$94,498,890
Jul-15	33,382	115	1,042	0	4,164	34,424	24,068	29,219	$3.233892	$94,490,621
Aug-15	33,378	115	1,042	0	4,164	34,420	24,068	29,215	$3.233971	$94,480,301
Sep-15	33,377	115	1,042	0	4,164	34,419	24,068	29,214	$3.195551	$93,354,619
Oct-15	33,580	115	1,042	0	4,163	34,622	24,068	29,417	$3.172952	$93,337,178
Nov-15	33,579	115	1,042	0	4,163	34,621	24,068	29,416	$3.172475	$93,321,376
Dec-15	33,662	115	1,042	0	4,163	34,704	24,068	29,499	$3.170781	$93,535,202

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

$(CCP-2)_{Pool}) * (CSO_{Pool} + HQICC\ MW_{pool} - Excess\ RTEG\ MW_{pool}) * (-1)$

$CLO_{Capacity\ Zone} = Capacity\ Requirement_{Capacity\ Zone} - HQICC\ MW_{Capacity\ Zone} - CLO\ Self\text{-}Supply\ MW_{Capacity\ Zone}$

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
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
Apr-15	Rest-of-Pool	32,870	996	3,166	33,866	26,911	29,704	$3.039607	$90,287,005
May-15	Rest-of-Pool	32,870	996	3,166	33,866	26,911	29,704	$3.039346	$90,279,260
Jun-15	Rest-of-Pool	33,388	1,042	4,164	34,430	24,068	29,225	$3.233514	$94,498,890
Jul-15	Rest-of-Pool	33,382	1,042	4,164	34,424	24,068	29,219	$3.233892	$94,490,621
Aug-15	Rest-of-Pool	33,378	1,042	4,164	34,420	24,068	29,215	$3.233971	$94,480,301
Sep-15	Rest-of-Pool	33,377	1,042	4,164	34,419	24,068	29,214	$3.195551	$93,354,619
Oct-15	Rest-of-Pool	33,580	1,042	4,163	34,622	24,068	29,417	$3.172952	$93,337,178
Nov-15	Rest-of-Pool	33,579	1,042	4,163	34,621	24,068	29,416	$3.172475	$93,321,376
Dec-15	Rest-of-Pool	33,662	1,042	4,163	34,704	24,068	29,499	$3.170781	$93,535,202

12.3 PER Adjustment

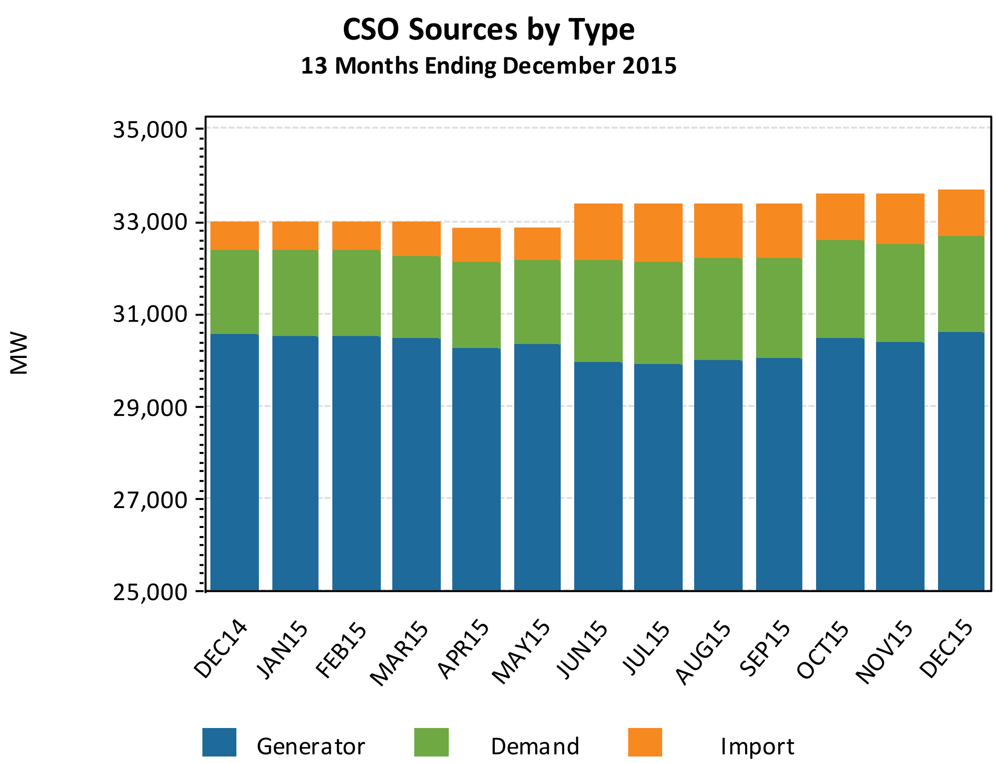
As stated above, PER is a payment adjustment made to reflect revenues earned by resources during high priced hours in the Energy markets. Generation and Import resources with a CSO are subject to PER adjustments (excluding self-supply CSO MWs). Demand resources are not subject to PER adjustments.

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
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
Apr-15	Rest-of-Pool	27,893	0.096	$2,677,728
May-15	Rest-of-Pool	27,974	0.096	$2,685,472
Jun-15	Rest-of-Pool	27,066	0.132	$3,572,771
Jul-15	Rest-of-Pool	27,059	0.132	$3,571,826
Aug-15	Rest-of-Pool	27,037	0.132	$3,568,844
Sep-15	Rest-of-Pool	27,116	0.173	$4,691,033
Oct-15	Rest-of-Pool	27,306	0.197	$5,379,309
Nov-15	Rest-of-Pool	27,383	0.197	$5,394,379
Dec-15	Rest-of-Pool	27,503	0.198	$5,445,629

12.4 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
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
Apr-15	1,840	30,269	760	32,870
May-15	1,836	30,340	694	32,870
Jun-15	2,194	29,967	1,227	33,388
Jul-15	2,188	29,907	1,287	33,382
Aug-15	2,209	29,987	1,182	33,378
Sep-15	2,146	30,049	1,182	33,377
Oct-15	2,135	30,467	978	33,580
Nov-15	2,132	30,378	1,069	33,579
Dec-15	2,095	30,601	967	33,662

12.5 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
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
Apr-15	Rest-of-Pool	146	0	78	194	418
May-15	Rest-of-Pool	80	0	78	194	352
Jun-15	Rest-of-Pool	82	0	0	180	261
Jul-15	Rest-of-Pool	82	0	0	180	261
Aug-15	Rest-of-Pool	82	0	39	180	300
Sep-15	Rest-of-Pool	82	0	39	180	300
Oct-15	Rest-of-Pool	82	0	0	31	113
Nov-15	Rest-of-Pool	82	0	0	31	113
Dec-15	Rest-of-Pool	82	0	0	31	113

12.6 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.

12.6.1 *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
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
Apr-15	0	0.00	Generator	0	0	$0
Apr-15	0	0.00	Import	0	0	$0
May-15	0	0.00	Generator	0	0	$0
May-15	0	0.00	Import	0	0	$0
Jun-15	0	0.00	Generator	0	0	$0
Jun-15	0	0.00	Import	0	0	$0
Jul-15	0	0.00	Generator	0	0	$0
Jul-15	0	0.00	Import	0	0	$0
Aug-15	0	0.00	Generator	0	0	$0
Aug-15	0	0.00	Import	0	0	$0
Sep-15	0	0.00	Generator	0	0	$0
Sep-15	0	0.00	Import	0	0	$0
Oct-15	0	0.00	Generator	0	0	$0
Oct-15	0	0.00	Import	0	0	$0
Nov-15	0	0.00	Generator	0	0	$0
Nov-15	0	0.00	Import	0	0	$0
Dec-15	0	0.00	Generator	0	0	$0
Dec-15	0	0.00	Import	0	0	$0

12.6.2 *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 ($)	Performance Incentive ($)
Dec-14	ON_PEAK	44	1,032.94	1,649.05	-12.80	628.90	-$36,533	$111,478
Dec-14	REAL_TIME	0	296.15	331.18	-32.27	67.31	-$92,771	$11,375
Dec-14	REAL_TIME_EG	0	145.22	145.42	-15.04	15.24	-$35,705	$2,072
Dec-14	SEASONAL_PEAK	4	347.18	592.22	0.00	245.04	$0	$40,084
Jan-15	ON_PEAK	42	1,033.04	1,657.12	-11.43	635.51	-$32,644	$183,246
Jan-15	REAL_TIME	0	282.64	333.14	-37.44	87.93	-$120,177	$23,570
Jan-15	REAL_TIME_EG	0	179.03	146.19	-47.23	14.38	-$112,119	$3,182
Jan-15	SEASONAL_PEAK	30	347.18	553.62	0.00	206.44	$0	$54,943
Feb-15	ON_PEAK	0	1,032.24	1,654.07	-9.18	631.01	-$26,215	$118,243
Feb-15	REAL_TIME	0	274.02	326.20	-4.27	56.45	-$12,154	$9,955
Feb-15	REAL_TIME_EG	0	186.59	145.80	-55.17	14.38	-$130,981	$2,070
Feb-15	SEASONAL_PEAK	0	347.18	572.92	0.00	225.74	$0	$39,082
Mar-15	ON_PEAK	0	1,040.29	1,653.41	-10.02	623.14	-$28,610	$28,925
Mar-15	REAL_TIME	0	280.69	332.22	-4.63	56.16	-$13,196	$2,466
Mar-15	REAL_TIME_EG	0	126.14	145.80	-0.01	19.67	-$21	$705
Mar-15	SEASONAL_PEAK	0	347.18	572.92	0.00	225.74	$0	$9,731
Apr-15	ON_PEAK	0	1,033.65	1,233.77	-2.94	203.06	-$8,388	$5,969
Apr-15	REAL_TIME	0	318.75	355.32	-0.32	36.89	-$865	$1,073
Apr-15	REAL_TIME_EG	0	140.86	159.32	-0.01	18.48	-$19	$430
Apr-15	SEASONAL_PEAK	0	347.18	411.45	0.00	64.27	$0	$1,800

Month	DR Type	Performance Hours	CSO MW	Capacity Value (MW)	Negative Capacity Variance (MW)	Positive Capacity Variance (MW)	Performance Penalty ($)	Performance Incentive ($)
May-15	ON_PEAK	0	1,028.85	1,234.19	-2.75	208.10	-$7,854	$5,692
May-15	REAL_TIME	0	318.74	355.32	-0.32	36.90	-$865	$989
May-15	REAL_TIME_EG	0	140.86	159.32	-0.01	18.48	-$19	$397
May-15	SEASONAL_PEAK	0	347.18	411.45	0.00	64.27	$0	$1,659
Jun-15	ON_PEAK	88	1,321.97	1,506.82	-23.37	208.23	-$73,125	$112,809
Jun-15	REAL_TIME	0	322.86	372.56	-8.07	57.77	-$24,182	$32,018
Jun-15	REAL_TIME_EG	0	192.31	165.41	-34.74	7.84	-$105,736	$4,141
Jun-15	SEASONAL_PEAK	0	356.86	456.44	0.00	99.58	$0	$54,075
Jul-15	ON_PEAK	88	1,321.31	1,533.53	-20.79	233.01	-$65,136	$138,231
Jul-15	REAL_TIME	0	325.06	351.79	-29.84	56.58	-$94,737	$33,783
Jul-15	REAL_TIME_EG	0	184.86	172.14	-25.91	13.20	-$78,882	$7,633
Jul-15	SEASONAL_PEAK	7	356.86	456.28	0.00	99.43	$0	$59,107
Aug-15	ON_PEAK	84	0.00	0.00	0.00	0.00	$0	$0
Aug-15	SEASONAL_PEAK	1	0.00	0.00	0.00	0.00	$0	$0
Sep-15	ON_PEAK	0	0.00	0.00	0.00	0.00	$0	$0
Sep-15	SEASONAL_PEAK	0	0.00	0.00	0.00	0.00	$0	$0
Oct-15	ON_PEAK	0	0.00	0.00	0.00	0.00	$0	$0
Oct-15	SEASONAL_PEAK	0	0.00	0.00	0.00	0.00	$0	$0
Nov-15	ON_PEAK	0	0.00	0.00	0.00	0.00	$0	$0
Nov-15	SEASONAL_PEAK	0	0.00	0.00	0.00	0.00	$0	$0
Dec-15	ON_PEAK	44	0.00	0.00	0.00	0.00	$0	$0
Dec-15	SEASONAL_PEAK	0	0.00	0.00	0.00	0.00	$0	$0

12.7 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
Dec-14	1,912	2,326	2,477	0	565	16,393	361
Jan-15	2,845	3,693	3,933	-93	995	17,416	50
Feb-15	2,472	2,621	2,791	0	319	17,604	0
Mar-15	1,362	1,602	1,706	-63	281	16,160	0
Apr-15	63	123	131	-25	42	14,277	0
May-15	1,720	2,108	2,245	-22	503	14,977	0
Jun-15	1,428	1,983	2,092	-146	517	16,116	137
Jul-15	3,385	4,538	4,787	-42	1,361	18,901	316
Aug-15	3,018	4,349	4,588	-22	1,547	18,982	81
Sep-15	2,238	3,065	3,233	-26	969	17,407	0
Oct-15	1,929	2,261	2,385	-14	442	14,087	0
Nov-15	2,391	2,755	2,906	-20	495	14,474	0
Dec-15	1,937	2,926	3,087	-3	1,147	15,315	291

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
Dec-14	$108,880	$41,030	$14,153	$164,062	$0.00
Jan-15	$256,865	$99,589	$3,611	$360,064	$0.00
Feb-15	$346,410	$45,652	$0	$392,062	$0.00
Mar-15	$125,681	$24,695	$0	$150,375	$0.00
Apr-15	$4,228	$3,096	$0	$7,325	$0.00
May-15	$61,626	$17,615	$0	$79,241	$0.00
Jun-15	$40,974	$16,848	$2,510	$60,332	$0.00
Jul-15	$163,842	$63,461	$15,375	$242,678	$0.00
Aug-15	$146,694	$115,481	$10,076	$272,250	$0.00
Sep-15	$117,715	$85,101	$4	$202,820	$0.00

Month	DA Payment Dollars	RT Payment Dollars	FCM Audit Demand Reduction Dollars	Total Payment (Charge) Dollars	Charge per MWh
Oct-15	$90,737	$18,058	$0	$108,794	$0.00
Nov-15	$88,988	$18,309	$0	$107,297	$0.00
Dec-15	$57,216	$39,956	$6,869	$104,041	$0.00

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.

15. Document History

Date	Version	Description
1/12/2016	Original Posting	