



David T. Doot
Secretary

September 26, 2014

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of October 3, 2014 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the NEPOOL Participants Committee will be held on **Friday, October 3, 2014 at 10:00 a.m. at The Colonnade Hotel, 120 Huntington Avenue, Boston, MA.** The Participants Committee meeting will be held in the Huntington Ballroom for the purposes set forth on the attached agenda and posted with the meeting materials at http://nepool.com/NPC_2014.php. For your information, this meeting is recorded, as are all the NEPOOL Participants Committee meetings.

We remind you of two items requiring your attention following the October meeting:

- The November 7, 2014 Participants Committee meeting will be preceded by discussions among members and the ISO Board and members and State regulators. That November meeting and meetings with the Board and regulators will be at the Hilton Logan Boston Airport Hotel. The format for the Board and regulators discussions will continue to be separate meetings organized along modified Sector lines. The ISO has requested that groups consider providing written materials for review by the Board ahead of those meetings, and that any materials be furnished to the ISO for distribution by **Friday, October 17** (but in no event later than Tuesday, October 21). This schedule will allow all materials to be consolidated and provided to the Board (and regulators as appropriate) in time for them to prepare for discussions prior to the meetings on November 7.
- Sectors should begin the process for choosing their Sector officers for 2015. Please review the memorandum concerning the selection process for next year's Committee officers that is included with this notice.

Rooms at the Colonnade for the October 3 meeting are available at the rate of \$279.00 per night, on a first-come, first-served basis **UNTIL next Monday, September 29, 2014.** To take advantage of these arrangements, please contact the Colonnade (617-424-7000) and reference the "NEPOOL Participants Committee" block of rooms. Please note that hotel rooms in Boston during this time period are very limited so please make your reservations as soon as possible.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. ~~To approve the preliminary minutes of the Participants Committee meeting held on September 12.~~ *Deferred.* [The preliminary September 12, 2014 minutes will be considered at the November meeting.]
2. To adopt and approve all actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice. Please note that Consent Agenda Item No. 3.b has been removed at the request of VELCO and will be discussed as Item 6A.
3. To receive an ISO Chief Executive Officer Report.
4. To receive an ISO Chief Operating Officer Report.
5. To consider, and take action, as appropriate, on the following proposed budgets:
 - a. 2015 ISO-NE Operating and Capital Budgets; and
 - b. 2015 NESCOE pro forma budget.

Background materials and draft resolutions are included with this supplemental notice.

6. To consider, and to take action as appropriate on, follow up compliance with Order No. 784 for Regulation and Frequency Response Service (Docket No. ER14-877-000). Background materials and a draft resolution are included with this supplemental notice.
- 6A. To consider, and to take action as appropriate on, Reliability Committee-recommended values for the New England Installed Capacity Requirement (ICR), the capacity requirement values for the System-Wide Capacity Demand Curve and the Connecticut, NEMA/BOSTON and SEMA/RI Local Sourcing Requirements for the 2018-19 Capability Period (FCA9). Background materials and a draft resolution are included with this supplemental notice.
7. To consider, and take action as appropriate on, proposed modifications to the Peak Energy Rent (PER) mechanism in the Forward Capacity Market. Background materials and a draft resolution are included with this supplemental notice.
- 7A. To consider, and to take action as appropriate on, Markets Committee-recommended revisions to Market Rule 1 (including Appendices E1 and E2) and the Tariff's Definition Section (I.2.2) that address Demand Response Resource participation in the Energy and Reserve Markets. Background materials and a draft resolution are included with this supplemental notice.
8. To consider, and to take action as appropriate on, (a) the request of Tangent Energy Solutions to transition to the AR Load Response Small Group Member from the AR Load Response Provisional Group Member), and (b) the balloting of amendments to the NEPOOL and Participants Agreements to allow for that transition. Revised materials and a draft resolution are included with this supplemental notice.

9. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts. The litigation report will be posted in advance of the meeting.
10. To receive reports from committees and subcommittees.
11. To transact such other business as may properly come before the meeting.

blank

CONSENT AGENDA

From the notice of actions of the September 3-4, 2014 **Markets Committee**¹ meeting, dated September 5, 2014, which has been previously circulated:

1. **Market Rule Revisions (FCM Administrative Clarifications)**

Support revisions to Market Rule 1 to implement corrections to the application of PER for certain demand resources to include Real-Time Reserve Designations in the calculation of Actual Capacity Provided for resources under the previously filed FCM Performance Incentives provisions and clarifications regarding pricing terminology under certain situations, as recommended by the Markets Committee at its September 3-4, 2014, 2014 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously with two abstentions (1- Transmission Sector; 1- Supplier Sector).

2. **Conforming Revisions (Capacity Zone Modeling Rules)**

Support revisions to Market Rule 1 and Manual M-20 to implement conforming rules which address the recent changes to the triggers for modeling capacity zones in the Forward Capacity Auctions to address bilateral trading and other issues, as recommended by the Markets Committee at its September 3-4, 2014 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

From the notice of actions of the September 16, 2014 **Reliability Committee**² meeting, dated September 17, 2014, which has been previously circulated:

3. **HQICC Values for FCA9 (2018/2019 Capability Period)**

3a. **HQICC Values for FCA9 (2018-19 Capability Period)**

Support the following megawatt values that represent the Hydro-Québec Interconnection Capability Credit (HQICC) for the Forward Capacity Auction for the 2018/2019 Capacity Commitment Period (FCA9), as recommended by the Reliability Committee at its September 16, 2014 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve:

¹ Markets Committee Notices of Actions are posted on the ISO website at: http://www.iso-ne.com/committees/comm_wkgrps/mrktts_comm/mrktts/actions/index.html

² Reliability Committee Notices of Actions are posted on the ISO website at: http://www.iso-ne.com/committees/comm_wkgrps/reblty_comm/reblty/actions/index.html.

2018/2019 Capacity Commitment Period Month	HQICC Values (MW)
June	953
July	953
August	953
September	953
October	953
November	953
December	953
January	953
February	953
March	953
April	953
May	953

The motion to recommend Participants Committee support was approved, with two oppositions and one abstention in the Supplier Sector noted.

**FCA9 ICR/DEMAND CURVE/LSR VALUES REMOVED FROM CONSENT AGENDA.
TO BE DISCUSSED AS AGENDA ITEM #6A**

3b. ICR/Demand Curve/LSR Values for FCA9 2018-19 Capability Period

Support the following megawatt values that represent the New England Installed Capacity Requirement (ICR), the capacity requirement values for the System-Wide Capacity Demand Curve (Demand Curve) and the Connecticut, NEMA/BOSTON and SEMA/RI Local Sourcing Requirements (LSR) for FCA9, as recommended by the Reliability Committee at its September 16, 2014 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve:

	2018/2019 Values (MW)
Installed Capacity Requirement	35,142
Net Installed Capacity Requirement (Net ICR)	34,189
1-in-5 LOLE Demand Curve capacity value	33,132
1-in-87 LOLE Demand Curve capacity value	37,027
Connecticut Local Sourcing Requirement	7,331
NEMA/Boston Local Sourcing Requirement	3,572
SEMA/RI Local Sourcing Requirement	7,479

The motion to recommend Participants Committee support was approved, with four oppositions (1 Transmission Sector; 1 Publicly Owned Entity Sector; 2 Supplier Sector) and one abstention (Transmission Sector) noted.

4. Market Rule Changes (Price Responsive Demand Reserve Auditing)

Support revisions to Market Rule I, Sections III.1.5.2 and III.9.5.3 to allow a demand resource to establish a CLAIM 10/30 value to reflect its reserve capability period and implement ISO-Initiated Parameter Auditing, as recommended by the Reliability Committee at its September 16, 2014 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was unanimously approved.

5. Revisions to OP-14, OP-14E and OP-14G (Order 755-Related Changes)

Support Order 755-related revisions to OP-14, OP-14E and OP-14G (Technical Requirements for Generators, Demand Resources and Asset Related Demands Appendices), as recommended by the Reliability Committee at its September 16, 2014 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was unanimously approved.

blank

Summary of ISO New England Board and Committee Meetings

October 3, 2014 Participants Committee Meeting

Since the last update, the System Planning and Reliability Committee met in Boston on September 11, and the Ad Hoc Cyber Security Committee met in Boston on September 12. The Compensation and Human Resources Committee, the Markets Committee, the Nominating and Governance Committee, and the Board of Directors each met on September 18 in Holyoke.

The System Planning and Reliability Committee met to prepare for the 2014 Regional System Plan public meeting. The Committee reviewed the schedule for the meeting and discussed comments received on the Plan.

The Ad Hoc Cyber Security Committee convened to review the cyber defense strategy employed by the Company. The Committee discussed the internal processes, the testing of a variety of systems, and the system recovery processes that would be used in the event a security breach were successful. Finally, the Committee reviewed details regarding previous and ongoing evaluations of the Company's approach to cyber risk management and readiness.

The Compensation and Human Resources Committee considered proposed changes to the Company's Supplemental Retirement and Savings Plan regarding a new investment option, and participation in an Investment Fee Revenue Credit program that provides credits for excess fee revenues. The Committee agreed to recommend the proposals for approval by the Board. Next, the Committee reviewed national compensation survey data regarding projected merit and promotional increase budgets. After reviewing information specific to the utility industry, all-industry data, and data from other system operators, the Committee approved a 3.0% merit increase and a 0.5% promotional/equity increase for 2015. The increases were within the survey ranges, with the objective of ensuring the competitiveness of the Company's compensation.

The Markets Committee received reports from the internal and external market monitors, and the COO's report on reliability costs. The Committee discussed the short-

term, weather-related price spikes that occurred in the real-time energy and reserve markets in August. The Committee also discussed causes of minimum generation condition events and plans to address energy market pricing issues associated with fast-start resources. Next, The Committee received a summary on the FERC's recent actions concerning the results of the eighth Forward Capacity Auction, and a summary of a recent order accepting the capacity supply obligation deferral mechanism. The Committee discussed the participation of imports in the capacity market, and the potential for application of Offer Review Trigger Price rules to capacity imports. The Committee was provided with an update on the Internal Market Monitor's review of de-list bids for the ninth Forward Capacity Auction. Finally, the Committee was informed that the federal circuit court of appeals for the District of Columbia had declined to hear en banc the July 2014 decision by a panel of the court to generally invalidate Order No. 745, FERC's rulemaking addressing demand response compensation.

The Nominating and Governance Committee adopted resolutions electing the slate of directors, as approved by the NEPOOL Participants Committee at its last meeting.

The Board of Directors met and received an update on Forward Capacity Auction #9, including qualification decisions and the Internal Market Monitor's review and analysis of de-list bids. The Board also received reports from the Committees and the CEO, including an update on the Governors' Infrastructure Initiative. During the report of the Compensation and Human Resources Committee, the Board approved the proposed changes to the Company's Supplemental Retirement and Savings Plan regarding a new investment option, and participation in an Investment Fee Revenue Credit program that provides credits for excess fee revenues. During the Nominating and Governance Committee report, the Board elected Messrs. Denis, Levy and Wilson as Directors for three-year terms, elected Phil Shapiro as Chair, and approved committee assignments as follows:

- Audit and Finance Committee: Ms. VanZandt and Messrs. Rush and Wilson, with Mr. Wilson to serve as Chair;
- Compensation and Human Resources Committee: Messrs. Denis, Hill and Levy, with Mr. Levy to serve as Chair;

- Markets Committee: Ms. Abernathy and Messrs. Denis, Hill and Rush, with Mr. Hill to serve as Chair;
- Nominating and Governance Committee: Mses. Brown and Abernathy and Messrs. Levy and Shapiro, with Ms. Brown to serve as Chair;
- System Planning and Reliability Committee: Mses. Brown and VanZandt and Messrs. Levy and Wilson, with Ms. VanZandt to serve as Chair;
- Joint Nominating Committee: Ms. VanZandt and Messrs. Denis, Hill, Levy, Rush and Wilson, with Mr. Rush to serve as Chair.

The Board also elected the Company's officers for the upcoming year. Finally, the Board discussed the 2015 budgets and the remaining stakeholder process, noting that the vote on the budgets will take place after receiving input from the NEPOOL Participants Committee and the states.

OCTOBER 3, 2014 | BOSTON, MA



NEPOOL Participants Committee Report

October 2014

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER



Table of Contents

NEPOOL PARTICIPANTS COMMITTEE
OCT 3, 2014 MEETING, AGENDA ITEM #4

• Highlights	Page 3
– Capacity Deficiency – Sunday, September 28	Page 9
– Interstate Reliability Project Update	Page 10
– 2014/15 Winter Reliability Program Update	Page 11
– Hourly Market Project Update	Page 13
– Order 745 Update	Page 14
• System Operations	Page 15
• Market Operations	Page 28
• Back-Up Detail	Page 45
– Load Response	Page 46
– New Generation	Page 48
– Forward Capacity Market	Page 55
– Reliability Costs - Net Commitment Period Compensation (NCPC) Operating Costs	Page 60
– Regional System Plan (RSP) & Interregional Planning	Page 91
– Operable Capacity Analysis – Fall 2014	Page 116
– Operable Capacity Analysis – Preliminary Winter 2014/2015	Page 123
– Operable Capacity Analysis – Appendix	Page 130



Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
 - September natural gas prices over the period were 20.7% higher than August 2014 average values
 - Average RT Hub Locational Marginal Prices (LMPs) over the period were 15.4% higher than August 2014 averages
 - Average September 2014 natural gas prices and RT Hub LMPs over the period were down 15.1% and 3.8%, respectively, from September 2013 averages
- Average daily (peak hour) DA cleared physical energy as percent of forecasted load was 97.8% in September, down from 98.6% in August
 - Slides 35-38 offer more details on this topic

All data through September 24, unless otherwise noted.

*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

Underlying natural gas data furnished by:



Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)*
 - September payments totaled \$5.4M
 - First Contingency payments totaled \$2.3M, up \$731K from August
 - \$2.2M paid to internal resources
 - \$880K charged to DALO, \$1.3M to RT Deviations
 - \$110K paid to resources at external locations
 - \$93K charged to DALO at external locations, \$17K to RT Deviations
 - Second Contingency payments totaled \$3.1M, up \$230K from the August total of \$2.9M
 - Voltage payments were \$1K, down \$938K from August
 - NCPC payments over the period as percent of Energy Market value were 1.6%

*Total includes NCPC payments to eligible resources at external locations.



Highlights, cont.

- Draft Regional System Plan 2014 was submitted to the ISO Board for approval
- Distributed Generation Forecast Working Group meeting was held on September 15. The meeting focused on PV forecast issues and the ISO urged DG resources to participate in the Forward Capacity Market
- Non-Price Retirement request has been received for the Mt. Tom coal plant (142.881 MW)
- Variable Resource Working Group held a meeting on September 29



Forward Capacity Market (FCM) Highlights

- CCP #3 (2012-2013)
 - One generating resource remains partially commercial (short by approximately 2 MW) and will be terminated this fall
- CCP #4 (2013-2014)
 - Approximately 113 MW (Demand Reduction Value (DRV)) of demand resources and 75 MW of generation are yet to be commercial. Discussions with non-commercial resources are continuing.
- CCP #5 (2014-2015)
 - Approximately 257 MW (DRV) of demand are yet to be commercial. These resources have been put on monthly CPS monitoring to determine the likelihood of becoming commercial in the near term.

CCP – Capacity Commitment Period



FCM Highlights, cont.

- CCP #6 (2015-2016)
 - Next opportunity to trade obligations will be in December 2014
- CCP #7 (2016-2017)
 - Next opportunity to trade obligations will be in May 2015
- CCP #8 (2017-2018)
 - First opportunity to trade obligations will be in April 2015
- CCP #9 (2018-2019)
 - New capacity resource and de-list bid qualification determination notification letters were sent on September 26
 - The static de-list finalization window closes on October 3
 - Non-Price Retirement window closes on October 5. To date, three Non-Price Retirements have been received:
 - Wallingford Refuse, 6 MW, CT
 - Demand Resource, 1.179 MW, CT
 - Mt. Tom, 142.881 MW, ROP



Highlights, cont.

- The lowest 50/50 and 90/10 Fall Operable Capacity Margin is projected for week beginning November 1st, 2014
- The lowest 50/50 and 90/10 Winter Operable Capacity Margin is projected for week beginning January 17th, 2015



Capacity Deficiency - Sunday, September 28

- The Morning Report forecasted a peak load of 16,380 MW at hour ending 20:00, with a 872 MW surplus
- Actual temperatures in Hartford and Boston were slightly higher than forecast
- Actual peak load was 16,670 MW for hour ending 20:00
- Various generation restrictions and a loss of a large generator at 18:50 resulted in a deficiency of 30-minute reserves during the peak hour
 - Energy prices ranged between \$543 to \$700 between 19:00 and 19:35
- Implemented M/LCC2, Abnormal Conditions Alert, and Operating Procedure #4, Action During a Capacity Deficiency

Action(s)	Implemented	Canceled
M/LCC 2	18:50	22:00
OP#4 Action 1	19:00	20:30



Interstate Reliability Project Update

- The ISO hasn't received a complete set of outages for the Interstate Reliability project, most notably 'substation outages'
- Based on the outages received to date (mostly scheduled in Q3 and Q4, 2015), the ISO expects the biggest impact to be restricted West-East flows
- At least for the set of submitted outages in Q3/Q4 2015, the ISO doesn't expect prolonged out-of-merit commitments
- It is likely that some commitments will be necessary for Eastern New England and SEMA/RI (nature of commitments, whether first or second contingency, will depend on various other system conditions)
- The ISO will provide an update in 2015, when a more complete set of outages is submitted
- Please note that this is the ISO's best expectation at this point in time, and various factors between now and Q3 2015 could impact these expectations



2014/15 Winter Reliability Program Update – Preliminary Numbers as of October 1, 11:30 AM

- Oil Program*
 - 69 Units have submitted intent to provide at least 4,065,626 BBLS
- LNG Program*
 - 8 Units have submitted intent to provide at least 1.5 BCF
- Demand Response Program*
 - 3 Assets have submitted intent to provide at least 14 MWs of Demand Relief.

*These notices are the Market Participant's commitment to meet the relevant minimum requirements set forth in this Appendix K.



Future Winter Reliability Program Schedule Update

- The ISO plans to file a stakeholder schedule, as required, with the FERC on October 9
- The schedule will specify that discussions about future winter programs will occur at monthly, regularly scheduled Markets Committee meetings in November through March
 - The Reliability Committee will be invited to attend the Markets Committee meetings
- The ISO plans to seek a Markets Committee vote in March 2015, and a Participants Committee vote in April 2015



Hourly Market Project Update

- The hourly markets project is scheduled to go-live on December 3
- The ISO is in the final stages of testing, and operator training is underway
- Participants have been active in the sandbox, and ISO customer service has reached out to the few participants that are yet to participate in the sandbox
- The ISO is hosting weekly project readiness calls with participants, that includes both IT and business functions



Order 745 Update

- On September 17, 2014, the petitions for rehearing *en banc* were denied by the Court of Appeals for the District of Columbia Circuit
- The Commission and other interested parties are still pursuing appeals, and it is unclear at this time when and if the decision will become effective
- The ISO plans to file the market rules related to integration of demand resources into reserve markets for Commission review; however, if the decision to vacate Order No. 745 is ultimately upheld, any resources that the ISO expends to implement the proposed market rule changes will likely be wasted
 - Therefore, the ISO plans to revisit the June 1, 2017 implementation date in early 2015 at the time of the priorities discussion to determine how to best balance stakeholders' interests with the need to prudently expend the ISO's resources
- Until the above-mentioned court proceedings are resolved, the ISO will postpone additional items related to demand response, particularly resource-intensive projects and projects that would be directly impacted by a mandate to vacate Order No. 745



SYSTEM OPERATIONS

System Operations

<u>Weather Patterns</u>	Boston	Temperature – Normal (+0.9) Max: 93, Min: 46 Precipitation 0.52” - Below normal Normal - 3.35”	Hartford	Temperature –Normal (+0.3) Max: 93, Min: 41 Precipitation 1.60” - Below Normal Normal – 4.00”

<u>Peak Load:</u>	23,703 MW	September 2, 2014	15:00

<u>MLCC2:</u> September 2, 2014 – Capacity Deficiency , September 28, 2014 – Capacity Deficiency		
<u>OP-4 :</u> September 28, 2014 – Capacity Deficiency		
<u>NPCC Simultaneous Activation of Reserve Events:</u>		
09/09/14	ISONE	780 MW
09/12/14	ISONE	500 MW
09/12/14	IESO	800 MW
09/20/14	ISONE	660 MW
09/20/14	PJM	1300 MW



System Operations

<u>NPCC Simultaneous Activation of Reserve Events:</u>		
09/22/14	IESO	800 MW
09/24/14	PJM	1300 MW



System Operations

Minimum Generation Warnings & Events:

Minimum Generation Warning	09/04/14	Start – 02:00, Expired - 06:00 Interchange Cuts & SS Denied
Minimum Generation Warning	09/11/14	Start – 03:00, Expired – 06:00 Interchange Cuts Only
Minimum Generation Warning	09/12/14 – 09/13/14	Start – 23:00, Expired – 09:00 Interchange Cuts Only
Minimum Generation Warning	09/13/14	Start - 00:01, Expired – 09:00 No Actions Taken
Minimum Generation Warning	09/13/14	Start – 09:00, Expired - 17:00 Interchange Cuts Only
Minimum Generation Warning	09/13/14 - 09/14/14	Start - 21:00, Expired - 14:00 Interchange Cuts & SS Denied
Minimum Generation <u>Event</u>	09/14/14	Start – 05:00, Expired – 13:00 Interchange Cuts & SS Denied
Minimum Generation Warning	09/15/14	Start – 03:00, Expired – 07:00 Interchange Cuts Only
Minimum Generation <u>Event</u>	09/15/14	Start – 04:00, Expired – 06:30 Interchange Cuts Only
Minimum Generation Warning	09/16/14	Start – 05:00, Expired - 07:00 Interchange Cuts & SS Denied
Minimum Generation Warning	09/17/14	Start – 04:00, Expired - 07:00 Interchange Cuts Only



System Operations

NEPOOL PARTICIPANTS COMMITTEE
OCT 3, 2014 MEETING, AGENDA ITEM #4

Minimum Generation Warnings & Events:

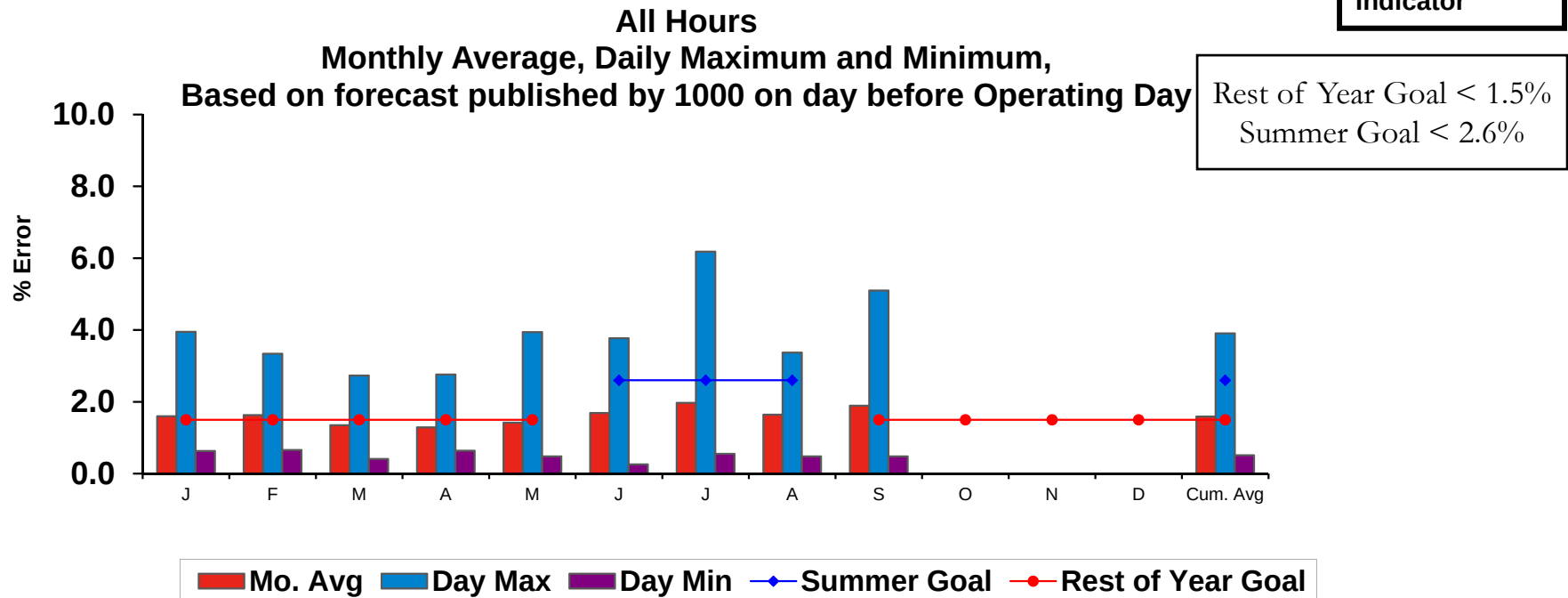
Minimum Generation Warning	09/20/14	Start – 00:01, Expired - 09:00 Interchange Cuts Only
Minimum Generation Warning	09/23/14	Start – 02:00, Expired – 07:00 Interchange Cuts & SS Denied
Minimum Generation Warning	09/25/14	Start – 21:46, Expired – 23:59 Interchange Cuts Only
Minimum Generation Warning	09/27/14	Start – 03:00, Expired-09:00 Interchange cuts only



2014 System Operations – Load Forecast Accuracy

NERPOOL PARTICIPANTS COMMITTEE
OCT 3, 2014 MEETING AGENDA ITEM #4

Dashboard
Indicator



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.60	1.63	1.35	1.29	1.42	1.69	1.97	1.64	1.89				1.59
Day Max	3.95	3.34	2.73	2.76	3.94	3.77	6.18	3.37	5.10				3.90
Day Min	0.63	0.66	0.41	0.64	0.48	0.26	0.55	0.48	0.48				0.51
Summer Goal						2.6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of year Actual	1.60	1.63	1.35	1.29	1.42				1.89				1.52
Summer Actual						1.69	1.97	1.64					1.74

Summer Goal - 2.6%, Rest of Year Goal - 1.5%

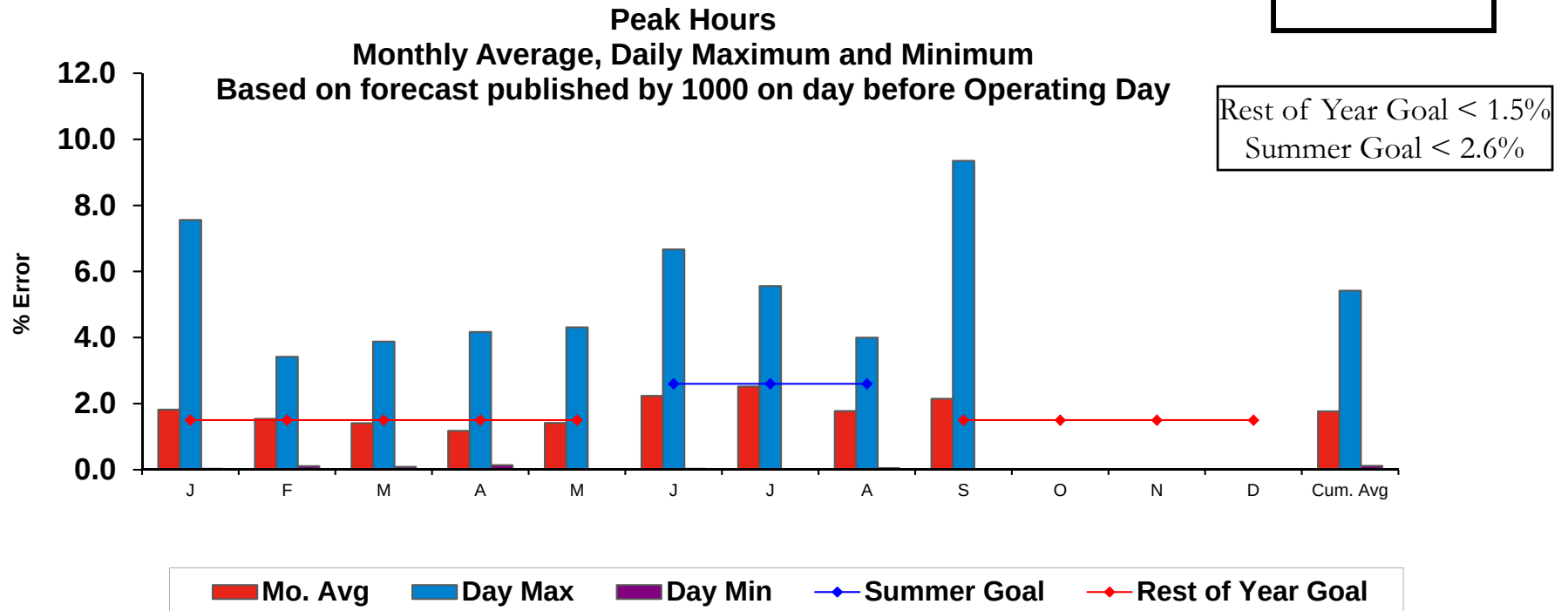
Summer consists of June, July & August



2014 System Operations - Load Forecast Accuracy cont.

NEPOOL PARTICIPANTS COMMITTEE
OC 3, 2014 MEETING, AGENDA ITEM 14

Dashboard
Indicator



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.82	1.54	1.41	1.18	1.42	2.24	2.52	1.78	2.15				1.77
Day Max	7.56	3.42	3.88	4.17	4.31	6.67	5.56	4.00	9.35				5.42
Day Min	0.03	0.11	0.09	0.14	0.01	0.03	0.02	0.05	0.01				0.05
Summer Goal						2.6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of year Actual	1.82	1.54	1.37	1.11	1.42								1.45
Summer Actual						2.24	2.52	1.78					2.17

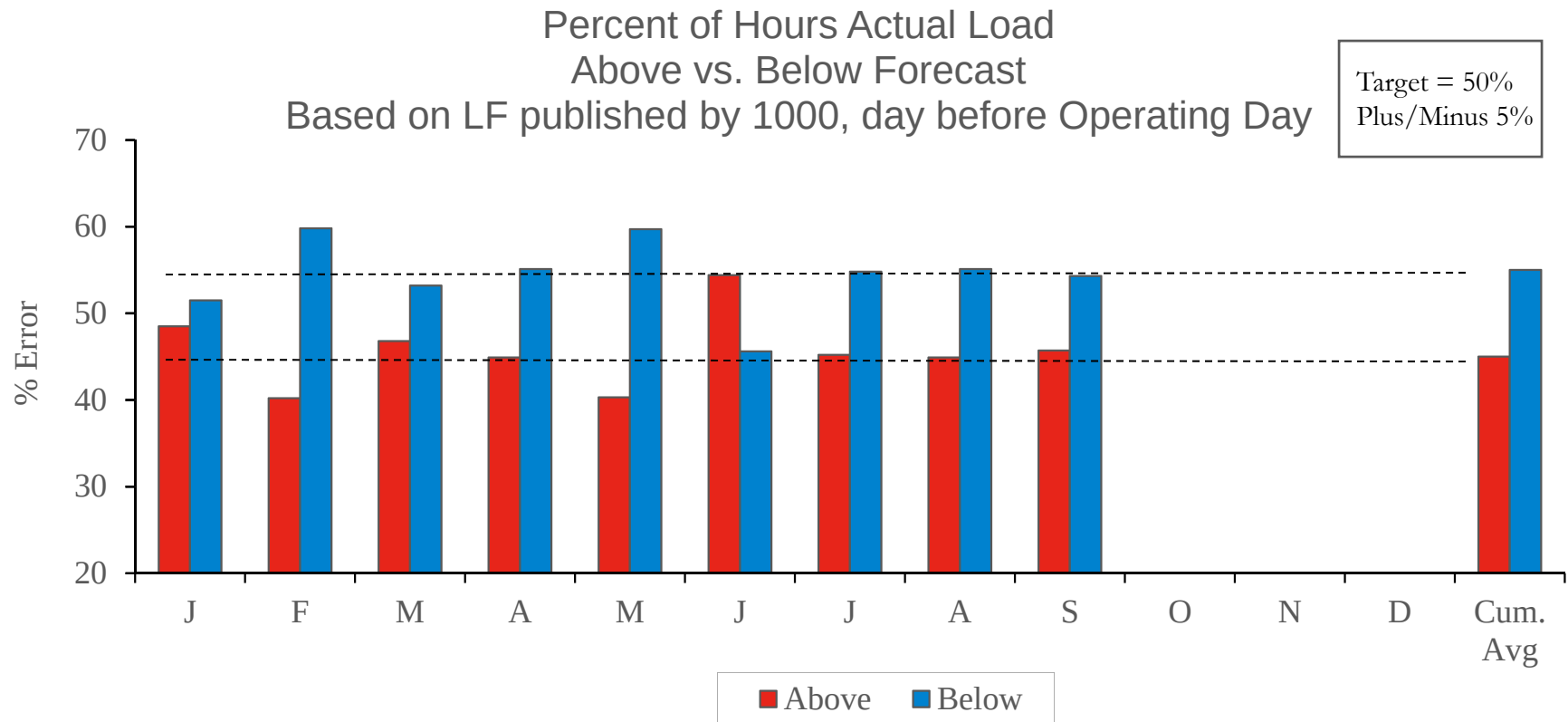
Summer Goal - 2.6%, Rest of Year Goal - 1.5%

Summer consists of June, July & August



2014 System Operations - Load Forecast Accuracy

NEPOOL PARTICIPANTS COMMITTEE
OCT 3, 2014 MEETING AGENDA ITEM #4



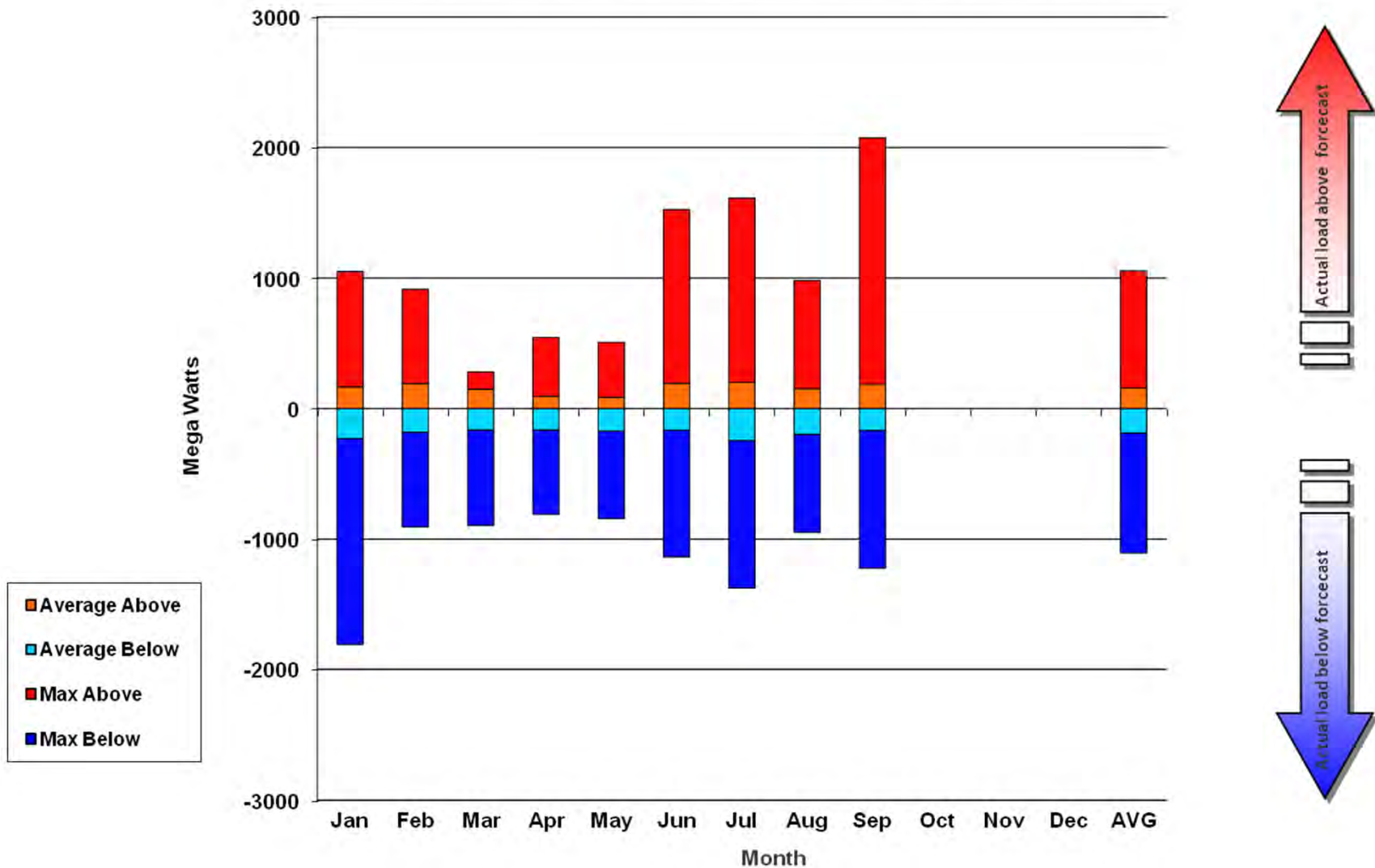
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	48.5	40.2	46.8	44.9	40.3	54.4	45.2	45.4	45.7				45
Below %	51.5	59.8	53.2	55.1	59.7	45.6	54.8	54.6	54.3				55
Avg Above	167.0	192.0	139.0	89.0	86.0	193	200	153.0	185.0				146
Avg Below	-230.0	-181.0	-161.0	163.0	-172.0	-164	-245	-197.0	-167.0				-178
Avg All	-52.0	-21.0	-27.0	68.0	-77.0	35.0	-45.0	-44.0	17.0				-33

Percent of hours that the actual load was above versus below the forecast



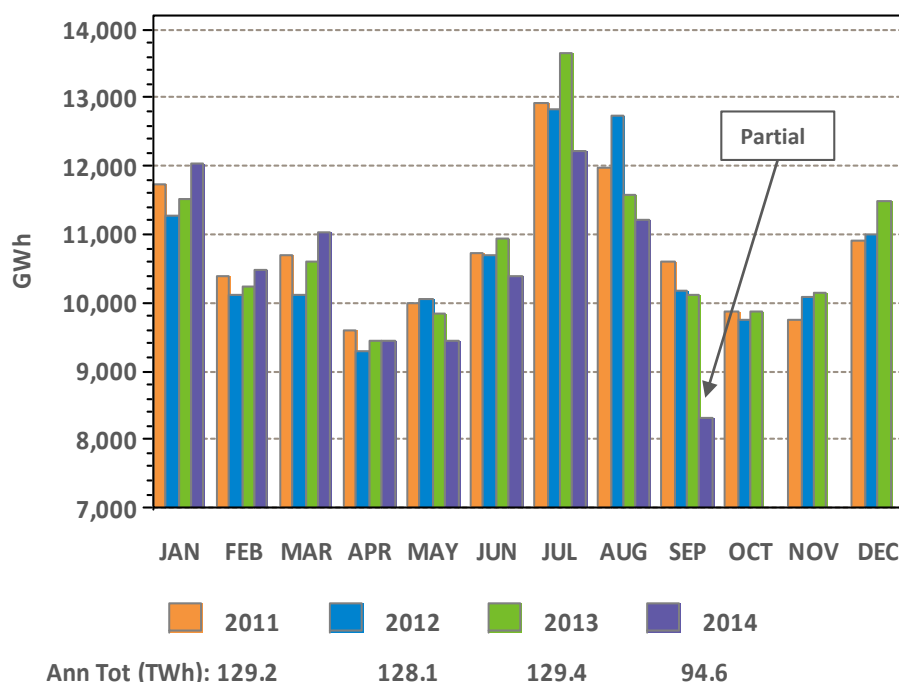
2014 System Operations - Load Forecast Accuracy

Deviation of Actual Load from Forecasted Load Year to Date 2014

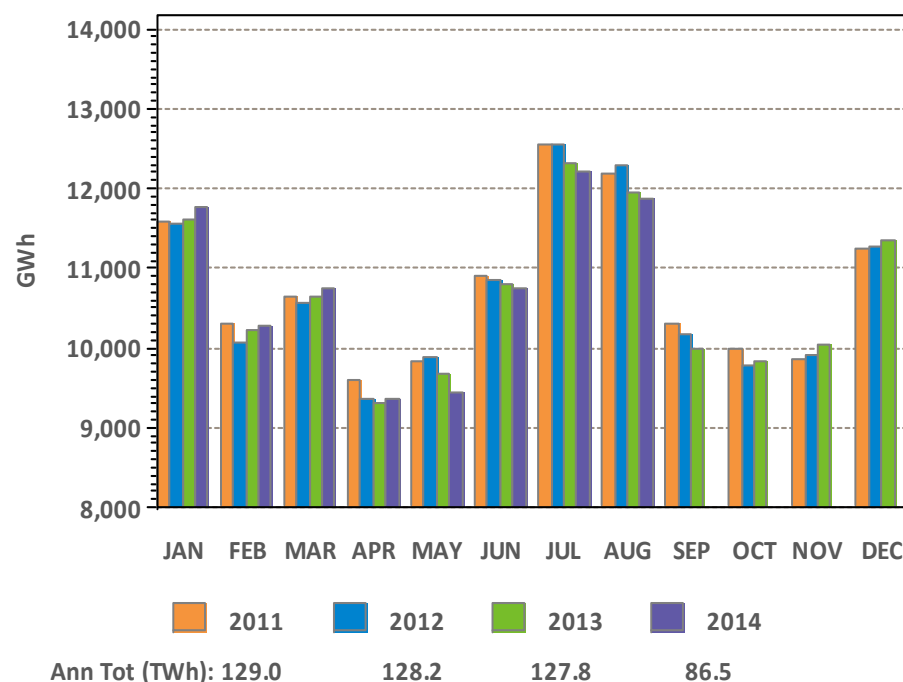


Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

Net Energy for Load (NEL)



Weather Normalized NEL

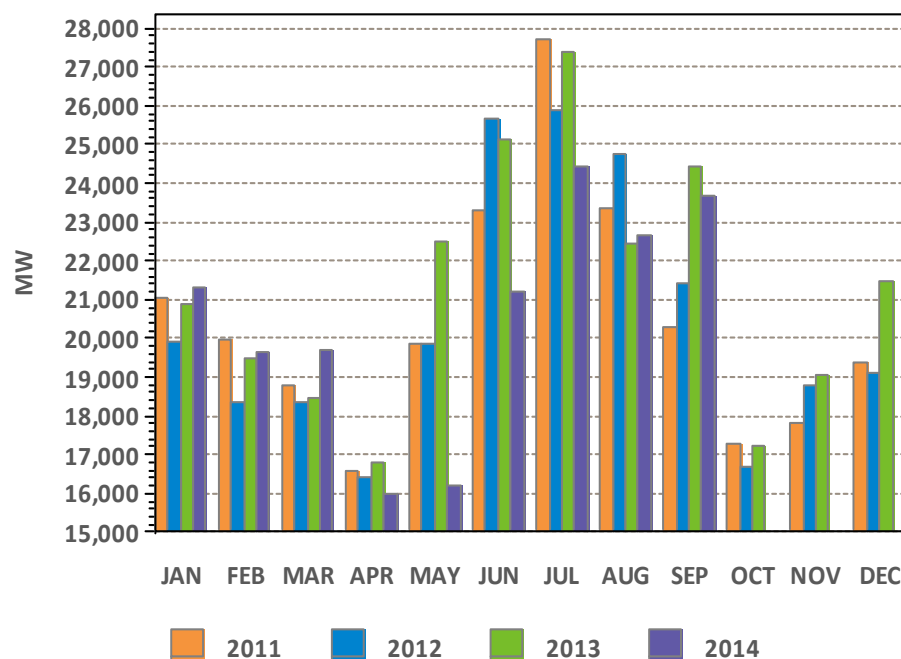


NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load'. NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.
Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

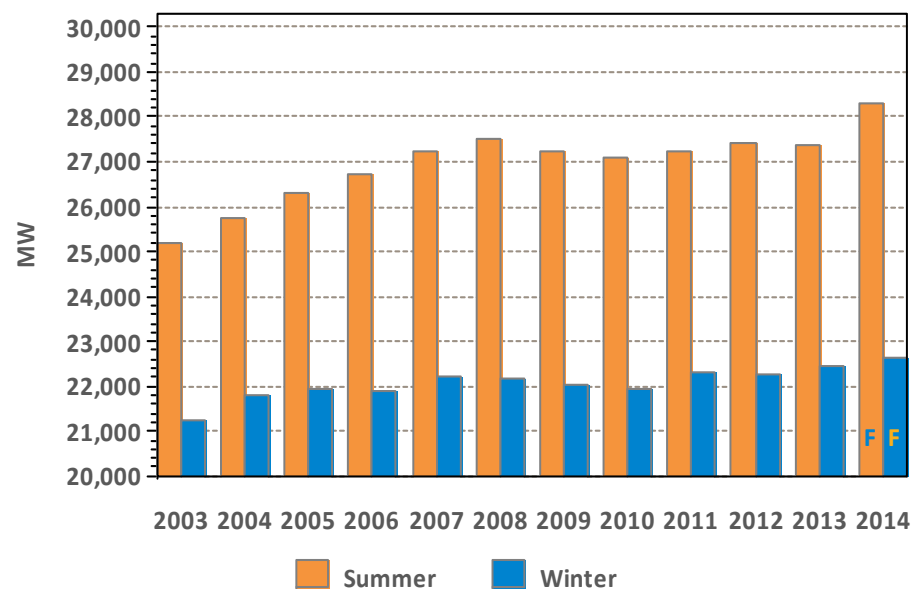


Monthly Peak Loads and Weather Normalized Seasonal Peak History

System Peak Load



Weather Normalized Seasonal Peaks



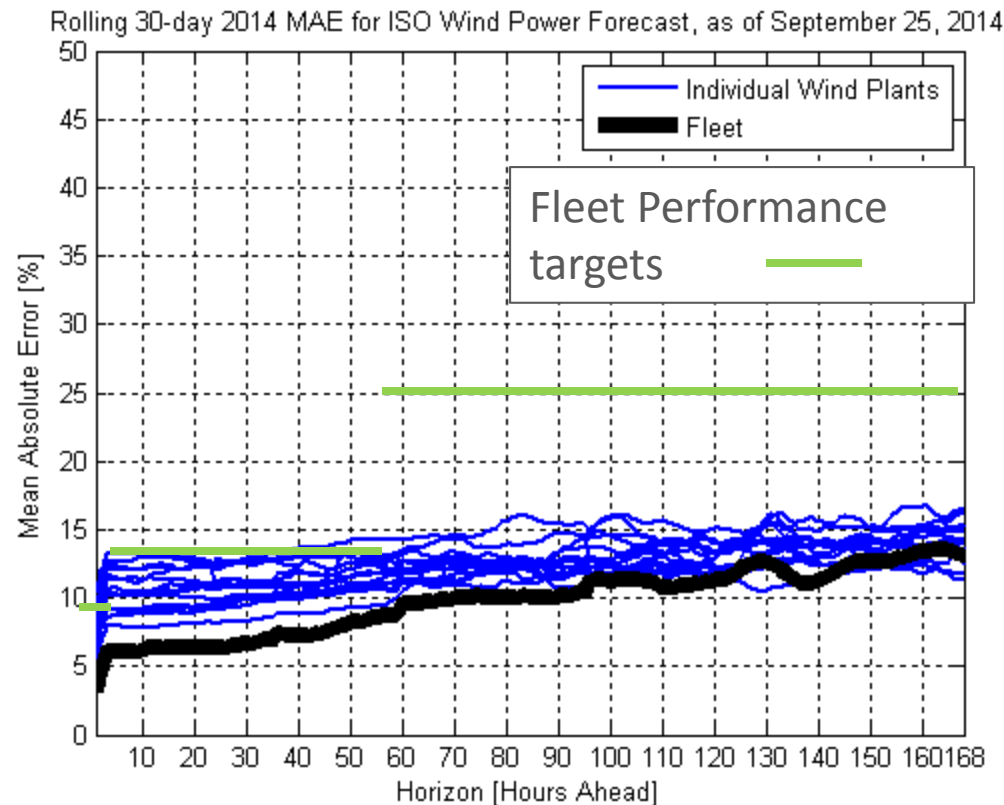
Winter beginning in year displayed

F – designates forecasted values, which are updated in April/May of the following year; represents “gross forecast”



Wind Power Forecast Error Statistics: MAE

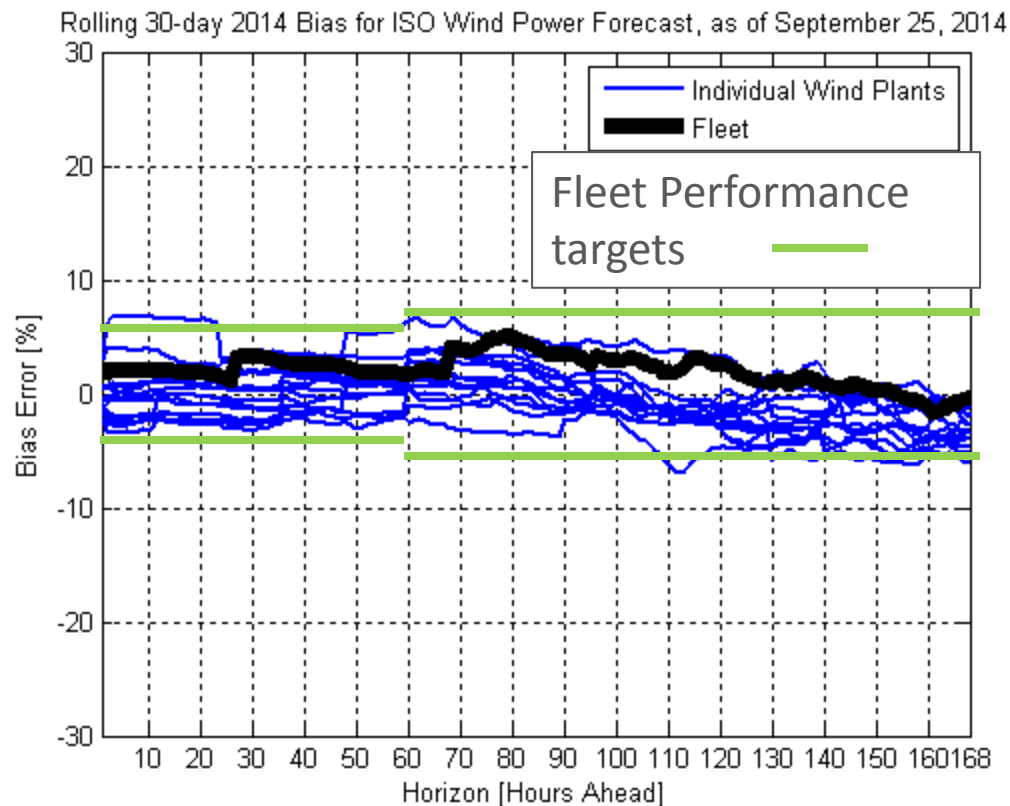
Dashboard Indicator 



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/GH forecast is very good compared to industry standards, and continues to be well within the yearly performance targets specified in the forecast RFP.

Wind Power Forecast Error Statistics: Bias

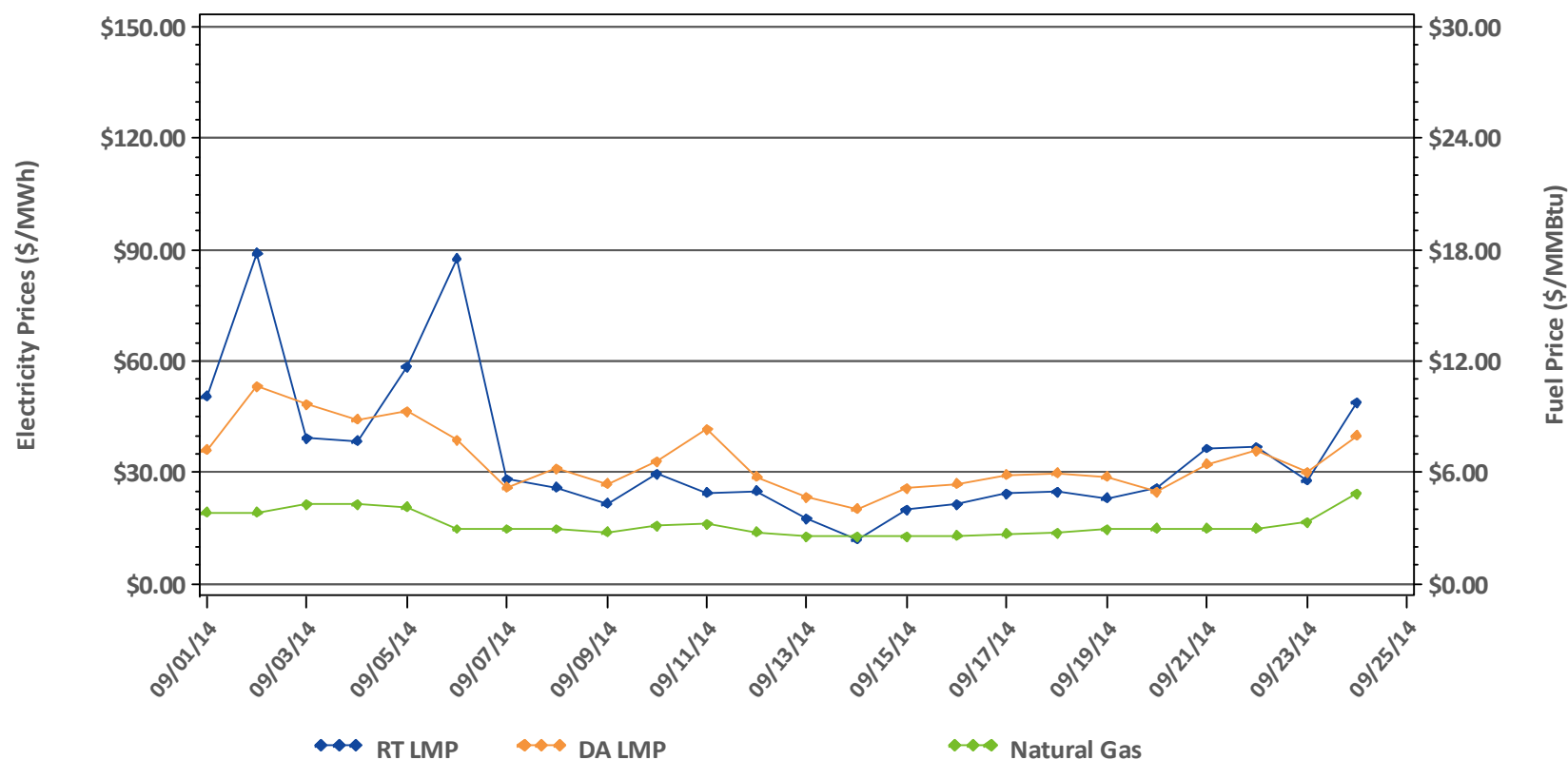
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/GH forecast is very good compared to industry standards, and continues to be within the yearly performance targets specified in the forecast RFP.

MARKET OPERATIONS

Daily DA and RT ISO-NE Hub Prices and Input Fuel Prices: September 1-24, 2014



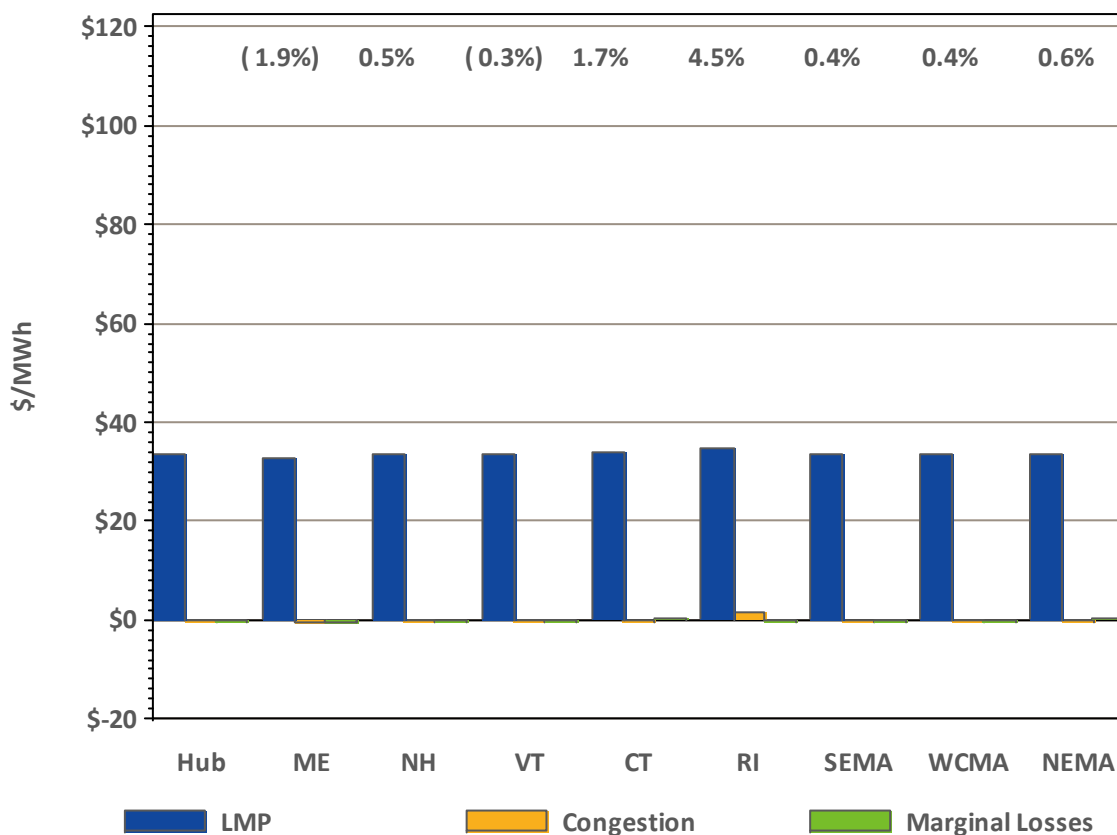
Underlying natural gas data furnished by:



Average price difference over this period (DA-RT): \$-1.46
 Average price difference over this period ABS(DA-RT): \$9.23
 Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 26%
 Gas price is average of Massachusetts delivery points



DA LMPs Average by Zone & Hub, September 2014

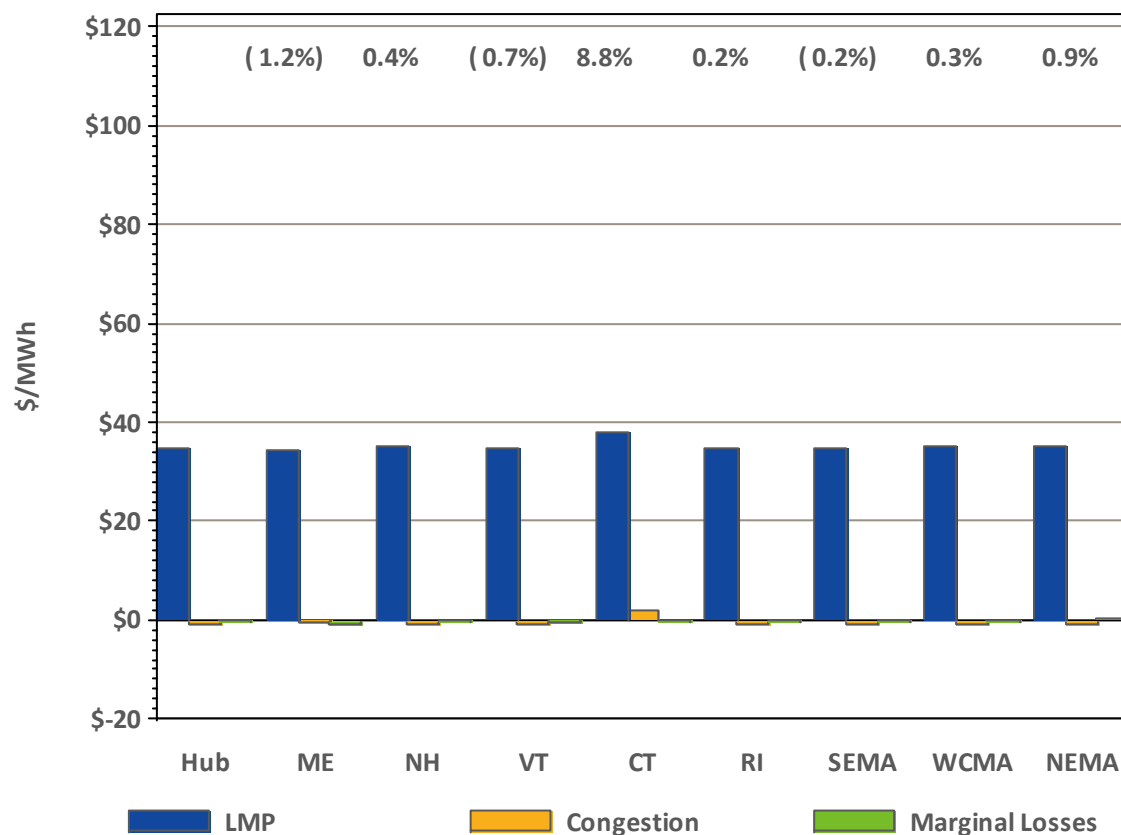


ME - Maine
NH - New Hampshire
VT - Vermont
CT - Connecticut

RI - Rhode Island
SEMA - Southeastern Massachusetts
WCMA - Western/Central Massachusetts
NEMA - Northeastern Massachusetts



RT LMPs Average by Zone & Hub, September 2014

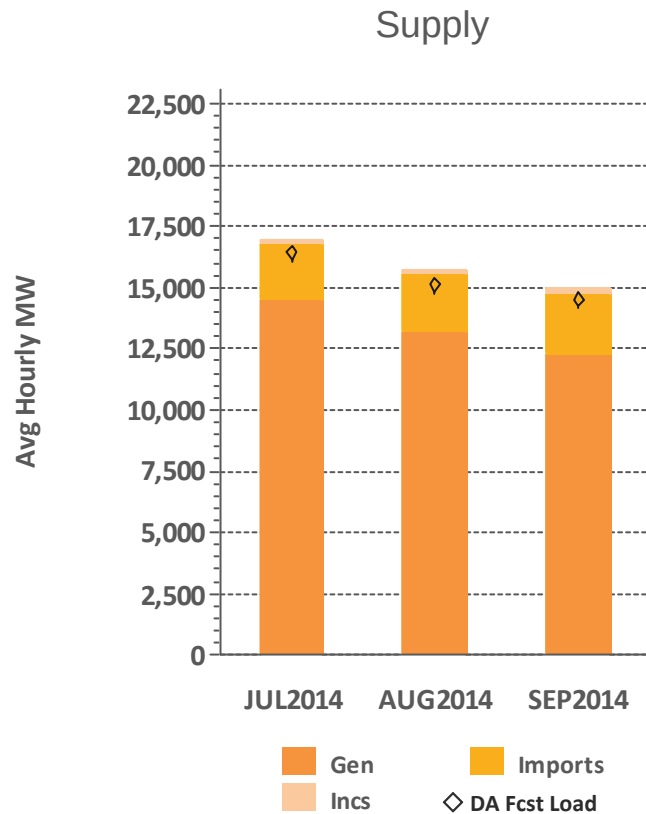


Definitions

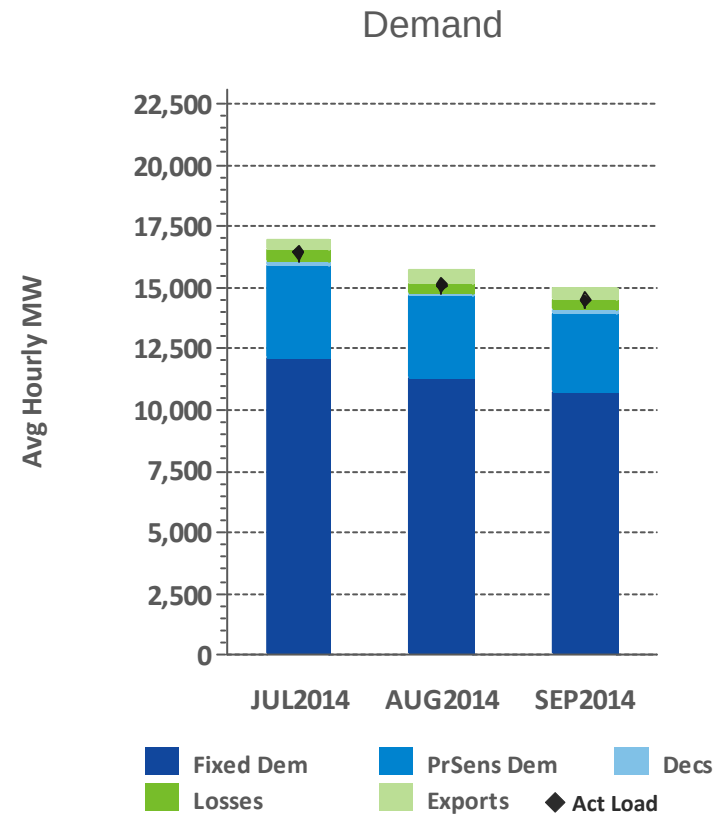
Day-Ahead Concept	Definition
Day-Ahead Load Obligation (DALO)	The sum of day-ahead cleared load (including pump load), exports, and virtual purchases (excluding bulk losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports



Components of Cleared DA Supply and Demand – Last Three Months



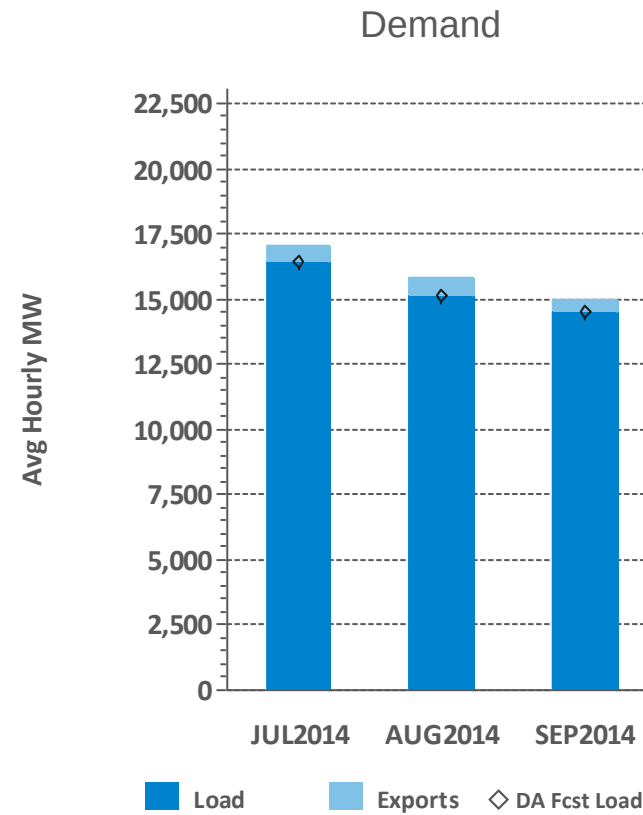
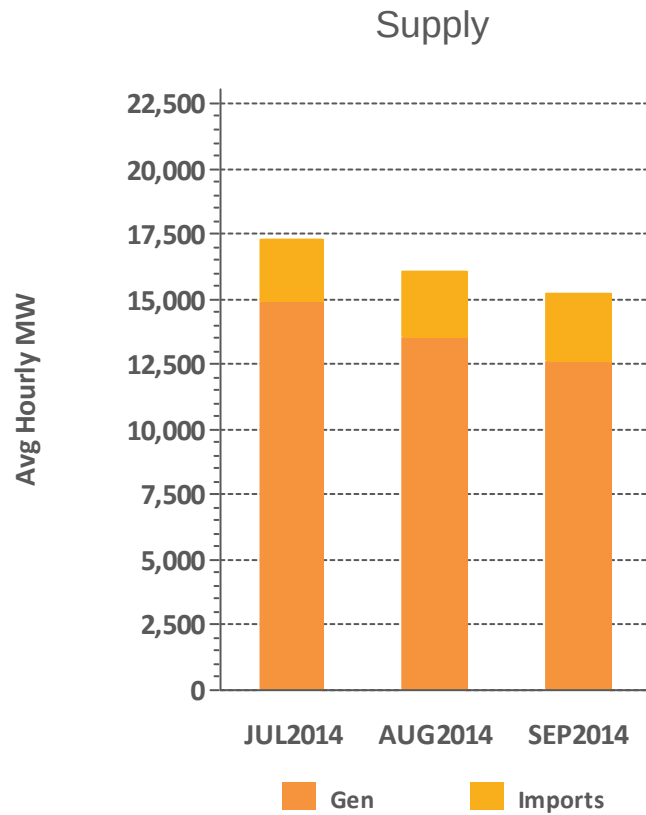
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



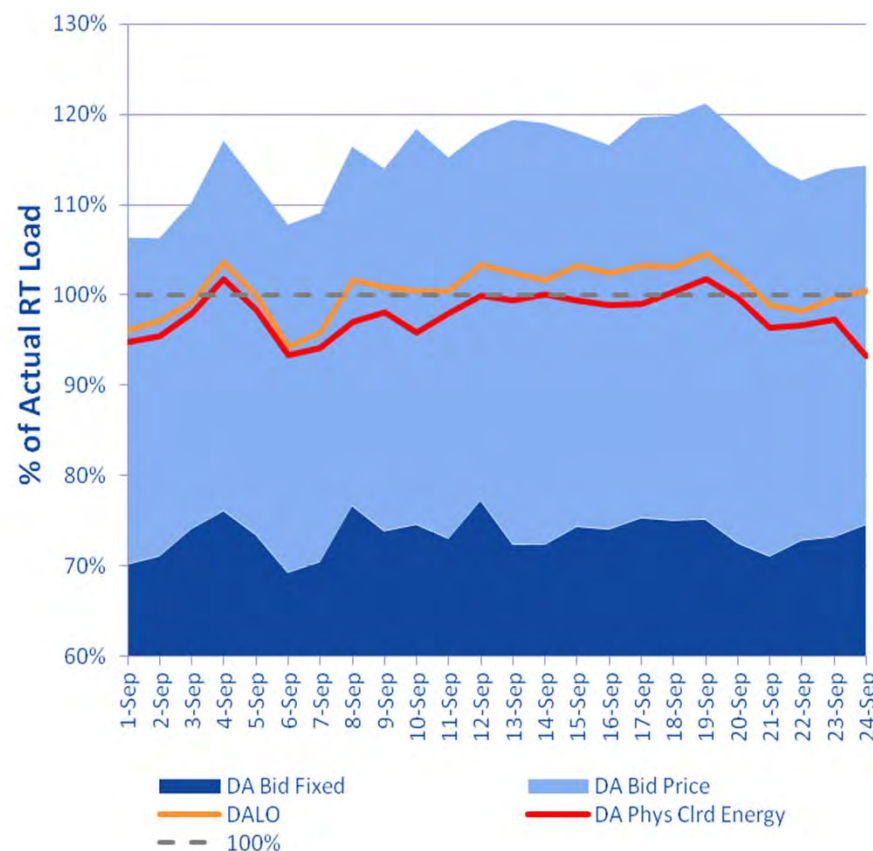
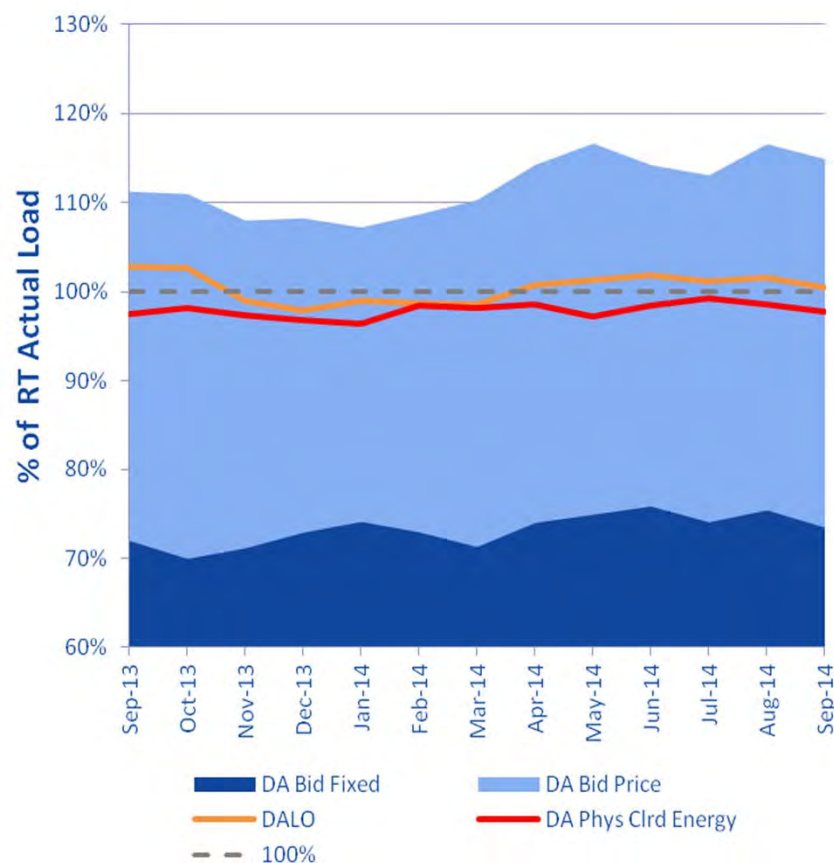
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load



Components of RT Supply and Demand – Last Three Months



DAM Volumes vs. RT Actual Load (at Peak Hour): Monthly and Daily

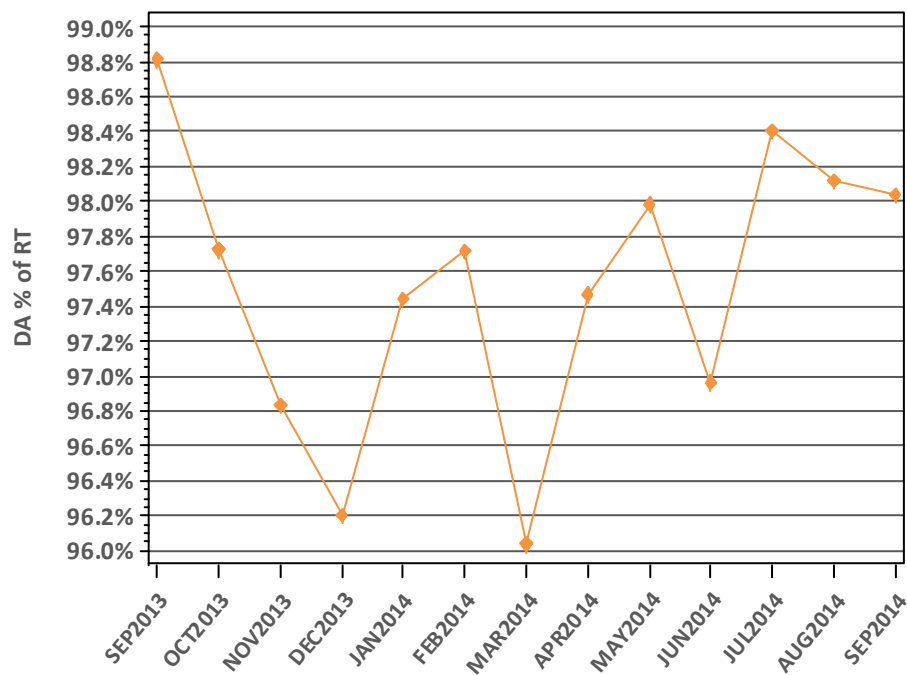


Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.

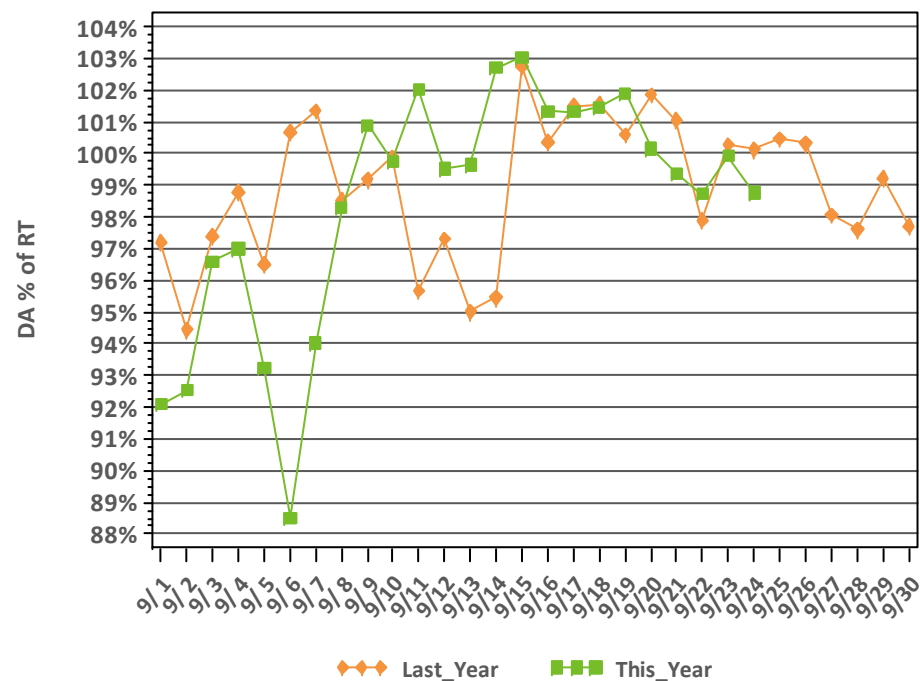


DA vs. RT Load Obligation: September, This Year vs. Last Year

Monthly, Last 13 Months



Daily, This Year vs. Last Year

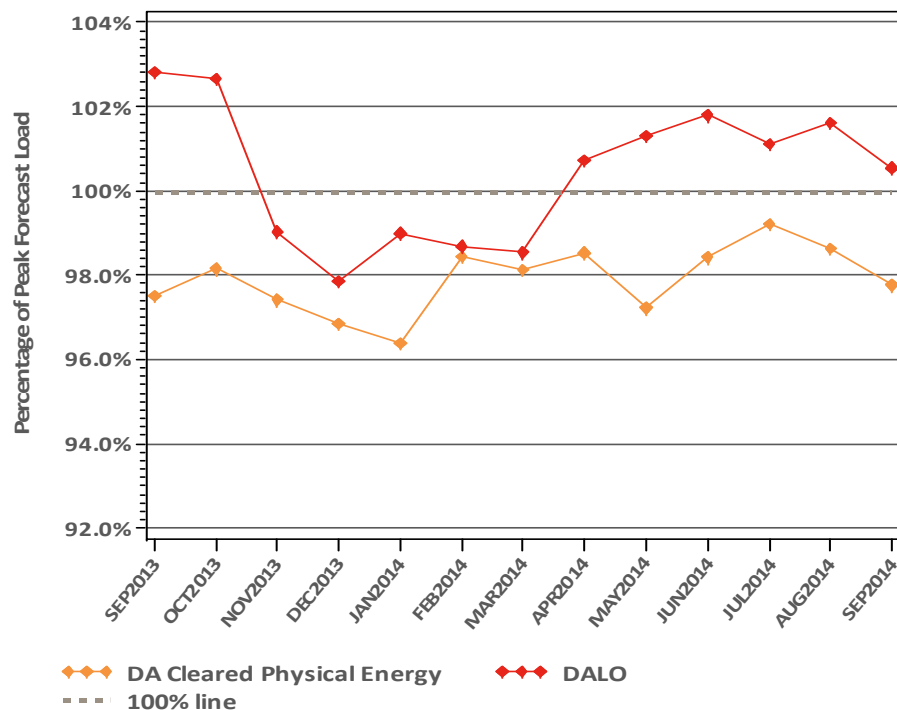


*Hourly average values

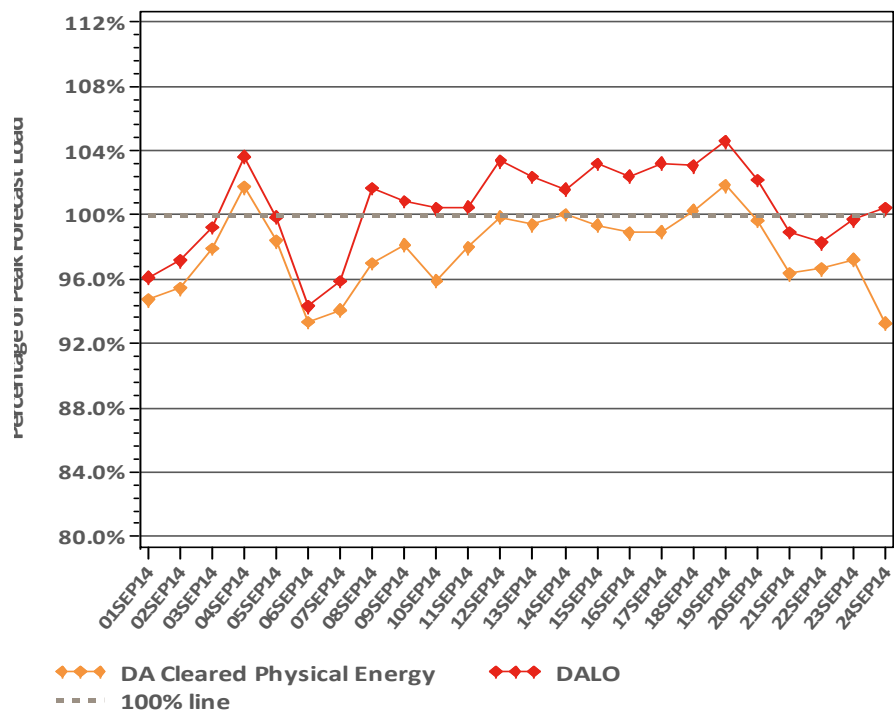


DA Volumes as % of Forecast (Peak Hour)

Monthly, Last 13 Months



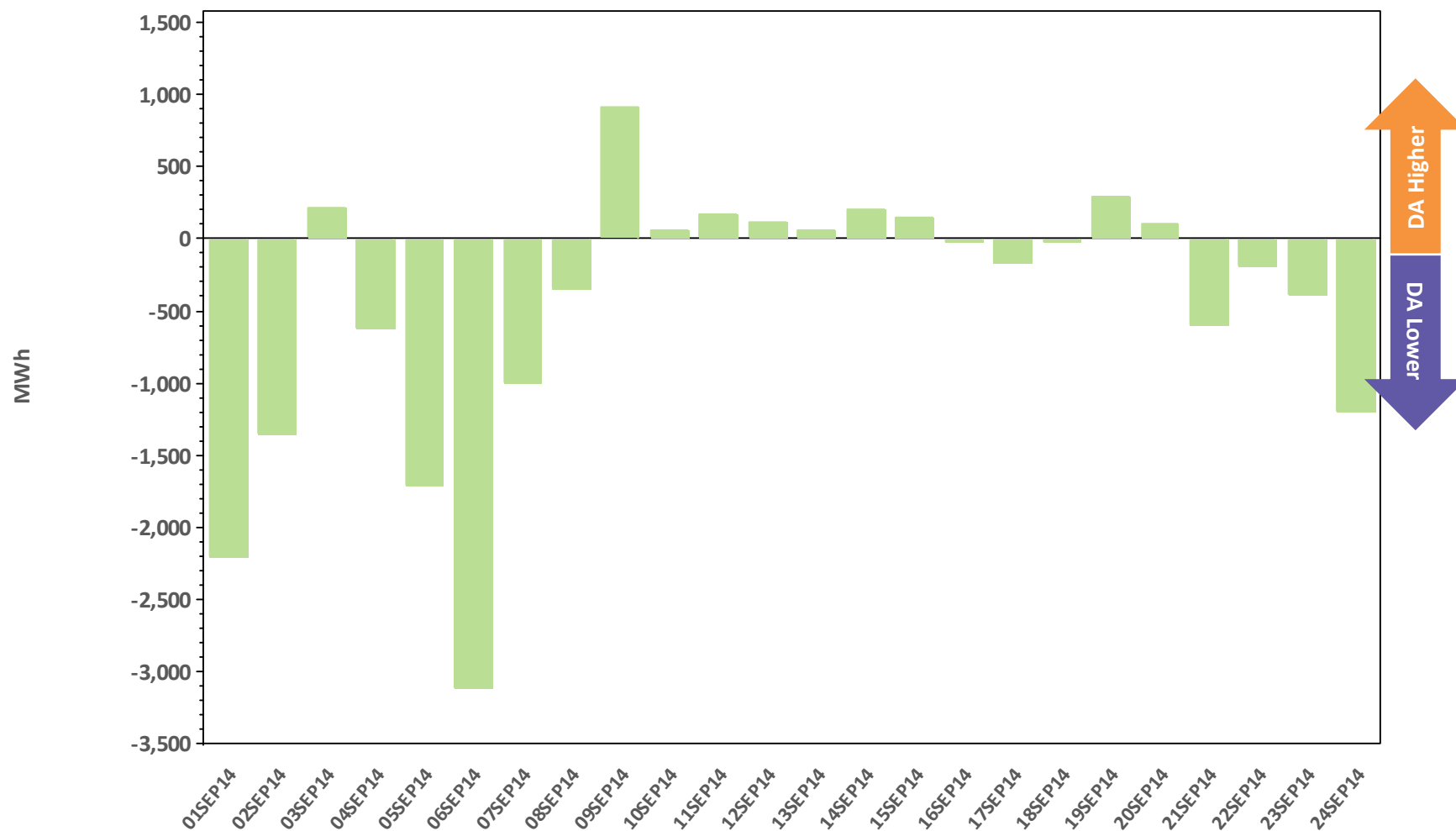
Daily: This Month



*Forecasted peak hour is reflected.



DA Cleared Physical Energy Difference from RT System Load at Peak Hour



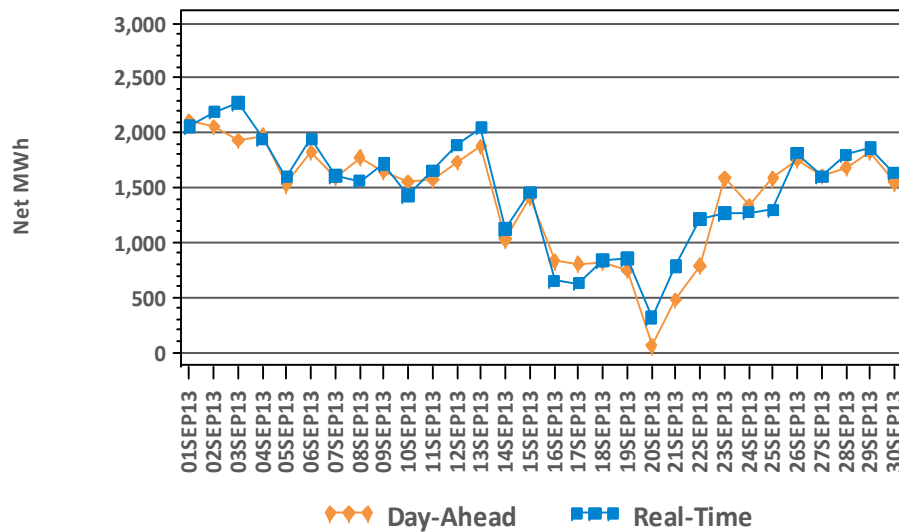
*Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.



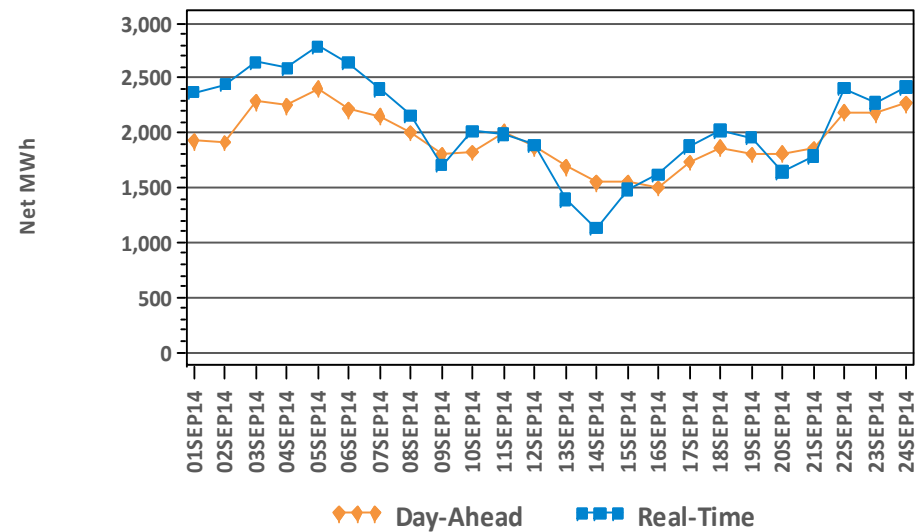
DA vs. RT Net Interchange

September 2014 vs. September 2013

Hourly Average by Day, Last Year



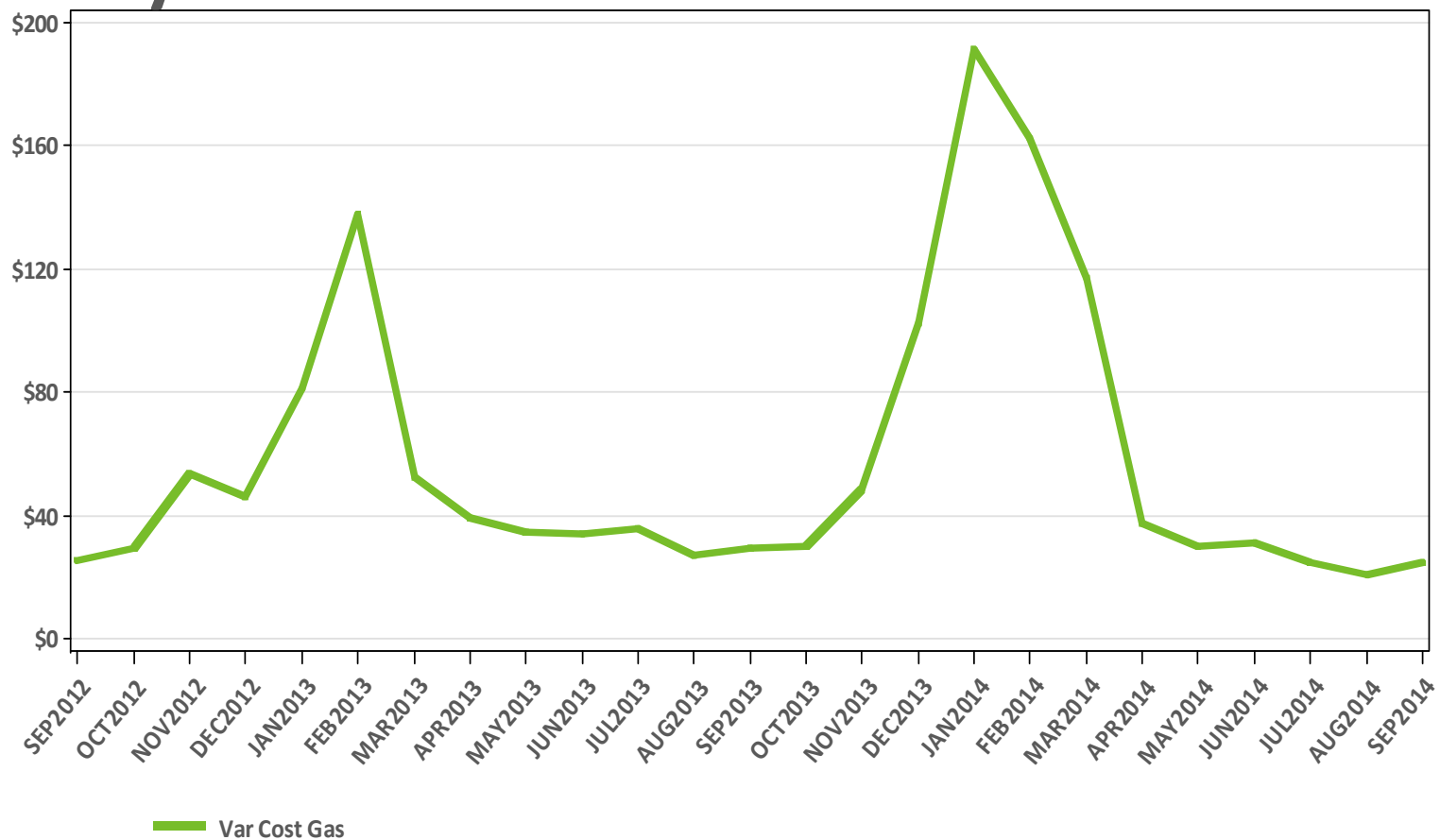
Hourly Average by Day, This Year



Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports



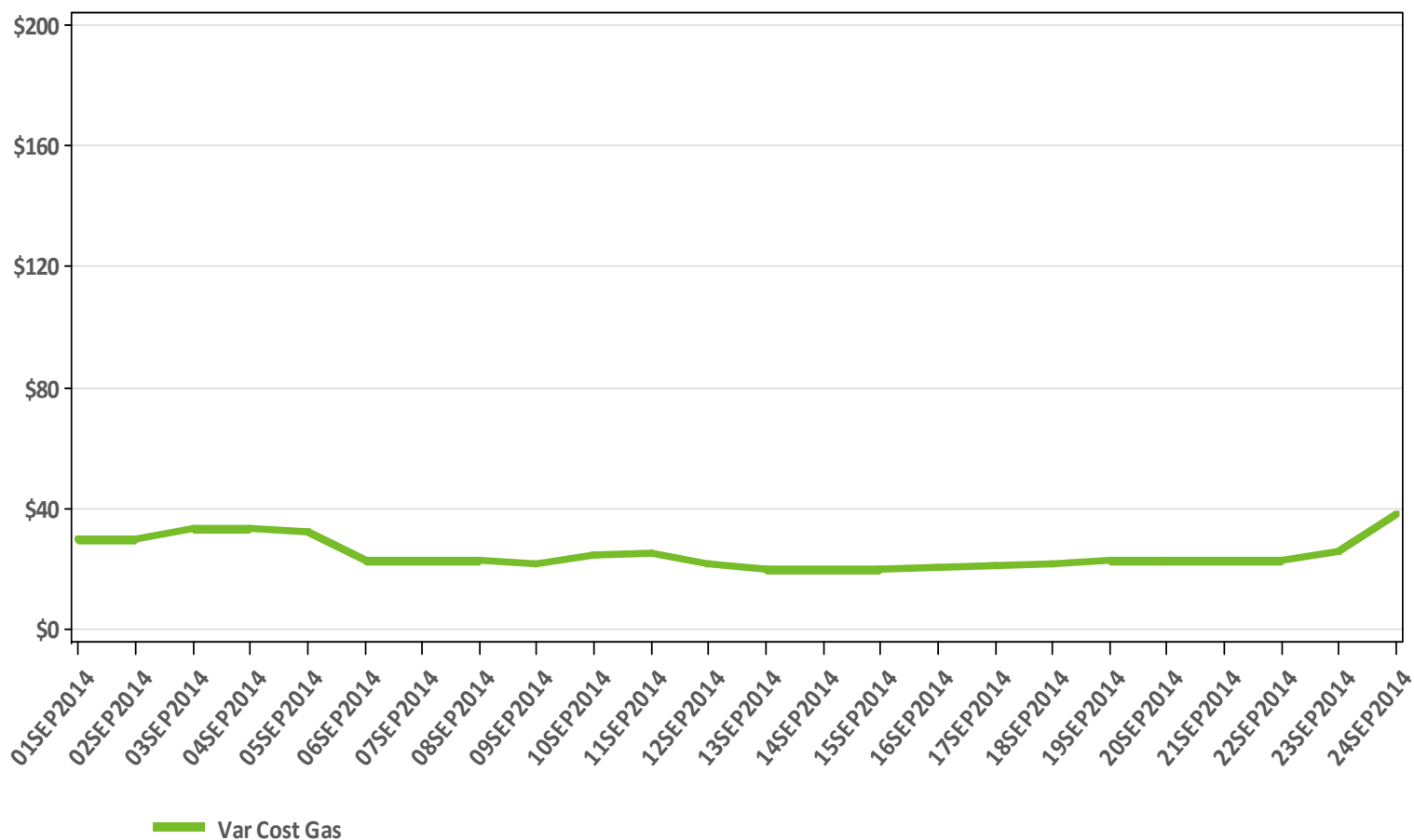
Variable Production Cost of Natural Gas: Monthly



Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.



Variable Production Cost of Natural Gas: Daily



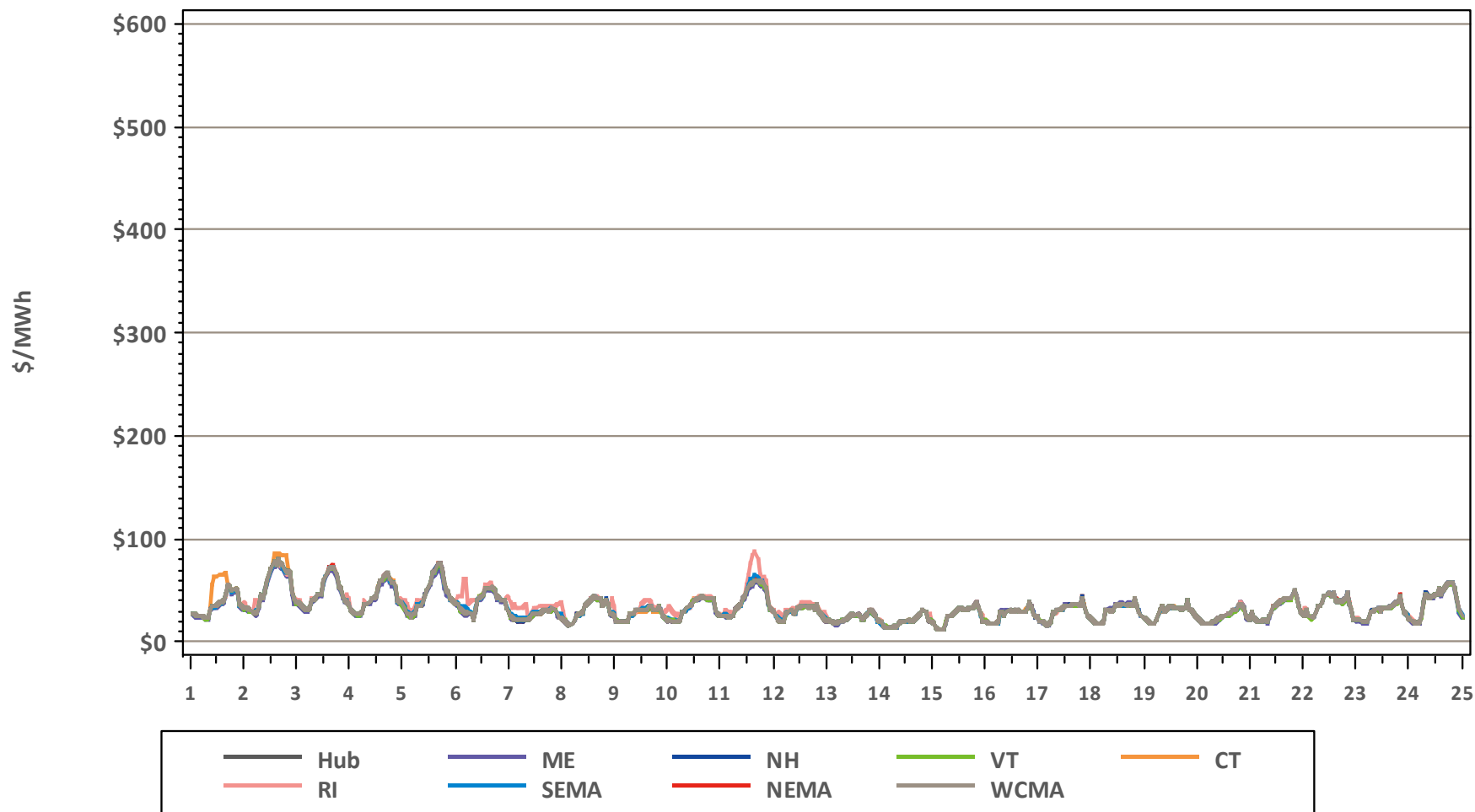
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.



Hourly DA LMPs, September 1-24, 2014

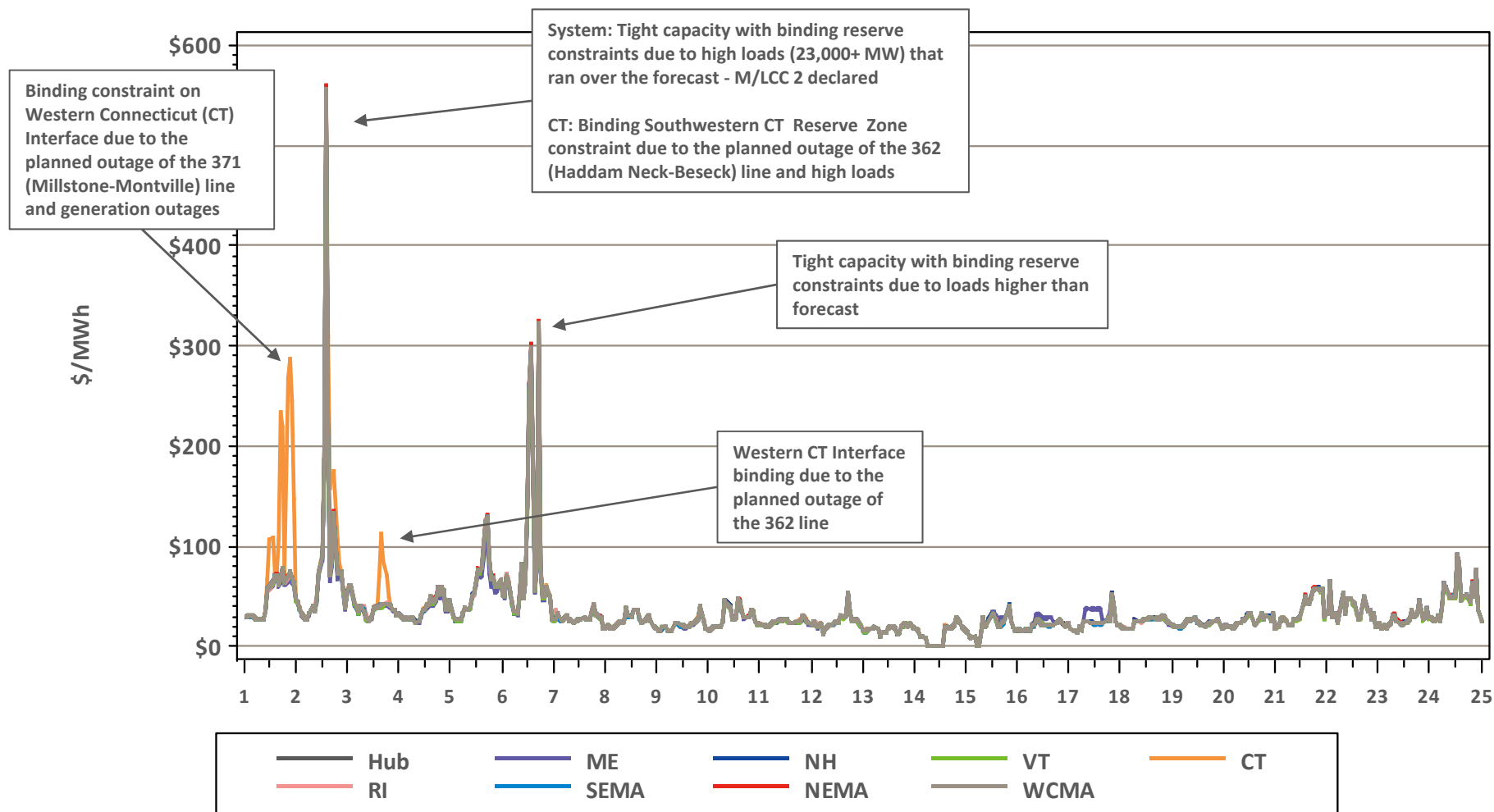
NEPOOL PARTICIPANTS COMMITTEE
SEPTEMBER 3, 2014 MEETING, AGENDA ITEM #4

Hourly Day-Ahead LMPs



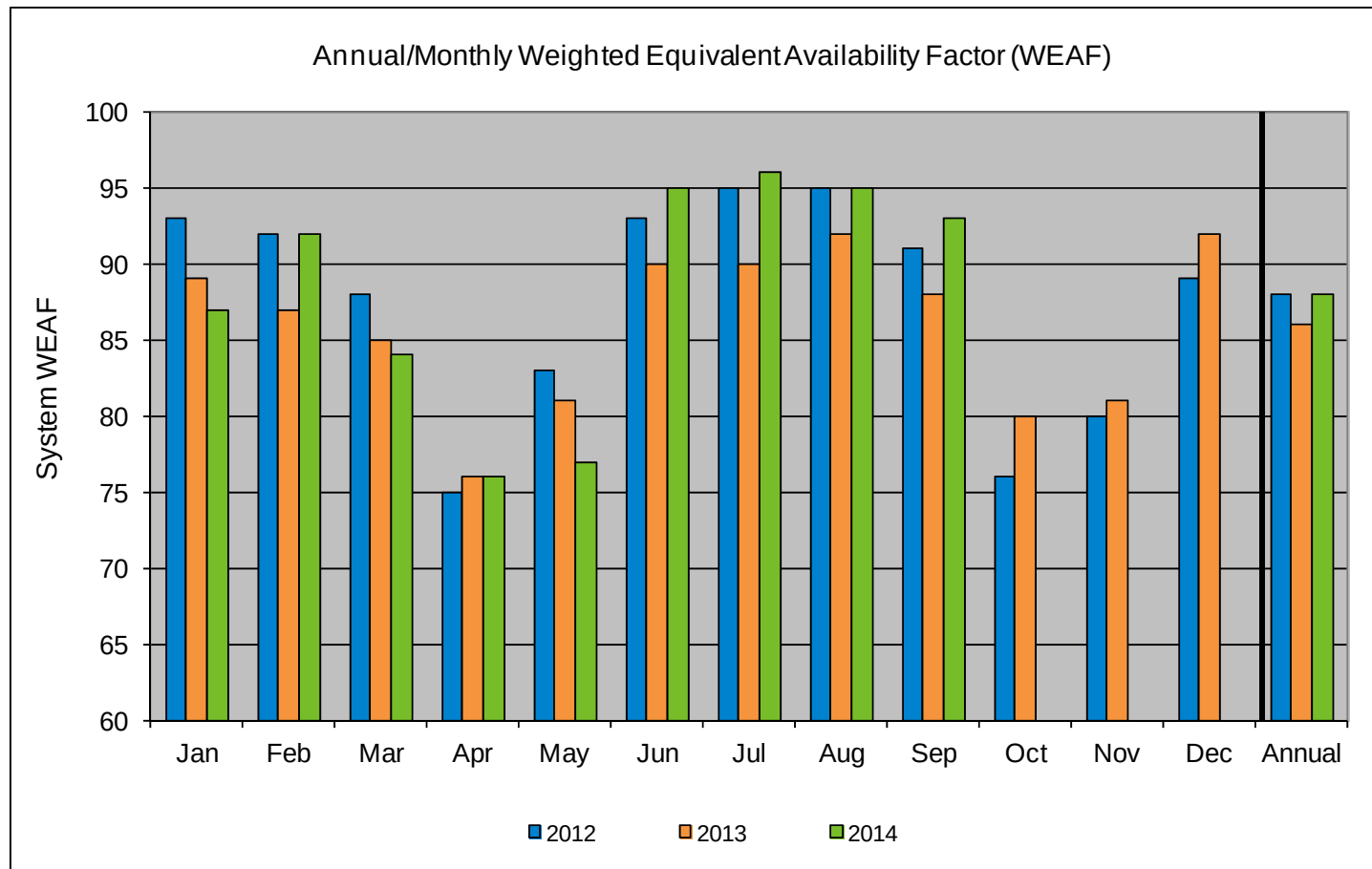
Hourly RT LMPs, September 1-24, 2014

Hourly Real-Time LMPs



System Unit Availability

NEPOOL PARTICIPANTS COMMITTEE
OCT 3, 2014 MEETING, AGENDA ITEM #4



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2014	87	92	84	76	77	95	96	95	93				88
2013	89	87	85	76	81	90	90	92	88	80	81	92	86
2012	93	92	88	75	83	93	95	95	91	76	80	89	88
2011	92	89	83	74	76	95	96	95	90	73	83	89	86

Data as of 9/29/14



BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for October 2014

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	139.2	3.8	103.1	0.0	246.1
NH	8.0	12.1	69.9	0.0	90.0
VT	28.0	3.3	94.1	0.0	125.4
CT	86.4	72.2	78.5	312.3	549.5
RI	12.8	13.7	83.7	0.0	110.2
SEMA	11.5	8.1	152.4	0.0	171.9
WCMA	21.1	17.4	139.9	34.9	213.3
NEMA	16.1	18.7	306.3	0.0	341.2
Total	323.0	149.5	1,027.9	347.2	1,847.6

* Real Time Demand Response

** Real Time Emergency Generation

NOTE: CSO values include T&D loss factor (8%) and, as applicable, a reserve margin gross-up of either 14.3% or 16.1%, respectively, for portions of resources that selected a multi-year obligation in the FCA 1 or FCA 2. Otherwise, reserve margin gross-ups were discontinued with FCA 3.



NEW GENERATION

New Generation Update

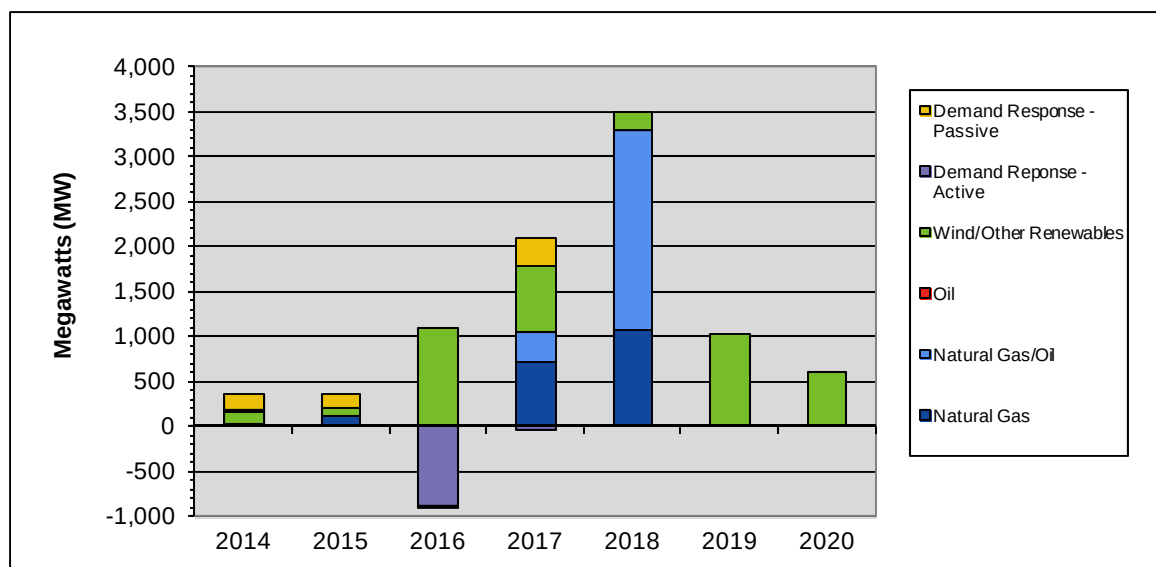
Based on Interim 9/26/14 Queue Update

- No new projects have applied for interconnection study since the last update
- No projects have withdrawn from the Queue or gone commercial
- In total, 54 generation projects are currently being tracked by the ISO, totaling 8,300 MW



Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2014	2015	2016	2017	2018	2019	2020	Total MW	% of Total ¹
Demand Response - Passive	188	157	-12	330	0	0	0	663	8.1
Demand Response - Active	19	3	-868	-37	0	0	0	-883	-10.8
Wind & Other Renewables	140	97	1,096	717	208	1,029	601	3,888	47.6
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil ²	2	0	8	346	2,223	0	0	2,579	31.6
Natural Gas	21	111	0	716	1,075	0	0	1,923	23.5
Totals	370	368	224	2,072	3,506	1,029	601	8,170	100.0

¹ Sum may not equal 100% due to rounding

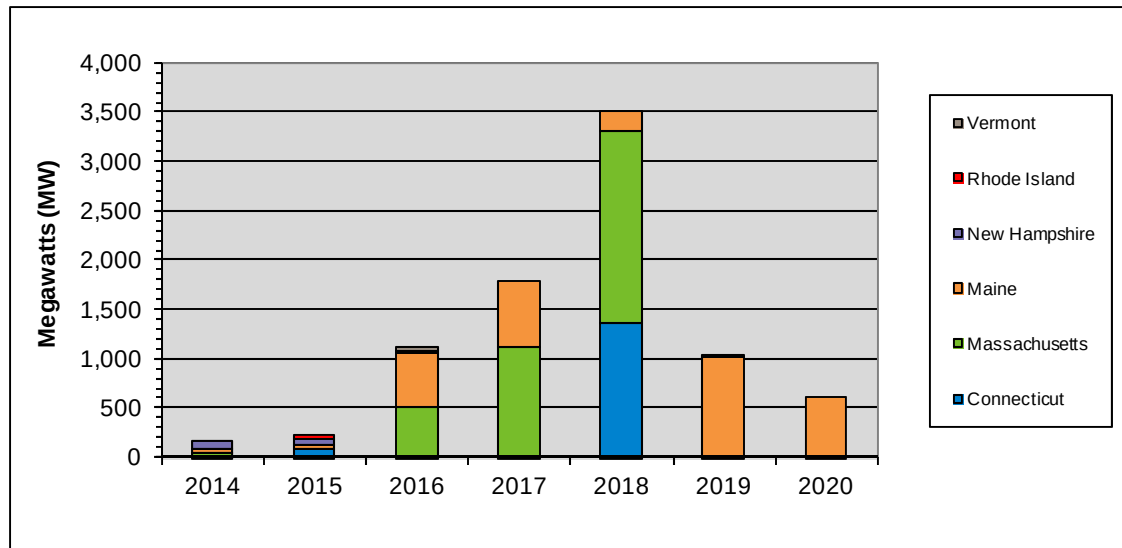
² The projects in this category are dual fuel, with either gas or oil as the primary fuel

- 2014 values include the 116 MW of generation that has gone commercial in 2014
- Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11



Actual and Projected Annual Generator Capacity Additions

By State



	2014	2015	2016	2017	2018	2019	2020	Total MW	% of Total ¹
Vermont	0	0	33	0	0	30	0	63	0.8
Rhode Island	0	27	29	0	0	0	0	56	0.7
New Hampshire	89	63	0	0	0	0	0	152	1.8
Maine	41	34	534	675	208	999	601	3,092	36.9
Massachusetts	33	0	508	1,104	1,935	0	0	3,580	42.7
Connecticut	0	84	0	0	1,363	0	0	1,447	17.2
Totals	163	208	1,104	1,779	3,506	1,029	601	8,390	100.0

¹ Sum may not equal 100% due to rounding

- 2014 values include the 116 MW of generation that has gone commercial in 2014



New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	2	70	0	0	2	70
Hydro	5	35	0	0	5	35
Landfill Gas	0	0	0	0	0	0
Natural Gas	7	1,902	0	0	7	1,902
Natural Gas/Oil	10	2,577	0	0	10	2,577
Oil	0	0	0	0	0	0
Solar	1	6	0	0	1	6
Wind	29	3,684	6	294	23	3,390
Total	54	8,274	6	294	48	7,980

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications



New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	2	70	0	0	2	70
Intermediate	13	3,190	0	0	13	3,190
Peaker	10	1,330	0	0	10	1,330
Wind Turbine	29	3,684	6	294	23	3,390
Total	54	8,274	6	294	48	7,980

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications



New Generation Projection

By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	2	70	2	70	0	0	0	0	0	0
Hydro	5	35	0	0	4	10	1	25	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	7	1,902	0	0	4	1,345	3	557	0	0
Natural Gas/Oil	10	2,577	0	0	5	1,835	5	742	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	1	6	0	0	0	0	1	6	0	0
Wind	29	3,684	0	0	0	0	0	0	29	3,684
Total	54	8,274	2	70	13	3,190	10	1,330	29	3,684

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel



FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 5

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	ARA 2	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	2,104.141	2,001.126	-103.015	1,385.670	-615.456	1,074.461	-311.21	899.125	-175.336	699.930	-199.195
	Passive Demand	1,485.713	1,397.586	-88.127	1,345.283	-52.303	1,348.593	3.31	1,365.947	17.354	1399.564	33.617
Demand Total		3,589.854	3,398.712	-191.142	2,730.953	-667.759	2,423.054	-307.90	2,265.072	-157.982	2099.494	-165.578
Generator	Non-Intermittent	30,558.220	28,337.481	-2,220.739	27,917.690	-419.791	28,364.588	446.90	28,517.097	152.509	28557.855	40.758
	Intermittent	880.737	827.804	-52.933	778.165	-49.639	795.545	17.38	795.767	0.222	718.908	-76.859
Generator Total		31,438.957	29,165.285	-2,273.672	28,695.855	-469.430	29,160.133	464.28	29,312.864	152.731	29276.763	-36.101
Import Total		2,011.001	1,831.372	-179.629	1,831.372	0.000	1,635.835	-195.54	1,635.835	0.000	1382.551	-253.284
***Grand Total		37,039.812	34,395.369	-2,644.443	33,258.180	-1,137.189	33,219.022	-39.16	33,213.771	-5.251	32,758.808	-454.963
Net ICR (NICR)		33,200	33,200	0	33,200	0	32,209	-991	32,209	0	32,588	379

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.



Capacity Supply Obligation FCA 6

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	2,001.510	1,918.662	-82.848	1,368.608	-550.054	1,271.984	-96.624	1,085.347	-186.64	842.791	-242.56				
	Passive Demand	1,643.334	1,553.054	-90.280	1,521.535	-31.519	1,521.535	0.000	1,516.504	-5.03	1700.586	184.08				
Demand Total		3,644.844	3,471.716	-173.128	2,890.143	-581.573	2,793.519	-96.624	2,601.851	-191.67	2543.377	-58.47				
Generator	Non-Intermittent	29,866.098	27,957.613	-1,908.485	28,121.731	164.118	28,343.440	221.709	28,442.424	98.98	28727.16	284.73				
	Intermittent	891.069	840.563	-50.506	827.047	-13.516	828.252	1.205	829.219	0.97	820.743	-8.48				
Generator Total		30,757.167	28,798.176	-1,958.991	28,948.778	150.602	29,171.692	222.914	29,271.643	99.95	29547.9	276.26				
Import Total		1,924.000	1,768.111	-155.889	1,768.111	0.000	1,641.821	-126.290	1,616.821	-25.00	1399.037	-217.78				
***Grand Total		36,326.011	34,038.003	-2,288.008	33,607.032	-430.971	33,607.032	0.000	33,490.315	-116.72	33490.32	0.00				
Net ICR (NICR)		33,456	33,456	0	33,456	0	33,456	0	33,114	-342	33,114	0.00				

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.



Capacity Supply Obligation FCA 7

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	1,116.698	1,043.719	-72.979	944.27	-99.45	932.721	-11.549								
	Passive Demand	1,631.335	1,519.740	-111.595	1,519.311	-0.43	1,543.793	24.482								
Demand Total		2,748.033	2,563.459	-184.574	2,463.581	-99.88	2,476.514	12.933								
Generator	Non-Intermittent	30,704.578	28,146.837	-2,557.741	28,127.044	-19.79	28,523.002	395.958								
	Intermittent	936.913	893.710	-43.203	903.244	9.53	913.083	9.839								
Generator Total		31,641.491	29,040.547	-2,600.944	29,030.288	-10.26	29,436.085	405.797								
Import Total		1,830.000	1,606.862	-223.138	1,606.862	0.00	1,616.401	9.539								
***Grand Total		36,219.524	33,210.868	-3,008.656	33,100.731	-110.14	33,529.000	428.269								
Net ICR (NICR)		32,968	32,968	0	33,529	561	33,529	0								

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.



Capacity Supply Obligation FCA 8

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	1,080.079												
	Passive Demand	1,960.517												
Demand Total		3,040.596												
Generator	Non-Intermittent	28,547.813												
	Intermittent	876.925												
Generator Total		29,424.738												
Import Total		1,237.034												
***Grand Total		33,702.368												
Net ICR (NICR)		33,855												

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Change columns contains the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column.



RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS

What are Daily NCPC Payments?

- “Make-whole” payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource’s offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area



Definitions

1 st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2 nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2 nd Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR)
Voltage NCPC Payments	Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
Delisted Units	Resources within the control area that have requested to be classified as a non-installed capacity (ICAP) resource, and as such, are not required to offer their capacity into the DA Energy Market
OATT	Open Access Transmission Tariff



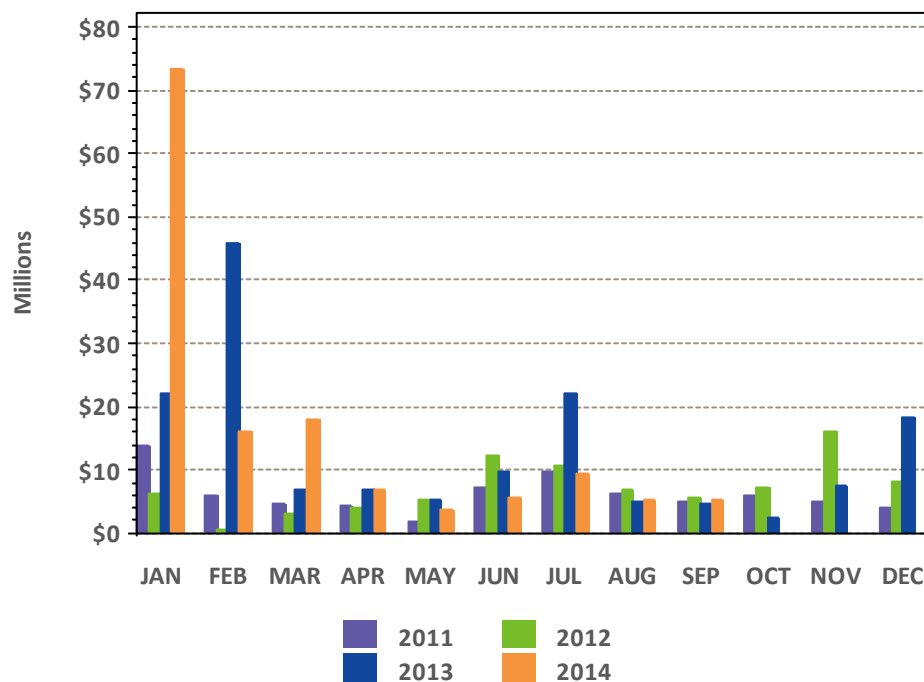
Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1 st Contingency	Market	DA 1 st C (excluding at external nodes) is allocated to system DALO. RT 1 st C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1 st Contingency	Market	DA 1 st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2 nd Contingency	Market	DA and RT 2 nd C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service

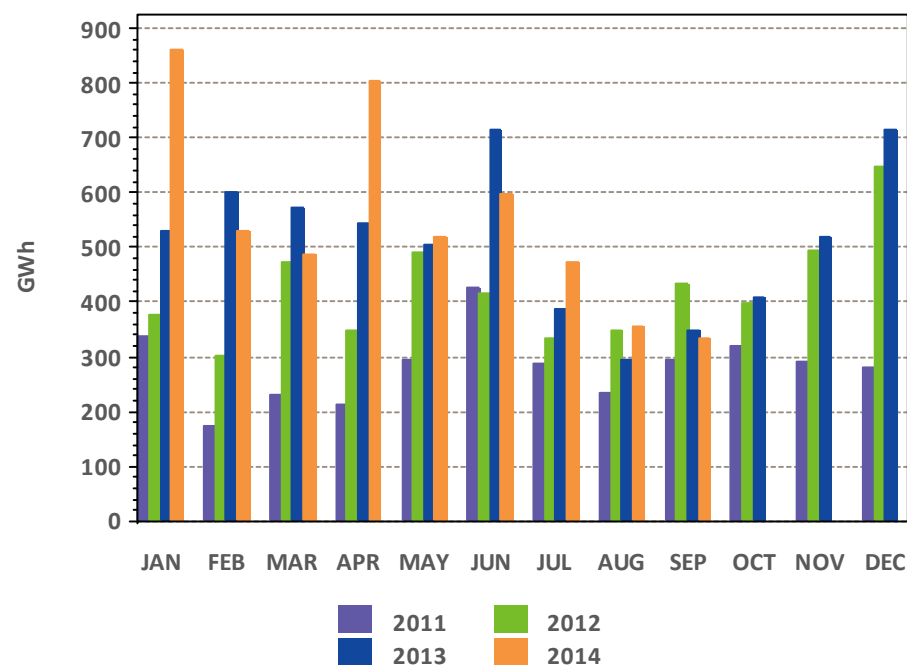


Year-Over-Year Total NCPC Dollars and Energy

NCPC Dollars



NCPC Energy*

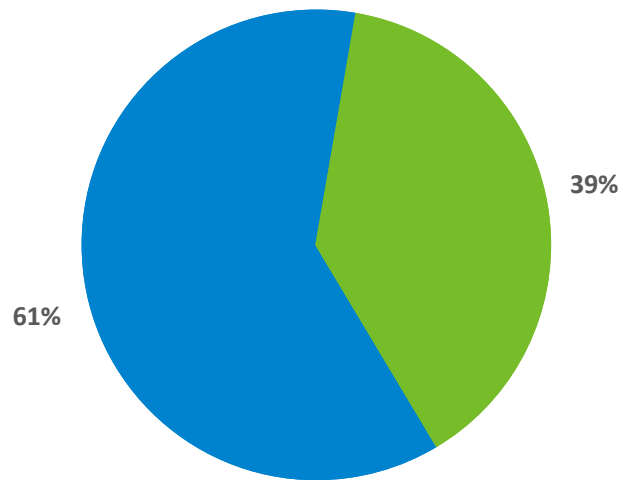


* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.



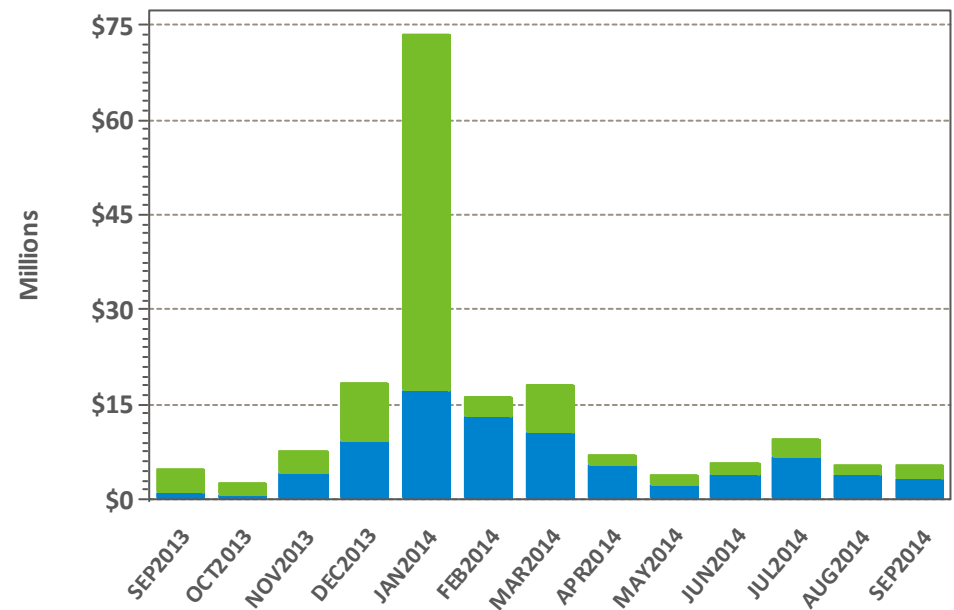
DA and RT NCPC Charges

SEP-14 Total = \$5.43 M



Day-Ahead Real-Time

Last 13 Months

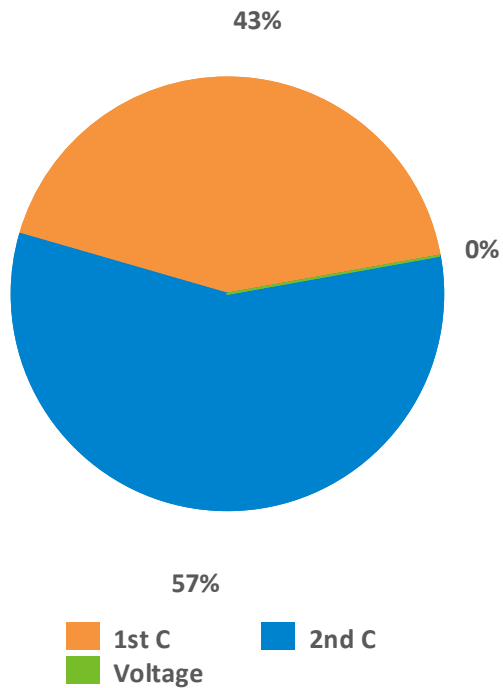


Day-Ahead Real-Time

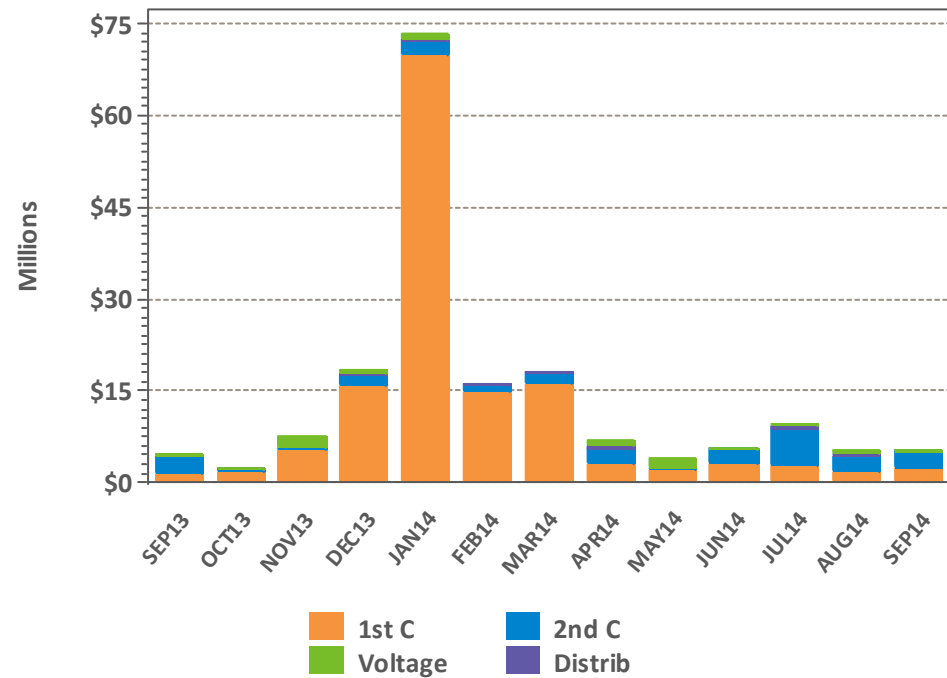


NCPC Charges by Type

SEP-14 Total = \$5.43 M



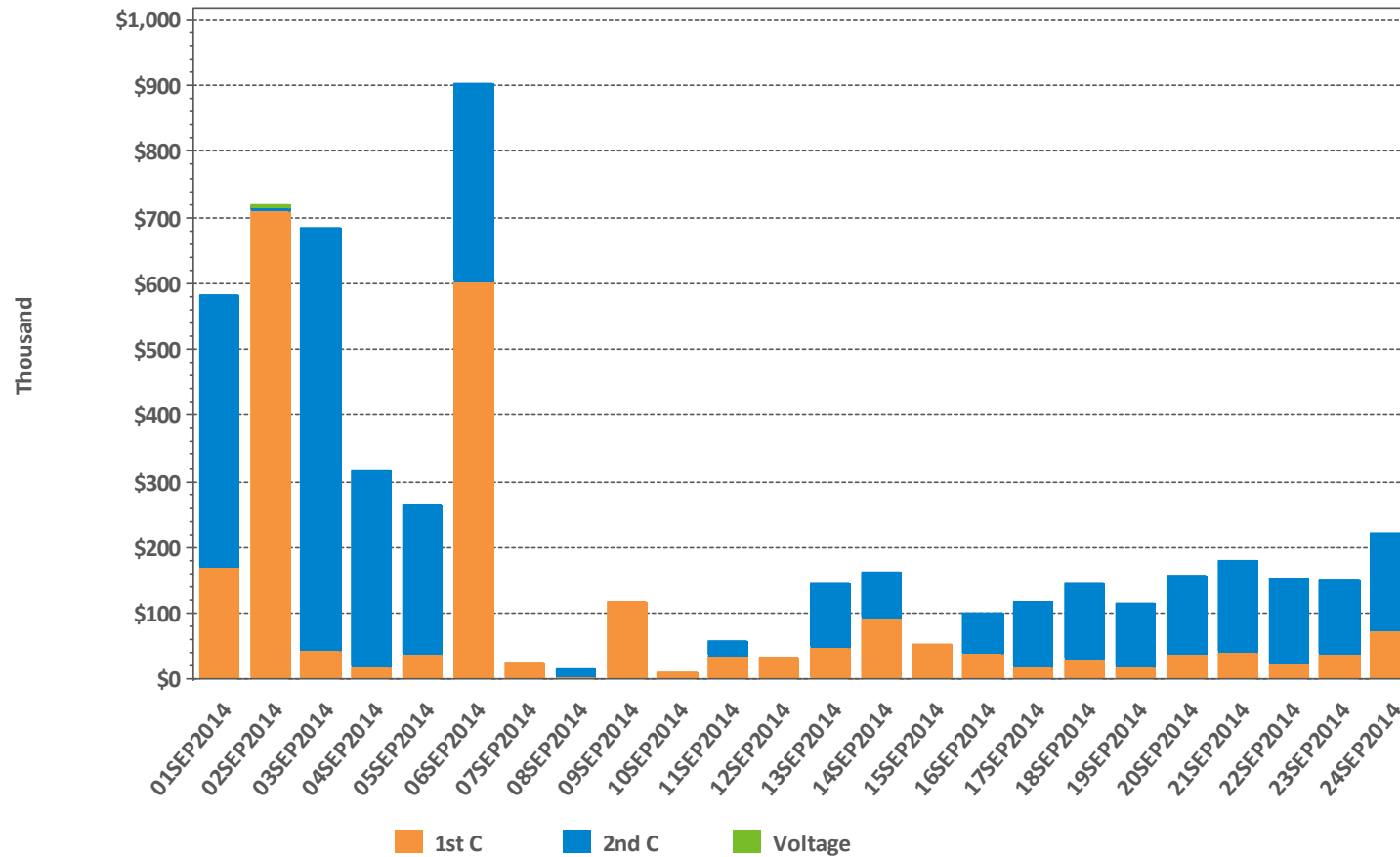
Last 13 Months



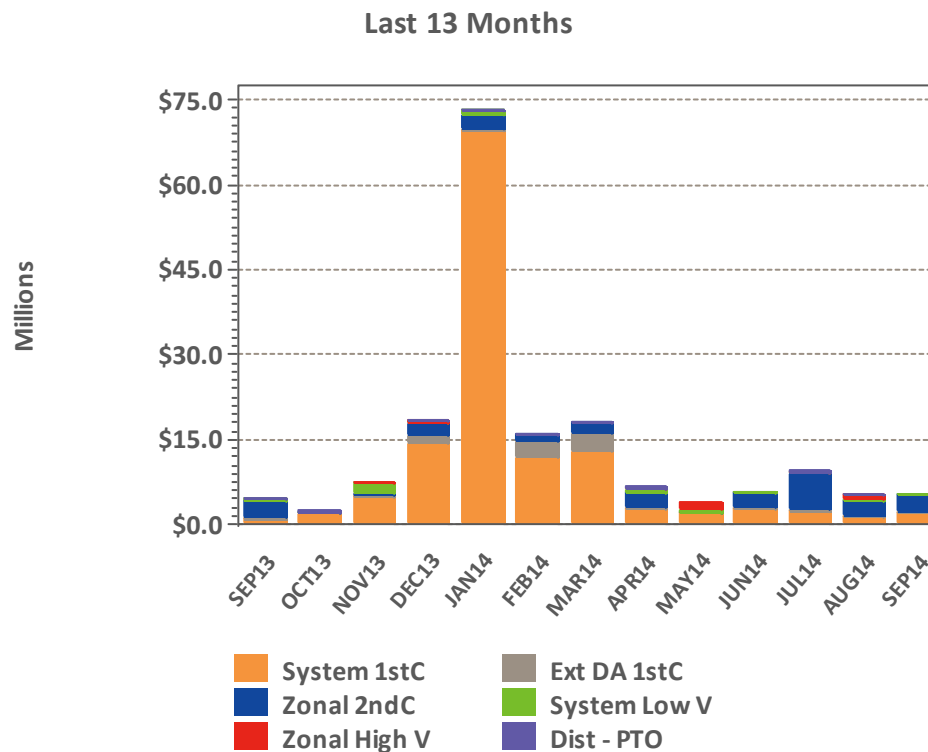
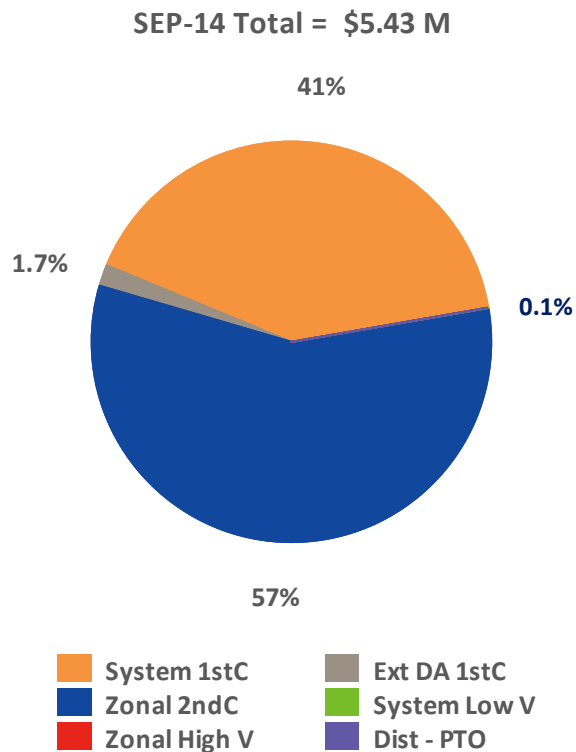
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage



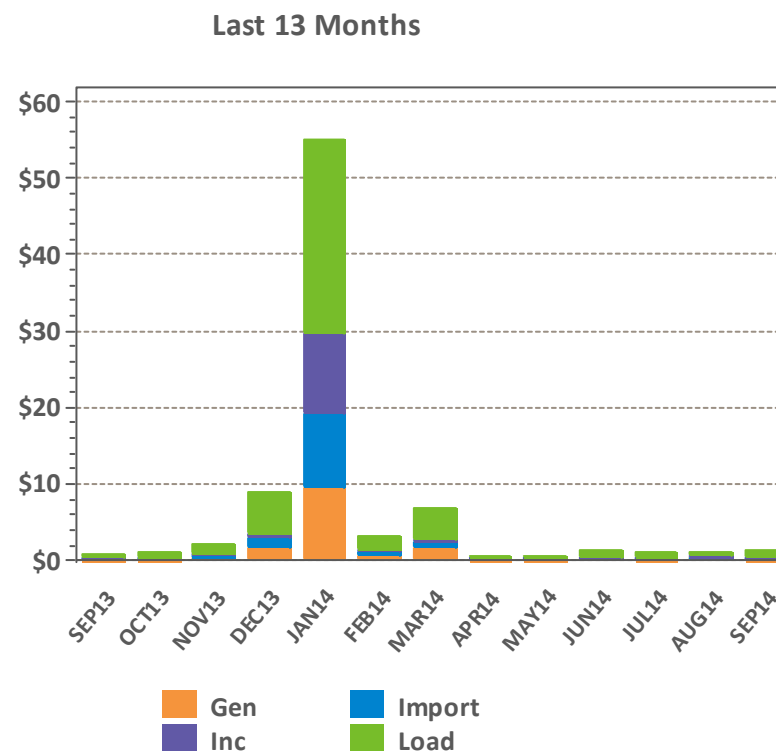
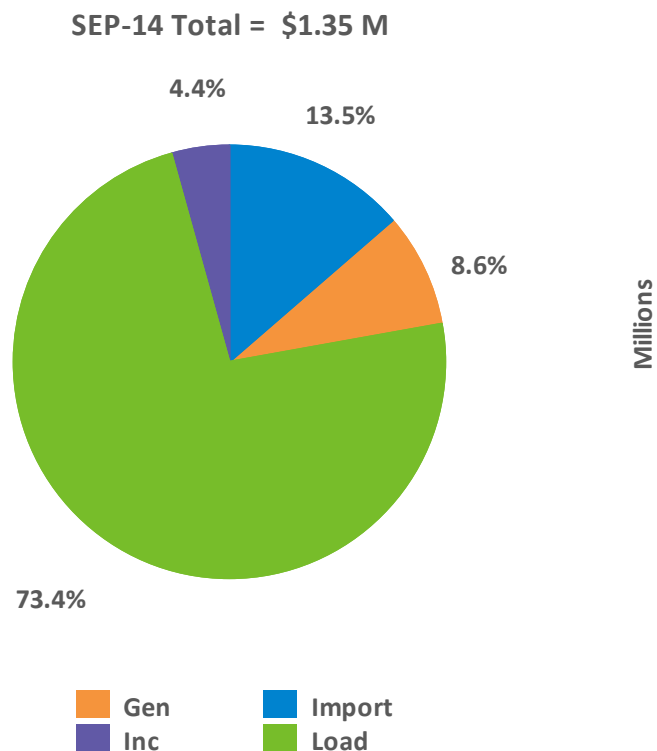
Daily NCPC Charges by Type



NCPC Charges by Allocation



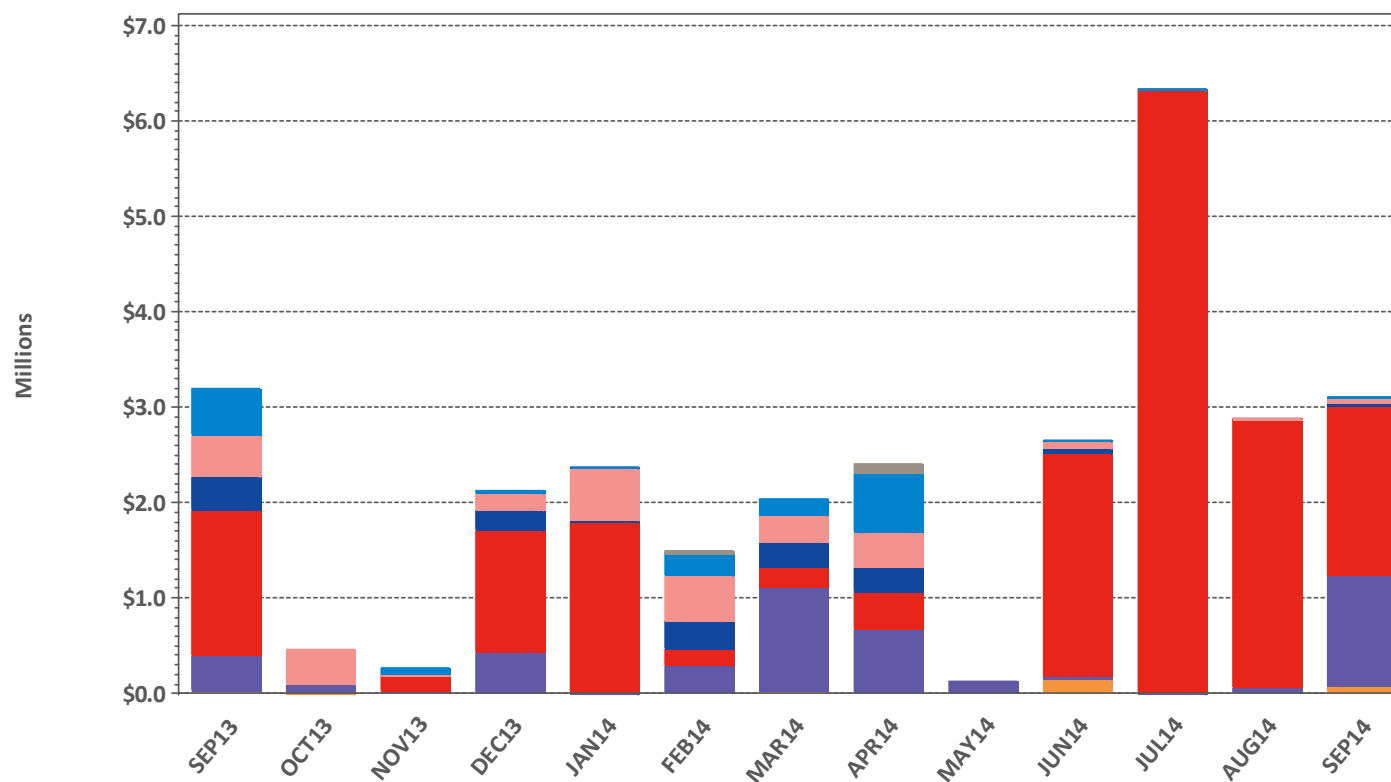
RT First Contingency Charges by Deviation Type



Gen – Generator deviations
Inc – Increment Offer deviations
Imp – Import deviations
Load – Load obligation deviations



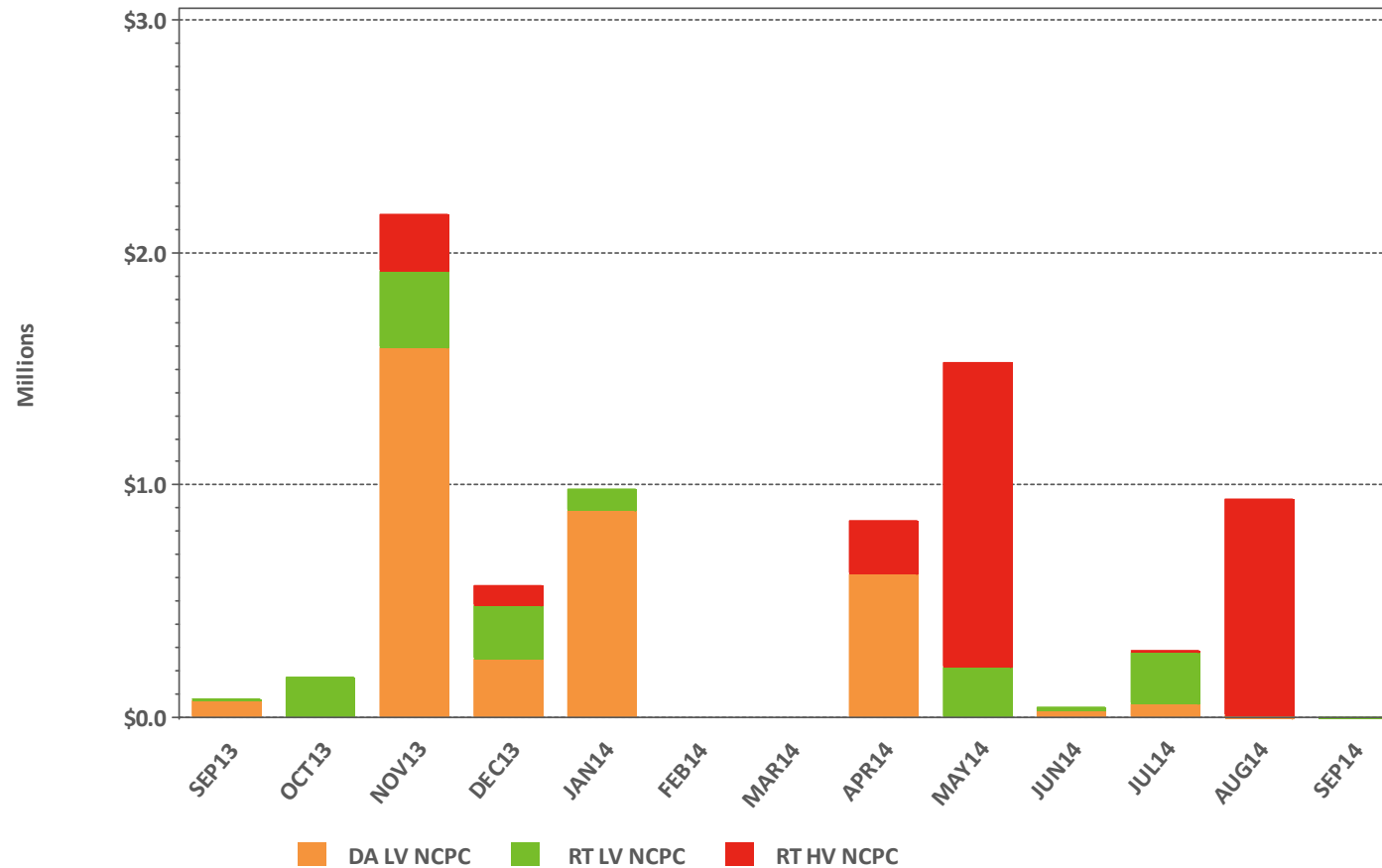
LSCPR Charges by Zone



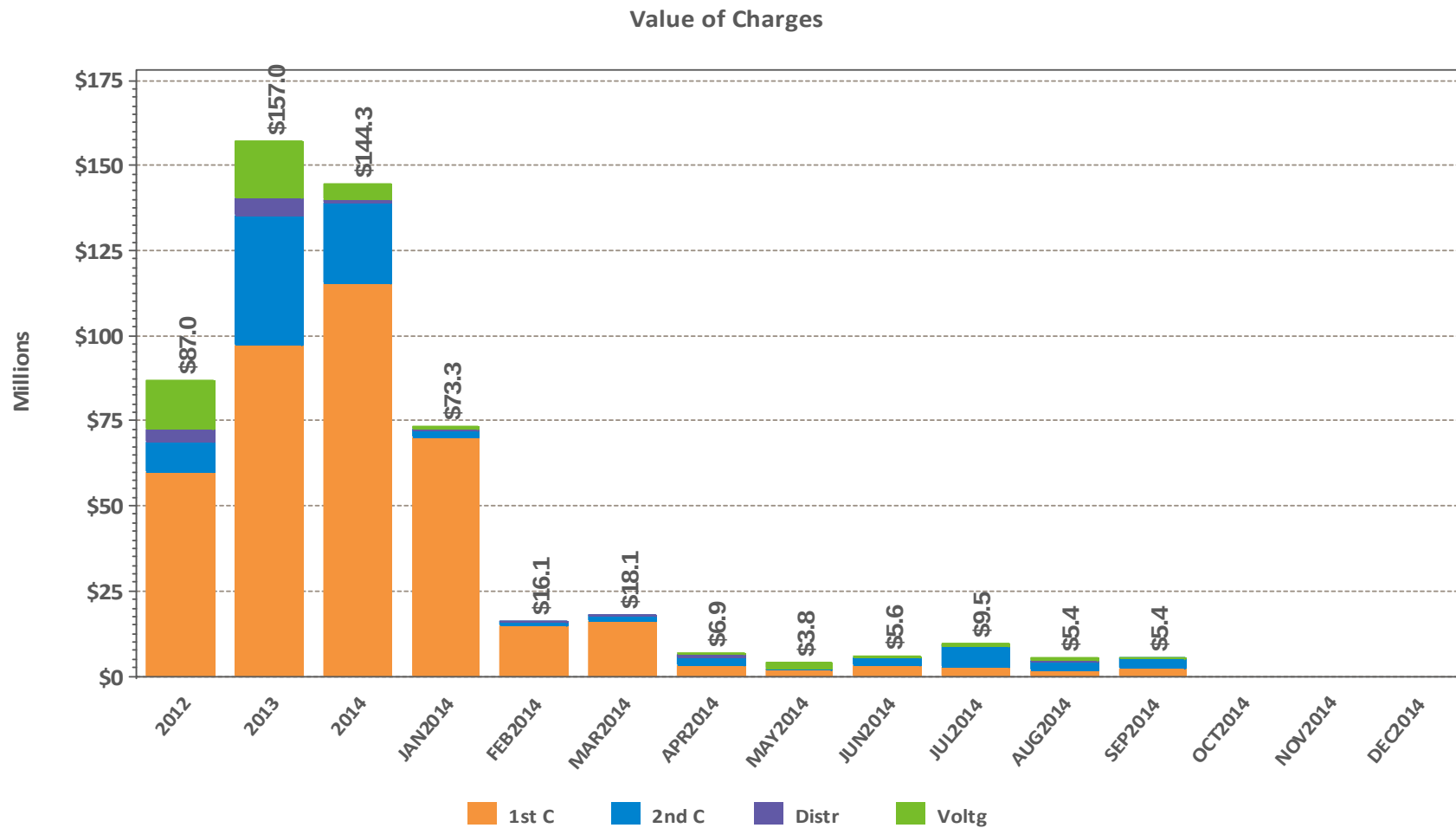
CT – Connecticut Region
 ME – Maine Region
 NH – New Hampshire Region
 RI – Rhode Island Region
 VT – Vermont Region
 SEMA – Southeast Massachusetts Region
 WCMA – Western/Central Massachusetts Region
 NEMA – Northeast Massachusetts Region
 EXT – External Locations



NCPC Charges for Voltage Support and High Voltage Control

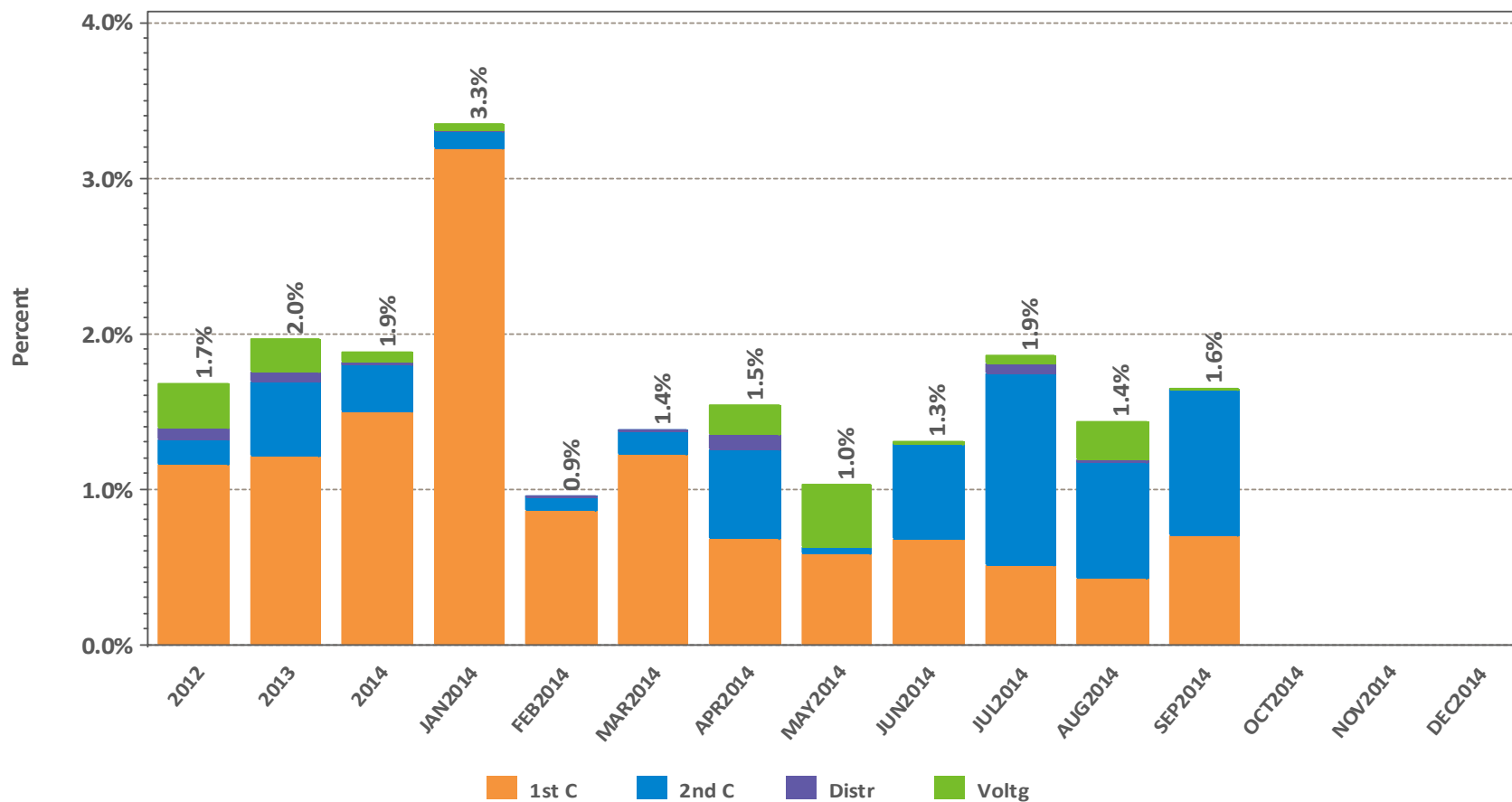


NCPC Charges by Type

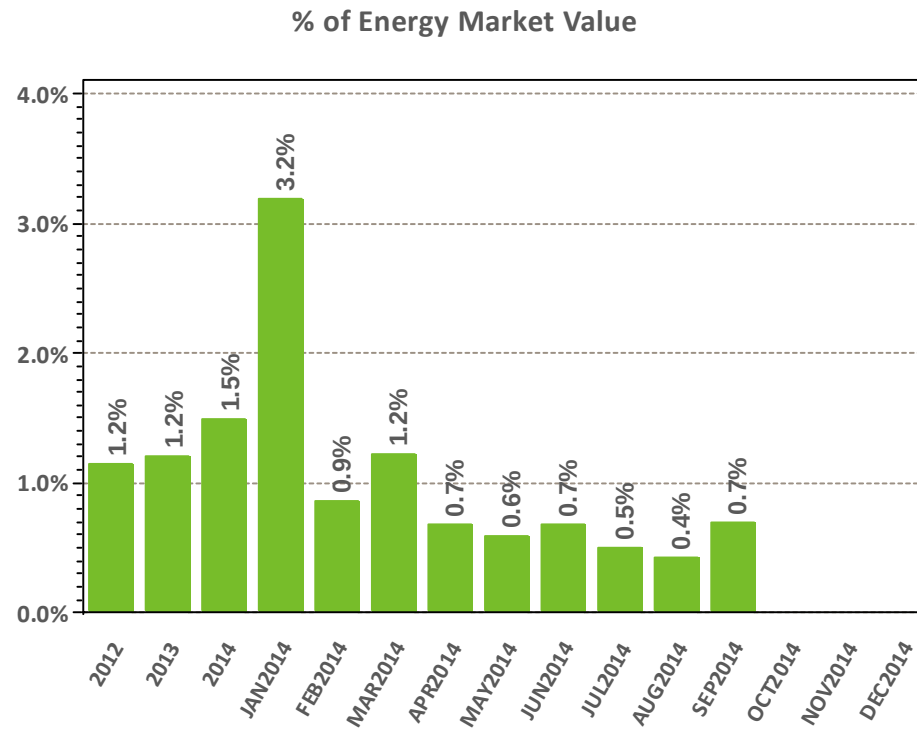
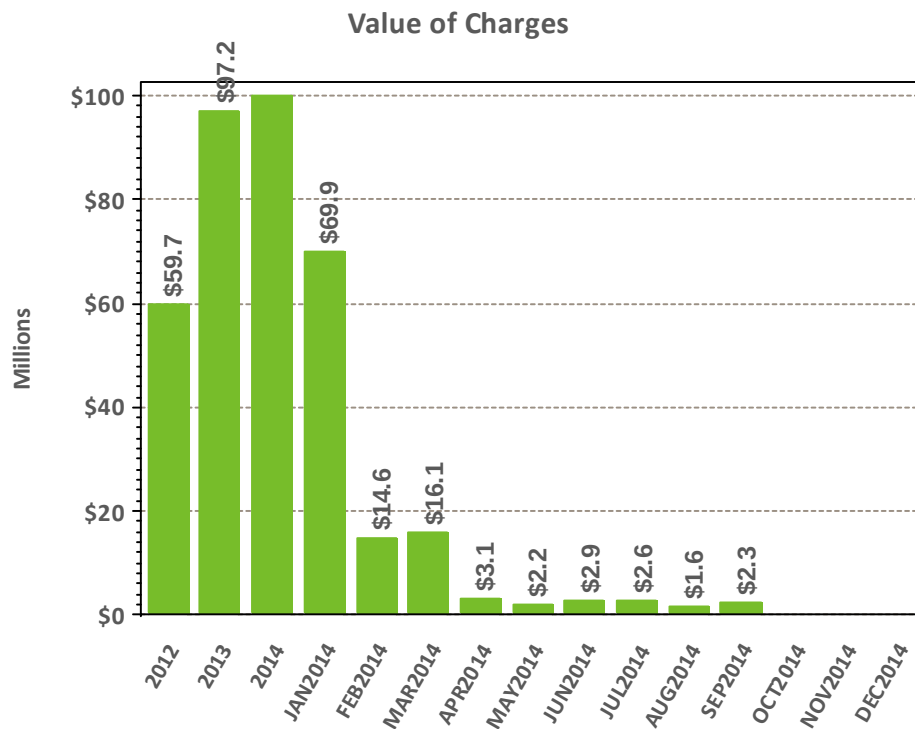


NCPC Charges as Percent of Energy Market

NCPC By Type as Percent of Energy Market



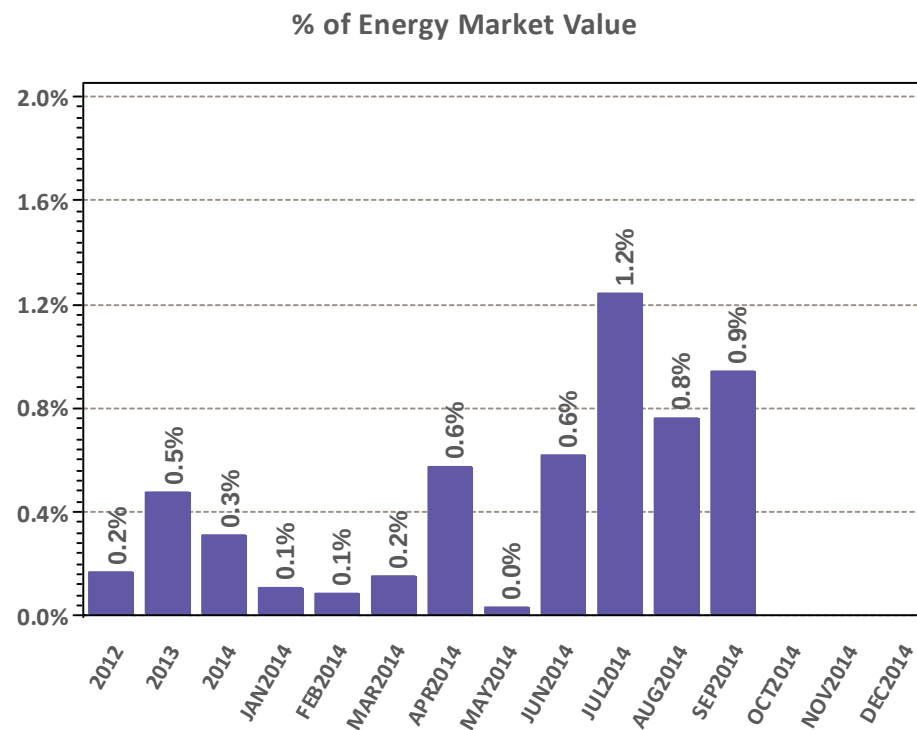
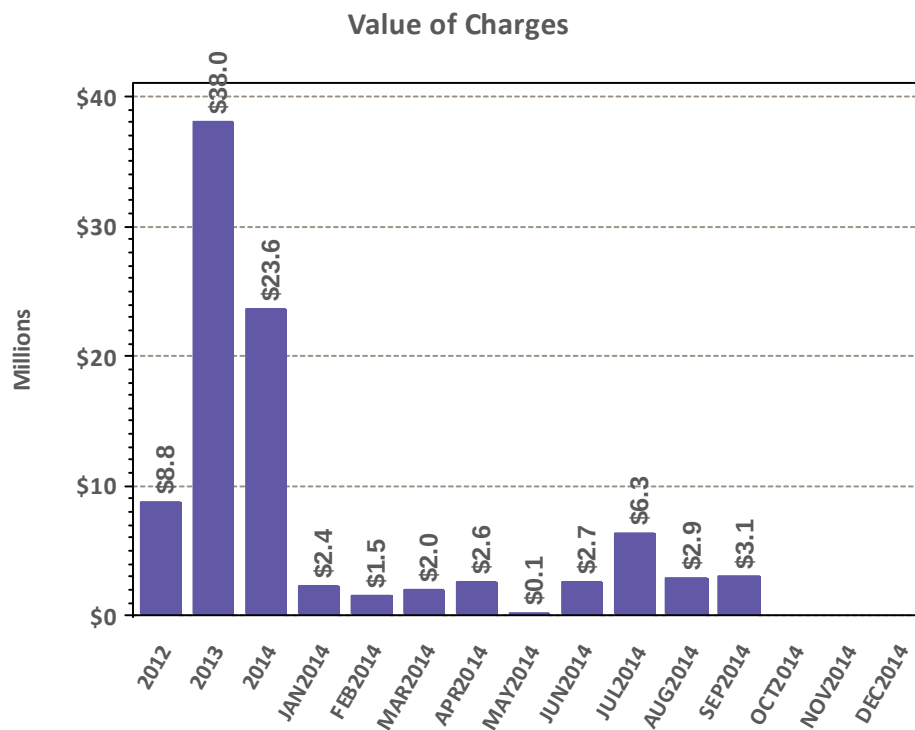
First Contingency NCPC Charges



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market



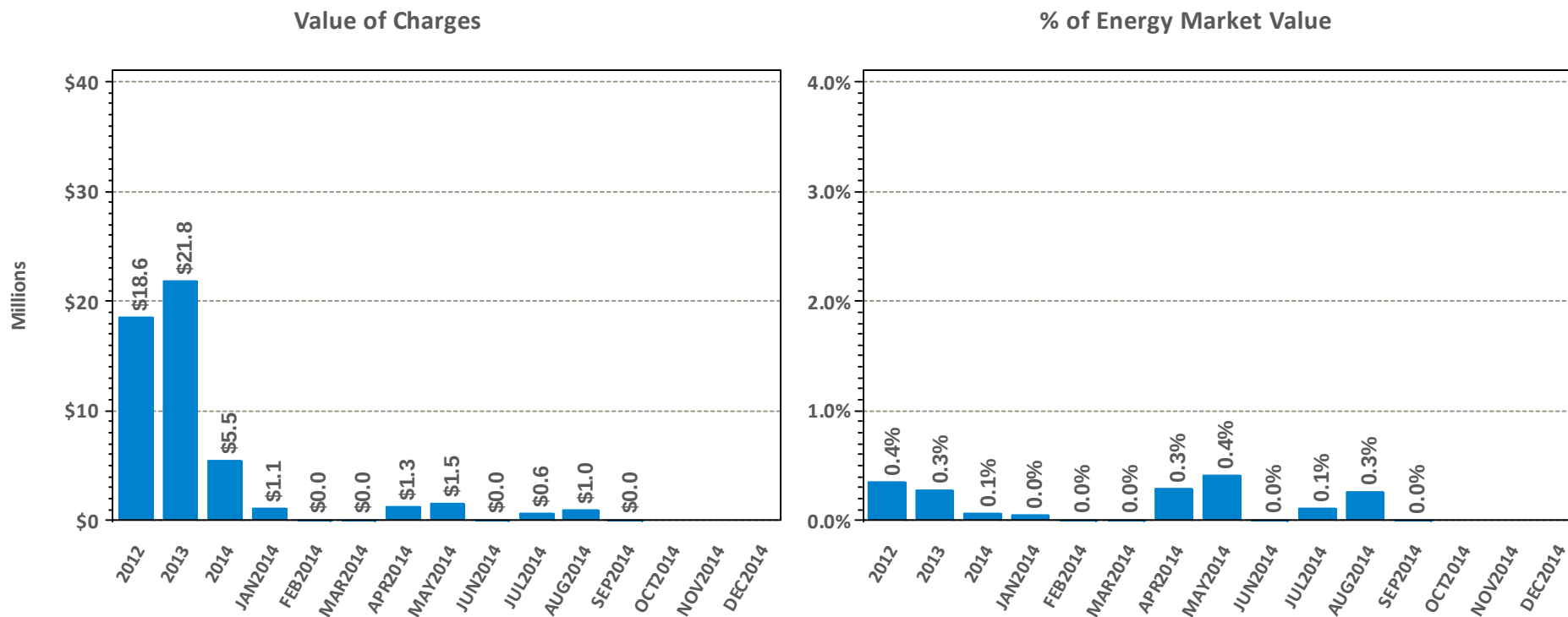
Second Contingency NCPC Charges



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market



Voltage and Distribution NCPC Charges



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market



DA vs. RT Pricing

The following slides outline:

- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange



DA vs. RT LMPs (\$/MWh)

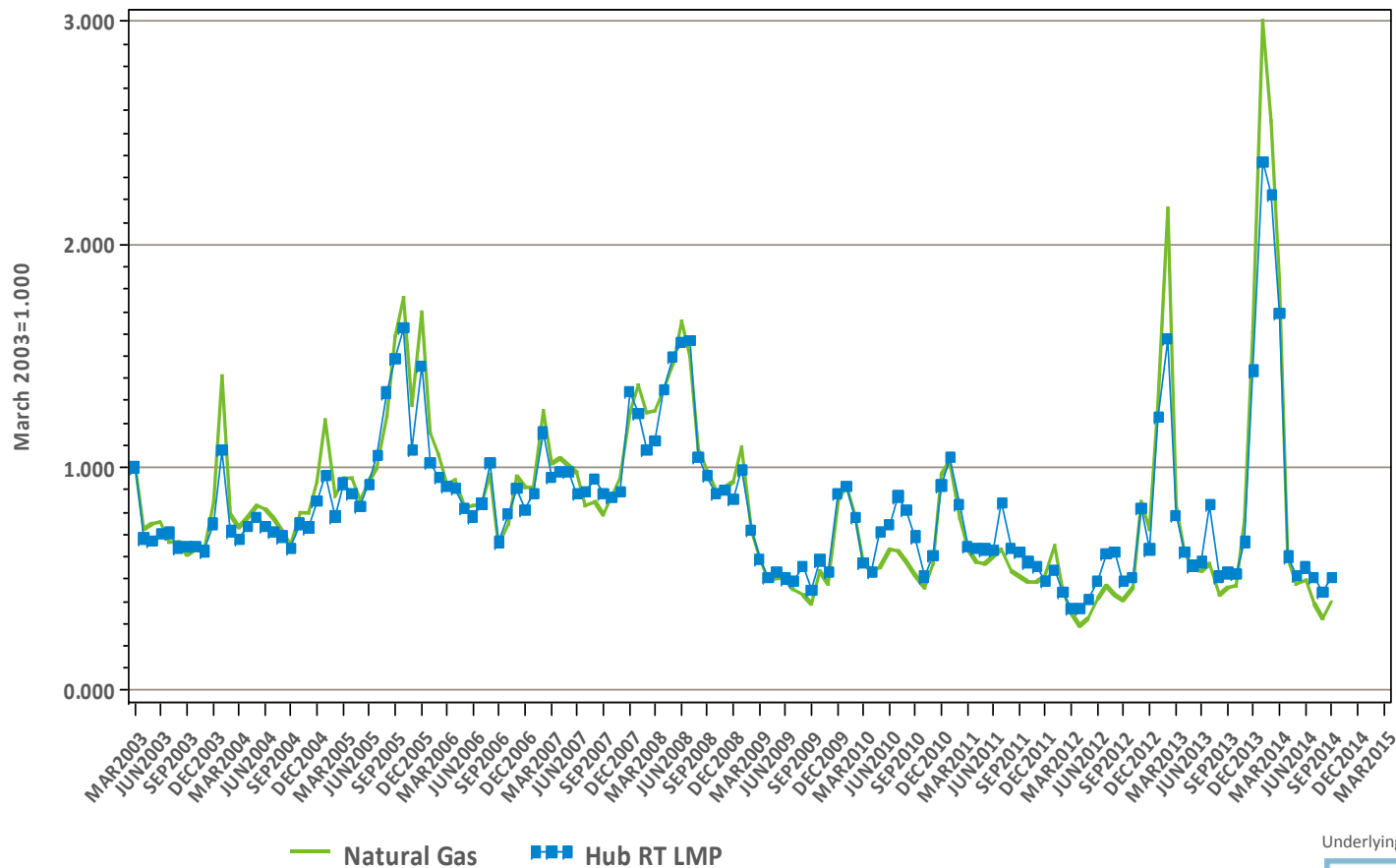
Arithmetic Average

Year 2012	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$36.48	\$37.09	\$36.20	\$36.24	\$36.57	\$36.56	\$36.44	\$37.29	\$36.43
Real-Time	\$36.22	\$36.95	\$35.25	\$36.00	\$36.22	\$35.96	\$36.22	\$36.97	\$36.17
RT Delta %	-0.7%	-0.4%	-2.6%	-0.7%	-0.9%	-1.7%	-0.6%	-0.8%	-0.7%
Year 2013	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$56.90	\$55.43	\$54.48	\$55.98	\$55.36	\$57.80	\$57.02	\$56.38	\$56.43
Real-Time	\$56.32	\$55.90	\$53.23	\$55.15	\$55.08	\$56.10	\$56.43	\$56.12	\$56.06
RT Delta %	-1.0%	0.8%	-2.3%	-1.5%	-0.5%	-2.9%	-1.0%	-0.5%	-0.7%

September-13	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$38.52	\$38.28	\$34.97	\$37.30	\$37.77	\$38.60	\$38.16	\$38.64	\$40.43
Real-Time	\$36.55	\$36.58	\$33.25	\$35.28	\$35.78	\$35.83	\$36.13	\$36.39	\$36.26
RT Delta %	-5.1%	-4.4%	-4.9%	-5.4%	-5.3%	-7.2%	-5.3%	-5.8%	-10.3%
September-14	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$33.61	\$33.98	\$32.77	\$33.58	\$33.33	\$34.91	\$33.54	\$33.57	\$33.42
Real-Time	\$35.18	\$37.95	\$34.45	\$35.01	\$34.64	\$34.93	\$34.82	\$34.97	\$34.88
RT Delta %	4.7%	11.7%	5.1%	4.3%	3.9%	0.1%	3.8%	4.2%	4.4%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-12.8%	-11.2%	-6.3%	-10.0%	-11.7%	-9.6%	-12.1%	-13.1%	-17.3%
Yr over Yr RT	-3.7%	3.7%	3.6%	-0.8%	-3.2%	-2.5%	-3.6%	-3.9%	-3.8%



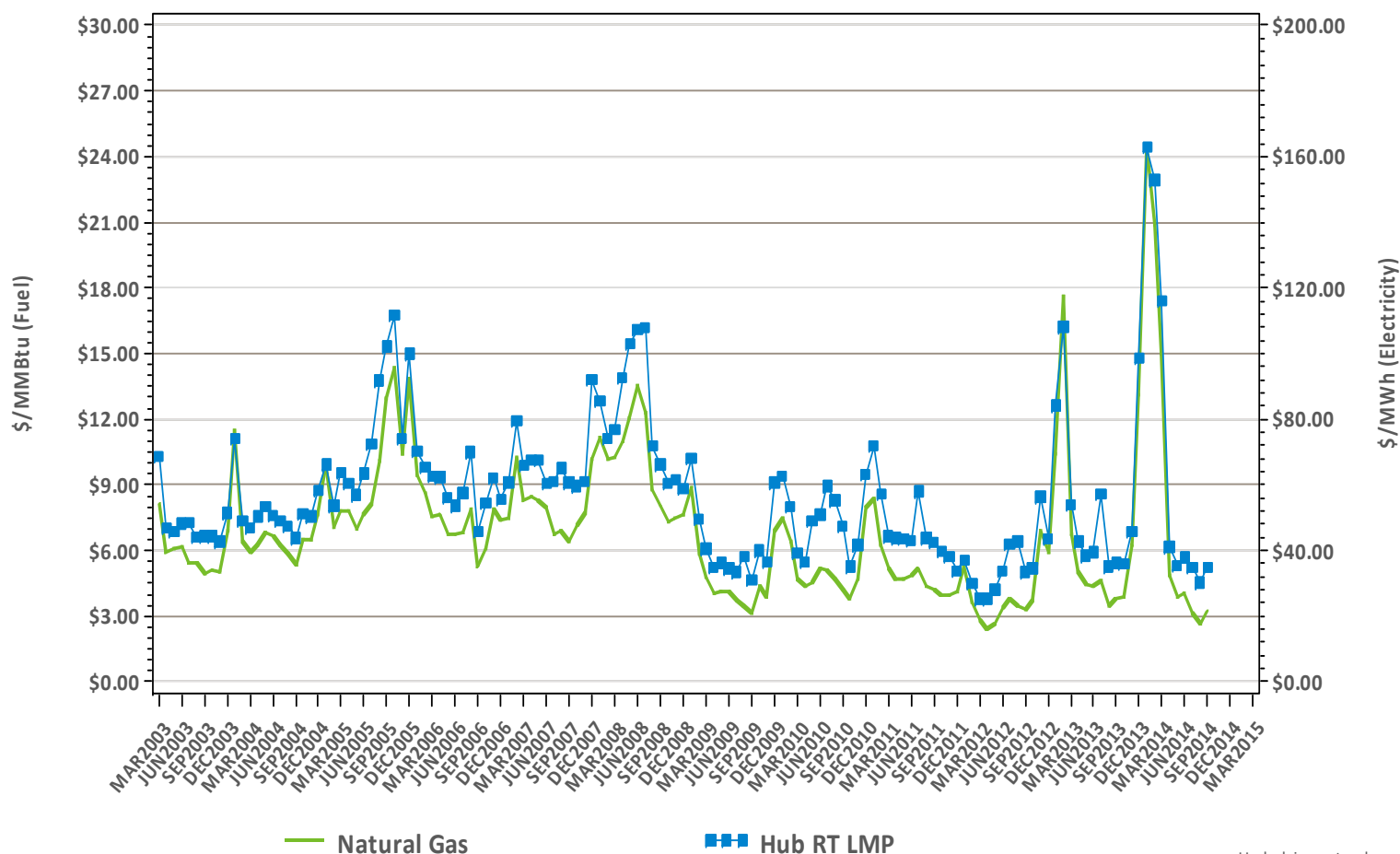
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:



Monthly Average Fuel Price and RT Hub LMP

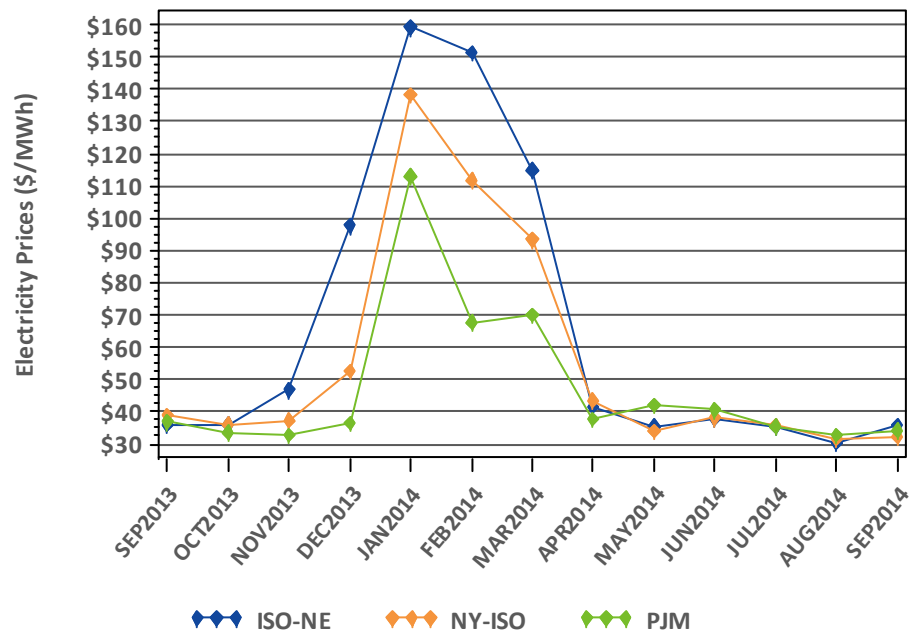


Underlying natural gas data furnished by:



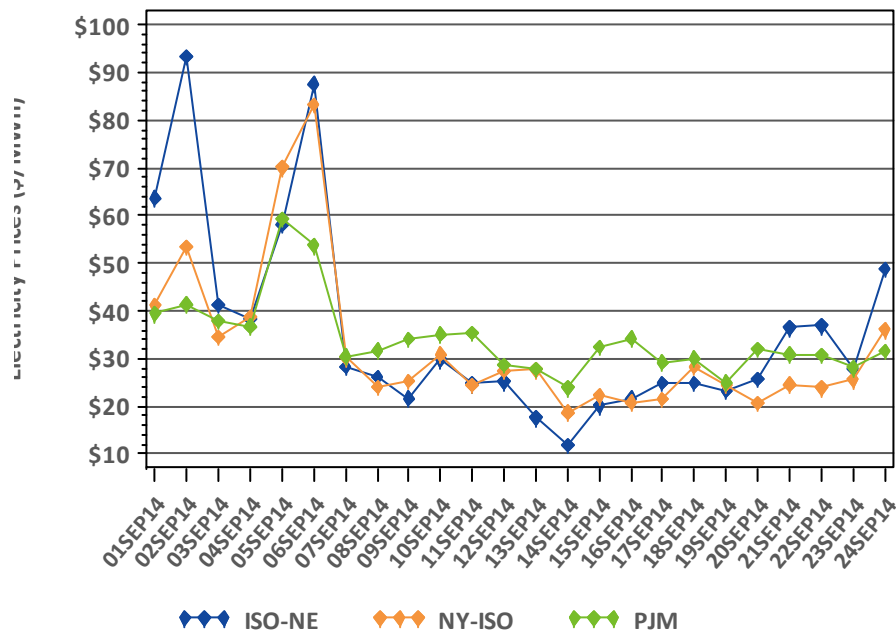
New England, NY, and PJM Real Time Prices

Monthly, Last 13 Months



*Note: Hourly average prices are shown.

Daily: This Month

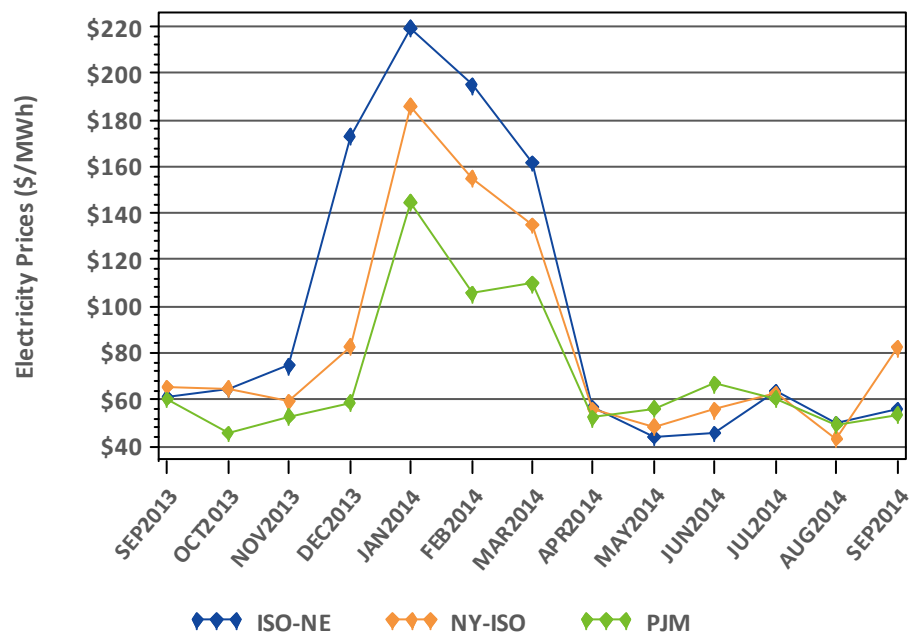


*Note: Hourly average prices are shown.

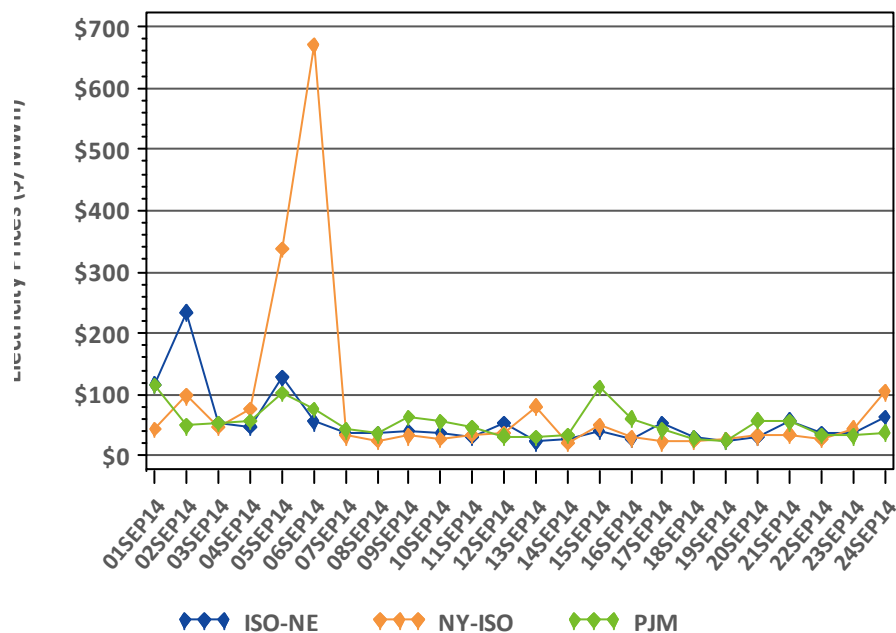


New England, NY, and PJM Real Time Prices (Peak hour)

Monthly, Last 13 Months



Daily: This Month



*Forecasted peak hour is reflected.



Reserve Market Results – September 2014

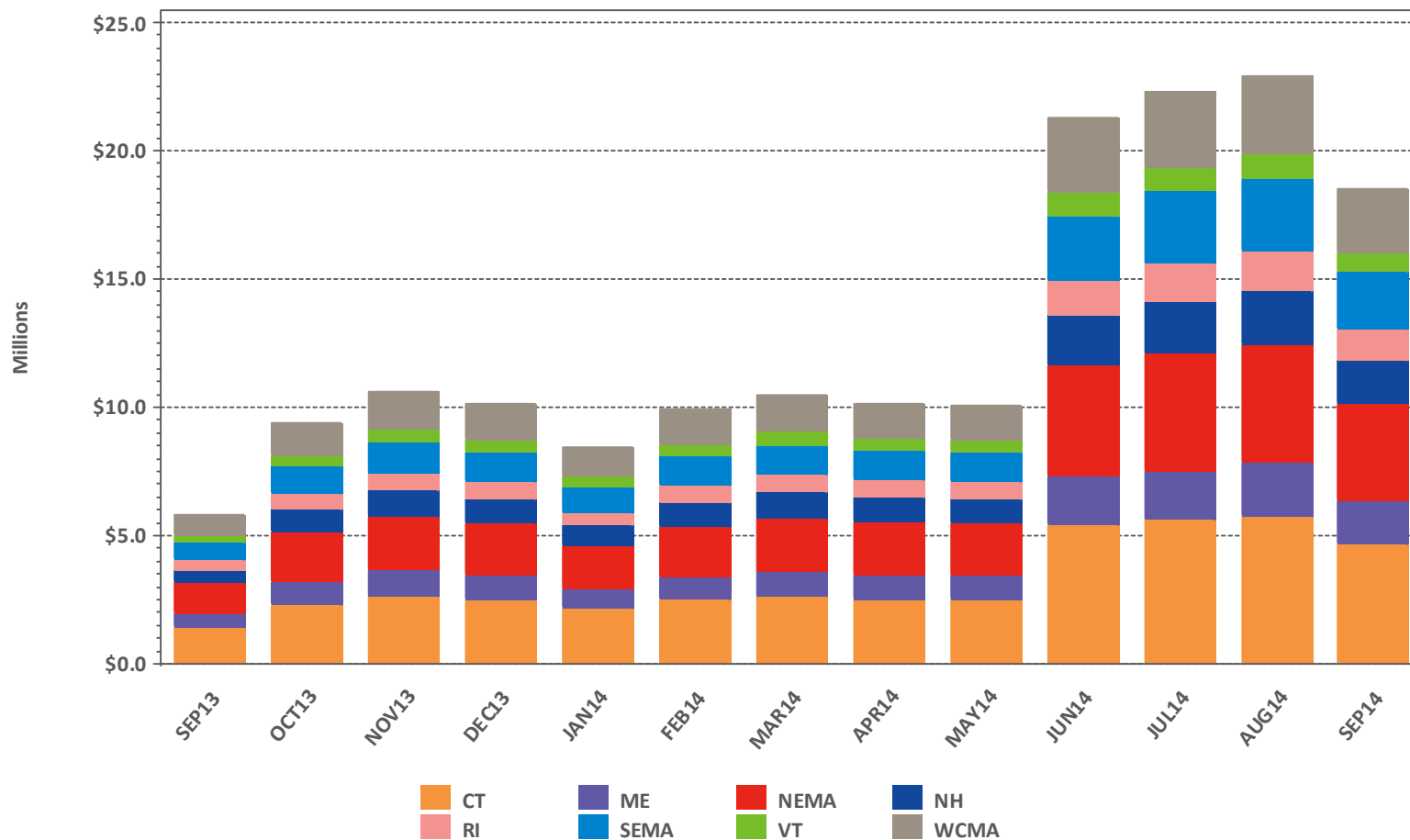
- Maximum potential Forward Reserve Market payments of \$18.9M were reduced by credit reductions of \$159K, failure-to-reserve penalties of \$247K and failure-to-activate penalties of \$0, resulting in a net payout of \$18.5M or 98% of maximum
 - Rest of System: \$10.25M/\$10.45M (98%)
 - Southwest Connecticut: \$1.43M/\$1.47M (98%)
 - Connecticut: \$6.86M/\$7.03M (98%)
- \$3.8M total Real-Time credits were reduced by \$782K in Forward Reserve Energy Obligation Charges for a net of \$3.1M in Real-Time Reserve payments
 - Rest of System: 138 hours, \$1.9M
 - Southwest Connecticut: 138 hours, \$587K
 - Connecticut: 138 hours, \$405K
 - NEMA: 138 hours, \$221K

* “Failure to reserve” results in both credit reductions and penalties in the Locational Forward Reserve Market.



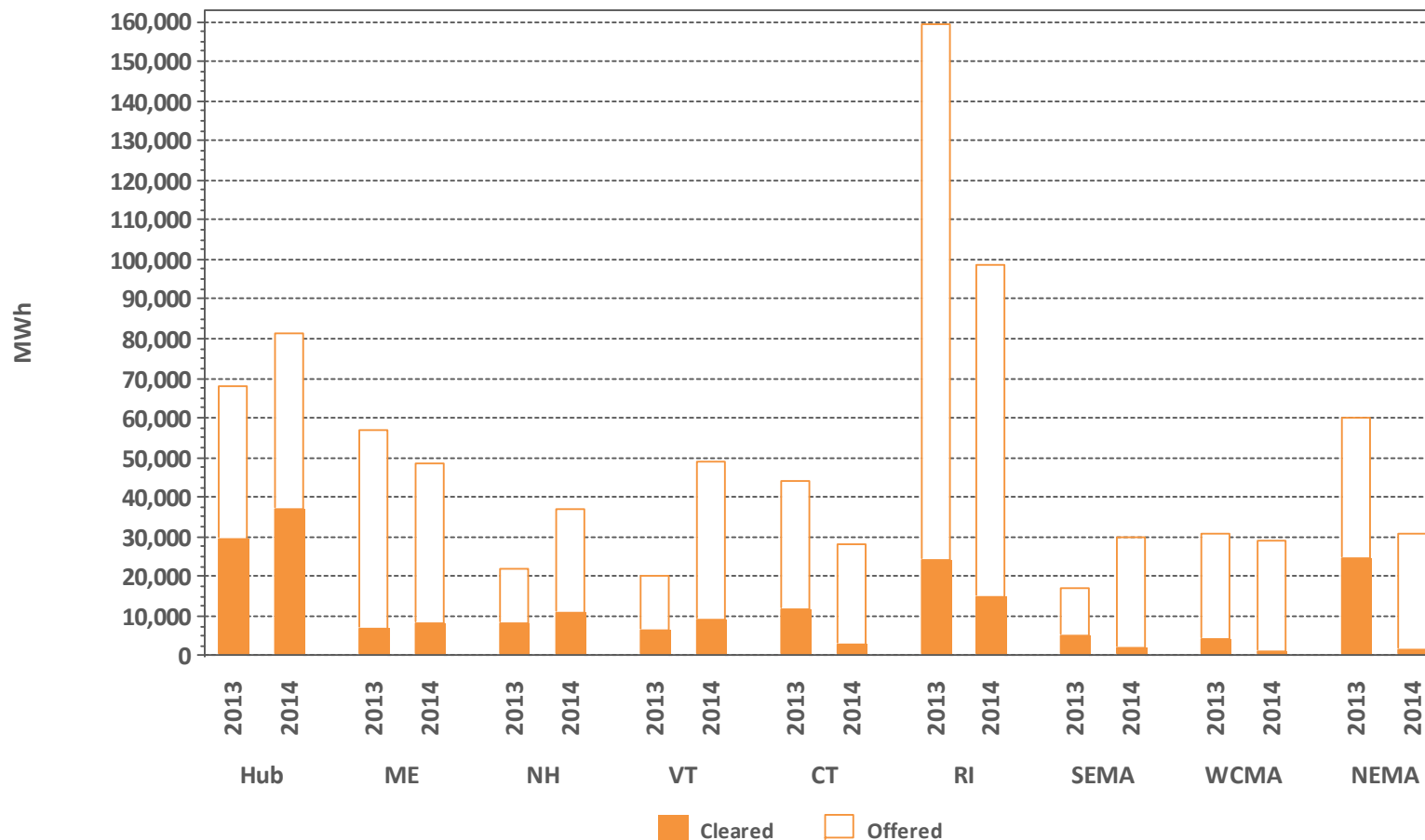
LFRM Charges to Load by Load Zone (\$)

LFRM Charges by Zone, Last 13 Months



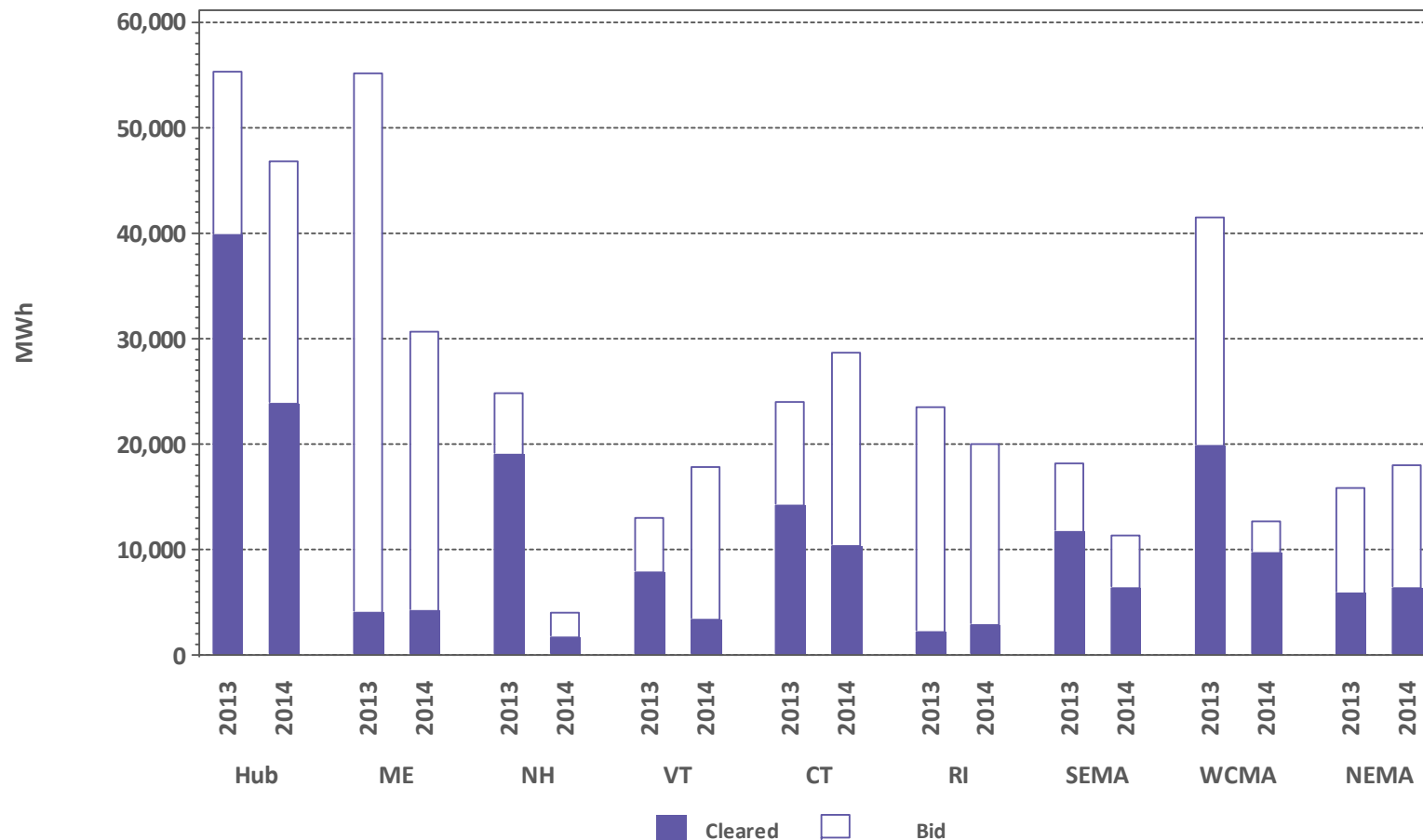
Zonal Increment Offers and Cleared Amounts

September Monthly Totals by Zone



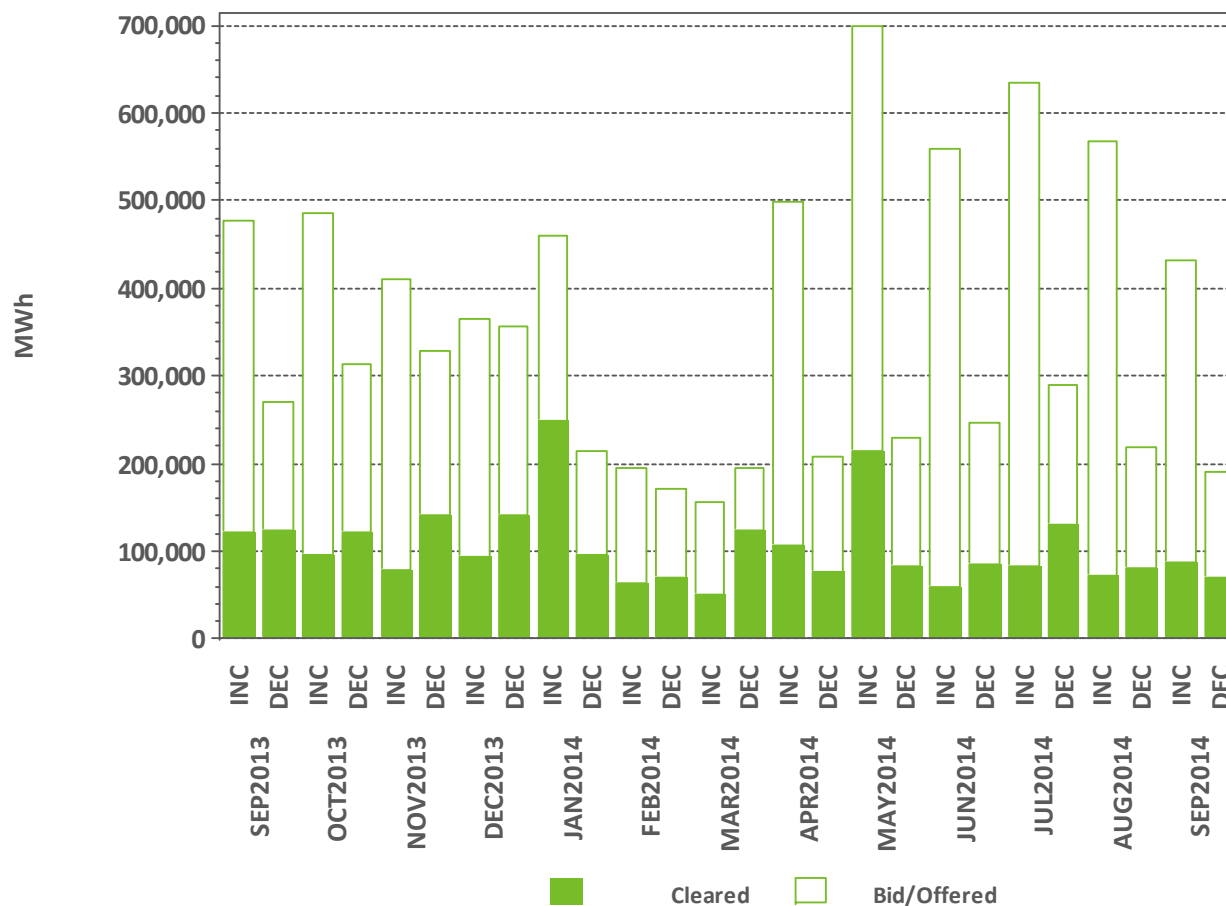
Zonal Decrement Bids and Cleared Amounts

September Monthly Totals by Zone



Total Increment Offers and Decrement Bids

Zonal Level, Last 13 Months

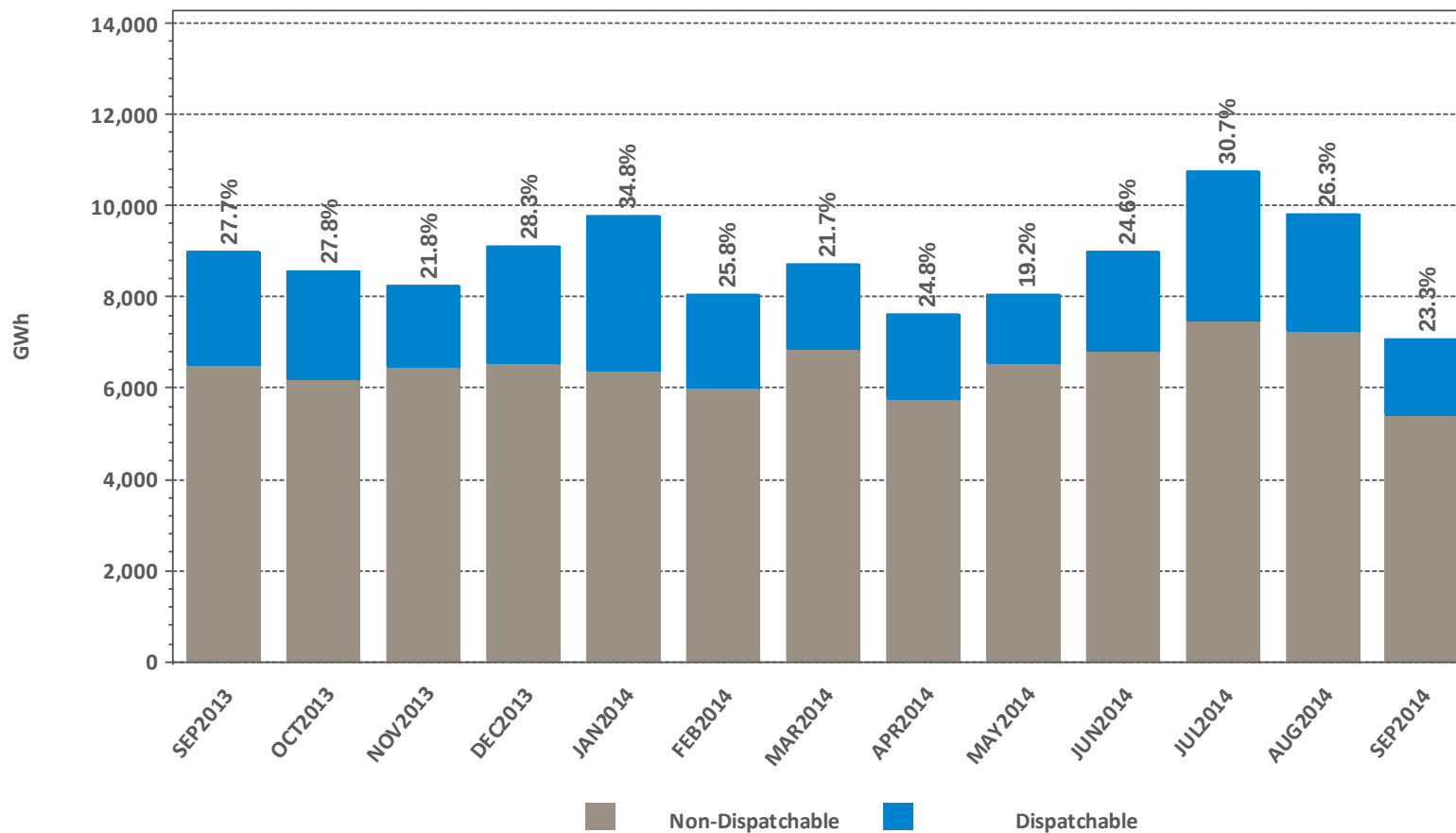


Data excludes nodal offers and bids

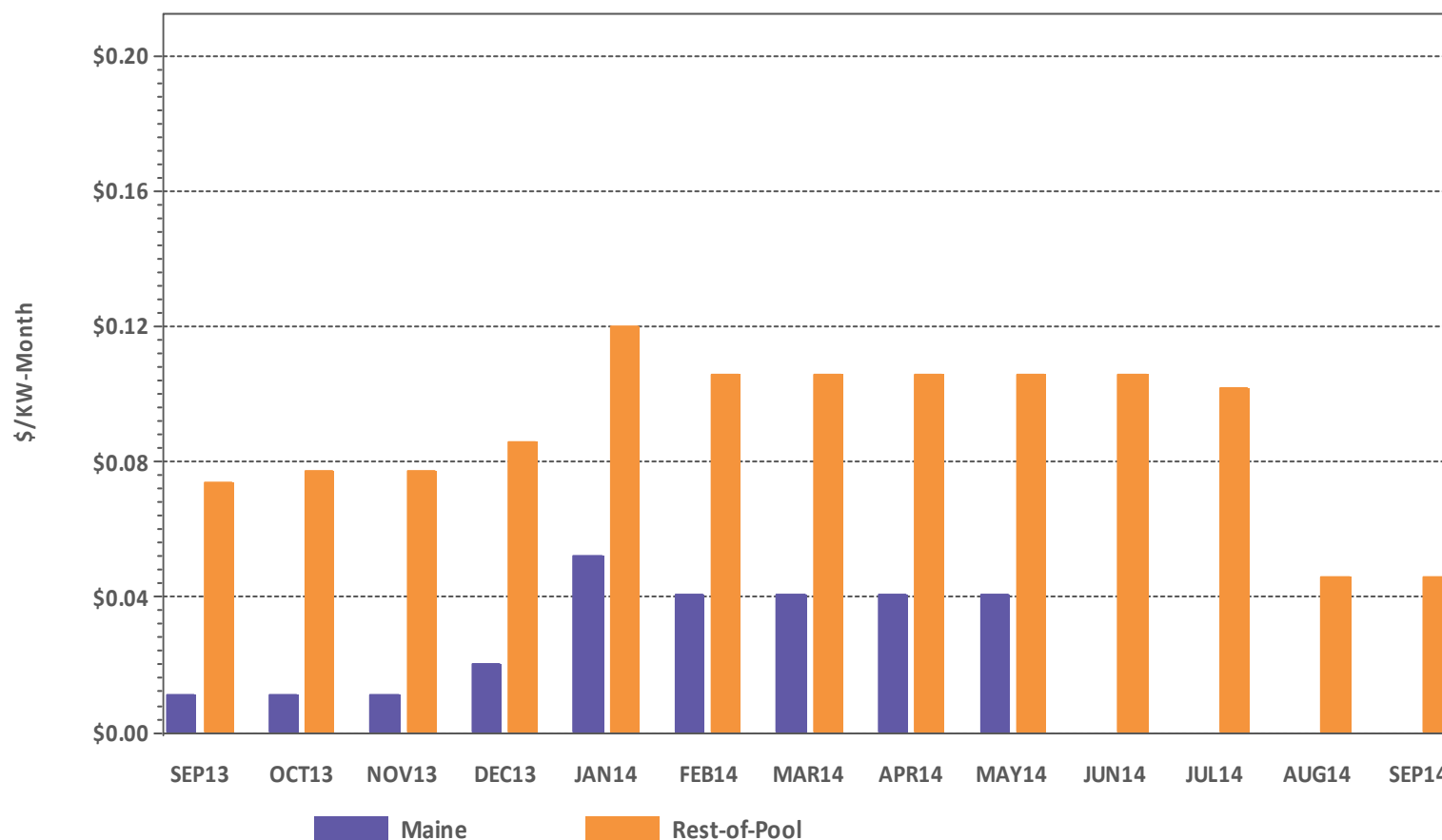


Dispatchable vs. Non-Dispatchable Generation

Total Monthly Energy; Dispatchable % Shown



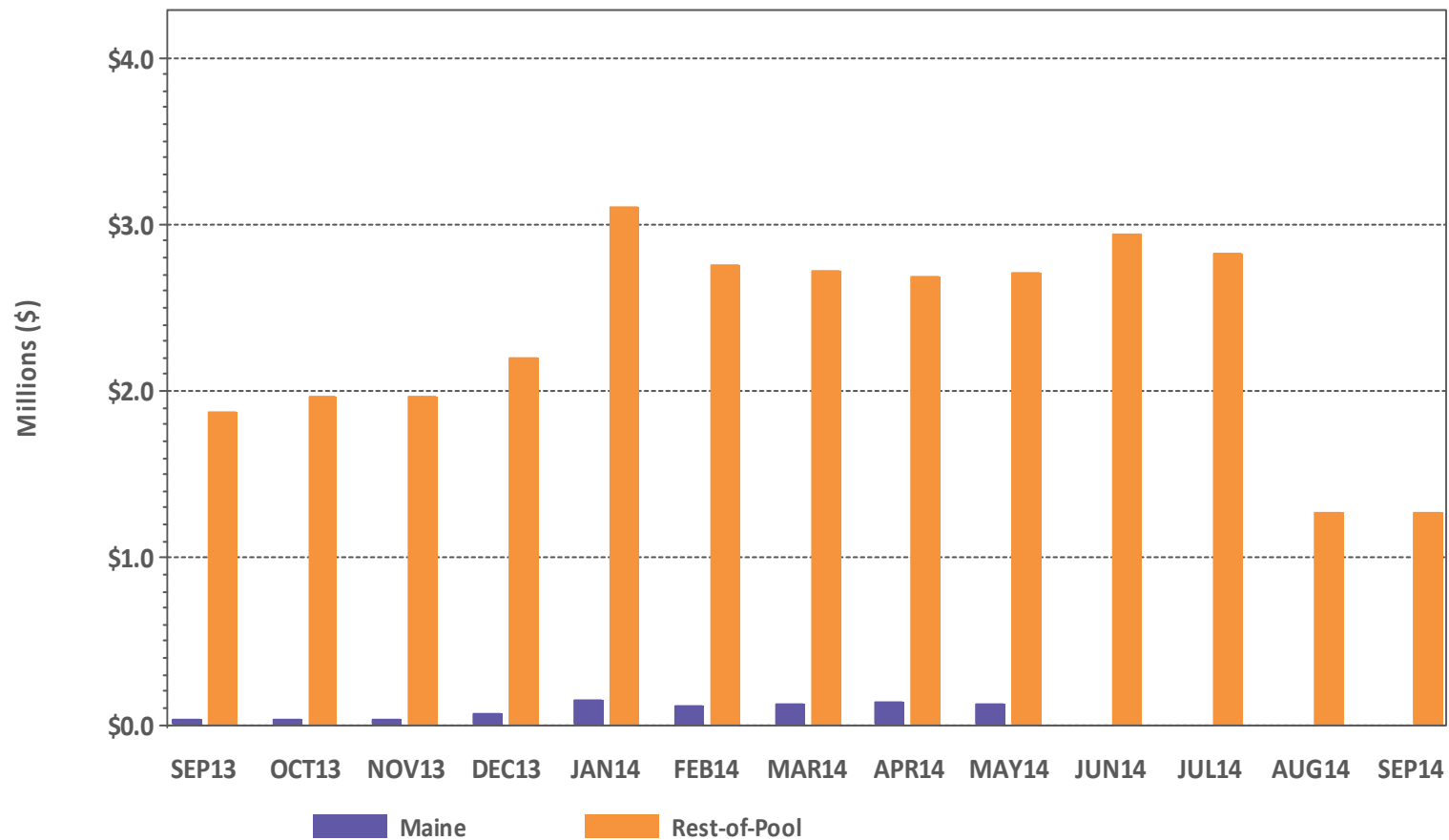
Rolling Average Peak Energy Rent (PER)



Rolling Average PER is currently calculated as a rolling twelve month average of individual monthly PER values for the twelve months preceding the obligation month.

Individual monthly PER values are published to the ISO web site here: [Home > Markets > Other Markets Data > Forward Capacity Market > Reports](#) and are subject to resettlement.

PER Adjustments



PER Adjustments are reductions to Forward Capacity Market monthly payments resulting from the rolling average PER.



REGIONAL SYSTEM PLAN (RSP) AND INTERREGIONAL PLANNING

Planning Advisory Committee (PAC)

- Draft 2014 Regional System Plan to be submitted to the ISO Board by September 30
- Tentative October 22-23 PAC Meeting Agenda Topics
 - EIPC Update
 - RSP Project List Update
 - CT Minimum Load Analysis Results
 - Greater Boston Solution Alternatives
 - Pittsfield/Greenfield Reassessment Solutions (Preferred)
 - Load Forecast Analysis
 - Planning Guide Update
 - SEMA/RI Critical Need & Short Circuit Results
 - Carver Street Station Needs & Solutions
 - Webster Street Tap Upgrade
 - TOPAC Local System Plans



Distributed Generation Forecast Working Group (DGFWG)

- ISO is working with the transmission owners, distribution owners, the states, and IEEE to resolve interconnection issues
- PV forecast will be used in new economic studies and new transmission planning studies
 - The ISO will be working with stakeholders on use of the forecast in resource adequacy studies
 - The ISO urges DG resources to participate in FCM
- Next Steps
 - The ISO will be surveying the states for updated policy goals and other information on PV and more generally for DG development
 - The ISO will continue surveying distribution owners to monitor the development of PV and DG
 - The ISO will review its budget and plans on contracting with a consultant to assist with examining the economic drivers of PV development
 - The ISO will continue participation in DOE projects that support operational and planning forecasts of PV



Other Stakeholder Groups

- Variable Resource Working Group (VRWG)
 - The VRWG is a NEPOOL advisory stakeholder group that will provide a forum for the exchange of information on issues affecting participation by variable resources in New England
 - Meeting held on September 29 to provide an update on the wind plant forecast integration project, summary of existing curtailment procedures and priority, review of FCM qualification and commercial audit procedures for intermittent resources, and planned implementation of real-time dispatch of intermittent resources “Do Not Exceed” dispatch overview
- Environmental Matters
 - Environmental Advisory Group met on August 27 to discuss regional and federal environmental developments, including the proposed EPA Clean Power Plan and final Cooling Water Intake Structure Rule



RSP Project Stage Descriptions

Stage	Description
1	Planning and Preparation of Project Configuration
2	Pre-construction (e.g., material ordering, project scheduling)
3	Construction in Progress
4	In Service



Lower Southeastern Massachusetts (SEMA) Proposed Long-term Upgrades

Status as of 9/29/14

Project Benefit: Improves system reliability for the Lower SEMA area

Upgrade	Expected In-service	Present Stage
Expand the Carver Substation	Jun-13	4
Build New 345 kV Line from Carver to Vicinity of Bourne Substation and connect to Line 120. Expand Bourne with one breaker position.	Jun-13	4*
Construct New 115 kV Substation with 345-115 kV Autotransformer and Loop Line 115 into the new substation	Dec-13	4
Upgrade the 115 kV Bell Rock to High Hill D21 Line	May-13	4
Separate the 345 kV (342 / 322) Double Circuit Tower Lines	Jun-13	4

Project approved by MA EFSB on 4/27/12

* The work is in service in a temporary configuration. The final in-service configuration was completed in September 2014.



NEEWS: Interstate Reliability Project

Status as of 9/29/14

Plan Benefit: Improves New England reliability by increasing transfer limits of three critical interfaces

Upgrade	Expected In-service	Present Stage
Build New 345 kV Line 3271 Card - Lake Road	Dec-15	3
Card 345 kV Substation Expansion	Dec-15	3
Lake Road 345 kV Substation Expansion	Dec-15	3
Build New 345 kV Line 341 Lake Road to CT/RI Border	Dec-15	3
Build New 345 kV Line 341 CT/RI Border to West Farnum	Dec-15	3
West Farnum 345 kV Substation Additions (New Line Terminations)	Dec-15	1
New Sherman Road 345 kV Substation	Dec-15	3
West Farnum 115 kV Substation Upgrades	Sep-14	4
Reconductor 345 kV Line 328 West Farnum to Sherman Road	Dec-15	3
Riverside Substation Relay Upgrades	Sep-14	4
Woonsocket Substation Relay Upgrades	Sep-14	4
Hartford Avenue Substation Relay Upgrades	Sep-14	4
Build New 345 kV Line 366 West Farnum to MA/RI Border	Dec-15	3
Build New 345 kV Line 366 MA/RI Border to Millbury 3	Dec-15	3
Millbury 3 Substation Expansion	Dec-15	2
Carpenter Hill Substation Relay Upgrades	Dec-15	3



Maine Power Reliability Program (MPRP)

Status as of 9/29/14

Project Benefit: Addresses long-term system needs of Emera Maine and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

New 345 kV Lines	Expected In-Service	Present Stage
Construct New Section 3023 Orrington to Albion Road	May-13	4
Construct New Section 3024 Albion Road to Coopers Mills	Mar-15	3
Construct New Section 3025 Coopers Mills to Larrabee Road	Mar-15	3
Construct New Section 3026 Larrabee Road to Surowiec	Dec-12	4
Construct New Section 3020 Surowiec to Raven Farm	Nov-13	4
Construct New Section 3021 South Gorham to Maguire Road	Apr-14	4
Construct New Section 3022 Maguire Road to Eliot	Aug-14	4

- The above listing focuses on major transmission line construction and rebuilding.



Maine Power Reliability Program, *cont.*

Status as of 9/29/14

Project Benefit: Addresses long-term system needs of Emera Maine and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

New 115 kV Lines	Expected In-Service	Present Stage
Construct New Section 254 Orrington to Coopers Mills	Mar-15	3
Construct New Section 243A Livermore Falls to Junction Section 243	May-14	4
Construct New Section 251 Livermore Falls to Larrabee Road	May-14	4
Construct New Section 255 Larrabee Road to Middle Street	May-15	3
Construct New Section 86A Tap to Belfast	Jul-14	4
Construct New Section 256 Middle Street to Lewiston Lower	May-16	1

- The above listing focuses on major transmission line construction and rebuilding.



Maine Power Reliability Program, *cont.*

Status as of 9/29/14

Project Benefit: Addresses long-term system needs of Emera Maine and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

115 kV Lines Rebuilds	Expected In-Service	Present Stage
Rebuild Section 60 Coopers Mills to Bowman Street	Feb-15	3
Rebuild Section 88 Coopers Mills to Augusta East Side	Feb-15	3
Rebuild Section 89 Livermore Falls to Riley	May-14	4
Rebuild Section 229 Riley to Rumford IP	May-13	4
Rebuild Section 212 Monmouth to Larrabee Road	Feb-13	4
Rebuild Section 269 Bowman Street to Monmouth	May-12	4
Rebuild Section 238 Loudon to Maguire Road	Feb-12	4
Rebuild Section 250 Maguire Road to Three Rivers	Dec-13	4

- The above listing focuses on major transmission line construction and rebuilding.



Maine Power Reliability Program, *cont.*

Status as of 9/29/14

Project Benefit: Addresses long-term system needs of Emera Maine and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

345/115 kV Autotransformers	Expected In-Service	Present Stage
Install One 345/115 kV Autotransformer at Albion Road	Apr-13	4
Install One 345/115 kV Autotransformer at Coopers Mills	Mar-15	3
Install One 345/115 kV Autotransformer at Larrabee Road	Dec-12	4
Install One 345/115 kV Autotransformer at Maguire Road	Apr-14	4
Install One 345/115 kV Autotransformer at South Gorham	Nov-09	4

- The above listing focuses on major transmission line construction and rebuilding.



New Hampshire/Vermont 10-Year Upgrades

Status as of 9/29/14

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	1
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	3
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	3
New 115 kV overhead line, Fitzwilliam-Monadnock	Dec-14	3
New 115 kV overhead line, Scobie Pond-Huse Road	Dec-15	3
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-16	1
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	3
New 115 kV overhead line, Coolidge-Ascutney	Dec-16	1

- The above listing focuses on major transmission line construction and rebuilding.



New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 9/29/14

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Dec-15	2
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	3
Rebuild 115 kV line H137, Merrimack-Garvins	Jun-13	4
Rebuild 115 kV line D118, Deerfield-Pine Hill	Dec-14	3
Oak Hill Substation - Loop in 115 kV line V182, Garvins-Webster	Apr-15	3
Uprate 115 kV line G146, Garvins-Deerfield	Feb-15	3
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

- The above listing focuses on major transmission line construction and rebuilding.



New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 9/29/14

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Dec-14	3
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Mar-15	2
Upgrade 115 kV line T198, Keene-Monadnock	Nov-13	4
Upgrade 345 kV line 326, Scobie Pond-NH/MA Border	Dec-13	4
Upgrade 115 kV line J114-2, Greggs - Rimmon	Dec-13	4
Upgrade 345 kV line 381, between MA/NH border and NH/VT border	Jun-13	4

- The above listing focuses on major transmission line construction and rebuilding.



Greater Hartford and Central Connecticut (GHCC)

NEEP PARTICIPANTS COMMITTEE
OCT 9, 2014 MEETING, AGENDA ITEM #4

Projects*

Status as of 9/29/14

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Dec-17	1
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Dec-17	1
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add a 115 kV 37.8 MVAR capacitor bank	Dec-17	1
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-17	1
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Dec-17	1
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-17	1

* Replaces the NEEWS Central Connecticut Reliability Project



Greater Hartford and Central Connecticut Projects, cont.*

Status as of 9/29/14

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Dec-17	1
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Dec-17	1
Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-17	1
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-17	1
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	Dec-17	1
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Dec-17	1
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-17	1

* Replaces the NEEWS Central Connecticut Reliability Project



Greater Hartford and Central Connecticut Projects, cont.*

Status as of 9/29/14

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	1
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	1
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-17	1
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-17	1
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Dec-17	1
Add a 345 kV breaker in series with breaker 5T at Southington	Dec-17	1

* Replaces the NEEWS Central Connecticut Reliability Project



Greater Hartford and Central Connecticut Projects, cont.*

Status as of 9/29/14

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected In-service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-17	1
Add a new 115 kV line from Frost Bridge to Campville	Dec-17	1
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Dec-17	1
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-17	1
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-17	1
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-17	1
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Dec-17	1

* Replaces the NEEWS Central Connecticut Reliability Project



Southwest Connecticut (SWCT) Projects

Status as of 9/29/14

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Dec-17	1
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Dec-17	1
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Dec-17	1
Rebuild Bunker Hill to a 9-breaker substation in breaker-and-a-half configuration	Dec-17	1
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-17	1
Loop the 1990 line in and out the Bunker Hill substation	Dec-17	1
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Dec-17	1
Loop the 1570 line in and out the Pootatuck substation	Dec-17	1
Replace two 115 kV circuit breakers at the Freight substation	Dec-17	1



Southwest Connecticut Projects, cont.

Status as of 9/29/14

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	1
Add a new 115 kV line from Plumtree to Brookfield Junction	Dec-17	1
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-17	1
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Dec-17	1
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	Dec-17	1
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	Dec-17	1
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Dec-17	1
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	Dec-17	1



Southwest Connecticut Projects, cont.

NEPOOL PARTICIPANTS COMMITTEE
OCT 3, 2014 MEETING, AGENDA ITEM #4

Status as of 9/29/14

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Dec-16	1
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	Dec-17	1
Terminal equipment upgrade at the Newtown substation (1876)	Dec-17	1
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Dec-17	1
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-17	1
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-17	1



Southwest Connecticut Projects, cont.

Status as of 9/29/14

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-service	Present Stage
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Dec-16	1
Upgrade the 115 kV bus at the Baird substation	Dec-17	1
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	3
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-16	1
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Dec-17	1
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Dec-17	1



Southwest Connecticut Projects, cont.

Status as of 9/29/14

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected In-service	Present Stage
Remove the Sackett phase shifter	Dec-17	1
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-17	1
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-17	1
Separate the 3827 (Beseck to East Devon) and 1610 (Southington to June to Mix Avenue) double circuit towers	Dec-17	1
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Dec-17	1
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Dec-17	1
Replace two 115 kV circuit breakers at Mill River	Dec-14	3



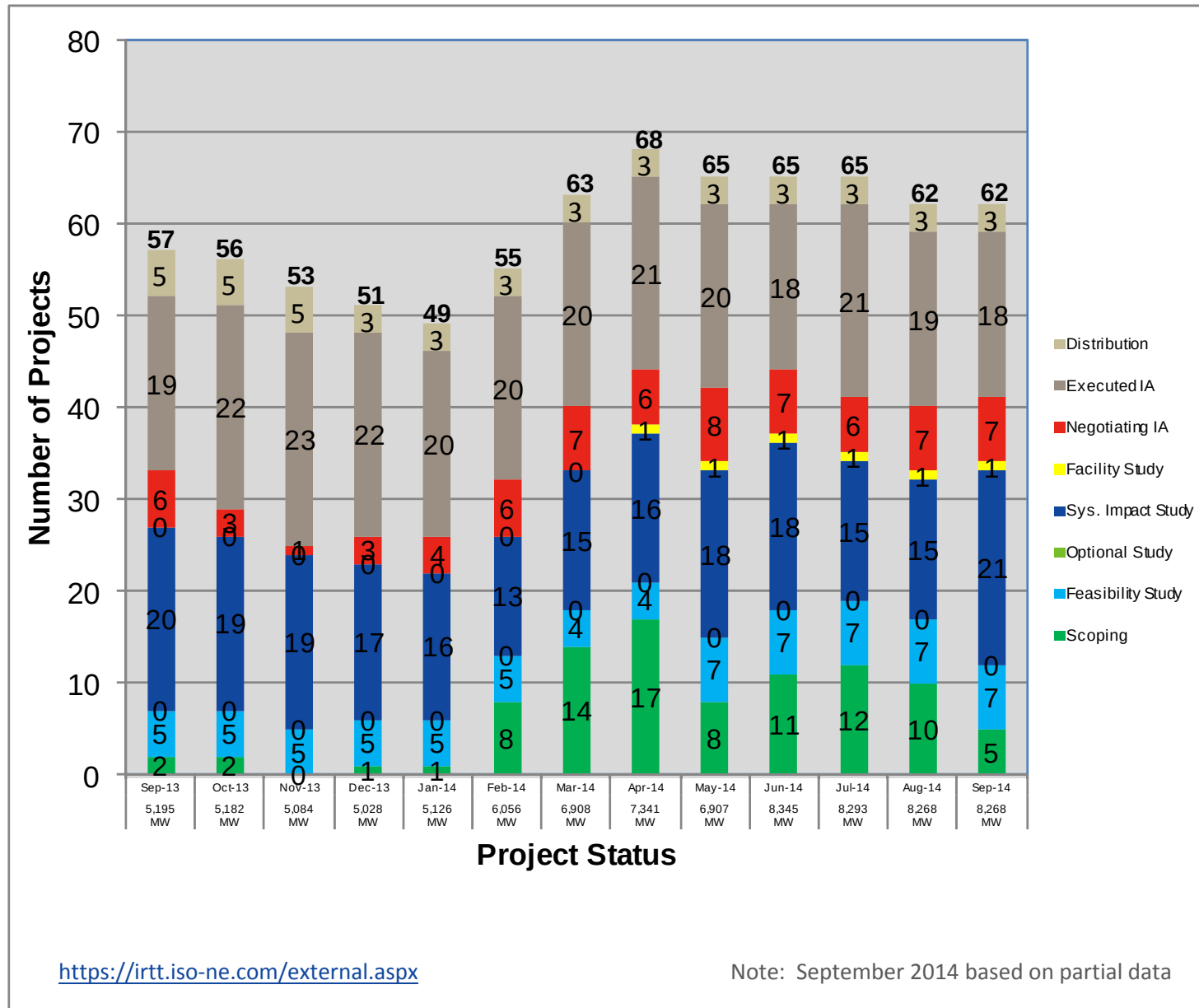
Transmission Siting Update

- NEEWS
 - Interstate Reliability Project
 - National Grid siting application was filed in MA on 6/21/12
 - National Grid siting application was filed in RI on 7/19/12
 - CL&P's siting hearings in CT were completed on 8/30/12
 - Received siting approval from CT on 1/2/13. The RI Energy Facilities Siting Board approved the project on 6/14/13. MA EFSB approved the project on 5/16/14.
- MPRP
 - Project filed with the Maine Public Utility Commission on 7/1/08
 - Maine PUC approved most of the project on 6/10/10
 - Hearings are complete - written order received on Lewiston Loop



Status of Tariff Studies

NEPOOL PARTICIPANTS COMMITTEE
OCT 3, 2014 MEETING, AGENDA ITEM #4



OPERABLE CAPACITY ANALYSIS

Fall 2014

Fall 2014 Operable Capacity Analysis

NEPOOL PARTICIPANTS COMMITTEE
OCT 3, 2014 MEETING, AGENDA ITEM #4

50/50 Load Forecast (Reference)	November - 2014 ² CSO	November -2014 ² SCC
Generator Operable Capacity MW ¹	29,680	33,134
OP CAP From OP-4 RTDR (+)	486	486
OP CAP From OP-4 RTEG (+)	211	211
Operable Capacity Generator with OP-4 DR and RTEG	30,377	33,831
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	812	812
Non Commercial Capacity (+)	6	6
Non Gas-fired Planned Outage MW (-)	4,431	5,609
Gas Generator Outages MW (-)	1,380	1,988
Allowance for Unplanned Outages (-)	3,600	3,600
Generation at Risk Due to Gas Supply (-) ⁴	0	0
Net Capacity (NET OPCAP SUPPLY MW) ³	21,784	23,452
Peak Load Forecast MW(adjusted for Other Demand Resources) ²	17,917	17,917
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,904	24,904
Operable Capacity Margin ³	1,492	3,160

¹ Generator Operable Capacity is based on data as of September 11th, 2014 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

² Based on week with lowest Operable Capacity Margin, week beginning November 1st, 2014.

³ Includes OP4 actions associated with RTEG and RTDR

⁴ Total of (Gas at Risk MW) – (Gas Gen Outages MW)



Fall 2014 Operable Capacity Analysis

NEPOOL PARTICIPANTS COMMITTEE
OCT 3, 2014 MEETING, AGENDA ITEM #4

90/10 Load Forecast (Extreme)	November - 2014 ² CSO	November - 2014 ² SCC
Generator Operable Capacity MW ¹	29,680	33,134
OP CAP From OP-4 RTDR (+)	486	486
OP CAP From OP-4 RTEG (+)	211	211
Operable Capacity Generator with OP-4 DR and RTEG	30,377	33,831
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	812	812
Non Commercial Capacity (+)	6	6
Non Gas-fired Planned Outage MW (-)	4,431	5,609
Gas Generator Outages MW (-)	1,380	1,988
Allowance for Unplanned Outages (-)	3,600	3,600
Generation at Risk Due to Gas Supply (-) ⁴	0	0
Net Capacity (NET OPCAP SUPPLY MW) ³	21,784	23,452
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	18,450	18,450
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,870	26,870
Operable Capacity Margin ³	959	2,627

¹ Generator Operable Capacity is based on data as of September 11th, 2014 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

² Based on week with lowest Operable Capacity Margin, week beginning November 1st, 2014

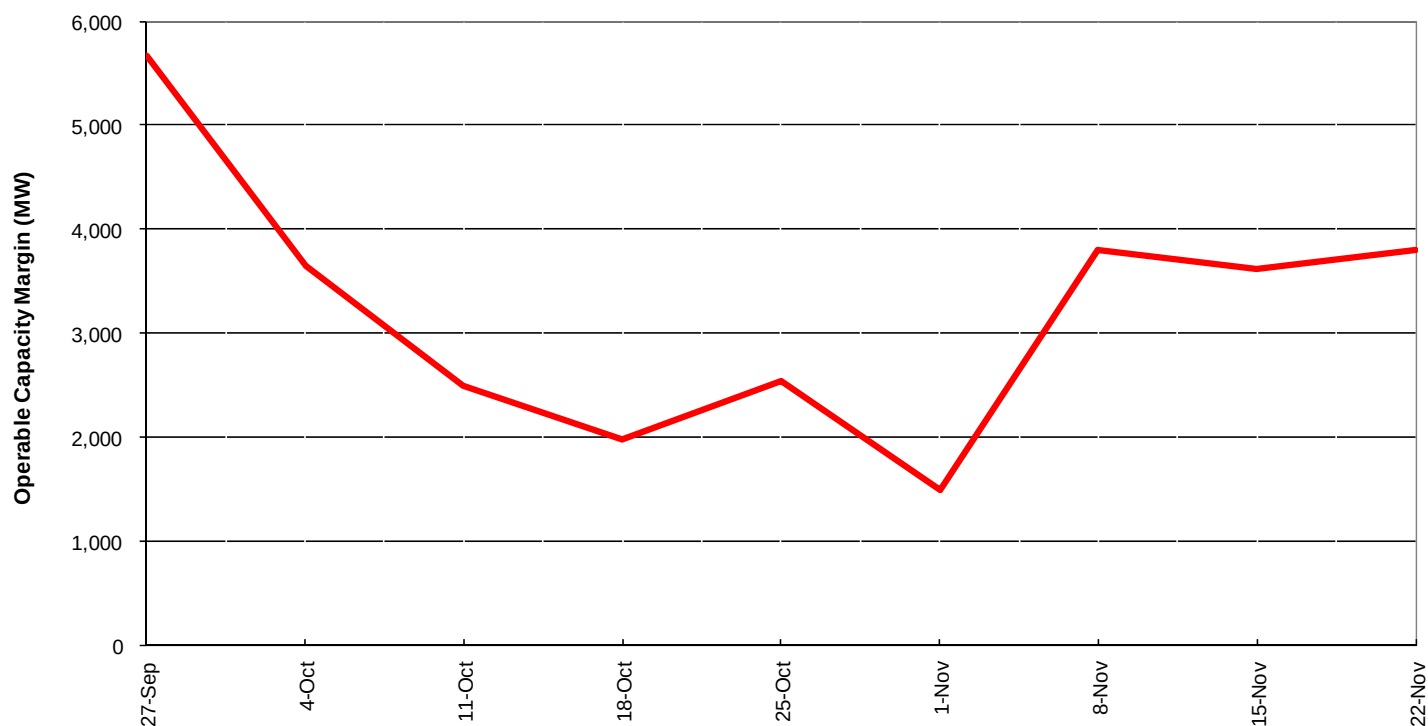
³ Includes OP4 actions associated with RTEG and RTDR

⁴ Total of (Gas at Risk MW) – (Gas Gen Outages MW)



Fall 2014 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)

ISO-NE 2014-15 OPERABLE CAPACITY ANALYSIS - CSO - with RTDR and RTEG
- 50/50 FORECAST

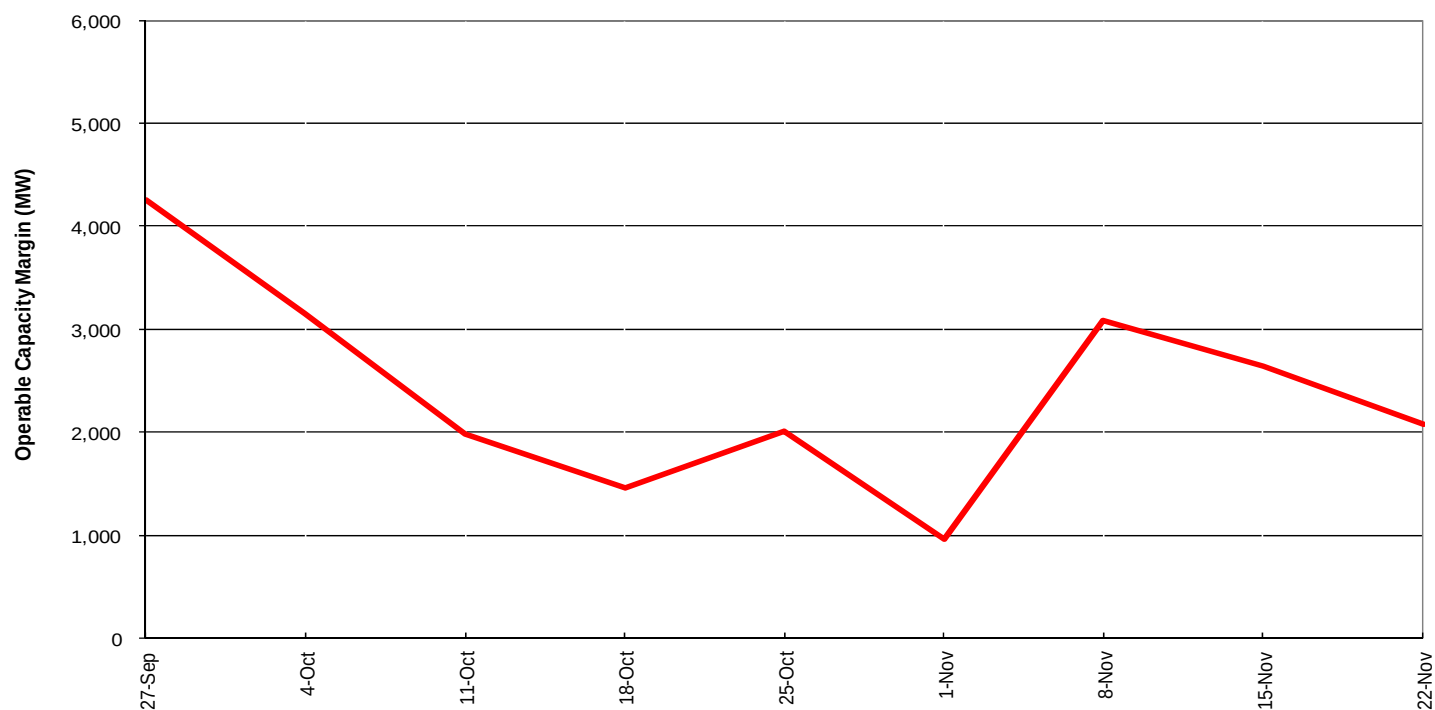


September 27, 2014 -November 22, 2014, W/B Saturday



Fall 2014 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)

ISO-NE 2014-15 OPERABLE CAPACITY ANALYSIS - CSO - with RTDR and RTEG
- 90/10 FORECAST



September 27, 2014 - November 22, 2014, W/B Saturday



Fall 2014 Operable Capacity Analysis(MW) 50/50 Forecast (Reference)

ISO-NE 2014-15 OPERABLE CAPACITY ANALYSIS

October 3, 2014 - 50/50 FORECAST using CSO values with RTDR and RTEG

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL- TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
	9/27/2014	29,541	200	0	1,572	1,617	2,800	0	23,752	16,244	2,375	18,619	5,133	332	5,465	208
10/4/2014	30,219	318	0	3,752	2,159	2,800	0	21,826	16,280	2,375	18,655	3,171	323	3,494	149	3,643
10/11/2014	30,219	512	0	4,353	1,962	2,800	0	21,616	17,219	2,375	19,594	2,022	323	2,345	149	2,494
10/18/2014	30,219	512	0	4,664	1,792	2,800	0	21,475	17,589	2,375	19,964	1,511	323	1,834	149	1,983
10/25/2014	30,219	512	0	3,673	2,012	2,800	0	22,246	17,799	2,375	20,174	2,072	323	2,395	149	2,544
11/1/2014	29,680	812	6	4,431	1,380	3,600	0	21,087	17,917	2,375	20,292	795	486	1,281	211	1,492
11/8/2014	29,680	812	6	2,776	370	3,600	0	23,752	18,266	2,375	20,641	3,111	486	3,597	211	3,808
11/15/2014	29,680	812	6	2,079	506	3,600	0	24,314	19,016	2,375	21,391	2,923	486	3,409	211	3,620
11/22/2014	29,680	812	6	960	261	3,600	459	25,219	19,747	2,375	22,122	3,097	486	3,583	211	3,794

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources that have acquired a CSO but have not become commercial.
4. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2014 CELT Report and adjusted for Passive Demand Resources. <http://www.iso-ne.com/trans/celt/report/index.html>
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula (9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).



Fall 2014 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)

ISO-NE 2014-15 OPERABLE CAPACITY ANALYSIS

October 3, 2014 - 90/10 FORECAST using CSO values with RTDR and RTEG

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERAT OR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL- TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
	9/27/2014	29,541	200	0	1,572	1,617	2,800	0	23,752	17,661	2,375	20,036	3,716	332	4,048	208
10/4/2014	30,219	318	0	3,752	2,159	2,800	0	21,826	16,766	2,375	19,141	2,685	323	3,008	149	3,157
10/11/2014	30,219	512	0	4,353	1,962	2,800	0	21,616	17,734	2,375	20,109	1,507	323	1,830	149	1,979
10/18/2014	30,219	512	0	4,664	1,792	2,800	0	21,475	18,112	2,375	20,487	988	323	1,311	149	1,460
10/25/2014	30,219	512	0	3,673	2,012	2,800	0	22,246	18,328	2,375	20,703	1,543	323	1,866	149	2,015
11/1/2014	29,680	812	6	4,431	1,380	3,600	0	21,087	18,450	2,375	20,825	262	486	748	211	959
11/8/2014	29,680	812	6	2,776	370	3,600	186	23,566	18,809	2,375	21,184	2,382	486	2,868	211	3,079
11/15/2014	29,680	812	6	2,079	506	3,600	420	23,894	19,579	2,375	21,954	1,940	486	2,426	211	2,637
11/22/2014	29,680	812	6	960	261	3,600	1,591	24,087	20,331	2,375	22,706	1,381	486	1,867	211	2,078

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources that have acquired a CSO but have not become commercial.
4. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2014 CELT Report and adjusted for Passive Demand Resources. <http://www.iso-ne.com/trans/celt/report/index.html>
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula (9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)
This does not include Emergency Energy Transactions (EETs).



OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2014-2015

Preliminary Winter 2014-15 Operable Capacity Analysis

NEPOOL PARTICIPANTS COMMITTEE
OCT 21, 2014 MEETING AGENDA ITEM #4

50/50 Load Forecast (Reference)	January - 2015 ² CSO	January - 2015 ² SCC
Generator Operable Capacity MW ¹	29,833	33,134
OP CAP From OP-4 RTDR (+)	454	454
OP CAP From OP-4 RTEG (+)	202	202
Operable Capacity Generator with OP-4 DR and RTEG	30,489	33,790
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	812	812
Non Commercial Capacity (+)	10	10
Non Gas-fired Planned Outage MW (-) ⁵	165	939
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-)	2,800	2,800
Generation at Risk Due to Gas Supply (-) ⁴	3,598	3,998
Net Capacity (NET OPCAP SUPPLY MW) ³	24,748	26,875
Peak Load Forecast MW (adjusted for Other Demand Resources) ²	21,086	21,086
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,461	23,461
Operable Capacity Margin ³	1,287	3,414

¹ Generator Operable Capacity is based on data as of September 11th, 2014 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

² Based on week with lowest Operable Capacity Margin, week beginning January 17th, 2015.

³ Includes OP4 actions associated with RTEG and RTDR

⁴ Total of (Gas at Risk MW) – (Gas Gen Outages MW)

⁵ Greater SCC MW outages observed due to unit retirements that do not have CSO but do have an SCC value for the winter operable capacity period.



Preliminary Winter 2014-15 Operable Capacity Analysis

NERPOOL PARTICIPANTS COMMITTEE
OCTOBER 2014 MEETING, AGENDA ITEM #4

90/10 Load Forecast (Extreme)	January - 2015 ² CSO	January - 2015 ² SCC
Generator Operable Capacity MW ¹	29,833	33,134
OP CAP From OP-4 RTDR (+)	454	454
OP CAP From OP-4 RTEG (+)	202	202
Operable Capacity Generator with OP-4 DR and RTEG	30,489	33,790
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	812	812
Non Commercial Capacity (+)	10	10
Non Gas-fired Planned Outage MW (-) ⁵	165	939
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-)	2,800	2,800
Generation at Risk Due to Gas Supply (-) ⁴	4,631	5,145
Net Capacity (NET OPCAP SUPPLY MW) ³	23,715	25,728
Peak Load Forecast MW(adjusted for Other Demand Resources) ²	21,706	21,706
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,081	24,081
Operable Capacity Margin ³	(366)	1,647

¹ Generator Operable Capacity is based on data as of September 11th, 2014 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

² Based on week with lowest Operable Capacity Margin, week beginning January 17th, 2015.

³ Includes OP4 actions associated with RTEG and RTDR

⁴ Total of (Gas at Risk MW) – (Gas Gen Outages MW)

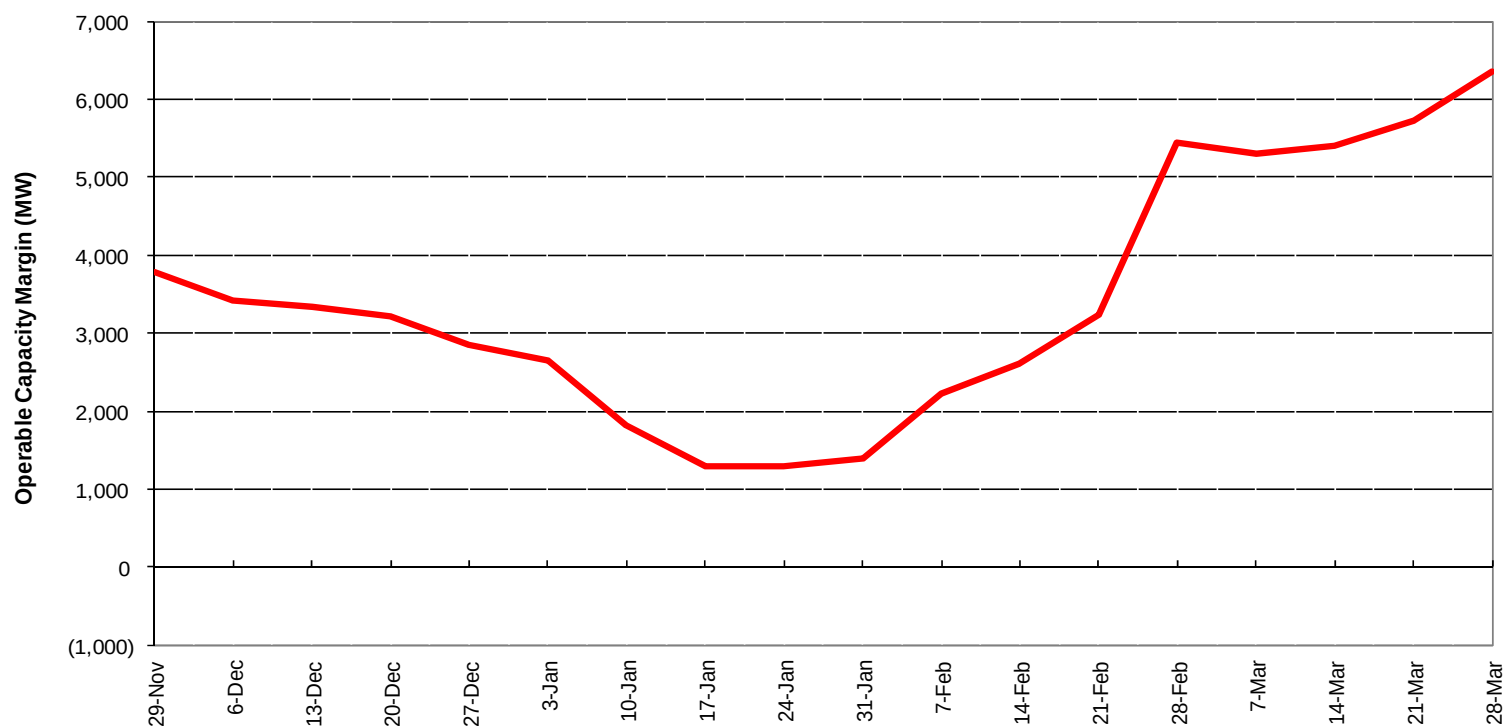
⁵ Greater SCC MW outages observed due to unit retirements that do not have CSO but do have an SCC value for the winter operable capacity period.



Preliminary Winter 2014-15 Operable Capacity Analysis(MW)

50/50 Forecast (Reference)

ISO-NE 2014-15 OPERABLE CAPACITY ANALYSIS - CSO - with RTDR and RTEG
- 50/50 FORECAST

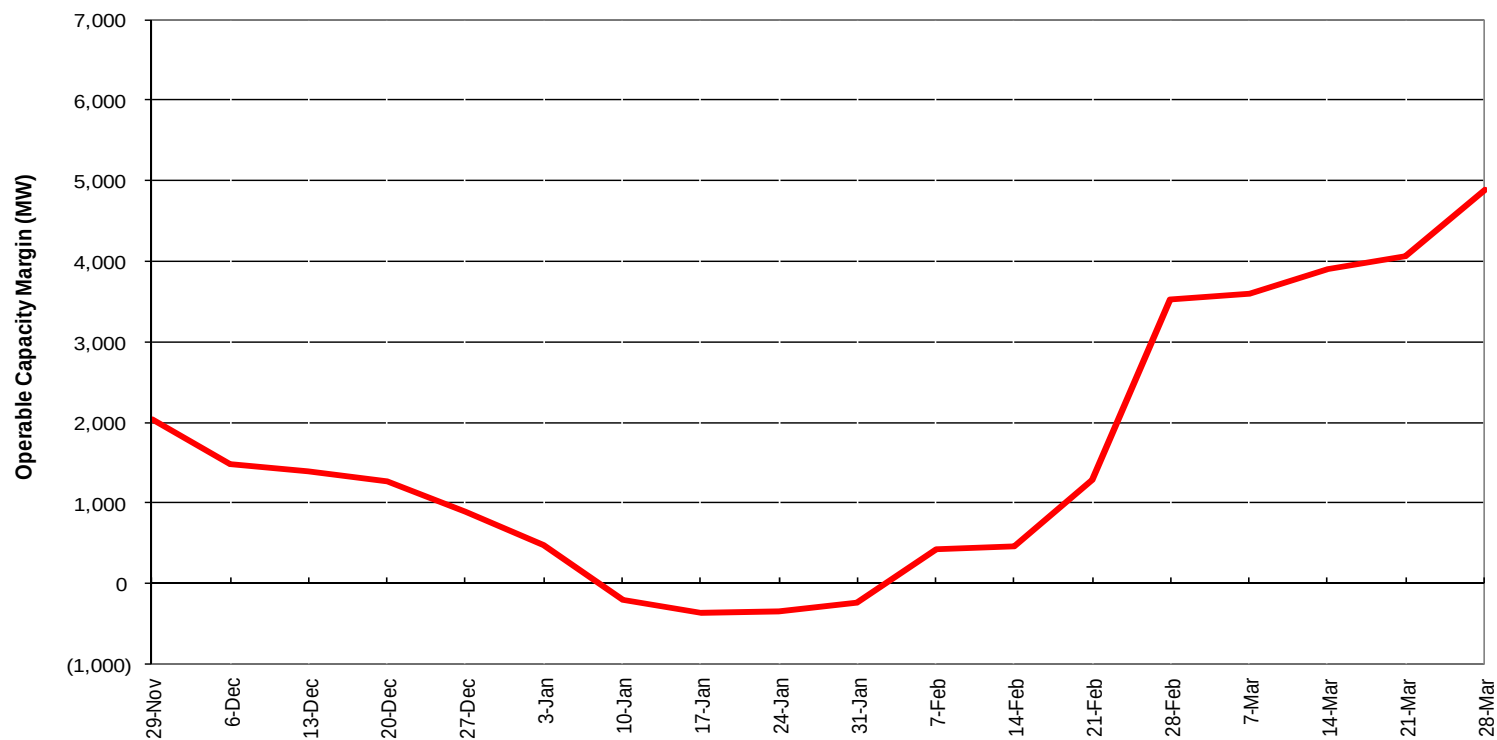


November 29, 2014 - March 28, 2015, W/B Saturday



Preliminary Winter 2014-15 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)

ISO-NE 2014-15 OPERABLE CAPACITY ANALYSIS - CSO - with RTDR and RTEG
- 90/10 FORECAST



November 29, 2014 - March 28, 2015, W/B Saturday



Preliminary Winter 2014-15 Operable Capacity Analysis(MW)

50/50 Forecast (Reference)

ISO-NE 2014-15 OPERABLE CAPACITY ANALYSIS

October 3, 2014 - 50/50 FORECAST using CSO values with RTDR and RTEG

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL- TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
11/29/2014	29,680	812	10	435	0	3,200	1,439	25,428	19,969	2,375	22,344	3,084	486	3,570	211	3,781
12/6/2014	29,833	812	10	439	255	3,200	1,364	25,397	20,262	2,375	22,637	2,760	454	3,214	202	3,416
12/13/2014	29,833	812	10	143	255	3,200	1,724	25,333	20,273	2,375	22,648	2,685	454	3,139	202	3,341
12/20/2014	29,833	812	10	20	0	3,200	2,159	25,276	20,337	2,375	22,712	2,564	454	3,018	202	3,220
12/27/2014	29,833	812	10	20	0	3,200	2,519	24,916	20,337	2,375	22,712	2,204	454	2,658	202	2,860
1/3/2015	29,833	812	10	0	0	2,800	2,879	24,976	20,614	2,375	22,989	1,987	454	2,441	202	2,643
1/10/2015	29,833	812	10	0	0	2,800	3,238	24,617	21,086	2,375	23,461	1,156	454	1,610	202	1,812
1/17/2015	29,833	812	10	165	0	2,800	3,598	24,092	21,086	2,375	23,461	631	454	1,085	202	1,287
1/24/2015	29,833	812	10	153	0	2,800	3,598	24,104	21,086	2,375	23,461	643	454	1,097	202	1,299
1/31/2015	29,833	812	10	153	0	3,100	3,418	23,984	20,860	2,375	23,235	749	454	1,203	202	1,405
2/7/2015	29,833	812	10	138	257	3,100	2,622	24,538	20,589	2,375	22,964	1,574	454	2,028	202	2,230
2/14/2015	29,833	812	10	138	257	3,100	2,262	24,898	20,560	2,375	22,935	1,963	454	2,417	202	2,619
2/21/2015	29,833	812	10	138	506	3,100	1,653	25,258	20,294	2,375	22,669	2,589	454	3,043	202	3,245
2/28/2015	29,833	812	10	198	1,403	2,200	396	26,458	19,291	2,375	21,666	4,792	454	5,246	202	5,448
3/7/2015	29,833	812	10	1,233	468	2,200	792	25,962	18,937	2,375	21,312	4,650	454	5,104	202	5,306
3/14/2015	29,833	812	10	1,697	462	2,200	438	25,858	18,738	2,375	21,113	4,745	454	5,199	202	5,401
3/21/2015	29,833	812	10	2,100	246	2,200	294	25,815	18,368	2,375	20,743	5,072	454	5,526	202	5,728
3/28/2015	29,833	812	10	2,096	0	2,700	0	25,859	17,795	2,375	20,170	5,689	454	6,143	202	6,345

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
 2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
 3. New resources that have acquired a CSO but have not become commercial.
 4. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
 5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
 6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
 7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
 8. Net OpCap Supply MW Available $(1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)$
 9. Peak Load Forecast as provided in the 2014 CELT Report and adjusted for Passive Demand Resources. <http://www.iso-ne.com/trans/celt/report/index.html>
 10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
 11. Total Net Load Obligation per the formula $(9 + 10 = 11)$
 12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation $(8 - 11 = 12)$
 13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
 14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 $(12 + 13 = 14)$
 15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
 16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 $(14 + 15 = 16)$
- This does not include Emergency Energy Transactions (EETs).



Preliminary Winter 2014-15 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme)

ISO-NE 2014-15 OPERABLE CAPACITY ANALYSIS

October 3, 2014 - 90/10 FORECAST using CSO values with RTDR and RTEG

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

This analysis is a radiation of weekly assessments and with a single table. The information shows the operator capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and into September.																
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERAT OR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL- TIME EMER- GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
11/29/2014	29,680	812	10	435	0	3,200	2,593	24,274	20,559	2,375	22,934	1,340	486	1,826	211	2,037
12/6/2014	29,833	812	10	439	255	3,200	2,709	24,052	20,859	2,375	23,234	818	454	1,272	202	1,474
12/13/2014	29,833	812	10	143	255	3,200	3,080	23,977	20,870	2,375	23,245	732	454	1,186	202	1,388
12/20/2014	29,833	812	10	20	0	3,200	3,519	23,916	20,936	2,375	23,311	605	454	1,059	202	1,261
12/27/2014	29,833	812	10	20	0	3,200	3,890	23,545	20,936	2,375	23,311	234	454	688	202	890
1/3/2015	29,833	812	10	0	0	2,800	4,446	23,409	21,221	2,375	23,596	(187)	454	267	202	469
1/10/2015	29,833	812	10	0	0	2,800	4,631	23,224	21,706	2,375	24,081	(857)	454	(403)	202	(201)
1/17/2015	29,833	812	10	165	0	2,800	4,631	23,059	21,706	2,375	24,081	(1,022)	454	(568)	202	(366)
1/24/2015	29,833	812	10	153	0	2,800	4,631	23,071	21,706	2,375	24,081	(1,010)	454	(556)	202	(354)
1/31/2015	29,833	812	10	153	0	3,100	4,446	22,956	21,473	2,375	23,848	(892)	454	(438)	202	(236)
2/7/2015	29,833	812	10	138	257	3,100	3,818	23,342	21,195	2,375	23,570	(228)	454	226	202	428
2/14/2015	29,833	812	10	138	257	3,100	3,818	23,342	21,165	2,375	23,540	(198)	454	256	202	458
2/21/2015	29,833	812	10	138	506	3,100	3,013	23,898	20,892	2,375	23,267	631	454	1,085	202	1,287
2/28/2015	29,833	812	10	198	1,403	2,200	1,746	25,108	19,861	2,375	22,236	2,872	454	3,326	202	3,528
3/7/2015	29,833	812	10	1,233	468	2,200	1,940	24,814	19,497	2,375	21,872	2,942	454	3,396	202	3,598
3/14/2015	29,833	812	10	1,697	462	2,200	1,390	24,906	19,293	2,375	21,668	3,238	454	3,692	202	3,894
3/21/2015	29,833	812	10	2,100	246	2,200	1,421	24,688	18,913	2,375	21,288	3,400	454	3,854	202	4,056
3/28/2015	29,833	812	10	2,096	0	2,700	926	24,933	18,323	2,375	20,698	4,235	454	4,689	202	4,891

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources that have acquired a CSO but have not become commercial.
4. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Peak Load Forecast as provided in the 2014 CELT Report and adjusted for Passive Demand Resources. <http://www.iso-ne.com/trans/celt/report/index.html>
10. Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
16. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)

This does not include Emergency Energy Transactions (EETs).



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.	0 ¹ 600
2	Dispatch real time Demand Resources.	September 332 ³ October 323 ³ November 486 ³ December - March 454 ³
3	Voluntary Load Curtailment of Market Participants' facilities.	40 ²
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	133 ⁴ September 208 ³ October 149 ³ November 211 ³ December – March 202 ³
7	Request generating resources not subject to a Capacity Supply Obligation to voluntarily provide energy for reliability purposes	0



Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
8	Voltage Reduction requiring 10 minutes or less	267 ⁴
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 ²
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 ²
11	Request State Governors to Reinforce Power Warning Appeals.	100 ²
Total		September 3,085 MW October 3,017 MW November 3,242 MW December – March 3,201 MW

NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of September 11th, 2014.
4. The MW values are based on a 26,658 MW system load and the most recent voltage reduction test % achieved.



MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: September 26, 2014

RE: ISO New England Inc. (“ISO”) 2015 Operating and Capital Budgets
New England States Committee on Electricity (“NESCOE”) 2015 Budget

At its October 3, 2014 meeting, the NEPOOL Participants Committee (the “NPC”) will be asked to vote on the ISO’s proposed 2015 operating and capital budgets (collectively, the “ISO Budgets”) and on NESCOE’s 2015 operating budget (the “NESCOE Budget”). We have included with this memorandum background materials regarding these Budgets.

The ISO 2015 Budgets

The ISO Budgets were prepared according to the processes included in the Participants Agreement and in the Settlement Agreement with state agencies in FERC Dockets Nos. ER13-185 and ER13-192. The ISO presented its preliminary budgets at the NECPUC conference in June. The ISO revised those budgets based on the feedback received and presented the revised ISO Budgets to the NEPOOL Budget and Finance Subcommittee (the “Subcommittee”) at its August 27 meeting. The ISO then presented those ISO Budgets to New England state agencies and attorneys general on August 28. Mr. Ludlow also provided an overview of the ISO Budgets at the September 12 NPC meeting and offered to answer any questions that NPC members may have on the ISO Budgets. On September 25, certain New England state regulators and consumer advocates provided comments on the ISO Budgets. Those state regulators and consumer advocates have been invited to participate next Friday in the Participants Committee’s discussions of this matter so that their input is considered fully ahead of a vote by the Committee. As noted below, information as to their questions and positions have been posted.

The following documents relating to the ISO Budgets are included with this material:

- A summary presentation of the ISO Budgets;
- The questions provided to the ISO by the Connecticut Attorney General’s office after the August 28 meeting, with the ISO’s responses to those questions;¹
- The September 25 letter from the Connecticut Public Utilities Regulatory Authority, the Connecticut Office of Consumer Counsel, the New Hampshire Office of the Consumer Advocate, the Maine Public Advocate, the Connecticut Attorney General, the Rhode Island Division of Public Utilities and Carriers, and the Rhode Island Attorney General, commenting on the ISO Budgets; and
- The ISO’s September 26 memo regarding the allocation of its projected costs among the ISO Tariff Schedules.

¹ The attachments to the ISO responses are not included. Members interested in reviewing those attachments should contact us.

The updated version of the detailed presentation on the ISO Budgets that was provided to the Subcommittee is available at this link:

[http://iso-ne.com/static-assets/documents/2014/09/2015 Operating Cap Budget for NEPOOL BF Update 09 11 14.pdf](http://iso-ne.com/static-assets/documents/2014/09/2015%20Operating%20Cap%20Budget%20for%20NEPOOL%20BF%20Update%2009%2011%2014.pdf)

According to the ISO, the updates included in the revised presentation are described below. These changes affected the following slides in the presentation: 5-7; 9; 12;16; 17; 20; 23; 24; 29; 31-34; 40; 50; 60; 63-65; 88-90; 92-93; 112-113; 117; 119. Please also note that all subsequent slide numbers may be incremental by one page from the original presentation due to the addition of the ATRM capital project on slide 93.

The changes to the ISO's operating budget result in a net reduction of approximately \$500,000. A \$100,000 reduction resulted from replacing the placeholder 0.75% promotional increase budget with 0.5%, which was the final number adopted by the ISO's Board Compensation Committee at its September 18 meeting. The Committee selected this final promotional increase budget based on compensation surveys. Second, the projected increase in the medical plan costs was reduced by \$400,000. The ISO had sent out a Request for Proposals that included modifications to the medical plans and, as a result of the final pricing for the modified plans, the increase year over year is 4%, much lower than the earlier 11% projection.

There were also changes made to reallocate the \$28 million 2015 Capital Budget to accommodate changes made in 2014. Specifically, because spending in 2014 was reallocated to accommodate the additional resources required on the FCA 9 and Hourly Market Projects, 2014 spending on other projects was delayed. For example, because work has been delayed in 2014 on the Coordinated Transaction Scheduling and the Alternative Technologies and Regulation Market (ATRM) projects, these projects will have increased costs in 2015. In addition, the overall total project cost for the ATRM project has increased to reflect the additional work required by FERC's order, and the Divisional Accounting project was increased by \$80,000. These cost increases for 2015 were funded by reducing the Other Emerging Work portion of the capital budget.

The following form of resolution can be used by the NPC on this matter:

RESOLVED, that the Participants Committee supports the Year 2015 operating budget and capital budget proposed by the ISO, as presented at this meeting.

The NESCOE 2015 Budget

Ms. Heather Hunt, the Executive Director of NESCOE, joined the Subcommittee's August 27 meeting and informed the Subcommittee that NESCOE expected the NESCOE Budget for 2015 to be approximately \$2,094,000, consistent with the five-year pro forma projections provided to the NPC in March 2012 and accepted by the FERC. Peter Fuller, Chair of the Subcommittee, also reviewed the NESCOE Budget at the September 12 NPC meeting. Both Ms. Hunt and Mr. Fuller noted that, because over-collections for NESCOE expenses in prior years exceed the amount of the 2015 budget, no amount will be included in ISO Tariff rates for NESCOE in 2015. A summary presentation regarding the NESCOE Budget is also included with this memorandum.

The following form of resolution can be used by the NPC in its consideration of the proposed 2015 NESCOE Budget:

RESOLVED, that the Participants Committee supports the 2015 NESCOE budget, as proposed by NESCOE at this meeting, as the Year 2015 operating budget for NESCOE.

cc: R. Ludlow
C. Arnold
H. Hunt
NEPOOL Budget and Finance Subcommittee

OCTOBER 3, 2014



ISO New England Proposed 2015 Operating and Capital Budgets

NEPOOL Participants Committee Meeting

Robert Ludlow

VP, CHIEF FINANCIAL & COMPLIANCE OFFICER



INTRODUCTION AND OVERVIEW

Background: Discussion with Stakeholders

- At the June 17, 2014 meeting with the New England Conference of Public Utilities Commissioners (NECPUC), management presented and reviewed the preliminary operating and capital budgets for 2015
- The proposed budget in this presentation is in line, overall, with the services and funding included in the preliminary budget presented in June.



Overview of 2015 Operating Budget

- The 2015 budget includes funding to execute on prior decisions/orders:
 - Our focus will be the execution of decisions already made to support existing services (i.e., Hourly Market, Coordinated Transaction Scheduling, Forward Capacity Market and increasing cyber security threats)
- The 2015 operating budget includes adjustments to the previous year's budget as follows:
 - Cost reductions from previous year's budget (e.g., one time studies, non-recurring costs)
 - Increases to fund previously committed costs (e.g., Pension and Medical Benefit costs, increased computer services, Cyber Security costs, Energy Market Offer Flexibility (Hourly Market), Coordinated Transaction Scheduling (with New York ISO), and NERC/NPCC Fees)
 - A reallocation of certain resources for 2015 priorities and work
 - Costs of maintaining competitive compensation
 - Proposed budget includes a 3.0% merit increase, with 0.5% for equity and promotional increases



Overview of 2015 Operating Budget (*cont.*)

- The proposed operating budget (excluding depreciation and the true-up for past years) represents an increase of 4.0% (or \$5.7 million) over the 2014 budget
- Depreciation expense increase of \$3.4 million is primarily due to a number of large capital projects going in-service in late 2014 or early 2015.
- These increases are more than offset from the 2013 true-up of \$9.8M resulting in a 1.6% reduction in the tariff revenue requirement for 2015.
- For further detail on ISO-NE's 2015 budget, please see the presentation provided to the NEPOOL Budget and Finance Subcommittee at the August 27, 2014 meeting, which was updated on September 11 and September 26, 2014.



Overview of 2015 Operating Budget (*cont.*)

- The September 11 update was to include the timing of State Agencies questions and the ISO's responses on the Proposed 2015 budget as agreed upon in the 2013 Budget Settlement.
- The September 26 update was for changes as follows:
 - The 2015 Operating Budget was reduced by \$0.5 million to reflect final healthcare benefit renewals and for a reduction in the 2015 Salary Promotion & Equity budget to 0.5% as approved by the Compensation Committee at their September 18th meeting.
 - The 2015 Capital Budget, which had no overall change from \$28.0 million, was updated to reflect the addition of the Alternative Technologies and Regulation Market project which is now anticipated to extend into 2015. Changes were also made to amounts for the Coordinated Transaction Scheduling and Divisional Accounting projects, as well as the Other Emerging Work.
- These presentations can be found at <http://www.iso-ne.com/committees/participants/budget-finance> and filtering by the 8/27/2014 Meeting Date.



SUMMARY BUDGET INFORMATION

Summary Budget Information

(Budget Amounts are in Millions)	<u>2015</u>	<u>% Change</u>	<u>2014</u>	<u>% Change</u>	<u>2013</u>	<u>% Change</u>	<u>2012</u>	<u>% Change</u>	<u>2011</u>	<u>% Change</u>	<u>2010</u>
Operating Budget Before Depreciation	\$146.6	4.0%	\$140.9	4.0%	\$135.5	9.4%	\$123.9	5.4%	\$117.5	7.9%	\$108.9
Capital Budget (1)	28.0	0.0%	28.0	(4.4%)	29.3	4.6%	28.0	5.7%	26.5	(5.4%)	28.0
Total Cash Budget	\$174.6	3.4%	\$168.9	2.5%	\$164.8	8.5%	\$151.9	5.5%	\$144.0	5.2%	\$136.9
Operating Budget Before Depreciation	\$146.6	4.0%	\$140.9	4.0%	\$135.5	9.4%	\$123.9	5.4%	\$117.5	7.9%	\$108.9
Depreciation	31.7	11.6%	28.4	(0.4%)	28.5	5.2%	27.1	4.6%	25.9	7.5%	24.1
Revenue Requirement Before True-up	178.3	5.3%	169.3	3.2%	164.0	8.6%	151.0	5.3%	143.4	7.8%	133.0
True up	(9.8)		1.9		0.9		(7.4)		(9.7)		4.2
Revenue Requirement	\$168.5	(1.6%)	\$171.2	3.8%	\$164.9	14.8%	\$143.6	7.4%	\$133.7	(2.6%)	\$137.2
Forecast – GWhs (2)	140.4	1.1%	138.9	0.0%	138.9	0.7%	138.0	4.2%	132.4	1.2%	130.8
\$/KWh Rate	\$0.00120	(2.5%)	\$0.00123	3.4%	\$0.00119	14.4%	\$0.00104	3.0%	\$0.00101	(3.8%)	\$0.00105
Average Monthly Consumer Cost (3)	\$0.90		\$0.92		\$0.89		\$0.78		\$0.76		\$0.79

(1) 2014 Capital Budget includes the Backup Control Center (BCC) Data Center Transition Project, however, it excludes the BCC Project, which is funded by tax-exempt bonds
 (2) 2015 Forecast based on May 2014 CELT Report. All other years based on CELT Report for the applicable year, which can be found on www.iso-ne.com.
 (3) Based on average consumption of 750 kWh per month.
 Note: Throughout the presentation some schedules may be inconsistent due to rounding.



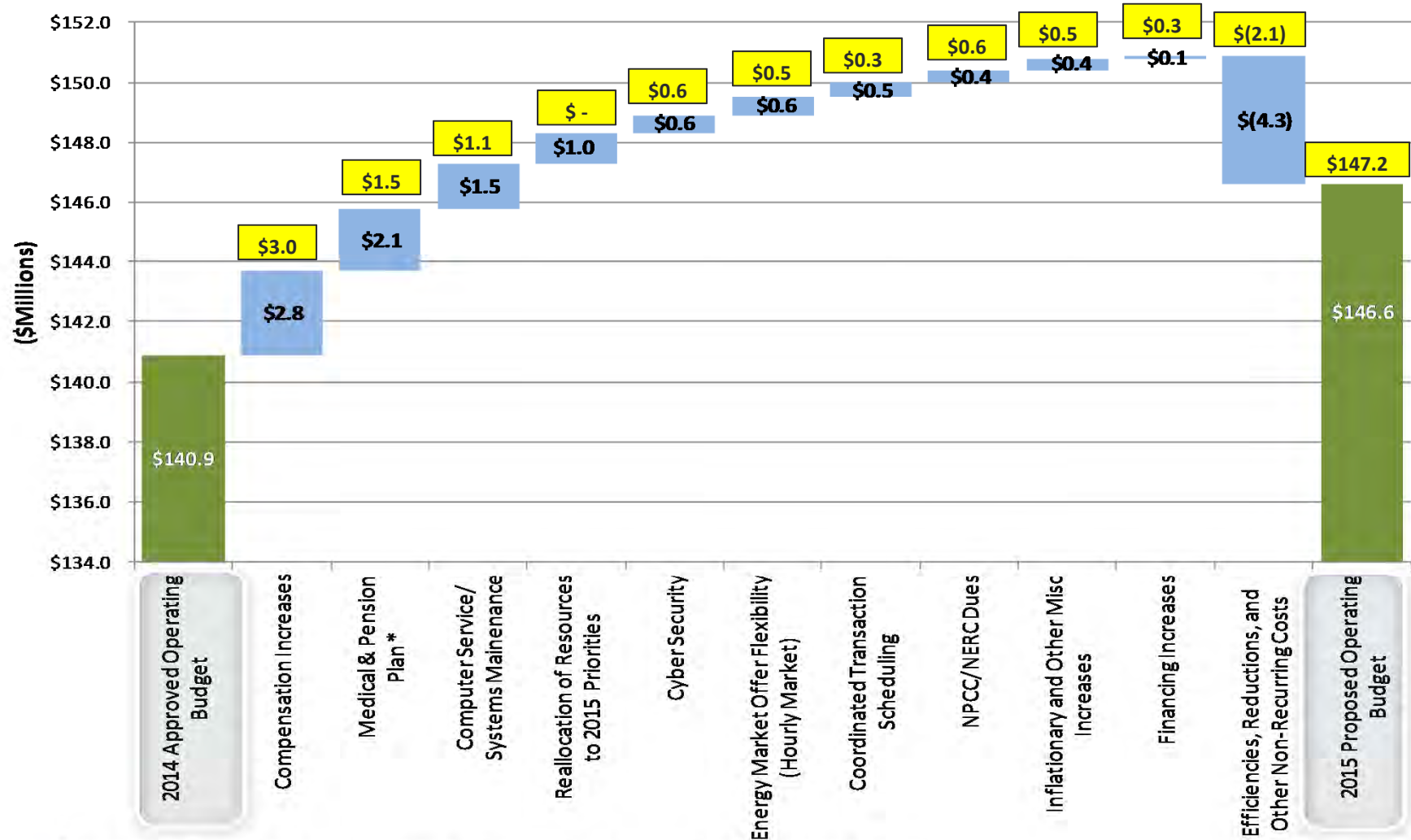
Analysis of New England Residential Retail Rates

Region/State	Cents/kWh
2014 Year-to-Date Amounts through May*	
New England	17.71
Connecticut	19.34
Maine	14.96
Massachusetts	17.33
New Hampshire	17.25
Rhode Island	18.44
Vermont	17.46
ISO Tariff (Operating Budget) Rate (see slide 7)	0.12

* New England Region and Individual State rates were obtained from the U.S. Energy Information Administration June 2014 Report @ <http://www.eia.gov/electricity/monthly/>



2015 Budget Components



* Includes Pension Plan increase of \$1.8 million and Medical Plan increase of \$0.3 million.

Note: Items in yellow above represent the estimate that was included in the 2015 Preliminary budget presented in June 2014.

CAPITAL BUDGET

Capital Budget

NEPOOL PARTICIPANTS COMMITTEE
OCT 3, 2014 MEETING, AGENDA ITEM #5a

2015 Expenditures

Major Projects In Development:		
	Coordinated Transaction Scheduling	\$4.2M
	Generation Control Application Production Part 1	\$1.7M
	Divisional Accounting	\$1.0M
	Alternative Technologies and Regulation Market	\$0.5M
	Forward Capacity Auction (FCA) 9	\$0.2M
	Voltage Stability	\$0.1M
	Control Room Visualization	\$0.1M
In Planning/Conceptual Design		
	Business Continuity Plan Infrastructure Enhancements Phase III	\$2.0M
	Forward Capacity Auction (FCA) 10	\$2.0M
	Third Party Financial Transmission Rights (FTR) Administration	\$1.8M
	Generation Control Application Production Part 2	\$1.5M
	VPN System Upgrade	\$1.0M
	Issues Resolution Project 2015	\$1.0M
	Simultaneous Feasibility Test Lite Production Version	\$1.0M
	Power System Modeling	\$1.0M
	Quarterly Release Projects 2015	\$0.8M
Continued Next Page		



Capital Budget

2015 Expenditures (*cont.*)

In Planning/Conceptual Design (Continued):		
	LMP Calculator Replacement	\$0.5M
	Wind Integration Phase II	\$0.5M
	Web Enhancements	\$0.5M
	Phasor Measurement Unit (PMU) Data Application	\$0.5M
	Price Responsive Demand	\$0.3M
	Software Testing Tool 2015	\$0.3M
	Non-Project Capital Expenditures	\$3.4M
	Other Emerging Work	\$1.6M
	Capital Interest	\$0.5M
Total 2015 Capital Budget		\$28.0M



ISO/RTO FINANCIAL COMPARISON

Financial Results Summary

ISO/RTO Financial Summary - 2013 Actual Results

Operating Expense and Capital Expenditures for Calendar Year 2013, and Outstanding Debt as of December 31, 2013⁽¹⁾

(Amounts in Millions)

	ISO-NE ⁽²⁾	NYISO	CAISO	IESO ⁽³⁾⁽⁴⁾	PJM	MISO	SPP	ERCOT
Operating Expense - 2013	\$ 157.3	\$ 159.8	\$ 256.3	\$ 148.8	\$ 328.1	\$ 307.8	\$ 153.1	\$ 172.4
Less: Amortization & Depreciation	(24.9)	(22.7)	(74.6)	(18.2)	(55.3)	(49.7)	(19.4)	(31.5)
Regulatory Fees	(5.1)	(11.2)	-	-	(53.9)	(34.7)	(14.7)	(11.7)
Grant Expenses	-	(4.9)	-	-	-	-	-	-
Net Operating Expense - 2013	\$ 127.3	\$ 121.0	\$ 181.6	\$ 130.6	\$ 218.9	\$ 223.5	\$ 119.0	\$ 129.2
Other Financial Data								
Capital Expenditures for 2013	\$ 51.8	\$ 45.6	\$ 15.7	\$ 22.2	\$ 35.5	\$ 34.1	\$ 49.8	\$ 15.0
Outstanding Debt as of 12/31/2013	\$ 119.2	\$ 105.7	\$ 225.8	\$ 78.2	\$ 60.6	\$ 218.5	\$ 258.3	\$ 88.6
Actual full-time equivalent headcount as of 12/31/2013	560.0	524.0	581.0	464.0	665.0	795.0	569.0	636.0

(1) Applicable amounts were taken from each entity's 2013 audited financial statements

(2) ISO-NE Amortization & Depreciation and Capital Expenditures are presented on a cash-flow basis

(3) Amounts are in Canadian dollars

(4) IESO excludes regional System Planning function and costs which are provided by Ontario Power Authority



Employee Counts by Functional Area

(1) Please fill in the numbers of FTEs for ISO Budgeted, actual (full year and partial year) and new FTE positions, by area in the following chart:

Area	12/31/ 2012 Actual	2013 Budget approved (total)	2013 new ¹ (incl in tot)	At 6/30 2013 ²	At 12/31 2013	2014 Budget approved (total)	2014 new (incl in total)	At 6/30 2014	2014 Actual partial ↓	2015 budget request	2015 new	
Systems Operations	101.5	107.5	3.0	105.5	105.5	107.5	--	105.5		107.5		
System Planning	62.0	67.0	3.0	63.0	62.0	68.0	1.0	62.0		66		
Market Operations	75.5	79.5	2.0	78.5	80.0	79.5	1.0 ³	80.0		81 ⁴	0.5 ~~1.5~~	
Market Developmnt	19.0	22.0	2.0	19.0	20.0	22.0	--	21.0		22		
Information Services	140.5	150.5	6.0	144.5	148.5	156.5	5.0 ⁵	153.5		163.5	7.0	
Program Managemnt +	30.0	33.0	4.0	29.0	31.0	33.0	--	33.0		34	1.0	
Market Monitoring +	18.0	20.0	1.0	20.0	19.0	20.0	--	19.0		20		
Legal Services	13.0	14.0	1.0	13.0	14.0	15.0	1.0	15.0		15		
External Affairs +	18.0	18.0	--	18.0	17.0	18.0	--	18.0		18		
Compliance, Risk Mngmnt +	39.0	43.0	4.0	40.0	41.0	43.0	--	43.0		45	1.0	
Human Resources	14.0	14.0	--	13.0	13.0	14.0	--	13		14		
CEO & COO & support	5.0	5.0	--	5.0	5.0	5.0	--	5.0		5		
Building Services	4.0	4.0	--	4.0	4.0	4.0	--	4.0		4		
Vacancy		(14.5)	--			(17.5)				(18.0)		
Totals ⁶	539.5	563	26.039			568	585.5	8-22.5		577	595	9.5

¹ These numbers are also included in the "2013 Budgeted approved" column (i.e., they are not additive).

² Changes column headings were made in accordance with discussions with the CT AG's Office.

³ Numbers don't reconcile (i.e., "2013 budget approved total" + "2014 new" does not equal "2014 budget approved total") because one FTE (Tariff Coordinator) was moved from Market Operations to Risk Management.

⁴ Similarly, the numbers from 2014 to 2015 don't reconcile because two employees who perform FCM operations were moved from System Planning to Market Operations.

⁵ Numbers don't reconcile because Information Services gained a headcount when the A/V Services Coordinator moved to Information Services from Market Operations.

⁶ This is the number of funded positions in the budget for the applicable year.

- (2) For the "December 31, 2012 actual" column, please provide the number of FTEs actually hired and working at ISO NE on December 31, 2012, separated out by area. *Done*
- (3) For "Budget approved" columns, please provide the FTE levels approved for each area for that budget year. *Done*
- (4) For "New" columns, please provide the FTE positions sought to be fully funded above the fully funded FTE positions from the prior year for the specific budget year for each area. *Done (note these positions are also included in "Budget approved" columns).*
- (5) For "Actual Full" columns, please provide the number of that area's FTE positions that were filled for the entire year in question. *See (6).*
- (6) For "Actual Partial" columns, please provide the number of that area's FTE positions that were filled for only part of the year in question. *On (5) and (6), per discussion, we are including the numbers at mid-year and, where applicable, year end.*
- (7) The 2015 Budget and 2015 new columns are gleaned from slides 21, 24-42 from the August 27, 2014 presentation. Please confirm that the numbers are correct. *Changes were made in red where necessary.*
- (8) Please provide the actual vacancy rates from 2009-2014 and the vacancy rates used in your budgets from 2009-2015.

Budgeted and Actual Average Vacancy by Year for 2009 through 2015:

Year	Budgeted Vacancy %	Actual Average Vacancy %
2009	5.0%	5.2%
2010	2.0%	4.6%
2011	5.0%	6.3%
2012	5.0%	2.6%
2013	2.5%	4.5%
2014	3.0%	3.3%
2015	3.0%	N/A

For 2014, the *Actual Average Vacancy %* is Year-to-Date through August.

ISO-NE agreed to additionally provide the monthly and quarterly vacancy rates in 2013 and 2014. We have included below the YTD averages as well (which include the quarterly numbers).

2013 Period	Period Vacancy %	Avg YTD Vacancy %		2014 Period	Period Vacancy %	Avg YTD Vacancy %
January	5.9%	5.9%				
February	5.5%	5.7%				
March	5.2%	5.5%				
April	4.7%	5.2%				
May	4.3%	5.0%		January	4.0%	4.0%
June	4.3%	4.9%		February	4.1%	4.0%
July	4.0%	4.8%		March	3.9%	4.0%
August	4.0%	4.7%		April	3.1%	3.8%
September	4.3%	4.7%		May	3.2%	3.7%
October	4.5%	4.7%		June	2.4%	3.4%
November	4.1%	4.6%		July	2.7%	3.3%
December	3.0%	4.5%		August	3.1%	3.3%

- (9) For position vacancies in calendar years 2013 and 2014, please indicate how many applicants applied for each position and how many of those applicants were qualified for the position.

We have the requested information for 2014, as HR began systematically tracking it in a single document this year. See the attached document titled “2014 Resumes to Hires.” Per your request we have also included information on days to fill positions. See the two additional attached documents, which include staffing reports for 2013 and 2014 respectively, and the chart below showing the average days to fill certain groups of positions.

Jobs Groups With Similar Skills Sets	Avg Days to Fill -- 2013 ⁷	Avg days to fill – 2014 to date
Analyst	169	191
Analyst - Market Monitoring	158	None to fill
Business Analyst	74	112
Compliance	104	145
Economist	168	105
Engineer – EMS	109	143
Engineer - Power Systems	115	223
Finance	82	101
Information Technology	109	141
Legal	121	187
Market Analyst - Market Operations	79	78
Operations	100	94
PMO - Project Manager	423	None to fill
Other	153	92

⁷ Days to Fill is defined as the number of days between the posting date to the actual start date of employment.”

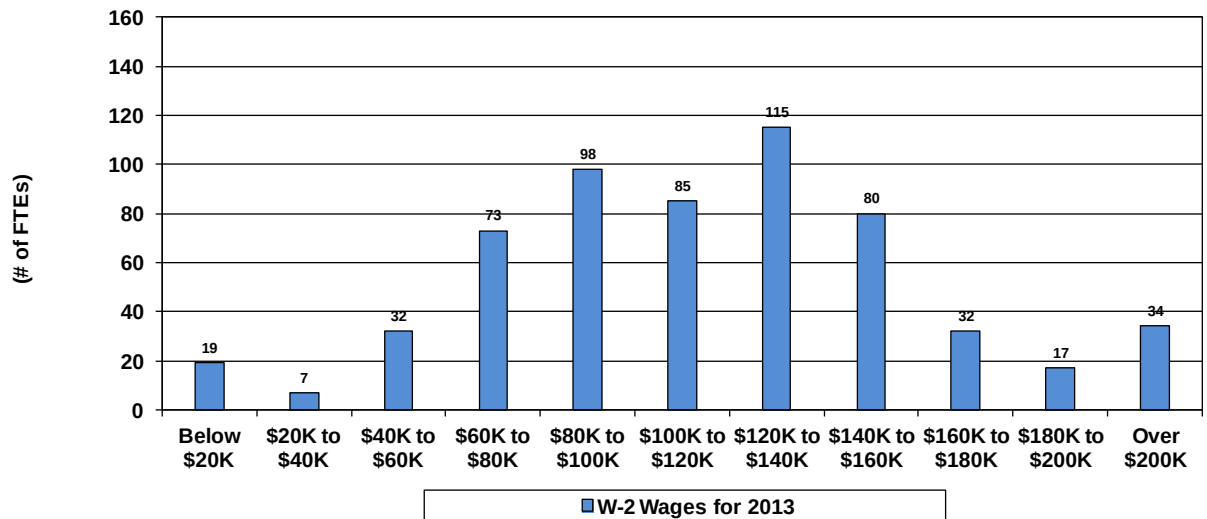
Compensation

- (10) Please provide a brief written explanation of the differences between salaries, performance incentive bonuses, merit increases and promotional increases and identify where each category is reflected in the budget. Please also provide the ranges of percentage increases for performance incentive bonuses, merit increases and promotional increases.

All of these items are included in the Salaries line of the budget, with the exception of any salaries that have been budgeted as capital, which are included in the cost of the relevant capital project. Below, we define each of these categories and indicate the relevant ranges.

- Salaries: base salaries are the annualized compensation paid to employees on a biweekly basis.
 - Performance incentive bonuses: performance incentive amounts are tied to the level of the employee's position, and are contingent upon the level of achievement of corporate goals and individual performance. The range of annual performance incentive opportunities for employees is 6.5%-16% of salary, and is 25%-50% for officers.
 - Merit increases: each year, ISO-NE budgets a pool of dollars for merit increases, which are performance-based increases to annual salaries, varying by the job performance of the employee. Top performers receive a larger increase, while the bottom performers receive no increase. There is no specific range, although the entire program is limited by the budgeted pool. Most recently merit increases ranged from 0% - 7%, with the majority (40.5%) of employees receiving 3%; 30% of employees receiving less than 3%; 25% receiving 3.1%-3.9%; and 4% of employees receiving 4%-7%.
 - Promotional increases: ISO-NE establishes a pool of dollars for promotional increases, to provide financial recognition to employees who are promoted or for use when the ISO must make a market adjustment. Again, there is no prescribed policy or matrix regarding ranges for promotional increases, although the entire program is limited by the budgeted pool. In the most recent year, promotional increases ranged from 0.3% - 7%, with 81% of those increases at less than 5%.
- (11) Using the *Operating Budget Details -- Staffing – Number of Employees by Salary Band* chart on slide 61 as the template, please provide the same chart, presenting the number of employees by combined “salary & bonuses” band rather than just by salary band. Please also extend x-axis to include \$200K to \$220K, \$220K to \$250K and over \$250K.

Please see the chart below. The bands reflect W-2 Form wage amounts for 2013 as the basis for the chart. The ISO did not expand the number of bands on the axis. Please see the Form 990 for key employees' and officers' salaries by person.



- (12) For fiscal years 2013 and 2014, what percentage of full-time employees received:
- (a) 100% of their eligible performance incentive bonus?
 - (b) 90% of their eligible performance incentive bonus?
 - (c) 75% of their eligible performance incentive bonus?
 - (d) 50% of their eligible performance incentive bonus?
 - (e) 0% (none) of their eligible performance incentive bonus?

	2013	2014
100% or more	6%	7.3%
90%- 99%	18%	18.8%
75% -89%	70%	69.3%
50% - 74%	5%	1.8%
1% - 49%	1%	0.4%
0%	0.4% ¹	2.4% ²

¹ This number does not reflect the five employees with poor performance who were managed out of the organization in the 12 months prior to payment.

² This figure excludes 24 additional employees who did not work long enough to earn an incentive payment in 2014, and four employees who were managed out of the organization for poor performance.

- (13) For new employees hired since January 1, 2014, what are their salaries and what level of performance incentive bonuses are they eligible for, without providing individual identification of the employees.

2014	
Annual Salary	Incentive Opportunity
\$ 90,000	16%
\$ 68,500	10%
\$ 68,000	10%
\$ 119,999	16%
\$ 74,417	10%
\$ 80,000	10%
\$ 83,000	10%
\$ 63,000	6.5%
\$ 82,000	10%
\$ 85,000	10%
\$ 120,000	16%
\$ 87,000	10%
\$ 95,000	10%
\$ 56,000	10%
\$ 76,000	10%
\$ 85,000	10%
\$ 80,000	10%
\$ 67,500	10%
\$ 230,000	25%
\$ 50,000	6.5%
\$ 90,000	10%
\$ 92,000	10%
\$ 66,000	10%
\$ 65,000	10%
\$ 61,000	10%
\$ 63,000	6.5%
\$ 95,000	10%
\$ 65,000	10%
\$ 175,000	16%
\$ 62,500	10%
\$ 100,000	16%
\$ 62,500	10%
\$ 125,000	16%
\$ 87,500	10%
\$ 63,000	6.5%
\$ 92,500	10%

Current Pension Plans

(9) Please provide the latest copy of ISO-NE's FERC Form 1. *Document provided.*

(10) Please provide the discount rates used for the defined benefit pension costs in the 2009-2014 budgets and provide a detailed explanation for any differences in the discount rate assumptions between the 2014 and 2015 budgets.

The discount rates, reflected in the table below, are tied to the interest rate environment. Each year's rate is proposed by the Company's actuaries, Sibson, and reviewed with the pension plans' investment advisors. KPMG, the Company's external auditors, also reviews the discount rate as part of the annual audit of financial statements.

Budgeted Discount Rates	2009	2010	2011	2012	2013	2014	2015
Pension (Non-Contract)	6.00%	6.13%	5.50%	5.51%	4.00%	4.75%	4.30%
Pension (Contract)	6.00%	6.13%	5.50%	5.51%	4.00%	4.75%	4.50%

(11) Please provide a detailed explanation of all cost control measures put into place in the past five years to keep Post-Retirement Benefits other than Pensions (PBOP) costs at a reasonable level.

In 2009, ISO-NE moved to high deductible medical plans, including for retirees under age 65. This plan design change has kept premium increases below the national trend for the last five years, and has shared more of the cost of care with those retirees. We also increased the retirees' share of premiums in 2010, with retirees currently covering up to 32% of the premium, varying by the plan and level of coverage selected. We continue to maintain a cap of \$160 per month on ISO-NE's contribution to coverage for retirees over age 65, limiting the Company's liability as the cost of those plans increases. Going forward we will assess the plan design of our benefits and the access to retiree medical benefits, based on competitive practice.

(12) Section III.2 of the Settlement Agreement requires ISO-NE to provide information regarding the "cost and structure of the proposed defined contribution pension plan and any associated post-retirement benefits". The materials were not provided last year because the plan was still being developed. Since the defined contribution pension plan has been effective for all new hires since January 1, 2014, please provide the required information, including but not limited to

- a. A complete explanation of the terms and conditions of the current defined contribution plan;

See attached FAQ and SPD as well as the employee "Fast Facts" document. Note that, structurally, the new DC pension plan was added to the "umbrella" of the 401(k) plan document. This is explained in the attached FAQ. In the SPD, new DC plan balances and contributions are referred to as the "Non Elective Contributions."

- b. A copy of all material and information provided to employees covered by the defined contribution plan; *See attached FAQ and SPD*

- c. A detailed explanation as to how the age & service weightings were calculated and arrived upon;

We engaged TowersWatson to complete a competitive analysis of DC plans offered by other employers and to recommend a plan construct that would be appropriate for our industry and to ISO-NE. They made several recommendations, with several formulas for age and service. After reviewing the options, related costs and resulting benefits, management recommended and the Board approved the current DC plan design, which provides projected replacement income at retirement at the median compared to ISO peers and reduces ISO's costs over time as more employees are covered by new plan.

- d. A detailed explanation regarding the aggregate cost of the defined contribution pension plan vis-à-vis the existing defined benefits plan, including any expected savings in 2014 and 2015.

The last work on this topic done by ISO-NE is reflected in slides 63-65 of last year's budget presentation, which can be found at http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/budgfin_comm/budgfin/mtrls/2013/aug232013/1_update_2014_operat_budg.pdf

Rate Impact

- (14) Please provide the specific rate impacts from the proposed revenue requirements from the proposed 2015 budget, preferably in the form of a redline markup of the various tariffs.

Revised rates will not be final until October.

- (15) Please provide the Projected 2015 Revenue Requirements for ISO NE Administrative Cost Studies, including all information provided in the memorandum to the NEPOOL Budget and Finance Subcommittee from last year for the 2014 budget in the September 23, 2013 Memorandum from Robert Ludlow and Cheryl Arnold.

We will have estimated changes to Schedules 1, 2 and 3 by the fourth week in September. These estimated changes will be provided to stakeholders through our customary letter to the NEPOOL Participants Committee.

Depreciation

- (14) Please provide the most recent Form 990. *Document provided.*
- (15) Reference slide 85 "table of ISO's asset classes and depreciable lives". Have there been any changes to depreciation rates of existing assets in any of the asset classes listed? *No.*

- (16) Reference slide 84 “ISO NE Depreciation”. Please site the specific FASB standard(s), or reference, used for capitalizing Software Development Costs.
Computer Service Software Development Topic of the FASB Accounting Standards Codification
- (17) What depreciation method is used for the Main Controller Center and the Back Control Center? *Straight-line by component.*
- (18) Reference slide 118 “2015-2018 Pro-Forma Budgets”. What is expected to cause the pro-forma depreciation expense to increase in 2016 and 2017?

The increase in 2016 over 2015 is a result a number of large projects going live in late 2015 and the beginning of 2016 (e.g., Coordinated Transaction Scheduling, Divisional Accounting, GCA Phase 1, etc.). Therefore, a full year of depreciation is realized in 2016, creating an \$8M increase. Additionally, the Company is projecting to spend \$28m in capital in 2016 on projects that do not have identifiable go-live date(s). As a practice, the Company assumes an overall 36 month life on all such expenditures and depreciates one-third of the capital costs in the current budget year. The effect of this results in a \$3M increase in depreciation expense for 2016. The increase as described above is partially offset by \$8M of projects becoming fully depreciated within the year (System Improvement Requests, Hardware, SIDU – Smart Grid, FCM Reforms, various others), and therefore are no longer a cost in 2016.

The increase in 2017 is a result of two large projects going live in mid to late 2016; therefore, a full year of depreciation is realized in 2017 (Web Enhancements, GCA Phase 2 - \$900k). Additionally, as described above, the 2016 capital spend for conceptual design will result in a full year depreciation of \$9M in 2017, which is partially offset by \$6M of projects fully depreciated (NX9/NX12, Wind Integration, FCA-8, System Improvement Requests, and others), and therefore are no longer a cost in 2017.

Capital Budget Expenditures

- (19) Please provide a detailed explanation of any capitalized labor costs, including what percentage of total capital costs include internal labor expenses, and what percentage of the administrative salary and benefits expenses are reflected in the capital budget, with an assurance that the same expenses are not being reflected in both the capital and the administrative budgets.

Capitalized labor costs are utilized to fund the development of new software or the enhancement of existing software. In the 2015 budget, capitalized labor (including burden) equals \$8.6 million. This amount represents 30.7% of the capital budget and 8.5% of the total salary and burden budget. The ISO confirms that these amounts are not reflected in both the capital and administrative (operating) budgets. On page 64 of the budget presentation provided at the August 28, 2014 meeting, it indicates in footnote (3) that internal capital development and reimbursable study time are excluded from the operating budget. The internal capital development amount of \$8.6 million is included in the \$9.2 million referenced in footnote (3) on page 64 of the budget presentation.

Settlement Compliance

- (20) Please include the deadlines and process provided in section II.B.5 of the Settlement Agreement into your 2015-2018 Business Plan (appendix 3), and elsewhere in future versions of your August presentation, as appropriate.¹

We have revised the 2015 budget presentation that is online with the Budget & Finance Subcommittee materials. We do not include that level of granularity about the stakeholder process (including the NEPOOL process) in the business plan.

- (21) In section III.1 of the Settlement Agreement, ISO-NE is obligated to reduce the 2013 Revenue Requirement by \$2.25 million, by reducing the administrative budget expenses. The \$2.25 million reduction was to be reflected in the true-up for this budget year. Please confirm that the \$2.25 million reduction is included in the true-up for this budget year. *Confirmed*

- (22) For fiscal year 2013, ISO-NE added 26 new positions and funded an additional 13 positions, adding a total of 39 additional funded positions, for a total full-time employee (FTE) count of 563 FTEs. *[not accurate; 26 were requested.]* For fiscal year 2014, ISO-NE added 8 new positions and funded an additional 13.5 positions, adding a total of 22.5 additional funded positions. *[not accurate; discussed below.]* For fiscal year 2015, ISO-NE proposes to add 9 additional positions and whether there are additional funded positions is unclear. Section II.A of the Settlement Agreement requires ISO-NE to rely

to the greatest extent possible on its current employee complement to perform all existing and proposed new projects, and shall document its efforts to do so as set forth below.

As of December 31, 2012, ISO-NE had 539.5 full-time employees. Two years later, ISO-NE seeks to employ 595 full-time employees. Please provide an explanation as to how

¹ This exact same request was made last year. In response to last year's request, ISO NE committed as follows:

As discussed at August 28, 2013 meeting with the States and NESCOE, ISO will include the deadlines specific to the Settlement Agreement in budget presentations starting with the budget year 2015.

The Settlement Agreement deadlines and process were not included in the 2015 budget presentations.

this complies with section II.A of the Settlement Agreement, and provide all supporting documentation. Please explain how many current employees' duties were eliminated and redirected to new tasks.

In preparing the 2014 budget, the ISO looked at the workload to be completed including on-going work from 2013, non-repetitive work from 2013 to 2014, and new work for 2014. Additionally, each area of the Company then reviewed the current resources available to complete this work. In approaching the completion of the bottom up budget, the ISO looked to only add positions if (1) the position was needed for resource purposes or (2) the position was cost beneficial to the overall budget. Although the ISO requested eight additional positions in the 2014 budget (funding for five net of vacancy change), this represented only a small portion of the additional work being taken on for 2014. In addition to taking on a portion of FERC Order 1000 with existing staff, the ISO also undertook number of other Market Rule and Operational Changes with existing staff, as explained on pages 23 and 24 of last year's budget presentation. Of the eight requested positions, the Legal and IT Systems/Network and Desktop positions were added as alternatives to higher-cost options of external resources, while the other six positions were for resourcing issues to cover new Measured Growth alternatives, as explained on page 27 of last year's budget presentation. As noted on page 18 of that budget presentation, the requested 2014 budget was \$5.0 million less than the estimate provided in June 2013, which was due in large part to the ISO seeking to contain costs and cover its work with existing resources. The addition of headcount as a less expensive alternative to using outside resources also contributed to this reduction.

In preparing the 2015 budget, the ISO looked at the work load to be completed including on-going work from 2014, non-repetitive work from 2014 to 2015, and new work or increased work for 2015. Additionally, each area of the Company then reviewed the current resources available to complete this work. For 2015, the ISO is proposing to add 9.5 FTEs in 2015 (funding for nine net of vacancy). In approaching the completion of the bottom up budget, the ISO looked to only add positions if (1) the position was needed for resource purposes or (2) if the position was cost beneficial to the overall budget.

For 2015, we are including new positions to support the work we have already committed to in 2014 (see slide 16). We are adding 7 FTEs in various Information Technology areas to support increased and more complex work associated with Cyber Security improvements, Forward Capacity market changes, Energy Market Offer Flexibility, Coordinated Transaction Scheduling, and data base maintenance. In addition we are adding 2.5 positions for payroll, a business analyst in market operations, and a dedicated software tester in the Project Management office (PMO). The payroll supervisor is needed in order to supervise and provide full back-up capability to processing payroll. There is one payroll analyst position, which processes payroll for the entire company with ad hoc back-up. This position requires that a person with full backup capability exists. The business analyst is converting a part-time position to full time and results in a net cost savings, since the work was needed in the past and was being done by a consultant. Finally, the dedicated tester within the PMO will have the technical skills necessary to perform the testing function for a myriad of new systems and enhancements, resulting in expedited testing for projects.

The salary and burden costs included in the operating budget of the new 9.5 FTEs for 2015 is \$1.1M (see slides 21 and 6 of this year's budget presentation). \$300,000 of the new 9.5 FTEs salaries and burden costs is included in the capital budget. Total full cost (salaries and burden) of the new positions for 2015 is \$1.4M.

As noted on slide 20, of the budget presentation, the requested 2015 budget is \$1.1 million lower, or approximately 8 FTEs less than it would have been, had ISO not been seeking to contain costs and cover its work by reallocating existing resources. The addition of headcount as a less expensive alternative to using outside resources also contributed to this reduction. The reallocated resources will focus on the Forward Capacity Market (FCM) changes for System Planning including new capacity zone evaluation and reconfiguration, development and implementation of zonal demand curves, and evaluation of natural gas availability in FCM resource qualification; Market Operations/Settlements integration for Divisional Accounting, Sub-Hourly Settlements, Third Party FTR Administration, Customer and Asset Management System Improvements, and Oracle Business Intelligence Report Integration; and System Operations development of a training program for Non-Operations Staff for compliance under NERC Standard PER 005.

- (23) Please explain in detail how many current employees' duties were eliminated and redirected to new tasks for purposes of the 2015 budget request.

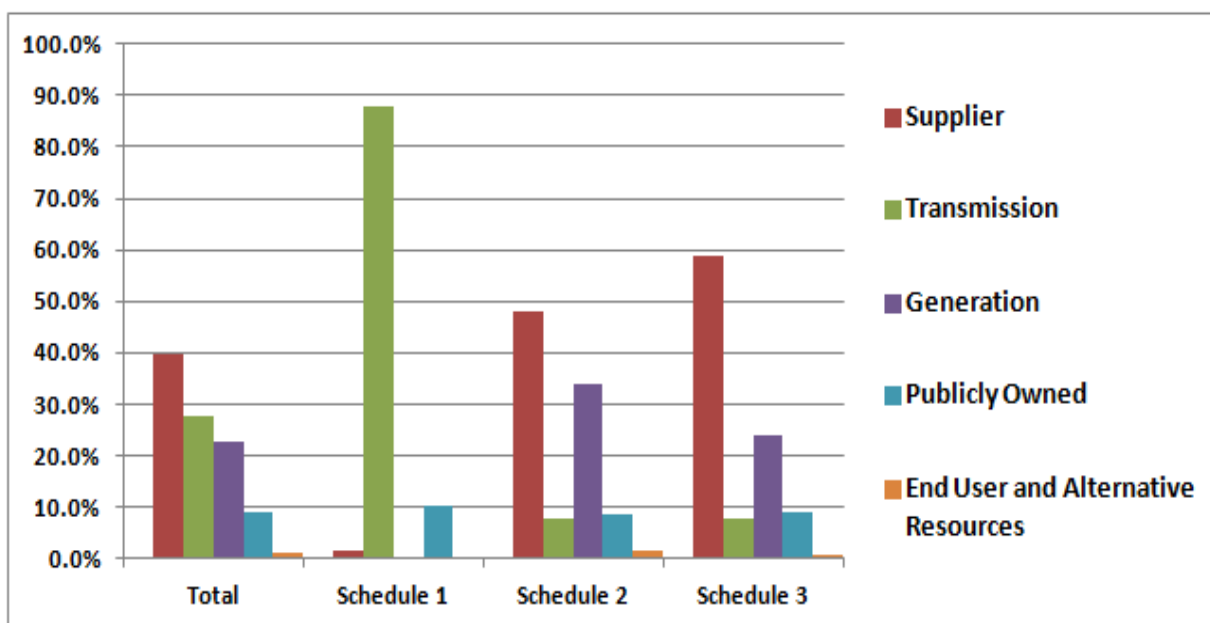
See above.

ISO New England, Inc.

Administrative Cost Tariff Schedule Collections by Schedule by NEPOOL Sector

For Calendar Year 2013

Sector	Total	Schedule 1	Schedule 2	Schedule 3
Supplier	39.8%	1.5%	48.2%	58.8%
Transmission	27.6%	88.0%	7.7%	7.6%
Generation	22.6%	0.2%	34.0%	23.9%
Publicly Owned	9.1%	10.3%	8.6%	9.1%
End User and Alternative Resources	0.9%	0.0%	1.5%	0.6%
Total	100.0%	100.0%	100.0%	100.0%



ISO New England, Inc.
Administrative Cost Tariff Rates



	Draft 2015 Proposed	Filed 2014	\$ Change	% Change
Schedule 1				
Network Load (per kW-hour)	\$0.00021	\$0.00021	\$0.00000	0.0%
Schedule 2				
TU Bids (Virtual Inc/Dec)				
Submitted	\$0.00500	\$0.00500	\$0.00000	0.0%
Cleared	\$0.06000	\$0.06000	\$0.00000	0.0%
FTR Bids				
Submitted	\$0.85853	\$1.23712	(\$0.37859)	(30.6)%
Cleared	\$1.21377	\$1.76776	(\$0.55399)	(31.3)%
TU's				
Block 1 - 1st 12,500	\$0.65101	\$0.73167	(\$0.08066)	(11.0)%
Block 2 - Next 27,000	\$0.59182	\$0.66515	(\$0.07333)	(11.0)%
Block 3 - Over 39,500	\$0.53264	\$0.59864	(\$0.06600)	(11.0)%
Volumetric				
Block 1 - 1st 250,000	\$0.25517	\$0.26149	(\$0.00632)	(2.4)%
Block 2 - Next 1,250,000	\$0.23197	\$0.23772	(\$0.00575)	(2.4)%
Block 3 - Over 1,500,000	\$0.20877	\$0.21395	(\$0.00518)	(2.4)%
Schedule 3				
R-T NCP Load Obligation	\$0.18763	\$0.17790	\$0.00973	5.5%
Export Rate	\$0.37000	\$0.37000	\$0.00000	0.0%

September 25, 2014

Philip N. Shapiro
Chairman
ISO New England
One Sullivan Road
Holyoke, MA 01040

Re: Comments of State Agencies on proposed 2015 ISO Budget

Dear Chairman Shapiro:

In conformance with the FERC-approved Settlement Agreement dated May 13, 2013 in docket nos. ER13-185 and ER13-192 between ISO and the New England State Agencies (the "Settlement Agreement"), the undersigned New England State Agencies are pleased to continue their role of providing written comments concerning ISO's proposed 2015 budget. For its 2015 Budget, ISO New England management proposes a 4.4% increase in spending. Because of a \$9.8 million over-collection from last year's tariff, the proposed 4.4% increase is offset entirely by the over-collection, resulting in an anticipated reduction of 1.2% in revenue requirements and a 2.1% reduction in the proposed \$/kWh rate.¹ We note that \$2.25 million of the \$9.8 million offset from this year is returned pursuant to the FERC-approved Settlement Agreement.

We believe that the Settlement Agreement sets forth an efficient, effective means for the States to review and express their views regarding ISO's annual budgets. This process is having positive results, but some of the details of the review, input and communication process are not yet working smoothly. We therefore ask for your continued support and commitment to this process. As an example of an issue of concern, the Settlement Agreement requires the States to provide written comments no later than September 25, and for ISO-NE to respond to those comments no later than "five business days before the ISO-NE Board of Directors votes on the proposed budgets."² By its terms, the Settlement Agreement contemplates that the ISO Board will consider the States' comments. Thus we were surprised to learn that the Board considered and discussed the budget on September 18, 2014, a week before the deadline for our comments. We understand that the Board's actual vote on the budget will be by written consent, on or before October 16.³ Since the Business Plan has ISO submitting its budget to FERC on the same day, there is no meaningful opportunity for the Board to consider the States' comments or to change any aspect of the budget

¹ We were informed that the actual tariff impact would not be available until the end of this month and thus rely upon the representations made in the budget presentation materials.

² Settlement Agreement II.B.5.

³ See ISO New England's 2015-2019 Business Plan, p.7.

Philip N. Shapiro
Chairman, ISO New England
September 25, 2014
Page 2

based on its consideration of those comments.⁴ We respectfully submit that this process fails to comply with the intent and structure of the Settlement Agreement, namely that the ISO-NE Board of Directors fully consider, discuss and evaluate formal input from State governments before approving a budget that is funded by New England ratepayers. Moreover, despite a commitment otherwise in last year's budget answers, the required process established in the Settlement Agreement is not reflected in either the 2015-2019 Business Plan (see p.7), or the budget presentation.⁵ We request your commitment to full compliance with the letter and intent of the Settlement Agreement for the 2016 budget process.

For the 2015 Budget, we appreciate that management is proposing a reduction in the tariff rate and the revenue requirement. We understand that management could have found ways to spend the over-collection, and give management full credit for returning an amount that effectively offsets this year's requested budget increase.

We also approve and appreciate some of the specific steps management has taken to contain administrative and operational costs. For example, in the Settlement Agreement, ISO agreed to switch from a defined benefit to a defined contribution retirement plan for new employees, a change we welcome. We agree that it will provide budgeting predictability and lower overall expense in the long run.⁶

The largest driver of costs in ISO's budget is personnel. We recognize the high quality and caliber of ISO staff. We support management's stated commitment to redeploy existing personnel to address new programmatic challenges. We would, however, request a better quantification of that redeployment, and a more effective effort to comply with the Settlement Agreement's mandate to rely "to the greatest extent possible on its current employee complement to perform all existing and proposed new projects."⁷ On December 31, 2012, ISO employed 539.5 full-time employees (FTEs), and eighteen months later, as of June 30, 2014, it employs 572 FTEs, or 32.5 additional employees.⁸ In its proposed 2015 budget, management seeks an additional 9.5 FTE positions, in addition to the eight new FTE positions obtained in the 2014 budget and

⁴ See ISO New England's 2015-2019 Business Plan, p.7.

⁵ See ISO 2014 Response to State Agencies' question no. 4.

⁶ We do note that the adopted defined contribution plan is not modest, as it contributes between 4% and 9% of an employee's combined base salary and performance bonus into the defined contribution account on an annual basis. This is in addition to the existing 401(k) plan, where New England ratepayers are matching 100% of employee contributions up to 3% of wages, and 50% of employee contributions for the next 2%.

⁷ Settlement Agreement II.A.

⁸ See ISO 2015 Response to State Agencies' question no. 1.

Philip N. Shapiro
Chairman, ISO New England
September 25, 2014
Page 3

the 26 new FTE positions obtained in the 2013 budget. This continued growth raises the total number of FTE positions to 595 for the 2015 budget.⁹

We ask the ISO Board to seriously question why management requires increasing the numbers of employees at this rate. While the New England State Agencies are not proposing a moratorium on new hires at this time, it is often the case that a defined limit on new hires spurs the creativity needed to respond to changing conditions without adding new personnel. We suggest that the ISO-NE Board set a guideline of limiting new hires to a number that more closely approximates the budget constraints of most other employers, including competitive businesses, regulated monopolies and regulatory agencies. This will control costs and encourage management to find ways to better deploy and redeploy the significant personnel resources currently available. Certainly the rate of growth in the employee count that we have seen at ISO over the past decade is not sustainable.

The State Agencies submit that the ISO could update its practices in its planning area to significantly reduce operating expenses. For example, as the ISO has recognized, most major transmission congestion issues have been eliminated. Given the reduced need to study transmission congestion needs, the ISO should consider conducting Regional System Planning studies biennially instead of annually, and redeploying any affected staff to new projects. Moreover, ISO could either eliminate Economic Studies or allocate the costs of conducting such studies in a more equitable manner. We are certain that if pressed, ISO's management could identify other areas where resources critical for a prior need can now be better deployed to address current needs. We understand that some cost savings may require tariff changes and we are willing to participate in such efforts.

In your 2013 CELT Report, you predicted a decline in electricity demand in New England over the next ten years, and you predicted a very modest increase in your 2014 CELT report.¹⁰ Nonetheless, with the exception of Hawaii, New England has the highest electricity costs in the country, and ISO-NE is the most expensive RTO in the country. As State Agencies, and on behalf of the ratepayers of New England, we ask the ISO Board to affirm and adopt a commitment to lower and more reasonable electricity rates as part of its metrics for evaluating management's performance, particularly given the forecast for level or a slight increase in electricity demand.

⁹ Management contends that because of its anticipated vacancy rate, it is only seeking budget authority for 577 FTE positions. Since management requests 9.5 new positions rather than five new hires for 2015 in addition to its current employee count of 572 FTEs, management clearly does not view 577 as a cap on total number of FTEs, but instead anticipates it is able to hire up to the full 595 FTE complement requested.

¹⁰ See ISO 2013-2023 Forecast of Capacity, Energy, Loads and Transmission (2013 CELT Report), issued May 1, 2013; ISO 2014-2023 Forecast of Capacity, Energy, Loads and Transmission (2014 CELT Report), revised May 16, 2014.

Philip N. Shapiro
Chairman, ISO New England
September 25, 2014
Page 4

We look forward to continuing our collaboration to ensure reliable, secure and affordable electricity in New England.

Respectfully submitted,

Arthur H. House
Arthur H. House
Chairman
Public Utilities Regulatory Authority
Ten Franklin Square
New Britain, CT 06051

Susan W. Chamberlin
Susan W. Chamberlin, Esq.
Consumer Advocate
Office of the Consumer Advocate
21 S. Fruit St. Suite 18
Concord, NH 03301

George Jepsen
George Jepsen
Attorney General
Office of the Attorney General
55 Elm Street
Hartford, CT 06103

Leo Wold
Leo Wold, Assistant Attorney General
for Attorney General Peter Kilmartin
150 South Main Street
Providence, RI 02903

Elin Swanson Katz
Elin Swanson Katz
Consumer Counsel
Office of the Consumer Counsel
Ten Franklin Square
New Britain, CT 06051

Timothy Schneider
Timothy Schneider
Maine Public Advocate
Office of the Maine Public Advocate
112 State House Station
Augusta, ME 04333

Leo Wold
Leo Wold, Assistant Attorney General
Rhode Island Division of Public Utilities
and Carriers
89 Jefferson Blvd
Warwick, RI 02888

Cc: Gordon van Welie, President and CEO
Raymond W. Hepper, General Counsel
Robert C. Ludlow, Vice President and Chief Financial & Compliance Officer



To: NEPOOL Budget & Finance Subcommittee and Participants Committee

From: Bob Ludlow and Cheryl Arnold

Date: September 26, 2014

Subject: Projected 2015 Revenue Requirement for ISO New England Administrative Cost
Tariff Schedules

To help our Participants prepare their 2015 budgets and consistent with information provided in previous years, this memo includes a preliminary indication of ISO-NE's 2015 costs and related tariff schedules. Specifically, the memo includes (1) the estimated 2015 Revenue Requirement, including the final true-up for 2013, and a comparison to the 2014 Revenue Requirement (see Exhibit 1 below), (2) the Draft 2015 Revenue Requirement by activity (see Exhibit 2), and (3) the Draft 2015 Rate Components (Exhibit 3). Both Exhibits 2 and 3 are attached and, in their final form, will be part of the ISO's budget filing with the FERC. The cost assignment and allocation mechanisms that were utilized in the Draft 2015 tariff schedules were established as part of the settlement that has been in effect for the last thirteen years.

Overall Change in Revenue Requirement

As shown in Exhibit 1 below, the overall Revenue Requirement has decreased by \$2.7 million year-over-year, from \$171.2M for 2014 to \$168.5M for 2015. The change includes a \$9.0 million increase for the revenue requirement before taking into account the change in prior year true-ups. Prior year true-ups resulted in a decrease of \$11.7M. The 2014 tariff included a \$1.9M revenue requirement increase for the final 2012 true-up, while the 2015 tariff will include a decrease of \$9.8M as a result of the final 2013 true-up.

Draft Exhibit 1				
ISO New England Revenue Requirement By Tariff Schedule 2015 Estimated Amount vs. 2014 ACT Filed Amount				
	Sch 1	Sch 2	Sch 3	Total
2015 Revenue Requirement Before Prior Year True Ups	\$ 42,327,088	\$ 81,019,153	\$ 54,968,671	\$ 178,314,912
2014 Revenue Requirement Before Prior Year True Ups	38,455,349	78,752,397	52,116,450	169,324,196
\$ Increase/(Decrease) from 2014 to 2015	3,871,739	2,266,756	2,852,221	8,990,716
% Increase/(Decrease) from 2014 to 2015	10.1%	2.9%	5.5%	5.3%
2015 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	\$ (4,386,346)	\$ (3,053,121)	\$ (2,338,408)	\$ (9,777,875)
2014 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	805,723	1,871,196	(759,165)	1,917,754
\$ Increase/(Decrease) from 2014 to 2015	(5,192,069)	(4,924,317)	(1,579,243)	(11,695,629)
2015 Revenue Requirement Including Prior Year True-Ups	\$ 37,940,742	\$ 77,966,032	\$ 52,630,263	\$ 168,537,037
2014 Revenue Requirement Including Prior Year True-Ups	39,261,072	80,623,593	51,357,285	171,241,950
\$ Increase/(Decrease) from 2014 to 2015	(1,320,330)	(2,657,561)	1,272,978	(2,704,913)
% Increase/(Decrease) from 2014 to 2015	(3.4%)	(3.3%)	2.5%	(1.6%)

Projected 2015 Revenue Requirement for ISO NE
Administrative Cost Tariff Schedules
September 26, 2014
Page 2

Change in Revenue Requirement by Schedule

Before true-ups in 2015 and 2014, the 2015 Revenue Requirement reflects an overall increase of \$9.0M or 5.3% over the 2014 Revenue Requirement. By tariff schedule, the changes are: Schedule 1, a \$3.9M or 10.1% *increase*; Schedule 2, a \$2.3M or 2.9% *increase*; and Schedule 3, a \$2.8M or 5.5% *increase*.

The Tariff Schedule 1 increase of \$3.9M is attributable to:

- Funding for items that impact all three tariff schedules, including an increase for: Compensation (annual Merit and Promotion) and Benefits (Pension and Healthcare cost increases); Cyber Security Improvements; Computer Service Licensing and Maintenance; Energy Market Offer Flexibility (Hourly Market) Operating Costs; and Depreciation Expense for in service projects including Hourly Market, Business Continuity Planning Phase III, and a full year of the new Backup Control Center.
- Funding for items that are predominantly or entirely allocated to Schedule 1, including Operating Costs for Coordinated Transaction Scheduling, and Depreciation Expense for Coordinated Transaction Scheduling, Voltage Stability, and Control Room Visualization.

The Tariff Schedule 2 increase of \$2.3M is predominantly attributable to the increases that impact all three tariff schedules, as noted above in the explanation for Schedule 1. The increase was lessened by an overall reduction in Depreciation Expense for Schedule 2 as a result of previously implemented projects becoming fully depreciated during 2015, including Standard Market Design Upgrade Phase III, Automated Market Mitigation, and Generation Control Application Phase I.

The Tariff Schedule 3 increase of \$2.8M includes:

- NPCC and NERC Dues (including funding for the Eastern Interconnect Data Sharing Network) as well as Depreciation Expense for projects allocated entirely to Schedule 3, including Forward Capacity Auction (FCA) 9, Alternative Technologies and Regulation Market, and Forward Capacity Market Terminations and Retirements.
- Funding for items that impact all three tariff schedules, as noted above in the explanation for Schedule 1.
- The increase is partially offset by a reduction in FERC Order 1000 related costs, which are allocated entirely to Schedule 3.

The ISO 2015 Revenue Requirement will be reviewed and voted on at the October 3, 2014 NPC meeting. Should you have any questions regarding the information provided in this memo, do not hesitate to contact us.

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No.	Description		Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		<u>Administration-CEO</u>					
2	12651	Adm/Finance/HR - Indirect Administrative Support	Total Dir Labor	\$ 7,783,348	\$ 1,677,158	\$ 4,027,968	\$ 2,078,222
3	12652	Adm/Finance/HR - NEPOOL Committee Support	Total Dir Labor	2,990	644	1,547	798
4	12654	Adm/Finance/HR - National Committee Support	Total Dir Labor	13,679	2,947	7,079	3,652
5	12657	Adm/Finance/HR - Indirect Administrative Support for BCC	Total Dir Labor	660,747	142,378	341,944	176,425
6		Total		8,460,764	1,823,127	4,378,538	2,259,098
7							
8		<u>Finance</u>					
9	11601	Payroll Administration	Total Dir Labor	364,566	78,557	188,667	97,342
10	11701	Accounts Payable	Total Dir Labor	207,225	44,653	107,241	55,331
11	11702	Procurement	Total Dir Labor	498,029	107,315	257,735	132,978
12	11901	Billing for Transmission and Energy Settlements	Total Dir Labor	70,756	15,247	36,617	18,893
13	12001	Budgeting and Forecasting	Total Dir Labor	517,080	111,420	267,594	138,065
14	12005	Credit Administration	Total Dir Labor	342,981	73,906	177,496	91,579
15	12015	BCC Construction	Total Dir Labor	48,169	10,379	24,928	12,861
16	12017	Forward Capacity Market (FCM) Reforms	Alloc-Fixed	140,871	-	-	140,871
17	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	564,032	121,538	291,893	150,601
18	12201	Treasury and Cash Management	Total Dir Labor	2,420,884	521,651	1,252,834	646,397
19	92004	Depreciation Expense 2004 Assets	Alloc-Fixed	43,160	8,988	22,535	11,637
20	92005	Depreciation Expense 2005 Assets	Alloc-Fixed	802,617	169,813	417,365	215,439
21	92006	Depreciation Expense 2006 Assets	Total Dir Labor	570,895	123,028	295,438	152,429
22	92007	Depreciation Expense 2007 Assets	Total Dir Labor	165,460	35,657	85,626	44,178
23	92008	Depreciation Expense 2008 Assets	Alloc-Fixed	43,667	24,011	12,966	6,690
24	92009	Depreciation Expense 2009 Assets	Alloc-Fixed	41,416	24,240	12,948	4,228
25	92010	Depreciation Expense 2010 Assets	Alloc-Fixed	510,846	163,766	199,913	147,167
26	92011	Depreciation Expense 2011 Assets	Alloc-Fixed	2,642,552	522,364	888,163	1,232,024
27	92012	Depreciation Expense 2012 Assets	Alloc-Fixed	6,490,210	1,233,652	2,831,154	2,425,404
28	92013	Depreciation Expense 2013 Assets	Alloc-Fixed	7,527,261	1,386,217	3,615,157	2,525,887
29	92014	Depreciation Expense 2014 Assets	Alloc-Fixed	12,250,841	3,715,761	4,195,754	4,339,328
30	92015	Depreciation Expense 2015 Assets	Alloc-Fixed	561,394	127,989	279,022	154,383
31	99707	Amortization of Land Recovery	Alloc-Fixed	54,396	10,516	19,353	24,527
32	99995	NPCC/NERC Dues	Alloc-Fixed	5,775,936	-	-	5,775,936
33	99996	Operating Contingency	Total Dir Labor	700,000	150,836	362,258	186,906
34	99996	Operating Contingency	Total Dir Labor	1,100,000	237,028	569,262	293,710
35	99998	Payroll & Other Accruals	Total Dir Labor	8,811,695	1,898,746	4,560,149	2,352,800
36		Total		53,266,938	10,917,279	20,972,067	21,377,591
37							
38		<u>Building Services</u>					
39	12664	Building Maintenance	Total Dir Labor	3,546,150	764,125	1,835,172	946,853
40	12668	Building Maintenance - Offsite Temporary Offices	Total Dir Labor	-	-	-	-
41		Total		3,546,150	764,125	1,835,172	946,853
42							
43		<u>Enterprise Risk Management</u>					
44	22701	ERM -Enterprise Risk Mgmt - Admn	Alloc-Fixed	7,619	2,537	2,537	2,545
45	22703	ERM-Bus Cont Pl Prog Admin & Support	Alloc-Fixed	152,374	50,741	50,741	50,893
46	22704	ERM - Record Retention Services	Alloc-Fixed	92,989	30,965	30,965	31,058
47	22705	ERM - Corporate Scorecard	Alloc-Fixed	7,619	2,537	2,537	2,545
48	22706	ERM - Document Management Services	Alloc-Fixed	99,043	39,617	29,713	29,713
49	22708	ERM Administration	Total Dir Labor	7,619	1,642	3,943	2,034
50	22709	ERM Management	Total Dir Labor	80,208	17,283	41,508	21,416
51	22710	Employee Development	Total Dir Labor	22,856	4,925	11,828	6,103
52	22711	FAP Admin - FCM Cap Adjustments	Total Dir Labor	26,773	5,769	13,855	7,149
53	22712	FAP Admin - Risk Policy Assessments	Total Dir Labor	76,187	16,417	39,428	20,343
54	22713	FAP Admin - MEC/Financials	Total Dir Labor	33,522	7,223	17,348	8,951
55	22714	FAP Analysis	Total Dir Labor	121,899	26,267	63,084	32,548
56	22716	FAM Rebuild	Total Dir Labor	30,475	6,567	15,771	8,137
57	22718	CAPA 2.0	Total Dir Labor	137,137	29,550	70,970	36,617
58	22719	Human Performance Improvement	Total Dir Labor	1,524	328	789	407
59	22720	Business Process Change Management	Total Dir Labor	144,755	31,192	74,912	38,651
60	22721	Corp Strategic Risk	Total Dir Labor	38,093	8,208	19,714	10,171
61	22722	Corp Strategic Plan	Total Dir Labor	7,619	1,642	3,943	2,034
62	22725	OSHA procedures	Total Dir Labor	7,619	1,642	3,943	2,034
63	22726	Project Risk Management Meeting	Total Dir Labor	2,724	587	1,410	727
64	22727	ERM Business Analysis	Total Dir Labor	83,806	18,058	43,370	22,377
65	23003	CP - Safety / Security / Facilities	Total Dir Labor	22,856	4,925	11,828	6,103
66	23006	Business Continuity Planning	Total Dir Labor	38,093	8,208	19,714	10,171
67	25006	ERM - Business Process Maintenance	Alloc-Fixed	52,780	23,751	23,751	5,278
68	25011	Corrective Action/Preventive Action	Alloc-Fixed	290,544	96,751	96,751	97,042
69	25012	OE - Business Process Re-Engineering	Alloc-Fixed	1,524	507	507	509
70	25014	EtQ Tools Dev & Support	Total Dir Labor	102,143	22,010	52,860	27,273
71		Total		1,690,398	459,850	747,720	482,828

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No.	Description		Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		Human Resources					
2	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	24,668	5,315	12,766	6,586
3	12701	Recruiting/Interviewing	Total Dir Labor	458,427	98,782	237,241	122,404
4	12801	Employee Relations	Total Dir Labor	154,957	33,390	80,192	41,375
5	12901	Benefit Administration	Total Dir Labor	1,179,682	254,198	610,499	314,986
6	12951	Compensation	Total Dir Labor	302,994	65,289	156,803	80,902
7	12961	HR - General	Total Dir Labor	1,195,356	257,576	618,610	319,170
8	12962	HR - Training	Total Dir Labor	1,150,437	247,897	595,364	307,177
9	13410	Power Training & Development	Total Dir Labor	1,395,159	300,629	722,010	372,520
10	13411	Markets Training & Development	Total Dir Labor	344,304	74,191	178,181	91,932
11	13412	People Training & Development	Total Dir Labor	260,740	56,184	134,936	69,620
12	13413	Business Skills Trng & Dev	Total Dir Labor	290,602	62,619	150,390	77,593
13	13414	Technology Trng & Development	Total Dir Labor	682,111	146,981	353,000	182,130
14		Total		7,439,436	1,603,051	3,849,990	1,986,395
15							
16		Legal Department					
17	8301	GC - Federal Regulatory	Total Dir Labor	298,729	64,370	154,596	79,763
18	12423	GC - Financial Assurance Policy (FAP)	Total Dir Labor	12,007	2,587	6,214	3,206
19	12425	GC - Price Response Demand	Total Dir Labor	40,001	8,619	20,701	10,681
20	12502	Board of Directors	Total Dir Labor	148,039	31,899	76,612	39,528
21	12504	ISO Tariff Litigation	Total Dir Labor	63,279	13,635	32,748	16,896
22	12505	Administration of OATT	Alloc-Fixed	425,072	425,072	-	-
23	12508	Energy Markets/Compliants/Rule Changes	Alloc-Fixed	85,913	-	85,913	-
24	12509	Market Monitoring and Sanctions	Alloc-Fixed	100,232	-	50,116	50,116
25	12512	GC - BSIA - General Corporate	Total Dir Labor	59,990	12,927	31,046	16,018
26	12513	Miscellaneous Labor Matters	Total Dir Labor	156,002	33,615	80,733	41,654
27	12514	NEPOOL Participants Committee	Total Dir Labor	68,856	14,837	35,634	18,385
28	12517	Administrative and Clerical Support	Total Dir Labor	458,205	98,734	237,126	122,345
29	12520	Market Monitoring Rules/Regulations	Alloc-Fixed	315,016	-	126,006	189,010
30	12521	Billing Disputes	Total Dir Labor	35,999	7,757	18,630	9,612
31	12523	NEPOOL Information Policy	Total Dir Labor	42,957	9,256	22,231	11,470
32	12542	Transmission Upgrades CT	Alloc-Fixed	62,410	-	43,687	18,723
33	12543	Independent Market Advisor	Alloc-Fixed	883,000	-	618,100	264,900
34	12544	FERC Proceedings	Total Dir Labor	193,436	41,682	100,105	51,649
35	12552	GC - S&G - General Corporate	Total Dir Labor	235,586	50,764	121,918	62,903
36	12555	GC - Transmission Upgrades - VT	Total Dir Labor	3,002	647	1,553	802
37	12556	GC - Patents	Total Dir Labor	3,002	647	1,553	801
38	12559	General Corporate	Total Dir Labor	937,926	202,104	485,387	250,434
39	12562	Transmission Upgrades VT	Alloc-Fixed	13,194	-	9,236	3,958
40	12563	Regulatory Matters	Total Dir Labor	384,002	82,745	198,725	102,532
41	12565	GC - Conn Regulatory Matters - WBAM	Total Dir Labor	13,194	2,843	6,828	3,523
42	12569	NOPR / Rulemaking Comments	Total Dir Labor	35,999	7,757	18,630	9,612
43	12570	Operations	Total Dir Labor	12,007	2,587	6,214	3,206
44	12571	ISO Reporting	Total Dir Labor	12,007	2,587	6,214	3,206
45	12572	GC - BSAI - 205 General Proceedings	Total Dir Labor	35,999	7,757	18,630	9,612
46	12573	206 General Proceedings	Total Dir Labor	120,003	25,858	62,103	32,042
47	12574	Market Rule 1 Proceedings	Total Dir Labor	240,007	51,717	124,206	64,084
48	12575	Transmission Cost Allocation	Alloc-Fixed	90,008	-	63,006	27,003
49	12587	Capacity Market Development	Alloc-Fixed	474,684	-	-	474,684
50	12588	Web Content Management	Total Dir Labor	522,230	112,530	270,260	139,440
51	12592	GC - State Proceedings	Alloc-Fixed	240,007	-	120,003	120,003
52	12594	Maine Transmission Siting	Alloc-Fixed	30,577	-	21,404	9,173
53	12595	NEEWS Transmission Siting	Alloc-Fixed	2,940	-	2,058	882
54	12598	GC - ERO	Alloc-Fixed	35,999	14,399	14,399	7,200
55	12663	Public Information	Total Dir Labor	1,429,324	307,991	739,691	381,642
56	12669	Government Affairs	Total Dir Labor	1,704,015	367,182	881,847	454,987
57	12673	Market Conference	Total Dir Labor	999	215	517	267
58		Total		10,025,854	2,005,324	4,914,579	3,105,951
59							
60		Internal Audit					
61	15001	Audit - Indirect Mgmt Duties	Total Dir Labor	73,469	15,831	38,021	19,617
62	15002	Audit- Personnel Management	Total Dir Labor	17,112	3,687	8,856	4,569
63	15003	Audit- Budget & Forecasting	Total Dir Labor	8,556	1,844	4,428	2,285
64	15004	Audit- Audit Followup Activities	Total Dir Labor	8,556	1,844	4,428	2,285
65	15005	Audit - Audit & Finance Committee	Total Dir Labor	85,071	18,331	44,025	22,715
66	15006	Audit- Internal Audit Business Process Update	Total Dir Labor	8,556	1,844	4,428	2,285
67	15007	Audit- Annual Audit Work Plan	Total Dir Labor	43,194	9,307	22,353	11,533
68	15008	Audit-Training	Total Dir Labor	71,963	15,507	37,241	19,215
69	15020	Internal Audit - Finance	Total Dir Labor	42,781	9,218	22,140	11,423
70	15021	Audit- Performance Measurements	Total Dir Labor	25,669	5,531	13,284	6,854
71	15022	Audit- Vendor Contracts	Total Dir Labor	12,834	2,766	6,642	3,427
72	15023	Audit- Wire Transfers	Total Dir Labor	8,556	1,844	4,428	2,285
73	15040	Audit-Operations	Total Dir Labor	200,518	43,208	103,770	53,540
74	15065	Audit - Wind Integration Project	Alloc-Fixed	42,781	17,112	17,112	8,556
75	15068	Audit - FCM Settlements Audit	Alloc-Fixed	8,290	-	-	8,290
76	15085	Audit - Information Technology	Total Dir Labor	152,018	32,757	78,671	40,590
77	15090	Audit - Training	Total Dir Labor	1,298	280	672	347
78	15110	External Audit - Operations	Total Dir Labor	42,781	9,218	22,140	11,423
79	15133	Audit- Satellite Reviews	Total Dir Labor	46,063	9,926	23,838	12,299
80	15134	Audit- SCADA Operations Reviews	Total Dir Labor	1,651	356	854	441
81	15160	External Audit - Finance	Total Dir Labor	15,336	3,305	7,937	4,095
82	15161	External Audit- Pension Audit	Total Dir Labor	62,341	13,433	32,262	16,645
83	15162	Ext Audit- Financial Audit	Total Dir Labor	101,400	21,850	52,476	27,075
84	15166	Ext Audit -Pricing Module Certification	Alloc-Fixed	25,350	-	25,350	-
85	15175	Ext Audit - Info Technology	Total Dir Labor	15,600	3,361	8,073	4,165
86	15186	Ext Audit - SSAE 16 Direct Support	Total Dir Labor	34,225	7,375	17,712	9,138
87	15190	Int Audit Special Projects	Total Dir Labor	11,700	2,521	6,055	3,124
88	15192	IA Special Projects - Data Mining - Audit Command Language Impr	Total Dir Labor	16,614	3,580	8,598	4,436
89	25702	External Audit - SSAE 16	Alloc-Fixed	449,048	-	449,048	-
90	28160	Audit - MS Universal Access Gateway Review	Total Dir Labor	42,290	9,113	21,885	11,292
91		Total		1,675,620	264,947	1,086,726	323,947

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No.	Description		Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		COO-Adm					
2	19001	COO - NEPOOL Committee Support	Total OPS Labor	59,321	15,899	28,446	14,976
3	19002	COO - Regional Committee Support	Total OPS Labor	58,310	15,628	27,962	14,720
4	19003	COO - National Committee Support	Total OPS Labor	89,924	24,101	43,122	22,701
5	19005	COO - Indirect Supervision/Clerical Support	Total OPS Labor	1,144,639	306,781	548,894	288,964
6	19007	COO - Operational Excellence	Total OPS Labor	250,000	67,004	119,884	63,113
7	19009	COO - Renewable Resource Integration	Alloc-Fixed	113,448	-	-	113,448
8	19010	COO - Quality Improvement	Total OPS Labor	100,000	26,802	47,953	25,245
9		Total		1,815,643	456,214	816,261	543,167
10							
11							
12		System Operations - Administration					
13	14404	System Ops Mgt & Adm - NEPOOL Committee Support	SOA Labor	9,005	3,110	4,180	1,714
14	14405	System Ops Mgt & Adm - Indirect Supervision/Clerical Support	SOA Labor	271,349	93,724	125,960	51,665
15	14407	System Ops Mgt & Adm - Regional Committee Support	SOA Labor	9,005	3,110	4,180	1,714
16		Total		289,358	99,944	134,320	55,094
17							
18		Operations					
19	14001	Ops - Generation Dispatch	Alloc-Fixed	3,727,871	-	3,131,411	596,459
20	14002	Ops - Transmission Operations	Alloc-Fixed	2,351,539	1,881,231	117,577	352,731
21	14304	Ops - Advanced Scheduling and Forecasting	Alloc-Fixed	1,771,745	88,587	1,399,678	283,479
22	14402	Ops - Operations Training	Alloc-Fixed	2,123,325	849,330	849,330	424,665
23	14561	Ops - NEPOOL Committee Support	OPS Labor	10,190	2,849	5,642	1,700
24	14563	Ops - National Committee Support	OPS Labor	10,190	2,849	5,642	1,700
25	14564	Ops - Indirect Supervision/Clerical Support	OPS Labor	1,417,869	396,388	784,985	236,496
26	14565	Ops - Employee Development	OPS Labor	19,650	5,493	10,879	3,278
27	14702	TPC - Procedure Documentation	Alloc-Fixed	354,675	141,870	141,870	70,935
28		Total		11,787,053	3,368,597	6,447,014	1,971,442
29							
30		Reliability and Operations Services					
31	14703	TPC - NEPOOL Committee Support	OS Labor	330,858	183,782	63,963	83,114
32	14704	TPC - Regional Committee Support	OS Labor	14,241	7,910	2,753	3,577
33	14706	TPC - Indirect Supervision/Clerical Support	OS Labor	26,081	14,487	5,042	6,552
34	14711	ISO TMS Tariff-Section 2 - (OATT) and Agreements Support	Alloc-Fixed	212,871	70,886	70,886	71,099
35	14715	EIPC - Non DOE Funded/Unallowable	Alloc-Fixed	158,580	-	-	158,580
36	14813	ROC - ICP Policy/Procedure	Alloc-Fixed	77,052	30,821	30,821	15,410
37		Total		819,683	307,886	173,465	338,333
38							
39		Reliability and Operations Compliance					
40	14801	ROC - Compliance Monitoring	Alloc-Fixed	675,357	270,143	270,143	135,071
41	14803	ROC - Regional Committee Support	OS Labor	11,906	5,953	-	5,953
42	14804	ROC - National Committee Support	OS Labor	166,801	83,400	-	83,400
43	14806	ROC - Employee Development	Alloc-Fixed	19,693	10,939	3,807	4,947
44	14807	ROC - Compliance Audit	OS Labor	240,873	120,437	-	120,437
45	14808	ROC - Change Management	Alloc-Fixed	28,894	13,002	2,889	13,002
46	14809	ROC - Tariff Compliance	Alloc-Fixed	48,157	14,447	28,894	4,816
47	14810	ROC - NERC Self Certifications	Alloc-Fixed	20,855	17,726	-	3,128
48		Total		1,212,536	536,048	305,734	370,755
49							
50		Operations Support Services					
51	14451	TSO - NEPOOL Committee Support	TSO Labor	15,280	4,947	7,305	3,028
52	14452	TSO - Regional Committee Support	TSO Labor	15,532	5,028	7,426	3,078
53	14453	TSO - National Committee Support	TSO Labor	139,858	45,278	66,864	27,716
54	14454	TSO - Indirect Supervision/Clerical Support	TSO Labor	494,653	160,140	236,486	98,026
55	14462	OSS - General Systems Operations Support	TSO Labor	839,684	271,842	401,440	166,402
56	18361	OSS - Transmission Studies, Operations, OASIS Support	Alloc-Fixed	2,318,249	1,854,599	115,912	347,737
57	18381	OSS - Transmission Outage Appl - Short Term	Alloc-Fixed	1,114,557	891,646	55,728	167,184
58	18382	OSS - Trans Out Ap Lg Term	Alloc-Fixed	1,114,557	-	-	1,114,557
59		Total		6,052,369	3,233,480	891,162	1,927,728
60							
61		System Operations Support					
62	14752	SOS - National Committee Support	Alloc-Fixed	6,280	2,033	3,002	1,245
63	14757	Winter 2014/15 Reliability Project	Alloc-Fixed	330,587	-	66,117	264,470
64		Total		336,867	2,033	69,120	265,714
65							
66		Market Operations - Adm					
67	19101	MO - NEPOOL Committee Support	MOA Labor	19,948	-	13,964	5,985
68	19103	MO - National Committee Support	MOA Labor	14,071	-	9,850	4,221
69	19104	MO - Indirect Supervision/Clerical Support	MOA Labor	1,178,014	-	824,610	353,404
70	19105	Employee Development	MOA Labor	6,370	-	4,459	1,911
71	19112	Settlements - Customer Service	MOA Labor	4,145	-	2,901	1,243
72	19120	CEII Requests	Total Dir Labor	6,370	1,373	3,297	1,701
73		Total		1,228,918	1,373	859,080	368,465

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No.	Description		Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		<u>Market Monitoring</u>					
2	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	3,292,039	-	2,304,427	987,612
3	16102	Regulatory Activities	Alloc-Fixed	10,913	-	7,639	3,274
4	16111	Employee Development	MMM Labor	7,312	-	5,118	2,194
5	16115	Analysis & Internal Reports	MMM Labor	449,087	-	314,361	134,726
6	16121	FCM Market Monitoring	Alloc-Fixed	10,521	-	-	10,521
7		Total		3,769,871	-	2,631,545	1,138,326
8							
9		<u>Market Operations</u>					
10	21901	Day Ahead Market Administration	Alloc-Fixed	553,998	-	553,998	-
11	21902	Real Time Price Verification	Alloc-Fixed	443,198	-	443,198	-
12	21903	FTR/ARR Administration	Alloc-Fixed	18,467	9,233	9,233	-
13	21904	MA - NEPOOL Committee Support	MA Labor	39,903	-	38,643	1,260
14	21907	MA - Indirect Supervision/Clerical Support	MA Labor	447,233	-	433,110	14,123
15	21908	Employee Development	MA Labor	36,933	-	35,767	1,166
16	21909	Customer Support	MA Labor	18,467	-	17,883	583
17	21913	MA-Data Collection/Report Writing	Alloc-Fixed	295,465	-	295,465	-
18	21915	FTR/Auction Administration	Alloc-Fixed	295,465	-	295,465	-
19	21916	Forward Reserve Market - Administration	Alloc-Fixed	18,467	-	-	18,467
20	21917	Real Time Price Finalization	Alloc-Fixed	36,933	-	36,933	-
21	21951	FCM Annual Reconfiguration Auction Administration	Alloc-Fixed	18,467	-	-	18,467
22	21952	FCM Annual CSO Bilaterals Administration	Alloc-Fixed	18,467	-	-	18,467
23	21953	FCM Monthly Administration	Alloc-Fixed	295,465	-	-	295,465
24		Total		2,536,928	9,233	2,159,697	367,998
25							
26		<u>Market Analysis & Settlements</u>					
27	1701	Billing Statements - Energy	Alloc-Fixed	63,711	-	63,711	-
28	1702	Billing Statements - Transmission	Alloc-Fixed	68,024	68,024	-	-
29	1713	Billing Statements - ISO Tariff	Total Dir Labor	14,816	3,193	7,667	3,956
30	2036	MAS - Market Analysis - Projects	Alloc-Fixed	273	-	273	-
31	2037	MAS - Bill Job Aid	Alloc-Fixed	819	123	491	205
32	2039	MAS - BITT and Business Tools	Alloc-Fixed	4,492	674	2,695	1,123
33	2043	MAS - Release Checkout and Support	Alloc-Fixed	35,322	5,298	21,193	8,830
34	2044	MAS - EQR Reporting	Alloc-Fixed	537	81	322	134
35	2047	MAS - Score Card	Alloc-Fixed	6,800	1,006	3,312	2,482
36	2048	MAS - FCM	Alloc-Fixed	145,011	-	-	145,011
37	2049	MAS - Product Testing	Alloc-Fixed	7,420	-	5,936	1,484
38	2051	MAS - Legal Support	Alloc-Fixed	8,585	-	4,293	4,293
39	2052	MAS - FERC Data Request	Alloc-Fixed	10,536	-	5,268	5,268
40	2053	MAS - Tariff Change Coordination (TCC)	Total Dir Labor	167,134	36,017	86,492	44,625
41	2054	MAS - Markets Development Support	Alloc-Fixed	19,411	-	9,705	9,705
42	2005	Settlements - Customer Service	STLM Labor	140,285	20,745	68,338	51,201
43	2007	Settlements - Admin support - NEPOOL Committees	STLM Labor	29,557	4,371	14,398	10,788
44	2008	Settlements - Admin support (ISO)	STLM Labor	128,263	18,968	62,482	46,814
45	2009	Settlements - Indirect Supervision/Clerical Support	STLM Labor	826,643	122,244	402,689	301,710
46	2010	Settlements - Employee Development	STLM Labor	22,889	3,385	11,150	8,354
47	2013	Settlements - FTR Administration	Alloc-Fixed	17,517	-	17,517	-
48	2014	Billing Statements - NCP	Alloc-Fixed	160,100	-	80,050	80,050
49	2020	Settlements-Billing Disputes	Total Dir Labor	3,400	733	1,760	908
50	2021	Settlements-Analysis & Reporting	Total Dir Labor	276,617	59,605	143,152	73,859
51	2022	Settlements-Demand Response	Alloc-Fixed	12,111	-	-	12,111
52	2024	Settlements - ASM Regulation	Alloc-Fixed	18,535	-	-	18,535
53	2025	Settlements - ASM Locational Forward Reserve	Alloc-Fixed	91,080	-	-	91,080
54	2026	Settlements-Batch Processing	Total Dir Labor	26,323	5,672	13,622	7,028
55	2032	Settlements - Billing	STLM Labor	35,705	5,280	17,393	13,032
56	2033	Settlements - Market Analysis	Alloc-Fixed	81,868	-	81,868	-
57	2034	Settlements - COPQ	Alloc-Fixed	89,920	13,488	35,968	40,464
58		Total		2,513,702	368,906	1,161,745	983,050
59							
60		<u>Market Operations Support Services</u>					
61	3000	MOSS - Hourly Settlements Support	Alloc-Fixed	122,522	-	61,261	61,261
62	3002	MOSS - Monthly Settlements Support	Alloc-Fixed	93,874	46,937	-	46,937
63	3003	MOSS - Market Analysis Support	Alloc-Fixed	1,524	-	1,524	-
64	3004	MOSS - Generation & Load Admin Support	Alloc-Fixed	124,015	-	124,015	-
65	3005	MOSS - Demand Resource Admin Support	Alloc-Fixed	133,542	-	133,542	-
66	3006	MOSS - Customer Service	Alloc-Fixed	20,636	-	20,636	-
67	3007	MOSS - NEPOOL Committees Support	Alloc-Fixed	10,017	-	5,009	5,009
68	3008	MOSS - Admin Support	Alloc-Fixed	15,215	-	15,215	-
69	3009	MOSS - Indirect Supervision (Principal Analysts only)	Alloc-Fixed	20,480	-	20,480	-
70	3010	MOSS - Employee Development	Alloc-Fixed	44,643	-	44,643	-
71	3011	MOSS - Release Checkout and Support	Alloc-Fixed	9,705	-	9,705	-
72	3012	MOSS - FERC Data Request	Alloc-Fixed	6,114	-	6,114	-
73	3013	MOSS - Tariff Change Coordination (TCC)	Total Dir Labor	2,602	561	1,346	695
74	3014	MOSS - Markets Development Support	Alloc-Fixed	829	-	415	415
75		Total		605,717	47,498	443,903	114,316

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No.	Description		Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		<u>Market Services</u>					
2	16001	Participant/membership support	Alloc-Fixed	144,160	-	72,080	72,080
3	16006	Call Support (HEAT)	Alloc-Fixed	933,663	242,752	616,218	74,693
4	16403	MSS NEPOOL Market Committee	MS Labor	23,561	-	21,205	2,356
5	16419	Asset Registration Implemented	Alloc-Fixed	184,666	-	184,666	-
6	16420	Asset Registration Reivew	Alloc-Fixed	184,666	-	184,666	-
7	16421	C10/C30 Audits	Alloc-Fixed	128,791	-	108,184	20,607
8	16422	Claimed Capability Audits	Alloc-Fixed	36,933	-	36,933	-
9	16424	Demand Resource Audits	Alloc-Fixed	295,465	-	295,465	-
10	16425	DR Registration Implemented	Alloc-Fixed	36,933	-	36,933	-
11	16426	DR Registration Review	Alloc-Fixed	36,933	-	36,933	-
12	16429	MSS Business Analysis - Process Improvement	Alloc-Fixed	168,480	-	151,632	16,848
13	16432	New Generation Coordination and Registration	Alloc-Fixed	18,467	-	18,467	-
14	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	184,666	39,796	95,565	49,306
15	16435	Resource Performance Monitoring	Alloc-Fixed	36,933	-	36,933	-
16		Total		2,414,318	282,548	1,895,880	235,890
17							
18		<u>Market Training and Reliability Contracts</u>					
19	16021	Training Development	Alloc-Fixed	849,890	-	424,945	424,945
20	16024	Training Delivery	Alloc-Fixed	6,255	-	3,127	3,127
21		Total		856,145	-	428,072	428,072
22							
23		<u>Resource Adequacy</u>					
24	14315	PSR - Employee Development	PSR Labor	92,570	10,059	4,672	77,839
25	17101	PSR Analysis	Alloc-Fixed	739,574	-	517,702	221,872
26	17131	PSR - Calculate Objective Capability	Alloc-Fixed	140,871	-	-	140,871
27	17201	PSR Regulatory Liaison	Alloc-Fixed	43,737	-	13,121	30,616
28	17231	PSR Regulatory Filings	Alloc-Fixed	17,609	-	-	17,609
29	17241	PSR-Transmission Plan Admin Support	Alloc-Fixed	35,218	17,609	17,609	-
30	17251	PSR-Regional Bulk Power System Assessment	Alloc-Fixed	246,525	123,262	123,262	-
31	17331	PSR NEPOOL Committee Support	PSR Labor	91,696	9,964	4,627	77,105
32	17361	PSR Regional Committee Support	PSR Labor	35,218	3,827	1,777	29,614
33	17401	PSR Indirect Supervisory Activities	PSR Labor	105,834	11,500	5,341	88,994
34	17403	TCA Application Review	Alloc-Fixed	67,724	-	-	67,724
35	17404	Non-Transmission Alternative Analyses	Alloc-Fixed	35,218	-	17,609	17,609
36	17405	Energy Efficiency Forecast	Alloc-Fixed	35,218	-	-	35,218
37	17406	SP - North American Energy Standards Board (NAESB)	Alloc-Fixed	20,652	-	10,326	10,326
38	17407	SP - National Standards Work	Alloc-Fixed	18,826	-	9,413	9,413
39	17408	MA-EEAC	Total Dir Labor	19,435	4,188	10,057	5,189
40	17501	FCA - Evaluate Existing Resource De-list Bids	Alloc-Fixed	146,110	-	-	146,110
41	17502	FCA - Preliminary Review of Show of Interest Applications	Alloc-Fixed	70,436	-	-	70,436
42	17503	FCA - New Resource Qualification Support	Alloc-Fixed	271,860	-	-	271,860
43	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	52,827	-	-	52,827
44	17505	FCA - Perform Existing Resource Qualification	Alloc-Fixed	70,436	-	-	70,436
45	17507	FCA - Auctions & Filings	Alloc-Fixed	868,274	-	-	868,274
46	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	88,045	-	-	88,045
47	18101	LF - Develop Load Forecast	Alloc-Fixed	305,098	61,020	61,020	183,059
48	18121	SP - Operations Forecast Support	Alloc-Fixed	88,045	17,609	17,609	52,827
49	18131	LF - Other Load Forecasting Activities	Alloc-Fixed	35,218	7,044	7,044	21,131
50		Total		3,742,271	266,081	821,189	2,655,002
51							
52		<u>System Planning</u>					
53	18148	SP - NEPOOL Committee Support	Alloc-Fixed	43,851	-	43,851	-
54	18150	SP - Regional Transmission Expansion Plan	Alloc-Fixed	585,693	439,270	146,423	-
55	18152	States Requests	Alloc-Fixed	240,265	120,132	60,066	60,066
56	18401	SP - Regional Activities	Alloc-Fixed	278,199	278,199	-	-
57	18501	SP - Regulatory Activities	Alloc-Fixed	4,456	4,456	-	-
58	18521	SP - Employee Development	SP Labor	28,471	7,068	5,048	16,355
59	18531	SP - Indirect Supervision/Clerical Support	SP Labor	186,230	46,234	33,016	106,980
60	18562	SP - Project Management	Alloc-Fixed	70,436	70,436	-	-
61		Total		1,437,600	965,795	288,405	183,401
62							
63		<u>Transmission Planning</u>					
64	11201	System Design Task Force	Alloc-Fixed	26,945	26,945	-	-
65	18201	TR - Transmission System Assessment	Alloc-Fixed	3,191,325	3,191,325	-	-
66	18261	TR - Transmission Tariff Information Requirements	Alloc-Fixed	13,487	13,487	-	-
67	18301	TR - NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	104,379	104,379	-	-
68	18333	TR - General SIS/FS	Alloc-Fixed	980,048	980,048	-	-
69	18334	TR - Indirect Supervision/Clerical Support	TP Labor	604,639	604,639	-	-
70	18335	TR - Regulatory Activities - NPCC	TP Labor	154,233	154,233	-	-
71	18336	TR - National Activities	TP Labor	50,679	50,679	-	-
72	18337	TR - Regulatory Activities	TP Labor	134,204	134,204	-	-
73	18338	TR - Employee Development	TP Labor	87,057	87,057	-	-
74	18341	TR - NERC Compliance	TP Labor	35,668	35,668	-	-
75	18343	FERC Order 1000	Alloc-Fixed	959,012	-	-	959,012
76		Total		6,341,678	5,382,665	-	959,012

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No.	Description		Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		<u>Program Management</u>					
2	801	Program Management - Administration	Total Dir Labor	510,402	109,982	264,139	136,282
3	1661	ISO Program Management	Alloc-Fixed	337,731	-	236,411	101,319
4	25002	PMO Support	Alloc-Fixed	55,929	16,779	19,575	19,575
5	25822	System Restoration and Blackstart Resource Resource Mgmt	Alloc-Fixed	50,400	50,400	-	-
6	25902	Coordinated Transaction Scheduling - O&M	Alloc-Fixed	456,856	319,799	137,057	-
7	25912	Generation Auditing - Claim 10/30	Alloc-Fixed	9,883	-	-	9,883
8	25914	Divisional Accounting (for Market Participants)	Total Dir Labor	58,143	12,529	30,090	15,525
9	25919	Alternative Technologies & Regulation Market	Alloc-Fixed	171,828	-	-	171,828
10	25926	Hourly Market	Alloc-Fixed	748,903	299,561	224,671	224,671
11	25948	FCA 9	Alloc-Fixed	35,218	-	-	35,218
12	25953	ICCP and ED Network Upgrades	Alloc-Fixed	75,639	68,075	-	7,564
13	25955	Financial Assurance BI Integration	Alloc-Fixed	21,304	-	10,652	10,652
14		Total		2,532,237	877,125	922,595	732,517
15							
16		<u>Business Architecture and Technology</u>					
17	21201	Business Architecture and Technology	Total Dir Labor	2,261,344	487,275	1,170,270	603,799
18	21203	BAT - Employee Development	Total Dir Labor	12,648	2,725	6,546	3,377
19		Total		2,273,992	490,000	1,176,816	607,176
20							
21		<u>Market Development Administration</u>					
22	21001	Markets Development	Total Dir Labor	2,954,384	636,611	1,528,926	788,846
23	21002	MD - Indirect Supervision/Clerical Support	Total Dir Labor	75,854	16,345	39,255	20,254
24	21003	MD - Employee Development	Total Dir Labor	125,240	26,987	64,813	33,440
25	21005	MD - ICAP	Total Dir Labor	296,027	63,788	153,197	79,042
26	21007	MD - Budget/Forecast Support	Total Dir Labor	18,734	4,037	9,695	5,002
27	21009	Increased Scope of Impact Analysis	Alloc-Fixed	150,000	39,000	99,000	12,000
28	16607	National Committee Support	MD Labor	208,214	1,248	111,081	95,885
29		Total		3,828,452	788,015	2,005,968	1,034,469
30							
31		<u>Market Design</u>					
32	22601	MDes-Direct Supervision&Clerical	Total Dir Labor	47,069	10,143	24,359	12,568
33	22602	MDes-Committee Meetings	Total Dir Labor	288,938	62,260	149,529	77,149
34	22603	MDes-Employee Development	Total Dir Labor	5,352	1,153	2,770	1,429
35	22606	MDes-Market Analysis/Governing Documents	Total Dir Labor	281,321	60,619	145,587	75,115
36	22607	MDes - NEPOOL Markets Committee Administration	Alloc-Fixed	279,920	27,992	125,964	125,964
37		Total		902,601	162,167	448,208	292,225
38							
39		<u>Demand Resource Strategy</u>					
40	22401	Demand Response	Total Dir Labor	96,332	20,758	49,853	25,721
41	22402	DR-Regulatory Committees and Working Groups	Total Dir Labor	43,931	9,466	22,735	11,730
42	22404	RFP Linkages	Total Dir Labor	327,198	70,505	169,328	87,365
43	22409	DR - Winter Supplemental Program	Total Dir Labor	579	125	300	155
44		Total		468,040	100,853	242,216	124,971
45							
46		<u>IT Management</u>					
47	6517	Employee Development - Hardware/Software	Total Dir Labor	48,101	10,365	24,893	12,843
48	6519	Indirect Supervision and Clerical Support	Total Dir Labor	2,602,208	560,724	1,346,671	694,812
49	6552	IT - Security	Total Dir Labor	648,132	139,660	335,416	173,057
50	6556	IT - Budget Preparation, Tracking & Forecast	Total Dir Labor	174,075	37,510	90,086	46,480
51	6557	IT - Information Technology Committee	Total Dir Labor	22,187	4,781	11,482	5,924
52	22501	IT CM/QA - Change Management Support	Alloc-Fixed	89,168	40,126	40,126	8,917
53	22505	IT CM/QA - Administrative	Alloc-Fixed	345,553	117,488	114,032	114,032
54		Total		3,929,424	910,653	1,962,706	1,056,066
55							
56		<u>IT System/Network & Desktop</u>					
57	6510	Desktop Support - Hardware	Total Dir Labor	452,893	97,589	234,377	120,926
58	6511	Desktop Support - Software	Total Dir Labor	616,621	132,870	319,108	164,643
59	6512	Host Computer - Hardware	Alloc-Fixed	824,921	-	618,691	206,230
60	6513	Host Computer - Software	Alloc-Fixed	1,596,370	-	1,197,277	399,092
61	6514	Networking - Hardware	Total Dir Labor	359,607	77,488	186,101	96,018
62	6516	Communications	Total Dir Labor	1,511,307	325,657	782,118	403,532
63	6550	IT - Data Communications Support	Total Dir Labor	190,349	41,017	98,508	50,825
64	6602	Help Desk Support	Total Dir Labor	349,611	75,334	180,927	93,349
65	6615	IT - Host Computer Monitoring	Alloc-Fixed	1,174,719	-	587,359	587,359
66	6616	IT - Desktop Support	Total Dir Labor	528,569	113,896	273,540	141,132
67	6617	IT - System Administration - Unix	Total Dir Labor	675,155	145,483	349,400	180,272
68	6618	IT - System Administration - Windows	Total Dir Labor	877,775	189,143	454,258	234,374
69	6619	IT - Systems Support Misc	Total Dir Labor	103,248	22,248	53,432	27,568
70	6620	IT - Systems Support - Security	Total Dir Labor	241,436	52,025	124,946	64,466
71	6621	IT - Network Support	Total Dir Labor	377,835	81,416	195,534	100,885
72	6622	IT - Network/Systems Compliance 2009 Initiative	Total Dir Labor	6,637	1,430	3,435	1,772
73	6623	IT - Asset Management	Total Dir Labor	549,043	118,308	284,136	146,599
74		Total		10,436,097	1,473,904	5,943,148	3,019,046

Line No.	Activity Code		Allocation Factor (1)	Self-Funding Tariff			
	No.	Description		Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		<u>IT Cyber Security</u>					
2	6539	IT Policy/Procedures Program	Total Dir Labor	59,480	12,817	30,782	15,882
3	6540	IT Security Compliance and Reporting	Total Dir Labor	1,284,381	276,759	664,681	342,941
4	6540A	IT Controls Assessment	Total Dir Labor	32,238	6,947	16,683	8,608
5	6540B	IT Virus/Malware Reporting and Response	Total Dir Labor	10,746	2,316	5,561	2,869
6	6540D	IT Intrusion Monitoring and Response	Total Dir Labor	118,205	25,471	61,172	31,562
7	6540E	IT System Compliance Enhancement	Total Dir Labor	96,713	20,840	50,050	25,823
8	6541	IT Security SW Tools Program	Total Dir Labor	148,352	31,967	76,774	39,611
9	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	33,930	7,311	17,559	9,060
10	6544	Infragrad (FBI)	Total Dir Labor	98,010	21,119	50,721	26,170
11	6546	IT Internal Audit Support	Total Dir Labor	23,184	4,996	11,998	6,190
12	6547	IT - Security Training	Total Dir Labor	1,488	321	770	397
13	6548	CIP Compliance & Monitoring	Total Dir Labor	134,999	29,090	69,864	36,046
14		Total		2,041,727	439,952	1,056,616	545,159
15							
16		<u>IT Enterprise Applications Support</u>					
17	6571	DBA Support - MOPS	Total Dir Labor	1,741,165	375,187	901,072	464,906
18	6591	Data Architect - MOPS	Total Dir Labor	255,323	55,017	132,133	68,174
19	6594	IT Data Analyst	Total Dir Labor	344,381	74,207	178,221	91,953
20	6595	IT WEB Application Support	Total Dir Labor	414,337	89,281	214,424	110,632
21	6596	IT Data Governance	Total Dir Labor	172,190	37,104	89,110	45,976
22	21706	IT Markets Software Development - Enterprise	Total Dir Labor	368,980	79,508	190,951	98,521
23	21801	IT Markets Software Support - Settlements	Alloc-Fixed	649,981	-	519,985	129,996
24	21802	IT Markets Software Support - Publishing	Alloc-Fixed	258,961	-	207,168	51,792
25	21803	IT Markets Software Support - Finance	Alloc-Fixed	547,544	-	438,035	109,509
26	21804	IT Markets Software Support - Mitigation	Alloc-Fixed	239,986	-	191,989	47,997
27	21805	IT Markets Software Support - TSO	Total Dir Labor	341,464	73,579	176,711	91,174
28	21806	IT Markets Software Support - Enterprise	Total Dir Labor	1,416,807	305,294	733,213	378,300
29	21807	IT Markets Software Support - Planning	Alloc-Fixed	290,013	-	232,010	58,003
30	21808	IT CM/QA - Training Delivery to NON-IT	Alloc-Fixed	294,605	-	235,684	58,921
31	21809	IT CM/QA - Tools	Alloc-Fixed	40,549	-	32,439	8,110
32	21811	FSIT - Single Sign On Support	Alloc-Fixed	229,931	-	183,945	45,986
33	21818	Discoverer Support	Total Dir Labor	189,522	40,838	98,080	50,604
34	21819	Ceridian Support	Total Dir Labor	51,792	11,160	26,803	13,829
35	21821	Compliance Management	Total Dir Labor	118,237	25,478	61,189	31,570
36		Total		7,965,768	1,166,653	4,843,163	1,955,952
37							
38		<u>IT Energy Management Systems</u>					
39	21600	EMS - Indirect Supervision and Administration	Total Dir Labor	495,352	106,739	256,350	132,263
40	21601	EMS - Power System Modeling	Total Dir Labor	68,201	14,696	35,295	18,210
41	21603	EMS - Applications Support	Total Dir Labor	1,171,472	252,429	606,250	312,793
42	21604	EMS/DTS Support	Alloc-Fixed	1,236,045	988,836	247,209	-
43	21605	EMS - DAM Support	Alloc-Fixed	749,238	149,848	449,543	149,848
44	21606	EMS - Real-time Market Support	Alloc-Fixed	2,075,786	415,157	1,245,472	415,157
45	21607	EMS - Forecast Support	Alloc-Fixed	111,339	22,268	66,803	22,268
46		Total		5,907,432	1,949,972	2,906,921	1,050,539
47							
48		<u>IT Enterprise Applications Development</u>					
49	21707	Application Analysis and Conceptual Design	Alloc-Fixed	919,376	-	735,501	183,875
50	21710	ESD - Indirect Supervision and Administration	Alloc-Fixed	651,207	-	520,965	130,241
51	21711	EWR and CAPA Analysis	Alloc-Fixed	147,757	-	118,206	29,551
52		Total		1,718,340	-	1,374,672	343,668
53							
54		<u>IT Power System Modeling Management</u>					
55	21650	PSMM- Indirect Supervision and Administration	Total Dir Labor	121,999	26,291	63,135	32,574
56	21651	PSMM- Power System Modeling	Alloc-Fixed	768,214	307,285	307,285	153,643
57	21652	PSMM- System Application Support	Alloc-Fixed	176,500	70,600	70,600	35,300
58	21654	PSMM- NX9 Administration	Alloc-Fixed	276,854	110,742	110,742	55,371
59	21655	PSMM- ICCP Support	Alloc-Fixed	670,873	268,349	268,349	134,175
60	21656	PSMM- Transmission Project Management	Alloc-Fixed	23,152	18,521	4,630	-
61	21657	PSMM- Model On Demand Admin	Alloc-Fixed	342,861	-	-	342,861
62	21658	PSMM- Model on Demand Case Requests	Alloc-Fixed	64,532	-	-	64,532
63		Total		2,444,985	801,788	824,741	818,455
64							
65							
66		Total ISO		\$ 178,314,912	\$ 42,327,088	\$ 81,019,153	\$ 54,968,671

Exhibit 3

Table 8
Draft 2015 Rate Components (1)

Tariff Schedule	Jan. 1, 2015
(a)	(b)
Schedule 1	
Network Load (per kW-hour)	\$0.00021
Schedule 2	
TU Bids (Virtual Inc/Dec)	
Submitted	\$0.00500
Cleared	\$0.06000
FTR Bids	
Submitted	\$0.85853
Cleared	\$1.21377
TU's	
Block 1 - 1st 12,500	\$0.65101
Block 2 - Next 27,000	\$0.59182
Block 3 - Over 39,500	\$0.53264
Volumetric	
Block 1 - 1st 250,000	\$0.25517
Block 2 - Next 1,250,000	\$0.23197
Block 3 - Over 1,500,000	\$0.20877
Schedule 3	
R-T NCP Load Obligation	\$0.18763
Export Rate	\$0.37000

(1) From Exh 3, RCL-7, Sch 3.

New England States Committee on Electricity

2015 Budget Presentation

NEPOOL Budget & Finance Subcommittee
August 27, 2014

Background: Budget Review

Term Sheet Provision: "... the annual review of its [NESCOE's] proposed budgets by at least the NEPOOL Participants Committee will be limited to considerations of accounting and reconciliation, so long as spending remains within the boundaries established by those frameworks..... NESCOE will develop an operating budget recommendation for each year in consultation with NEPOOL, the PTO Administrative Committee and ISO-NE within the boundaries of the then-approved five year budget framework ..."

- ✓ Proposed 2015 budget conforms to:
 - 1) Boundaries of previously reviewed 5-year pro forma (2013 - 2017) supported in March 2012 by NEPOOL & filed and accepted by the FERC
 - 2) NESCOE commitment not to seek an increase over pro forma budget of more than 10% in any 1 year - 2015 proposed budget is *less than* 2015 pro forma budget (and *less than* the 2014 approved budget)
- ✓ As with prior audits, following calendar year 2013, independent auditor concluded NESCOE books conform to generally accepted accounting principles

Background: Policy Priorities

Term Sheet Provision Governing Identification of Policy Priorities

“Each year NESCOE will produce a *Report to the New England Governors* that will document its accomplishments from the preceding year and its projected policy priorities for the coming two years. This report will include a full accounting of spending by NESCOE during the preceding year and proposed budgets for each of the upcoming two years.”

Consistent with Term Sheet, *2013 Report to the New England Governors*:

- ✓ Reviewed work in 2013
- ✓ Projected policy priorities
- ✓ Provided spending from prior year
- ✓ Projected budget information for upcoming two years

Projected Policy Priorities

- ✓ In February 2014, NESCOE provided to the Governors the *2013 Annual Report to New England Governors*
- ✓ Report simultaneously released to NEPOOL & ISO-NE & circulated to the NEPOOL Participants Committee on February 25, 2014
- ✓ NESCOE identified forward looking policy priorities at Section V, pages 29-35.
<http://www.nescoe.com/uploads/2013AnnualReport.pdf>

New England States Committee on Electricity



*2013 Annual Report
to the New England Governors*

Projected Policy Priorities, Update

Gas-Electric and System Reliability Challenges: Pursuant to states' direction, advance potential solutions for diverse resources and infrastructure to resolve New England's energy infrastructure challenges.

Transmission Planning and Analysis: Continue to seek progress on enhancing consistency in regional system planning by using probabilities in developing base cases and to advance the draft transmission planning guides.

Distributed Generation Forecast: Ensure that consumers receive the full benefits of state policies and consumer investment in all forms of power generation technologies through a DG Forecast used appropriately in transmission planning, markets and operations.

Zonal Demand Curve Matters: Participate in the satisfactory resolution of matters related to the zonal demand curve.

FERC Order 1000: Rehearing Request pending. Way forward unclear. NESCOE will have central role in public policy process.

NESCOE Organization Status

Employees

- ✓ Diversity in academic training, skills; blend of private & public sector experience
- ✓ Current total employee level: 6

Office Space

- ✓ 4 Bellows Road, Westborough, MA
- ✓ Current lease runs through September 2015, anticipate renewing
- ✓ Also provides small group meeting space needs

Organizational Status, Con't.

Technical Consultants

Technical consultants, such as transmission engineers and economists, assist NESCOE in the regular course of business in analyzing ISO-NE studies & data

Continue work with technical consultants to conduct independent analysis to inform policymakers' decisions on key issues. Looking ahead, primary growth in spending will relate to increased use of consultants to conduct independent analysis for policymakers. For example,

- ✓ George Smith, PE - transmission engineer with New England experience
- ✓ Wilson Energy Economics - assistance with economic analysis
- ✓ PeterGFlynn, LLC - New England transmission infrastructure expertise

Legal Counsel

Litigation is not the primary means by which NESCOE seeks to accomplish its objectives & thus, greater resource & focus on technical consulting

- ✓ FERC Counsel: McCarter & English LLP (following merger with Miller, Balis & O'Neil, PC)

5 Year Pro Forma

Proposed 2015 budget conforms to 2015 budget in 5 year Pro Forma Framework

- 2015 Projected Budget in 5 Year Pro Forma: \$2,249,957
 (supported by NPC in March 2012 & filed and accepted by the FERC)
- 2015 Proposed Budget: \$2,093,615
- 2014 Budget, for reference: \$2,158,421

In relation to 2015 Pro Forma, 2015 Proposed Budget reflects:

- Reduction in assumed health and other benefit expenses based on experience
- Slight reduction in several general & administrative expenses, for example, office & travel

5 Year Pro Forma, for reference

NESCOE PRO FORMA BUDGET 2013-2017*

Expense Category	Year 6 (2013)	Year 7 (2014)	Year 8 (2015)	Year 9 (2016)	Year 10 (2017)
Salaries and Wages					
Salaries	800,000	824,000	848,720	874,182	900,407
Payroll Taxes	80,000	82,400	84,872	87,418	90,041
Health and Other Benefits	200,000	206,000	212,180	218,545	225,102
Retirement 401(k)	25,000	25,750	26,523	27,318	28,138
Total, Salaries and Wages	1,105,000	1,138,150	1,172,295	1,207,463	1,243,687
Direct Expenses - Consulting					
Technical Analysis	460,000	473,800	488,014	502,654	517,734
Legal (FERC)	125,000	128,750	132,613	136,591	140,689
Total Direct Expenses - Consulting	585,000	602,550	620,627	639,245	658,423
General and Administrative					
Rent	16,000	16,480	16,974	17,484	18,008
Utilities	4,000	4,120	4,244	4,371	4,502
Office and Administrative Expenses	42,000	43,260	44,558	45,895	47,271
Professional Services	71,000	73,130	75,324	77,584	79,911
Travel and Lodging	100,000	103,000	106,090	109,273	112,551
Total General and Administrative	233,000	239,990	247,190	254,605	262,244
Capital Expend. & Contingencies					
Office Furniture					
Computer Equipment	5,000	5,150	5,305	5,464	5,628
Contingencies	192,800	198,584	204,542	210,678	216,998
Total Capital Expend. & Contingencies	197,800	203,734	209,846	216,141	222,626
TOTAL EXPENSES**	2,120,800	2,184,424	2,249,957	2,317,455	2,386,979

*Based on projected 3% annual adjustment. Line items and categories subject to increases greater than, or decreases from, amounts projected.

Any such changes will be subject to review, input, and recommendations by the NEPOOL Participants Committee (and/or its designees).

**At no time during this 5-year period will NESCOE seek a budget increase of more than 10% in any 1 year or more than 30% on a cumulative basis.

2015 Proposed Budget

NESCOE Pro Forma Budget 2015

	2015
Salaries and Wages	
Salaries	899,602
Payroll Taxes	89,960
Health and Other Benefits	75,000
Retirement §401(k)	30,900
Total, Salaries and Wages	1,095,462
Direct Expenses - Consulting	
Technical Analysis	473,800
Legal (FERC)	128,750
Total, Direct Expenses, Consulting	602,550
General and Administrative	
Rent	18,566
Utilities	4,244
Office and Administrative Expenses	26,265
Professional Services	73,645
Travel and Lodging	77,250
Total General and Administrative	199,969
Capital Expend. & Contingencies	
<i>IT Equipment</i>	5,305
Contingencies	190,329
Capital Expend. & Contingencies	195,633
TOTAL EXPENSES	2,093,615
BUDGET	2,249,957

2013 & 2014 Spending & Implications for 2015

- ✓ Unspent funds in any year credited toward future years
- ✓ Expenses increasing over time, commensurate with increased substantive activity & analysis

2013 Total Spending: \$1,457,101

2014 Spending to end of July: \$757,274

2014 Projected Year End: \$1,494,986

projection subject to development of matters pending at FERC, such as Order 1000, other unanticipated matters that emerge and potential for state-level litigation by a NEPOOL Participant

2015 Projected Billing Rate

With thanks to ISO-NE for calculations -

2015 Budget: \$2,093,615

Less Prior Years' True Up: (\$2,093,615)

Total Revenue Recovery: \$ 0

Divided by Total Network Load: 251,024,419

*(total network load from 2014 ISO-NE tariff; no escalation or reduction
used in calculation)*

2015 Schedule 5 Estimated Rate: \$0.00000

Thank you.
Questions?

**NESCOE
Pro Forma Budget
2015**

	2015
Salaries and Wages	
Salaries	899,602
Payroll Taxes	89,960
Health and Other Benefits	75,000
Retirement §401(k)	<u>30,900</u>
Total, Salaries and Wages	<u>1,095,462</u>
Direct Expenses - Consulting	
Technical Analysis	473,800
Legal (FERC)	<u>128,750</u>
Total, Direct Expenses, Consulting	<u>602,550</u>
General and Administrative	
Rent	18,566
Utilities	4,244
Office and Administrative Expenses	26,265
Professional Services	73,645
Travel and Lodging	<u>77,250</u>
Total General and Administrative	<u>199,969</u>
Capital Expend. & Contingencies	
<i>IT Equipment</i>	5,305
Contingencies	<u>190,329</u>
Capital Expend. & Contingencies	<u>195,633</u>
TOTAL EXPENSES	<u><u>2,093,615</u></u>
<i>BUDGET</i>	2,249,957

MEMORANDUM

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: September 25, 2014

RE: FERC Order 784 Compliance Vote

At the October 3, 2014 Participants Committee meeting, you will be asked to vote on revisions to Schedule 3 of Section II of the ISO Tariff. On September 9, 2014, the FERC issued an order (the “September 9 Order”) rejecting the ISO’s December 27, 2013 Order 784 compliance filing. The FERC disagreed that the ISO had demonstrated that the ISO Tariff was consistent with or superior to the reforms directed by Order 784.¹ The FERC directed the ISO to incorporate a statement into the ISO Tariff that the ISO will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made “alternative comparable arrangements” as required by the schedule. The September 9 Order required the ISO to make a compliance filing with these changes within thirty days of the date of the order. The proposed changes to comply with that Order are included with this memorandum, together with the September 9 Order and a memorandum from the ISO regarding the Schedule 3 revisions.

The ISO presented the proposed Schedule 3 compliance revisions to the Transmission Committee for consideration at its September 23, 2014 meeting. The Transmission Committee voted, with no opposition,² to recommend Participants Committee support for the compliance revisions. This item would have been on the Consent Agenda but for the timing of the Transmission Committee vote.

The following resolution could be used for Participants Committee consideration of this matter:

RESOLVED, that the Participants Committee supports the proposed revisions to Schedule 3 of Section II of the ISO Tariff as recommended by the Transmission Committee and as reflected in the materials distributed to the Participants Committee for its October 3, 2014 meeting, together with[any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

¹ The FERC also denied the ISO’s request to waive Order 784’s new data posting requirements.

² Three (3) abstentions were noted in the Publicly Owned Entity Sector.

SCHEDULE 3

REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service (automatic generator control or AGC) is necessary to provide for continuous balancing of resources (generation and interchange) with load, and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the ISO and this service will be available to all Transmission Customers that have a load obligation in the New England Markets pursuant to Market Rule 1. The Transmission Customer must either take this service from the ISO through the New England Markets or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The ISO Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the ISO Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

Charges for this Service shall be determined on the basis of offers submitted by Market Participants in accordance with Market Rule 1. The transmission service required with respect to Regulation and Frequency Response Service will be paid for as part of Regional Network Service or Through or Out Service by all Market Participants and other entities that have a load obligation in the New England Markets Pursuant to Market Rule 1. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.



memo

To: Transmission Committee

From: Monica Gonzalez and Bill Henson

Date: September 17, 2014

Subject: Compliance with September 9, 2014 Order re Order No. 784 Requirements

At the September 23, 2014, Transmission Committee, ISO New England Inc. (the “ISO”) will be presenting, and **requesting the Transmission Committee’s support of**, revisions to Schedule 3 (Regulation and Frequency Response Service) of the ISO Open Access Transmission Tariff (“ISO OATT”) that are necessary to comply with the Federal Energy Regulatory Commission’s (“Commission”) directives in an order issued on September 9, 2014 (included in the materials).

For background, on December 27, 2013, in Docket No. ER14-877-000, the ISO submitted to the Commission a compliance filing in response to Order No. 784 (included in the materials). As pertinent here, Order No. 784 required Transmission Providers to revise Schedule 3 of the *pro forma* OATT to incorporate a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made “alternative comparable arrangements” as required by the schedule. The order also required Transmission Providers to post on OASIS one- and ten- minute historical data on Area Control Error (“ACE”). In its compliance filing, the ISO proposed not to adopt the new Schedule 3 provision on the basis that the current Tariff provisions were consistent with or superior to the *pro forma* OATT and requested a waiver from the ACE data posting requirement.

The September 9 Order rejected the ISO’s compliance filing and directed the ISO to file by October 9, 2014, revisions to Schedule 3 reflecting the *pro forma* language adopted in Order No. 784, and requiring the ISO to post historical ACE on its OASIS. Accordingly, the ISO has revised Schedule 3 of the ISO OATT to incorporate the *pro forma* language adopted in Order No. 784, with a minor deviation – namely, to replace the term “Transmission Provider” with “ISO”, which is the term that is currently used in the ISO OATT’s Schedule 3. A redlined draft of the ISO OATT Schedule 3 is included in the materials.

As the ISO’s compliance filing is due on October 9th, the ISO requests the Transmission Committee’s consideration and support of the proposed changes at its September 23rd meeting. The proposed revisions will be included in the materials for the October 3rd meeting of the Participants Committee.

Should you have any questions, please do not hesitate to contact Bill Henson (whenson@iso-ne.com) or Monica Gonzalez (mgonzalez@iso-ne.com).

148 FERC ¶ 61,180
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
and Norman C. Bay.

ISO New England Inc.

Docket No. ER14-877-000

ORDER REJECTING COMPLIANCE FILING

(Issued September 9, 2014)

1. On December 27, 2013, ISO New England (ISO-NE) submitted a filing intended to comply with the requirements of Order No. 784.¹ In its compliance filing, ISO-NE argues that its current Transmission, Markets and Services Tariff (Tariff) provisions are consistent with or superior to the *pro forma* Open Access Transmission Tariff (OATT) and requests waiver from the Area Control Error data posting requirements of Order No. 784. As discussed below, we reject ISO-NE's compliance filing and deny its requested waiver.

I. Background

2. On July 18, 2013, the Commission issued Order No. 784 to foster competition and transparency in ancillary services markets. In Order No. 784, the Commission explained that, under the then-current *pro forma* OATT, Transmission Customers considering using their own or third-party resources to self-supply Regulation Service are required to demonstrate to the public utility Transmission Provider that they have made "alternative comparable arrangements."² However, the Commission noted that the then-current *pro forma* OATT provided no information as to how such a determination would be made, and contained no express obligation on the part of the Transmission Provider to

¹ *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Order No. 784, 78 Fed. Reg. 46,178 (July 30, 2013), FERC Stats. & Regs. ¶ 31,349 (2013), *order on clarification*, Order No. 784-A, 146 FERC ¶ 61,114 (2014).

² Order No. 784, FERC Stats. & Regs. ¶ 31,349 at P 112.

consider the relative speed and accuracy of resources a customer might desire to use in self-supplying Regulation Service. Given this lack of clarity in the *pro forma* OATT, the Commission found that if the performance characteristics of a Transmission Provider's regulation resources differed from those of a customer's regulation resources, the Transmission Provider may under- or overstate the regulation reserve requirements and impair a Transmission Customer's ability to self-supply Regulation Service at the lowest possible cost.³ The Commission determined that certain reforms were necessary to address this potential undue discrimination in the provision of Regulation Service.⁴

3. Thus, relevant here, Order No. 784 requires that each public utility Transmission Provider add to its OATT Schedule 3 (Regulation and Frequency Response Service) a *pro forma* statement that:

The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.⁵

4. In addition, to aid the Transmission Customer's ability to make an "apples-to-apples" comparison of regulation resources, Order No. 784 amended Part 37 of the Commission's regulations⁶ to require each public utility Transmission Provider to post historical one- and ten-minute Area Control Error data on its Open Access Same-Time Information System (OASIS).⁷

³ *Id.*

⁴ *Id.* P 111.

⁵ *Id.* at Appendix B.

⁶ 18 C.F.R. § 37.6(k) (2014).

⁷ Order No. 784, FERC Stats. & Regs. ¶ 31,349 at P 1, 116.

5. As further detailed below, in its compliance filing, ISO-NE asserts that its existing Tariff is consistent with or superior to Order No. 784's OATT requirements and that therefore it need not file Tariff language in that regard. ISO-NE also seeks waiver of the posting requirement of Area Control Error data.

II. Notice of Filing and Responsive Pleadings

6. Notice of ISO-NE's compliance filing was published in the *Federal Register*, 79 Fed. Reg. 820 (2013), with interventions, comments, and protests due on or before January 17, 2014. The New England Power Pool Participants Committee, Exelon Corporation, and Northeast Utilities Service Company filed timely motions to intervene. No comments or protests were filed.

III. Discussion

A. Procedural Matters

7. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2014), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

B. Substantive Matters

1. Speed and Accuracy of Regulation Resources

a. Compliance Filing

8. In its compliance filing, ISO-NE declines to add to its Tariff Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation Service, as required by Order No. 784. Instead, ISO-NE asserts that the provisions of its Tariff governing ISO-NE's regulation market are consistent with or superior to the reforms directed by Order No. 784 and that it is unnecessary for ISO-NE to implement the Order No. 784 changes.⁸

9. ISO-NE argues that the Order No. 784 reforms primarily seek to help Transmission Customers who want to self-supply Regulation Service under Schedule 3 of the *pro forma* OATT and to address the potential for undue discrimination in the provision of Regulation Service for Transmission Customers who want to self-supply that service. ISO-NE contends that it neither provides Regulation Service with resources that it owns, nor provides Regulation Service at cost-based rates. ISO-NE asserts that, instead, it operates a competitive regulation market that is effective in achieving efficient

⁸ ISO-NE Compliance Filing at 3.

clearing prices to procure the least-cost Regulation Service, such that a Transmission Customer is highly unlikely to realize a financial benefit from self-supplying Regulation Service with resources that it owns or operates. ISO-NE explains that, for this reason, no market participants in ISO-NE currently exercise their option to self-supply Regulation Service.⁹

10. ISO-NE contends that although ISO-NE's Schedule 3¹⁰ includes the *pro forma* Schedule 3 language describing the basic purpose of Regulation Service, ISO-NE does not rely on Schedule 3 to provide Regulation Service, and ISO-NE's Schedule 3 does not include a "rate." ISO-NE states that its Schedule 3 instead cross-references to the ISO-NE regulation market rules for Regional Network Service¹¹ and Through or Out Service.¹² ISO-NE argues that it is therefore unnecessary to add language to Schedule 3 that merely describes what ISO-NE's Commission-approved market rules regarding Regulation Service already govern with significantly more detail.¹³

11. ISO-NE further asserts that its regulation market rules already take into account the speed and accuracy of regulation resources. First, ISO-NE contends that it audits regulation resources to assess their historical performance and ensure that they can perform adequately to provide Regulation Service. Second, ISO-NE contends that its regulation assessment software determines the optimal set of generating units required to meet the regulation requirement for a given period¹⁴ and will therefore tend to call on faster and more accurate regulation resources to ramp up and down more frequently and quickly, resulting in a larger revenue opportunity for the market participant owning such resources.¹⁵

12. Lastly, ISO-NE argues that inserting the precise new *pro forma* Schedule 3 language may create confusion. ISO-NE explains that it determines its regulation reserve requirement by a historical analysis of regulation needs in the prior month and prior year

⁹ *Id.* at 5.

¹⁰ ISO-NE, Tariff, § II.H, Schedule 3 Regulation and Frequency Response Service, 1.0.0.

¹¹ ISO-NE, Tariff, § II.H, Schedule 9 Regional Network Service, 1.0.0.

¹² ISO-NE, Tariff, § II.H, Through or Out Service - The Pool PTF Rate, 1.0.0.

¹³ ISO-NE Compliance Filing at 5.

¹⁴ ISO-NE, Tariff, § III.1 Market Operations, § III.1.10.1A(e), 19.0.0.

¹⁵ ISO-NE Compliance Filing at 6.

before using its regulation market to procure the optimal set of resources to meet that requirement. However, ISO-NE notes that the new *pro forma* Schedule 3 language states that the Transmission Provider will take into account the speed and accuracy of regulation resources “in its determination of Regulation and Frequency Response reserve requirements”¹⁶ ISO-NE argues that inserting the new *pro forma* Schedule 3 language into ISO-NE’s Schedule 3 may create confusion because, while ISO-NE takes into account speed and accuracy in selecting the resources to meet the regulation reserve requirement, speed and accuracy are not the sole factors in first determining the regulation reserve requirement itself.¹⁷

b. Commission Determination

13. We find that ISO-NE has failed to demonstrate that the existing Tariff is consistent with or superior to the reforms directed by Order No. 784. The first sentence of the new *pro forma* Schedule 3 language required by Order No. 784 reads as follows: “The Transmission Provider will take into account the speed and accuracy of regulation resources in its *determination of Regulation and Frequency Response reserve requirements*, including as it reviews *whether a self-supplying Transmission Customer has made alternative comparable arrangements*.”¹⁸ This language thus pertains to the Transmission Provider’s determination of both the system-wide regulation reserve requirement that must be purchased from the Transmission Provider (or, as relevant here, from a regulation market) and the alternative requirement applicable to any individual self-supplying Transmission Customer. We address ISO-NE’s arguments pertaining to each of these two aspects below.

14. With respect to self-supplying Transmission Customers, ISO-NE argues that because it operates an effective, competitive regulation market in which no market participants currently opt to self-supply Regulation Service, it is therefore unnecessary to insert the new *pro forma* Schedule 3 language into the Tariff. However, while no market participants currently choose to self-supply Regulation Service, they are nonetheless permitted to do so and may well choose to do so in the future. In that eventuality, a market participant requesting to self-supply deserves the same protection against discrimination as any other Transmission Customer. For that reason, we disagree that it is unnecessary for ISO-NE to insert the new *pro forma* Schedule 3 language into its Tariff.

¹⁶ *Id.* at 7 (citing Order No. 784, FERC Stats. & Regs. ¶ 31,349 at Appendix B).

¹⁷ *Id.* at 8.

¹⁸ Order No. 784, FERC Stats. & Regs. ¶ 31,349 at Appendix B (emphasis added).

15. With respect to ISO-NE's determination of the system-wide regulation reserve requirement that must be met through its regulation market, we disagree with ISO-NE's argument that inserting the new *pro forma* Schedule 3 language may create confusion. First, as ISO-NE explains, ISO-NE determines its regulation reserve requirement by a historical analysis that includes consideration of Control Performance Standard-1 (CPS-1)¹⁹ and Control Performance Standard-2 (CPS-2)²⁰ scores based on the prior month. ISO-NE states that this historical review allows the regulation requirements to vary with changing system conditions in order to meet ISO-NE's CPS-1 and CPS-2 requirements and to be based on the historical performance of regulation resources.²¹ Given this consideration of the historical performance of regulation resources, we do not agree that inclusion of the new *pro forma* Schedule 3 language would create confusion. The historical performance of regulation resources certainly includes their speed and accuracy, so ISO-NE's stated practice is not at odds with the new *pro forma* Schedule 3 language. Second, the new *pro forma* Schedule 3 language is neither at odds with nor limits ISO-NE's ability to take into account several factors, in addition to speed and accuracy, in determining the regulation reserve requirement itself. While the *pro forma* language requires that the speed and accuracy of resources be taken into account, those are not the only factors a Transmission Provider may consider. We are therefore not persuaded that inclusion of the new *pro forma* Schedule 3 language in the Tariff will introduce confusion. Accordingly, we reject ISO-NE's compliance filing and direct ISO-NE to submit a compliance filing within 30 days of the date of this order to insert the new *pro forma* Schedule 3 language regarding consideration of the speed and accuracy of resources into Schedule 3 of the Tariff.

¹⁹ ISO-NE's System Operating Procedures state the following: "[CPS-1] is a statistical measure of [Area Control Error] variability and its relationship to frequency error, providing a measure of the [Reliability Coordinator Area]/[Balancing Authority Area] performance. The measure is intended to provide the [Reliability Coordinator Area]/[Balancing Authority Area] with a frequency-sensitive evaluation of how well the respective [Reliability Coordinator Area]/[Balancing Authority Area] met its demand requirements." ISO-NE, System Operating Procedures – Real-Time Markets, SOP-RTMTKS.0170.0020, Manage Resource and Demand Balancing at 3.

²⁰ ISO-NE's System Operating Procedures state the following: "[CPS-2] is a statistical measure designed to limit unacceptably large net unscheduled power flows. [CPS-2] relates to a bound on the ten-minute average of [Area Control Error], providing an oversight function to limit excessive unscheduled power flows that could result from large [Area Control Errors]." *Id.*

²¹ ISO-NE Compliance Filing at 7.

2. Area Control Error Data Posting

a. Compliance Filing

16. ISO-NE requests that the Commission waive the Area Control Error data posting requirements of Order No. 784. ISO-NE argues that the Commission created those requirements to aid a Transmission Customer in comparing a Transmission Provider's regulation resources with those of the Transmission Customer itself when considering whether to self-supply Regulation Service. ISO-NE contends that none of its market participants self-supply Regulation Service and that a market participant that owns or operates a resource that can provide Regulation Service would likely be financially advantaged by offering into the regulation market instead of self-supplying.²²

17. ISO-NE argues that, in addition, Area Control Error data would provide little value to a market participant in New England that is considering self-supplying Regulation Service. ISO-NE explains that the automatic generation control set-point that a resource receives from ISO-NE to provide Regulation Service is derived from a complicated, non-linear function that includes Area Control Error data, but also includes other factors as well, including the mix of other resources that are online and providing Regulation Service simultaneously. ISO-NE argues that the complicated, non-linear relationship between Area Control Error and automatic generation control means that it is inefficient, and potentially misleading, to rely on Area Control Error data to design a resource to provide Regulation Service in New England.²³

18. Finally, ISO-NE argues that Area Control Error data will have even less value once ISO-NE implements its Order No. 755 compliance changes in 2014. ISO-NE explains that the Tariff language accepted by the Commission in compliance with Order No. 755 provides that ISO-NE will have a "regulation resource test environment that allows market participants to evaluate or demonstrate the performance of a resource without an operational history of providing regulation prior to participation in the regulation market."²⁴ ISO-NE further explains that the introduction of new resources into the regulation market in this manner will render historical Area Control Error data even less valuable for purposes of designing or comparing resources to provide Regulation Service in New England.²⁵

²² *Id.* at 10.

²³ *Id.* at 9.

²⁴ *Id.* (citing ISO-NE, Tariff, § III.14, Regulation Market, 2.0.0 § 14.9).

²⁵ *Id.*

b. Commission Determination

19. We deny ISO-NE's request to waive the new data posting requirements of Order No. 784 and direct ISO-NE to post historical one-minute and ten-minute Area Control Error data on its Open Access Same-Time Information System, consistent with the requirements of Order No. 784, within 30 days of the date of this order.

20. ISO-NE argues that posting Area Control Error data is unnecessary because no market participants in New England currently choose to self-supply Regulation Service and that posting the data would provide little value to a market participant considering self-supplying Regulation Service due to the complexity of the relationship between the Area Control Error and the automatic generation control set-point in ISO-NE. We disagree. As discussed above, simply because no market participant chooses to self-supply today does not mean that no market participant will ever choose to do so. In addition, the benefits of access to Area Control Error data, in terms of greater transparency and enhanced ability to compare resources, extend to a market participant that is merely considering self-supplying Regulation Service. A market participant that does not currently self-supply could be assessing the benefits and costs of doing so. Denying such a market participant access to the Area Control Error data limits these potential benefits.

21. As to ISO-NE's assertion that Area Control Error data would have little value to a market participant in New England that wants to self-supply, we find this rationale insufficient to justify a waiver. So long as a market participant in New England may opt to self-supply Regulation Service and access to Area Control Error data may provide some positive value to that participant, we find it appropriate for ISO-NE to post such data, consistent with the requirement of Order No. 784.

The Commission orders:

(A) ISO-NE's compliance filing is hereby rejected, as discussed in the body of this order.

(B) ISO-NE's request for waiver of the Area Control Error data posting requirement is hereby denied, as discussed in the body of this order.

Docket No. ER14-877-000

- 9 -

(C) ISO-NE is hereby directed to submit a compliance filing within 30 days of the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.



memo

To: NEPOOL Participants Committee

From: Erin Wasik-Gutierrez, Secretary
NEPOOL Transmission Committee

Date: September 25, 2014

Subject: **ACTIONS OF THE TRANSMISSION COMMITTEE**

This memo is notification to the Participants Committee of the actions taken by the Transmission Committee at its September 23, 2014 meeting. The following actions were taken, with oppositions and abstentions noted:

Agenda Item No. 2: Transmission Committee Meeting Minutes

It was moved and seconded to approve the July 22, 2014 meeting minutes of the Transmission Committee.

The motion to approve the minutes passed unanimously, based on a show of hands.

Agenda Item No. 3: Follow-up Compliance with Order No. 784 – Regulation and Frequency Response Service

RESOLVED, that the Transmission Committee recommends that the Participants Committee support the amendments to Schedule 3 – Regulation and Frequency Response Service of Section II of the ISO New England Transmission, Markets and Services Tariff to comply with Order No. 784 as directed by the Federal Energy Regulatory Commission in its order issued on September 9, 2014, as proposed by ISO New England Inc. and as circulated for the September 23, 2014 Transmission Committee meeting and as modified at that meeting with such further non-substantive changes as the Chair and Vice-Chair of the Transmission Committee subsequently approve.

The motion to recommend Participants Committee support passed, based on a show of hands, with three (“3”) abstentions from the Publicly Owned sector.

cc: Transmission Committee

blank

MEMORANDUM

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: September 26, 2014

RE: FCA9 ICR Values Vote

At the October 3, 2014, Participants Committee you will be asked to vote on proposed megawatt values for Installed Capacity Requirements (“ICR Values”) for the Forward Capacity Auction for the 2018/2019 Capacity Commitment Period. The ICR Values are used to determine how much capacity is procured in the Forward Capacity Auction. Background materials from the ISO are included with this memorandum.

The ISO’s proposed ICR Values include the following components: New England Installed Capacity Requirement (ICR), the capacity requirement values for the System-Wide Capacity Demand Curve (Demand Curve) and the Connecticut, NEMA/BOSTON and SEMA/RI Local Sourcing Requirements (LSR) for the Forward Capacity Auction for the 2018/2019 Capacity Commitment Period, which are as follows in megawatts: Installed Capacity Requirement 35,142; Net Installed Capacity Requirement (Net ICR) 34,189; 1-in-5 LOLE Demand Curve capacity value 33,132; 1-in-87 LOLE Demand Curve capacity value 37,027; Connecticut Local Sourcing Requirement 7,331; NEMA/Boston Local Sourcing Requirement 3,572; and SEMA/RI Local Sourcing Requirement 7,479.

At its September 16, 2014 meeting the Reliability Committee considered and voted to recommend Participants Committee support for the ICR Values (with four oppositions). This item was initially included as part of the Consent Agenda but was removed for inclusion on the discussion agenda at the request of VELCO.

The following resolution could be used for Participants Committee consideration of this matter:

RESOLVED, that the Participants Committee supports the ISO’s proposed ICR Values (New England Installed Capacity Requirement, system-wide capacity demand curve values and local sourcing requirements) for the Forward Capacity Auction for the 2018/2019 Capacity Commitment Period, as recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its October 3, 2014 meeting, together with[any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

	2018/2019 Values (MW)
Installed Capacity Requirement	35,142
Net Installed Capacity Requirement (Net ICR)	34,189
1-in-5 LOLE Demand Curve capacity value	33,132
1-in-87 LOLE Demand Curve capacity value	37,027
Connecticut Local Sourcing Requirement	7,331
NEMA/Boston Local Sourcing Requirement	3,572
SEMA/RI Local Sourcing Requirement	7,479

SEPTEMBER 16, 2014 | WESTBOROUGH MA

Proposed Values for the Installed Capacity Requirement (ICR) & Related Values for the 2018/19 Forward Capacity Auction (FCA9)



Maria Scibelli



Objective of this Presentation

- Review the ICR development and FERC filing schedules
- Review the proposed ICR Values for calculating:
 - Installed Capacity Requirement (ICR),
 - Transmission Security Analysis (TSA),
 - Local Resource Adequacy Requirement (LRA),
 - Local Sourcing Requirement (LSR), and
 - Maximum Capacity Limit (MCL)**
 - Capacity requirement values for the System-Wide Capacity Demand Curve (Demand Curve)

*The ICR, LSR, MCL and requirements for the Demand Curve points are collectively the ICR Values

**At the 8/28/2014 PSPC Meeting ISO-NE presented an analysis showing that Maine will not be a Capacity Zone for FCA9



ICR Review and FERC Filing Schedule

- ICR for 2018/19 Forward Capacity Auction (FCA9)
 - PSPC to review Capacity Zone determinations – **Jun 30, 2014**
 - PSPC final review of all assumptions – **Jul 24, 2014**
 - PSPC review of ISO recommendation of ICR Values – **Aug 28, 2014**
 - RC review/vote of ISO recommendation of ICR Values – **Sep 16, 2014**
 - PC review/vote of ISO recommendation of ICR Values – **Oct 3, 2014**
 - File with the FERC – by **Nov 5, 2014**
 - FCA9 begins – **Feb 2, 2015**



PROPOSED ICR VALUES FOR THE 2018/19 FCA

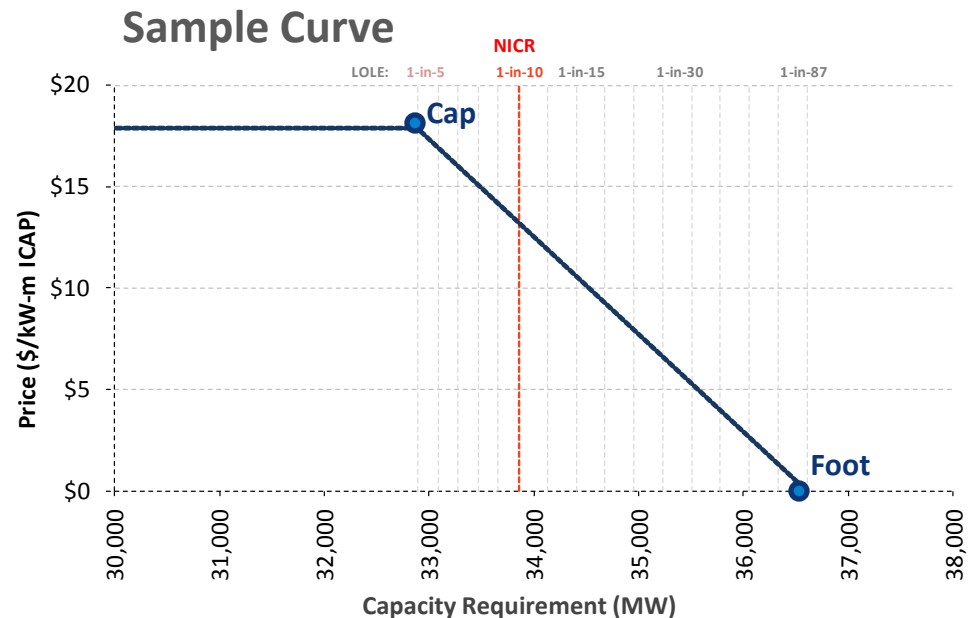
System-Wide Capacity Demand Curve

- Beginning in FCA9, ISO-NE will calculate the quantity parameters associated with the System-Wide Capacity Demand Curve

Curve Price-Quantity Parameters :

Cap [1-in-5 LOLE Demand Curve capacity value ,
Max (1.6 x Net CONE, Gross CONE)]

Foot [1-in-87 LOLE Demand Curve capacity value,
\$0]



- The Demand Curve capacity values are the capacity requirement values net of Hydro-Quebec Interconnection Capability Credits (HQICCs)
- The Demand Curve capacity values are calculated at 1-in-5 LOLE and 1-in-87 LOLE in addition to Net ICR at the 1-in-10 LOLE

ISO Proposed ICR Values for the 2018/19 FCA (MW)

2018/19 FCA	New England	Connecticut	NEMA/Boston	SEMA/RI
Peak Load (50/50)	30,005	7,725	6,350	5,910
Existing Capacity Resources*	32,842	9,239	3,868	6,984
Installed Capacity Requirement	35,142			
NET ICR (ICR Minus 953 MW HQICCs)	34,189			
1-in-5 LOLE Demand Curve capacity value	33,132			
1-in-87 LOLE Demand Curve capacity value	37,027			
Local Sourcing Requirements		7,331	3,572	7,479

*Existing Capacity Resources consists of capacity resources used in the ICR Values calculation and excludes HQICCs for New England.

*In addition to the Existing Capacity Resources shown, proxy units are required in the following amounts:

- ICR Calculation = 1,600 MW
- 1-in-5 LOLE Demand Curve capacity value calculation = 400 MW
- 1-in-87 LOLE Demand Curve capacity value calculation = 4,400 MW
- SEMA/RI LRA Calculation = 800 MW

Comparison of ICR Values (MW)

- 2018/19 Vs 2017/18 FCA

	New England		Connecticut		NEMA/Boston		SEMA/RI	
	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA
Peak Load (50/50)	30,005	29,790	7,725	7,650	6,350	6,260	5,910	-
Existing Capacity Resources*	32,842	35,443	9,239	9,768	3,868	3,685	6,984	-
Installed Capacity Requirement	35,142	34,923						
NET ICR (ICR Minus HQICCs)	34,189	33,855						
1-in-5 LOLE Demand Curve capacity value	33,132	-						
1-in-87 LOLE Demand Curve capacity value	37,027	-						
Local Resource Adequacy Requirement			7,268	7,319	3,129	2,968	7,479	-
Transmission Security Requirement			7,331	7,273	3,572	3,428	7,116	-
Local Sourcing Requirement			7,331	7,319	3,572	3,428	7,479	-

*Existing Capacity Resources consists of capacity resources used in the ICR Values calculation and excludes HQICCs for New England.

*In addition to the Existing Capacity Resources shown for the 2018/19 FCA, proxy units are required in the following amounts:

- ICR Calculation = 1,600 MW
- 1-in-5 LOLE Demand Curve capacity value calculation = 400 MW
- 1-in-87 LOLE Demand Curve capacity value calculation = 4,400 MW
- SEMA/RI LRA Calculation = 800 MW

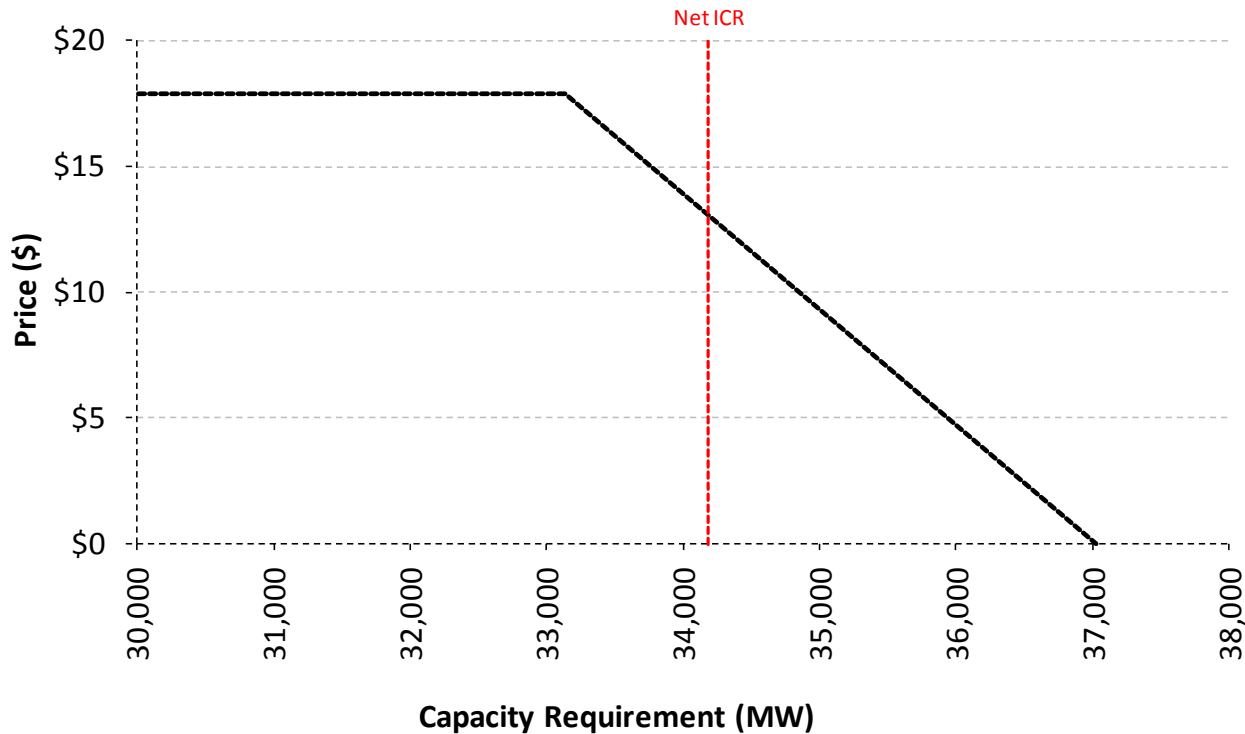
ICR Calculation Details

Total Capacity Breakdown	1-in-5	2018/19 FCA ICR	1-in-87
Generating Resources	29,829	29,829	29,829
Tie Benefits	1,970	1,970	1,970
Imports/Sales	(41)	(41)	(41)
Demand Resources	3,054	3,054	3,054
OP4 - Action 6 & 8 (Voltage Reduction)	441	441	441
Minimum Reserve Requirement	(200)	(200)	(200)
Proxy Unit Capacity	400	1,600	4,400
Total Capacity	35,453	36,653	39,453
Installed Capacity Requirement Calculation Details	1-in-5	2018/19 FCA ICR	1-in-87
Annual Peak	30,005	30,005	30,005
Total Capacity	35,453	36,653	39,453
Tie Benefits	1,970	1,970	1,970
HQICCs	953	953	953
OP4 - Action 6 & 8 (Voltage Reduction)	441	441	441
Minimum Reserve Requirement	(200)	(200)	(200)
ALCC	99	222	175
Installed Capacity Requirements	34,085	35,142	37,980
Net ICR	33,132	34,189	37,027
Reserve Margin with HQICCs	13.6%	17.1%	26.6%
Reserve Margin without HQICCs	10.4%	13.9%	23.4%

$$\text{Installed Capacity Requirement (ICR)} = \frac{\text{Capacity} - \text{Tie Benefits} - \text{OP4 Load Relief}}{1 + \frac{\text{ALCC}}{\text{APk}}} + \text{HQICCs}$$

- All values in the table are in MW except the Reserve Margin shown in percent
- ALCC is the “Additional Load Carrying Capability” used to bring the system to the target Reliability Criterion

System-Wide Capacity Demand Curve for FCA9



Cap [1-in-5 LOLE Demand Curve capacity value = 33,132 MW, 1.6 x Net CONE]

Foot [1-in-87 LOLE Demand Curve Capacity value = 37,027 MW , \$0]

- Slope of the Demand Curve is calculated as $(y_2 - y_1) / (x_2 - x_1)$
 $= (\$17.73 - \$0) / (33,132\text{MW} - 37,027\text{MW}) = -.005 \text{ \$/MW}$

Effect of Updated Assumptions on ICR

Assumption	2018/2019 FCA		2017/2018 FCA		Effect on ICR (MW)
Tie Benefits & Updated External Interface Outage Assumptions	346 MW New York		227 MW New York		-213
	523 MW Maritimes		492 MW Maritimes		
	953 MW Quebec (HQICCs)		1068 MW Quebec (HQICCs)		
	148 MW Quebec via Highgate		83 MW Quebec via Highgate		
Total	1,970 MW		1,870 MW		
	MW	Weighted Forced Outage	MW	Weighted Forced Outage	
Generation & IPR	29,699	6.5%	32,098	5.8%	178
Demand Resources	3,054	4.0%	3,416	5.8%	-85
Imports	89	0.0%	89	0.0%	0
	MW		MW		
Load Forecast	30,005		29,790		348
	MW	%	MW	%	
OP 4 5% VR	441	1.50%	432	1.50%	-9
	MW		MW		
ICR	35,142		34,923		219

- Methodology: Begin with model for the 2017/18 FCA ICR calculation. Change one assumption at a time and note the change in ICR caused by each change in assumption.
- While the increase in the 50/50 load forecast is 215 MW, the decrease in the ALCC is 309 MW. This means that the system requires 348 MW of additional capacity to meet the load forecast in 2018/19 versus 2017/18

FCA #9 TSA Requirements

FCA #9 TSA Requirements	Connecticut	NEMA/Boston	SEMA-RI
2014 Sub-area 90/10 Load*	8,415	6,835	6,465
Reserves (Largest unit or loss of import capability)	1,225	1,412	700
Sub-area Transmission Security Need	9,640	8,247	7,165
Sub-area Existing Resources	9,239	3,868	6,984
Assumed Unavailable Capacity	-808	-190	-723
Sub-area N-1 Import Limit	2,950	4,850	786
Sub-area Available Resources	11,381	8,528	7,047

$$\begin{aligned}
 \text{TSA Requirement*} &= (9640-2950)/(1-808/9239) \quad (8247-4850)/(1-190/3868) \quad (7165-786)/(1-723/6984) \\
 &= \mathbf{7,331} \qquad \qquad \qquad = \mathbf{3,572} \qquad \qquad \qquad = \mathbf{7,116}
 \end{aligned}$$

*The 90/10 peak load for the sub-area differs slightly from the 90/10 peak load for the Load Zone.

NOTE: All values have been rounded off to the nearest whole number

FCA #9 – FCA #8 TSA Requirements Comparison

	FCA 8 TSA Requirement (MW)		FCA 9 TSA Requirement (MW)	
	Connecticut	NEMA/Boston	Connecticut	NEMA/Boston
Sub-area 2013 & 2014 90/10 Load (for FCA 8 & FCA 9 respectively)	8,330	6,745	8,415	6,835
Reserves (Largest unit or loss of import capability)	1,200	1,395	1,225	1,412
Sub-area Transmission Security Need	9,530	8,140	9,640	8,247
Existing Resources	9,768	3,685	9,239	3,868
Assumed Unavailable Capacity	-729	-149	-808	-190
Sub-area N-1 Import Limit	2,800	4,850	2,950	4,850
Sub-area Available Resources	11,839	8,386	11,381	8,528

TSA Requirement 7,273 3,428 7,331 3,572

- 2017-18 FCA TSA Requirement values were presented during the September 18, 2013 Reliability Committee Meeting.



LRA - Connecticut

Local Resource Adequacy Requirement - Connecticut			
Connecticut Zone		2018/19 FCA	2017/18 FCA
Resource _z	[1]	9,239	9,768
Proxy Units _z	[2]	0	0
Firm Load Adjustment _z	[3]	1,825	2,282
FOR _z	[4]	0.074	0.068
LRA _z	[5]=[1]+[2]-([3]/(1-[4]))	7,268	7,319
Rest of New England Zone			
Resource	[6]	23,603	25,675
Proxy Units	[7]	1,600	0
Firm Load Adjustment	[8] = -[3]	-1,825	-2,282
Total System Resource	[9]=[1]+[2]-[3]+[6]+[7]-[8]	34,442	35,443

- All values in the table are in MW except the FOR_z
- Resources for Rest of New England excludes HQICCs

LRA – NEMA/Boston

Local Resource Adequacy Requirement - NEMA/BOSTON			
NEMA/BOSTON Zone		2018/19 FCA	2017/18 FCA
Resource _z	[1]	3,939	3,685
Proxy Units _z	[2]	0	0
Firm Load Adjustment _z	[3]	775	685
FOR _z	[4]	0.042	0.044
LRA _z	[5]=[1]+[2]-([3]/(1-[4]))	3,129	2,968
Rest of New England Zone			
Resource	[6]	28,903	31,758
Proxy Units	[7]	1,600	0
Firm Load Adjustment	[8] = -[3]	-775	-685
Total System Resource	[9]=[1]+[2]-[3]+[6]+[7]-[8]	34,442	35,443

- All values in the table are in MW except the FOR_z
- Resources for Rest of New England excludes HQICCs

LRA – SEMA/RI

Local Resource Adequacy Requirement - SEMA/RI			
NEMA/BOSTON Zone		2018/19 FCA	2017/18 FCA
Resource _z	[1]	6,984	-
Proxy Units _z	[2]	800	-
Firm Load Adjustment _z	[3]	278	-
FOR _z	[4]	0.090	-
LRA _z	[5]=[1]+[2]-([3]/(1-[4]))	7,479	-
Rest of New England Zone			
Resource	[6]	25,857	-
Proxy Units	[7]	800	-
Firm Load Adjustment	[8] = -[3]	-278	-
Total System Resource	[9]=[1]+[2]-[3]+[6]+[7]-[8]	34,442	-

- All values in the table are in MW except the FOR_z
- Resources for Rest of New England excludes HQICCs

MCL - Maine

Local RA Requirement - RestofNewEngland (for Maine MCL calculation)			
Rest of New England Zone		2018/19 FCA	2017/18 FCA
Resource _z	[1]	29,289	31,850
Proxy Units _z	[2]	1,600	0
Surplus Capacity Adjustment _z	[3]	250	1,570
Firm Load Adjustment _z	[4]	323	268
FOR _z	[5]	0.067	0.060
LRA _z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))]	30,275	29,894
Maine Zone			
Resource	[7]	3,552	3,593
Proxy Units	[8]	0	0
Surplus Capacity Adjustment _z	[9]	-250	-1,570
Firm Load Adjustment	[10] = -[4]	-323	-268
Total System Resource	[11]=[1]+[2]-[3]-[4]+[7]+[8]-[9]-[10]	34,442	35,443
Maximum Capacity Limit - Maine			
Commitment Period		2018/19 FCA	2017/18 FCA
ICR for New England	[1]	34,189	33,855
LRA _{RestofNewEngland}	[2]	30,275	29,894
Maximum Capacity Limit _y	[3]=[1]-[2]	3,913	3,960

- At the 8/28/2014 PSPC Meeting ISO-NE presented an analysis showing that Maine will not be a Capacity Zone for FCA9
- Maine-New Hampshire transmission transfer capability export limit used in the analysis is 1,900 MW
- All values in the table are in MW except the FOR_z
- Resources for Rest of New England excludes HQICCs

Questions



Assumptions for the 2018/19 FCA ICR Values Calculation



Modeling the New England Control Area

The New England ICR is calculated using the GE MARS model

- Internal transmission constraints are not modeled. All loads and resources are assumed to be connected to a single electric bus.
- Internal transmission constraints are addressed through LSR and MCL
- For FCA9, LSR is calculated for the Connecticut, NEMA/Boston Load Zones and SEMA/RI combined Load Zones. MCL will be calculated for the Maine Load Zone as a final step in the review of capacity zone determination for Maine, however, currently Maine is not expected to be export constrained



Assumptions for the ICR Calculations

- *Load Forecast*
 - Load Forecast distribution
- *Resource Data Based on Existing Qualified Capacity Resources for FCA9*
 - Generating Capacity Resources
 - Intermittent Power Capacity Resources
 - Import Capacity Resources
 - Demand Resources (DR)
- *Resource Availability*
 - Generating Resources Availability
 - Intermittent Power Resources Availability
 - Demand Resources Availability
- *Load Relief from OP 4 Actions*
 - Tie Reliability Benefits
 - Quebec
 - Maritimes
 - New York
 - 5% Voltage Reduction



Resources with Higher Summer than Winter Qualified Capacity

- Market Rule III.13.1.2.2.5.2. relating to requirements for an Existing Generating, Demand or Import Capacity Resource which has a Higher Summer Qualified Capacity than Winter Qualified Capacity must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or *(ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity*
- Resources in this situation can submit a composite offer in late September or they will have their Qualified Capacity decreased according the MR quoted above on October 20th. ISO-NE will not know the exact MWs of the reduced capacity in time to remove them from the model for the FCA9 ICR calculation.
- Table below summarizes the MWs of Qualified Capacity that may potentially be removed from the FCA9 Existing Qualified Capacity but will be included in the ICR model

Demand Resources		265.211
	Passive	207.536
	RTDR	47.507
	RTEG	10.168
Generators		53.452
	Non-Intermittent	53.452
	Intermittent	-
Imports		0
Total MWs		318.663

Load Forecast Data

- **Load forecast assumption from the 2014 CELT Report Load Forecast**
- **The load forecast weather related uncertainty is represented by specifying a series of multipliers on the peak load and the associated probabilities of each load level occurring**
 - derived from the 52 weekly peak load distributions described by the expected value (mean), the standard deviation and the skewness.



Load Forecast Data – New England System Load Forecast

Monthly Peak Load (MW) – 50/50 Forecast

Year	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
2018/19	26,860	30,005	30,005	24,805	19,090	20,840	23,195	23,195	22,080	20,575	18,460	21,355

There is a distribution associated with each monthly peak. The distribution associated with the Summer Seasonal Peak (July & August) is show below:

Probability Distribution of Annual Peak Load (MW)

Year	10/90	20/80	30/70	40/60	50/50	60/40	70/30	80/20	90/10	95/5
2018/19	29,045	29,275	29,510	29,935	30,005	30,310	30,860	31,310	32,430	33,120



Resource Data – Generating Capacity Resources (MW)

Load Zone	Non-Intermittent Generation		Intermittent Generation		Total	
	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	2,888.145	3,054.733	267.626	392.759	267.626	392.759
NEW HAMPSHIRE	4,070.494	4,273.306	167.628	222.733	167.628	222.733
VERMONT	255.102	294.141	79.038	121.579	79.038	121.579
CONNECTICUT	8,255.015	8,722.159	186.092	202.197	186.092	202.197
RHODE ISLAND	1,861.432	2,070.641	4.684	6.435	4.684	6.435
SOUTH EAST MASSACHUSETTS	4,471.042	4,934.675	75.866	77.907	75.866	77.907
WEST CENTRAL MASSACHUSETTS	3,880.929	4,128.907	59.642	93.077	59.642	93.077
NORTH EAST MASSACHUSETTS & BOSTON	3,235.563	3,642.555	70.231	72.023	70.231	72.023
Total New England	28,917.722	31,121.117	910.807	1,188.710	29,828.529	32,309.827

- Existing Qualified generating capacity resources for FCA9
- Intermittent resources have both summer and winter values modeled; non-Intermittent winter values provided for informational purpose
- A 30 MW derating is applied to Citizens Block Load (modeled as a generator) to reflect the value of the Vermont Joint Owners (VJO) contract

Resource Data – Import Capacity Resources (MW)

Import Resource	Qualified Summer MW	External Interface
VJO - Highgate	6.000	Hydro-Quebec Highgate
NYPA - CMR	68.800	New York AC Ties
NYPA - VT	14.000	New York AC Ties
Total MW	88.800	

- Existing Qualified Import capacity resources for FCA9
- A 30 MW derating is applied to Citizens Block Load (modeled as a generator) to reflect the value of the VJO contract
- System-backed imports modeled as 100% available

Resource Data – Export Delist (MW)

Export	Summer MW
LIPA via CSC	100.000

- Based on Administrative Delist Bid
- Modeled as removed capacity from the resource supplying the export



Resource Data – Demand Resources (MW)

Load Zone	On-Peak		Seasonal Peak		RT Demand Response		RT Emergency Gen		Total	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	176.925	164.463	0.000	0.000	207.892	225.787	11.802	9.299	396.619	399.549
NEW HAMPSHIRE	94.951	75.500	0.000	0.000	18.707	17.987	14.022	12.045	127.680	105.532
VERMONT	125.420	118.277	0.000	0.000	37.007	44.940	2.866	2.866	165.293	166.083
CONNECTICUT	80.728	58.930	324.316	279.113	254.510	227.087	138.338	137.824	797.892	702.954
RHODE ISLAND	172.704	166.857	0.000	0.000	57.595	54.064	33.540	29.149	263.839	250.070
SOUTH EAST MASSACHUSETTS	252.710	229.658	0.000	0.000	38.785	36.911	15.962	15.962	307.457	282.531
WEST CENTRAL MASSACHUSETTS	260.352	239.112	52.968	40.916	91.799	85.422	27.798	27.244	432.917	392.694
NORTH EAST MASSACHUSETTS & BOSTON	486.312	461.435	0.000	0.000	50.189	46.711	26.099	25.871	562.600	534.017
Total New England	1,650.102	1,514.232	377.284	320.029	756.484	738.909	270.427	260.260	3,054.297	2,833.430

- Existing Qualified Demand Resource capacity for FCA9
- Includes the Transmission and Distribution (T&D) Loss Adjustment (Gross-up) of 8%.

Sub-area Resource and Load Assumptions Used in LRA and MCL Calculations (MW)

Type of Resource	New England	Connecticut	NEMA/Boston	SEMA/RI
Generating Resources	28,787.722	8,255.015	3,235.563	6,332.474
Intermittent Power Resources	910.807	186.092	70.231	80.550
Passive Demand Resources	2,027.386	405.044	486.312	425.414
Active Demand Resources	1,026.911	392.848	76.288	145.882
Import Resources	88.800	-	-	-
Total MW Modeled	32,841.626	9,238.999	3,868.394	6,984.320
Load Forecast 50/50	30,005	7,725	6,350	5,910

- Resources for New England excludes HQICCs
- Load and generating resource assumptions are for the corresponding RSP area used as a proxy for the load zone. DR values are the load zone values.
- New England needs an additional 1,600 MW of proxy units to perform the ICR calculation
- SEMA/RI needs an additional 800 MW of proxy units to perform the LRA analysis

FCA #9 TSA Assumptions

- Load Forecast Data
 - 2014 CELT forecast
 - Connecticut sub-area 90/10 peak load*: 8,415 MW
 - Boston sub-area 90/10 peak load*: 6,835 MW
 - SEMA-RI sub-area 90/10 peak load*: 6,465 MW
- Resource Data
 - Generating Capacity
 - Connecticut sub-area existing qualified capacity: 8,441 MW
 - Includes 6,730 MW of regular generation resources, 186 MW of intermittent generation resources and 1,526 MW of peaking generation resources
 - Boston sub-area existing qualified capacity: 3,306 MW
 - Includes 2,938 MW of regular generation resources, 70 MW of intermittent generation resources and 297 MW of peaking generation resources
 - SEMA-RI sub-area existing qualified capacity: 6,413 MW
 - Includes 6,084 MW of regular generation resources, 81 MW of intermittent generation resources and 249 MW of peaking generation resources

*The 90/10 peak load for the sub-area differs slightly from the 90/10 peak load for the Load Zone.

NOTE: All values have been rounded off to the nearest whole number

FCA #9 TSA Assumptions, *cont.*

- Resource Data
 - Passive Demand Resources
 - Connecticut sub-area existing qualified capacity: 405 MW
 - Boston sub-area existing qualified capacity: 486 MW
 - SEMA-RI sub-area existing qualified capacity: 425 MW
 - Non-RTEG Active Demand Resources
 - Connecticut sub-area existing qualified capacity: 255 MW
 - Boston sub-area existing qualified capacity: 50 MW
 - SEMA-RI sub-area existing qualified capacity: 96 MW
 - Real-Time Emergency Generation
 - Connecticut sub-area existing qualified capacity: 138 MW
 - Boston sub-area existing qualified capacity: 26 MW
 - SEMA-RI sub-area existing qualified capacity: 50 MW

NOTE: All values have been rounded off to the nearest whole number



FCA #9 TSA Assumptions, *cont.*

- Resource Unavailability Assumptions
 - Regular Generation Resources - Weighted average EFORD
 - Connecticut sub-area: 8%
 - Boston sub-area: 8%
 - SEMA-RI sub-area: 11%
 - Peaking Generation Resources - Operational de-rating factor: 20%
 - Passive Demand Resources: 0%
 - Non-RTEG Active Demand Resources - De-rating based on performance factors
 - Connecticut sub-area: 18%
 - Boston sub-area: 19%
 - SEMA sub-area: 16%
 - RI sub-area: 15%
 - Real-Time Emergency Generation - De-rating based on performance factors
 - Connecticut sub-area: 15%
 - Boston sub-area: 11%
 - SEMA sub-area: 16%
 - RI sub-area: 10%

NOTE: All values have been rounded off to the nearest whole number

LRA & TSA Internal Transmission Transfer Capability Assumptions (MW)

- Transfer Limits – 2014 Regional System Plan (RSP) for 2018/19
 - Internal Transmission Transfer Capability
 - Connecticut Import
 - N-1 Limit: 2,950 MW
 - N-1-1 Limit: 1,750 MW
 - Boston Import
 - N-1 Limit: 4,850 MW
 - N-1-1 Limit: 4,175 MW
 - SEMA/RI Import
 - N-1 Limit: 786 MW
 - N-1-1 Limit: 473 MW
- Boston Import includes the impact of the Salem Harbor station retirement and the inclusion of the advanced NEMA/Boston upgrades. The effect of the addition of the Footprint generation project on the Boston import capability will be evaluated at a future date and will not be reflected in the LSR calculations for FCA9.
- The New England East-West Solution (NEEWS) is expected to be in-service by 12/2015 and has been certified and accepted by ISO-NE to be included in FCA9 analyses.



Availability Assumptions - Generating Resources

- **Forced Outages Assumption**

- Each generating unit's Equivalent Forced Outage Rate on Demand (non-weighted EFORD) modeled
- Based on a 5-year average (Jan 2009 – Dec 2013) of generator submitted Generation Availability Data System (GADS) data
- NERC GADS Class average data is used for immature units

- **Scheduled Outage Assumption**

- Each generating unit weeks of Maintenance modeled
- Based on a 5-year average (Jan 2009 – Dec 2013) of each generator's actual historical average of planned and maintenance outages scheduled at least 14 days in advance
- NERC GADS Class average data is used for immature units



Availability Assumptions - Generating Resources

Resource Category	Summer MW	Assumed Average EFORd (%) Weighted by Summer Ratings	Assumed Average Maintenance Weeks Weighted by Summer Ratings
Combined Cycle	12,523	3.6	5.8
Fossil	6,254	14.9	5.2
Nuclear	4,024	3.1	3.9
Hydro (Includes Pumped Storage)	2,931	4.6	6.5
Combustion Turbine	2,908	9.5	2.3
Diesel	193	6.5	1.0
Miscellaneous	86	14.2	1.8
Total System	28,918	6.7	5.1

- Assumed summer MW weighted EFORd and Maintenance Weeks are shown by resource category for informational purposes. In the LOLE simulations, individual unit values are modeled.

Availability Assumptions - Intermittent Power Resources

- Intermittent Power Resources are modeled as 100% available since their outages have been incorporated in their 5-year historical output used in their ratings determination.



Demand Resource Availability

Load Zone	On-Peak		Seasonal Peak		RT Demand Response		RT Emergency Gen		Total	
	Summer (MW)	Performance	Summer (MW)	Performance	Summer (MW)	Performance	Summer (MW)	Performance	Summer	Performance
MAINE	176.925	100%	-	-	207.892	99%	11.802	93%	396.619	99%
NEW HAMPSHIRE	94.951	100%	-	-	18.707	88%	14.022	99%	127.680	98%
VERMONT	125.420	100%	-	-	37.007	92%	2.866	82%	165.293	98%
CONNECTICUT	80.728	100%	324.316	100%	254.510	82%	138.338	85%	797.892	92%
RHODE ISLAND	172.704	100%	-	-	57.595	85%	33.540	90%	263.839	95%
SOUTH EAST MASSACHUSETTS	252.710	100%	-	-	38.785	84%	15.962	84%	307.457	97%
WEST CENTRAL MASSACHUSETTS	260.352	100%	52.968	100%	91.799	89%	27.798	89%	432.917	97%
NORTH EAST MASSACHUSETTS & BOSTON	486.312	100%	-	-	50.189	81%	26.099	89%	562.600	98%
Total New England	1,650.102	100%	377.284	100%	756.484	88%	270.427	88%	3,054.297	96%

- Uses historical DR performance from summer & winter 2010 – 2013. See presentation at: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/jun302014/2014_dr_availability.pdf for more information.
- Modeled by zone and type of DR with outage factor calculated as 1- performance/100

OP 4 Assumptions

- Action 6 & 8 - 5% Voltage Reduction (MW)

	90-10 Peak Load	Passive DR	RTDR	RTEG	Action 6 & 8 5% Voltage Reduction
Jun 2018 - Sep 2018	32,430	2,027	756	270	441
Oct 2018 - May 2019	23,940	1,834	739	260	317

- Use the 90-10 Peak Load Forecast minus all Passive DR & Active DR with RTEG limited to 600 MW, if necessary
- Multiplied by the 1.5% value used by ISO Operations in estimating relief obtained from OP4 voltage reduction



OP 4 Assumptions

- Tie Benefits (MW)

- The results of the 2018/19 Tie Benefits Study

Control Area	2018/19 FCA9	2017/18 FCA8
Québec via Phase II	953	1,068
Québec via Highgate	148	83
Maritimes	523	492
New York	346	227
Total Tie Benefits	1,970	1,870

- Modeled in the ICR calculations with the tie line availability assumptions shown below:

External Tie	Forced Outage Rate (%)	Maintenance (Weeks)
HQ Phase II	0.39	2.7
Highgate	0.07	1.3
New Brunswick Ties	0.08	0.4
New York AC Ties	0	0
Cross Sound Cable	0.89	1.5

OP 4 Assumptions

- Minimum Operating Reserve Requirement(MW)

- Minimum Operating Reserve is the 10-Minute minimum Operating Reserve requirement for ISO Operations
- Modeled at 200 MW in the ICR calculation



Summary of all MW Modeled in the ICR Calculations (MW)

Type of Resource/OP 4	2018/19 FCA
Generating Resources	28,917.722
Intermittent Power Resources	910.807
Demand Resources	3,054.297
Import Resources	88.800
Export Delist	(100.000)
Import Deratings	(30.000)
OP 4 Voltage Reduction	441.000
Minimum Operating Reserve	(200.000)
Tie Benefits (Includes 953 MW of HQICCs)	1,970.000
Proxy Units	1,600.000
Total MW Modeled in ICR	36,652.626

Notes:

- Intermittent Power Resources have both the summer and winter capacity values modeled
- Import deratings reflect the value of the firm VJO contract
- OP 4 Voltage Reduction includes both Action 6 and Action 8 MW assumptions.
- Minimum Operating Reserve is the 10-Minute minimum Operating Reserve requirement for ISO Operations



Questions



SEPTEMBER 16, 2014 | WESTBOROUGH, MA

2018/19 FCA Tie Benefits Study



Objective

- To review the tie benefits results for the 2018/19 FCA (FCA9)
 - Total tie benefits for New England
 - Tie benefits contribution from individual or group of interconnection(s)
 - Maritimes
 - HQ Phase II
 - Highgate
 - New York AC ties
 - Cross Sound Cable (CSC)



Recap of Calculation Process

- Process 1.0
 - Calculate the tie benefits values for all possible interconnection states using isolated New England system as the reference
- Process 2.0
 - Calculate initial total tie benefits for New England from all neighboring control areas
- Process 3.0
 - Calculate initial tie benefits for each individual neighboring control area
 - Pro-rate tie benefits values of individual control areas based on the total tie benefits, if necessary
- Process 4.0
 - Calculate initial tie benefits for individual interconnection or group of interconnections
 - Pro-rate tie benefits values of individual interconnection or group of interconnections based on the individual control area tie benefits, if necessary
- Process 5.0
 - Adjust tie benefits of individual interconnection or group of interconnections to account for capacity imports
- Process 6.0
 - Calculate the final tie benefits for each individual neighboring control area
- Process 7.0
 - Calculate the final total tie benefits for New England



Process 1.0

Calculation of Tie Benefits for All Interconnection States

Interconnection State	Discription	Interconnection Status					LOLE	Equivalent TB (MW)
		Maritimes	Ph II	Highgate	NY-AC	CSC		
1	Cut All	x	x	x	x	x	0.414	0
2	Cut None	✓	✓	✓	✓	✓	0.100	1970
3	Cut MT	x	✓	✓	✓	✓	0.143	1455
4	Cut Ph II	✓	x	✓	✓	✓	0.190	1060
5	Cut Highgate	✓	✓	x	✓	✓	0.114	1785
6	Cut NY-AC	✓	✓	✓	x	✓	0.114	1785
7	Cut CSC	✓	✓	✓	✓	x	0.100	1970
8	Cut MT & Ph II	x	x	✓	✓	✓	0.252	695
9	Cut MT & Highgate	x	✓	x	✓	✓	0.155	1320
10	Cut MT & NY-AC	x	✓	✓	x	✓	0.167	1225
11	Cut MT & CSC	x	✓	✓	✓	x	0.143	1455
12	Cut Ph II & Highgate	✓	x	x	✓	✓	0.206	955
13	Cut Ph II & NY-AC	✓	x	✓	x	✓	0.243	740
14	Cut Ph II & CSC	✓	x	✓	✓	x	0.190	1060
15	Cut Highgate & NY-AC	✓	✓	x	x	✓	0.129	1610
16	Cut Highgate & CSC	✓	✓	x	✓	x	0.114	1785
17	Cut NY-AC & CSC	✓	✓	✓	x	x	0.114	1785
18	Cut MT, Ph II & Highgate	x	x	x	✓	✓	0.273	580
19	Cut MT, Ph II & NY-AC	x	x	✓	x	✓	0.357	200
20	Cut MT, Ph II & CSC	x	x	✓	✓	x	0.252	695
21	Cut MT, Highgate & NY-AC	x	✓	x	x	✓	0.183	1125
22	Cut MT, Highgate & CSC	x	✓	x	✓	x	0.155	1320
23	Cut MT, NY-AC & CSC	x	✓	✓	x	x	0.167	1225
24	Cut Ph II, Highgate & NY-AC	✓	x	x	x	✓	0.270	595
25	Cut Ph II, Highgate & CSC	✓	x	x	✓	x	0.206	955
26	Cut Ph II, NY-AC & CSC	✓	x	✓	x	x	0.243	740
27	Cut Highgate, NY-AC & CSC	✓	✓	x	x	x	0.129	1610
28	Cut MT, Ph II, Highgate & NY-AC	x	x	x	x	✓	0.414	0
29	Cut MT, Ph II, Highgate & CSC	x	x	x	✓	x	0.273	580
30	Cut MT, Ph II, NY-AC & CSC	x	x	✓	x	x	0.357	200
31	Cut MT, Highgate, NY-AC & CSC	x	✓	x	x	x	0.183	1125
32	Cut Ph II, Highgate, NY-AC & CSC	✓	x	x	x	x	0.270	595

Process 2.0

Calculation of Initial Total Tie Benefits

- Compare state 1 (without any ties) and state 2 (with all the ties)
 - $TB_{total\_initial} = 1,970 \text{ MW}$
 - This value is subjected to the adjustment later to account for imports



Process 3.0

Calculation of Tie Benefits for Neighboring Control Areas

- All interconnections connected to a given neighboring control area are grouped together to represent the state of interconnection between New England and that neighboring control area. The simple average of values for all the interconnection states represents the tie benefits of the target neighboring control area (four states for each area)
- Tie Benefits from Maritimes
 - 1 vs. 32 = 595 2 vs. 3 = 515 12 vs. 18 = 375 17 vs. 23 = 560
 - Average = 511 MW
- Tie Benefits from Hydro Quebec
 - 1 vs. 23 = 1225 2 vs. 12 = 1015 3 vs. 18 = 875 17 vs. 32 = 1190
 - Average = 1076MW
- Tie Benefits from New York
 - 1 vs. 18 = 580 2 vs. 17 = 185 3 vs. 23 = 230 12 vs. 32 = 360
 - Average = 339 MW
- Tie Benefits after Proration (since $511 + 1076 + 339 \neq 1970$)
 - $TB\_MTCA\_initial = 1970 * 511 / (511 + 1076 + 339) = 523 \text{ MW}$
 - $TB\_HQCA\_initial = 1970 * 1076 / (511 + 1076 + 339) = 1101 \text{ MW}$
 - $TB\_NYCA\_initial = 1970 * 339 / (511 + 1076 + 339) = 346 \text{ MW}$



Process 4.0

Calculation of Tie Benefits for Individual or Group of Interconnections

- Each individual interconnection or group of interconnections subject to individual tie benefits contribution calculation is treated independently. The simple average of values for all the interconnection states represents tie benefits of the target interconnection or group of interconnections
- Interconnections with Maritimes
 - No individual interconnections subject to the calculation
- Interconnections with Quebec
 - Phase II and Highgate are subject to the calculation
 - Phase II
 - 1 vs. 31 = 1125 2 vs. 4 = 910 3 vs. 8 = 760 5 vs. 12 = 830
 - 9 vs. 18 = 740 17 vs. 26 = 1045 23 vs. 30 = 1025 27 vs. 32 = 1015
 - Average = 931 MW
 - Highgate
 - 1 vs. 30 = 200 2 vs. 5 = 185 3 vs. 9 = 135 4 vs. 12 = 105
 - 8 vs. 18 = 115 17 vs. 27 = 175 23 vs. 31 = 100 26 vs. 32 = 145
 - Average = 145 MW
 - Tie Benefits after Proration (since $931 + 145 \neq 1101$)
 - $TB_{Ph-II\_initial} = 1101 * 931 / (931 + 145) = 953$ MW
 - $TB_{HG\_initial} = 1101 * 145 / (931 + 145) = 148$ MW



Process 4.0 (*cont.*)

- Interconnections with New York
 - NY AC ties and Cross Sound Cable (CSC) are subject to the calculation
 - NY AC ties
 - 1 vs. 29 = 580 2 vs. 6 = 185 3 vs. 10 = 230 7 vs. 17 = 185
 - 11 vs. 23 = 230 12 vs. 24 = 360 18 vs. 28 = 580 25 vs. 32 = 360
 - Average = 339 MW
 - CSC
 - 1 vs. 28 = 0 2 vs. 7 = 0 3 vs. 11 = 0 6 vs. 17 = 0
 - 10 vs. 23 = 0 12 vs. 25 = 0 18 vs. 29 = 0 24 vs. 32 = 0
 - Average = 0 MW
 - Tie Benefits after Proration (since $339 + 0 \neq 346$)
 - TB_NYAC_initial = 346 MW
 - TB_CSC_initial = 0 MW



Process 5.0

Adjustment to Initial Tie Benefits Values

- Tie benefits determined in Process 4.0 for individual interconnection or group of interconnections are adjusted to account for capacity imports
- Interconnections with Maritimes
 - No adjustments required as no existing capacity imports
- Interconnections with Quebec
 - Phase II
 - No adjustments required as no existing capacity imports
 - Highgate
 - Existing import = 6 MW
 - Assumed total import capability = 200 MW
 - Remaining import capability after import = $200 - 6 = 194$ MW
 - Tie benefits value calculated in Process 4.0 = 148 MW
 - Since $148 \text{ MW} < 194 \text{ MW}$, no adjustment is required
 - $TB_{HG} = 148 \text{ MW}$



Process 5.0 (*cont.*)

- Interconnections with New York
 - NY AC Ties
 - Existing import = 82.8 MW
 - Assumed total import capability = 1400 MW
 - Remaining import capability after import = $1400 - 82.8 = 1317.2$ MW
 - Tie benefits value calculated in Process 4.0 = 346 MW
 - Since $346 < 1317.2$ MW, no adjustment is required
 - TB_NY-AC = 346 MW
 - CSC
 - No adjustments required as no existing capacity imports
 - TB_CSC = 0 MW



Process 6.0

Determination of Tie Benefits for Individual Neighboring Control Area

- Final tie benefits for each neighboring control area are the sum of the tie benefits from the individual interconnections or groups of interconnections with that control area, after accounting for the adjustments for capacity imports as determined in Process 5.0
 - Maritimes
 - $TB_{MTCA} = 523 \text{ MW}$
 - Quebec
 - $TB_{HQCA} = 953 + 148 = 1101 \text{ MW}$
 - New York
 - $TB_{NYCA} = 346 + 0 = 346 \text{ MW}$



Process 7.0

Determination of Total Tie Benefits for New England

- Final total tie benefits from all neighboring control areas are the sum of the control area tie benefits after the adjustments made to account for capacity imports as determined in Process 6.0.
 - $TB\_Total = 523 + 1101 + 346 = 1970 \text{ MW}$



Summary of Tie Benefits Results

- Total tie benefits
 - TB_Total = 1970 MW
- Tie benefits for New Brunswick ties
 - TB_NB = 523 MW
- Tie benefits for HQ Phase II
 - TB_PH-II = 953 MW
- Tie benefits for Highgate
 - TB_HG = 148 MW
- Tie benefits for NY AC ties
 - TB_NY-AC = 346 MW
- Tie benefits for Cross Sound Cable
 - TB_CSC = 0 MW



Comparison of Tie Benefits for FCA9 and FCA8

	2018/19(FCA9) (MW)	2017/18(FCA8) (MW)
Total Tie Benefits	1,970	1,870
New Brunswick	523	492
HQ Phase II	953	1,068
Highgate	148	83
New York AC	346	227
CSC	0	0

Sensitivity Case

– Maine as Export Constrained Capacity Zone

- Trigger analysis to determine if Maine will be an export constrained zone requires the Maximum Capacity Limit (MCL) calculation that uses tie benefits study results as an input. Preliminary analysis using FCA8 MCL suggests Maine will not be modeled as an export constraint zone.
- We had proposed to first run simulations assuming that Maine is not an export constrained zone (model Maine-New Hampshire interface), and conduct a sensitivity case to verify the results assuming that Maine is an export constrained zone (do not model Maine-New Hampshire interface).
- The total tie benefits remains unchanged at 1,970 MW for the sensitivity case when Maine is modeled as an export constrained zone (Maine-New Hampshire interface limit not modeled)



APPENDIX: STUDY ASSUMPTIONS AND METHODOLOGY

Scope of Study

- To calculate tie benefits values from neighboring control areas to New England for the 2018/19 FCA through a probabilistic analysis, using the calculation methodology described in III.12.9 of Market Rule 1. The calculations include:
 - Total tie benefits from all neighboring control areas
 - Tie benefits associated with each neighboring control area
 - Tie benefits associated with individual interconnection or group of interconnections of interest



Resource Assumptions

- *New England*

- All existing qualified resources are modeled
 - Ratings, EFORd, Maintenance Weeks consistent with assumptions for the 2018/19 FCA ICR calculation*
- Real-Time Emergency Generations (RTEG)
 - modeled as resources that are dispatched under OP-4
 - Derated to account for unavailability
- Real-Time Demand Resources (RTDR)
 - RTDR assumed fully integrated into the energy markets, and dispatched economically to meet system load and operating reserve requirements
 - modeled as resources that are dispatched prior to OP-4
 - Availability metrics considered

* http://www.iso-ne.com/committees/comm_wkgrps/reblty_comm/pwrsuppln_comm/mtrls/2014/jun302014/2018-19_fca_icr_assumptions.pdf

Resource Assumptions

- *New England, cont.*

- Proxy Units

- New England is short of existing resources to meet 0.1 days/year LOLE criterion, four proxy units^(*) are added to the subareas of Boston, CMA/NEMA, SEMA, and NOR.
- III.12.9.2.5.
 - A. Adding Proxy Units within New England when the New England system is short of capacity
 - proxy units (with the characteristics identified in Section III.12.7.1) will be added to the sub-areas that are created by any modeled internal transmission constraints within New England, beginning with the sub-area with the highest LOLE. If there are no modeled internal transmission constraints in the New England Control Area, then proxy units will be added to the entire Control Area. If, as a result of the addition of one or more proxy units, the system is surplus of capacity, then the methodology in Section III.12.9.2.5(b) will be used to remove the surplus capacity

Note: (*) A presentation on proxy unit characteristics made to PSPC on May 22 http://www.iso-ne.com/committees/comm_wkgrps/reblty_comm/pwrsuppln_comm/mtrls/2014/may222014/proxy_unit_2014_study.pdf

Resource Assumptions

- *External Areas*

- Resources assumptions based on
 - 2013 NPCC Long Range Adequacy Overview
 - 2014 NPCC Seasonal Assessments
 - 2014 New York Gold Book
 - 2014 New York Reliability Needs Assessment (RNA)
- New York has adequate existing resources to meet the LOLE of 0.1 days/year for 2018. No proxy units are needed.



Load Assumptions

- Load Forecast
 - New England: based on 2014 CELT
 - Other Areas: based on their latest load models used in NPCC studies
- Load Shape
 - 2002 shape is used, consistent with current NPCC studies



Transmission System Representation

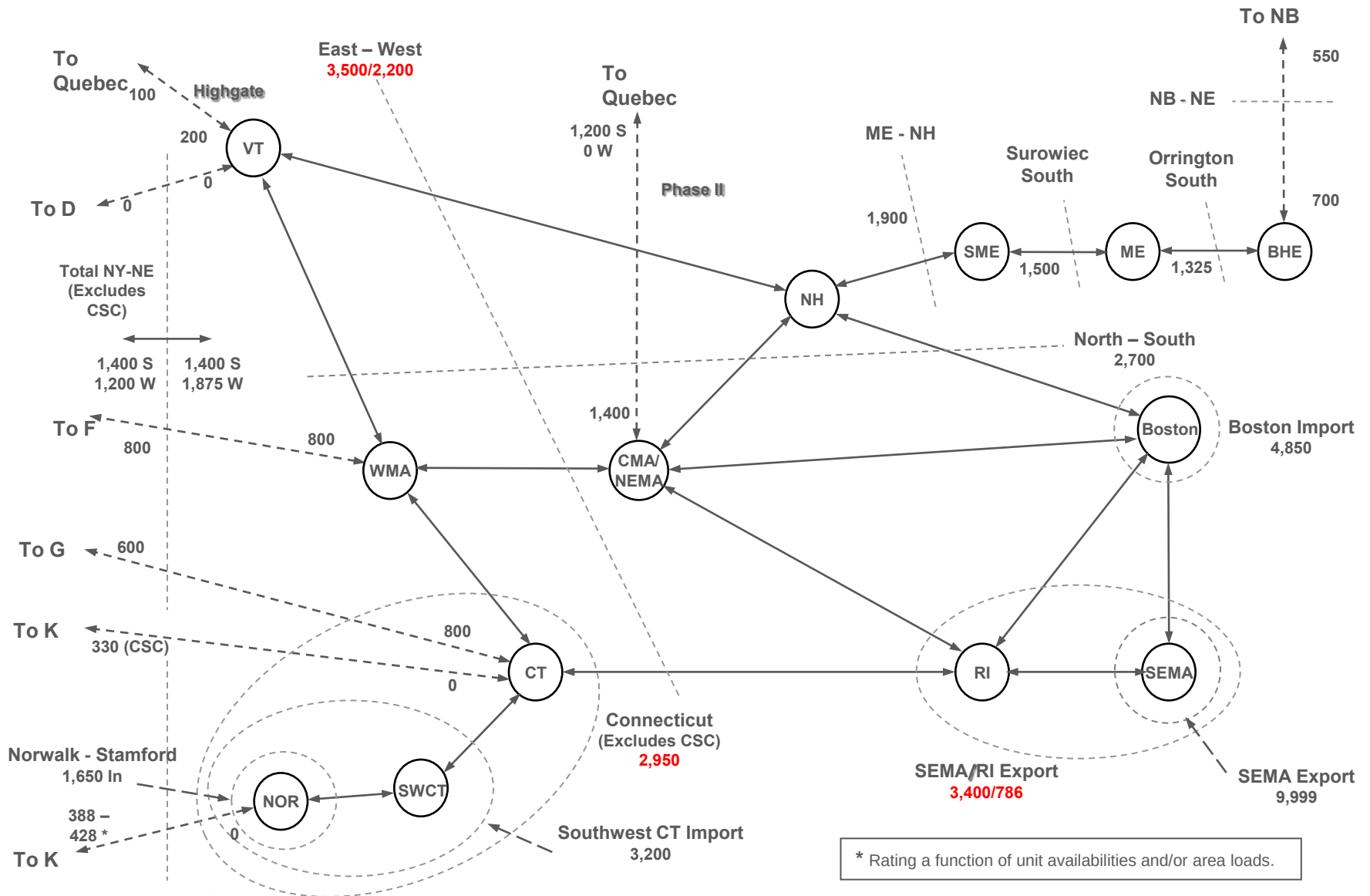
- Areas to be modeled
 - New England, Maritimes, Quebec, and New York are simulated using bubble transportation model
 - Equivalent model is used to reflect the impacts of capacity import/export between New York and its neighbors
- Transmission interfaces and transfer capabilities
 - New England
 - Thirteen RSP subarea representation
 - Transfer capabilities consistent with RSP14 values^(*)
 - Interfaces associated with capacity zones are not modeled
 - Preliminary analysis indicates that NEMA/Boston, Connecticut, SEMA/RI will be modeled as import constrained capacity zones
 - Trigger analysis to determine if Maine will be an export constrained zone requires the Maximum Capacity Limit (MCL) calculation that uses tie benefits study results as an input. Preliminary analysis using FCA8 MCL suggests Maine will not be modeled as an export constraint zone. Propose to
 - First run simulations assuming Maine not as export constrained zone (model Maine-New Hampshire interface)
 - Verify the results assuming Maine as export constrained zone (do not model Maine-New Hampshire interface)
 - Other Areas
 - Consistent with their latest model used in NPCC studies

Note: (*) A presentation on transmission interface transfer capabilities made to PAC on March 17 http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/mar172014/a8_rsp14_transmission_interface_transfer_capabilities.pdf





New England System Representation



Other Assumptions

- Emergency Operating Procedures
 - New England
 - 2,375 MW of system-wide operating reserve assumed
 - Allowed to deplete to a minimum of 200 MW as OP-4 procedures progress prior to firm load shedding
 - Local reserve requirements are based on the latest forward reserve market requirements. They are allowed to deplete to 0 MW as OP-4 procedures progress prior to firm load shedding.
 - CT: 900 MW (summer); 578 MW (winter)
 - SWCT: 94 MW (summer); 155 MW (winter)
 - BOSTON: 0 MW
 - Voltage reductions
 - Consistent with the ICR calculation, and the amount for subareas calculated as
 - $(90/10 \text{ Subarea Coincident Peak Load MW} - \text{Subarea DR MW with a system-wide RTEG limited to 600 MW}) * 1.5\%$
 - Other Areas
 - Consistent with their latest model in NPCC studies



Imports used for Tie Benefits Adjustments

Name	Hydro-Quebec Highgate	New Brunswick	New York AC Ties	Phase I/II HQ Excess
NYPA - CMR			68.8	
NYPA - VT			14	
VJO - Highgate	6			
VJO - Phase I/II				
Total	6	0	82.8	0

Study Methodology

Calculation Process

- Process 1.0
 - Calculate the tie benefits values for all possible interconnection states using isolated New England system as the reference
- Process 2.0
 - Calculate initial total tie benefits for New England from all neighboring control areas
- Process 3.0
 - Calculate initial tie benefits for each individual neighboring control area
 - Pro-rate tie benefits values of individual control areas based on the total tie benefits, if necessary
- Process 4.0
 - Calculate initial tie benefits for individual interconnection or group of interconnections
 - Pro-rate tie benefits values of individual interconnection or group of interconnections based on the individual control area tie benefits, if necessary
- Process 5.0
 - Adjust tie benefits of individual interconnection or group of interconnections to account for capacity imports
- Process 6.0
 - Calculate the final tie benefits for each individual neighboring control area
- Process 7.0
 - Calculate the final total tie benefits for New England



Study Methodology

Calculation Process 1.0

- Calculation of tie benefits values for all possible interconnection states
 - Bring all interconnected areas to LOLE of 0.1 days/year simultaneously
 - Calculate New England's LOLE for all the possible interconnection states, e.g.
 - with no interconnections (isolated state)
 - With any single interconnection only
 - With any of two interconnections
 - With any of three interconnections
 - ...
 - Calculate the equivalent tie benefits values for each interconnection state using the isolated state as reference
 - As the equivalent MW to bridge the LOLE delta between these two states



Study Methodology

Calculation Process 2.0

- Calculation of total tie benefits for New England
 - Compare the following two interconnection states
 - New England system with all interconnections to neighboring control areas connected
 - New England System with all interconnections with neighboring Control Areas disconnected
 - Total tie benefits for New England is the equivalent MW value to bridge the LOLE delta between these two states
 - This initial total tie benefits value is subject to adjustment to account for capacity imports in the later process.



Study Methodology

Calculation Process 3.0

- Calculation of initial tie benefits for each individual neighboring control area
 - all interconnections connected to a given neighboring control area are grouped together to represent the state of interconnection between New England and that neighboring control area
 - For each target neighboring control area, identify all the related interconnection states and calculate the equivalent tie benefits values for each of these states
 - With a total of three neighboring control areas, there are four interconnection states for each neighboring area
 - Use the simple average of values for all the interconnection states to represent the tie benefits of the target neighboring control area
 - If the sum of the individual control area tie benefits calculated above is different than the total tie benefits calculated in Process 2.0, each control area's tie benefits shall be adjusted based on the ratio of the individual control area tie benefits to the total tie benefits
 - These initial individual control area tie benefits are subject to further adjustment to account for capacity imports in the later process.



Study Methodology

Calculation Process 4.0

- Calculation of preliminary tie benefits for individual interconnection or group of interconnections
 - Each individual interconnection or group of interconnections subject to individual tie benefits contribution calculation is treated independently.
 - For each target interconnection or group of interconnections, identify all the related interconnection states and calculate the equivalent tie benefits values for each of these states
 - Use the simple average of values for all the interconnection states to represent the tie benefits of the target interconnection or group of interconnections
 - If the sum of the individual interconnection's or group of interconnection's tie benefits calculated above is different than the relative control area's tie benefits calculated in Process 3.0, tie benefits of the individual interconnection or group of interconnections shall be adjusted ratio of the tie benefits of the individual interconnection or group of interconnections to the relative control area's tie benefits
 - These initial individual interconnection's or group of interconnection's tie benefits are subject to further adjustment to account for capacity imports in the later process.



Study Methodology

Calculation Process 5.0

- Adjustment to the initial tie benefits for individual interconnection or group of interconnections
 - Deduct capacity imports from the import capability of each individual interconnection or group of interconnections to determine the remaining available import capability to support tie benefits
 - Capacity imports are the Qualified Existing Import Capacity for FCA 2014/15
 - Compare the tie benefits value of an individual interconnection or group of interconnections as determined in Process 4.0 to its remaining transmission import capability
 - If the tie benefits value is greater than the remaining transmission import capability, the tie benefit value of the individual interconnection or group of interconnections is capped to the remaining transmission import capability
 - Otherwise, no adjustments are made.



Study Methodology

Calculation Process 6.0

- Determination of tie benefits for individual neighboring control area
 - Final tie benefits for each neighboring control area are the sum of the tie benefits from the individual interconnections or groups of interconnections with that control area, after accounting for any adjustment for capacity imports as determined in Process 5.0



Study Methodology

Calculation Process 7.0

- Determination of total tie benefits for New England
 - Final total tie benefits from all neighboring control areas are the sum of the control area tie benefits after accounting for any adjustment for capacity imports as determined in Process 6.0.



Questions





memo

To: Participants Committee

From: Marc Lyons, Secretary – Reliability Committee

Date: September 17, 2014

Subject: **ACTIONS OF THE RELIABILITY COMMITTEE**

This memo is to notify the Participants Committee (“PC”) of the actions taken by the Reliability Committee (“RC”) at its September 16, 2014 meeting.

(Agenda Item 2.1) Jericho Wind Farm Expansion Project - Proposed Plan Application (PPA) NU-14-G16

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of the Jericho Wind Farm Expansion Project described in Proposed Plan Application (“PPA”) NU-14-G16 from Northeast Utilities Service Company (“NU”) as detailed in Mr. James DiLuca’s September 2, 2014 transmittal to Mr. Donald Gates, Chair, Reliability Committee, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

The proposed in service date of the project will be November 1, 2014.

The motion to recommend a determination of no adverse effects passed based on a show of hands with none opposed and no abstentions.

(Agenda Item 2.2) Southeast Substation Project – Proposed Plan Application (PPA) NEP-14-T10

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of the North Oxford Substation Project described in Proposed Plan Application (“PPA”) NEP-14-T10 from New England Power Company (“NEP”) as detailed in Mr. Amanuel Kesete’s September 2, 2014 transmittal to Mr. Donald Gates, Chair, Reliability Committee, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

The proposed in service date of the project is December 1, 2018.

The motion to recommend a determination of no adverse effects passed based on a show of hands with none opposed and no abstentions.

(Agenda Item 4.1) Wallingford Refuse Non-Price Retirement

It was moved and seconded to recommend to ISO New England Inc. that the analyses performed for the Non-Price Retirement Requests submitted for Resource ID 623 – Wallingford Refuse, which has a

Participants Committee
September 17, 2014
Page 2 of 3

Qualified Capacity of 5.993 Summer MW for the Capacity Commitment Period beginning June 1, 2018 were performed in accordance with Market Rule 1, Section III.13.2.5.2.5 and Planning Procedure 10, Section 7.

The motion to recommend approval to ISO New England passed based on a show of hands with none opposed and no abstentions.

(Agenda Item 6.0) HQICC and ICR Values for FCA 9 2018/2019 Capability Period

HQICC Motion

It was moved and seconded to recommend Participants Committee support of the following megawatt values that represent the Hydro-Québec Interconnection Capability Credit (HQICC) for the Forward Capacity Auction for the 2018/2019 Capacity Commitment Period:

2018/2019 Capacity Commitment Period Month	HQICC Values (MW)
June	953
July	953
August	953
September	953
October	953
November	953
December	953
January	953
February	953
March	953
April	953
May	953

A motion to recommend approval to the Participants Committee passed based on a show of hands with two opposed (2 Supplier Sector) and one abstention (1 Supplier Sector).

ICR/Demand Curve/LSR Motion

It was moved and seconded to recommend Participants Committee support for the following megawatt values that represent the New England Installed Capacity Requirement (ICR), the capacity requirement values for the System-Wide Capacity Demand Curve (Demand Curve) and the Connecticut, NEMA/BOSTON and SEMA/RI Local Sourcing Requirements (LSR) for the Forward Capacity Auction for the 2018/2019 Capacity Commitment Period:

Participants Committee
September 17, 2014
Page 3 of 3

	2018/2019 Values (MW)
Installed Capacity Requirement	35,142
Net Installed Capacity Requirement (Net ICR)	34,189
1-in-5 LOLE Demand Curve capacity value	33,132
1-in-87 LOLE Demand Curve capacity value	37,027
Connecticut Local Sourcing Requirement	7,331
NEMA/Boston Local Sourcing Requirement	3,572
SEMA/RI Local Sourcing Requirement	7,479

A motion to recommend approval to the Participants Committee passed based on a show of hands with four opposed (1 Transmission Sector, 1 Publicly Owned Sector, 2 Supplier Sector) and one abstention (1 Transmission Sector).

(Agenda Item 7.0) Price Responsive Demand (PRD) Reserve Auditing

It was moved and seconded to recommend Participants Committee support for revisions to Market Rule I, Section III.9.5.3 and Market Rule I, Section III.1.5.2 to support implementation of PRD Claimed 10 and Claim 30 Values and ISO Initiated Parameter Auditing together with such other changes as discussed and agreed to at the meeting] and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

The motion to recommend approval to the Participants Committee passed based on a show of hands with none opposed and no abstentions.

(Agenda Item 8.6) ISO New England Operating Procedures No. 14A, 14E, & 14G

It was moved and seconded to recommend Participants Committee support for revision of ISO New England Operating Procedure No. 14A (OP 14A), 14E (OP 14E), and 14G (OP 14G) together with such other changes as discussed and agreed to at the meeting] and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting. The revision of OP 14A, OP 14E and OP 14G – Technical Requirements for Generators, Demand Resources and Asset Related Demands Appendices supports the Winter Reliability Program.

The motion to recommend approval to the Participants Committee passed based on a show of hands, with none opposed and no abstentions.

(

VERMONT PUBLIC POWER SUPPLY AUTHORITY

PO Box 126 • 5195 Waterbury-Stowe Road • Waterbury Ctr., VT 05677-0126
(802) 244-7678 Fax (802) 244-6889 www.vppsa.com

VIA ELECTRONIC MAIL

October 1, 2014

Joel Gordon
NEPOOL Participants Committee Chair
PSEG Power Connecticut, LLC
7 Steeple Lane
Amherst, NH 03031
joel.gordon@pseg.com

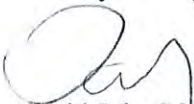
David Doot
NEPOOL Participants Committee Secretary
City Place 1
185 Asylum St.
Hartford, CT 06103
dtdoot@daypitney.com

Re: Open Letter for consideration by the Members and Alternates of the NEPOOL
Participants Committee

Dear Joel:

Please find below some comments for consideration regarding Agenda Item 6A
"Reliability Committee recommended values for the New England Installed Capacity
Requirement (ICR)" for the upcoming October 3rd NEPOOL Participants Committee meeting.
We would appreciate the posting of this letter as additional materials in time for review by the
NEPOOL Participants Committee Members and Alternates.

Thank you for your consideration.



David John Mullett
General Manager
Vermont Public Power Supply Authority
dmullett@vppsa.com

– VPPSA –

October 1, 2014

VERMONT PUBLIC POWER SUPPLY AUTHORITY

PO Box 126 • 5195 Waterbury-Stowe Road • Waterbury Ctr., VT 05677-0126
(802) 244-7678 Fax (802) 244-6889 www.vppsa.com

Comments of Vermont Public Power Supply Authority for Consideration by the Members and Alternates of the NEPOOL Participants Committee re: Agenda Item 6A

Vermont Public Power Supply Authority ("VPPSA") is concerned that the recommended values for the New England Installed Capacity Requirement ("ICR") contain a correctable bias arising from the lack of recognition of significant present and continuing investment within the region in renewable distributed generation resources for the 2018-2019 Forward Capacity Auction ("FCA") Commitment Period. VPPSA asks the Members and Alternates of the NEPOOL Participants Committee to consider this concern prior to voting on the recommended ICR value.

In June of 2013, Synapse Energy Economics produced a report recognizing that the Forward Capacity Market ("FCM") did not accurately value significant New England ratepayer investment in renewable distributed generation ("DG") resources, and requested that the region develop a DG Forecasting Working Group ("DGFWG"). This was a timely request that recognized the previously held FCAs for commitment periods FCA6, FCA7 and FCA8 (2015 through 2018) lacked recognition of this investment, likely leading to the region over procuring capacity in those FCAs. The report also identified significantly accelerated development of these resources and the need for a method to incorporate them into future FCAs and Regional System Plans in order to protect the region's ratepayer investment. Absent this method, the region's ratepayers will pay for capacity twice; once in the FCM and again through statewide renewable policies driven by incentives not related to ISO-NE markets.

In response to the Synapse report, the DGFWG was created in September 2013 with members including regional stakeholders and State representatives. The DGFWG produced a finalized 2014 PV forecast for inclusion in the May 2014 CELT report that showed by the end of the 2018-2019 commitment period more than 1,500 MWs of solar resources would be installed in the region. These resources are expected to contribute more than 500 MWs of seasonal Summer Claimed Capability, an equivalent of "Qualified Capacity" in the FCM. While some participants expressed concern that the estimates were too conservative, the inclusion of the forecast in the CELT is an acknowledgement that these resources are significant to the region and should be counted in the future.

In June 2014, the New England States Committee on Electricity ("NESCOE") submitted a letter to the Planning Advisory Committee Chair requesting that ISO-NE "use the Solar PV Forecast in the nearest possible term." The letter goes on to highlight that not doing so in a timely manner is likely to cause continued harm to New England Consumers. The FERC

- VPPSA -

October 1, 2014

accepted region wide Demand curve for FCA9 helps to quantify the possible “excess” payments by the region. The downward slope of the FCA9 Demand Curve represents a reduction in price of roughly \$0.48/ kW-Month for every capacity quantity reduction of 100 MW. The DGFWG calculation of 500 MWs of summer qualified capacity delivered by statewide programs could result in excess capacity payments between \$600 million and \$1 billion in the first year alone (roughly 20% of the entire capacity market). While the calculations are simplified, they show the anticipated contribution by distributed PV has a significant impact on the overall cost to the region because it impacts the FCA clearing price paid to more than 34,000 MWs of capacity resources.

The Annual Reconfiguration Auctions (“ARAs”) have been suggested as a way to address the concerns of over-procurement in the upcoming FCA. This is likely to address the amount of capacity that will have an obligation for the FCA9 commitment period, but not the economic impact. Under this scenario the ISO will sell the excess capacity into the ARA as the region gets closer to the commitment period. What this approach will *not* do is rebate the region in an economically sufficient manner. While the inclusion of the DGFWG forecast in the FCA impacts the clearing price for procurement of more than 34,000 MWs, the rebate to the region obtained in the ARA will only be applied to the amount of capacity sold (roughly 500 MWs.) A more appropriate use of the DGFWG forecast is to include it in the FCA. If the DGFWG forecast proves too liberal, capacity can be procured in subsequent ARAs, saving the region potentially hundreds of millions of dollars in capacity payments.

The region has shown in the past that it can act quickly when reliability is a concern. The 2013-14 and 2014-15 winter reliability programs were created in a matter of months, and we have seen market rules changed to allow generation to remain in the capacity market due to reliability concerns even more quickly. Modification of the forecasted annual peak to include the DGFWG forecast will impact only a few figures in the overall ICR calculation. Most of the values (Tie benefits, HQICC’s, etc) used in the calculation do not require adjustment. Adequate time remains to make that necessary adjustment.

VPPSA opposes the ISO ICR calculation, as it did at the Reliability Committee, for four reasons.

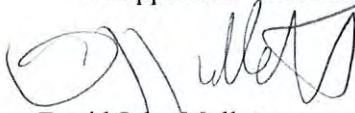
- 1- A known bias is included in the ICR calculation when the Market Rule states that known bias should be addressed
- 2- The recommended ICR value causes significant avoidable impact to the region’s electric ratepayers
- 3- The economic harm done in the FCA cannot be substantially relieved after the auction is held
- 4- There is time correct the annual peak forecast for the FCA9 commitment period

We hope that other participants in the region will join our concerns by opposing the recommended ICR value. VPPSA also wishes to thank NESCOE and our State regulators for emphasizing these points during the DGFWG process, as well as Synapse for bringing this significant concern to the region’s attention over a year and a half ago.

– VPPSA –

October 1, 2014

We appreciate the Committee's consideration of these comments.

A handwritten signature in black ink, appearing to read 'D. Mullett', is written over the typed name and title.

David John Mullett
General Manager
Vermont Public Power Supply Authority
dmullett@vppsa.com

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian M. Lombardi, NEPOOL Counsel

DATE: September 26, 2014

RE: Proposed Modifications to the Peak Energy Rent (PER) Mechanism

At its October 3, 2014 meeting, the Participants Committee will be asked to consider ISO-proposed modifications to the Peak Energy Rent (PER) mechanism in the FCM (the “PER Revisions”). A copy of these proposed PER Revisions are included with this memorandum.

The PER Revisions are proposed in response to concerns raised about the interaction between the current PER mechanism and increases to the Reserve Constraint Penalty Factor (RCPF) values. The increases in RCPF values were required by the FERC’s May 30, 2014 order on the performance incentives jump ball filing, and have already been filed to become effective on December 3, 2014. The RCPF increases were intended broadly to provide additional incentives for resources to be available when operating reserves are scarce. The ISO has explained that under the current PER adjustment mechanism the RCPF increases “could create a revenue transfer from resource owners to load-serving entities.” The PER Revisions would raise the daily PER adjustment strike price by \$250 (for the remainder of Capacity Commitment Period 5 – Capacity Commitment Period 8),¹ with the effect of reducing the potential for a revenue transfer via the PER mechanism to load-serving entities. The ISO has also explained that it views the proposal as one designed to address equity issues, not reliability or economic efficiency concerns. For that reason, the ISO has indicated that it will fully consider the outcome of Participants Committee consideration before deciding whether it would file such a proposal with the FERC. Background materials providing further information on the PER Revisions are included with this memorandum.

The NEPOOL Markets Committee vetted the PER Revisions over three meetings, with a Markets Committee vote taken at its September 3 meeting. The Markets Committee failed to recommend Participants Committee support for the ISO-proposed PER Revisions with a Vote of 57.74% in favor.² Prior to the Markets Committee’s vote on the ISO’s proposal, one motion to amend the main motion was considered. That one Participant-sponsored amendment failed to

¹ A separate evaluation and stakeholder process will be conducted with respect to the PER mechanism in the FCM under the performance incentives construct (for Capacity Commitment Periods 9 and beyond).

² The individual Sector votes were Generation (17.17% in favor, 0% opposed, 2 abstentions), Transmission (3.43% in favor, 13.74% opposed), Supplier (9.24% in favor, 7.93% opposed, 5 abstentions), Alternative Resources (14.17% in favor, 0% opposed, 1 abstention), Publicly Owned Entity (0% in favor, 17.17% opposed), and End User (13.73% in favor, 3.44% opposed, 5 abstentions).

garner the requisite 60% Vote threshold required for Markets Committee support, with a Vote of 31.15% in favor.³

We have been advised that the Participants Committee will be asked at its October 3 meeting to consider the same motion to amend, which was initially sponsored by GDF SUEZ Energy Marketing North America (“GDF SUEZ”), as follows:

To revise ISO-proposed Section III.13.7.1.2 of Market Rule 1 to modify how the PER adjustment would be calculated as described in the materials from GDF SUEZ which are included with this memorandum. (“GDF Amendment 1”)

The ISO does not support GDF Amendment 1 for reasons articulated in an earlier memorandum and PowerPoint presentation, both of which were previously circulated to the Markets Committee and are also included with this memorandum.

In addition, GDF SUEZ will also ask that the Participants Committee consider an amendment that would eliminate the PER mechanism under FCM PI beginning June 1, 2018 (“GDF Amendment 2”). GDF Amendment 2, also addressed in the GDF MC Presentation included with this memorandum, was discussed but not voted on by the Markets Committee.

If there are additional amendments to the PER Revisions that any Participant may wish the Participants Committee to consider, please provide those amendments to NEPOOL Counsel (slombardi@daypitney.com) as soon as possible so that they can be circulated, reviewed and considered ahead of the meeting.

The following form of resolution may be used for Participants Committee action on the ISO’s PER proposal:

RESOLVED, that the Participants Committee supports revisions to Market Rule 1 to increase the daily Peak Energy Rent strike price by \$250, as proposed by ISO and as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

³ The individual Sector votes were Generation (17.17% in favor, 0% opposed, 4 abstentions), Transmission (0% in favor, 17.17% opposed, 1 abstention), Supplier (11.04% in favor, 6.13% opposed, 4 abstentions), Alternative Resources (2.95% in favor, 11.22% opposed, 2 abstentions), Publicly Owned Entity (0% in favor, 17.17% opposed), and End User (0% in favor, 17.17% opposed, 3 abstentions).

ISO-PROPOSED MODIFICATIONS TO THE PEAK ENERGY RENT MECHANISM

III.13.7.2.7. Adjustments to Monthly Capacity Payments.

Monthly capacity payments to resources with a Capacity Supply Obligation as of the beginning of the Obligation Month will be adjusted as described in Section III.13.7.2.7.1.

III.13.7.2.7.1. Adjustments to Monthly Capacity Payments of Generating Capacity Resources.

III.13.7.2.7.1.1. Peak Energy Rents.

Payments to New Generating Capacity Resources and Existing Generating Capacity Resources with Capacity Supply Obligations, except for resources not commercial as described in Section III.13.7.1.1.3(h) or Section III.13.7.1.1.3(i), shall be decreased by Peak Energy Rents ("PER") calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone.

III.13.7.2.7.1.1.1. Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

$$\text{Hourly PER}(\$/\text{kW}) = [(\text{LMP} - \text{Strike Price}) * [\text{Scaling Factor}] * [\text{Availability Factor}]]$$

Where:

Strike Price = [the heat rate x fuel cost of the PER Proxy Unit described below] + \$250.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in

ISO-PROPOSED MODIFICATIONS TO THE PEAK ENERGY RENT MECHANISM

the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.2.7.1.1.2. Monthly PER Application.

(a) The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as follows:

PER Adjustment = the minimum of: (i) the PER cap or (ii) the Average Monthly PER x PER Capacity Supply Obligation.

ISO-PROPOSED MODIFICATIONS TO THE PEAK ENERGY RENT MECHANISM

Where the PER cap for each resource equals the FCA Payment, plus the product of the net value of any other Capacity Supply Obligations assumed or shed after the Forward Capacity Auction for the same Capacity Commitment Period multiplied by the Capacity Clearing Price applicable to that resource's location from that Forward Capacity Auction. Where the calculation results in a PER cap value less than zero, the PER cap will be revised to zero.

Where the PER Capacity Supply Obligation is equal to the minimum of the Capacity Supply Obligation or the Capacity Supply Obligation less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource. However, if the Capacity Supply Obligation less any Capacity Supply Obligation from any portion of a Self-Supplied FCA Resource is less than zero, it will be zero for purposes of comparing it to the Capacity Supply Obligation in the PER Capacity Supply Obligation calculation.

- (b) PER shall be deducted from capacity payments independently of availability penalties.
- (c) FCA Payment minus PER may not be negative for any month.



To: NEPOOL Markets Committee
From: Catherine McDonough
Date: August 27, 2014
Subject: PER Modifications for CCP5-CCP8

Background

As directed by the order that FERC issued on May 30, 2014 in Docket No. ER14-1050, the ISO submitted rule changes on July 14, 2014 in Docket No. ER14-2419 to increase Reserve Constraint Penalty Factors (RCPFs) effective on December 3, 2014.

The increase in RCPFs will have no adverse impact on economic efficiency but could create a revenue transfer from resource owners to load-serving entities. Because the Peak Energy Rent adjustment mechanism (PER Adjustment) is applied to reach resource's entire CSO, the increase in RCPFs will have a larger impact on the PER Adjustment (a deduction from FCM payments) than the prospective increase in real-time energy and reserve market revenue. The increase in RCPFs is also likely to increase Day-Ahead Energy Market and Forward Reserve Market revenue but these revenue impacts are difficult to accurately predict.

Resource owners are concerned that they could not factor the higher potential cost of the PER Adjustment into their FCA bids for auctions that have already occurred (FCA5 - FCA8) and that the increase in RCPFs may create a revenue transfer from resource owners to load-serving entities.

ISO Proposal

The ISO is proposing to recalibrate the PER Adjustment to minimize the real-time revenue impact of higher RCPFs on resource owners by raising the daily PER Adjustment strike price by \$250.¹ Adjusting the PER strike price is a simple way to reduce the impact of higher RCPFs on the PER Adjustment and could be done by December 3, 2014. With the higher PER strike price

¹http://www.iso-ne.com/committees/comm_wkgrps/mrks_comm/mrks/mtrls/2014/aug562014/a03_mr_1_section_13_7_redlined_08_05_14.docx

in place, the real-time revenue impact² of higher RCPFs on resource owners would have been close to zero in CCP4. Resource owners would still experience the potential benefit of higher RCPFs on day-ahead energy and forward reserve prices.

Stakeholder Discussion

At the July 8-10, 2014 Markets Committee meeting, the ISO discussed the implications of raising RCPFs for the PER Adjustment. Near term (CCP5-to-CCP8), the FERC-ordered increase in RCPFs will increase energy and reserve market revenue and the Peak Energy Rent Adjustment Mechanism (a deduction from FCM payments). Longer term (FCA-9 and beyond), the implementation of the FCM Pay-for-Performance (PFP) mechanism may reduce the usefulness of the PER Adjustment in curbing the incentive to exercise market power. The ISO indicated that two separate evaluations would be required to address these issues. The ISO also reviewed recent history regarding in RCPFs and an example that described how higher RCPFs impact the PER Adjustment. The ISO also requested stakeholder input regarding how to address the near term and longer term issues related to the PER Adjustment.³

At the August 5-6, 2014 Markets Committee meeting, the ISO reviewed a proposal to address both issues based on the input provided at the previous meeting and responded to suggestions from stakeholders. To address the near term issue, the ISO proposed to increase the PER Adjustment strike price by \$250 as described above. To address the longer term issue, the ISO proposed to evaluate the usefulness of the PER Adjustment following the implementation of the PFP mechanism and to include the hedging role for the PER Adjustment as part of that evaluation.⁴

Response to GDF Suez Proposals

At the August 5-6, 2014 Markets Committee meeting, GDF Suez proposed that the PER Adjustment be eliminated.⁵

³See http://www.iso-ne.com/committees/comm_wkgrps/mrks_comm/mrks/mtrls/2014/jul89102014/a13_iso_presentation_07_10_14_r2.pptx

⁴See http://www.iso-ne.com/committees/comm_wkgrps/mrks_comm/mrks/mtrls/2014/aug562014/a03_iso_presentation_08_05_14.pptx

⁵See http://www.iso-ne.com/committees/comm_wkgrps/mrks_comm/mrks/mtrls/2014/aug562014/a03_gdf_suez_presentation_08_05_14.pdf

The ISO does not support the elimination of the PER Adjustment for CCP5-to-CCP8. Higher RCPFs do not reduce the rationale for the PER Adjustment under the existing FCM design. Moreover, FCA bids and clearing results for FCA-5-to-FCA-8 already factored in the existing PER Adjustment calculation. The ISO also indicated that it may support eliminating the PER Adjustment for FCA-10 and beyond if an internal review demonstrates that it no longer serves a useful role and this decision is made prior to running the auction for FCA-10.

GDF Suez further proposed that the PER Adjustment be calculated differently (unless the PER Adjustment is eliminated).

The ISO does not support the alternative calculation of the PER Adjustment proposed by GDF Suez for any commitment period. Even if participants do not change their DAEM bidding behavior, the alternative PER calculation weakens the hedge to load-serving entities; load-serving entities would get smaller PER Adjustment credit than what they paid for in the form of higher FCM clearing prices in CCP5-to-CCP8. More important, the alternative PER Adjustment changes day-ahead market bidding incentives in a way that could eliminate the PER Adjustment. If the ISO evaluation indicates that the PER Adjustment serves no useful role in FCA-10 and beyond, it is would be preferable to simply eliminate the PER Adjustment than to implement an alternative calculation of the PER Adjustment that essentially has the same effect.⁶

Next Steps

At the September 3, 2014 Markets Committee, the ISO will be asking participants to support the ISO proposal to increase the PER strike price by \$250. Because the ISO proposal addresses revenue allocation issues that raise equity issues and does not address a reliability or economic efficiency concern, the ISO likely would only file the proposal if there is at least 60% support from stakeholders. Please feel free to contact e-mail me at cmcdonough@iso-ne.com or call me at (315) 420-7322 if you have any questions or comments ahead of the meeting.

SEPTEMBER 3-4, 2014 | MARKETS COMMITTEE MEETING



Peak Energy Rent (PER) Adjustment Mechanism

*Summary of ISO Proposal &
Response to GDF Suez Proposals*

Catherine McDonough

CMCDONOUGH@ISO-NE.COM | 413-535-4027



Summary

- ISO proposes to increase the daily PER strike price by \$250 to reduce the impact of the FERC-ordered increase in Reserve Constraint Penalty Factors (RCPFs) on the PER Adjustment
 - ISO will likely only file the proposal if there is at least 60% support from stakeholders.



FERC Ordered Impact Increase in RCPFs

May Shift Revenue from Resource Owners to Load via PER Adjustment

- To comply with the May 30, 2014 FERC Order [ER14-1050](#), ISO will increase the Reserve Constraint Penalty Factors (RCPFs)
 - Coincident with the Hourly Offers project, which is currently scheduled for Dec. 3, 2014
- Higher RCPFs may increase energy and reserve market revenue and the PER Adjustment.
 - Higher RCPFs will have a bigger impact on the PER Adjustment (a deduction from FCM payments) than the increase in real-time energy and reserve market revenue
 - Day-Ahead Locational Marginal prices (DALMPs) and Forward Reserve Market (FRM) prices will also rise but impact is hard to accurately predict
 - Resource owners were not able to factor the revenue impact of higher RCPFs into bids for Forward Capacity Auctions (FCA) associated with CCP5-CCP8.
 - So, the increase in RCPFs could transfer revenue from resource owners to load between December 2014 and May 2018



ISO Proposal

Raise the PER Adjustment Strike Price by \$250

- ISO proposes to recalibrate the PER Adjustment to minimize the Real-time (RT) revenue impact of higher RCPFs on resource owners by raising the daily PER strike price by \$250
 - Adjusting the PER strike price is a simple way to reduce the impact of higher RCPFs on the PER Adjustment and can be done by December 3, 2014
 - With a higher PER strike price in place, the RT revenue impact of higher RCPFs on resource owners would have been close to zero in CCP4
 - See Appendix slide 17
 - Reducing the impact of higher RCPFs on the PER Adjustment does not impact economic efficiency
- Because the ISO proposal addresses revenue allocation issues that raise equity issues and does not address reliability or economic efficiency concerns, the ISO likely would only file the proposal if there is at least 60% support from stakeholders.



ISO RESPONSE TO GDF SUEZ AMENDMENTS

Highlights

- ISO does not support GDF Suez Proposal to eliminate the PER Adjustment in CCP5-to-CCP9
 - Higher RCPFs do not change the rationale for the PER Adjustment under existing FCM market rules
 - Clearing results for FCA5 to FCA-8 already factor in the existing PER Adjustment
 - Bids for FCA-9 already factor in the existing PER Adjustment and Higher RCPFs
- ISO does not support GDF Suez Proposal to Change the PER Adjustment
 - Alternative calculation proposed by GDF Suez changes DAEM bidding incentives in a way that will effectively eliminate the PER Adjustment
 - If the ISO review shows that the PER Adjustment plays no useful role in FCA10 and beyond, then it would be preferable to simply eliminate the PER Adjustment



ISO Does not Support GDF Suez Proposal to the Eliminate PER Adjustment: CCP5-CCP9

- GDF Suez proposes that the PER Adjustment be eliminated
- ISO does not support the elimination of the PER Adjustment in CCP5-to-CCP9
 - Higher RCPFs do not reduce the rationale for the PER Adjustment under the existing FCM design
 - FCA bids and clearing results for FCA5-to-FCA-8 already factored in the existing PER Adjustment calculation.
 - Bids for FCA-9 already factor in the existing PER Adjustment and Higher RCPFs
- ISO may support eliminating the PER Adjustment for FCA-10 and beyond if an internal review demonstrates that the PER Adjustment no longer serves a useful role and this determination is made prior to running the auction for FCA-10



ISO Does not Support GDF Suez Proposal for an Alternative PER Adjustment Calculation

- If the PER Adjustment is not eliminated, GDF Suez proposes that the PER Adjustment be calculated differently:
 - Hourly PER for MWs cleared in DAEM and delivered as energy, reserves or regulation in real time should be based on DALMP
 - Hourly PER for MWs that do not clear in the DAEM but are delivered as operating reserve in real time should be based on lower of the real-time operating reserve price or RTLMP
 - Hourly PER should be zero for all MWs offering regulation service
 - Hourly PER should be same as existing calculation (RTLMP) for all other CSO MWs
- ISO does not support the Alternative PER Adjustment calculation proposed by GDF Suez for any commitment period



Alternative PER Adjustment Calculation Weakens Existing Energy Price Hedge for Load

- Even with no change in participant behavior, the Alternative PER calculation weakens the hedge to load (See Example on page 10)
 - Hourly PER associated with MWs that clear in the DAEM (the majority of MWs cleared in energy market) is effectively zero
 - DALMP should always be less or equal to the PER Strike
 - Hourly PER for MWs that do not clear and provide reserves in real time will be less because reserve prices are sometimes less than RTLMPs
 - Hourly PER will be zero for all resources that provide regulation MWs
 - Monthly PER Adjustment credit to load for CCP-4 would have been at least 54% lower with Alternative PER Calculation
- Load gets a smaller PER Adjustment credit than what they paid for in the form of higher FCM clearing prices in CCP5-to-CCP9
 - FCA-5 to FCA-8 clearing prices were based on bids from resource owners that incorporate the expected PER Adjustment under existing rules which is higher than what the expected PER Adjustment would be under the Alternative PER Calculation proposed by GDF Suez
 - Bids for FCA-9 already factor in the existing PER Adjustment



Alternative PER Adjustment Weakens Energy Price Hedge For Load (even w/no change in participant behavior): *Example*

Assumptions	Existing PER*	Alternative PER**
Resource CSO (MW)	100	100
DAEM Clearing		
Cleared Generation (MW)	90	90
Cleared Decrements (MW)	90	90
DALMP= PER Strike (S)	\$500	\$500
RTEM Clearing		
Cleared Physical Load (MW)	100	100
RTLMP	\$800	\$800
Settlement		
Energy Market Cost to Physical Load	\$80,000	\$80,000
FCM PER Adjustment	\$30,000	\$3,000
Net Cost to Physical Load	\$50,000	\$77,000
Max(RTLMP-S,0) PER CSO **Max (DALMP-S,0)* min(DA CLR MW,PER CSO) + Max ((RTLMP-S),0)*max(PER CSO- DA CLR MW),0)		

Existing PER Adjustment Creates a Price Cap for Load at the PER Strike Price

Alternative PER Adjustment Weakens this Hedge for Load



Alternative PER Adjustment Changes DAEM Bidding Incentives in a Way that Effectively Eliminates the PER Adjustment

- Alternative PER Adjustment changes DAEM bidding incentives in a way that will effectively eliminate the PER Adjustment
 - CSO resources that clear in the DAEM will not pay any PER Adjustment because $DALMP \leq$ to PER strike price
 - CSO resources that do not clear in the DAEM can avoid the PER Adjustment by submitting the following
 - Supply offer at the floor price in the DAEM
 - Decrement (DEC) bid for same amount of power at same location at high price
 - Supply Re-offer at MC in the RTEM (See example on slide 12)
- If the ISO evaluation indicates that the PER Adjustment serves no useful role in FCA-10 and beyond, it is preferable to eliminate the PER Adjustment than to implement an Alternative Calculation of the PER Adjustment that essentially has the same effect.



Alternative PER Adjustment Changes DAEM Bidding Incentives in a Way that Effectively Eliminates PER Adjustment : *Example*

Assumptions	(a) Existing PER Adjustment *	(b) Existing PER Adjustment *	(c) Alternative PER Adjustment **	(d) Alternative PER Adjustment **
Resource Owner Bidding Strategy	Offer Resource @ MC in DAEM	Offer Resource @ low-price DAEM DEC @ High price in DAEM Re-Offer Resource @ MC in RTEM	Offer Resource @ MC in DAEM	Offer Resource @ low-price DAEM DEC @ high-price in DAEM Re-offer Resource @ MC in RTEM
Resource MC	\$400	\$400	\$400	\$400
Resource CSO (MW)	100	100	100	100
DAEM Cleared Supply MW	0	100	0	100
Cleared DEC MW	0	100	0	100
RTEM Cleared Supply MW	100	100	100	100
PER Strike Price (\$)	\$500	\$500	\$500	\$500
DALMP	\$200	\$200	\$200	\$200
RTLMP				
No Shortage	\$50	\$50	\$50	\$50
Shortage	\$800	\$800	\$800	\$800
PER Adjustment				
No Shortage	\$0	\$0	\$0	\$0
Shortage	\$30,000	\$30,000	\$30,000	\$0
Variable Profit = Revenue-Cost- PER Adjustment				
No Shortage	\$0	\$0	\$0	\$0
Shortage	\$10,000	\$10,000	\$10,000	\$40,000
* $\text{Max}(\text{RTLMP}-S, 0) * \text{PER CSO}$ ** $\text{Max}(\text{DALMP}-S, 0) * \min(\text{DA CLR MW}, \text{CSO}) + \text{Max}((\text{RTLMP}-S), 0) * \max(\text{PER CSO} - \text{DA CLR MW}, 0)$				



Summary and Next Steps

- May 30, 2014 FERC Order [ER14-1050](#) has implications for the PER Adjustment
- RCPFs will be increased, coincident with the Hourly Offers project, independent of any action taken to modify PER Adjustment rules for CCP5 and beyond
- ISO is proposing to increase the PER strike price by \$250 to reduce the impact of the increase in RCPFs on the PER Adjustment for the interim CCP5-CCP8 period

Date	Action
July 2014	Introduction
August 2014	Discussion of ISO Proposal to Address Impact of Higher RCPFs
September 2014	MC Vote on ISO Proposal
October 2014	PC Vote and Filing with FERC, pending support by participants
December 2014	Implementation of Higher RCPFs & ISO Proposal to raise PER Strike price, if filed and approved by FERC



APPENDIX

Background Material

Simulated Revenue Impact of Higher RCPFs

Reserve Market Impact of FERC-ordered Increase in RCPFs:

Simulated Back-cast for CCP3 and CCP4 (June 2012-May 2014)

Simulated Increase in Revenues (millions)				
Year	TMSR	TMNSR	TMOR	Total
CCP3	\$ 0.79	\$ 1.90	\$ 0.64	\$ 3.34
CCP4	\$ 8.55	\$ 11.66	\$ 4.47	\$ 24.68
Annual Average	\$ 4.67	\$ 6.78	\$ 2.56	\$ 14.01

Reserve Market Revenue would have been \$25M greater in CCP4, and \$14M greater on average in CCP3 & CCP4



Some Revenue Impacts of FERC-ordered Increase in RCPFs:

Simulated Back-cast for CCP4 (June 13-May 14)

Years	Capacity Commitment Period	Reserve Market Revenue	RT Peak Energy Rents	PER Adjustment Revenues
2010-2011	CCP1	\$ 13.6	\$ 12.1	\$ (188.1)
2011-2102	CCP2	\$ 6.9	\$ 0.2	\$ (36.3)
2012-2013	CCP3	\$ 34.8	\$ 0.3	\$ (1.6)
2013-2014	CCP4	\$ 63.7	\$ 1.4	\$ (25.2)
2013-2014	CCP4 Estimate w/ Higher RCPFs	\$ 88.4	\$ 8.4	\$ (124)
Estimated Impact of Higher RCPFs CCP4		\$ 24.7	\$ 7.0	\$ (99.0)

- If the FERC-ordered increase in RCPFs had been in place in CCP4:
- Reserve market revenue would have been \$25M higher
- RT peak energy rents would have been \$7M higher
- PER Adjustment would have credited \$99M more back to load.
- RT impact on resource owners net of the PER Adjustment would have been
 $= \$25M + \$7M - \$99M = -\$67M$
- Excludes the potential impact of higher RCPFs on DAEM revenue, which is likely positive, but difficult to predict



Summary of Participant Input

Summary of Participant Comments

Near Term Issue

- Several Participants suggested that nothing be done.
 - The impact of higher RCPFs on the PER Adjustment was not unexpected and NEPOOL previously voted down proposals to change/eliminate the PER Adjustment when they voted to increase the RCPFs as part of the NEPOOL alternative to the FCM PFP.
 - Participants also observed that the increase in the PER Adjustment due to higher RCPFs could be offset by higher energy and reserve market revenue.
- Several participants suggested ‘re-calibrating’ the PER Adjustment to neutralize impact of higher RCPFs (on the PER Adjustment).
- Some participants recommend that the PER Adjustment use an Adjusted RTLMPs that ‘nets out’ the increase in the RCPFs when they take effect on December 3, 2014.



Summary of Participant Comments & ISO Response

Near Term Issue

- Some participants suggested that the PER Adjustment be eliminated in CCP5-CCP8, indicating that:
 - PER Adjustment is not necessary to curb the incentive to exercise market power in the energy market because IMM has other means to do so via the actions detailed in Appendix A.
 - PER Adjustment is an imperfect hedge for load; commercial retailers can also provide hedges.
 - Previously proposed during the debates of on the FCM PFP and NEPOOL's Alternative
- ISO does not support eliminating the PER Adjustment in CCP5-CCP9
 - Higher RCPFs do not reduce the rationale for the PER Adjustment under the existing FCM design
 - ISO may support eliminating the PER Adjustment for FCA10 and beyond if an internal review demonstrates that it no longer serves a useful role.



Summary of Participant Comments & ISO Response

Near Term Issue (continued)

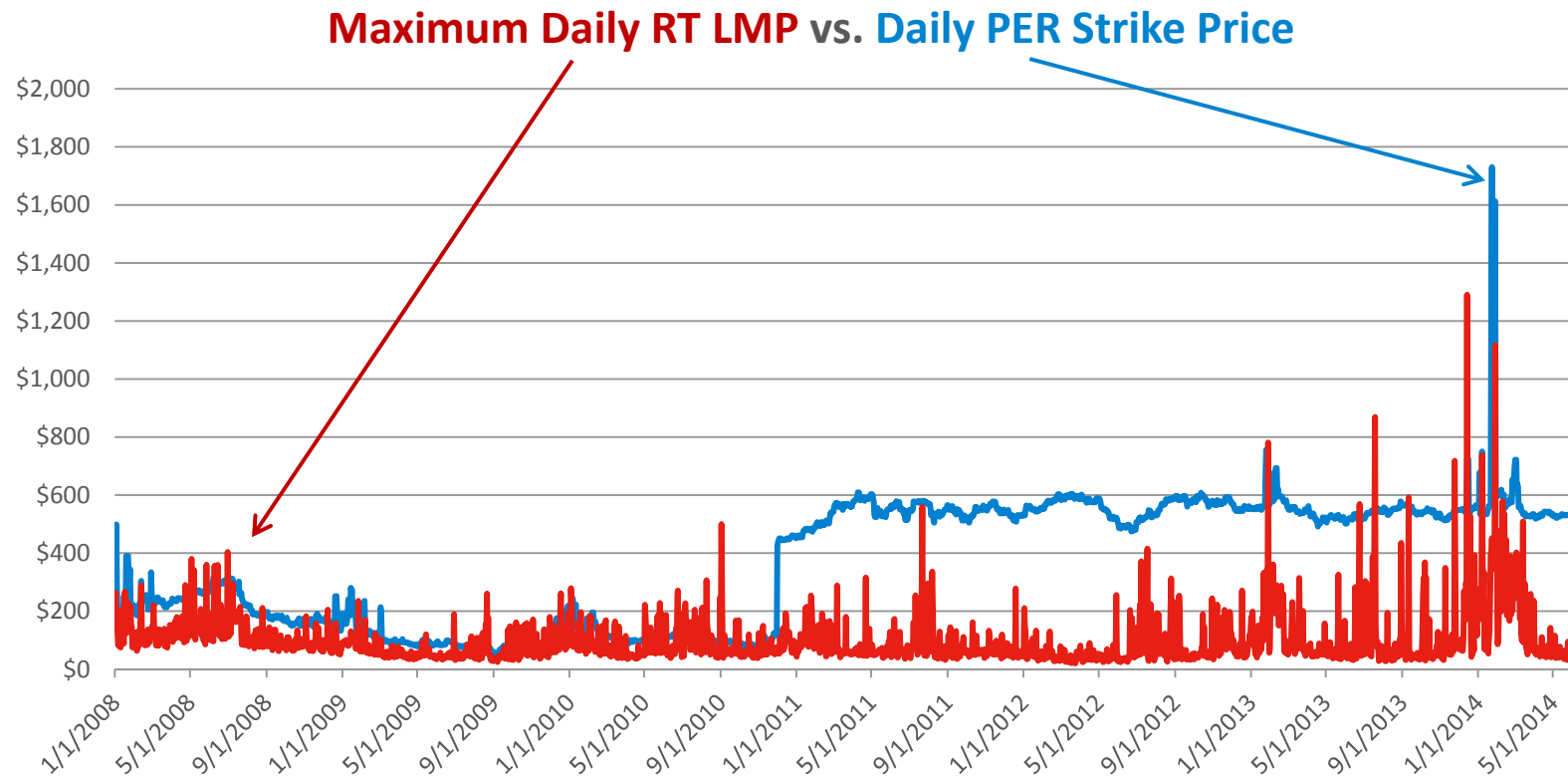
- Some Participants suggested we calculate the PER Adjustment based on a resource's cleared status in energy/reserve markets
 - The PER Adjustment calculation should depend on whether a supplier clears in the Day-Ahead Energy Market (DAEM) or in the Real-Time Energy Market (RTEM) and whether a supplier provides energy or reserves in real time.
 - This approach was previously proposed by GDF Suez during debates on the FCM PFP and NEPOOL's Alternative.
- ISO does not support any proposal to calculate the PER Adjustment based on a resource's cleared status for any commitment period
 - Calculating the PER Adjustment in this way distorts DA/RT bidding incentives (See Examples in Appendix pages 27-30)



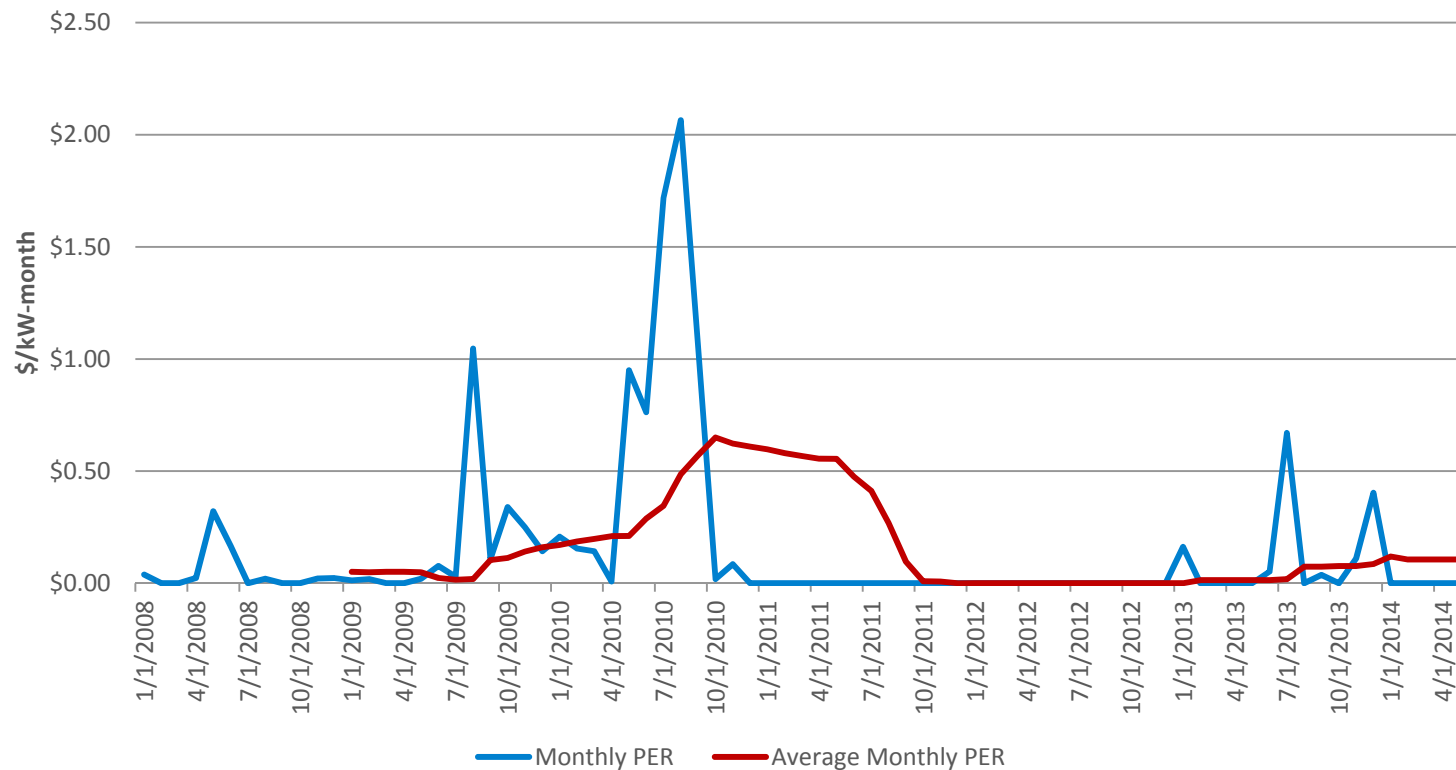
Historical Perspective on PER Adjustment

Existing PER Adjustment:

Historical View of Key Components



Existing PER Adjustment : Historical View of Monthly PER and Moving Average of Monthly PER



Hours when Hourly PER Value Has Been Positive Since December of 2010;

Day	Hour	PER Strike	RT LMP	DA LMP	RT-DA LMP
1/28/2013	18	\$ 560	\$ 781	\$ 209	\$ 572
6/24/2013	16	\$ 513	\$ 569	\$ 88	\$ 481
7/19/2013	13	\$ 558	\$ 704	\$ 183	\$ 521
7/19/2013	14	\$ 558	\$ 869	\$ 196	\$ 673
7/19/2013	15	\$ 558	\$ 709	\$ 207	\$ 503
7/19/2013	16	\$ 558	\$ 630	\$ 209	\$ 421
7/19/2013	17	\$ 558	\$ 585	\$ 219	\$ 366
9/11/2013	17	\$ 552	\$ 592	\$ 419	\$ 173
11/24/2013	20	\$ 548	\$ 717	\$ 100	\$ 618
12/14/2013	18	\$ 724	\$ 1,290	\$ 275	\$ 1,015
Average		\$ 569	\$ 745	\$ 211	\$ 534

•Average RT/DA LMP Differential when Hourly PER Value is Positive = +\$535

•RCPFs were activated in all of these hours

Note: All prices and differentials shown in \$/ MWh



*Existing PER Adjustment DOES NOT DISTORT DA/RT Bidding
incentives*

Existing PER Adjustment Does Not Distort DA/RT Bidding Incentives

- Current PER Adjustment is based on the supplier's CSO and *not on the megawatts that a supplier clears in real time.*
- A competitive supplier cannot change the PER Adjustment by bidding more or less in the DA or RT energy market



Example

- Assume
 - Supplier has one unit with $MC = \$50/\text{MWh}$ and $CSO = 300 \text{ MW}$
 - PER Strike price is $\$120/\text{MWh}$
 - $DALMP = \$100$
 - $RTLMP = \$150$
 - Case 1 : Clears DA w/ PER Adjustment
 - Case 2 : Clears RT w/ PER Adjustment
 - Case 3 : Clears DA w/ No PER Adjustment
 - Case 4 : Clears RT w/ No PER Adjustment
 - Table on slide 24 shows calculation of total variable profit for each case with the existing PER Adjustment
 - Table on slide 25 compares the relative profit of clearing DA or RT with the existing PER Adjustment



Existing PER Adjustment Mechanism

Example *(continued)*

	MW	Revenues	VC	PER ADJ	Total
Case 1: Clears DA w/ PER Adjustment					
DA	300	\$ 30,000		\$ (9,000)	\$ 21,000
RT	300		\$ (15,000)		\$ (15,000)
RT-DA	0	\$ -			
Variable Profit					\$ 6,000
Case 2: Clears RT w/ PER Adjustment					
DA	0	\$ -			\$ -
RT	300		\$ (15,000)	\$ (9,000)	\$ (24,000)
RT-DA	300	\$ 45,000			\$ 45,000
Variable Profit					\$ 21,000
Case 3: Clears DA w/ no PER Adjustment					
DA	300	\$ 30,000			\$ 30,000
RT	300		\$ (15,000)		\$ (15,000)
RT-DA	0	\$ -			
Variable Profit				\$ -	\$ 15,000
Case 4: Clears RT w/ no PER Adjustment					
DA	0	\$ -			\$ -
RT	300		\$ (15,000)		\$ (15,000)
RT-DA	300	\$ 45,000			\$ 45,000
Variable Profit				\$ -	\$ 30,000



Existing PER Adjustment Mechanism: Example *(continued)*

Summary of Total Variable Profit		
	PER Adj.	No PER Adj
Clears DA	\$ 6,000	\$ 15,000
Clears RT	\$ 21,000	\$ 30,000
Difference	\$ 15,000	\$ 15,000

Existing PER Adjustment Does Not Change the Profitability
of Clearing in DA versus Clearing in Real Time



*Calculating the PER Adjustment Based on A Resource's
Cleared Status DISTORTs DA/RT Bidding incentives*

Alternative Calculation of PER Adjustment

- Calculate PER Adjustment based on whether a participant clears in the DAEM or RTEM

$\text{Max}(\text{DALMP}-S, 0) * \min(\text{DA CLR MW}, \text{CSO}) +$

$\text{Max}((\text{RTLMP}-S), 0) * \max(\text{PER CSO} - \text{DA CLR MW}, 0)$

- NEPOOL voted down a variant of this approach proposed by GDF Suez
 - Hourly PER for MWs cleared in DAEM and delivered as energy, reserves or regulation in real time should be based on DALMP
 - Hourly PER for MWs that do not clear in the DAEM but are delivered as operating reserve in real time should be based on lower of real time operating reserve price or RTLMP for
 - Hourly PER should be zero for all MWs offering regulation service
 - Hourly PER should be same as existing calculation (RTLMP) for all other CSO MWs
- ISO does not support any approach that makes the calculation hinge on how a resource clears because to do so would interfere with bidding incentives as shown in the following example



Example: Alternative PER Adjustment Calculation

	MW			Revenues	VC	ALT PER ADJ	Total
Case 1: Clears DA w/ PER Adjustment							
DA	300			\$ 30,000		\$ -	\$ 30,000
RT	300				\$ (15,000)		\$ (15,000)
RT-DA	0			\$ -			
Variable Profit							\$ 15,000
Case 2: Clears RT w/ PER Adjustment							
DA	0			\$ -			\$ -
RT	300				\$ (15,000)	\$ (9,000)	\$ (24,000)
RT-DA	300			\$ 45,000			\$ 45,000
Variable Profit							\$ 21,000
Case 3: Clears DA w/ no PER Adjustment							
DA	300			\$ 30,000			\$ 30,000
RT	300				\$ (15,000)		\$ (15,000)
RT-DA	0			\$ -			
Variable Profit							\$ 15,000
Case 4: Clears RT w/ no PER Adjustment							
DA	0			\$ -			\$ -
RT	300				\$ (15,000)		\$ (15,000)
RT-DA	300			\$ 45,000			\$ 45,000
Variable Profit							\$ 30,000



Example: Alternative versus Existing PER Calculation

Summary of Total Variable Profit		
	PER Adj.	No PER Adj
Clears DA	\$ 6,000	\$ 15,000
Clears RT	\$ 21,000	\$ 30,000
Difference	\$ 15,000	\$ 15,000
	ALT PER Adj.	No PER Adj
Clears DA	\$ 15,000	\$ 15,000
Clears RT	\$ 21,000	\$ 30,000
Difference	\$ 6,000	\$ 15,000

Existing PER Adjustment Does Not
Change the Profitability of Clearing
DA versus in Real Time

Alternative PER Adjustment
Changes the Profitability of Clearing
in DA versus Real Time



PER Adjustment Mechanism: The Details

Existing PER Adjustment Mechanism:

Details

- Hourly PER = (RTLMP-S)* Scale Factor*Availability Factor
 - RTLMP: for each Load Zone associated with particular capacity zone
 - S: variable cost of marginal generating proxy unit (22,000 BTU/kWh) * daily cost of gas or oil whichever is *higher*
 - Scale factor: creates lower weighting for hours when load is low relative to forecasted peak
 - Calculated as the actual hourly integrated load divided by the summer 50/50 predicted peak forecast
 - Availability Factor: marginal proxy unit = 0.95
- Monthly PER = Sum of Hourly PER values for the month.
- Average Monthly PER = 12 month moving average of Monthly PER values prior to the obligation month.



Existing PER Adjustment Mechanism

Details (continued)

NEPOOL PARTICIPANTS COMMITTEE
OCT 3, 2014 MEETING, AGENDA ITEM #7

- $\text{PER Adjustment} = \text{Average Monthly PER} * \text{PER CSO}$
 - $\text{PER CSO} = \text{minimum} [\text{CSO}, (\text{CSO} - \text{Self Supply Obligation})]$
 - Monthly PER Adjustment is capped at the FCA Payment adjusted to account for obligations acquired or shed for the same commitment period after the FCA
 - $\text{PER CAP} = \text{FCA Payment} + [(\text{ARA CSO} + \text{MRA CSO} + \text{IBT CSO}) * \text{FCA Clearing Price}^*]$
 - FCA payment is payment received for activity in the Forward Capacity Auction
 - $[\text{ARA CSO} + \text{MRA CSO} + \text{IBT CSO}]$ are obligations acquired or shed
 - FCA clearing price * is adjusted for price collar (This price is used as a proxy price to prevent opportunities to manipulate the PER CAP such as could be done with a bilateral at zero contract price)
 - ARA is annual reconfiguration auction, MRA is the monthly reconfiguration auction and IBT is internal bilateral transactions



GDF SUEZ AMENDMENT

Peak Energy Rent (PER) Modifications

(yellow highlights reflect mark-up by ISO for FCM PI Proposal)

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.3.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1, as adjusted to account for peak energy rents as described in Section III.13.7.1.2.

III.13.7.1.1. Monthly Payments and Charges Reflecting Capacity Supply Obligations.

[Text below moved from old Section III.13.7.2.1.1, then redlined.]

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period based on the following amounts:

- (a) **Forward Capacity Auction.** For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity (or in the case of a New Generating Capacity Resource that has cleared in the Forward Capacity Auction and has completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service is not able to achieve Commercial Operation, and is able to conduct a capability audit, the lesser of the resource's Capacity Supply Obligation or its audited amount) and the Capacity Clearing Price in the appropriate Capacity Zone in the New England Control Area as adjusted by applicable indexing for

resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions.** For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals.** For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

[This is old Section III.13.7.1.1 being deleted.]

III.13.7.1.2 Peak Energy Rents. [Text below moved from old Section III.13.7.2.7.1.1, then redlined.]

Capacity Base Payments to resources with Capacity Supply Obligations, except for New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve Commercial Operation, shall be decreased by Peak Energy Rents (“PER”) calculated for that Resource, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs, Day-Ahead LMPs, and Real Time Operating Reserve prices. For each Resource in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs, Day-Ahead LMPs and Real Time Operating Reserve prices for the Capacity Zone applicable to each Resource, using the Real-Time Hub Price, Day-Ahead Hub Price, and Rest-of-Pool Real Time Operating

Reserve prices for the Rest-of-Pool Capacity Zone. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.

III.13.7.1.2.1 Hourly PER Calculations.

(a) Where the respective portion of the Qualified Capacity of a resource is not: (i) scheduled as energy in the Day-Ahead Energy Market, (i) designated as real time operating reserves, or (iii) providing Regulation in real time, or, are scheduled as energy in the Day-Ahead Energy Market but not delivered in real time as energy, operating reserves or Regulation, for hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute that portion of its PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

$$\text{Hourly PER}(\$/\text{kW}) = [\text{RTLMP} - \text{Strike Price}] * [\text{Scaling Factor}] * [\text{Availability Factor}]$$

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95.

(b) Where the respective portion of the Qualified Capacity of a resource is scheduled as energy in the Day-Ahead Energy Market and delivered in real time as energy, operating reserves or Regulation, the ISO shall compute that portion of its PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

$$\text{Hourly PER}(\$/\text{kW}) = [\text{DALMP} - \text{Strike Price}] * [\text{Scaling Factor}] * [\text{Availability Factor}]$$

(c) Where the respective portion of the Qualified Capacity of a resource is not scheduled as energy in the Day-Ahead Energy Market and are designated as real time operating reserves, the ISO shall compute that portion of its PER for each hour ("Hourly PER") equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

$$\text{Hourly PER}(\$/\text{kW}) = [\min(\text{RTOR Price, RTLMP}) - \text{Strike Price}] * [\text{Scaling Factor}] * [\text{Availability Factor}]$$

Where,

RTOR Price = the Real Time Operating Reserve price for Thirty Minute Operating Reserves.

(d) Where the respective portion of the Qualified Capacity of a resource is not scheduled as energy in the Day-Ahead Energy Market and provided Regulation in the hour, the ISO shall set that portion of its PER for each such hour ("Hourly PER") equal to zero.

$$\text{Hourly PER}(\$/\text{kW}) = 0$$

(e) For each Qualified Capacity resource, the ISO shall calculate its PER for each such hour ("Hourly PER") as the weighted average of the relevant calculations in (a)-(d) above for that resource for that hour.

(f) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the

state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.1.2.2 Monthly PER Application.

The Hourly PER shall be summed for each Qualified Capacity resource for that calendar month to determine the total PER for that resource in that month ("Monthly PER"). The Average Monthly PER for each resource shall be equal to the average of the Monthly PER values for that resource for the 12 months prior to the Obligation Month. Where a resource had zero Qualified Capacity for any of the 12 months prior to the Obligation Month, its Average Monthly PER shall be equal to the average of the Monthly PER values for the months in which it had any Qualified Capacity. The PER deduction for each resource shall be calculated as the Average Monthly PER for that resource multiplied by the resource's Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource's PER deduction for an Obligation Month be less than zero or greater than the resource's Capacity Base Payment for the Obligation Month. **[Moved to new Section III.13.7.1.1, then redlined.]**

III.13.7.1.3 Export Capacity.

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

Charge Amount to Resource Exporting = [Capacity Clearing Price_{location of the interface} - Capacity Clearing Price_{location of the resource}] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located = [Capacity Clearing Price_{location of the interface} - Capacity Clearing Price_{location of the resource}] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.3.1.

III.13.7.1.4 Monthly Capacity Payments for Real-Time Emergency Generation Resources.

For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

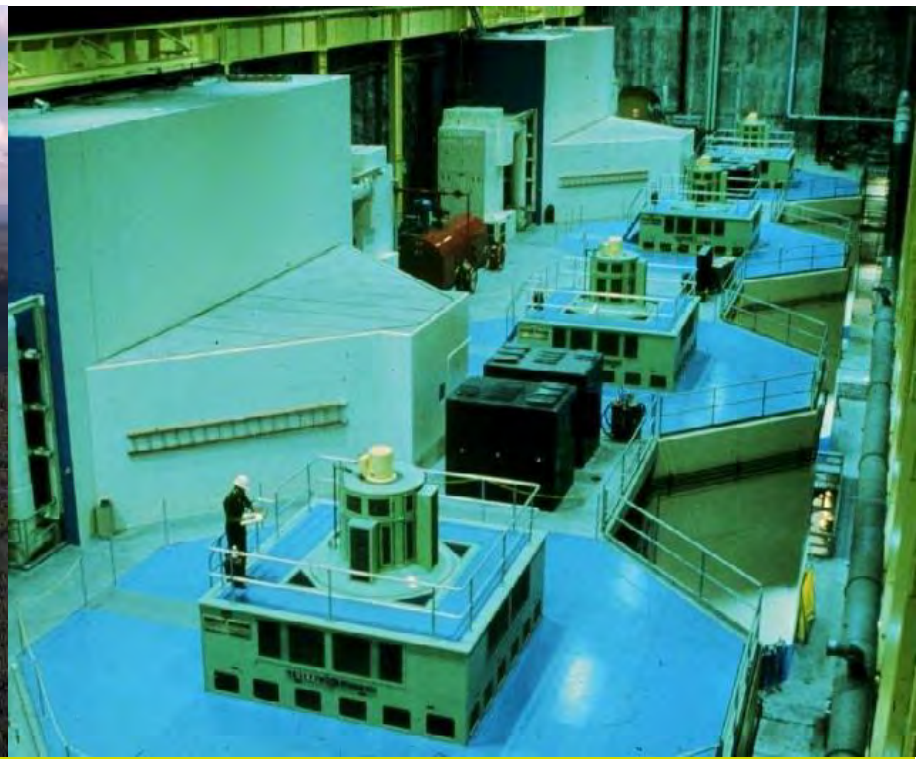
III.13.7.1.5 Energy Settlement for Real-Time Emergency Generation Resources

A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.1.5.1 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2017, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2017. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.1.5.1 Adjustment for Net Supply Generator Assets.

For Capacity Commitment Periods commencing on or after June 1, 2017, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section 8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the output eligible for payments will be set equal the adjusted Demand Response Baseline of the Demand Response Asset.

[Moved to new Section III.13.7.1.2, then redlined.]



Peak Energy Rent Design Flaws & Recommended Solution

Tom Kaslow

Director, Market Design & Regulatory Affairs – NE

GDF SUEZ Energy Marketing NA

GDF SUEZ

BY PEOPLE FOR PEOPLE



Overview

- PER – The Flaws
- Proposed PER modifications
- Analysis of ISO Feedback
- Conclusion



Peak Energy Rent – The Flaws

GDF SUEZ

BY PEOPLE FOR PEOPLE

PER penalizes generation sellers in the DAEM

- Capacity sellers are required to offer their energy into the Day Ahead Energy Market (DAEM) and most generation is sold (and purchased) at DAEM LMPs.
- Where the DAEM LMP includes inadequate margin to cover the capacity seller's real time PER risk, a capacity seller can be forced to sell energy below cost (example below). Assume:
 - PER proxy rate of \$400/MWh
 - DAEM sale at \$60/MWh (resource's Supply Offer of \$40/MWh)
 - DAEM sale physically supplied by resource in real time
 - RTEP LMP of \$430/MWh on a 50/50 peak load hour
- In this example, the PER charge = $\$30/\text{MWh} * 0.95 * 1.0 = \$28.50$
- The resource delivered the energy it sold in the DAEM but ultimately did not recover its costs and incurred a net loss of \$8.50/MWh!



PER penalizes real-time flexible resource performance

- PER penalizes Fast Start resources for partial hour generation under Integrated hourly energy pricing/settlement.
- Assume 100MW Fast Start unit has no DAEM sale, and
- Economically offline as operating reserve for first 30 minutes of hour (marginal energy price = \$50/MWh; RT Operating Reserve Price = 0)
- Responds with generation at full load for last 30 minutes when marginal price rises to \$810/MWh
- Integrated hourly RTLMP = \$430/MWh
- PER proxy rate = \$400/MWh
- PER charge of \$28.50/MWh charged to all 100MW, yet this flexible response only receives an energy settlement credit of 50MWh since energy market settled on the integrated hour.
- If the event happened in the first 30 minutes of the hour, it may encourage self-schedule in balance of hour to avoid this outcome.



GDF SUEZ Proposed Modifications

GDF SUEZ

BY PEOPLE FOR PEOPLE



PER not needed under FCM Pay-For-Performance (FCM-PFP)

- These PER flaws must be fixed and the best way to do this under FCM-PFP is to simply eliminate the PER mechanism.
- Section III.13.1.2.3.2.1.2 – Remove Peak Energy Rent term from the Going Forward Cost formula.
- Section III.13.7.2.7.1.1 – Eliminate the entire Peak Energy Rent section.



PER modifications needed prior to FCM-PFP period

- Before FCM-PFP, the hourly PER needs to be calculated consistent with ISO's use of the resource:
- Where megawatts sold in the Day Ahead Energy Market (DAEM) and deliver energy, operating reserves or Regulation in real time, base hourly PER on DAEM prices.
- Where megawatts not sold in the DAEM, and:
 - MWs supplying operating reserves - calculate the hourly PER based on the lower of the real time operating reserve price for thirty minute operating reserves or the real-time Locational Marginal Price (LMP).
 - MWs supplying Regulation service - set the hourly PER to zero.
- For all other MWs – calculate PER at the Real-Time Energy Market LMP.



Analysis of ISO New England Feedback

GDF SUEZ

BY PEOPLE FOR PEOPLE

Modified PER encourages efficient DA-RT activity

- ISO analysis inappropriately assumes that maintaining the same gap between DA and RT energy prices before/after the PER deduction is necessary to avoid distortion to DA-RT economics.
- Reality is that DA (virtual) bidders are unable to predict RT high price periods resulting in trigger of PER deduction.

Day	Hour	PER Strike	RT LMP	DA LMP	RT-DA LMP
1/28/2013	18	\$ 560	\$ 781	\$ 209	\$ 572
6/24/2013	16	\$ 513	\$ 569	\$ 88	\$ 481
7/19/2013	13	\$ 558	\$ 704	\$ 183	\$ 521
7/19/2013	14	\$ 558	\$ 869	\$ 196	\$ 673
7/19/2013	15	\$ 558	\$ 709	\$ 207	\$ 503
7/19/2013	16	\$ 558	\$ 630	\$ 209	\$ 421
7/19/2013	17	\$ 558	\$ 585	\$ 219	\$ 366
9/11/2013	17	\$ 552	\$ 592	\$ 419	\$ 173
11/24/2013	20	\$ 548	\$ 717	\$ 100	\$ 618
12/14/2013	18	\$ 724	\$ 1,290	\$ 275	\$ 1,015
Average		\$ 569	\$ 745	\$ 211	\$ 534

Note: All prices and differentials shown in \$/ MWh



Modified PER encourages efficient DA-RT activity (cont'd)

- Further, only Load Serving Entities (LSEs) with Capacity Load Obligation get the PER rebate, not other virtual bidders whose incentive to arbitrage the full extent of any DA-RT LMP difference is unaffected by PER.
- Applying a PER deduction relevant to DA (purchase and sale) price will not adversely change virtual bid activity.
- However, it will reduce the existing demand bid DA under-clearing incentive currently provided to LSEs by providing all PER rebates indexed to RT prices.



Conclusion

GDF SUEZ

BY PEOPLE FOR PEOPLE



Conclusion

- The existing PER design:
 - Requires good performing resources to sell a hedge inconsistent with the ISO's efficient use of their resource
 - Provides the incentive to reflect a PER risk premium in DAEM bids
 - Provides the incentive to sell real-time energy, not operating reserve or Regulation service, in potential PER hours
 - Supports LSE under-clearing of DA demand on higher energy price days
- The proposed PER modifications are needed to correct these flaws.

GDF SUEZ Energy Marketing N.A., Inc. Amendment #2 – Elimination of the Peak Energy Rent deduction under FCM Pay-For-Performance

III.13.1.2.3.2.1.2. Net Going Forward Costs.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. A Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Generating Capacity Resource's net going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{[GFC - (IMR - PER)] \times InfIndex}{(CQ_{Summer, kw}) \times (12, months)}$$

Where:

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and

shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

$CQ_{\text{Summer}}^{\text{kW}}$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid), this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be \$0.00. As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

~~PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.~~

~~At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected.~~

InfIndex = inflation index. $\text{infIndex} = (1 + i)^4$

Where: “i” is the most recent reported 4-Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.7.1.2 — Peak Energy Rents.

Capacity Base Payments to resources with Capacity Supply Obligations, except for New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve Commercial Operation, shall be decreased by Peak Energy Rents (“PER”) calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real Time LMPs for each Capacity Zone, using the Real Time Hub Price for the Rest of Pool Capacity Zone. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.

III.13.7.1.2.1 — Hourly PER Calculations.

(a) — For hours with a positive difference between the hourly Real Time energy price and a strike price, the ISO shall compute PER for each hour (“Hourly PER”) equal to this positive difference in accordance with the following formula, which includes scaling adjustments for system load and availability:

$$\text{Hourly PER} (\$/\text{kW}) = [\text{LMP} - \text{Strike Price}] * [\text{Scaling Factor}] * [\text{Availability Factor}]$$

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real Time Load Obligations for the system as calculated in the settlement of the Real Time Energy Market and adjusted for losses and including imports delivered in the Real Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95.

(b) — PER Proxy Unit characteristics shall be as follows:

(i) — The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation or day-ahead gas measured at the Algonquin City Gate, as determined on a daily basis;

(ii) — The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run-time constraints;

(iii) — The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.1.2.2. — Monthly PER Application.

The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as the Average Monthly PER multiplied by the resource's Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource's PER deduction for an Obligation Month be less than zero or greater than the product of the resource's Capacity Supply Obligation and the relevant Forward Capacity Auction Capacity Clearing Price.

III.13.7.1.3. Export Capacity.

If there are any Export Bids or Administrative Export De-list Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an

import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows ~~(for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).~~

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), ~~less PER adjustments for resources in the zone as defined in Section III.13.7.1.2,~~ and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. ~~A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.~~

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: David T. Doot and Sebastian M. Lombardi, NEPOOL Counsel

DATE: September 26, 2014

RE: Demand Response Participation in the Forward Reserve Market

At the October 3, 2014 Participants Committee meeting, you will be asked to consider supporting a set of Market Rule changes to enable Demand Response Resources to participate in the Forward Reserve Market and to provide Real-Time Operating Reserves for the price-responsive demand full integration period that is currently scheduled to begin on June 1, 2017. These changes are described in greater detail in background materials included with this memorandum.

At its September 3-4 meeting, the Markets Committee voted to recommend Participants Committee support for an earlier version of these Demand Response rule changes, with one opposition from a Generation Sector member and several abstentions noted. However, since that recommendation by the Markets Committee and after further review, the ISO is now proposing minor corrections to those changes. These corrections are described by the ISO in its September 26 memorandum and highlighted in green in revised Tariff sheets, both of which are included with this memorandum.

The typical form of resolution contemplates that the Committee may agree to changes at the meeting. Thus, if there is no objection, the Committee may agree to move the changes as proposed by the ISO with the corrections. If there is any objection to the corrections, the form of motion would be to approve the Markets Committee recommended changes, with the ISO's proposed corrections considered in the form of a motion to amend. In either case, the following form of resolution may be used:

RESOLVED, that the Participants Committee supports the revisions to Market Rule 1 to enable Demand Response Resources to provide Real-Time Operating Reserves, as recommended by the Markets Committee at its September 3-4, 2014 meeting, and circulated to this Committee in advance of this meeting, together with [those changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Given the current status of the DC Circuit decision vacating *Order 745*,¹ NEPOOL's record of the meeting will make clear that a vote in favor of this resolution is with the understanding that the Demand Response changes proposed here would be appropriate only if *Order 745* proceeds as lawful, and without prejudice to any position taken or that may be taken by any Participant(s) in the court proceeding(s) on *Order 745*.

¹ *Order 745* required RTOs and ISOs to include provisions in their tariffs that assured demand response would be paid at LMP for interrupting their loads when such interruption was cost effective.

To: NEPOOL Participants Committee

From: Henry Yoshimura, ISO New England

Date: September 26, 2014

Subject: **Full Integration of Demand Response Resources into the Energy and Reserves Markets**

In preparing filing materials concerning the proposed market rules for the above-mentioned subject, the ISO discovered two minor errors in the proposed market rules, which should be corrected before being filed with the Federal Energy Regulatory Commission for review and acceptance. These corrections were not included when the Markets Committee voted on the proposed changes in September, but have been added in the redlined tariff sections that are being presented to the Participants Committee for its vote.

First, the phrase “or demand reduction” was missing from Section III.9.7.2(a), which describes the computation of Target Activation Megawatts for TMOR for Demand Response Resources that have been dispatched. Page 25 of my July 30, 2014, memo to the Markets Committee explained that the phrase “or demand reduction” should have been incorporated into this section of the market rules. Also, this phrase was correctly incorporated into the same section of the market rules with respect to the computation of Target Activation Megawatts for TMNSR. To address this oversight, the ISO is including the phrase “or demand reduction” into Section III.9.7.2(a) as shown in green highlight below:

Target Activation Megawatts for TMOR from on-line Forward Reserve Resources, or Demand Response Resources that have been dispatched, is the lesser of: (i) the Resource’s Manual Response Rate or Demand Response Resource Ramp Rate times 30 minutes or (ii) the Resource’s Economic Maximum Limit or Maximum Reduction minus the Resource’s initial output or demand reduction at activation, or; (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource’s initial output or demand reduction at activation.

Second, a paragraph in Section III.13.6.1.5.4.3.3.1 made an incorrect reference to Demand Response Capacity Resources where Demand Response Resources should have been referenced. The term “Audited Demand Reduction” is defined in Section I.2.2 as “the seasonal claimed capability of a ***Demand Response Resource*** as established pursuant to Section III.13.6.1.5.4” (emphasis added). Accordingly, the ISO is striking the word “Capacity” from Section III.13.6.1.5.4.3.3.1 as shown in green highlight below:

Within 7 calendar days of the event, the participant must inform the ISO that it wishes to use dispatch performance during the event to establish the ~~resource’s~~ Demand Response ~~Capacity~~ Resource’s Audited Demand Reduction.

Please note that the yellow highlighted items in the redlined tariff sections denote non-substantive clean-up changes made by the ISO in drafting the demand response revisions, and do not represent new changes made since the Markets Committee vote.

SECTION III

MARKET RULE 1

APPENDIX E1

DEMAND RESPONSE

Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2017.

APPENDIX E1
DEMAND RESPONSE
Table of Contents

Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2017.

1. Demand Response Registration
2. Metering and Communication
3. Demand Reduction Offers
4. Day-Ahead Clearing, Scheduling and Notification
5. Real-Time Scheduling of Demand Reductions
6. Determination of the Demand Reduction Threshold Price
7. Demand Response Baselines
8. Real-Time Demand Reduction Obligations
9. Settlement
10. Average Distribution Losses

APPENDIX E1

DEMAND RESPONSE

1. Demand Response Registration

Appendix E1 applies to Capacity Commitment Periods commencing prior to June 1, 2017.

A Market Participant may register a Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis to provide demand reductions during hours ending 0800 through 1800 on non-Demand Response Holiday weekdays subject to the following conditions:

- (a) the asset is able to produce at least 100 kW of demand reduction, and;
- (b) the metering and communication equipment associated with the asset meets the requirements specified in Section III.E1.2.

A Real-Time Demand Response Asset may consist of an aggregation of multiple end-use metered customers.

1.1 Registration Parameters

During the registration process, Market Participants must submit the following information for each Real-Time Demand Response Asset:

- (a) Maximum Interruptible Capacity;
- (b) Maximum Load, and;
- (c) Maximum Generation, for Real-Time Demand Response Assets that are comprised of Distributed Generation.

1.2 Restrictions on Real-Time Demand Response Asset Registration

A Market Participant may not register and must retire if previously registered a Real-Time Demand Response Asset that is comprised of:

- (a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;
- (b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

A Market Participant may not register an existing Generator Asset as a Real-Time Demand Response Asset for the purpose of submitting Demand Reduction Offers.

2. Metering and Communication

2.1 Interval Metering and Telemetry Requirements

The actual metered demand of each individual end-use customer facility that comprises a Real-Time Demand Response Asset must be measured using interval meters located at the individual end-use customer's retail delivery point and shall be reported to the ISO at an interval of five minutes. Actual metered demand submitted to the ISO shall not include average avoided peak distribution losses. ~~Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.~~

Interval meters required pursuant to Section III.E1.2.1 must meet the following requirements:

- (a) the interval meter must record and report meter data to the ISO in Real-Time at an interval of five minutes ~~or less~~;
- (b) if the interval meter is the same meter used by the distribution company for billing purposes, the meter is a revenue-quality meter that is accurate within $\pm 0.5\%$, and;
- (c) if the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue-quality meter that is accurate within $\pm 0.5\%$ or a non-revenue-

quality meter with an overall accuracy of $\pm 2.0\%$. For each non-revenue-quality meter used, the Market Participant must, during the registration process, submit certification from the meter manufacturer that the interval meter being used meets the $\pm 2.0\%$ accuracy threshold, and shall specify accuracy for the following parameters:

- i. current measurement;
- ii. voltage measurement;
- iii. A/D conversion, and;
- iv. calibration.

2.2 Meter Testing

All interval meters must be periodically tested and calibrated.

Market Participants must conduct periodic meter data validation checks.

Market Participants must repair or replace meters that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters and meter data communication systems.

2.3 Auditing

The ISO may, for a Real-Time Demand Response Asset, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and measurement equipment, and witness the demand reduction activities of any facility associated with the asset.

Market Participants must make retail billing meter data from the Host Participant for the facilities associated with a Real-Time Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing, and certifying the metering, data recording and measurement equipment of Real-Time Demand Response Assets.

2.4 Communication/Telemetry

Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities comprising the Real-Time Demand Response Asset on the electricity network in the New England Control Area. If one or more generators whose output can be controlled is located behind the retail delivery point of the Real Time Demand Response Asset, other than emergency generators that cannot operate synchronized to the electrical grid, then the Market Participant must also submit to the ISO in Real-Time a single set of interval meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

~~For Real Time Demand Response Assets whose demand reductions are not achieved by Distributed Generation but where there is a generator located behind the retail delivery point, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility comprising the Real Time Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of all generation.~~

~~For Real Time Demand Response Assets whose demand reductions are achieved in part or in whole by Distributed Generation, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility comprising the Real Time Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of Distributed Generation associated with the Real Time Demand Response Asset.~~

3. Demand Reduction Offers

3.1 Required Demand Reduction Offer Parameters

Market Participants must submit a Demand Reduction Offer for each Real-Time Demand Response Asset that meets the requirements of this section in order to be eligible for a demand reduction payment.

A Demand Reduction Offer must be equal to or greater than the Demand Reduction Threshold Price in effect on the day the Demand Reduction Offer is made.

Demand Reduction Offers reflect the amount of demand reduction offered at the retail delivery point excluding transmission and distribution losses.

A Demand Reduction Offer shall consist of a single offer price in \$/MWh (less than or equal to \$1000/MWh) and a single demand reduction amount (in MW to the nearest 0.1 MW) that shall apply to hours ending 0800 through 1800 in the Operating Day.

A Market Participant may submit a single Demand Reduction Offer for each of its Real-Time Demand Response Assets for each Operating Day that is a non-Demand Response Holiday weekday.

Demand Reduction Offers for the following Operating Day must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the Operating Day and may not be changed thereafter.

The minimum Demand Reduction Offer amount for each Real-Time Demand Response Asset is 100 kW.

The maximum Demand Reduction Offer amount for each Real-Time Demand Response Asset cannot exceed the asset's Maximum Interruptible Capacity.

Market Participants are prohibited from submitting a Demand Reduction Offer for a Real-Time Demand Response Asset for an Operating Day with a scheduled curtailment, or for an Operating Day with a known forced curtailment. If an unanticipated forced curtailment has occurred, Market Participants are prohibited from submitting a Demand Reduction Offer for the affected Real-Time Demand Response Asset for any subsequent Operating Days until the forced curtailment is over and electrical service to the asset has been restored.

3.2 Optional Demand Reduction Offer Parameters

A Demand Reduction Offer may specify a minimum interruption duration of one to four hours. If a Market Participant does not specify a minimum interruption duration in its Demand Reduction Offer, the minimum interruption duration shall be one hour.

A Demand Reduction Offer may specify a curtailment initiation price (in \$ per interruption). If a Market Participant does not specify a curtailment initiation price, the curtailment initiation price shall be \$0.

A Demand Reduction Offer must meet the following minimum and maximum price requirements:

- (a) The offer price not including the curtailment initiation price shall be greater than or equal to the Demand Reduction Threshold Price; and
- (b) The offer cost of the Demand Reduction Offer, which shall include the curtailment initiation price, shall be less than or equal to \$1000/MWh. The offer cost shall be computed as follows: $\text{offer cost} = \text{offer price} + [\text{curtailment initiation price} / (\text{minimum interruption duration} \times \text{bid amount (MW)})]$.

4. Day-Ahead Clearing, Scheduling and Notification

Demand Reduction Offers are cleared after the Day-Ahead Energy Market results are determined. Demand Reduction Offers are cleared by comparing the Demand Reduction Offer to the hourly Day-Ahead LMPs for the Load Zone in which the Real-Time Demand Response Asset is located. A Demand Reduction Offer associated with a Real-Time Demand Response Asset will clear in one or more hours of the Operating Day if the sum of the hourly Day-Ahead LMP times the Demand Reduction Offer amount in the cleared hours of the Operating Day is greater than or equal to the sum of the curtailment initiation price for the Operating Day and the sum of the Demand Reduction Offer price times the Demand Reduction Offer amount in the cleared hours of the Operating Day.

The ISO will provide Market Participants with demand curtailment schedules for Real-Time Demand Response Assets based on cleared Demand Reduction Offers.

The demand curtailment schedule shall reflect demand reductions (MW) at the Real-Time Demand Response Asset's retail delivery point.

5. Real-Time Scheduling of Demand Reductions

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for the next Operating Day pursuant to Section III.E1.4. If a Market Participant's Demand Reduction Offer is not cleared Day-Ahead to reduce demand in an hourly time interval for the next Operating Day, the Market Participant may initiate a Real-Time demand reduction by reducing demand when the offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which a Real-Time Demand Response Asset is located.

A Market Participant will not receive a Dispatch Instruction in Real-Time for a Real-Time Demand Response Asset.

5.1 Requirements for Demand Reductions of 5 MW and Above

A Market Participant with a Real-Time Demand Response Asset that has submitted a Demand Reduction Offer for the Operating Day, must request permission from the ISO prior to reducing demand in an amount greater than or equal to 5 MW during a 60 minute period, unless the asset was dispatched or audited pursuant to Section III.13. Permission must be requested not less than 15 minutes and not greater than 60 minutes before the start of the demand reduction. The ISO may approve or deny the requested interruption based on the impact of the interruption on system reliability.

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data for the same month of the previous year. The ISO may adjust the offer data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

- i. Each generator and import offer block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

- ii. An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.
- iii. A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.
- iv. A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from demand response exceeds the cost to load associated with compensating demand response.
- v. The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$D RTP = P_{th} \times \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the resulting Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the preceding month in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Real-Time Demand Response Assets located anywhere within the New England Control Area.

7. Demand Response Baselines

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8A prior to submitting a Demand Reduction Offer for a Real-Time Demand Response Asset.

A Market Participant shall take no actions to establish a Demand Response Baseline or affect a Demand Response Baseline adjustment that results in a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers absent demand reduction payments.

For Real-Time Demand Response Assets comprised of Distributed Generation, a Market Participant shall take no actions to establish a Demand Response Baseline that results in a Demand Response Baseline that reduces the expected output levels of its generation absent demand reduction payments.

8. Real-Time Demand Reduction Obligations

8.1 Real-Time Demand Reduction of Assets Without Generation

The Real-Time demand reduction amount of a Real-Time Demand Response Asset is equal to the difference between its Demand Response Baseline adjusted pursuant to Section III.8A.4 and the asset's Real-Time metered demand, during the intervals that the Real-Time Demand Response Asset was scheduled Day-Ahead by the ISO to reduce demand or was otherwise eligible to receive payment for a demand reduction in Real-Time. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered demand is greater than its adjusted Demand Response Baseline.

8.2 Real-Time Demand Reduction of Assets With Generation

To the extent a generator is located behind the retail delivery point of an individual end-use customer facility that comprises a Real-Time Demand Response Asset, the metered output of the generator in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline. The Real-Time demand reduction amount achieved by the individual end-use customer facility that comprises a Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of all of the generators located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction

amount is negative if the sum of the asset's Real-Time metered demand and the output of all of the generators is greater than its adjusted Demand Response Baseline.

If a Real-Time Demand Response Asset is comprised of a Distributed Generation asset located behind the retail delivery point of an individual end-use customer facility, the interval metered output of the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be used to determine its Demand Response Baseline. The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset comprised of the Distributed Generation asset shall be equal to the asset's incremental output in each five-minute interval relative to its Demand Response Baseline in the same intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the asset's Real-Time metered output is less than its Demand Response Baseline.

8.2.1 Real-Time Demand Reduction of Assets With Generation But With No Other Real-Time Demand Response Asset at that Location

For a Real-Time Demand Response Asset located at a retail delivery point with no other Real-Time Demand Response Assets at or behind the same retail delivery point, the metered output of any Real-Time Emergency Generation Assets in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline.

The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval, calculated pursuant to Section III.8A.4.4, minus the sum of the metered demand measured at the retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of any Real-Time Emergency Generation Assets is greater than its adjusted Demand Response Baseline.

8.3 Treatment of Net Supply

If the metered amount measured at the retail delivery point reflects net energy supply during intervals in which Real-Time Demand Response Assets and/or Real-Time Emergency Generation Assets behind the

retail delivery point had positive Real-Time demand reductions, then the amount of net energy supplied in an interval with a positive Real-Time demand reduction shall be subtracted from the Real-Time demand reduction amount in the same interval of each Real-Time Demand Response Asset and/or Real-Time Emergency Generation Asset behind that retail delivery point on a *pro rata* basis. The adjustment for net energy supply shall not result in a negative Real-Time demand reduction amount.

8.4 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Real-Time Demand Response Asset is equal to its Real-Time demand reduction amount adjusted for net supply (limited to 200% of the associated Demand Reduction Offer amount) multiplied by one plus the percent average avoided peak distribution losses.

9. Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Real-Time Demand Response Asset will be paid for its Day-Ahead Demand – Reduction Obligation multiplied by the Day-Ahead LMP for the Load Zone within which the Real-Time Demand Response Asset is located.

9.2 Real-Time Settlement

9.2.1. Real-Time Demand Response Assets with Cleared Demand Reduction Offers

A Market Participant with a Real-Time Demand Response Asset will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the final hourly Real-Time LMP for the Load Zone within which the Real-Time Demand Response Asset is located. The payment for the amount by which the Real-Time Demand Reduction Obligation exceeds the Day-Ahead Demand Reduction Obligation in an hour shall be set to zero if the provisional Real-Time LMP for that hour is less than the Demand Reduction Threshold Price.

A Market Participant will not be charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E1.5.1.

9.2.2. Real-Time Demand Response Assets without Cleared Demand Reduction Offers

If the Demand Reduction Offer price (not including the curtailment initiation price) is less than or equal to the provisional hourly Real-Time LMP published in the Operating Day for the Load Zone in which the Real-Time Demand Response Asset is located, the Market Participant will be paid the final hourly Real-Time LMP multiplied by its Real-Time Demand Reduction Obligation.

A Market Participant will not be charged pursuant to Section III.E1.9.2.2 if:

- (a) a Demand Reduction Offer does not clear Day-Ahead pursuant to Section III.E1.4, and;
- (b) the Real-Time Demand Response Asset produces a negative Real-Time demand reduction amount.

A Market Participant will not be paid for a Real-Time Demand Reduction Obligation for which a demand reduction request is denied pursuant to Section III.E1.5.1.

9.3 Cost Allocation

Payments and charges pursuant to this section will be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes or incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

10. Average Distribution Losses

For purposes of Section III.E1, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

SECTION III

MARKET RULE 1

APPENDIX E2

DEMAND RESPONSE

Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2017.

APPENDIX E2
DEMAND RESPONSE
Table of Contents

Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2017.

1. Demand Response Registration
2. Metering and Communication
3. Day-Ahead Energy Market Demand Reduction Offers
4. Real-Time Energy Market Demand Reduction Offers
5. Scheduling and Dispatching
6. Determination of the Demand Reduction Threshold Price
7. Real-Time Demand Reduction Obligation
8. Demand Response Resource Baseline
9. Energy Market Settlement
10. Average Avoided Peak Distribution Losses

APPENDIX E2 DEMAND RESPONSE

Appendix E2 applies to Capacity Commitment Periods commencing on or after June 1, 2017.

1. Demand Response Registration

1.1 Demand Response Resource Registration

A Market Participant may register a Demand Response Resource for purposes of submitting Demand Reduction Offers on a Day-Ahead and Real-Time basis and providing Operating Reserve subject to the following conditions:

- (a) each Demand Response Resource must be a single Demand Response Asset or an aggregation of Demand Response Assets located within the same Dispatch Zone and Reserve Zone;
- (b) each Demand Response Resource must be able to produce at least 100 kW of demand reduction;
and
- (c) the Market Participant must comply with ISO required auditing and testing requirements; and
- (d) the Market Participant must indicate whether it intends to maintain CLAIM10 or CLAIM30 capability for the Demand Response Resource.

A Market Participant may not register a Real-Time Emergency Generation Resource, an On-Peak Demand Resource, a Seasonal Peak Demand Resource or a Dispatchable Asset Related Demand to participate as a Demand Response Resource in the Day-Ahead Energy Market or Real-Time Energy Market. A Market Participant may not register an existing Generator Asset as a Demand Response Asset for the purpose of submitting Demand Reduction Offers. A Market Participant may not register a Demand Response Asset at the same Retail Delivery Point as an existing Generator Asset, and may not register a Generator Asset at the same Retail Delivery Point as an existing Demand Response Asset; provided that this provision shall not apply if the Generator Asset is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

1.2 Demand Response Capacity Resource Registration

A Market Participant may register a Demand Response Capacity Resource subject to the following conditions:

- (a) each Demand Response Capacity Resource must have mapped to it at least one Demand Response Resource within the same Dispatch Zone in order to comply with the energy market offer requirements in Section III.13.6.1.5; and
- (b) a Demand Response Resource cannot be mapped to a Demand Response Capacity Resource, or maintain the mapping to a Demand Response Capacity Resource, if the Demand Response Resource violates the mapping provisions in Section III.E2.1.4(c).

1.3 Demand Response Asset Registration

A Market Participant may register a Demand Response Asset subject to the following conditions:

- (a) Unless it meets the conditions for aggregation in sub-section (b) below, a Demand Response Asset must have a defined, single Retail Delivery Point and be registered at a single Node. ~~For each Demand Response Asset capable of delivering Net Supply, a single Net Supply Generator Asset may be registered at the same Node as the Demand Response Asset unless the asset meets the conditions for aggregation in sub-section (b) below.~~
- (b) A Demand Response Asset may be the aggregate demand reduction capability ~~consumption~~ of multiple end-use customers from multiple delivery points within a single Dispatch Zone and Reserve Zone if (i) the demand reduction from each Retail Delivery Point in the aggregation is less than 10 kW, and (ii) the demand at the multiple Retail Delivery Points satisfy the criteria for a homogenous population. A Demand Response Asset that meets these conditions for aggregation must be registered ~~at the Dispatch Zone~~ at a single Dispatch Zone and Reserve Zone rather than at a single ~~the~~ Node. ~~For each Demand Response Asset capable of delivering Net Supply that meets the conditions for aggregation as described in this sub-section, a single Net Supply Generator Asset may be registered at the same Dispatch Zone as the Demand Response Asset.~~
- (c) No more than one Demand Response Asset may be located at a single Retail Delivery Point.
- (d) Each Demand Response Asset must be mapped to a Demand Response Resource.
- (e) Each Demand Response Asset must be able to produce at least 10 kW of demand reduction.

- (f) A Demand Response Asset with a registered Maximum Interruptible Capacity equal to or greater than 5 MW from the same Retail Delivery Point must be registered as a single Demand Response Resource at a Node. ~~A Demand Response Asset capable of delivering Net Supply where the sum of its Maximum Interruptible Capacity and Maximum Net Supply from the same Retail Delivery Point is equal to or greater than 5 MW must register as a single Demand Response Resource at a Node, and may register a single Net Supply Generator Asset at the same Node. In the event the Demand Response Asset and associated Net Supply Generator Asset have participated in a seasonal audit, the~~ The evaluation of whether a Demand Response Asset's Maximum Interruptible Capacity ~~or the sum of the Maximum Interruptible Capacity and Net Supply~~ is equal to or greater than 5 MW shall account for the most recent seasonal audit results for the assets.
- (g) The metering and communication equipment associated with each Demand Response Asset must meet the requirements in Section III.E2.2.

During the registration process, Market Participants must submit the following for each Demand Response Asset:

- (a) Maximum Interruptible Capacity;
- (b) Maximum Load;
- (c) Maximum Generation, for Demand Response Assets that are comprised of Distributed Generation;
- (d) ~~For any Net Supply Generator Asset associated with a Demand Response Asset, the~~ For a Demand Response Asset capable of producing Net Supply, the Maximum Net Supply permitted under the asset's interconnection agreement; and
- (e) ~~retail~~ Retail account number and meter number for the end-use customer.

1.4 Restrictions on Demand Response Resource Registration

A Market Participant may not register and must retire if previously registered a Demand Response Resource that is comprised of:

- (a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year, if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or;

- (b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.
- (c) The Maximum Interruptible Capacity adjusted for the Audited Demand Reduction of each Demand Response Resource registered by a Market Participant within a single Dispatch Zone and Reserve Zone must be at least 1 MW before the Market Participant registers a new Demand Response Resource within that same Dispatch Zone and Reserve Zone. This restriction shall not apply if either:
 - (i) all Demand Response Assets registered by the Market Participant in the Dispatch Zone and Reserve Zone are mapped to a Demand Response Resource mapped to a Demand Response Capacity Resource and the Market Participant wants to register a Demand Response Resource that is not mapped to a Demand Response Capacity Resource; or
 - (ii) all Demand Response Assets registered by the Market Participant in the Dispatch Zone and Reserve Zone are mapped to a Demand Response Resource not mapped to a Demand Response Capacity Resource and the Market Participant wants to register a Demand Response Resource that is mapped to a Demand Response Capacity Resource.
- (d) In the event the Audited Demand Reductions of two or more Demand Response Resources registered by a Market Participant within a single Dispatch Zone and Reserve Zone are less than 1 MW following an audit, Demand Response Asset mapping for that Market Participant shall be adjusted if doing so decreases the number of Demand Response Resources within that Dispatch Zone and Reserve Zone.

1.5 Restrictions on Demand Response Asset Mapping

Demand Response Assets may be un-mapped from a Demand Response Resource for re-mapping to another Demand Response Resource, or un-mapped without re-mapping, subject to the following conditions:

- (a) A Demand Response Asset cannot be unmapped from a Demand Response Resource that is mapped to a Demand Response Capacity Resource if, following the un-mapping, the sum of the demand reductions of the remaining Demand Response Assets that are associated with the Demand Response Capacity Resource, as reflected in the most recent seasonal audit for that resource, would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.
- (b) When a Demand Response Asset can be mapped to more than one Demand Response Resource that is mapped to a Demand Response Capacity Resource, a Demand Response

- Asset shall be mapped to a Demand Response Resource associated with a Demand Response Capacity Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period before being mapped to a Demand Response Resource associated with a non-commercial Demand Response Capacity Resource or non-commercial increment of a Demand Response Capacity Resource.
- (c) A Demand Response Asset may be re-mapped to another Demand Response Resource only if the Audited Full Reduction Time of the asset's new Demand Response Resource, adjusted for the Audited Demand Reduction of the asset's current Demand Response Resource, is equal to or greater than the Audited Full Reduction Time of the Demand Response Resource from which the Demand Response Asset is being un-mapped.
 - (d) If a Demand Response Asset is re-mapped to a Demand Response Resource, and the Audited Full Reduction Time of the Demand Response Resource to which the asset is being mapped, adjusted for the Audited Demand Reduction of the Demand Response Resource from which the asset is being mapped, is less than the Audited Full Reduction Time of the Demand Response Resource from which the asset is being mapped, the Demand Response Asset audit value will be set to zero.

2. Metering and Communication

2.1 Revenue Quality Interval Metering ~~and Telemetry Requirements~~

The metered demand used for settlement purposes of each individual end-use customer facility that comprises a Demand Response Asset must be measured using interval meters located at the individual end-use customer's Retail Delivery Point and shall be reported to the ISO at an interval of five minutes.

Metered demand data submitted to the ISO shall not include average avoided peak distribution losses. ~~Each generator located behind an individual end-use customer's Retail Delivery Point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.~~

The interval meters required pursuant to Section III.E2.2.1 must meet the following requirements:

- (a) The interval meter must record and report meter data to the ISO in Real-Time at an interval of five-minutes ~~or less~~;

~~(b) If the interval meter is the same meter used by the distribution company for billing purposes, the meter is can be the same a revenue-quality meter that is accurate within $\pm 0.5\%$ used by the distribution company for billing purposes; and~~

(c) If the interval meter is not the same revenue-quality meter used by the distribution company for billing purposes, the Market Participant must validate and provide documentation to the ISO that the difference between the values recorded by the Market Participant's meter in each interval and the value recorded by the distribution company's billing meter in the same interval is within $\pm 2.0\%$; provided that, if accurate interval data from the distribution company are not available, the Market Participant shall validate that the difference between the sum of the values recorded by the Market Participant's meter and the sum of the values recorded by the distribution company's billing meter over the same time period is within $\pm 2.0\%$; and further provided that the Market Participant specifies the meter manufacturer and model, and the accuracy for the following parameters:

- i. current measurement;
- ii. voltage measurement;
- iii. A/D conversion; and
- iv. calibration.

(d) The Market Participant shall provide documentation to the ISO of any inaccuracies found in distribution company meter data and of any communications with the distribution company to address the meter data inaccuracies.

~~(b) If the interval meter is not the same meter used by the distribution company for billing purposes, the interval meter is either a revenue quality meter that is accurate within $\pm 0.5\%$ or a non-revenue quality meter with an overall accuracy of $\pm 2.0\%$. For each non-revenue quality meter used, the Market Participant must, during the registration process, submit certification from the meter manufacturer that the interval meter being used meets the $\pm 2.0\%$ accuracy threshold, and shall specify accuracy for the following parameters:~~

~~(c)~~

~~(d) current measurement;~~

~~(e) voltage measurement;~~

~~(f) A/D conversion; and~~

~~(g) calibration.~~

2.2 Communication/Telemetry

Market Participants must report in Real-Time to the ISO a single set of telemetry data for each individual end-use customer facility that comprises a Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of the Demand Response Asset as measured at the Retail Delivery Point, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide Ten Minute Spinning Reserve or Ten Minute Non-Spinning Reserve, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

The Market Participant must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions from the ISO.

~~Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facilities that comprise the Demand Response Asset on the electricity network in the New England Control Area.~~

~~For Demand Response Assets whose demand reductions are not achieved by Distributed Generation but where there is a generator located behind the Retail Delivery Point, Market Participants must submit a single set of interval meter data representing the metered demand of the end-use facility that comprises the Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of all generation.~~

If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of telemetry data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

~~For Demand Response Assets whose demand reductions are achieved by Distributed Generation, Market Participants must submit a single set of interval meter data representing the metered demand of the end-~~

~~use facility that comprises the Demand Response Asset on the electricity network in the New England Control Area and a single set of interval meter data representing the combined output of Distributed Generation associated with the Demand Response Asset.~~

The telemetry measurement device used to measure the real-time demand and any Net Supply pursuant to Section III.E2.2.2 must have an overall accuracy of $\pm 2.0\%$. If the Market Participant is not using the meter used by the distribution company for billing purposes to obtain the real-time telemetry, then the Market Participant must specify the device manufacturer and model, and submit certification from the measurement device manufacturer that the device being used meets the $\pm 2.0\%$ accuracy threshold, and shall specify the accuracy for the following parameters:

- i. current measurement;
- ii. voltage measurement;
- iii. A/D conversion; and
- iv. calibration.

2.3 ~~Meter~~ Testing of Meters and Telemetry Measurement Devices

All interval meters and telemetry measurement devices must be periodically tested and calibrated.

Market Participants must conduct periodic meter and telemetry data validation checks.

Market Participants must repair or replace meters or telemetry measurement devices that are found to be inaccurate pursuant to periodic testing and data validation checks.

Market Participants must perform an annual independent certification of the accuracy and precision of the meters, telemetry measurement devices, and ~~meter~~ data communication systems.

2.4 Auditing

The ISO may, for Demand Response Resources, review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset.

Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

Market Participants are responsible for all expenses associated with installing, maintaining, calibrating, testing and certifying the metering, data recording and telemetry measurement equipment of Demand Response Assets.

3. Day-Ahead Energy Market Demand Reduction Offers

Market Participants must submit a Demand Reduction Offer for each Demand Response Resource that meets the requirements of this section in order to be eligible for a payment for a demand reduction-payment.

The Market Participant's Demand Reduction Offer for a Demand Response Resource must satisfy the following conditions:

- (a) Demand Reduction Offers must be submitted by the offer submission deadline for the Day-Ahead Energy Market of the day before the applicable Operating Day.
- (b) The Market Participant can submit up to 10 monotonically increasing price/demand reduction amount pairs for each Operating Day. The demand reduction amount shall not include an adjustment for average avoided peak transmission and distribution losses.
- (c) The minimum amount for each price/demand reduction amount pair of a Demand Reduction Offer is 100 kW.
- (d) The sum of all price/demand reduction amount pairs for a Demand Reduction Offer cannot exceed the sum of the Maximum Interruptible Capacities of the resource's Demand Response Assets.
- (e) The minimum Demand Reduction Offer price must be equal to or greater than the Demand Reduction Threshold Price in effect for the day the Demand Reduction Offer is submitted.
- (f) The maximum Demand Reduction Offer price must be less than or equal to the Energy Offer Cap-\$1000/MWh.

Market Participants may not Self-Schedule interruptions in the Day-Ahead Energy Market.

3.1 Required Demand Reduction Offer Parameters

The Market Participant shall provide the following hourly values in its Demand Reduction Offer. The Market Participant shall maintain up-to-date values for each of these parameters prior to and throughout the Operating Day:

- (a) Available or Unavailable;
- (b) Minimum Reduction (MW), and;
- (c) Maximum Reduction (MW).

3.2 Optional Demand Reduction Offer Parameters

The Market Participant may also specify the following in its Demand Reduction Offer:

- (a) Interruption Cost (\$)
- (b) Minimum Reduction Time (Hrs)
- (c) Minimum Time Between Reductions (Hrs)
- (d) Demand Response Resource Start-Up Time (Hrs)
- (e) Demand Response Resource Notification Time (Hrs)
- (f) Demand Response Resource Ramp Rate (MW/min)

| (g) Offered CLAIM10 (MW)

| (h) Offered CLAIM30 (MW)

4. Real-Time Energy Market Demand Reduction Offers

During the Re-Offer Period, Market Participants may submit revisions to the price or demand reduction amount parameters of a Demand Reduction Offer. Demand Response Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices.

Revisions to Demand Reduction Offers during the Re-Offer Period are subject to the following conditions that apply to Day-Ahead Demand Reduction Offers under Section III.E2.3: limitation to 10 monotonically increasing price/demand reduction amount pairs, minimum amount, maximum amount, minimum price and maximum price.

A Demand Reduction Offer shall continue to apply in Real-Time during the Operating Day even if the Demand Reduction Offer is not scheduled Day-Ahead for that Operating Day pursuant to Section III.E2.5 or modified during the Re-Offer Period.

No changes will be allowed to the Demand Reduction Offer after the close of the Re-Offer Period. Market Participants may not Self-Schedule interruptions in the Real-Time Energy Market.

5. Scheduling and Dispatching

The ISO shall schedule in the Day-Ahead Energy Market and ~~commit~~schedule and dispatch in the Real-Time Energy Market the Demand Response Resource ~~based on:~~

~~(a) least cost, security constrained dispatch and commitment as specified in Section III.1.7.6(a); and~~

~~(b) the Demand Reduction Offer for the Demand Response Resource, with demand reduction by average avoided peak distribution losses.~~

At the conclusion of the Day-Ahead Energy Market clearing, the ISO will provide Market Participants with Day-Ahead demand reduction schedules for Demand Response Resources reflecting demand reduction amounts that do not include average avoided peak transmission and distribution losses for each hour of the following Operating Day.

During the Operating Day, the ISO will issue Dispatch Instructions to the Market Participant specifying the expected demand reduction amount that does not include average avoided peak transmission and distribution losses from their Demand Response Resource and the Dispatch Rate.

A Market Participant must notify the ISO, as soon as practicable, of a facility or generator shutdown or equipment outage (including partial outages) that reduces the Demand Response Resource's ability to achieve the demand reduction reflected in the Demand Reduction Offer for an Operating Day. ~~Net Supply Generator Assets will be dispatched at the same Location as the Demand Response Resource with which they are associated.~~

6. Determination of the Demand Reduction Threshold Price

The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed supply curve for the month. The smoothed supply curve shall be derived from real-time generator and import offer data for the same month of the previous year. The ISO may adjust the offer data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

- (a) Each generator and import offer block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.
- (b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer block.
- (c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.
- (d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from demand response exceeds the cost to load associated with compensating demand response.
- (e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} \tilde{A} - \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the resulting Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the preceding month in advance of the Demand Reduction Threshold Price's effective date.

The Demand Reduction Threshold Price shall apply to all Demand Reduction Offers associated with Demand Response Resources located anywhere within the New England Control Area.

7. Real-Time Demand Reduction Obligation

A Demand Response Resource's Real-Time Demand Reduction Obligation will be calculated for each dispatch interval in which the Demand Response Resource receives a Dispatch Instruction to reduce demand.

7.1 Real-Time Demand Reductions

The Real-Time demand reduction in a dispatch interval is the difference between the adjusted Demand Response Baseline, further adjusted for any metered output for a Real-Time Emergency Generation Asset located at the same Retail Delivery Point, and the metered demand for each Demand Response Asset associated with the Demand Response Resource.

If a Market Participant receives a Dispatch Instruction for a Demand Response Resource to reduce demand in a dispatch interval by zero MW, then in calculating the Real-Time Demand Reduction Obligation of the Demand Response Resource the Real-Time demand reductions of the Demand Response Assets comprising the resource shall be equal to zero for that dispatch interval.

7.2 Real-Time Demand Reduction Obligations

The Real-Time Demand Reduction Obligation of a Demand Response Resource is the sum of the hourly integrated Real-Time demand reduction amounts of the Demand Response Assets comprising the Demand Response Resource, multiplied by one plus the percent average avoided peak distribution losses, except that any Net Supply produced by the Demand Response Assets comprising the Demand Response Resource will not be adjusted by average avoided peak distribution losses~~In calculating the Real-Time Demand Reduction Obligation of a Demand Response Resource, the Real-Time demand reduction amounts of the Demand Response Assets comprising the resource shall be as specified in Section III.E2.7.3 below.~~

If a Market Participant fails to comply with the metering and communication requirements in Section III.E2.2 for a Demand Response Resource for any period of time, then the Real-Time Demand Reduction Obligation shall be zero for that period of time.

7.3 — Treatment of Net Supply

~~If a Demand Response Asset's metered demand represents Net Supply, the Demand Response Asset's metered demand in the interval will be set equal to zero and that value will be used in establishing the Real-Time Demand Reduction Obligation.~~

8. Demand Response Resource Baseline

A Market Participant must establish a Demand Response Baseline pursuant to Section III.8B prior to submitting a Demand Reduction Offer for a Demand Response Resource, and must comply with the requirements for maintaining and resetting the Demand Response Baseline as set forth in Section III.8B.

A Market Participant shall not take actions to create or maintain a Demand Response Baseline that exceeds the expected electricity consumption levels of its end-use metered customers in the absence of demand reduction payments.

9. Energy Market Settlement

9.1 Day-Ahead Settlement

A Market Participant with a Demand Response Resource will be paid for its Day-Ahead Demand Reduction Obligation multiplied by the Day-Ahead LMP for the Dispatch Zone or Node at which the resource is registered.

9.2 Real-Time Settlement

A Market Participant with a Demand Response Resource will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation multiplied by the hourly Real-Time LMP for the Dispatch Zone or Node at which the resource is registered.

9.3 Cost Allocation

Charges or payments resulting from Real-Time demand reductions produced by Demand Response Resources or Real-Time Emergency Generation Resources shall be allocated on an hourly basis proportionally to Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Dispatchable Asset Related Demand Postured by the ISO, on a system-wide basis.

9.4 NCPC Credits and Charges

A Market Participant with a Demand Response Resource is eligible for NCPC credits if the resource is following Dispatch Instructions. A Market Participant with a Demand Response Resource is ineligible for NCPC credits and may be assessed NCPC charges if the resource is not operating within the acceptable dispatch tolerance. A resource is not operating within the acceptable dispatch tolerance if in any five-minute interval for an hour the resource is not operating within 10% above or below the resource's Dispatch Instruction, except that a Market Participant with a resource that is not operating within the acceptable dispatch tolerance will not be assessed NCPC charges if during the entire hour the resource operates within 5% above or below the resource's Dispatch Instruction.

10. Average Avoided Peak Distribution Losses

For purposes of Section III.E2, the percent average avoided peak distribution losses shall be the percent average avoided peak transmission and distribution losses used for the associated Capacity Commitment Period in the Forward Capacity Market less the percent average avoided peak transmission system losses.

STANDARD MARKET DESIGN

III.1.5.2 ISO-Initiated Parameter Auditing.

- (a) The ISO may perform an audit of any Supply Offer or Demand Reduction Offer parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.
- (b) Generator Audits shall be performed using the following methods:
 - (i) **Economic Maximum Limit.** The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.
 - (ii) **Manual Response Rate.** The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.
 - (iii) **Start-Up Time.** The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.
 - (iv) **Notification Time.** The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.
 - (v) **CLAIM10.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5 of Market Rule 1.
 - (vi) **CLAIM30.** The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5 of Market Rule 1.
 - (vii) **Automatic Response Rate.** The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second ISO-issued electronic Dispatch Instructions.
- (c) Demand Response Resource audits shall be performed using the following methods:
 - (i) **Maximum Reduction.** The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.
 - (ii) **Demand Response Resource Ramp Rate.** The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.
 - (iii) **Demand Response Resource Start-Up Time.** The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered

Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) Demand Response Resource Notification Time. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) CLAIM10. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5.

(vi) CLAIM30. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5.

~~(c)~~(d) To Conduct an audit based upon historical data, the ISO shall:

- (i) Obtain data through random sampling of generator or Demand Response Resource performance in response to ~~ISO~~ Dispatch Instructions; or
- (ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to ~~ISO~~ Dispatch Instructions.

~~(d)~~(e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset's ~~net output~~ or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.

~~(e)~~(f) To the extent that the audit results indicate a Market Participant is providing Supply Offer or Demand Reduction Offer parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, Supply Offer or Demand Reduction Offer parameter values for the Generator Asset or Demand Response Resource shall be restricted to the value that is supported by the audit.

~~(f)~~(g) In the event that a Generator Asset or Demand Response Resource has had a Supply Offer or Demand Reduction Offer parameter value restricted:

- (i) The ~~Lead~~ Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:
 - 1. Provide an explanation of the discrepancy;
 - 2. Indicate the steps that the Market Participant will take to re-establish the Supply Offer or Demand Reduction Offer parameter's value;
 - 3. Indicate the timeline for completing the restoration; and
 - 4. Explain the testing that the Market Participant will undertake to verify restoration of the Supply Offer or Demand Reduction Offer parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the Supply Offer or Demand Reduction Offer parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the Supply Offer or Demand Reduction Offer parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to

transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 [Reserved.]

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the hourly Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices in an hour caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices in an hour, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect the integrated hourly Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

(a) Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for

dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

(b) [Reserved.]

(c) [Reserved.]

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

- (a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.
- (b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.
- (c) The Seasonal Claimed Capability of a Generator Asset is:
 - (i) Based upon review of historical data for non-intermittent daily cycle hydro.
 - (ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) netmetered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.
 - (iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:
 - a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.
 - b. For a Generator Asset that is off-line and not available for commitment shall be zero.
 - c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.

- (iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 [Reserved.]

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall schedule ~~to~~ the Operating Reserve and load-following requirements of the New England Control Area and the New England Markets in scheduling Resources pursuant to this Market Rule 1. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Regulation.

(a) Regulation shall be supplied from generators located within the metered electrical boundaries of the New England Control Area. Market Participants offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall obtain and maintain an amount of Regulation equal to the New England Control Area Regulation objective as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) The Regulation range of a unit shall be at least twice the amount of Regulation assigned and no less than the minimum specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(d) A unit that is providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided. The amount of Regulation provided by a unit shall serve to redefine

the Economic Minimum Limit and Economic Maximum Limit of that unit, in that the amount of Regulation shall be added to the unit's Economic Minimum Limit or automatic low limit while regulating, whichever is greater, and subtracted from its Economic Maximum Limit or automatic high limit, which ever is less. Qualified Regulation must satisfy the verification tests described in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19 Ramping.

A generating unit or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the unit's megawatt output or demand reduction level shall be able to change output or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that unit and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19A Real-Time Reserve.

(a) Real-Time TMSR, TMNSR, TMOR and Real-Time Replacement Reserve, if applicable, shall be supplied from Resources located within the metered boundaries of the New England Control Area subject to the condition set forth in Section III.1.7.19A(c) below. The ISO shall designate Operating Reserve in Real-Time only to Market Participant Resources that comply with the applicable standards and requirements for provision and dispatch of Operating Reserve capability as specified in **Section III.10 and** the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and locational Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) External Resources will be permitted to participate in the Real-Time reserve market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO units that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New

England Control Area; respond to the ISO's directives to start, shutdown or change output or demand reduction levels of generating units or Demand Response Resources, or change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating and demand reduction equipment is operated with control equipment functioning as specified in the ISO New England Manuals ~~&~~and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market, along with Dispatch Rate levels above which it does not desire to purchase.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

III.1.9.1 [Reserved.]

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 **[Reserved.]**

III.1.9.6 **[Reserved.]**

III.1.9.7 **Market Participant Responsibilities.**

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 **[Reserved.]**

III.1.10 **Scheduling.**

III.1.10.1 **General.**

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of generating Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers for such units.

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market

Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

- (i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;
- (ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;
- (iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

- (iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to the Energy Offer Cap;
 - (v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.
- (d) Market Participants selling into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Regulation, Operating Reserve or other services as applicable, for the following Operating Day.

Energy offered from generating Resources without a Capacity Supply Obligation shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. All Supply Offers and Demand Bids:

- (i) Shall specify the Resource or Load Asset and energy for each hour of the Operating Day;
- (ii) Shall specify, for Supply Offers, Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The price and quantity values in a Block may each vary on an hourly basis;
- (iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify, for Supply Offers, Start-Up Fees and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee values may vary on an hourly basis;
- (iv) For a dual fuel Resource, shall specify, for Supply Offers, the fuel type. The fuel type value may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual fuel Resources in Section III.A.3 of Appendix A;

- (v) Shall specify, for Supply Offers, a Minimum Run Time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;
 - (vi) Supply Offers shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;
 - (vii) Shall constitute, for Demand Bids, an offer to submit the Dispatchable Asset Related Demand Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes to the Maximum Consumption Limit and Minimum Consumption Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Minimum Consumption Limit may vary on an hourly basis to reflect the Self-Scheduled consumption level of the Resource;
 - (viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day; and
 - (ix) Shall not specify an energy offer or bid price below the Energy Offer Floor or above the Energy Offer Cap.
- (e) A Market Participant that wishes to make a Resource available to sell Regulation service shall submit a Supply Offer for Regulation, the price and quantity of which can vary on an hourly basis. The Supply Offer for Regulation shall specify the Automatic Response Rate in megawatts per minute, the price in dollars per MWh of the Regulation capability being offered, such Regulation capability as

calculated by the ISO by multiplying the submitted Automatic Response Rate by five minutes, and such other information specified by the ISO as may be necessary to evaluate the Supply Offer and the generating Resource's Regulation Opportunity Costs. The price of the Supply Offer shall not exceed \$100/MWh. Qualified Regulation capability must satisfy the verification tests specified in the ISO New England Manuals and ISO New England Administrative Procedures. Regulation capability amounts will be adjusted as necessary in the case where a generating unit's compliance rating is less than 90%. The audited Regulation capability will be deemed equal to the most recently calculated compliance rating times the 5-minute Regulation capability quantities utilized in that compliance rating calculation, rounded to the nearest whole megawatt. The Resource's Automatic Response Rate will then be adjusted based upon the audited Regulation capability.

(f) [Reserved.].

(g) Each Supply Offer or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits ~~and~~ Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, ~~and~~ Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to **the amount** of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers or Demand Reduction Offers to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as generators or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide energy in the Real-Time dispatch unless the schedules for such units Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) The Market Participant seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for energy or related services, or for Start-Up Fees ~~and~~, No-Load Fees or Interruption Costs, from the ISO on behalf of the Market Participant buyers in accordance with Section III.3 of this Market Rule 1.

(e) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.11.1 Resource Output and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output or demand reduction of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output or demand reduction of Pool-Scheduled Resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (c) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.

- (a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.
- (b) The ISO shall implement the dispatch of energy from Pool-Scheduled Resource increments and the designation of Real-Time Operating Reserve to Pool-Scheduled Resource increments, including the dispatchable increments from resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall ensure that the entity controlling a Pool-Scheduled Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.
- (c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.
- (d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to dispatched output or demand reduction levels as practical, consistent with Good Utility Practice.
- (e) Wind resources are treated as not economically dispatchable until the ISO is technically capable of determining and telemetering a Do Not Exceed Dispatch Point to the resource.
- (f) The ISO may request that dual-fueled generating Resources that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel

in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fueled units that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fueled units that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of generation supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area, transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, Demand Response Resource, an External Transaction purchase Resource and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and locational Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the most recent power flow solution produced by the State Estimator, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 **Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.**

(a) During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market.

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, Demand Response Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, Demand Response Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable Supply Offer or Demand Reduction Offer price submitted by a Market Participant for energy from the generating Resource, Demand Response Resource or External Transaction purchase is less than or equal to the Dispatch Rate associated with that ~~generating~~ Resource or External Transaction purchase; ~~and~~

(ii) the applicable Demand Bid price submitted by a Market Participant for energy from the Dispatchable Asset Related Demand Resource is greater than or equal to the Dispatch Rate associated with that Dispatchable Asset Related Demand Resource; ~~and~~

(iii) the generating Resource, other than a Fast Start Generator, is operating at or above its Economic Minimum Limit; ~~or~~

(iv) the Fast Start Generator is operating at or above its Economic Minimum Limit and the applicable Supply Offer price submitted by a Market Participant for energy from the Fast Start Generator is less than or equal to the Dispatch Rate associated with that Fast Start Generator;

~~or~~

(v) The Demand Response Resource, other than a Fast Start Demand Response Resource, is operating at or above its Minimum Reduction;

~~(vi)~~ (vi) The Fast Start Demand Response Resource is operating at or above its Minimum Reduction and the applicable Demand Reduction Offer price submitted by a Market Participant for energy from the Resource is less than or equal to the Dispatch Rate associated with the Resource; and

(vii) the generating Resource, Demand Response Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource is specifically requested to operate or reduce consumption by the ISO's dispatcher and the associated energy offers or bids submitted are otherwise eligible to be included in the calculation of Real-Time Locational Marginal Prices.

(c) In determining whether a generating Resource or External Transaction purchase satisfies the condition described in Section III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above or below the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

(d) In determining whether a Dispatchable Asset Related Demand Resource satisfies the condition described in Section III.2.4(b), the ISO will determine the Demand Bid price associated with a Demand Bid by comparing the actual megawatt consumption of the Dispatchable Asset Related Demand Resource with the Market Participant's Demand Bid price curve for that Dispatchable Asset Related Demand Resource. Because of practical Dispatchable Asset Related Demand Resource response limitations, a Dispatchable Asset Related Demand Resource whose megawatt consumption is greater than or equal to ninety percent, and less than or equal to 110%, of the megawatt level specified in the Demand Bid price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy demand bid price used in the calculation of Real-Time Prices shall not be lower than the applicable Dispatch Rate.

(e) In determining whether a Demand Response Resource satisfies the condition described in Section III.2.4(b), the ISO will compare the actual megawatt demand reduction of the Demand Response

Resource with the Market Participant's Demand Reduction Offer price curve for that Resource. Because of practical response limitations, a Demand Response Resource whose megawatt demand reduction is not more than ten percent above or below the megawatt level specified in the Demand Reduction Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

III.2.5 Calculation of Real-Time Nodal Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, Demand Response Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.8; and (5) the effect on transmission losses caused by the increment of load, ~~and~~ generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5. shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes if the Minimum Generation Emergency was declared on a New England Control Area wide basis or shall be set equal to the Energy Offer Floor for all Nodes and External Nodes within a sub-region if the Minimum Generation Emergency was declared within the sub-region.

III.2.6 Calculation of Day-Ahead Nodal Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying a linear optimization method to minimize energy, congestion and transmission loss costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can serve an increment of load at a

Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

The process for clearing External Nodes differs from the process for clearing other Nodes in that, in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available generation at its Economic Maximum Limit and demand reduction at the Demand Response Resource's Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

- (i) All fixed External Transaction sales are considered to be dispatchable at the Energy Offer Cap;
- (ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line generation, dispatched Demand Response Resources, Increment Offers or External Transaction purchases; and
- (iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the

highest offer price of all on-line generation, dispatched Demand Response Resources, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide generation MW (including fixed External Transaction purchases) with all possible generation off and with all remaining generation at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic generation in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed generation down proportionately by ratio of Economic Minimum Limits but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line generation; and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all committed generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone and Dispatch Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone and Dispatch Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and Dispatch Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

- (b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.
- (c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.
- (d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.
- (e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.
- (f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.
- (g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.
- (h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.
- (i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer's knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints,

including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The unit-specific Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a ~~generating~~ Resource shall be determined for each ~~generating~~ Resource that the ISO ~~requires to reduce output~~ re-dispatches in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the ~~generation Node-Location~~ for the generating Resource, Demand Response Resource or Dispatchable Asset Related Demand Resource and (ii) the offer price associated with the ~~reduction of the generating re-dispatch of the Resource's output~~ necessary to create the additional Operating Reserve or local TMOR from the ~~generating~~ Resource's expected output, or consumption, or demand-reduction level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the

constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

<u>Requirement</u>	<u>Requirement Sub-Category</u>	<u>RCPF</u>
Local TMOR		\$250/MWh
System TMOR	minimum TMOR	\$500/MWh
	Replacement Reserve	\$250/MWh
System TMNSR		\$850/MWh
System TMSR		\$50/MWh

The RCPFs shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve Requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed every five minutes, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour to be used in settlements.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

- (i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;
 - (ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;
 - (iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;
 - (iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and
 - (v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.
- (b) The ISO shall calculate and publish hourly Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

- (a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation Clearing Prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the

Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary,

reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area; provided that Section III.E2.9 sets forth the Day-Ahead Energy Market and Real-Time Energy Market settlement rules for Demand Response Resources.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

(a) For each Market Participant for each hour, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the ~~ISO~~ Day-Ahead Energy Market as follows:

~~To accomplish this, the ISO will perform calculations to determine the following:~~

- (i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.

- (ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each hour a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its generation Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.
 - (iii) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.
 - (iv) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each hour a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation at that Location
- (b) For each Market Participant for each hour, the ISO will determine a Real-Time Energy Market position. To accomplish this, the ISO will perform calculations to determine the following:
- (i) **Real-Time Load Obligation** – Each Market Participant shall have for each hour a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for any applicable internal bilateral transactions which transfer Real-Time load obligations.
 - (ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each hour a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by generating Resources, External Resources, and External Transaction purchases at that Location.
 - (iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each hour a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each hour a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation** – Each Market Participant shall have for each hour a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue.

(c) For each Market Participant for each hour, the ISO will determine the difference between the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)) and the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each hour a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each hour a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each hour a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each hour a Real-Time Locational Adjusted Net Interchange Deviation at each

Location equal to the difference in MWhs between the Real-Time Locational Adjusted Net Interchange and the Day-Ahead Locational Adjusted Net Interchange.

(d) For each Market Participant for each hour, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(e) For each Market Participant for each hour, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market. The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that hour multiplied by the Energy Component of the Real-Time Locational Marginal Prices for that hour. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that hour multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices for that hour.

The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that hour multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices for that hour.

(f) For each hour, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Congestion Charge/Credits.

(g) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(h) For each hour for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(g)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(i) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for Inadvertent Energy Revenue, as calculated under Section III.3.2.1(k) and Emergency transactions as described under Section III.4.3(a).

(j) Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each hour multiplied by the difference between the Loss Component of the hourly Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the hourly Real-Time Price at the source point or New England Control Area boundary source interface.

(k) For each hour, the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at each External Node by the associated Real-Time Locational Marginal Price and then summing these values for all External Nodes.

(l) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(k)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations and Real-Time Generation Obligations over all Locations, measured as absolute values.

(m) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(i)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

III.3.2.6 Emergency Energy.

(a) Hourly net costs in excess of Real-Time Prices attributable to the purchase of Emergency energy by the ISO from other Control Areas shall be allocated to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for Pool-Scheduled Resources not following ISO dispatch instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generation-generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations.

(b) Hourly net revenues in excess of Real-Time Prices attributable to the sale of Emergency energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for Pool-Scheduled Resources following ISO dispatch instructions and Self-Scheduled generating Resources with dispatchable increments above their Self-Scheduled amounts following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generation-generating

Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load or in such other manner as may be described in ISO New England Manual M-28 (Market Rule 1 Accounting). Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6 and Section III.E2 of this Market Rule 1, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.8A Demand Response Baselines

Section III.8.A shall govern Demand Response Baselines calculated for Capacity Commitment Periods commencing prior to June 1, 2017.

A Demand Response Baseline is calculated for any Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that requires a baseline on a daily basis using five-minute meter data.

8A.1 Establishing the Initial Demand Response Baseline

The Demand Response Baseline for a new Real-Time Demand Response Asset or Real-Time Emergency Generation Asset (an asset with no previously computed Demand Response Baseline) shall be the simple average of meter data for the asset for each five-minute interval from the initial ten non-Demand Response Holiday weekdays. The initial ten non-Demand Response Holiday weekdays of meter data used to establish the Demand Response Baseline shall consist of the first ten consecutive non-Demand Response Holiday weekdays with a complete set of interval meter data. A Market Participant may not submit Demand Reduction Offers until the month following the initial establishment of a Demand Response Baseline for an asset.

If two or more existing Real-Time Demand Response Assets (assets registered with the ISO with previously computed Demand Response Baselines) located at or behind the same retail delivery point are consolidated into one Real-Time Demand Response Asset located at the retail delivery point, or a significant change in load, generation, or reported meter data at an existing Real-Time Demand Response Asset or Real-Time Emergency Generation Asset occurs, a new initial Demand Response Baseline must be established for the asset.

8A.2 Establishing the Demand Response Baseline for the Next Day

If, for a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

- (a) the asset has been dispatched or audited in the present day pursuant to Section III.13, or;
- (b) the Demand Reduction Offer associated with the asset is eligible in the present Operating Day for payments pursuant to Section III.E1.9, or;
- (c) the present day is a Demand Response Holiday, Saturday or Sunday, then:

the asset's Demand Response Baseline, in each five-minute interval, for the next day is equal to the Demand Response Baseline, in the same five-minute interval from the present day.

8A.3 Determining if Meter Data From the Present Day is Used in the Demand Response Baseline for the Next Day

If, for a Real-time Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline:

- (a) the present day is not a Demand Response Holiday, Saturday or Sunday, and; the asset has not been dispatched or audited in the present day pursuant to Section III.13, and; the Demand Reduction Offer associated with the asset is not eligible in any hour of the present day for payments pursuant to Section III.E1.9, or;
- (b) the present day is not a Demand Response Holiday, Saturday or Sunday and more than seven of the prior 10 non-Demand Response Holiday weekdays have established a Demand Response Baseline determined pursuant to Section III.8A.2; then:

the asset's Demand Response Baseline in each five-minute interval, for the next day is calculated as the sum of 0.9 times the asset's Demand Response Baseline established for the present day in the same five-minute interval and 0.1 times the asset's meter data in the same five-minute interval from the present day.

8A.4 Baseline Adjustment

8A.4.1 Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets Without Generation or From Real-Time Emergency Generation Assets Without Additional Generation

For each day the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between the asset's actual metered demand and its Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Load.

8A.4.2 Baseline Adjustment for Real-Time Demand Reductions From Real-Time Demand Response Assets with Generation or From Real-Time Emergency Generation Assets With Additional Generation

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between the sum of the asset's actual metered demand and the output of all generators, or for Real-Time Emergency Generation Assets all additional generators, located behind the asset's end-use customer meter in the same time intervals and the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Facility Load.

8A.4.3 Baseline Adjustment for Real-Time Demand Reductions Produced By Directly Metered Generation

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset that is comprised of a Distributed Generation asset located behind the end-use customer meter of an individual end-use customer facility, the asset's Demand Response Baseline shall not be subject to the baseline adjustment.

8A.4.4 Baseline Adjustment for Real-Time Demand Reductions Produced by a Real-Time Demand Response Asset Located At a Retail Delivery Point Where There Are No Other Real-Time Demand Response Assets At or Behind that Retail Delivery Point

For a Real-Time Demand Response Asset located at a retail delivery point with no other Real-Time Demand Response Assets at or behind the same retail delivery point, the metered output of any Real-Time Emergency Generation Assets in each five-minute interval shall be added to the metered demand measured at the retail delivery point in the same intervals to determine the Real-Time Demand Response Asset's Demand Response Baseline. Each generator located behind an individual end-use customer's retail delivery point shall be separately measured using an interval meter and shall be reported to the ISO at an interval of five minutes.

For each day that the ISO calculates the Real-Time demand reduction amount of a Real-Time Demand Response Asset, the ISO will calculate an adjustment factor equal to the average difference (MW) between (1) the sum of the asset's actual metered demand as measured at the asset's retail delivery point

and the output of any Real-Time Emergency Generation Assets located behind the asset's retail delivery point in the same time intervals, and (2) the asset's Demand Response Baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the Operating Day. The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, for assets that cannot produce net supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the asset's Maximum Facility Load. For assets that can produce net supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than the maximum ~~hourly~~ amount (MW) that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement (where the amount (MW) pushed back into the electric system is a negative value) and shall not exceed the asset's Maximum Facility Load.

The Real-Time demand reduction amount achieved by the Real-Time Demand Response Asset shall be equal to the asset's adjusted Demand Response Baseline in each five-minute interval minus the sum of the metered demand measured at the retail delivery point and the output of any Real-Time Emergency Generation Assets located behind the Real-Time Demand Response Asset's retail delivery point in the same time intervals. A Real-Time Demand Response Asset's Real-Time demand reduction amount is negative if the sum of the asset's Real-Time metered demand and the output of any Real-Time Emergency Generation Assets is greater than its adjusted Demand Response Baseline.

8A.5 Establishing the Demand Response Baseline for a Day with a Scheduled or a Forced Curtailment

8A.5.1 Notification of Forced and Scheduled Curtailments

A Market Participant, with a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset for which a Demand Response Baseline measured at the retail delivery point is utilized, may notify the ISO of a forced curtailment for any reductions in demand that occur as a result of actions outside the control of the Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that is subject to the forced curtailment.

A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions in a Real-Time Demand Response Asset's demand or a Real-Time Emergency Generation Asset's demand where a Demand Response Baseline measured at

the retail delivery point is utilized, that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Real-Time Demand Response Assets or Real-Time Emergency Generation Assets with a Maximum Interruptible Capacity ~~and/or Maximum Net Supply~~ of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

8A.5.2 Submitting Meter Data Values for Days with Forced or Scheduled Curtailments

For each calendar day on which a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset where a Demand Response Baseline measured at the retail delivery point is utilized, is on a forced or scheduled curtailment, the asset's Demand Designated Entity shall submit to the ISO meter data values equal to the unadjusted baseline calculated for the first day of the forced or scheduled curtailment for all intervals excluding those in which the Real-Time Demand Response Resource with which the Real-Time Demand Response Asset is associated, or the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13, and excluding those in which a Demand Reduction Offer associated with the Real-Time Demand Response Asset had cleared day-ahead or became eligible in real-time pursuant to Section III.E1 on a day with an unanticipated forced curtailment.

8A.5.3 Performance Assessment for Days with Forced or Scheduled Curtailments

To assess the performance of Real-Time Demand Response Assets and Real-Time Emergency Generation Assets that are on a forced or scheduled curtailment, actual meter data values shall be submitted to the ISO for intervals during which the Real-Time Demand Response Resource with which the Real-Time Demand Response Asset is associated, or the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13, and intervals in which a Demand Reduction Offer associated with the Real-Time Demand Response Asset was cleared day-ahead or became eligible during the Operating Day pursuant to Section III.E1 on a day with an unanticipated forced curtailment.

III.8B Demand Response Baselines

Section III.8B shall govern Demand Response Baselines calculated for Capacity Commitment Periods commencing on or after June 1, 2017.

A Demand Response Baseline is calculated in 5-minute intervals for each Demand Response Asset and each Real-Time Emergency Generation Asset that is metered at the Retail Delivery Point for the following day types:

- (a) weekdays (Monday-Friday) that are non-Demand Response Holidays;
- (b) Saturdays, and;
- (c) Sundays (including Demand Response Holidays).

8B.1 Demand Response Baseline Calculations

If a Demand Response Asset's metered demand represents Net Supply in an interval, ~~that Net Supply the Demand Response Asset's metered demand in the interval will be set equal to zero and that zero demand value~~ will be used in the Demand Response Baseline calculations for that interval pursuant to Sections III.8B.2 and III.8B.4.

8B.1.1 Demand Response Baseline Real-Time Emergency Generation Asset Adjustment

To the extent a Real-Time Emergency Generation Asset is located at the same Retail Delivery Point as a Demand Response Asset, the metered output of the Real-Time Emergency Generation Asset, in each five-minute interval, shall be added to the metered demand measured at the Retail Delivery Point in the same intervals for purposes of determining the Demand Response Asset's Demand Response Baseline.

8B.2 Establishing an Initial Demand Response Baseline and Resetting a Baseline

An initial Demand Response Baseline will be established for a Demand Response Asset with no previously computed Demand Response Baseline, and for a Real-Time Emergency Generation Asset with no previously computed Demand Response Baseline when a Demand Response Baseline measured at the Retail Delivery Point is utilized for the asset. A Demand Response Baseline will be reset using the initial baseline calculation methodology set forth below when a significant change in load, generation, or

reported meter data at an existing Demand Response Asset or Real-Time Emergency Generation Asset occurs.

The initial Demand Response Baseline, or a reset of a Demand Response Baseline, for a Demand-Response Asset or Real-Time Emergency Generation Asset that is metered at the Retail Delivery Point with no previously computed Demand Response Baseline shall be the simple average of metered demand data for the asset for each five-minute interval, subject to the conditions in Section III.8B.1, from the initial 10 days of the same day type. The initial 10 days of meter data used to establish the Demand Response Baseline shall consist of the first 10 consecutive days of the same day type with a complete set of interval meter data.

A Market Participant may not submit Demand Reduction Offers for a Demand Response Resource for a given day type until 1) the month following the establishment of the initial baseline by at least one Demand Response Asset mapped to the Demand Response Resource, provided that the initial baseline was established prior to the last calendar week of the month or, 2) two months following the establishment of the initial baselines for at least one Demand Response Asset mapped to the Demand Response Resource. This condition applies when establishing an initial Demand Response Baseline but not when resetting a Demand Response Baseline.

~~A Market Participant may not submit Demand Reduction Offers for a given day type until the month following the initial establishment of the Demand Response Baseline of the same day type for a Demand Response Asset.~~

8B.3 Establishing a Demand Response Baseline for the Next Day

If, for a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for a day type and the asset is associated with a Demand Response Resource that has been dispatched or audited in the present day pursuant to Section III.E2.5 or Section III.13 ~~or Section III.E2.5~~, the Demand Response Baseline of the Demand Response Asset or Real-Time Emergency Generation Asset, in each five-minute interval, for the next day of the same day type is equal to the Demand Response Baseline of that Demand Response Asset or Real-Time Emergency Generation Asset, in the same five-minute interval from the present day.

8B.4 Determining if Meter Data from the Present Day is Used in the Demand Response Baseline for the Next Day of the Same Day Type

If, for a Demand Response Asset or Real-Time Emergency Generation Asset that has established an initial Demand Response Baseline for that day type, the Demand Response Resource or Real-Time Emergency Generation Resource to which the asset is associated has not been dispatched or audited in the present day pursuant to Section III.E2.5 or Section III.13 ~~or Section III.E2.5~~, or more than seven of the prior 10 days of the same day type have a Demand Response Baseline determined pursuant to Section III.8B.3, then:

the Demand Response Baseline of the Demand Response Asset or Real-Time Emergency Generation Asset in each five-minute interval, for the next day of the same day type as the present day, is calculated as the sum of 0.9 times the Demand Response Baseline of that Demand Response Asset or Real-Time Emergency Generation Asset for the present day in the same five-minute interval and 0.1 times the Demand Response Asset's or Real-Time Emergency Generation Asset's meter data, subject to the conditions in Section III.8B.1, in the same five-minute interval from the present day.

8B.5 Baseline Adjustment

The Demand Response Baseline for each Demand Response Asset and each Real-Time Emergency Generation Asset is updated approximately every quarter hour by an adjustment factor that is calculated in accordance with this Section III.8B.5, which may increase or decrease the baseline.

- (a) An adjustment factor is calculated if the resource with which the asset is associated is not in a period of dispatch (as defined by the resource's Dispatch Instruction including the Demand Response Resource Start-Up Time and Demand Response Resource Notification Time). The adjustment factor is calculated with real-time telemetry data in Real-Time and is calculated with revenue quality metering data for settlement purposes.
- (b) For an asset that is part of a resource that is not in a period of dispatch, the adjustment factor is calculated using five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the start of the quarter hour. For an asset that is part of a resource that has received a Dispatch Instruction, the adjustment factor is calculated using five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the Dispatch Instruction was issued. After completion of a dispatch, the adjustment factor for an asset will be calculated using the five minute interval data from the three intervals that start 25 minutes before, and end 10 minutes before, the Dispatch Instruction was issued, until sufficient time has elapsed to calculate the adjustment using post-dispatch interval data.

~~(c) For each day that a Demand Response Resource associated with a Demand Response Asset is scheduled in the Day Ahead Energy Market or that a Demand Response Resource associated with a Demand Response Asset is dispatched in Real Time for a demand reduction amount greater than zero, the ISO will calculate an~~ For a Demand Response Asset, the adjustment factor is equal to the average difference (MW) between the Demand Response Asset's telemetered or metered demand, which shall be adjusted pursuant to Section III.8B.1.1 (inclusive of any Net Supply), and its Demand Response Baseline during in the three intervals ~~during the two-hour period for Demand Response Resources beginning two hours plus the Demand Response Resource Start-Up Time prior to the start of the first interruption interval in the present day.~~ For each day that a Real Time Emergency Generation Resource associated with a Real-Time Emergency Generation Asset the is dispatched in Real Time for a demand reduction amount greater than zero, the ISO ~~will calculate an~~ adjustment factor is equal to the average average difference (MW) between the Real-Time Emergency Generation Asset's telemetered or metered demand and its Demand Response Baseline in during the three intervals ~~during the two-hour period for Real-Time Emergency Generation Resource beginning 2.5 hours prior to the start of the first interruption interval in the present day.~~

~~(a)(d)~~ The adjustment factor will be added to the Demand Response Baseline in every interval of the day, which may increase or decrease the Demand Response Baseline. However, For Demand Response Assets that cannot produce Net Supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than zero and shall not exceed the facility's ~~asset's~~ Maximum Load. For Demand Response Assets that can produce Net Supply, the resulting adjusted Demand Response Baseline in any interval shall not be less than the maximum amount (MW) that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement (where the amount (MW) pushed back into the electric system is a negative value) and shall not exceed the asset's Maximum Facility Load. For purposes of establishing the adjusted Demand Response Baseline, if a Demand Response Asset's metered demand represents Net Supply, the Demand Response Asset's metered demand in the interval will be set equal to zero.

8B.6 Establishing the Demand Response Baseline for a Day with a Scheduled or a Forced Curtailment

8B.6.1 Notification of Forced and Scheduled Curtailments

A Market Participant, with a Demand Response Asset or a Real-Time Emergency Generation Asset for which a Demand Response Baseline measured at the Retail Delivery Point is utilized, may notify the ISO of a forced curtailment for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset or Real-Time Emergency Generation Asset that is subject to the forced curtailment.

A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions in a Demand Response Asset's demand or a Real-Time Emergency Generation Asset's demand where a Demand Response Baseline measured at the Retail Delivery Point is utilized, that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Demand Response Assets or Real-Time Emergency Generation Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

III.8B.6.2 Submitting Meter Data Values for Days with Forced or Scheduled Curtailments

For each calendar day on which a Demand Response Asset or a Real-Time Emergency Generation Asset, where a Demand Response Baseline measured at the Retail Delivery Point is utilized, is on a forced or scheduled curtailment pursuant to Section III.8B.6.1, the asset's Demand Designated Entity shall submit to the ISO meter data values equal to the unadjusted baseline calculated for the first day of the forced or scheduled curtailment for all intervals excluding those in which:

- (a) the Demand Response Resource with which the Demand Response Asset is associated was dispatched during the period of a Shortage Event as defined in Section III.13.7.1.1.1 for the Capacity Zone in which the resource is located,
- (b) the Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or
- (c) the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

III.8B.6.3 Performance Assessment for Days with Forced or Scheduled Curtailments

To assess the performance of Demand Response Assets and Real-Time Emergency Generation Assets that are on a forced or scheduled curtailment, actual meter data values shall be submitted to the ISO for intervals during which:

- (a) the Demand Response Resource with which the Demand Response Asset is associated was dispatched during the period of a Shortage Event as defined in Section III.13.7.1.1.1 for the Capacity Zone in which the Resource is located,
- (b) the Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or
- (c) the Real-Time Emergency Generation Resource with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

III.9 Forward Reserve Market

The Forward Reserve Market is a market to procure TMNSR and TMOR on a forward basis to satisfy forward TMNSR and TMOR requirements.

III.9.1 Forward Reserve Market Timing.

A Forward Reserve Auction will be held approximately two months in advance of each Forward Reserve Procurement Period. The Forward Reserve Auction input parameters and assumptions will be evaluated, published and reviewed with Market Participants prior to the Forward Reserve Auction.

The Forward Reserve Procurement Periods shall be the Winter Capability Period (October 1 through May 31) or the Summer Capability Period (June 1 through September 30), as applicable.

The Forward Reserve Delivery Period shall be hour ending 0800 through hour ending 2300 for each weekday of the Forward Reserve Procurement Period excluding those weekdays that are defined as NERC holidays.

III.9.2 Forward Reserve Market Reserve Requirements.

The ISO shall conduct an advance purchase of capability to satisfy the expected Forward Reserve requirements for the system and each Reserve Zone as calculated by the ISO in accordance with the following procedures and as specified more fully in the ISO New England Manuals. The Forward Reserve Market reserve requirements will be specified as part of the Forward Reserve Auction parameters and will be published and reviewed with Market Participants prior to each Forward Reserve Auction.

III.9.2.1 Forward Reserve Market Reserve Requirements.

The Forward Reserve Market requirements for the New England Control Area will be based on the forecast of the first and second contingency supply losses for the next Forward Reserve Procurement Period and will consist of the following:

- (i) One half of the forecasted first contingency supply loss will be specified as the minimum TMNSR to be purchased,
- (ii) An additional amount of TMNSR will be added to the minimum TMNSR if system conditions forecasted for the Forward Reserve Procurement Period indicate that the TMNSR available during the period would otherwise be insufficient to meet Real-Time Operating Reserve requirements. The additional amount of TMNSR shall be calculated to account for: (a) any historical under-performance of Resources dispatched in response to a System contingency and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR.
- (iii) One half of the second contingency supply loss will be specified as the minimum TMOR to be purchased,
- (iv) An amount of Replacement Reserve in the form of incremental TMOR will be specified in accordance with the Real-Time Replacement Reserve requirement as described in ISO New England Operating Procedure No. 8, Operating Reserve and Regulation and will be added to the minimum TMOR to be purchased.

The requirements specified above, further adjusted to respect the additional provisions described in Section III.9.2.2, represent the set of requirements that will be input into the Forward Reserve Auction.

III.9.2.2 Locational Reserve Requirements for Reserve Zones

Locational reserve requirements will be established for each Reserve Zone. The locational reserve requirements will reflect the need for 30-minute contingency response to provide 2nd contingency protection for each import constrained Reserve Zone. The locational reserve requirements can be satisfied only by Resources that are located within a Reserve Zone and that are capable of providing 30-minute or higher quality reserve products.

The ISO shall establish the locational reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each Reserve Zone for like Forward Reserve Procurement Periods. The ISO will commence the analysis on February 1 or the first business day thereafter for the subsequent summer Forward Reserve Procurement Period and on June 1 or the first business day thereafter for the subsequent winter Forward Reserve Procurement Period.

These daily peak hour requirements will be aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone will establish the locational requirement.

In the event of a change in the configuration of the transmission system or the addition, deactivation or retirement of a major generating Resource, ~~or Dispatchable Asset Related Demand~~, or Demand Response Resource the rolling two-year historical analysis will be calculated in a manner that reflects the change in configuration of the transmission system or the addition, deactivation or retirement of a major generating Resource, ~~or Dispatchable Asset Related Demand~~ or Demand Response Resource as of the commencement date of the analysis provided that the following conditions are met:

(a) Change in Configuration of the Transmission System

Any change in the configuration of the transmission system must have been placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the locational reserve requirements for the subsequent winter Forward Reserve Procurement Period.

If the change in the configuration of the transmission system consists of a new facility or upgrade of an existing facility, the facility must have operated at an availability level of at least 95% for the period beginning with its in service date and ending on January 31 prior to the summer Forward Reserve Procurement Period or ending on May 31 prior to the winter Forward Reserve Procurement Period.

(b) Addition, Deactivation or Retirement of a Major Generating Resource, ~~or Dispatchable Asset Related Demand~~ or Demand Response Resource

For the addition of a new generating Resource, Dispatchable Asset Related Demand, or Demand Response Resource, the Resource must be placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the locational reserve requirements for the subsequent winter Forward Reserve Procurement Period. For the deactivation or retirement of a generating Resource, ~~or~~ Dispatchable Asset Related Demand or Demand Response Resource, the Resource must have been removed from service on or before January 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before May 31 for inclusion in the analysis for setting the locational reserve requirements for the subsequent winter Forward Reserve Procurement Period.

The modified historical data set will be composed of actual data used in the operation of the reconfigured system and historical (pre-reconfiguration) data adjusted for the impact of the system reconfiguration. Pre-reconfiguration data will be revised by substituting values from the historical data set that are no longer valid with corresponding values used in the operation of the reconfigured system.

The locational reserve requirements will be recalculated using the modified historical data set until the rolling two-year historical data set reflects a common system configuration.

III.9.3 Forward Reserve Auction Offers.

Forward Reserve Auction Offers for TMNSR and TMOR shall be (a) made on a \$/MW-month basis, (b) made on a Reserve Zone specific basis, (c) made on a non-Resource specific basis and (d) shall be less than or equal to the Forward Reserve Offer Cap. Forward Reserve Auction Offers shall be submitted to the ISO by Market Participants. The Market Participants are responsible for complying with the requirements of this Section III.9 if the Forward Reserve Auction Offer is accepted.

III.9.4 Forward Reserve Auction Clearing and Forward Reserve Clearing Prices.

The Forward Reserve Auction shall simultaneously clear Forward Reserve Auction Offers to meet the Forward Reserve requirements for the system and each Reserve Zone using a mathematical programming algorithm. The objective of the mathematical programming based Forward Reserve Auction clearing is to minimize the total cost of Forward Reserve procured to meet the Forward Reserve requirements. The Forward Reserve Clearing Price for each Reserve Zone will reflect the cost to serve the next increment of reserve in that Reserve Zone based on the submitted offers. The Forward Reserve Auction algorithm

substitutes higher quality TMNSR for lower quality TMOR to meet system or Reserve Zone TMOR requirements when it is economical to do so provided that no constraints are violated.

The Forward Reserve Auction algorithm shall also utilize excess Forward Reserve in one Reserve Zone to meet the Forward Reserve requirements of another Reserve Zone or the system provided that the Forward Reserve can be delivered such that no constraints are violated. In addition, the Forward Reserve Auction shall apply price cascading such that the Forward Reserve Clearing Price for TMOR in a Reserve Zone is always less than or equal to the Forward Reserve Clearing Price for TMNSR in that Reserve Zone. If there is insufficient supply to meet the Forward Reserve requirements for a Reserve Zone, the Forward Reserve Clearing Price for that Reserve Zone will be set to the Forward Reserve Offer Cap.

III.9.4.1 Forward Reserve Clearing Price and Forward Reserve Obligation Publication and Correction.

Market Participants with cleared Forward Reserve Auction Offers will receive a Forward Reserve Obligation for each Reserve Zone, as applicable, that is equal to the amount of Forward Reserve megawatts cleared for that Market Participant adjusted for internal bilateral transactions that transfer Forward Reserve Obligations.

(a) Within five business days after the close of the Forward Reserve Auctions, the ISO shall post Forward Reserve Clearing Prices and Forward Reserve Obligations, which shall be final as posted, not subject to correction or other adjustment, and used for the purposes of settlement, except as provided in subsections (c) and (d). The permissibility of correction of errors in sections of Market Rule 1 relating to settlement and billing processes shall not apply to Forward Reserve Clearing Prices and Forward Reserve Obligations deemed final pursuant to this Section III.9.4.1.

(b) Before posting the final Forward Reserve Clearing Prices and Forward Reserve Obligations, the ISO shall make a good faith effort when clearing those markets to discover and correct any errors that may occur due to database, software or similar errors of the ISO or its systems before publishing the final prices awarded.

(c) If the ISO determines based on reasonable belief that there may be one or more errors in the final Forward Reserve Clearing Prices and Forward Reserve Obligations or if no Forward Reserve Clearing Prices and Forward Reserve Obligations are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 11:59 p.m. of the third

business day following the posting deadline specified in subsection (a), a notice that the Forward Reserve Clearing Prices and Forward Reserve Obligations are provisional and subject to correction or unavailable for initial publishing. The ISO shall confirm within three business days of posting a notice pursuant to this subsection whether there was an error in the Forward Reserve Clearing Prices and Forward Reserve Obligations and shall post a notice stating its findings.

(d) Within three business days after posting an initial notice pursuant to subsection (c); the ISO shall either: (1) publish final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations, or: (2) in the event that the ISO is unable to calculate and post final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations due to exigent circumstances not contemplated in this market rule, make an emergency filing with the Commission detailing the exigent circumstance which will not allow final Forward Reserve Clearing Prices and Forward Reserve Obligations to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

III.9.5 Forward Reserve Resources

III.9.5.1 Assignment of Forward Reserve MWs to Forward Reserve Resources.

(a) Prior to the close of the Re-Offer Period for each Operating Day of the Forward Reserve Procurement Period, Market Participants must convert their Forward Reserve Obligations into Resource-specific obligations by assigning Forward Reserve MWs to specific eligible Forward Reserve Resources, in accordance with procedures set forth in the ISO New England Manuals. The assignment of Forward Reserve MWs to a Forward Reserve Resource must be performed by the Lead Market Participant for the Resource.

(b) A Market Participant with a Forward Reserve Obligation must have an Ownership Share in a Forward Reserve Resource that is a generating Resource; in order to assign Forward Reserve MWs to that Forward Reserve Resource to fulfill that Market Participant's Forward Reserve Obligation. If more than one Market Participant has an Ownership Share in a Forward Reserve Resource, the Forward Reserve MWs assigned to that Resource will be allocated pro-rata to Market Participants by Ownership Share.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

(a) Forward Reserve Resources are ~~off-line or on-line~~ Resources that have been assigned by Market Participants to meet their Forward Reserve Obligations. To be eligible as a Forward Reserve Resource, a Resource must satisfy the following criteria:

(i) If the generating Resource is off-line, it must be a Fast Start Generator and have an audited CLAIM10 or CLAIM30 value established pursuant to Section III.9.5.3;

(ii) If the Resource is a Demand Response Resource which has not been dispatched, it must be a Fast Start Demand Response Resource and have an audited CLAIM10 or CLAIM30 value established pursuant to Section III.9.5.3;

(iii) If the generating Resource is expected to be on-line, or, for a Demand Response Resource, has been dispatched, during a Forward Reserve Delivery Period, it must be able to produce the energy or demand reduction equivalent to its assigned Forward Reserve Obligation within the timeframe of the assigned Forward Reserve Obligation when operating within its dispatch range;

~~(#iv)~~ If the Resource is an Asset Related Demand, it must have a CLAIM10 or CLAIM30 value established pursuant to Section III.9.5.3;

(iv) ~~The Resource may have a Capacity Supply Obligation for all, some, or none of its applicable Seasonal Claimed Capability.~~ Any portion of the Resource to which a Forward Reserve Obligation has been assigned that is without a Capacity Supply Obligation must not have been offered to support an External Transaction sale during the Operating Day for which it has been assigned;

(vi) The Resource must have Electronic Dispatch Capability;

(vii) The Resource must follow ISO-dDispatch Instructions during the Operating Day. The Resource must meet the technical requirements associated with the provision of Forward Reserve as specified in ISO New England Operating Procedure No. 14, ~~Technical Requirements For Generation, Dispatchable and Interruptible Loads~~ (Technical Requirements for Generators, Demand Resources and Asset Related Demands);

(viii) The portion of the Resource ~~with or without a Capacity Supply Obligation~~ that is assigned a Forward Reserve Obligation for any portion of an Operating Day must be eligible to provide Operating Reserve in accordance with the provisions of Section III.10.1.1;

(viii) The portion of the Resource ~~without a Capacity Supply Obligation~~ to which a Forward Reserve Obligation has been assigned must be offered into the Real-Time Energy Market in accordance with the provisions of either Section III.13.6.1.1.2 or Section III.13.6.1.5.2.

(b) External Resources will be permitted to participate in the Forward Reserve Market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.9.5.3 Resource CLAIM10 and CLAIM30 Values.

III.9.5.3.1 Calculating Resource CLAIM10 and CLAIM30 Values.

1. The CLAIM10 or CLAIM30 value of a Resource shall equal:

- (a) the maximum output or demand-reduction level reached, including ~~output the level~~ reached during a CLAIM10 or CLAIM30 audit, measured at the 10 minute or 30 minute point from the Resource's receipt of an initial electronic startup Dispatch Instruction during the current Forward Reserve Procurement Period or the preceding like-season Forward Reserve Procurement Period, subject to the conditions in Section III.9.5.3.1.2 below;
- (b) multiplied by the Resource's then effective CLAIM10 or CLAIM30 performance factor established pursuant to Section III.9.5.3.3.

2. The value in Section III.9.5.3.1.1(a) is subject to the following additional conditions:

- (a) The value shall not include any dispatch in which the unit becomes unavailable within 60 minutes following the receipt of the initial Dispatch Instruction;
- (b) If the maximum output or demand-reduction level reached, as measured at the 10 minute or 30 minute point from the initial Dispatch Instruction, is greater than the highest Desired Dispatch Point issued for the Resource for that 10 minute or 30 minute period, the value shall be capped at the highest Desired Dispatch Point.

~~(c) For the first two Forward Reserve Procurement Periods following the effective date of this Section III.9.5.3.1, the calculation in Section III.9.5.3.1.1(a) shall use for the maximum output level reached in that previous like Forward Reserve Procurement Period: (i) for a~~

~~Resource with a successful audit during the Forward Reserve Procurement Period, the audited CLAIM10 or CLAIM30 value in effect on the last day of the previous like Forward Reserve Procurement Period or (ii) for a Resource without a successful audit during the Forward Reserve Procurement Period, the value as determined in accordance with Section III.9.5.3.1.1.(a).~~

3. A Resource's CLAIM10 value shall be no greater than the Resource's CLAIM30 value.
4. The CLAIM10 or CLAIM30 value of a Resource shall be calculated and distributed to the Lead Market Participant weekly and shall become effective at 0001 of the Monday following the distribution.

III.9.5.3.2 CLAIM10 and CLAIM30 Audits.

(a) **General.** A ~~Lead~~ Market Participant ~~or Designated Entity~~ may request a CLAIM10 or CLAIM30 audit specifying the requested output or demand-reduction level that the Resource will attempt to reach in 10 or 30 minutes. A ~~Lead~~ Market Participant ~~or Designated Entity~~ may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(b) **CLAIM10 and CLAIM30 Audit Procedures.** The ISO will initiate a CLAIM10 or CLAIM30 audit by issuing an electronic Dispatch Instruction without providing prior notice to the ~~Lead~~ Market Participant ~~or Designated Entity~~. The ISO will normally perform the audit, at any time during the Forward Reserve Delivery Period, within five business days of receipt of the audit request or will advise the ~~Lead~~ Market Participant ~~or Designated Entity~~ if it will be unable to initiate the audit during the five business day period. The Resource's CLAIM10 or CLAIM30 audit value shall be the Resource's output or demand-reduction level reached at the 10 minute or 30 minute point after the receipt of the initial startup Dispatch Instruction.

III.9.5.3.3 CLAIM10 and CLAIM30 Performance Factors.

A Resource's CLAIM10 or CLAIM30 performance factor shall be established based upon the 10 most recent ISO-issued initial electronic startup Dispatch Instructions as described below. Dispatches greater than three years old shall not be used for the performance factor calculation. Resource performance factors will be calculated on a weekly basis.

(a) A Resource's performance factor is calculated as:

$$performance\ factor = \frac{\sum_{n=1}^{10} \left(\frac{resource\ output\ or\ demand\ reduction\ at\ 10\ or\ 30\ minutes_n\ (MW)}{resource\ target\ value_n\ (MW)} * n \right)}{\sum_{n=1}^{10} n}$$

$$performance\ factor = \frac{\sum_{n=1}^{10} \left(\frac{resource\ output\ at\ 10\ or\ 30\ minutes_n\ (MW)}{resource\ target\ value_n\ (MW)} * n \right)}{\sum_{n=1}^{10} n}$$

Where:

n is a value between 1 and 10, 1 representing the least recent dispatch signal, 10 representing the most recent dispatch signal;

the Resource output or demand reduction is measured at the 10 minute or 30 minute point from receipt of the initial startup Dispatch Instruction;

the Resource target value is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute or 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM10 or CLAIM30 value or (iii) the Resource's Offered CLAIM10 or Offered CLAIM30.

(b) For purposes of the performance factor calculation, the following conditions apply:

- (i) For each CLAIM10 or CLAIM30 audit, the Resource's target value shall be set to the Resource's output or demand reduction at 10 or 30 minutes.
- (ii) In the event the Resource has not had 10 electronic startup dispatches within the last three years, the "n" term in the performance factor calculation will be based on the number of startup dispatches that took place in the last three years, with the most recent dispatch having a weight of 10 and with the weighting decreasing by 1 for each previous startup dispatch.

(iii) If a Resource's output or demand reduction at 10 or 30 minutes is greater than the Resource's target value, then the Resource target value shall be set to the Resource output at 10 or 30 minutes.

(iv) A dispatch shall not be utilized in the performance factor calculation if a Resource starts and subsequently performs a normal shut down or ceases its demand reduction, in response to a Dispatch Instruction to shut down or, for a Demand Response Resource, in response to a Dispatch Instruction to cease its demand reduction, within the 10 or 30 minute period following the initial electronic startup Dispatch Instruction.

(v) Resource output or demand reduction at 10 or 30 minutes shall equal zero if the Resource becomes unavailable for dispatch within the 60 minute period following the initial electronic startup Dispatch Instruction.

III.9.5.3.4 Performance Factor Cure.

In the event a Resource either (a) is unable to reach at least 60% of the Resource target level, as reflected in the Dispatch Instruction issued for the Resource, either five times in a row or seven out of 10 times, as a result of a chronic operational problem with the Resource or (b) undergoes a major overhaul scheduled and performed during a planned outage that was approved in the ISO's annual maintenance scheduling process or during a scheduled curtailment for a Demand Response Resource, ~~the a Market Participant, Lead Market Participant, or Designated Entity~~ may submit a restoration plan to the ISO to restore the Resource's CLAIM10 or CLAIM30 operational capability. Restoration plans submitted because of a Resource's inability to reach its target output or demand reduction shall indicate the specific nature of the problem, the steps to be taken to remedy the problem, and the timeline for completing the restoration. Restoration plans submitted for a major overhaul shall explain the actions taken during the planned outage or scheduled curtailment that would result in the increase of the Resource's CLAIM10 or CLAIM30. The ISO shall accept restoration plans that, upon review, indicate a reasonable likelihood of success in remedying the identified problem or, for a major overhaul, increasing the Resource's CLAIM10 or CLAIM30. Upon completion of the restoration, the Market Participant, Lead Market Participant, or Designated Entity shall request a CLAIM10 or CLAIM30 audit of the Resource, using the procedures in Section III.9.5.3.2. Following the audit, the Resource's Performance Factor shall be set to 1.0, with all dispatches prior to the audit removed from the performance factor calculation.

III.9.6 Delivery of Reserve.

III.9.6.1 Dispatch and Energy Bidding of Reserve.

Forward Reserve shall be delivered by Forward Reserve Resources for an hour by offering the capability into the Real-Time Energy Market by submitting Supply Offers and Demand Bids no later than 30 minutes prior to the start of the operating hour at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Supply Offers and Demand Bids for Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day even if the Supply Offers do not clear the Day-Ahead Energy Market, notwithstanding the requirements of ~~Market Rule 1~~ Section III.13.6.2.1.1.2, unless superseded by a more recent Supply Offer or Demand Bid submitted no later than 30 minutes prior to the start of the operating hour. A Market Participant is not required to submit a Supply Offer or Demand Bid into the Day-Ahead Energy Market for a Resource without a Capacity Supply Obligation in order for the Resource to be eligible to be a Forward Reserve Resource. The Forward Reserve Threshold Prices shall be set in accordance with the ISO New England Manuals so that Forward Reserve Resource capability has (a) a low probability of being dispatched for energy and (b) a high probability of being held for reserve purposes.

Forward Reserve shall be delivered by Forward Reserve Resources that are ~~For~~ Demand Response Resources, for an hour by offering the capability into the Real-Time Energy Market by submitting Demand Reduction Offers no later than the close of the Re-Offer Period, at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Demand Reduction Offers for Demand Response Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day even if the Demand Reduction Offers do not clear the Day-Ahead Energy Market, notwithstanding the requirements of Section III.13.6.1.5.2.

Forward Reserve Resources are scheduled and operated in accordance with Section III.1 of Market Rule 1; no distinction is made due to their status as Forward Reserve Resources. Forward Reserve Resources are eligible to set the Locational Marginal Price in accordance with Section III.2 of Market Rule 1.

III.9.6.2 Forward Reserve Threshold Prices.

The formula for determining the Forward Reserve Threshold Prices shall be fixed for the duration of the Forward Reserve Procurement Period. The ISO will reevaluate the Forward Reserve Threshold Price level for successive Forward Reserve Auctions on the basis of experience, expected operating conditions and other relevant information.

Forward Reserve Threshold Price: is calculated as the Forward Reserve Heat Rate multiplied by the daily Forward Reserve Fuel Index.

Forward Reserve Heat Rate: shall be fixed for the duration of the Forward Reserve Procurement Period and announced in the announcement for the Forward Reserve Auction. New Forward Reserve Heat Rates shall be specified for successive auctions, and shall be the lesser of: (a) the value determined in accordance with applicable ISO New England Manuals; or (b) the heat rate defined for the PER Proxy Unit in Section III.13.7.2.7.1.1(b) less 1 Btu/kWh.

Forward Reserve Fuel Index: is a daily fuel index, or combination of daily indices, applicable to the New England Control Area and specified in the announcement of the Forward Reserve Auction.

III.9.6.3 Monitoring of Forward Reserve Resources.

In accordance with Section III.A.913.4 of Appendix A of this Market Rule 1, the Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Participant in accordance with Market Rule 1, Appendix A, Section III.A.3. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4.

III.9.6.4 Forward Reserve Qualifying Megawatts.

Qualifying megawatts for generating Resources and Dispatchable Asset Related Demand are calculated separately on an hourly basis for Forward Reserve Resources supplying Forward Reserve from an off-line state and Forward Reserve Resources supplying Forward Reserve from an on-line state as follows:

Off-line qualifying megawatts. Off-line qualifying megawatts are the amount of capability equal to or below the Economic Maximum Limit for an off-line Forward Reserve Resource offered at or above the Forward Reserve Threshold Price. The generating Resource must satisfy this requirement in the Real-Time Energy Market. In the case of off-line Forward Reserve Resources, the calculation for Forward Reserve Qualifying Megawatts shall include both the energy Supply Offer and a pro-rated amount of Start-Up Fees and No-Load Fees as defined below.

An off-line Forward Reserve Resource must offer its capability so that the following holds:

$$\frac{StartUp}{EcoMax \times 1 \text{ hour}} + \frac{NoLoad}{EcoMax} + Energy \text{ Offer }_i \geq ForwardReserveThresholdPrice$$

where:

StartUp = the generating Resource's cold Start-Up Fee.

NoLoad = the generating Resource's No-Load Fee.

EnergyOffer_i = the generating Resource's Energy Offer for
Energy Offer block _i.

EcoMax = the Economic Maximum Limit.

On-line qualifying megawatts: is the capability that is less than or equal to the Economic Maximum Limit and above the Economic Minimum Limit that is offered at or above the applicable Forward Reserve Threshold Price by an on-line generating Resource or, is the capability that is less than or equal to the Maximum Consumption Limit and greater than the Minimum Consumption Limit offered at or above the applicable Forward Reserve Threshold Price **for by** a Dispatchable Asset Related Demand **Resource**. The Forward Reserve Resource must satisfy this requirement in the Real-Time Energy Market. For an on-line generating Resource that has been assigned to meet a Forward Reserve Obligation and has not cleared in the Day-Ahead Energy Market and is operating in a delivery hour as the result of an ISO commitment for VAR or local second contingency protection, the on-line qualifying megawatts shall be zero.

Qualifying megawatts for Demand Response Resources supplying Forward Reserve are calculated separately on an hourly basis for Demand Response Resources that have not been dispatched and Demand Response Resources that have been dispatched as follows:

Qualifying megawatts for a Demand Response Resource that has not been dispatched: is the amount of capability equal to or below the Maximum Reduction for the Demand Response Resource offered at or above the Forward Reserve Threshold Price. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Resources that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Demand Reduction Offer price and a pro-rated amount of the Interruption Cost as defined below.

A Demand Response Resource that has not been dispatched must offer its capability so that the following holds:

$$\frac{\text{Interruption Cost}}{\text{MaxRed}} + \text{Energy Offer}_i \geq \text{Forward Reserve Threshold Price}$$

where:

Interruption Cost = the amount, in dollars, that must be paid each time the Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

EnergyOffer_i = the Resource's Demand Reduction Offer price for Energy Offer block _i.

Max Red = the Resource's Maximum Reduction x 1 hour.

Qualifying megawatts for a Demand Response Resource which has been dispatched: is the capability that is less than or equal to the Maximum Reduction and greater than the Minimum Reduction that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Resource. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Resource which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

III.9.6.5 Delivery Accounting.

Forward Reserve Delivered Megawatts are the quantity of Forward Reserve delivered in each hour of the Real-Time Energy Market to each Reserve Zone and is calculated as follows.

- (a) Forward Reserve Delivered Megawatts for an off-line generating Forward Reserve Resource are calculated in megawatts for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

- (i) the amount, in MW, of Forward Reserve that the off-line generating Resource can provide, based upon CLAIM10 and CLAIM30 values provided in the generating Resource's Real-Time Supply Offer,
 - (ii) Forward Reserve Assigned Megawatts, or
 - (iii) Forward Reserve Qualifying Megawatts for that Resource (energy at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.
- (b) Forward Reserve Delivered Megawatts for an on-line generating Resource are calculated in megawatts for each hour for each Reserve Zone as the minimum of:
- (i) 10 or 30 times the MW/minute ramping rate of the on-line generating Resource, as applicable,
 - (ii) Forward Reserve Assigned Megawatts, or
 - (iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)
- less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.
- (c) Forward Reserve Delivered Megawatts for a Dispatchable Asset Related Demand are calculated ~~in megawatts~~ for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:
- (i) 10 or 30 times the MW/minute ramp rate of the Resource, as applicable,
 - (ii) the amount of Forward Reserve capability specified in the Resource's CLAIM10 and CLAIM30 values,
 - (iii) Forward Reserve Assigned Megawatts, or

(iv) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2),

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(d) A Forward Reserve Resource's hourly Forward Reserve Delivered Megawatts for each Reserve Zone is calculated as the sum of the Market Participant's Resource specific hourly Forward Reserve Delivered Megawatts for each Reserve Zone.

(e) Resource specific Forward Reserve Delivered Megawatts for TMNSR within a Reserve Zone will be applied first to a Market Participant's higher value Forward Reserve Obligation for TMNSR in that Reserve Zone. Any surplus Forward Reserve Delivered Megawatts for TMNSR in that Reserve Zone will be applied to meet the Market Participant's Forward Reserve Obligation for TMOR in that Reserve Zone. Forward Reserve Delivered Megawatts remaining within that Reserve Zone after the Market Participant's Forward Reserve Obligation for that Reserve Zone have been met is available to be applied to the Market Participant's Forward Reserve Obligations in other Reserve Zones provided that the Forward Reserve Delivered Megawatts can be delivered to the other Reserve Zones.

(f) Forward Reserve Delivered Megawatts for a Demand Response Resource which has not been dispatched are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount of Forward Reserve that the Resource can provide, based upon CLAIM10 and CLAIM30 values provided in the Demand Response Resource's Demand Reduction Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (energy at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(g) Forward Reserve Delivered Megawatts for a Demand Response Resource which has been dispatched are calculated for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute Demand Response Resource Ramp Rate of that Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(h) In determining Forward Reserve Delivered Megawatts for Demand Response Resources the portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be multiplied by one plus the average avoided peak distribution losses.

(i) It will be assumed that all Demand Response Assets associated with a Demand Response Resource must first reduce their load from the electricity system before providing Net Supply.

(ii) The portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be the lesser of:

- Forward Reserve Delivered Megawatts, or
- The amount of load that the Demand Response Asset associated with a Demand Response Resource can reduce from the electric system as indicated from revenue quality meter data.

(iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with Net Supply will be capped at the Net Supply Limit.

III.9.7 Consequences of Delivery Failure.

III.9.7.1 Real-Time Failure-to-Reserve.

A Real-Time Forward Reserve Failure-to-Reserve occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

(a) Forward Reserve Failure-to-Reserve Megawatts: A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMNSR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(i) Market Participant Forward Reserve Obligation for TMNSR for that Reserve Zone minus the Market Participant's Forward Reserve Delivered Megawatts for TMNSR for that Reserve Zone; and

(ii) Zero.

A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMOR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(i) Market Participant Forward Reserve Obligation for TMOR for that Reserve Zone minus Market Participant's Forward Reserve Delivered Megawatts for TMOR for that Reserve Zone; and

(ii) Zero.

(b) Forward Reserve Failure-to-Reserve Penalties: A Market Participant's Forward Reserve Failure-to-Reserve Penalty for a Reserve Zone in an hour is defined as:

(i) Forward Reserve Failure-to-Reserve Penalty for TMNSR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Reserve Penalty for TMOR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Reserve Penalty Rate (calculated for each Forward Reserve product and for each Reserve Zone) = maximum of (1.5 multiplied by the Forward Reserve Payment Rate

for the Forward Reserve product, the applicable Real-Time Reserve Clearing Price for the Forward Reserve product in the Reserve Zone minus the Forward Reserve Payment Rate for the Forward Reserve product)

III.9.7.2 Failure-to-Activate Penalties.

Market Participants are required to pay a Forward Reserve Failure-to-Activate Penalty for each Forward Reserve Resource that fails to activate its Forward Reserve capability. For Forward Reserve Resources:

- providing TMNSR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction as part of the real-time contingency dispatch algorithm, or;
- providing TMOR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction when the ten-minute reserve requirement is binding or violated in an approved UDS case.

If a Market Participant's Forward Reserve Resource fails to activate Forward Reserve, which determination shall be made in accordance with subsection (a), that Market Participant shall be required to pay a Forward Reserve Failure-to-Activate Penalty associated with that Resource pursuant to subsection (b):

(a) Forward Reserve Failure-to-Activate Megawatts:

A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

- (i) Maximum of Forward Reserve Delivered Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;
- (ii) Maximum of Target Activation Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMNSR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched, which are subsequently dispatched as part of the real-time contingency dispatch algorithm is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM10 or; (iii) the Resource's Offered CLAIM10.

Target Activation Megawatts for TMNSR from on-line Forward Reserve Resources dispatched, or Demand Response Resources that have been dispatched, as part of the real-time contingency dispatch algorithm is the lesser of: (i) the Resource's Manual Response Rate or Demand Response Resource Ramp Rate times 10 minutes or (ii) the Resource's Economic Maximum Limit or Maximum Reduction minus the Resource's initial output or demand reduction at activation, or; (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial output or demand reduction at activation.

The actual amount of TMNSR energy delivered during activation is measured at the 10 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMNSR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMOR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(i) Maximum of Forward Reserve Delivered Megawatts for TMOR plus Forward Reserve Delivered Megawatts for TMNSR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

(ii) Maximum of Target Activation Megawatts for TMOR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMOR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched, is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM30, or; (iii) the Resource's Offered CLAIM30.

Target Activation Megawatts for TMOR from on-line Forward Reserve Resources, or Demand Response Resources that have been dispatched, is the lesser of: (i) the Resource's Manual Response Rate or Demand Response Resource Ramp Rate times 30 minutes or (ii) the Resource's Economic Maximum Limit or Maximum Reduction minus the Resource's initial output or demand reduction at activation, or; (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial output or demand reduction at activation.

The actual amount of TMOR energy delivered during activation is measured at the 30 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMOR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

In determining the Target Activation Megawatts for Demand Response Resources, the portion of the Target Activation Megawatts not associated with Net Supply shall be multiplied by one plus the average avoided peak distribution losses.

The portion of the Target Activation Megawatts not associated with Net Supply is the lesser of:

- Target Activation Megawatts, or
- The amount of load reduced during activation.

The portion of the Target Activation Megawatts associated with Net Supply is the lesser of:

- Target Activation Megawatts less the Target Activation Megawatts not associated with Net Supply, or
- The amount of Net Supply that the Demand Response Resource produced during activation.

A Forward Reserve Resource that is a Fast Start Generator that fails to activate Forward Reserve through a failure to start, or a Forward Reserve Resource that is a Fast Start Demand Response Resource that fails to activate Forward Reserve through a failure to provide a demand reduction, shall have its Forward Reserve Delivered Megawatts set equal to zero in each subsequent hour in the applicable Forward Reserve Delivery Period until such time that the Market Participant notifies the ISO that the Forward Reserve Resource is capable of providing the Forward Reserve Delivered Megawatts.

(b) **Forward Reserve Failure-to-Activate Penalties:**

A Market Participant's Forward Reserve Failure-to-Activate Penalty for a Resource in an hour is defined as:

- (i) Forward Reserve Failure-to-Activate Penalty for TMNSR = The sum of the Forward Reserve Payment Rate for TMNSR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMNSR; and
- (ii) Forward Reserve Failure-to-Activate Penalty for TMOR = The sum of the Forward Reserve Payment Rate for TMOR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Activate Penalty Rate = Maximum of 2.25 multiplied by the Forward Reserve Payment Rate, or the applicable nodal LMP.

III.9.7.3 Known Performance Limitations.

The ISO may have reason to believe that a particular Forward Reserve Resource is frequently receiving, or may frequently receive, Forward Reserve payments for a portion or all of its capability that is not capable of activating the Forward Reserve Assigned Megawatts for TMNSR or the Forward Reserve Assigned Megawatts for TMOR. When the ISO believes there is such a limited Forward Reserve Resource, the ISO shall contact and confer with the affected Market Participant before taking any action.

- (a) The ISO will, whenever practicable, contact the affected Market Participant of the Forward Reserve Resource to request an explanation of the relevant resource Offer Data;
- (b) If the explanation, if available, considered together with other information available to the ISO, indicates to the satisfaction of the ISO that the questioned Forward Reserve payments are consistent with Forward Reserve Resource capabilities, no further action will be taken; and
- (c) If no agreement is reached, or an acceptable explanation is not provided, the Market Participant may request a Resource performance audit ~~as specified in ISO New England Manuals~~. If the Forward Reserve Resource fails the performance audit or the Market Participant refuses to request a Resource performance audit, the ISO may take remedial action. Remedial actions may include, but are not limited to: (i) redeclaration, by the ISO, of any relevant operational Offer Data parameter, or (ii) removing the ~~asset Resource~~ or the relevant portion of the ~~Resource's asset's~~ capability to provide Forward Reserve on a going-forward basis.

III.9.8 Forward Reserve Credits.

Payment for Forward Reserve is based upon a Market Participant's Final Forward Reserve Obligation and the applicable Forward Reserve Clearing Prices. The ISO shall calculate these credits on an hourly basis for each Reserve Zone as follows:

- (a) Final Forward Reserve Obligations for TMNSR and TMOR for each Market Participant are calculated for each Reserve Zone for each hour as follows:
 - (i) Final Forward Reserve Obligation = minimum [Forward Reserve Obligation, Forward Reserve Delivered Megawatts]

- (b) $FCACP_{Zone}$ and $FRACP_{Zone}$ are defined as:

$FCACP_{Zone}$ for a Reserve Zone is the Forward Capacity Auction Capacity Clearing Price for the Capacity Zone in which the Reserve Zone is contained.

$FCACP_{Zone}$ for the Rest of System is the maximum Forward Capacity Auction Capacity Clearing Price for all Capacity Zones included in whole or in part in the Rest of System.

$FRACP_{Zone}$ is the Forward Reserve Clearing Price for the relevant Reserve Zone, for TMNSR or TMOR, respectively;

- (c) Market Participant Forward Reserve Credit for TMNSR = Final Forward Reserve Obligation for TMNSR multiplied by the applicable hourly Forward Reserve Payment Rate for TMNSR;

where,

the hourly Forward Reserve Payment Rate for TMNSR is equal:

maximum of [(applicable monthly $FRACP_{Zone}$ for TMNSR – $FCACP_{Zone}$), 0] divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

- (d) Market Participant Forward Reserve Credit for TMOR =
Final Forward Reserve Obligation for TMOR multiplied by
the applicable hourly Forward Reserve Payment Rate for
TMOR; where,

the hourly Forward Reserve Payment Rate for TMOR is equal to:

maximum of [(applicable monthly $FRACP_{Zone}$ for TMOR - $FCACP_{Zone}$), 0]
divided by the number of hours in the month associated with the Forward
Reserve Delivery Period.

III.9.9 Forward Reserve Charges.

Forward Reserve Charges are allocated to each Market Participant in two steps. The first step allocates the Forward Reserve Credits associated with the procurement of reserves to meet the Forward Reserve requirement for the system. The second step, if necessary, allocates any remaining Forward Reserve Credits.

III.9.9.1 Forward Reserve Credits Associated with System Reserve Requirement.

The portion of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is determined by simulating a Forward Reserve Auction using all submitted Forward Reserve Auction Offers to meet only the Forward Reserve Market minimum requirements for

the New England Control Area pursuant to Section III.9.2.1. The simulated Forward Reserve Auction will clear offers pursuant to the methodology set forth in Section III.9.4 to calculate TMNSR and TMOR proxy system clearing prices. The TMNSR and TMOR proxy system clearing prices will reflect the cost to serve the next increment of reserve above the Forward Reserve Market minimum requirement for the New England Control Area.

For each hour, the total amount of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is calculated as the lesser of:

- (i) The TMNSR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the maximum of the [TMNSR proxy system clearing price reduced by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, 0], plus the TMOR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the maximum of the [TMOR proxy system clearing price reduced by the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, 0] and divided by the number of hours in the month associated with the Forward Reserve Delivery Period, or
- (ii) Total Forward Reserve Credits for the New England Control Area as calculated pursuant to Section III.9.8.

III.9.9.2 Adjusting Forward Reserve Credits for System Requirement.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is reduced by:

- (i) Any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in the Rest of System or in a Load Zone that is ineligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, and
- (ii) A prorated amount of any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in a Load Zone that is eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.3 Allocating Forward Reserve Credits for System Requirements.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirements for the system as calculated pursuant to Section III.9.9.1, is reduced by any penalties calculated pursuant to Section III.9.9.2, and allocated on a pro rata basis using each Market Participant's share of Real-Time Load Obligation in each Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Real-Time Reserve Designations associated with Dispatchable Asset Related Demands within that Load Zone.

III.9.9.4 Allocating Remaining Forward Reserve Credits.

For each hour, any Forward Reserve Credits not allocated pursuant to Section III.9.9.3 are allocated on a pro rata basis to each Market Participant's share of Real-Time Load Obligation in a Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Real-Time Reserve Designations associated with Dispatchable Asset Related Demands within that Load Zone) that meets the criteria in Section III.9.9.4.1. The allocation for each Load Zone is based on the ratio of the Forward Reserve Credits cleared in the Respective Reserve Zone for the Forward Reserve Credits cleared in all Reserve Zones that meet the criteria in Section III.9.9.4.1, and is reduced by:

- (i) A prorated amount of any Forward Reserve Failure-to-Reserve Penalties or Forward Reserve Failure-to-Activate Penalties that occur in a Load Zone eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of the total Forward Reserve Credits less any Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.4.1 Allocation Criteria for Remaining Forward Reserve Credits.

If the following criteria are met, then a Market Participant with Real-Time Load Obligation in a Load Zone is eligible to receive any remaining Forward Reserve Credits not allocated pursuant to Section III.9.9.3.

- (i) The Load Zone is encompassed in whole or in part in a Reserve Zone with a locational reserve requirement greater than zero, and

- (ii) The Forward Reserve Clearing Price of a Reserve Zone is higher than the Forward Reserve Clearing Price of the Rest of System.

III.10 Real-Time Reserve

The ISO shall use a joint optimization dispatch algorithm to serve Real-Time Energy Market requirements and meet Real-Time Operating Reserve requirements based on a least-cost security constrained economic dispatch. The Real-Time dispatch algorithm will designate Resources to meet the Energy requirements and will designate Resources to meet the Operating Reserve requirements of the New England Control Area.

III.10.1 Provision of Operating Reserve in Real-Time

For each Market Participant for each hour, the ISO will determine each Market Participant's provision of Operating Reserve in Real-Time. To accomplish this, the ISO will perform calculations to determine the following.

III.10.1.1 Real-Time Reserve Designation

Each Market Participant shall have for each hour and for each eligible generating Resource capable of providing Operating Reserve a Real-Time Reserve Designation, in megawatts, equal to the amounts of Operating Reserve designated by the ISO to that Resource in Real-Time adjusted downward after-the-fact, if necessary, to account for differences in actual Resource output based upon revenue quality meter readings and the estimated Resource output utilized to determine the amount of Real-Time Reserve Designation. Each Market Participant shall have for each hour and for each eligible Asset Related Demand Resource or Demand Response Resource capable of providing Operating Reserve a Real-Time Reserve Designation, in megawatts, equal to the amounts of Operating Reserve designated by the ISO to that Resource in Real-Time adjusted downward after-the-fact, if necessary, to account for differences in actual Operating Reserve capability ~~Resource consumption~~ based upon revenue quality meter readings and the estimated Operating Reserve capability ~~Resource consumption~~ utilized to determine the amount of Real-Time Reserve Designation. Resource eligibility to provide Operating Reserve shall be specified in the ISO New England Manuals.

III.10.2 Real-Time Reserve Credits

For each Market Participant for each hour, the ISO will determine a credit for provision of Operating Reserve in Real-Time.

- (a) A Market Participant's Resource specific Real-Time Reserve Credit for TMSR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for TMSR multiplied by the Real-Time Reserve Clearing Price for TMSR. The Real-Time Reserve Credit for TMSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMSR in that Load Zone.
- (b) A Market Participant's Resource specific Real-Time Reserve Credit for TMNSR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for TMNSR multiplied by the Real-Time Reserve Clearing Price for TMNSR. The Real-Time Reserve Credit for TMNSR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMNSR in that Load Zone.
- (c) A Market Participant's Resource specific Real-Time Reserve Credit for TMOR shall be equal to that Market Participant's Resource specific Real-Time Reserve Designation for TMOR multiplied by the Real-Time Reserve Clearing Price for TMOR. The Real-Time Reserve Credit for TMOR associated with a Load Zone shall be equal to the sum of all Market Participants' Resource specific Real-Time Reserve Credits for TMOR in that Load Zone.

III.10.3 Real-Time Reserve Charges.

- (a) For each hour, the ISO will ~~as~~ allocate the sum of the Real-Time Reserve Credits and Forward Reserve Obligation Charges for each Load Zone, calculated separately for TMSR, TMNSR and TMOR, to each Market Participant as follows:

$$\text{Real-Time Reserve Charge}_{k,i} = [\text{Reserve Charge Allocation MW}_{k,i}] \times [\text{RT\_CHRG\_RT}_i]$$

Where:

Real-Time Reserve Charge_{k,i}, is Market Participant *k*'s Real-Time Reserve Charge for Load Zone *i* for all Real-Time reserve services and Forward Reserve Obligation Charges;

Reserve Charge Allocation MW = Market Participant *k*'s Real Time Load Obligation in Load Zone *i* adjusted for Market Participant *k*'s Dispatchable Asset Related Demand MWs in Load Zone *i* that are designated for Real-Time reserves.

$RT\_CHRG\_RT_i = [IRT\_SUP\_PMNT]/RT\_P\_WTD\_LD\_OB] \times$
[RT_P_RATIO] for TMSR, TMNSR, or TMOR, as applicable.

$RT\_P\_WTD\_LD\_OB = \sum [Reserve\ Charge\ Allocation\ MW_{si}] \times$
[P_RATIO_i] for TMSR, TMNSR or TMOR, as applicable;

[RT_SUP_PMNT] = The total over all Load Zones of Real-Time Reserve Credits for TMSR, TMNSR or TMOR, plus the total over all Load Zones of the Forward Reserve Obligation Charges for TMNSR or TMOR, as applicable;

RT_P_RATIO_i is the ratio of the Real Time Reserve Clearing Price in Load Zone i for TMSR, TMNSR or TMOR, as applicable, to the Real -Time Reserve Clearing Price in the Reference Zone for TMSR, TMNSR or TMOR, as applicable. To the extent that a Load Zone contains more than one Reserve Zone, that Load Zone's Real-Time Reserve Clearing Price for TMSR, TMNSR or TMOR shall be the Real-Time Reserve Designation weighted average of the Reserve Zone Real-Time Reserve Clearing Prices in that Load Zone for TMSR, TMNSR or TMOR, as applicable;

The Reference Load Zone is the Load Zone with the minimum, non-zero Real-Time Reserve Clearing Price for TMSR, TMNSR or TMOR, as applicable.

The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Load Zone from which the External Transaction is exporting for the purpose of calculating Real-Time Reserve Charges. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

III.10.4 Forward Reserve Obligation Charges.

For each Market Participant with a Forward Reserve Obligation, the ISO will determine a Forward Reserve Obligation Charge for each hour such that a Market Participant will not receive compensation for the provision of both Real-Time Operating Reserve MWs and Forward Reserve MWs for the same reserve service.

III.10.4.1 Forward Reserve Obligation Charge Megawatts for Forward Reserve Resources.

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Forward Reserve Resource are equal to the lesser of the Forward Reserve Delivered MW or Real-Time Reserve Designation MW (where any demand reduction portion of Real-Time Reserve Designation MW is increased by average avoided peak distribution losses).

III.10.4.2 Forward Reserve Obligation Charge Megawatts.

The Forward Reserve Obligation Charge megawatts for TMNSR and TMOR in each applicable Reserve Zone attributed to a Market Participant is equal to the lesser of the sum of Forward Reserve Obligation Charge megawatts for all the Reserve Resources assigned by the Market Participant, or the Final Forward Reserve Obligation

III.10.4.3 Forward Reserve Obligation Charge.

The Forward Reserve Obligation Charge will be calculated as follows:

- (a) A Market Participant's Forward Reserve Obligation Charge for TMNSR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge megawatts for TMNSR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMNSR in that Reserve Zone.
- (b) A Market Participant's Forward Reserve Obligation Charge for TMOR in each Reserve Zone shall be equal to the Market Participant's Forward Reserve Obligation Charge megawatts for TMOR in that Reserve Zone multiplied by the Real-Time Reserve Clearing Price for TMOR in that Reserve Zone.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (Section III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section III.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Resource, New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff

requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to (i) Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, ~~or (ii) Demand Resources participating in the Real Time Demand Response Program (30 Minute and 2 Hour) and in the Real Time Profiled Response Program, as defined in Appendix E of this Market Rule 1,~~ before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined

as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to

Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date

by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.

The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.

For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor's ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor's program to deliver capacity to meet the Demand Resource Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor's ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource Project Sponsor shall be subject to the ISO's critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period

associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form. A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package

the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

- (a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;
- (b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;
- (c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;
- (d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and
- (e) whether the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.

For each Existing Demand Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located,

and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. ~~A Net Supply Generator Asset or other Generator Asset located at the same Retail Delivery Point as a Demand Response Asset that is associated with a Demand Response Capacity Resource may not participate in the Forward Capacity Market as a Generating Capacity Resource, provided that this exclusion shall not apply to a Generator Asset if it is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.~~

The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the

Demand Resource project's Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor's total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor's total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Demand Resource Project Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications,

measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly Demand Reduction Values. For Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, or shall maintain records of aggregated Demand Reduction Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently delisted from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated using the Real-Time Emergency Generation Asset's Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the

Retail Delivery Point, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated ~~based upon~~ using the Real-Time Emergency Generation Asset's Average Hourly Load Reduction.

For Capacity Commitment Periods commencing before June 1, 2017, the output of the generators comprising a Real-Time Emergency Generation Asset must be directly metered and reported to the ISO as a single set of interval meter data, provided that if there is no other Real-Time Emergency Generation Asset, Real-Time Demand Response Asset or other generator whose output can be controlled at the same facility, the Market Participant may instead meter the Real-Time Emergency Generation Asset at the retail delivery point. Meter data associated with the Real-Time Emergency Generation Asset shall be recorded and reported by the Market Participant to the ISO in Real-Time at an interval of five minutes.

For Capacity Commitment Periods commencing before June 1, 2017, the output of generators comprising a Real-Time Demand Response Asset located behind the retail delivery point must be directly metered and reported to the ISO in Real-Time as a single set of interval meter data at an interval of five-minutes.

III.13.5.3.2. Submission of Supplemental Availability Bilaterals.

The Lead Market Participant for a resource previously designated as a Supplemental Capacity Resource in accordance with the provisions of Section III.13.5.3.1 for a term that included a Shortage Event may submit a Supplemental Availability Bilateral to the ISO assigning all or a portion of its available capability up to its designated supplemental capacity in each hour of that Shortage Event to a Generating Capacity Resource or Demand Response Capacity Resource having a Capacity Supply Obligation during that Shortage Event ("Supplemented Capacity Resource"). No other Market Participant may submit a Supplemental Availability Bilateral. The Supplemental Capacity Resource and the Supplemented Capacity Resource must either: (i) be located in the same Reserve Zone (although in no case may a Supplemental Capacity Resource located in an export-constrained Capacity Zone provide supplemental availability outside of that export-constrained Capacity Zone); or (ii) be located in different Reserve Zones such that direction of flow between the Supplemental Capacity Resource and the Supplemented Capacity Resource is counter to any Reserve Zone or Capacity Zone constraint. For purposes of this Section III.13.5.3.2, a Reserve Zone having a locational reserve requirement (established pursuant to Section III.9.2.2) that is less than or equal to zero shall be considered to be unconstrained with respect to the neighboring Reserve Zone. A Supplemental Capacity Resource may submit Supplemental Availability Bilaterals with multiple Supplemented Capacity Resources, but each MW of supplemental

capacity may only be assigned to one Supplemented Capacity Resource. No Supplemental Capacity Resource may itself be a Supplemented Capacity Resource for an hour.

III.13.5.3.2.1. Timing.

A Supplemental Availability Bilateral must be submitted in accordance with resettlement provisions as described in ISO New England Manuals. However, to be included in the initial settlement of payments and charges associated with the Forward Capacity Market for the month associated with the Supplemental Availability Bilateral, a Supplemental Availability Bilateral must be submitted to the ISO no later than 12:00 pm on the second Business Day after the end of that month, or at such later deadline as specified by the ISO upon notice to Market Participants (though a Supplemental Availability Bilateral may be revised by the parties to the transaction throughout the resettlement process). A Supplemental Availability Bilateral must be confirmed by the Lead Market Participant for the Supplemented Capacity Resource no later than the same deadline that applies to submission of the Supplemental Availability Bilateral.

III.13.5.3.2.2. Application.

The submission of a Supplemental Availability Bilateral to the ISO shall include the following: (i) the resource identification number for the Supplemental Capacity Resource; (ii) the resource identification number for the Supplemented Capacity Resource; (iii) the MW amount of capacity being assigned from the Supplemental Capacity Resource to the Supplemented Capacity Resource; (iv) the term of the transaction, which shall be in hourly increments coinciding with hourly boundaries, no less than one hour, and no greater than one calendar month.

III.13.5.3.2.3. ISO Review.

The ISO shall review the information provided in submission of the Supplemental Availability Bilateral, and shall reject the Supplemental Availability Bilateral if any of the provisions of this Section III.13.5.3 are not met. The ISO shall reject the applicability of a Supplemental Availability Bilateral in any hour of a Shortage Event unless: (i) the Supplemental Capacity Resource was on-line and following ISO dispatch instructions during that hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is (a) less than or equal to the difference between the Generating Capacity Resource's Economic Maximum Limit as submitted or redeclared by the Lead Market Participant and the Supplemental Capacity Resource's Capacity Supply Obligation or (b) less than or equal to the difference between (the greater of the sum of the Real-Time Demand Reduction Obligations of the Demand Response Resources associated with the Demand Response Capacity Resource's ~~Real-Time Demand Reduction Obligation~~ or the lesser of ((the sum of the Demand Response Baselines of the

Demand Response Assets comprising the Demand Response Resources associated with the Demand Response Capacity Resource's Demand Response Baseline as adjusted pursuant to Section III.8B.5, plus the Economic Maximum Limit for any associated available Net Supply Generator Assets the Net Supply Limit of the Demand Response Resources), the Hourly Adjusted Audited Demand Reduction, or (the Maximum Reduction as submitted or redeclared by the Lead Market Participant plus the Economic Maximum Limit of associated Net Supply Generator Assets Net Supply Limit of the Demand Response Resources))), adjusted for average avoided peak transmission and distribution losses as addressed in Section III.13.7.1.5.10, and the Supplemental Capacity Resource's Capacity Supply Obligation; or (ii) the Supplemental Capacity Resource was offline for the hour of the Shortage Event and the MW amount of capacity being assigned from the Supplemental Capacity Resource is less than or equal to the difference between the sum of the Supplemental Capacity Resource's Real-Time Reserve Designations of TMNSR, TMSR and TMOR and the Supplemental Capacity Resource's Capacity Supply Obligation.

III.13.5.3.2.4. Effect of Supplemental Availability Bilateral.

A Supplemental Availability Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Supplemental Availability Bilateral is to modify the Supplemental Capacity Resource's availability score as described in Section III.13.7.1.1.4.

III.13.6.1.5. Demand Resources.

III.13.6.1.5.1. Energy Market Offer Requirements.

Seasonal Peak Demand Resources, On-Peak Demand Resources and Real-Time Emergency Generation Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Markets. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix E.

Commencing June 1, 2017, a Market Participant with A a Demand Response Capacity Resource having a Capacity Supply Obligation shall submit Demand Reduction Offers through for its Demand Response Resources and submit Supply Offers of any associated Net Supply Generator Assets, into both the Day-Ahead Energy Market and Real-Time Energy Market. through its Demand Response Resources and associated Net Supply Generator Assets. The sum of the Demand Reduction Offers and Supply Offers must be equal to or greater than the Demand Response Capacity Resource's Capacity Supply Obligation

whenever the Demand Response Resources ~~and associated Net Supply Generator Assets~~ are physically available. ~~If the Net Supply Generator Asset is a Settlement Only Resource, then the Net Supply will not be represented in the offer for the Demand Response Resource.~~ If the Demand Response Resources ~~and associated Net Supply Generator Assets~~ are physically available at a level less than the Demand Response Capacity Resource's Capacity Supply Obligation, the sum of the Demand Reduction Offers ~~and Supply Offers will~~ equal ~~to~~ that level ~~and~~ shall be offered into both the Day-Ahead Energy Market and Real-Time Energy Market. Each Demand Reduction Offer from a Demand Response Resource made into the Day-Ahead Energy Market shall also meet one of the following requirements:

- (a) the sum of the Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time plus Minimum Reduction Time plus Minimum Time Between Reductions is less than or equal to 72 hours.
- (b) the sum of the Demand Response Resource's Minimum Reduction Time plus the Minimum Time Between Reductions is less than or equal to 24 hours.

~~Each Supply Offer for a Net Supply Generator Asset associated with a Demand Response Resource made into the Day-Ahead Energy Market shall also meet one of the following requirements:~~

- ~~(a) the sum of the Net Supply Generator Asset's Notification Time plus Start-Up Time plus Minimum Run Time plus Minimum Down Time is less than or equal to 72 hours.~~
- ~~(b) the sum of the Net Supply Generator Asset's Minimum Run Time plus Minimum Down Time is less than or equal to 24 hours.~~

III.13.6.1.5.2. Requirement that Offers Reflect Accurate Demand Response Capacity Resource Operating Characteristics.

For each day, Demand Reduction Offers ~~and, if applicable, Supply Offers of associated Net Supply Generator Assets~~, submitted into the Day-Ahead Energy Market and Real-Time Energy Market for ~~the portion of a resource~~ Demand Response Resources associated with a Demand Response Capacity Resource having a Capacity Supply Obligation must reflect the then-known operating characteristics of the resource. Resources must re-declare to the ISO any changes to the offer parameters that occur in real time to reflect the operating characteristics of the resource. A resource failing to comply with this

requirement shall be subject to economic penalties described in Appendix B, in addition to any applicable availability penalties pursuant to Section III.13.7.2.7.1.2.

III.13.6.1.5.3. Additional Requirements for Demand Resources.

Demand Resources shall comply with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals and the auditing and rating requirements as detailed in Section III.13.6.1.5.4 and the ISO New England Manuals. Demand Response Capacity Resources having a Capacity Supply Obligation are subject to the following additional requirements:

- (a) Operating Data collection requirements as detailed in the ISO New England Manuals and Market Rule 1;
- (b) outage requirements in accordance with the ISO New England Manuals and ISO New England Operating Procedures, provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.5.4. Demand Response Auditing.

Demand Resources shall be subject to ISO conducted audits for the purposes of:

- (a) Auditing Demand Reduction Values or determining the Audited Demand Reduction for a Demand Resource;
- (b) Verifying the Commercial Operation of a Demand Resource; and
- (c) Verifying the Demand Reduction Value or the Audited Demand Reduction of the Demand Resource when the ISO, based on objective criteria, has determined that the Demand Reduction Value or the Audited Demand Reduction of a Demand Resource may not be credible.

New Demand Response Asset Audits shall be performed pursuant to Section III.13.6.1.5.4.8.

III.13.6.1.5.4.1. General Auditing Requirements for Demand Resources Excluding Demand Response Capacity Resources.

- (a) Audits of a Demand Resource will be conducted by simultaneously evaluating the performance of each demand asset that is mapped to that Demand Resource.
- (b) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Real-Time Demand Response Resources containing Real-Time Demand Response Assets that are located behind the same end-use customer meter as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource.
- (c) An audit is valid beginning with the month in which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like seasonal DR Auditing Period. Additional audits performed in a month shall not replace the results of the initial audit conducted in a month and are valid on the first of the subsequent month following the audit. Audit results shall not replace a Demand Reduction Value that is based on Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours.
- (d) If one or more demand assets of a Demand Resource do not have audit results at the time the Demand Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those demand assets toward the audit value of the Demand Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit provided the demand asset was available for dispatch by the ISO in that prior month, and if the demand asset was not available for dispatch in that prior month, then the 1st of the month in which the demand asset was available for dispatch.

III.13.6.1.5.4.2. General Auditing Requirements for Demand Response Capacity Resources.

- (a) Audits of Demand Response Resources associated with a Demand Response Capacity Resource will be conducted by simultaneously evaluating the performance of each Demand Response Asset ~~and Net Supply Generator Asset~~ that is mapped to ~~each associated a~~ Demand Response Resource. The Demand Response Resources associated with a Demand Response Capacity Resource are not required to be evaluated simultaneously.

- (b) An audit of a Real-Time Emergency Generation Resource must be performed simultaneously with the audit of any Demand Response Resources containing Demand Response Assets that are located behind the same Retail Delivery Point as the Real-Time Emergency Generation Assets mapped to the Real-Time Emergency Generation Resource. When the output of the Real-Time Emergency Generation Asset is greater than the Demand Response Baseline, adjusted pursuant to Section **III.8B.5,** of the Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the Net Supply is reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset.
- (c) An audit is valid beginning with the date on which the audit is performed, and remains valid until the next audit is performed for a like season, which shall be no later than the end of the next like Seasonal DR Audit period. For the Capacity Commitment Period commencing on June 1, 2017, the audit results for Demand Response Resources comprised of Demand Response Assets ~~and associated Net Supply Generator Assets~~ that were associated with a Real-Time Demand Response Resource in the prior Capacity Commitment Period shall be the sum of the audit results for those assets in the prior like Seasonal DR Audit period. When using audit results from a period prior to June 1, 2017 for those former Real-Time Demand Response Assets, the Audited Full Reduction Time shall be 30 minutes.
- (d) If one or more Demand Response Assets of a Demand Response Resource ~~or associated Net Supply Generator Assets~~ do not have an Audited Demand Reduction at the time the Demand Response Resource is audited and the audit was conducted in a summer DR Auditing Period or a winter DR Auditing Period, then the contribution of those Demand Response Assets ~~or associated Net Supply Generator Assets~~ toward the Audited Demand Reduction of the Demand Response Resource shall be effective starting with the later of: (i) the start of the DR Auditing Period, or (ii) the 1st of the month prior to the month of the audit, provided the Demand Response Asset ~~or associated Net Supply Generator Asset~~ was available for dispatch by the ISO in that prior month, and if the Demand Response Asset ~~or associated Net Supply Generator Asset~~ was not available for dispatch in that prior month, then the 1st of the month in which the Demand Response Asset ~~or associated Net Supply Generator Asset~~ was available for dispatch.

III.13.6.1.5.4.3. Seasonal DR Audits.

A Seasonal DR Audit must be conducted for each Demand Resource during each seasonal DR Auditing Period.

III.13.6.1.5.4.3.1. Seasonal DR Audit Requirement.

A Market Participant shall submit each Demand Resource to an ISO initiated audit each season to verify the Demand Reduction Value or Audited Demand Reduction for the resource for one or more months of the season. The Seasonal DR Audit must be requested by the Market Participant for the Demand Resource within each Capacity Commitment Period in which the Demand Resource has a Capacity Supply Obligation. The summer DR Auditing Period begins on June 1 and ends on August 31. The winter DR Auditing Period begins on December 1 and ends on January 31. For all Demand Resources other than Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the audit results for the months of June, July, and August, and audits performed during the winter DR Auditing Period will be used to establish the audit results for the months of December and January. For Demand Response Capacity Resources, audits performed during the summer DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource summer months of June, July, August, September, October, November, and the following April and May, and audits performed during the winter DR Auditing Period will be used to establish the Audited Demand Reduction for the Demand Resource winter months of December and the following January, February and March.

III.13.6.1.5.4.3.2. Failure to Request or Perform an Audit.

If by the 1st of August for the summer DR Auditing Period or by the 1st of January for the winter DR Auditing Period a Market Participant has not requested a Seasonal DR Audit for a Demand Resource, the Market Participant shall be deemed to have requested a Seasonal DR Audit on those respective dates. A Demand Resource that does not successfully perform a Seasonal DR Audit for a DR Auditing Period shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

III.13.6.1.5.4.3.3. Use of Event Performance Data to Satisfy Audit Requirements for Certain Resources.

A Real-Time Demand Response Resource or Real-Time Emergency Generation Resource that has received a Dispatch Instruction in a season for 100% of its highest CSO for the current DR Auditing Period lasting at least one hour, not including the 30 minute notification time, may use the first 60 minute period of the event after the 30 minute notification time to satisfy the Seasonal DR Audit requirement for the applicable DR Auditing Period, subject to the provisions of Section III.13.6.1.5.4.1(b). A Real-Time

Demand Response Resource or Real-Time Emergency Generation Resource's audit value under this provision is based on the average load reduction or output demonstrated over the duration of the qualifying 60 minute period.

A Market Participant must request that an event be used to satisfy the Demand Resource's Seasonal DR Audit requirement or replace a currently effective audit result within seven days of the Operating Day on which the Dispatch Instruction for the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is received.

III.13.6.1.5.4.3.3.1. Demand Response Capacity Resources.

A Demand Response Capacity Resource may elect to use performance associated with a Shortage Event as defined in Section III.13.7.1.1.1 or a time period when the ISO has declared a capacity deficiency pursuant to ISO New England Operating Procedure No. 4 that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit; provided that any Demand Response Asset of a Demand Response Resource associated with the Demand Response Capacity Resource on a forced curtailment or scheduled curtailment as defined in Section III.13.7.1.5.10.2 is assessed a zero audit value.

If a Demand Response Resource associated with a Demand Response Capacity Resource does not reduce demand for some portion of the event, the audit results of its Demand Response Assets ~~and associated Net Supply Generator Assets~~ shall be set to zero. Otherwise, the Demand Response Resources associated with a Demand Response Capacity Resource will be measured based upon their offered parameters per Section III.13.6.1.5.4.6(d), and the Audited Demand Reduction for each Demand Response Resource will be capped at the average Desired Dispatch Point ~~(for the Demand Response Resource and its associated Net Supply Generator Assets)~~ over the audit duration by proportionally reducing each associated Demand Response Asset's ~~and Net Supply Generator Asset's~~ audit results.

Within 7 calendar days of the event, the participant must inform the ISO that it wishes to use dispatch performance during the event to establish the ~~resource's~~ Demand Response Capacity Resource's Audited Demand Reduction.

If a Shortage Event occurs before a Demand Response Resource has established an Audited Demand Reduction value and the resource was not dispatched during the Shortage Event at a level equal to its Maximum Reduction, a Market Participant may elect within seven calendar days after the event to set the

Audited Demand Reduction of the Demand Response Resource equal to its CLAIM10 or CLAIM30 value at the time of the event as determined pursuant to Section III.9.5.3.

A Market Participant may elect to use performance associated with a CLAIM10 or CLAIM30 audit of a Demand Response Resource that occurs during a DR Auditing Period in place of requesting a Seasonal DR Audit of that resource provided that the audit was conducted in a manner that meets the requirements of a Seasonal DR Audit. Within seven calendar days of the CLAIM10 or CLAIM30 audit, the Market Participant must inform the ISO that it wishes to use dispatch performance during the audit to establish the Demand Response Resource's Seasonal DR Audit value.

III.13.6.1.5.4.4. Demand Resource Commercial Operation Audit.

(a) A Market Participant with a Demand Resource that has one or more increments that have not demonstrated commercial operation prior to the commencement of a Capacity Commitment Period shall perform a Demand Resource Commercial Operation Audit. The results of the Demand Resource Commercial Operation Audit shall be used to verify the commercial capacity of the Demand Resource and establish the Audited Demand Reduction of a Demand Response Resource.

(b) If a Demand Resource Commercial Operation Audit is not performed prior to the commencement of the Capacity Commitment Period, an audit must be requested in time for performance within the first month in which the Demand Resource has a Capacity Supply Obligation in the Capacity Commitment Period or the Commercial Operation Date, whichever is earlier. A Demand Resource that does not successfully perform a Demand Resource Commercial Operation Audit prior to the end of the first month in which the Demand Resource has a Capacity Supply Obligation shall have the audit results of its mapped demand assets or Demand Response Assets set to zero.

(c) A Demand Resource that fails to demonstrate through its Demand Resource Commercial Operation Audit a demand reduction in the amount of its Capacity Supply Obligation shall be subject to the provisions of Section III.13.1.9 and Section III.13.3.4.

(d) A Market Participant may request additional Demand Resource Commercial Operation Audits during a Capacity Commitment Period to verify an increase in the commercial capacity of a Demand Resource.

(e) If a Demand Resource has summer Qualified Capacity, a Demand Resource Commercial Operation Audit must be performed during the summer season (April through November) to verify the commercial capacity of the resource. A Demand Resource Commercial Operation Audit performed during the winter season (December through March) may only be used to verify the winter commercial capacity of the resource.

(f) A Demand Resource Commercial Operation Audit performed during a summer DR Auditing Period or winter DR Auditing Period may be used to satisfy the Seasonal DR Audit requirement for the same seasonal period. If a Demand Resource conducts a Demand Resource Commercial Operation Audit outside of a summer DR Auditing Period or winter DR Auditing Period, the Seasonal DR Audit requirement shall not be satisfied, however the results shall be used in the calculation of the summer Seasonal DR Audit value or winter Seasonal DR Audit value as follows:

- (1) A Demand Resource Commercial Operation Audit conducted in the months of September, October, November, April, or May shall be considered a summer Seasonal DR Audit;
- (2) A Demand Resource Commercial Operation Audit conducted in February or March shall be considered a winter Seasonal DR Audit.

III.13.6.1.5.4.5. Additional Audits.

The ISO may initiate an audit to verify the Demand Reduction Value or Audited Demand Reduction of a Demand Resource when an evaluation based on objective criteria indicates a Market Participant is claiming demand reductions in excess of the Demand Resource's actual capability. Such criteria include, but are not limited to:

- (a) A pattern of submitting to the ISO a level of available interruption that is less than the resource's Demand Reduction Value or Audited Demand Reduction during the same time period;
- (b) Actual loads for the underlying assets of the resource that, when aggregated, are below the resource's Demand Reduction Value or Audited Demand Reduction; or
- (c) Failure to achieve the dispatched interruption.

The results of an additional audit shall replace the results of the last like Seasonal DR Audit or Demand Resource Commercial Operation Audit.

The ISO may perform additional audits for a Demand Resource to establish the audit results or Audited Demand Reduction and the performance of the installed measures of the demand asset or Demand Response Asset ~~and associated Net Supply Generator Asset~~. This additional auditing may consist of two levels.

- (a) Level 1 Audit: the ISO will establish the audit results by conducting a review of records of the demand asset or Demand Response Asset ~~and associated Net Supply Generator Asset~~ to verify that the reported measures have been installed and are operational. The audit shall include, but is not limited to, reviewing project or program databases, invoices, installation reports, work orders, and field inspection reports. In addition, the audit may involve reviewing any independent inspections or evaluations conducted as part of program implementation and program evaluation.
- (b) Level 2 Audit: the ISO shall establish the audit results by initiating or conducting an on-site field audit to verify the installation and performance of measures in the demand asset or Demand Response Asset ~~and associated Net Supply Generator Asset~~. Such an audit may include a random or select sample of facilities and measures.

A level 1 audit is not required to precede a level 2 audit. If the results of the audit indicate that the demand reduction capability of the Demand Resource is less than or greater than its Demand Reduction Value or Audited Demand Reduction in the same period, then the Demand Reduction Value or Audited Demand Reduction shall be adjusted to the value demonstrated through the audit.

III.13.6.1.5.4.6. Audit Methodologies.

- (a) For On-Peak Demand Resources, audit results shall be established based on the Average Hourly Output or Average Hourly Load Reduction in the DR Auditing Period.
- (b) For Seasonal Peak Demand Resources, audit results shall be established based on Average Hourly Output or Average Hourly Load Reduction or their equivalent in the DR Auditing Period.
- (c) For Real-Time Demand Response Resources and Real-Time Emergency Generation Resources, audits will be conducted via a Dispatch Instruction sent by the ISO. Audit results for a Real-Time Demand Response Resource and Real-Time Emergency Generation Resource will be based on the sum of

the average load reductions or average incremental output demonstrated during the audit by each demand asset mapped to the Demand Resource.

(d) For Demand Response Resources associated with Demand Response Capacity Resources, audits will be conducted via a Dispatch Instruction ~~sent by the ISO~~. Audit results for ~~a the~~ Demand Response ~~Capacity Resources~~ will be based on the sum of the average ~~load demand~~ reductions ~~or average Net Supply~~ demonstrated during the audit by each Demand Response Asset ~~and associated Net Supply Generator Asset~~ associated with the Demand Response Resource that is mapped to the Demand Response Capacity Resource using (i) each Demand Response Resource's Offered Full Reduction Time to establish the start of the audit period and (ii) the Minimum Reduction Time adjusted for ramping time as the audit duration. The Offered Full Reduction Time is the Demand Response Resource Notification Time plus the Demand Response Resource Start-Up Time plus ((the Maximum Reduction ~~plus the sum of the Economic Maximum Limits of any associated available Net Supply Generator Assets~~ minus the Minimum Reduction) divided by the Demand Response Resource Ramp Rate). For purposes of determining the Offered Full Reduction Time, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the ~~Economic Maximum Limit of the Net Supply Generator Asset~~ Maximum Reduction is reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset.

III.13.6.2.5. Demand Resources.

III.13.6.2.5.1. Energy Market Offer Requirements.

Real-Time Emergency Generation Resources, Seasonal Peak and On-Peak Demand Resources may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market. A Real-Time Demand Response Asset associated with a Real-Time Demand Response Resource may submit Demand Reduction Offers on a Day-Ahead and Real-Time basis pursuant to Appendix **E1**. A Market Participant with a Demand Response Resource associated with a Demand Response Capacity Resource ~~and associated Net Supply Generator Assets~~, without a Capacity Supply Obligation is not required to offer Demand Reduction Offers for the Demand Response Resource into the Day-Ahead Energy Market or Real-Time Energy Market.

For Demand Reduction Offers made into the Day-Ahead Energy Market and Real-Time Energy Market ~~from for~~ such Demand Response Resources, the sum of the Demand Response Resource's Minimum Reduction Time plus the Minimum Time Between Reductions must also be less than or equal to 24 hours.

~~For Supply Offers made into the Day Ahead Energy Market and Real Time Energy Market from such Net Supply Generator Assets, the sum of the Minimum Run Time plus the Minimum Down Time must also be less than or equal to 24 hours.~~

III.13.6.2.5.1.1. Day-Ahead Energy Market Participation.

A Market Participant with a Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation, may submit a Demand Reduction Offer ~~or, for any associated Net Supply Generator Asset, a Supply Offer,~~ into the Day-Ahead Energy Market. If any portion of the Demand Reduction Offer ~~or Supply Offer~~ clears in the Day-Ahead Energy Market, the entire Demand Reduction Offer ~~or Supply Offer~~, up to the Maximum Reduction ~~or Economic Maximum Limit~~ offered into the Day-Ahead Energy Market, will be subject to all of the rules and requirements applicable to that market for the Operating Day, including the obligation to follow Dispatch Instructions. Such a resource that clears shall be eligible for dispatch in the Real-Time Energy Market.

III.13.6.2.5.1.2. Real-Time Energy Market Participation.

A Market Participant with a Demand Response Resource not associated with a Demand Response Capacity Resource or a Demand Response Resource associated with a Demand Response Capacity Resource without a Capacity Supply Obligation, that did not submit an offer into the Day-Ahead Energy Market or was offered into the Day-Ahead Energy Market and did not clear, may submit a Demand Reduction Offer ~~or, for any associated Net Supply Generator Assets, a Supply Offer,~~ in the Real-Time Energy Market and shall be subject to all of the requirements associated therewith. Such a resource shall be eligible for dispatch in the Real-Time Energy Market.

III.13.7.1.5.10. Demand Response Capacity Resources.

The performance of a Demand Response Capacity Resource with a Capacity Supply Obligation will be measured during Shortage Events as defined in Section III.13.7.1.1.1. A Demand Response Capacity Resource's Shortage Event Availability Score and hourly availability score shall be calculated in the manner described in Section III.13.7.1.1.1.A and III.13.7.1.1.2, respectively (with the hourly availability score adjusted pursuant to Section III.13.7.1.2.1). For the portion associated with the ability to reduce

load at the Retail Delivery Point demand, availability for Demand Response Capacity Resources would be adjusted for average avoided peak transmission and distribution losses as described in Section III.13.7.1.5.1 and Section III.13.7.1.5.1.1. For the portion associated with the ability to provide Net Supply, availability for Demand Response Capacity Resources would not be adjusted for average avoided peak transmission and distribution losses.

III.13.7.1.5.10.1 Hourly Available MW.

A Demand Response Capacity Resource's available MW in each hour that contains any portion of a Shortage Event shall be determined based upon the sum of its associated Demand Response Resources as follows, provided, that in no case shall a Demand Response Capacity Resource's available MW in an hour exceed that resource's Qualified Capacity from the Forward Capacity Auction for the current Capacity Commitment Period per Section III.13.1.4.1. For purposes of the following calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, ~~any Net Supply of a Net Supply Generator Asset located at the same Retail Delivery Point, hourly Desired Dispatch Point and Economic Maximum Limit of the Net Supply Generator Asset, shall be reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset.~~ the calculated demand reduction of the Demand Response Asset measured at the Retail Delivery Point shall be reduced by the Real-Time Emergency Generation Asset's output.

(a) For a Demand Response Resource that ~~reduces~~ produces a demand reduction and is following Dispatch Instructions ~~and for any associated Net Supply Generator Assets that are following Dispatch Instructions~~ where the ~~total~~ Desired Dispatch Point for the Demand Response Resource ~~and the associated Net Supply Generator Assets~~ is less than ~~(the Maximum Reduction plus the Economic Maximum Limit for any associated available Net Supply Generator Assets)~~ and greater than or equal to the Minimum Reduction, the available MW in an hour shall be the greater of ~~(i)~~ the resource's Real-Time Demand Reduction Obligation ~~plus the Net Supply for any associated available Net Supply Generator Assets~~ and ~~(ii)~~ the lesser of ~~(the resource's Demand Response Baseline as adjusted pursuant to Section III.8B.5 plus the Net Supply Limit Economic Maximum Limit for any associated available Net Supply Generator Assets)~~, the resource's Hourly Adjusted Audited Demand Reduction, or ~~(the resource's Maximum Reduction as submitted or redeclared by the Lead Market Participant for the resource plus the Economic Maximum Limit for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant).~~

(b) For a Demand Response Resource that ~~reduces~~ produces a demand reduction and is following Dispatch Instructions ~~and for any associated Net Supply Generator Assets that are following Dispatch Instruction~~ where the ~~total~~ Desired Dispatch Point for the Demand Response Resource ~~and the associated Net Supply Generator Assets~~ is equal to the Maximum Reduction ~~plus the Economic Maximum Limit for any associated available Net Supply Generator Assets~~ or ~~(Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets equals Minimum Reduction plus Economic Minimum Limit for any associated available Net Supply Generator Assets)~~ or ~~total~~ the Desired Dispatch Point for the Demand Response Resource ~~and the associated Net Supply Generator Assets~~ is less than the Minimum Reduction ~~plus Economic Minimum Limit for any associated available Net Supply Generator Assets~~, the available MW in an hour shall be the resource's Real-Time Demand Reduction Obligation.

(c) For a Demand Response Resource that has ~~reduced~~ produced a demand reduction ~~or any associated Net Supply Generator Assets have been dispatch~~ but ~~are~~ is not ~~responding following~~ to Dispatch Instructions where the Real-Time Demand Reduction Obligation ~~plus any associated Net Supply~~ is less than the ~~total~~ Desired Dispatch Point for the Demand Response Resource ~~and the associated Net Supply Generator Assets~~, the available MW in an hour shall be the resource's Real-Time Demand Reduction Obligation ~~plus any associated Net Supply~~ for the hour.

(d) For a Demand Response Resource that has ~~reduced~~ produced a demand reduction ~~or any associated Net Supply Generator Assets that have been dispatch~~ but ~~are~~ is not ~~responding to~~ following Dispatch Instructions where the Real-Time Demand Reduction Obligation is greater than the ~~total~~ Desired Dispatch Point for the Demand Response Resource ~~and the associated Net Supply Generator Assets~~, the available MW in an hour shall be the lesser of the resource's Real-Time Demand Reduction Obligation ~~plus any associated Net Supply~~ and Hourly Adjusted Audited Demand Reduction for the hour.

(e) For a Demand Response Resource that is not ~~reducing~~ producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) and an Audited Full Reduction Time (adjusted for the Maximum Reduction ~~and Economic Maximum Limit for any associated available Net Supply Generator Assets~~) of thirty minutes or less, the available MW in an hour shall be the lesser of ~~(the lesser of~~ (the resource's (i) Maximum Reduction, as submitted or redeclared by the Lead Market Participant, ~~and~~ (ii) Actual Load plus the Net Supply Limit) ~~plus the sum of the Economic Maximum Limits for any~~

~~associated available Net Supply Generator Assets as submitted or redeclared by the Lead market Participant)~~ or (iii) Hourly Adjusted Audited Demand Reduction.

(f) For a Demand Response Resource that is not ~~reducing~~ producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction ~~and Economic Maximum Limit for any associated available Net Supply Generator Assets~~ as submitted or redeclared by the Lead Market Participant) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than thirty minutes and less than or equal to 12 hours, the available MW shall be zero unless the duration of the Shortage Event exceeds the Audited Full Reduction Time (adjusted for the Maximum Reduction ~~and Economic Maximum Limit for any associated available Net Supply Generator Assets~~) and Offered Full Reduction Time (adjusted for the Audited Demand Reduction), in which case the available MW in an hour shall be the lesser of ~~(the lesser of (i)~~ the resource's Maximum Reduction, as submitted or redeclared by the Lead Market Participant, ~~(ii)~~ the resource's Actual Load plus its Net Supply Limit, ~~Economic Maximum Limits for any associated available Net Supply Generator Assets as submitted or redeclared by the Lead Market Participant~~ or ~~(iii)~~ the resource's Hourly Adjusted Audited Demand Reduction time weighted to reflect the portion of the hour in which the Demand Response Resource Notification Time and Demand Response Resource Start-Up Time exceeded the Shortage Event duration.

(g) For a Demand Response Resource that (i) is not ~~reducing~~ producing a demand reduction, is available for dispatch and is able to respond to Dispatch Instructions, and has an Audited Full Reduction Time (adjusted for the Maximum Reduction ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~) or Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than 12 hours or (ii) is unavailable to reduce demand, the available MW shall be zero.

III.13.7.1.5.10.1.1 Adjusted Audited Demand Reduction.

A Demand Response Resource's Adjusted Audited Demand Reduction shall be determined as follows. For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the ~~Economic Maximum Limit of the Net Supply Generator Asset at the same location~~ Maximum Reduction shall be reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset:

(a) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) equal to its Audited Full Reduction Time (adjusted for the Maximum Reduction ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~) shall have its Adjusted Audited Demand Reduction set equal to the resource's Audited Demand Reduction.

(b) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) greater than its Audited Full Reduction Time (adjusted for the Maximum Reduction ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~) shall have its Adjusted Audited Demand Reduction calculated as:

((the Audited Full Reduction Time adjusted for the ~~(Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets)~~) divided by (the Offered Full Reduction Time adjusted for the Audited Demand Reduction)) multiplied by the lesser of (the Audited Demand Reduction or (Maximum Reduction as submitted or redeclared by the Lead Market Participant ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~)).

(c) A Demand Response Resource that has an Offered Full Reduction Time (adjusted for the Audited Demand Reduction) less than its Audited Full Reduction Time (adjusted for the Maximum Reduction ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~) shall have its Adjusted Audited Demand Reduction calculated as:

((the Offered Full Reduction Time adjusted for the Audited Demand Reduction) divided by (the Audited Full Reduction Time adjusted for the ~~(Maximum Reduction plus Economic Maximum Limit for any associated available Net Supply Generator Assets)~~)) multiplied by the lesser of (the Audited Demand Reduction or (Maximum Reduction as submitted or redeclared by the Lead Market Participant ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~)).

III.13.7.1.5.10.1.2 Hourly Adjusted Audited Demand Reduction.

The Hourly Adjusted Audited Demand Reduction shall be calculated as the time weighted average of the Adjusted Audited Demand Reduction and Audited Demand Reduction for the period the resource was dispatched.

III.13.7.1.5.10.2 Availability Adjustments.

The hourly availability score of a Demand Response Capacity Resource shall be increased in the same manner as described in Section III.13.7.1.1.4(a). The hourly availability score of a Demand Response Capacity Resource comprised of an aggregation of one or more Demand Response Resources shall be adjusted as described in Section III.13.7.1.1.4(b). In the case of Demand Response Resources comprised of an aggregation of one or more Demand Response Assets with a demand reduction and any Net Supply of less than 5 MW achieved by the asset in the most recent seasonal audit of the associated Demand Response ~~Capacity~~ Resource, a planned outage of the equipment used to produce the demand reduction scheduled in either December or January or during the period June 1 through September 15 may not be used to increase the resource's hourly availability score as described in Section III.13.7.1.1.4(b).

In addition, the hourly availability score of a Demand Response Capacity Resource shall be increased as described in this subsection:

(a) A Demand Response Capacity Resource's hourly availability score shall be increased, subject to verification by the ISO, when one or more Demand Response Assets of a Demand Response Resource associated with the Demand Response Capacity Resource is on a forced curtailment or scheduled curtailment.

(i) A forced curtailment can be submitted to the ISO as described in the ISO New England Manuals for any reductions in demand that occur as a result of actions outside the control of the Demand Response Asset that is subject to the forced curtailment. The forced curtailment can be submitted or revised during the resettlement process and cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response ~~Capacity~~ Resource.

(ii) A scheduled curtailment must be submitted to the ISO at least ~~15~~seven calendar days ahead of the start of the curtailment to be eligible for an adjustment for any reductions in load that are the result of a scheduled plant shutdown or maintenance of energy consuming equipment; for Demand Response Assets with a Maximum Interruptible Capacity of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The scheduled curtailment cannot exceed the demand reduction achieved by the Demand Response Asset in the most recent seasonal audit of the associated Demand Response ~~Capacity~~ Resource. Scheduled curtailments must be a minimum of a single calendar day, and shall not exceed a total of 14 calendar days per Capacity Commitment Period.

(b) The sum of the availability adjustments for an hour may not exceed:

(i) for a Demand Response Resource that has received a Dispatch Instruction to reduce its demand, the lesser of (x) the resource's Demand Response Baseline as adjusted pursuant to Section III.8B.5 ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~ and (y) Audited Demand Reduction adjusted down by the greater of (1) the Maximum Reduction, as submitted or redeclared by the Lead Market Participant ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets~~, or (2) Real-Time Demand Reduction Obligation ~~plus Net Supply for any associated Net Supply Generator Assets~~. For purposes of this calculation, when the output of a Real-Time Emergency Generation Asset at the same location exceeds the Demand Response Baseline, adjusted pursuant to Section III.8B.5, of a Demand Response Asset located at the same Retail Delivery Point, any Net Supply and the ~~Economic Maximum Limit~~ Maximum Reduction of the Net Supply Generator Asset at the same location of the Demand Response Asset shall be reduced by the difference between the Real-Time Emergency Generation Asset's output and adjusted Demand Response Baseline of the Demand Response Asset.

(ii) for a Demand Response Resource that **has** not received a Dispatch Instruction to reduce its demand, the lesser of (i) the resource's Actual Load ~~plus Net Supply Limit plus Economic Maximum Limit for any associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market Participant~~, and or (ii) the Audited Demand Reduction adjusted ~~down by~~ for (the Maximum Reduction, as submitted or redeclared by the Lead Market Participant ~~plus Economic Maximum Limit for any associated available Net Supply Generator Assets, as submitted or redeclared by the Lead Market Participant~~).

III.13.7.2.5. Demand Resources.

III.13.7.2.5.1. Monthly Capacity Payments for All Resources Except Real-Time Emergency Generation Resources.

For all Demand Resources except for Real-Time Emergency Generation Resources, the monthly payment shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1.

III.13.7.2.5.2. Monthly Capacity Payments for Real-Time Emergency Generation Resources.

For Real-Time Emergency Generation Resources, monthly payments shall be calculated in the same manner as for Generating Capacity Resources as described in Section III.13.7.2.1.1, except that such payments may also be adjusted as described in Section III.13.2.3.3(f).

III.13.7.2.5.3. Energy Settlement for Real-Time Demand Response Resources

A Market Participant with Real-Time Demand Response Assets associated with a Real-Time Demand Response Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions, adjusted for net supply as described in Section III.E1.8.3 and for the percent average avoided peak distribution losses, at the Real-Time LMP for the Load Zone in which the Real-Time Demand Response Resource is located. The demand reduction paid or charged shall be net of the Real-Time Demand Reduction Obligation of Real-Time Demand Response Assets that are part of the Real-Time Demand Response Resource that received payment pursuant to Sections III.E1.9.2.1 or III.E1.9.2.2 for the same dispatch or audit period. Demand reductions eligible for payments or charges pursuant to this section shall be those produced during Real-Time Demand Response Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

III.13.7.2.5.4. Energy Settlement for Real-Time Emergency Generation Resources

A Market Participant with Real-Time Emergency Generation Assets associated with a Real-Time Emergency Generation Resource that is dispatched or audited pursuant to Section III.13 shall be paid or charged for demand reductions or generator output, adjusted as described in Section III.E1.8.3 or III.13.7.2.5.4.1 and for the percent average avoided peak distribution losses for the portion of the asset reducing demand, at the Real-Time LMP for the Load Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing prior to June 1, 2017, and at the Real-Time LMP for the Dispatch Zone in which the Real-Time Emergency Generation Resource is located for Capacity Commitment Periods commencing on or after June 1, 2017. Demand reductions or generator output eligible for payments or charges pursuant to this section shall be those produced during Real-Time Emergency Generation Event Hours or, in the case of an audit, for the period during which the ISO has requested the resource to audit.

**III.13.7.2.5.4.1 Adjustment for Net Supply ~~Generator Assets~~ From Real-Time Emergency
Generation Assets.**

For Capacity Commitment Periods commencing on or after June 1, 2017, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline, adjusted pursuant to Section **III.8B.5**, of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, the demand reduction measured at the Retail Delivery Point is first credited to the output of the Real-Time Emergency Generation Asset starting with the Net Supply amount, and any remaining demand reduction is credited to the Demand Response Asset~~output eligible for payments will be set equal the adjusted Demand Response Baseline of the Demand Response Asset.~~ The Net Supply amount shall not be multiplied by one plus the average avoided peak distribution losses. The demand reduction amount shall be multiplied by one plus the average avoided peak distribution losses.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Demand Response Asset is an asset comprising the demand reduction capability ~~the electricity consumption~~ of an individual end-use customer at a Retail Delivery Point or the aggregated ~~electricity consumption~~ demand reduction capability of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, which could reflect Net Supply, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Resources, change External Transactions, or change the status of a Dispatchable Asset Related Demand in accordance with the ~~Resource's or contract's~~ Supply Offer, ~~or Demand Bid,~~ or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output, consumption or demand reduction level of each generating Resource, ~~and each~~ Dispatchable Asset Related Demand and ~~each~~ Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; (v) is capable of receiving and acknowledging a Dispatch Instruction electronically; and (vi) has satisfied its Minimum Time Between Reductions.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, ~~or Demand Bids~~ or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the

Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction. For assets that deliver demand reduction and Net Supply, the Maximum Interruptible Capacity is the asset's peak load plus Maximum Net Supply as measured at the Retail Delivery Point.

~~Net Supply Generator Asset is the Generator Asset registered in the energy market at the same Retail Delivery Point as a Demand Response Asset with Distributed Generation capable of delivering Net Supply.~~

Net Supply Limit is the estimated portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. The Net Supply Limit is calculated by multiplying the offered Maximum Reduction of the Demand Response Resource by the ratio of total Net Supply to total demand reduction performance from the prior like Seasonal DR Audit of the Demand Response Assets that are mapped to the Demand Response Resource for the month.

Offered CLAIM10 is, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of ~~the~~ Resource that represents the amount of TMNSR available from the Resource from an off-line state, and, for a Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched, is a Demand Bid or Demand Reduction Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR or TMSR available from the Resource.

Offered CLAIM30 is a Supply Offer, Demand Bid or Demand Reduction Offer value between 0 and the CLAIM30 of a Resource that represents the amount of ~~offline~~-TMOR available from ~~the Resource~~an off-line generating Resource, or Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of (1) a generating ~~unit~~ Resource that can be converted fully into energy within ten minutes from the request of the ISO, ~~and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System;~~ or the reserve capability of (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of (1) a generating ~~unit~~ Resource that is electrically synchronized to the New England Transmission System that can be converted fully into energy within ten minutes from the request of the ISO; (2) ~~or~~ a Dispatchable Asset Related Demand pump that is electrically synchronized to the New England Transmission System that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, ~~and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System;~~ or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO for which none of the associated Demand Response Assets have a generator whose output can be controlled located behind the Retail Delivery Point other than emergency generators that cannot operate electrically synchronized to the New England Transmission System.

Thirty-Minute Operating Reserve (TMOR) means the reserve capability of (1) a generating ~~unit~~ Resource that can be converted fully into energy within thirty minutes from the request of the ISO, ~~and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System;~~ or the reserve capability of (2) a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within thirty minutes from the request of the ISO.



memo

To: NEPOOL Markets Committee
NEPOOL Reliability Committee

From: Henry Yoshimura, ISO New England

Date: August 27, 2014

Subject: **Full Integration of Demand Response Resources into the Energy and Reserves Markets**

1) Introduction

At the August 2014 Markets Committee and Reliability Committee meetings, I presented the ISO's proposed Tariff changes that would enable Demand Response Resources to fully participate in the energy markets and provide Operating Reserves. After considering Market Participant comments on the ISO's proposal, the ISO modified several sections of the proposed Tariff changes. The ISO's most current proposed Tariff changes, with the most recent modifications **highlighted in gray**, have been posted for your review and consideration.

To facilitate a comprehensive understanding of the package of Tariff changes being proposed by the ISO, we are providing the Markets Committee and the Reliability Committee with the same review materials (i.e., the same set of proposed Tariff changes and the same explanatory memo). However, please note that the ISO will be requesting two separate votes on these Tariff changes at the September 2014 Markets Committee and Reliability Committee meetings as follows:

- **The Markets Committee** to vote on all of the proposed Tariff changes **except for** those in Section III.9.5.3, Resource CLAIM10 and CLAIM30 Values, and Section III.1.5.2, ISO-Initiated Parameter Auditing; and
- **The Reliability Committee** to vote on the proposed Tariff changes in Section III.9.5.3, Resource CLAIM10 and CLAIM30 Values, and Section III.1.5.2, ISO-Initiated Parameter Auditing.

The remainder of this memo explains the additional modifications made to the ISO's proposed Tariff changes relative to the version that was previously posted for the August 2014 committee meetings.

2) Detailed Explanation of Additional Tariff Modifications

a) Section I.2.2. Definitions

Several defined terms were modified as follows:

Maximum Interruptible Capacity – The definition of Maximum Interruptible Capacity was modified to include both the load reduction and Net Supply capability of a Demand Response Asset. A Demand Response Asset with behind-the-meter generation and an adequate interconnection could reduce load from the electric grid and inject Net Supply into the electric grid. The sum of these two activities comprises the total demand reduction capability of the asset. Since certain Real-Time Demand Response Assets and Real-Time Emergency Generation Assets could provide Net Supply under the present market rules, the ISO proposes that the change to the definition of Maximum Interruptible Capacity become effective as soon as possible.

Since the Net Supply potential of a Demand Response Asset is now part of the asset's Maximum Interruptible Capacity, it is no longer necessary to add the Maximum Net Supply of a Demand Response Asset to its the Maximum Interruptible Capacity to determine the asset's overall capability. Therefore, the phrase "and/or Maximum Net Supply" was deleted from Sections III.8A.5.1, III.8B.6.1, III.13.7.1.5.10.2(a)(ii), III.13.7.1.5.10.2(b)(ii), and III.E2.3. Similarly, the change in the definition of Maximum Interruptible Capacity simplifies Section III.E2.1.3(f).

Offered CLAIM10 and Offered CLAIM30 – These definitions were clarified by applying more appropriate (and equivalent) terminology to different resource types – i.e., an "off-line" state for generating Resources, and a "has not been dispatched" state for Demand Response Resources and Dispatchable Asset Related Demands.

Ten-Minute Non-Spinning Reserve (TMNSR) – This definition was modified to include Demand Response Resources as a type of Resource that can provide TMNSR. Further, the word "unit" (as in generating "unit") was changed to the defined term "Resource". Finally, the tautology "generating units that are either not electrically synchronized or synchronized to the New England Transmission System" was deleted from the definition.

Ten-Minute Spinning Reserve (TMSR) – This definition was clarified to include the requirement that a Demand Response Resource providing TMSR must provide demand reduction within ten minutes from the request of the ISO.

Thirty-Minute Operating Reserve (TMOR) – This definition was modified to include Demand Response Resources as a type of Resource that can provide TMOR. Further, the word "unit" (as in generating "unit") was changed to the defined term "Resource". Finally, the tautology "generating units that are either not electrically synchronized or synchronized to the New England Transmission System" was deleted from the definition.

b) Section III.1-12

Section III.1.7.20 – The "&" was replaced with the word "and".

Section III.2.4(c) and (d) – The word "Section" was added before each Tariff section reference.

Section III.2.7A(b) – The term “Node” was replaced with “Location” to recognize that unit-specific opportunity costs resulting from the re-dispatch of resources to maintain sufficient levels of Operating Reserve need to be measured at different Locations as a function of resource type – i.e., a generator is priced at a Node, and a Demand Response Resource is priced at either a Node or a Dispatch Zone pursuant to the asset aggregation requirements outlined in Section III.E.2.1.

Section III.3.2.6 – The word “generation” was replaced by the term “generating Resource” in the phrase “generation and Demand Response Resources”.

Section III.8A.5.1 – The phrase “and/or Maximum Net Supply” was deleted given the change in the definition of “Maximum Interruptible Capacity” as previously explained above.

Section III.8B.2 – The provision to reset the Demand Response Baseline when multiple Demand Response Assets at the same Retail Delivery Point are consolidated into one asset was eliminated. The proposed Tariff changes in Section III.8B.2 were modeled after those in Section III.8A.1, which are the baseline resetting provisions that were previously approved by the Commission and are presently in effect. Under the presently-effective market rules, one or more Real-Time Demand Response Assets can exist behind the same the Retail Delivery Point. Section III.8A.1 contemplated that some Market Participants may elect to consolidate multiple Real-Time Demand Response Assets at the same location into a single asset, which would then require a new, initial baseline for the new, consolidated asset. As of June 1, 2017 (i.e., under full integration), however, the market rules would permit only a single Demand Response Asset at a Retail Delivery Point. This means that any consolidation of multiple assets located at the same Retail Delivery Point would need to be completed by June 1, 2017. Accordingly, Section III.8B.2, which goes into effect on June 1, 2017, no longer needs to contemplate the consolidation of multiple Demand Response Assets at the same location.

Section III.8B.6.1 – The phrase “and/or Maximum Net Supply” was deleted given the change in the definition of “Maximum Interruptible Capacity” as previously explained above.

Section III.9.5.2(a) – This section was clarified by eliminating unnecessary terminology (i.e., the phrase “off-line or on-line” was unnecessary), and by modifying the term “Resource” to “generating Resource” where a rule provision specifically applied to generating Resources.

Further, unnecessary tautologies in subsections (v) and (viii) were deleted from the Tariff. These include sentences in which a Resource has a “Capacity Supply Obligation for all, some, or none” of its capability, and phrases referring to a portion of a Resource “with or without a Capacity Supply Obligation.” In subsection (ix), the phrase “without a Capacity Supply Obligation, or the portion of a Demand Response Resource” was unnecessary and was deleted from the Tariff.

Section III.9.6.1 – The second paragraph of this section includes non-substantive edits that provide better clarity. Further, the last sentence of this paragraph was unnecessary and was deleted.

Markets Committee Members and Alternates
August 27, 2014
Page 4 of 8

Section III.9.6.4 – This section was clarified by adding “Dispatchable Asset Related Demand” as a type of resource for which Forward Reserve Qualifying Megawatts are calculated.

Section III.9.6.5(h) – The terminology of this section was changed to be more technically correct. The entity that actually reduces load from the electric system or provides Net Supply to the electric system is a Demand Response Asset. Demand Response Resources consist of one or more Demand Response Assets.

Section III.9.7.2(a) – This section was clarified by applying terminology more appropriate for Demand Response Resources – e.g., the phrase “Demand Response Resources that are not dispatched” was added where “off-line Forward Reserve Resources” were referenced, and “Demand Response Resources that have been dispatched” was added where “on-line Forward Reserve Resources” were referenced. Further, context required other wording and punctuation changes to provide further clarity in this section.

In addition, the phrase “[t]he amount of load that the Demand Response Resource reduced at the Retail Delivery Point during activation” was corrected and simplified to “[t]he amount of load reduced during activation.” Retail Delivery Points are more appropriately associated with Demand Response Assets, not Demand Response Resources.

Section III.10.1.1 – The adjustment to the Real-Time Reserve Designation of a Demand Response Resource used in the settlement process was clarified. The difference between the actual demand reduction capability of a Demand Response Resource, which is based upon its revenue quality meter data, and the estimated demand reduction capability used in Real-Time to designate the resource to provide Operating Reserves could result in a downward adjustment to the Real-Time Reserve Designation MW used in settlement. For example, if a Demand Response Resource was designated in Real-Time to provide 5 MW of Operating Reserves, but after-the-fact revenue quality meter data showed that the resource was only consuming 4 MW (and assuming the resource is not capable of producing Net Supply), then the Real-Time Reserve Designation MW used in settlement would be adjusted downward to 4 MW.

Section III.10.1.1 and Section III.E2.5 – These sections were revised to exclude the consideration of average avoided peak distribution losses in the reserve designation and dispatch processes. Across time and locations, reducing load at end-use customer facilities reduces overall losses on the distribution system. Accordingly, the settlement provisions of the Tariff continue to apply an average avoided peak distribution loss factor to load reductions (and not to Net Supply) produced by Demand Response Resources. However, while avoided peak distribution losses are about 6.5% *on average*, actual avoided losses will vary depending on specific system loading conditions at the time a specific set of resources are dispatched. That is, actual avoided distribution losses will vary from moment-to-moment and location-to-location and may be substantially greater or less than 6.5%. The present Real-Time reserve designation and dispatch processes does not consider the impact of a resource on avoided losses given that these avoided losses are variable and may not materialize when a specific set of resources are dispatched. The ISO does not anticipate having the capability to estimate avoided distribution losses by time and location in the foreseeable future. Given that the ISO is reluctant to

Markets Committee Members and Alternates
August 27, 2014
Page 5 of 8

rely upon potential avoided distribution losses to meet NERC reserve requirements, the ISO plans to continue the current practice of not considering potential avoided losses in the Real-Time reserve designation and dispatch processes at this time.

Section III.10.4.1 – This section involves the computation of Forward Reserve Obligation Charge MW, which is a value used in the settlement of a Forward Reserve Resource. The Forward Reserve Obligation Charge MW is the lesser of the Forward Reserve Delivered MW or Real-Time Reserve Designation MW. The portion of Forward Reserve Delivered MW associated with load reductions (not including Net Supply) includes average avoided peak distribution losses. To facilitate an “apples-to-apples” comparison between Forward Reserve Delivered MW and Real-Time Reserve Designation MW in the determination of Forward Reserve Obligation Charge MW, the load reduction portion (and not the Net Supply portion) of Real-Time Reserve Designation MW must be increased by average avoided peak distribution losses in the settlement process.

c) Section III.13

Section III.13.1.4.3 and Section III.E2.1.1 – The requirement that prohibits Generator Assets and Demand Response Assets from being located at the same Retail Delivery Point, which could result in double-counting of any Net Supply, was clarified and moved to Section III.E2.1.1. No substantive change to these requirements is being proposed. Section III.E2.1.1 addresses the rules governing the registration of Demand Response Assets so it was appropriate to move all Demand Response Registration requirements from Section III.13.1.4.3 to Section III.E2.1.1.

Section III.13.1.4.3.2 – The computation of a Real-Time Emergency Generation Resource’s Demand Reduction Value for the period commencing June 1, 2017 was clarified. If a Real-Time Emergency Generation Asset is metered at the generator, the Average Hourly Output of that asset is used in the computation of the associated Real-Time Emergency Generation Resource’s Demand Reduction Value. If a Real-Time Emergency Generation Asset is metered at the Retail Delivery Point, the Average Hourly Load Reduction of that asset is used in the computation of the associated Real-Time Emergency Generation Resource’s Demand Reduction Value.

Section III.13.1.4.3.2, Section III.E1.2.1, Section III.E1.2.4, and Section III.E2.2.2 – These sections were modified to eliminate *the option* that more granular interval data other than five-minute data could be submitted to the ISO. This modification was necessary given that the ISO’s baseline-telemetry system, which is used to compute Demand Response Baselines, is designed to use five-minute interval data only.¹

¹ In addition to five-minute data, Market Participants must report telemetry values at least every one minute for Demand Response Resources providing ten-minute reserves. One-minute data will be used to monitor the Real-Time status of a Demand Response Resource providing 10-minute reserves and to develop CLAIM10 values; however, five-minute data (not one-minute data) will continue to be used to develop Demand Response Baselines.

Markets Committee Members and Alternates
August 27, 2014
Page 6 of 8

Section III.13.5.3.2.3 – This section was clarified so that the capacity being assigned from a Supplemental Capacity Resource does not exceed the difference between (1) the sum of the Supplemental Capacity Resource’s Real-Time Reserve Designations of TMNSR, TMSR and TMOR, and (2) its Capacity Supply Obligation. In contrast to a generator, a Demand Response Resource that is consuming energy from the electric grid (and does not have controllable behind-the-meter generation) can provide TMSR from a not dispatched state. Any TMSR provided by a Demand Response Resource ought to be considered in the Supplemental Capacity Resource assignment process.

Section III.13.6.1.5.4.3.3.1 – This section was modified in two ways. First, the Tariff was modified to permit a Market Participant to use the performance of a Demand Response Resource during a Shortage Event in place of a Seasonal DR Audit provided that any of the resource’s constituent Demand Response Assets that are on a forced or scheduled curtailment during the event are assessed a zero audit performance. Previously, this section prohibited the use of the performance of a Demand Response Resource during a Shortage Event as a substitute for a Seasonal DR Audit if any of the resource’s constituent Demand Response Assets were on a scheduled or forced curtailment. However, this would have prevented the use of a resource’s performance during a Shortage Event in place of a Seasonal DR Audit if a single asset that was part of the resource was on a forced or scheduled curtailment, even if the asset’s contribution to the overall capacity of the resource was small. Accordingly, the proposal was changed to allow the use of the performance of a Demand Response Resource during a Shortage Event in place of a Seasonal DR Audit provided that any constituent Demand Response Asset on a forced or scheduled curtailment during the event is assessed a zero audit performance.

Second, the Tariff was modified to allow the use of a Demand Response Resource’s CLAIM10 or CLAIM30 audit result, which was conducted during a DR Auditing Period, in place of requesting a Seasonal DR Audit of that resource on the condition that the audit was conducted in a manner that meets the requirements of a Seasonal DR Audit. This new provision helps reduce the need to conduct multiple audits of a resource in the same season to fulfill different purposes.

Sections III.13.7.1.5.10.1(a), (e), and (f); and Sections III.13.7.1.5.10.2(b)(i) and (ii) – These sections were each clarified to better indicate “the lesser of” a series of values, which would be used in the Hourly Availability MW and the Availability Adjustment of a Demand Response Resource. The Hourly Available MW of a Demand Response Resource that is not dispatched, but is available for dispatch, is determined as “the lesser of” several values. In eliminating Net Supply Generator Assets and incorporating the Net Supply into the performance of Demand Response Assets, which in turn contributes to the performance of Demand Response Resources, the comparison of the values used to determine a resource’s Hourly Availability MW and the Availability Adjustment became unclear. These changes restore the original intent of these sections of the Tariff.

Section III.13.7.1.5.10.2(a)(ii) and Section III.13.7.1.5.10.2(b)(ii) – The phrase “and/or Maximum Net Supply” was deleted given the change in the definition of “Maximum Interruptible Capacity” as previously explained above.

d) Section III.E1 and Section III.E2

Section III.E1.2.1 and Section III.E1.2.4 – These sections were modified to eliminate *the option* that more granular interval data other than five-minute data be submitted to the ISO. See the discussion with respect to Section III.13.1.4.3.2 above for further explanation.

Section III.E2.1.1 – The requirement that prohibits Generator Assets and Demand Response Assets from being located at the same Retail Delivery Point was clarified and moved from Section III.13.1.4.3 to Section III.E2.1.1. See the discussion with respect to Section III.13.1.4.3 above for further explanation.

Section III.E2.1.3(f) and Section III.E2.3 – These sections were modified given the change in the definition of “Maximum Interruptible Capacity” as previously explained above.

Section III.E2.2.1 – This section was revised to better ensure the integrity of revenue-quality meter data submitted by Market Participants for their Demand Response Assets. In some cases, Market Participants use the electric distribution company’s revenue-quality meter, which is used by the electric distribution company for billing purposes, as the source of data for wholesale settlement. Such meters are subject to state-regulated standards of accuracy, calibration, testing, etc., and the data submitted by Market Participants to the ISO for wholesale settlement can be (and is) cross-checked against customer billing data maintained by the electric distribution company. Accordingly, it does not appear that additional provisions are needed in the Tariff to better ensure the integrity of Market Participant submitted meter data if the source of the data is the electric distribution company’s revenue-quality meter.

In other cases, however, the Market Participant installs their own meters on Demand Response Assets and uses data derived from those meters for wholesale settlement purposes. To better ensure the integrity of these data, more detailed Tariff provisions were added that require the Market Participant to validate and provide documentation to the ISO that any difference between the values recorded by the Market Participant’s meter and the values recorded by the distribution company’s billing meter is within an acceptable tolerance range – i.e., that the difference between the Market Participant’s and the electric distribution company’s meter data in the same timeframe is within $\pm 2.0\%$. Further, if the Market Participant believes that the electric distribution company’s meter data is inaccurate, documentation of these inaccuracies and of any communications with the distribution company to address these inaccuracies must be provided to the ISO.

Section III.E2.2.2 – This section was modified in three ways. First, telemetry-quality data on controllable behind-the-meter generation will no longer be required in Real-Time. Rather, these data must be submitted to the ISO by the end of the Correction Limit for the Data Reconciliation Process. As of June 1, 2017, all Demand Response Assets must be measured at the Retail Delivery Point – i.e.,

Markets Committee Members and Alternates
August 27, 2014
Page 8 of 8

Demand Response Assets located behind the Retail Delivery Point will no longer be allowed.² As a result, directly-metered output of controllable behind-the-meter generation (apart from Real-Time Emergency Generation Assets) will no longer be needed for settlement or for Real-Time telemetry purposes. Rather, these data are needed only as a check against potential Demand Response Baseline manipulation. To perform this check, however, these data do not have to be submitted to the ISO in Real-Time.

Second, if the Market Participant does not use the electric distribution company's revenue-quality meter to obtain Real-Time telemetry, this section was modified to require that the Market Participant specify the manufacturer and the model of the device used. Further, the requirement to report telemetry device specifications to the ISO was made more general – i.e., reporting device specifications is no longer limited to only the asset registration process – given that Market Participants might change the telemetry device at some point after the asset registration process.

Third, this section was modified to eliminate *the option* that more granular interval data other than five-minute data be submitted to the ISO. See the discussion in Section III.13.1.4.3.2 above for further explanation.

Section III.E2.5 – This section was modified to exclude average avoided peak distribution losses in the dispatching process. See the discussion with respect to Section III.10.1.1 above for further explanation.

Please contact me if you have any questions regarding this memo or the proposed market rule changes.

² Under the currently-effective market rules, a Real-Time Demand Response Asset, e.g., consisting of a controllable behind-the-meter generator, may be individually metered and located behind a Retail Delivery Point. Multiple Real-Time Demand Response Assets may be located at and/or behind a single Retail Delivery Point under the currently-effective market rules.



memo

To: NEPOOL Markets Committee

From: Henry Yoshimura, ISO New England

Date: July 30, 2014

Subject: Full Integration of Demand Response Resources into the Energy and Reserves Markets

1) Introduction and Background

The purpose of this memo is to explain the market design and market rule changes that are needed to enable Demand Response Resources to participate in the Real-Time energy and reserve market structure and in the Forward Reserve Market. ISO New England (“ISO”) is committed to enabling Demand Response Resources to provide Operating Reserves beginning June 1, 2017, coincident with the full integration of Demand Response Resources into the energy markets.¹ The basic market design for the Real-Time Reserves and Forward Reserve Market into which Demand Response Resources would be integrated was discussed in detail in a whitepaper dated September 26, 2013.² That whitepaper also discussed certain market design challenges to enabling Demand Response Resources in providing Operating Reserves. These challenges, along with others that were discovered in the market assessment and change processes, have been addressed in this memo and in the proposed market rule changes that accompany this memo.

The proposed changes to the market rules have been posted for your review and consideration. Please note that the posted Tariff language contain changes other than those described in this memo. The ISO is requesting the Markets Committee to review all of the proposed market rule changes *except for* those in Section III.9.5.3, Resource CLAIM10 and CLAIM30 Values, and Section III.1.5.2, ISO-Initiated Parameter Auditing.³

¹ The ISO committed to fully integrating Demand Response Resources into the Day-Ahead and Real-Time Energy Markets by June 1, 2017, in response to Order No. 745. See *ISO New England Inc.*, Order No. 745 Compliance Filing, Docket Nos. ER11-4336-000 and ER11-4336-001 (August 19, 2011); http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/er11_4336_000_prd_filing.pdf, and *ISO New England Inc.*, Order on Compliance Filing, 138 FERC ¶ 61,042 (January 19, 2012), accepted with conditions; http://www.iso-ne.com/regulatory/ferc/orders/2012/jan/er11-4336-000_1-19-12_ordr_on_ordr745.pdf.

² This whitepaper is available at: http://www.iso-ne.com/committees/comm_wkgrps/mrmts_comm/mrmts/mtrls/2013/oct22013/a5_iso_white_paper_drr_reserves_09_26_13.doc.

³ Tariff changes related to CLAIM10/30 auditing rules and ISO-initiated parameter audits for Demand Response Resources are being reviewed and considered by the NEPOOL Reliability Committee.

Markets Committee Members and Alternates
July 30, 2014
Page 2 of 35

The ISO's current plan is to make the proposed market rule changes effective for June 1, 2017. As stated by the ISO in the April 26, 2012 Forward Capacity Market conforming changes filing with the Federal Energy Regulatory Commission ("the Commission"):

[T]he ISO will work to develop market rules to allow demand response resources that participate in the energy market to participate in the reserve market coincident with the implementation of the fully integrated [Price Responsive Demand] rules in June 2017.⁴

The ISO is seeking to have market rules for Demand Response Resources providing Operating Reserves in place before February 2015 so that demand response providers have this information before participating in Forward Capacity Auction 9, scheduled for February 2015. To meet this objective, the ISO plans to: (1) review the proposed market rule changes with stakeholders in August 2014, (2) ask the relevant NEPOOL committees for a vote on the proposed changes in September 2014, and (3) file the proposed market rule changes with the Commission in October 2014. This schedule would give the Commission a reasonable opportunity to issue an Order on the proposed market rule changes before February 2015.

While the current plan is to file market rule changes in October 2014 as described above, the ISO will also be closely monitoring court proceedings involving Order No. 745. As you are aware, the Court of Appeals for the District of Columbia Circuit issued a decision on May 23, 2014 vacating Order No. 745.⁵ Order No. 745 is the basis for the full integration of Demand Response Resources into the energy markets. The market rules proposed by the ISO today, which enable Demand Response Resources to provide Operating Reserves, are completely dependent upon Demand Response Resource participation in the energy markets. The court stayed its decision on May 23, 2014, to allow for the consideration of rehearing requests. On July 7, 2014, the Commission petitioned the court for rehearing *en banc*. Should the court ultimately invalidate Order No. 745, the implementation of the market rules proposed today will likely be impacted. However, we cannot predict the final outcome or the timing of court proceedings at this time. The ISO will discuss with stakeholders through established processes to determine how best to balance stakeholders' interests with the need to prudently expend the ISO's resources. Accordingly, we plan to revisit the June 1, 2017 implementation date no later than the first quarter of 2015 at the time of the market priorities discussion. At that time, we will evaluate the prudence of continuing with implementation activities and decide whether to file for a delay in implementation based on information known at that time.

The manner by which Demand Response Resources will be integrated into the Real-Time energy and reserve market structure and in the Forward Reserve Market is consistent with the September 26, 2013 whitepaper, and is consistent with the material I presented to the Markets Committee at its April, May, June, and July 2014 meetings. It is very important to note that the market rule changes proposed by the ISO today do not change the existing Real-Time Reserves and Forward Reserve Market structure

⁴ ISO New England Inc., Price-Responsive Demand FCM Conforming Changes, Docket No. ER12-1627-000 (April 26, 2012), p. 4; http://www.iso-ne.com/regulatory/ferc/filings/2012/apr/er12-1627-000_4-26-2012_prd.pdf.

⁵ *Electric Power Supply Ass'n v. FERC*, D.C. Cir. Nos. 11-1486, *et al.* (May 23, 2014).

Markets Committee Members and Alternates
July 30, 2014
Page 3 of 35

– rather, these changes are intended to integrate Demand Response Resources into the existing Real-Time Reserves and Forward Reserve Market structure.

The remainder of this memo is organized in accordance with the following outline:

- Modeling Demand Response Assets and Demand Response Resource
 - o Introduction
 - o Overview of the Net Supply Generator Asset Model
 - o Why Replace the Net Supply Generator Asset Model?
 - o Overview of the Common Dispatch Model
 - o The Impact of the Common Dispatch Model on Day-Ahead and Real-Time Energy Market
 - Application of Distribution Losses in Day-Ahead and Real-Time Energy Market Settlement
 - Application of Distribution Losses in Energy Dispatch and Reserve Designation
 - o Other Impacts on the Market Rules From Replacing the Net Supply Generator Asset Model With the Common Dispatch Model
- Establishing Rules Regarding How Demand Response Resources Provide Real-Time Reserves
 - o Introduction
 - o Dispatch Zone/Reserve Zone Registration
 - o Additional Reserve-Related Offer Parameters
 - o Real-Time Reserve Designation and Settlement
 - Introduction
 - Defining “Off-line” and “On-line” Demand Response Resources
 - Defining a Fast Start Demand Response Resource
 - Designating a Demand Response Resource to Provide TMSR
 - Designating a Demand Response Resource to Provide TMNSR and TMOR
 - o Telemetry Requirement for Demand Response Resources Providing 10-Minute Reserves
- Changing the Demand Response Baseline Adjustment Factor
 - o The Need for a Better Short-Term Forecast of DRR Consumption
 - o The Concept for a Real-Time Baseline Adjustment
 - o Research Conducted and Approach Recommended
 - o Tariff Changes Implementing the Recommended Baseline Adjustment Approach
- Integrating Demand Response Resources Into the Forward Reserve Market
 - o General Approach
 - o Eligibility Requirements for a Demand Response Resource to Meet Forward Reserve Obligations
 - o Measuring and Compensating Demand Response Resource Performance in the FRM

Markets Committee Members and Alternates
July 30, 2014
Page 4 of 35

- o Delivery of Forward Reserve
 - o Consequences for Failing to Deliver Forward Reserve
- Auditing Demand Response Resources in the Forward Capacity Market
- Related Market Rule Changes
 - o Implementation of Recent Demand Response Baseline Changes (that became effective June 1, 2014) for the Market Rules for Full Integration
 - Scheduled and Forced Curtailments (ER14-727-000)
 - Constraints on the Adjusted Baseline for Net Supply (ER14-1659-000)
 - o Clarify Metering Requirements for Behind-the-Meter Generators
- Other Minor Rule Changes

2) Modeling Demand Response Assets and Demand Response Resources

a) Introduction

The most significant market design change that the ISO proposes at this time is the implementation of a “common dispatch model.” Under the current market rules, a single facility that can reduce load from its Retail Delivery Point and inject energy into the electric grid (i.e., provide Net Supply) is modeled as two assets – a Demand Response Asset that reduces load from the electric grid, and a Net Supply Generator Asset that provides Net Supply to the electric grid. Under the common dispatch model, however, such a facility is modeled as a single Demand Response Asset, which then eliminates the need to create a separate Net Supply Generator Asset to model Net Supply in the energy market. This modeling change provides the “platform” that will allow reserves to properly be accounted on Demand Response Resources. In addition to impacting how reserves are designated for Demand Response Resources, this modeling change also impacts the market rules for the energy and capacity markets, and impacts Demand Response Baseline rules.

b) Overview of the Net Supply Generator Asset Model

As mentioned above, the present market design represented in the current Tariff models a customer facility capable of reducing load from the electric grid and providing Net Supply to the electric grid as two separate assets – a Demand Response Asset and a Net Supply Generator Asset, respectively. Demand Response Assets located in the same Dispatch Zone may be aggregated together to form a Demand Response Resource. Under the present energy market model, a Demand Response Resource is the entity that participates in the energy markets for which Demand Reduction Offers are submitted by Market Participants.⁶ Although a Net Supply Generator Asset may be directly related to a Demand Response Asset that is part of a Demand Response Resource, the Net Supply Generator Asset is treated as a separate asset in the energy market model. Supply Offers associated with a Net Supply

⁶ Large Demand Response Assets – those with 5 MW or more of capability to reduce load from and/or provide Net Supply to the electric grid – are required to participate in the energy markets individually as a separate and distinct Demand Response Resource.

Markets Committee Members and Alternates
July 30, 2014
Page 5 of 35

Generator Asset are submitted into the energy markets separately and distinctly from Demand Reduction Offers of Demand Response Resources.

Modeling a customer facility that is capable of reducing load from the electric grid and providing Net Supply to the electric grid as two separate assets facilitates the separate and distinct measurement of load reductions from Net Supply. Separately measuring load reduction from Net Supply addresses the potential double-counting of Net Supply. For example, take a facility that normally consumes 10 MW while simultaneously producing 6 MW with its own behind-the-meter generation. In this situation, the load at the Retail Delivery Point would show -4 MW (i.e., this facility puts 4 MW of load on the electric grid to meet its total energy requirement), so the facility's baseline would be -4 MW. If this facility responds to dispatch by reducing all 10 MW of power consumption while maintaining 6 MW of generation, the load at the Retail Delivery Point would change to +6 MW. The difference between a -4 MW baseline and a meter reading of +6 MW is 10 MW. Therefore, this facility could receive a payment based on 10 MW of demand response provided. However, if this facility also had a Generator Asset registered at the same Retail Delivery Point,⁷ the same facility could also receive a separate and additional payment for the 6 MW of power injected into the electric grid. This would result in a double-counting of the 6 MW of Net Supply produced by the facility, resulting in an incorrect total settlement based on 16 MW, not 10 MW.

The current Tariff addresses this situation by limiting load reduction quantities to the difference between the baseline and a meter reading of 0 MW. That is, if the meter at the Retail Delivery Point of a Demand Response Asset shows that Net Supply is being provided, the meter reading for the purposes of quantifying load reductions would be capped at 0 MW. Thus, the demand response payment from the above example would be based on the difference between a -4 MW baseline and capped meter reading of 0 MW – i.e., the customer facility would receive payment for 4 MW of reduced load from the grid. The 6 MW of Net Supply that was also provided – as shown by the +6 MW meter reading during the period of dispatch – would be credited to a separate Net Supply Generator Asset registered at the same location, resulting in the correct total settlement based on 10 MW delivered to the electric grid.

The Net Supply Generator Asset approach also facilitates the correct accounting for average avoided peak distribution losses. Reducing load on the electric grid reduces losses on the distribution system. Accordingly, load reduction quantities should be credited for average avoided peak distribution losses. On the other hand, like any other generation produced on the electric grid, Net Supply produced by a facility should *not* be credited for average avoided peak distribution losses because this increased generation incurs losses between the point of production and the point of consumption. Therefore, if a facility is able to both reduce load from and provide Net Supply to the electric grid, the load reduction amount ought to be increased by average avoided peak distribution losses whereas the Net Supply amount should not be increased. By separating load reductions produced by Demand Response Assets from Net Supply produced by Net Supply Generator Assets, the application of average avoided peak distribution losses in settlement quantities is clear and straightforward.

⁷ There are customer facilities in New England that register behind-the-meter generators as Generator Assets.

c) Why Replace the Net Supply Generator Asset Model?

There are hazards with modeling a single facility as two separate assets. The energy/reserve market into which Demand Response Resources will be integrated assumes that each asset in the market model is independent and can be dispatched in accordance with its individual energy offer parameters to meet both economic and security objectives. However, a customer facility capable of reducing load from the electric grid and providing Net Supply to the electric grid must first reduce its load from the grid before it could provide Net Supply – i.e., at any given Retail Delivery Point, it is physically impossible to provide Net Supply before load reduction. This means that there is an inter-temporal dependency between the Demand Response Asset and a Net Supply Generator Asset located at the same facility – i.e., the Demand Response Asset must be dispatched before the energy of the Net Supply Generator Asset becomes available.

In the energy markets, the dependency between a Demand Response Asset and a Net Supply Generator Asset can be somewhat enforced by the Market Participant offering the load reduction associated with the Demand Response Asset at a lower price than the Net Supply Generator Asset. Even if offered in this manner, however, the security-constrained dispatch algorithm may still dispatch a Net Supply Generator Asset before its associated Demand Response Asset – local transmission constraints at a location could result in assets with higher priced offers being dispatched before lower priced ones.

More importantly, the dependency between the Demand Response Asset and the Net Supply Generator Asset at a facility could also result in over-estimating the amount of Operating Reserves that could be provided by the facility. Expanding from the previous example – i.e., a facility that normally consumes 10 MW, produces 6 MW, and draws 4 MW from the grid – assume that the Demand Response Asset at this facility offered to provide 4 MW of TMOR, and the Net Supply Generator Asset offered to provide 6 MW of TMOR. With each asset treated independently, the facility could be designated to provide a total of 10 MW of TMOR. However, if the facility needs 30 minutes to reduce power consumption from 10 MW to 5 MW, and another 30 minutes to further reduce its consumption to 0 MW, the most TMOR that this facility could provide is 5 MW – i.e., 4 MW for the Demand Response Asset and 1 MW for the Net Supply Generator Asset. Therefore, treating each asset as independent could result in over-estimating the amount of Operating Reserves that can be provided by a facility that can produce both load reductions and Net Supply.

d) Overview of the Common Dispatch Model

To address these shortcomings, the ISO developed the “common dispatch model.” Rather than representing a customer facility that is capable of reducing its load from and delivering Net Supply to the electric grid as two separate assets, the common dispatch model represents this facility as a single Demand Response Asset that is part of a Demand Response Resource. The common dispatch model eliminates the need to create a separate Net Supply Generator Asset to account for the Net Supply that a facility with behind-the-meter generation could produce. Since there is no longer a Net Supply Generator Asset that is modeled separately from the Demand Response Asset, the potential for

Markets Committee Members and Alternates
July 30, 2014
Page 7 of 35

dispatching the Net Supply Generator Asset before its associated Demand Response Asset is eliminated.

Returning to the previous example of a facility that normally consumes 10 MW, produces 6 MW, and draws 4 MW from the grid, a single Demand Reduction Offer related to this facility would be entered under the common dispatch model. Assuming that the capacity of the behind-the-meter generator of this facility is 6 MW and the facility is willing and able to reduce all 10 MW of power consumption, the Market Participant of this facility could submit a single Demand Reduction Offer covering the entire 10 MW that this facility could produce, which consists of 4 MW of load reduction from the grid and 6 MW of Net Supply. The Demand Reduction Offer could consist of up to ten, monotonically-increasing, price/quantity pairs. Because a higher-priced block would never be dispatched before a lower-priced block from the same offer, there is no danger of this facility being dispatched in a way that is physically impossible – if this facility were dispatched to provide 6 MW, the Market Participant would know that it would need to reduce the facility's power consumption by 6 MW, which would produce 4 MW of load reduction and 2 MW of Net Supply.

The common dispatch model also eliminates the potential for over-estimating the amount of Operating Reserves that an asset, which is capable of reducing its load from and delivering Net Supply to the electric grid, can provide. The ability of this facility to provide Operating Reserves would be evaluated as a single asset as opposed to two separate assets. Under the Net Supply Generator Asset approach, it was explained previously how this facility could be counted to provide 10 MW of TMOR if the facility were represented as two separate, independent assets. Under the common dispatch model, however, the performance of this facility is evaluated as a single asset. So if this facility can reduce 5 MW of power consumption within 30 minutes – showing as 4 MW of load reduction from the grid and 1 MW of Net Supply as measured from its Retail Delivery Point – it would only be allowed to provide 5 MW of TMOR. Thus, the common dispatch model reduces the danger of over-estimating the amount of reserves that a facility that can provide Net Supply could provide to the electric grid.

To preserve the original purpose of the Net Supply Generator Asset model – i.e., to address potential double-counting of Net Supply – the market rules were clarified so as to credit any Net Supply produced at a location, which has both a Generator Asset and a Demand Response Asset, only to the Demand Response Asset, unless the Generator Asset is separately metered and its output is added to the metered load of the Demand Response Asset as measured at the Retail Delivery Point – see Section III.13.1.4.3.

e) The Impact of the Common Dispatch Model on Day-Ahead and Real-Time Energy Market

i) Application of Distribution Losses in Day-Ahead and Real-Time Energy Market Settlement

As explained previously, reductions in load at the Retail Delivery Points of Demand Response Assets comprising a Demand Response Resource will result in the reduction of distribution losses. On the

Markets Committee Members and Alternates
July 30, 2014
Page 8 of 35

other hand, Net Supply produced by Demand Response Assets comprising a Demand Response Resource does not result in a reduction in distribution losses. Accordingly, the settlement of load reductions measured at a Retail Delivery Point should be increased by the average avoided peak distribution losses whereas Net Supply should not be increased. Under the common dispatch model, however, any Net Supply produced by Demand Response Assets is now credited to the performance of the Demand Response Resource to which it is associated along with any load reductions produced. In order to correctly apply average avoided peak distribution losses to the performance of a Demand Response Resource, Net Supply and load reduction amounts need to be quantified separately in the settlement process.

In Real-Time, the amount of Net Supply produced by a Demand Response Asset is clear – when the sign of the meter reading at the Retail Delivery Point is positive, power is being delivered to the electric grid (i.e., Net Supply); if the sign of the meter reading is negative, power is being consumed from the electric grid. The ISO proposes to increase load reductions delivered in Real-Time at a Retail Delivery Point by one plus average avoided peak distribution losses, whereas Net Supply delivered in Real-Time would not be increased.

Prior to Real-Time, however, it is not clear what portion of a Market Participant's Demand Reduction Offer, particularly its Day-Ahead Demand Reduction Offer, is associated with the provision of Net Supply. Accordingly, an assumption regarding the application of distribution losses to a cleared Day-Ahead Demand Reduction Offer must be made. The assumption employed should allow Market Participants to mitigate the potential difference between the assumed level of Net Supply in a Day-Ahead Demand Reduction Offer and the actual level of Net Supply produced in Real-Time so as to minimize deviations between the quantities cleared Day-Ahead versus those expected to be delivered in Real-Time. To address this issue, the ISO proposes that the settlement process assume that all cleared Day-Ahead Demand Reduction Offers are associated with load reductions only – i.e., no Net Supply would be assumed in a cleared Day-Ahead Demand Reduction Offer. Accordingly, the entire cleared Day-Ahead Demand Reduction Offer would be multiplied by one plus average avoided peak distribution losses (i.e., “grossed-up”) in the settlement process. We believe that such an assumption is reasonable because of its simplicity and because we expect that the majority of demand reductions provided by Demand Response Resources will be in the form of load reductions measured at the Retail Delivery Point and not Net Supply.

To the extent a Market Participant expects that a portion of its Demand Response Resource would perform in Real-Time by providing Net Supply, the Market Participant can correspondingly reduce its Day-Ahead Demand Reduction Offer to reduce the potential deviation between the quantities cleared Day-Ahead versus those expected to be delivered in Real-Time. Presently, average avoided peak distribution losses are estimated to be 6.5 percent. Given that, the Market Participant can adjust its Day-Ahead Demand Reduction Offer for any Net Supply its Demand Response Resource is expected to produce in Real-Time – i.e., the Market Participant's Day-Ahead Demand Reduction Offer could include 1/1.065 MW or about 0.939 MW for each MW of Net Supply that is expected to be produced in Real-Time.

ii) Application of Distribution Losses in Energy Dispatch and Reserve Designation

When a Demand Response Resource is dispatched to provide energy or designated to provide Operating Reserves in Real-Time, the portion of the resource expected to reduce load as measured from each associated Demand Response Asset's Retail Delivery Point will be grossed-up by average avoided peak distribution losses, whereas any expected Net Supply expected will not be grossed-up. Prior to dispatch in Real-Time, however, the proportion of load reduction versus Net Supply that would be produced by a Demand Response Resource if dispatched is unclear. Yet, accurately predicting what proportion of a Demand Response Resource would be provided as a load reduction versus Net Supply if dispatched in Real-Time to provide energy within 10 or 30 minutes is important, especially if Demand Response Resources become a large proportion of total Operating Reserves. This is because 1.000 MW of load reduction produced at a Retail Delivery Point displaces 1.065 MW of generation whereas 1.000 MW of Net Supply displaces only 1.000 MW of generation.

In the energy dispatch and reserve designation process, therefore, the ISO proposes that the proportion of the demand reduction produced by a Demand Response Resource expected to be provided through load reductions at the Retail Delivery Point versus Net Supply will be estimated using the results of that resource's most recent Seasonal DR Audit. At the time of the Seasonal DR Audit, the ISO would determine the ratio of total Net Supply to total demand reduction⁸ of the Demand Response Assets that are mapped to the Demand Response Resource. That ratio would be multiplied by the current offered Maximum Reduction of the Demand Response Resource to estimate the portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. This quantity is defined as the "Net Supply Limit" – see Section I.2.2.

When committing and dispatching a Demand Response Resource in the Real-Time Energy Market, the ISO will assume that the Demand Response Resource must first reduce its load from the electrical system up to the difference between its Maximum Reduction and its Net Supply Limit before providing Net Supply. This assumption is reasonable given that, as explained previously, a Demand Response Asset must first reduce its load at its Retail Delivery Point before it can provide any Net Supply to the electric grid.⁹ The ISO will apply average avoided peak distribution losses to the estimated load reduction amounts and not to the estimated Net Supply Amount when committing and dispatching Demand Response Resources in Real-Time, and when designating Demand Response Resource when providing Operating Reserves.

The following sections of the Tariff were modified to reflect the application of distribution losses in the settlement process, and in the energy dispatch and reserve designation process:

⁸ The total demand reduction of a Demand Response Asset will be the sum of the load reduction measured at the asset's Retail Delivery Point and Net Supply produced.

⁹ It is certainly possible that one Demand Response Asset that is part of a Demand Response Resource could provide Net Supply before another Demand Response Asset that is part of the same resource produces a load reduction. Under the common dispatch model, the ISO would not be able to tell what portion of a Demand Reduction Offer represents load reductions versus Net Supply. However, to the extent the Market Participant understands the order by which a demand reduction would be conducted by its Demand Response Resource, it could adjust the various segments of its offer to account for the proportions provided by load reduction versus Net Supply.

Markets Committee Members and Alternates
July 30, 2014
Page 10 of 35

- Section III.10.1.1;
- Section III.13.7.2.5.4.1; and
- Sections III.E2.5, III.E2.7.2.

f) Other Impacts on the Market Rules From Replacing the Net Supply Generator Asset Model With the Common Dispatch Model

Replacing the Net Supply Generator Asset model with the common dispatch model is most noticeable in the proposed market rule changes in Section III.13.¹⁰ In numerous locations in Section III.13, phrases like “the Demand Response Resource and associated Net Supply Generator Asset” will be changed to simply “the Demand Response Resource.” Because Demand Response Resources consist of one or more Demand Response Assets, and since the definition of Demand Response Asset was modified to include any Net Supply,¹¹ there is no need to define a separate Net Supply Generator Asset.¹² Similarly, where the terms “the Demand Reduction Offers and Supply Offers” were used to refer to of energy market offers of Demand Response Resources and Net Supply Generator Assets, this phrase was modified to simply “the Demand Reduction Offer” since any Net Supply produced will be credited to the performance of the Demand Response Asset. Further, the requirements specific to Net Supply Generator Assets, such as offer requirements have been eliminated.

Replacing the Net Supply Generator Asset model with the common dispatch model also impacts other sections of the Tariff. In particular, the settlement quantity called “Real-Time Demand Reduction Obligation” originally was intended to apply to only the load reduction amount measured at the Retail Delivery Points of the Demand Response Assets comprising a Demand Response Resource; any Net Supply produced at a Retail Delivery Point was credited to a separate Net Supply Generator Asset. Under the common dispatch model, Net Supply Generator Assets have been eliminated and any Net Supply produced is credited to a Demand Response Asset. However, Net Supply should not be increased by average avoided peak distribution losses as previously discussed. Therefore, the calculation of the Real-Time Demand Reduction Obligation was modified so that only the load reduction portion measured at the Retail Delivery Points of the Demand Response Assets comprising a Demand Response Resource is multiplied by one plus the average avoided peak distribution losses; to that amount, any Net Supply produced by these Demand Response Assets is then added (unadjusted for losses) to determine the Real-Time Demand Reduction Obligation of the Demand

¹⁰ The affected sections include: Sections III.13.1.4.3, III.13.5.3.2.3, III.13.6.1.5.1, III.13.6.1.5.2, III.13.6.1.5.4.2, III.13.6.1.5.4.3.3.1, III.13.6.1.5.4.5, III.13.6.1.5.4.6, III.13.6.2.5.1, III.13.6.2.5.1.1, III.13.6.2.5.1.2, III.13.7.1.5.10.1, III.13.7.1.5.10.1.1, III.13.7.1.5.10.2, and III.13.7.2.5.4.1.

¹¹ Section I.2.2 now defines Demand Response Asset as “an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset’s actual demand measured at the Retail Delivery Point, **which could reflect Net Supply**, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline” (emphasis added).

¹² The defined term Net Supply Generator Asset was deleted from Section I.2.2.

Markets Committee Members and Alternates
July 30, 2014
Page 11 of 35

Response Resource. These changes are found in Sections III.E2.1.3, III.E2.2.1, III.E2.2.2, III.E2.3, III.E2.3.1, III.E2.5, III.E2.7.2, and III.E2.7.3.

Finally, Sections III.8B.1 and III.8B.5, which are related to the computation of Demand Response Baselines, are also affected by the replacement of the Net Supply Generator Asset model with the common dispatch model.

3) Establishing Rules Regarding How Demand Response Resources Provide Real-Time Reserves

a) Introduction

As mentioned previously, the primary intent of the market rule changes proposed by the ISO at this time is to integrate Demand Response Resources into the existing co-optimized energy and reserve structure. These rule changes are not intended to change the existing structure. To integrate Demand Response Resources into the co-optimized energy and reserve structure several modifications need to be made to address issues unique to Demand Response Resources.

b) Dispatch Zone/Reserve Zone Registration

In contrast to Generator Assets, Demand Response Resources mostly consist of aggregations of individual Demand Response Assets located within the same Dispatch Zone.¹³ In the Forward Reserve Market, the market for reserves varies by Reserve Zone. Since the ISO proposes to allow Demand Response Resources to meet a Forward Reserve Obligation in these market rule changes, Demand Response Assets that comprise a Demand Response Resource must be located in the same Reserve Zone. However, the current Dispatch Zones and Reserve Zones do not align in all cases given that the process for developing Dispatch Zones and Reserve Zones differ. That is, it is possible for a Dispatch Zone to span more than one Reserve Zone. For example, the present Western Connecticut Dispatch Zone spans the Southwest Connecticut and Connecticut Reserve Zones. Without market rules to address situations such as this, it is possible that some of the Demand Response Assets of a Demand Response Resource will be located in more than one Reserve Zone. At the extreme, it would be possible that a Demand Response Resource in a Dispatch Zone has all of its assets in one Reserve Zone and not the other – this would be very problematic if, for example, a Western Connecticut Demand Response Resource was paid to provide reserves in Southwest Connecticut Reserve Zone, but all of its assets were located in the Connecticut Reserve Zone, or vice versa.

To address this situation, the ISO proposes a market rule change, which would require all of the Demand Response Assets that are associated with a Demand Response Resource all be located within

¹³ Like Generator Assets, large Demand Response Assets – those with five MW or more of demand reduction capability at a single Retail Delivery Point – must be registered as its own Demand Response Resource at the Nodal level.

Markets Committee Members and Alternates
July 30, 2014
Page 12 of 35

a single Dispatch Zone and Reserve Zone.¹⁴ This market rule change is reflected in Sections III.E2.1.1, III.E2.1.3, III.E2.1.4, III.2.7A.

c) Additional Reserve-Related Offer Parameters

To provide Operating Reserves from an off-line state, a Generator Asset must have an Offered CLAIM10 and/or an Offered CLAIM30 value in its energy market offer. The Offered CLAIM10 value represents the amount of 10-minute reserve available from a Resource. The Offered CLAIM30 value represents the amount of 30-minute reserve available from a Resource. The Offered CLAIM10/30 values of a Resource are capped at values that reflect the Resource's performance during a CLAIM10/30 audit and in response to dispatch. For a Demand Response Resource to provide 10- and/or 30-minute Operating Reserves from an undischarged state, the resource must also have an Offered CLAIM10/30 value in its energy market offer. Therefore, the market rules were modified to allow the Market Participant of a Demand Response Resource to submit Offered CLAIM10 and Offered CLAIM30 values to represent the amount of 10-minute and 30-minute reserve that the Market Participant of an undischarged Demand Response Resource is willing to offer – the market rule changes allowing Demand Response Resources to submit Offered CLAIM10 and Offered CLAIM30 values are found in Section I.2.2., and Section III.E2.3.2. In addition, as part of the registration information maintained about the Demand Response Resource, the Market Participant must indicate whether the Demand Response Resource will maintain CLAIM10 or CLAIM30 capability – see Section III.E2.1.1.

d) Real-Time Reserve Designation and Settlement

i) Introduction

The manner in which Demand Response Resources would be designated to provide Operating Reserves will be identical to the manner in which other Resources, such as Generator Assets, are presently designated to provide Operating Reserves. Most of the market rule changes needed to effectuate the provision of Operating Reserves by Demand Response Resources involves the inclusion of “or Demand Response Resource” in numerous locations of the market rules where generators are mentioned, and “or demand reduction” in locations with generator output is mentioned. Section III.10 was clarified so that Demand Response Resources is identified as a type of resource that can be designated to provide Operating Reserve. Finally, since Demand Response Resources are eligible to supply reserves, they should also be eligible to help meet a Local Reserve Requirement and their retirement or deactivation, if significant, could result in a re-evaluation of the Local Reserve Requirement – see Section III.9.2.2.

These Tariff changes are further explained below.

¹⁴ This change does not affect the Demand Response Resource aggregation rules for the Forward Capacity Market. Demand Response Capacity Resources, which continue to be qualified at the Dispatch Zone level, can have more than one Demand Response Resource associated with it. For example, a Demand Response Resources in both the Southwest Connecticut and Connecticut Reserve Zones can be aggregated into a Demand Response Capacity Resource located in the Western Connecticut Dispatch Zone.

ii) Defining “Off-line” and “On-line” Demand Response Resources

The manner in which a Generator Asset is designated to provide Operating Reserve varies whether the generator is “off-line” or “on-line”. A resource that provides reserves from an off-line state must establish, through an audit or demonstrated performance in response to dispatch, its ability to provide energy within 10 or 30 minutes. A resource’s demonstrated ability to provide off-line 10-minute reserve is referred to as “CLAIM10” capability; its demonstrated ability to provide off-line 30-minute reserve is referred to as “CLAIM30” capability. An on-line generator does not have to demonstrate its capability to be eligible to provide reserves through a CLAIM10/30 audit. The capability of an on-line generator is determined based on real-time telemetry, its Economic Maximum Limit, and its ramp rate.

Similarly, the market rules that allow Demand Response Resources to provide reserves must recognize its “off-line” or “on-line” state at the time it is being designated. However, the application of generator terminology to Demand Response Resources could be extremely confusing. For example, an “on-line” generator is connected to the electric grid and has been dispatched to generate power.¹⁵ On the other hand, a Demand Response Resource is connected to the electric grid and is consuming power *before* it has been dispatched. So is a Demand Response Resource on-line or off-line in this instance?

To be clearer, the proposed market rules use somewhat different terminology for Demand Response Resources. A Demand Response Resource that has been “**dispatched**” to provide a portion or all of its demand reduction is similar to a generator that is “on-line”. A Demand Response Resource that is “**not dispatched**” or “**undispatched**” – i.e., has not received a commitment or Dispatch Instruction¹⁶ – is equivalent to a generator that is “off-line”.

iii) Defining a Fast Start Demand Response Resource

To provide Operating Reserves from an off-line state, a Generator Asset must meet the definition of a Fast Start Generator. A Fast Start Generator is a generating unit that the ISO may dispatch within the hour through electronic dispatch and that meets the following criteria: (i) minimum run time does not exceed one hour; (ii) minimum down time does not exceed one hour; (iii) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time. Similarly, a Demand Response Resource with similar “fast start” characteristics ought to be able to provide Operating Reserves from an undispatched state. Accordingly, the ISO proposes a new defined term – Fast Start Demand Response Resource – and proposes to integrate this term into the appropriate sections of the Tariff, which to allow Demand

¹⁵ An “off-line” generator is not connected (i.e., not synchronized) with the electric grid.

¹⁶ The defined term Dispatch Instruction was modified in the proposed rule to incorporate the dispatch of Demand Response Resources based upon its Demand Reduction Offer – see Section I.2.2.

Markets Committee Members and Alternates
July 30, 2014
Page 14 of 35

Response Resources to provide Operating Reserves from an undischarged state. The modified sections of the Tariff include Sections III.2.4; III.9.5.2; and III.9.7.2.

A Fast Start Demand Response Resource has similar requirements to Fast Start Generator. Like a Fast Start Generator, the ISO proposes that a Fast Start Demand Response Resource must be able to be dispatched within 30 minutes and meet the following criteria:

- Minimum Reduction Time does not exceed one hour;
- Minimum Time Between Reductions does not exceed one hour;
- Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes;
- Has personnel available to respond to Dispatch Instructions or has automatic remote response capability;
- Is capable of receiving and acknowledging a Dispatch Instruction electronically; and
- Has satisfied its Minimum Time Between Reductions.

The above-mentioned criteria were incorporated into a new defined term – Fast Start Demand Response Resource – which was included in Section I.2.2.

iv) Designating a Demand Response Resource to Provide TMSR

Demand Response Resources will be permitted, to the extent that they are capable, to provide TMSR, TMNSR, and TMOR. For a generator to provide TMSR (i.e., Ten-Minute Spinning Reserve), the generator must already be “on-line” – i.e., it must be synchronized to the electric grid and eligible for dispatch. In contrast, a Demand Response Resource that is consuming energy from the electric grid is already synchronized to the grid even though it is not dispatched.

By definition, an off-line generator is not synchronized to the electric grid. According to the standards set forth by the Northeast Power Coordinating Council (“NPCC”), such a resource cannot provide TMSR. Generating stations with multiple units behind a common metering point are similarly not allowed to provide TMSR given that the ISO cannot determine whether any individual unit behind the metering point is off-line and must be started and synchronized with the electric grid before it could provide service. Similarly, NPCC standards also provide that a Demand Response Resource that must start a behind-the-meter generator should not be allowed to provide TMSR. Also, like multi-unit generators, the ISO does not have situational awareness with respect to the status of any behind-the-meter generators that a Demand Response Resource would start in order to comply with a Dispatch Instruction. Accordingly, the market rules proposed by the ISO herein will prohibit a Demand Response Resource with any behind-the-meter generation (excluding Real-Time Emergency Generation Assets, which are separately metered assets) from providing TMSR – see the modified definition of Ten-Minute Spinning Reserve in Section I.2.2.

v) Designating a Demand Response Resource to Provide TMNSR and TMOR

Markets Committee Members and Alternates
July 30, 2014
Page 15 of 35

To provide reserves from an undischarged state, a Demand Response Resource must offer in a manner that is consistent with a Fast Start Demand Response Resource as defined above. While the reserve designation will never exceed the Offered CLAIM10/30 of the Demand Response Resource, it can be less. The designation will be limited in each hour by the lower of the adjusted Demand Response Baseline plus the Net Supply Limit, or CLAIM10/30 value established by audit and adjusted for actual performance in response to dispatch. For a Demand Response Resource that has been dispatched, the amount of reserves that can be designated is reduced by the amount of energy the resource has been dispatched to provide. These proposed rules are comparable with the rules that designate Generator Assets for Operating Reserves.

The sections of the Tariff that were modified to allow Demand Response Resources to be designated to provide TMNSR and TMOR include:

- Section I.2.2;
- Sections III.1.7.19, III.1.7.19A;
- Section III.9.2.2, III.9.6.4; and
- Section III.10.1.1.

e) Telemetry Requirement for Demand Response Resources Providing 10-Minute Reserves

The ISO proposes that any Demand Response Resource claiming 10-minute Operating Reserve capability be required to provide at least one-minute interval data in Real-Time for each Demand Response Asset associated with the Demand Response Resource. Market Participants with Demand Response Resources are also allowed to provide telemetry data at a faster rate.¹⁷ At the present time, all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources provide five-minute interval data in Real-Time. While five-minute data appears to be sufficient for the provision of energy and 30-minute reserves, five-minute interval data does not provide adequate information in a timely manner from which to determine the real-time performance and capability of the Demand Response Resource in providing 10-minute reserve. At the time of a reportable event, the ISO has 15 minutes from the start of that event to recover area control error (“ACE”) and avoid a NERC violation. Given this time constraint, system operators must know as soon as possible if resources providing ten-minute reserves have responded to a Dispatch Instruction when activated. If a resource does not deliver the dispatched amount of energy within 10 minutes, operations must determine whether it is necessary to dispatch another resource to recover ACE and avoid a NERC violation.

To illustrate the inadequacy of five-minute data to monitor the response of a resource providing 10-minute reserves, assume that five-minute data is reported to the ISO every five minutes (at the top of a clock hour and every five minutes thereafter) and a reportable event happens at 14:02 resulting in the dispatch of a resource providing 10-minute reserves. The figure below illustrates what happens:

¹⁷ Generator Assets and Dispatchable Asset Related Demands are required to provide data at 10-second intervals, and those resources providing Regulation and Frequency Response Service must provide data at 4-second intervals.

After the resource was dispatched, five-minute interval data is reported to the ISO at 14:05 and 14:10. However, the data submitted at 14:05 shows the status of the resource at 14:00 because of the five-minute lag or latency between the end of the interval and the retrieval and transmission of the telemetry data. In this example, therefore, a Resource providing 10-minute reserves and reporting only five-minute data will be measured based on a single five-minute interval submitted at 14:10 – but this data reflects performance of the Resource at 14:05, which is only three minutes into the event. This is unlikely to reflect the actual performance of the Resource at the end of ten minutes.

One-minute real-time telemetry would provide adequate information to the System Operator to measure the real-time performance of a DRR within ten minutes of dispatch. To maximize Market Participant flexibility, the one-minute data reported to the ISO can be measured in the form of MWh consumed during a one-minute interval, multiplied by 60 to convert that value to MW, or an instantaneous power reading each minute in the form of MW. Each Demand Response Asset associated with a Demand Response Resource providing ten-minute reserve must report one-minute real-time telemetry.

The one-minute interval data will be used to monitor 10-minute resources in real-time and to determine performance in establishing CLAIM10 and CLAIM30 values, but will not be used to compute the Demand Response Baseline or to compute settlement. Rather, the five-minute telemetry data and five-minute revenue quality meter data will continue to be used to compute the Demand Response Baselines and to compute settlement. Telemetry requirements for Demand Response Resources are specified in Tariff Section III.E2.2.1.

4) Changing the Demand Response Baseline Adjustment Factor

a) The Need for a Better Short-Term Forecast of DRR Consumption

In order to dispatch energy and designate reserves optimally and simultaneously, the ISO must be able to determine a resource's availability to provide energy and reserves, and to quantify a resource's

performance if dispatched. In addition to real-time telemetry and energy offer parameters, an estimate of expected consumption, absent a Dispatch Instruction to reduce consumption, is needed to determine the real-time capability of a Demand Response Resource to provide energy and reserves, and to quantify the Demand Response Resource's response to a Dispatch Instruction. The Demand Response Baseline is the level at which the Demand Response Resource is expected to consume energy during the Operating Day when not being dispatched by the ISO to reduce consumption. For the period during which Demand Response Resources are fully integrated into the energy and reserve markets, the Demand Response Baseline is calculated using the methodology specified in Section III.8B of the Tariff. That methodology provides an estimate of the expected energy consumption of a Demand Response Resource by simulating a rolling ten-day average of meter data from previous days on which the Demand Response Resource was not dispatched. The resulting Demand Response Baseline is an estimated consumption forecast for a Demand Response Resource.

The actual consumption of the Demand Response Resource on any given day, however, may vary significantly from the estimated consumption forecast. For example, the weather on a given Operating Day may be more extreme relative to the weather on previous days from which meter data were used to compute the consumption forecast. For this reason, based on the actual consumption in a day, an adjustment is added to the estimated consumption to better reflect the behavior of the resource during the Operating Day. The current Demand Response Baseline methodology updates the baseline only once a day, after the Operating Day is over. A baseline adjustment that is calculated and applied after the Operating Day is over does not facilitate the determination of a Demand Response Resource's availability and performance in real-time. That is, the baseline available during the day, which is unadjusted, does not account for real-time conditions, which may cause a Demand Response Resource's actual consumption to vary significantly from its baseline value. As a result, the calculated availability of the Demand Response Resource to provide reserves and/or the calculated real-time performance of the Demand Response Resource if dispatched to provide energy could be significantly over- or under-estimated. For this reason, a mechanism is needed to adjust the baseline in real time to provide a value that is meaningful in the calculation of a Demand Response Resource's real-time capability and performance.

b) The Concept for a Real-Time Baseline Adjustment

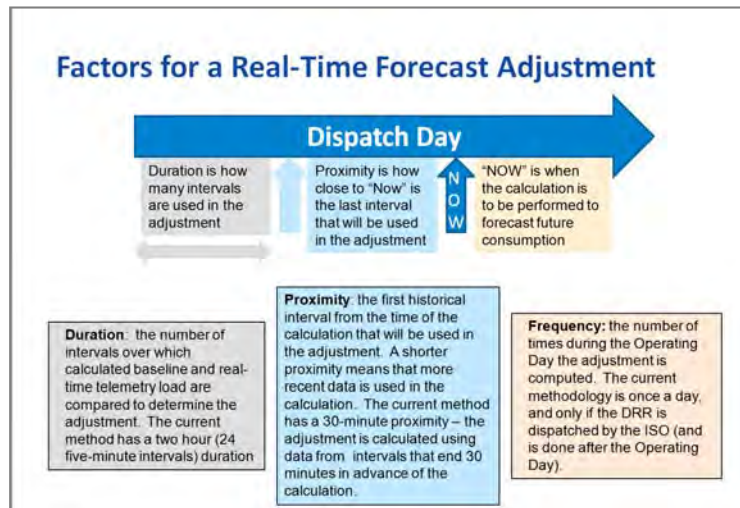
To forecast a Demand Response Resource's ability to provide reserves in real time and to determine its real-time performance in response to a Dispatch Instruction, its consumption will be forecasted using historical interval meter data and adjusted throughout the Operating Day using 5-minute real-time telemetry data. The initial estimated consumption forecast will be computed using the method presently in Section III.8B.

Rather than updating the baseline once a day, after the Operating Day is over, real-time telemetry data received during the Operating Day will be used to adjust the consumption forecast at various points throughout the Operating Day. The adjustment procedure will be performed frequently and will be based on telemetry data from recent historical intervals.

Markets Committee Members and Alternates
July 30, 2014
Page 18 of 35

c) Research Conducted and Approach Recommended

ISO New England engaged DNV GL to assist in analyzing accuracy of the resulting adjusted forecasts using different methods to determine the baseline adjustment. The figure below illustrates the factors considered in the analysis.



DNV GL analyzed the accuracy of different adjustment methods based on different combinations of proximities and durations:¹⁸

- Proximities of 3 to 7 intervals
- Duration of 3 to 24 intervals

Adjusted forecasts were analyzed for each day type (non-holiday weekdays, Saturdays, and Sunday/Holidays). The calculated adjustment is added to the forecast (which could increase or decrease the forecast) in future intervals to provide an estimate of expected consumption. Notification, startup and interruption intervals are excluded from the calculation. During these intervals, the most recent adjustment, calculated prior to the notification period, is added to the forecast. Following the end of an interruption, the scheduled adjustment recalculations resume.

Generally, the results of the DNV GL analysis showed real-time adjustments perform better than the current ISO adjustment when proximity is closer, duration is shorter, and the adjustment is recalculated frequently throughout the Operating Day rather than only once a day. In addition to the results of the DNV GL analysis, the ISO considered data latency, calculation time, and how quickly information must be available to provide adequate situational awareness when assessing adjustment mechanisms.

Based on these considerations, the ISO proposes to use a real-time forecast adjustment with a proximity of 3 intervals, a duration of 3 intervals, which is scheduled to be calculated and applied at a

¹⁸ This analysis also included the current baseline adjustment method, which is composed of a proximity of 7 intervals and a duration of 24 intervals.

Markets Committee Members and Alternates
July 30, 2014
Page 19 of 35

frequency of every 15 minutes.¹⁹ The adjustment factor is calculated with real-time telemetry data in real-time and, for settlement purposes, the adjustment is similarly calculated using revenue quality metering data.

d) Tariff Changes Implementing the Recommended Baseline Adjustment Approach

Section III.8B.5, Baseline Adjustment, specifies the baseline adjustment mechanism and its application. This section was modified to implement the above-mentioned recommendations.

The baseline adjustment factor will be calculated using five-minute interval-meter data from the three intervals that start 25 minutes before, and end 10 minutes before, the quarter hour interval when the adjustment calculation is performed. The adjustment factor is calculated with real-time telemetry data in Real-Time and is calculated with revenue quality metering data for settlement purposes. Further, the adjustment factor is updated approximately every quarter hour when the resource with which the asset is associated is not responding to a Dispatch Instruction.

During a response to a Dispatch Instruction, the adjustment factor is calculated using five-minute interval-meter data from the three intervals that start 25 minutes before, and end 10 minutes before, the Dispatch Instruction was issued. Following the end of a dispatch, the adjustment factor for an asset will continue to be calculated using five-minute interval-meter data from the three intervals that start 25 minutes before, and end 10 minutes before, the Dispatch Instruction was issued, until sufficient time has elapsed to calculate the adjustment using post-dispatch meter data.

5. Integrating Demand Response Resources Into the Forward Reserve Market

a) General Approach

The ISO proposes that eligible Demand Response Resources be able to participate in the Forward Reserve Market (“FRM”) and receive compensation for such participation. It is important to note that no changes to the basic design of the FRM are proposed. Most of the rule changes described herein integrate a new class of resource – i.e., Demand Response Resources – into the FRM. To enable Demand Response Resources to participate in the FRM, the market rules must be modified to:

- Specify the requirements that a Demand Response Resource must fulfill to be eligible for assignment to meet Forward Reserve Obligations,
- Establish how Demand Response Resources will be compensated for participation in the FRM, and
- Define CLAIM10 and CLAIM30 auditing rules for Demand Response Resources.

Generally, Section III.9 of the Tariff must be modified to:

¹⁹ The adjustment calculation will not be performed during notification, startup and interruption intervals and data from such intervals will not be included in the adjustment calculation. This is because Demand Response Asset consumption will likely be changing in response to Dispatch Instructions during such periods.

- Include Demand Reduction Offer parameters where Supply Offer parameters or Demand Bid parameters are referenced;
- Include Demand Reduction Offer data (adjusted for re-declarations) where Supply Offer or Demand Bid data are used in the determination of a Demand Response Resource's Forward Reserve Qualifying MWs ("FRQM");
- Specify the requirements and compensation calculations for Demand Response Resources in equivalent states to off-line and on-line generators;
- Include Fast Start Demand Response Resources, as previously defined; and

Telemetry and revenue quality meter data requirements for Demand Response Resources providing reserves are addressed in Section III.E2.2.

b) Eligibility Requirements for a Demand Response Resource to Meet Forward Reserve Obligations

Eligibility requirements for Forward Reserve Resources are specified in **Section III.9.5.2, Forward Reserve Resource Eligibility Requirements**. Some of these requirements are based on the resource's state (e.g., off-line or on-line) and resource type [e.g., a Fast Start Generator or a Dispatchable Asset Related Demand ("DARD")]. A Demand Response Resource has equivalent states to off-line and on-line generators:

- Demand Response Resources that have not been dispatched being equivalent to off-line generators, and
- Demand Response Resources that have been dispatched being equivalent to on-line generators.

Similar to a Fast Start Generator, a Fast Start Demand Response Resource may be eligible to be a Forward Reserve Resource.

In order to define eligibility requirements for Demand Response Resources, Section III.9.5.2 was modified to:

- Include Demand Response Resources which have not been dispatched where off-line Resources are referenced,
- Include Demand Response Resources which have been dispatched (i.e., have received a Dispatch Instruction) where on-line Resources are referenced,
- Include Fast Start Demand Response Resources which have not been dispatched where off-line Fast Start Generators are referenced, and
- Include Demand Response Resources in references to Resources without a Capacity Supply Obligation.

Additionally, the requirement in III.9.5.2 (viii) states, "[t]he portion of the Resource without a Capacity Supply Obligation to which a Forward Reserve Obligation has been assigned must be

offered into the Real-Time Energy Market in accordance with the provisions of III.13.6.1.1.2.” Section III.13.6.1.1.2, Requirement that Offers Reflect Accurate Generating Capacity Resource Operating Characteristics, is specific to generating resources. Therefore, Section III.9.5.2 (viii) was modified to clarify that Demand Response Resources without a Capacity Supply Obligation must be offered into the Real-Time Market in accordance with Section III.13.6.1.5.2, Requirement that Offers Reflect Accurate Demand Response Capacity Resource Operating Characteristics. In order to comply with this requirement, the Demand Reduction Offer of a Demand Response Resource to which a Forward Reserve Obligation has been assigned must be re-declared to reflect any changes to the offer parameters that occur in real time.

c) Measuring and Compensating Demand Response Resource Performance in the FRM

The ISO proposed to treat a Demand Response Resource like other resources for purposes of determining compensation for participation in the FRM. This means that Market Participants with Demand Response Resources assigned to meet Forward Reserve Obligations will:

- Be paid at the same rate,
- Be assessed comparable charges for non-performance, and
- Forego any Real-Time Reserve payment for MWs compensated as Forward Reserve.

Unlike other Forward Reserve Resources whose performance is either measured as output or consumption, a Demand Response Resource may provide performance in the form of a reduction in load as measured at the Retail Delivery Points of its constituent Demand Response Assets, an injection of energy to the grid (i.e., Net Supply), or a combination of the two. The portion of a Demand Response Resource’s performance that is not associated with Net Supply will be multiplied by one plus the average avoided peak distribution losses. For this reason, the measurement and compensation of a Demand Response Resource in the FRM must distinguish between performance that results from a reduction in load and performance that results from Net Supply. The adjustment for avoided peak distribution losses is included in the Tariff changes described below.

d) Delivery of Forward Reserve

Section III.9.6, Delivery of Reserve, includes rules related to:

- The dispatch and energy bidding of Forward Reserve Resources,
- The formula for determining the Forward Reserve Threshold Price (“FRTTP”),
- The monitoring of Forward Reserve Resources, and
- The calculation of on-line/off-line Forward Reserve Qualifying Megawatts and on-line/off-line Forward Reserve Delivered Megawatts.

Section III.9.6.1, Dispatch and Energy Bidding of Reserve, references Supply Offers and Demand Bids. These terms do not reflect the energy offer for a Demand Response Resource, i.e., the Demand Reduction Offer. Accordingly, this section was changed to include the Demand Reduction Offer of a Demand Response Resource as follows:

- Demand Reduction Offers, at or above the F RTP must be submitted by the close of the Re-Offer Period,
- Day-Ahead Demand Reduction Offers for Demand Response Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market whether or not such offers clear the Day-Ahead Energy Market, and
- A Market Participant is not required to submit a Demand Reduction Offer into the Day-Ahead Energy Market for a Demand Response Resource not associated with a Demand Response Capacity Resource or associated with a Demand Response Capacity Resource without a Capacity Supply Obligation in order for the Demand Response Resource to be eligible to be a Forward Reserve Resource.

No change is required to **Section III.9.6.2, Forward Reserve Threshold Prices** since the formula for the F RTP is not impacted by the addition of Demand Response Resources into the FRM.

Section III.9.6.3, Monitoring of Forward Reserve Resources, does not require any change in order to allow Demand Response Resources to provide Forward Reserves. A reference to Section III.A.9.4 was corrected to Section III.A.13.4. This change is unrelated to the inclusion of Demand Response Resources as Forward Reserve Resources.

Section III.9.6.4, Forward Reserve Qualifying Megawatts, details the calculation of Forward Reserve Qualifying MWs (“FRQM”) for off-line and on-line generators, and DARDs. The FRQM calculation relies on parameters in a resource’s Supply Offer or Demand Bid. In order to calculate FRQM for a Demand Response Resource, this section was changed to:

- Include Demand Reduction Offer parameters where Supply Offer parameters or Demand Bid parameters are referenced;
- Include Demand Reduction Offer data (adjusted for re-declarations) where Supply Offer or Demand Bid data are used to determine a Demand Response Resource’s FRQM, such as:
 - o Interruption Cost,
 - o Energy Offer,
 - o Maximum Reduction, and
 - o Minimum Reduction;
- Specify the calculation of FRQM for a Fast Start Demand Response Resource, which has not been dispatched:
 - o The F RTP will be compared to the Demand Response Resource’s offer price, which includes both the Demand Response Resource’s energy offer price and the pro-rated Interruption Cost.²⁰ FRQM are the amount of MWs, less than or equal to the offered Maximum Reduction, offered at a price which is at or above the F RTP;

²⁰ The pro-rated Interruption Cost = Interruption Cost/Maximum Reduction. The pro-rated Interruption cost is calculated for each hour.

Markets Committee Members and Alternates
July 30, 2014
Page 23 of 35

- Specify the calculation of FRQM for a Demand Response Resource which has been dispatched:
 - The FRTP will be compared to the Demand Response Resource's energy offer price. FRQM are the amount of MWs, less than or equal to the offered Maximum Reduction and greater than the Minimum Reduction, offered at a price which is at or above the FRTP.

Section III.9.6.5, Delivery Accounting, describes the calculation of Forward Reserve Delivered MWs ("FRDM") of a Forward Reserve Resource for each hour of the Real-Time Energy Market for each Reserve Zone. FRDM for each Demand Response Resource will be calculated by taking into account the Demand Response Resource's FRQM, Demand Reduction Offer parameters, and any re-declarations. FRDM for a Demand Response Resource which has not been dispatched are calculated as the minimum of:

- The amount of Forward Reserve that the undischarged Demand Response Resource can provide, based upon CLAIM10 and CLAIM30 values provided in the Demand Response Resource's Demand Reduction Offer,
- Forward Reserve Assigned Megawatts, or
- FRQM for the Demand Response Resource.

FRDM for a Demand Response Resource which has been dispatched are calculated as the minimum of:

- 10 or 30 times the Demand Response Resource Ramp Rate,
- Forward Reserve Assigned Megawatts, or
- FRQM for the Demand Response Resource.

At the time of settlement it must be determined what portion of the FRDM for a Demand Response Resource was not associated with Net Supply during the Operating Day. FRDM which are not associated with Net Supply will be multiplied by one plus the average avoided peak distribution losses. To determine FRDM not associated with Net Supply:

- It is assumed, as previously explained, that a Demand Response Resource must first reduce its load from the electricity system up to the difference between the its Maximum Reduction and its Net Supply Limit before providing Net Supply,
- The portion of the FRDM not associated with Net Supply is the lesser of:
 - Forward Reserve Delivered Megawatts, or
 - The amount of load that the Demand Response Resource can reduce from the electric system as indicated from revenue quality meter data; and
- Any remaining FRDM in excess of the portion not associated with Net Supply will be capped at the Net Supply Limit.

For all Resources, FRDM for TMNSR within a Reserve Zone will be applied first to a Market Participant's higher value Forward Reserve Obligation for TMNSR in the Reserve Zone. Any surplus FRDM for TMNSR in that Reserve Zone will be applied to meet the Market Participant's Forward Reserve Obligation for TMOR in the Reserve Zone. FRDM remaining within a Reserve Zone after the Market Participant's Forward Reserve Obligation for that Reserve Zone has been met is available to be applied to the Market Participant's Forward Reserve Obligations in other Reserve Zones provided the FRDM can be delivered to the other Reserve Zones.

e) Consequences for Failing to Deliver Forward Reserve

Section III.9.7, Consequences of Delivery Failure, specifies when Market Participants with Forward Reserve Obligations are assessed penalties. There are two types of penalties associated with delivery failure:

- A Failure-to-Reserve Penalty is assessed when the Market Participant fails to assign enough qualified resources to meet the reserve quantity it cleared in the FRM auction, and
- A Failure-to-Activate Penalty is assessed when any assigned resources fail to provide energy when activated.

Section III.9.7.1, Real-Time Failure-to-Reserve, specifies how the Failure-to-Reserve Penalty is calculated for a participant based on the total quantity of the Forward Reserve delivered in real time by the assigned Resources. This calculation is a resource level calculation and is not impacted by resource type. No changes are required to this section of the Tariff.

Section III.9.7.2, Failure-to-Activate Penalties, addresses the second penalty which is calculated at the resource level. The Failure-to-Activate Penalty is assessed when a Resource that has been assigned to provide reserves fails to "activate" its Forward Reserve capability when requested to do so by the ISO during a contingency. Forward Reserve capability is activated when a Forward Reserve Resource is dispatched by the ISO to convert reserve capability into energy.

Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource, for each hour is the lesser of the following values:

- Maximum of FRDM for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero; or
- Maximum of Target Activation Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero.

Target Activation Megawatts for TMNSR for a Demand Response Resource are calculated as follows:

- Target Activation Megawatts for a Demand Response Resource which has not been dispatched will be determined as the lesser of:

Markets Committee Members and Alternates
July 30, 2014
Page 25 of 35

- o The minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period, or the Resource's Minimum Reduction, whichever is greater,
 - o The Resource's CLAIM10, or
 - o The Resource's Offered CLAIM10.
- Target Activation Megawatts for a Demand Response Resource which has been dispatched will be determined as the lesser of:
 - o The Demand Response Resource Ramp Rate times 10 minutes,
 - o The Demand Response Resource's Maximum Reduction minus the Demand Response Resource's initial demand reduction at activation, or
 - o The minimum electronic Desired Dispatch Point sent to the Demand Response Resource during the 10 minute period minus the Demand Response Resource's initial demand reduction at activation.

Forward Reserve Failure-to-Activate Megawatts for TMOR for a Resource, for each hour is the lesser of the following values:

- Maximum of FRDM for TMOR plus FRDM for TMNSR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero; or
- Maximum of Target Activation Megawatts for TMOR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero.

Target Activation Megawatts for TMOR for a Demand Response Resource are calculated as follows:

- Target Activation Megawatts for a Demand Response Resource which has not been dispatched will be determined as the lesser of:
 - o The minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period, or the Resource's Minimum Reduction, whichever is greater,
 - o The Resource's CLAIM30, or
 - o The Resource's Offered CLAIM30.
- Target Activation Megawatts for a Demand Response Resource which has been dispatched will be determined as the lesser of:
 - o The Demand Response Resource Ramp Rate times 30 minutes,
 - o The Demand Response Resource's Maximum Reduction minus the Demand Response Resource's initial demand reduction at activation, or
 - o The minimum electronic Desired Dispatch Point sent to the Demand Response Resource during the 30 minute period minus the Demand Response Resource's initial demand reduction at activation.

Markets Committee Members and Alternates
July 30, 2014
Page 26 of 35

Using the Forward Reserve Payment Rate (“FRPR”), the penalty for failing to activate when dispatched, for all resource types, is calculated as:

$$(\text{Failure-To-Activate MWs}) * (\text{FRPR} + \text{MAX} (2.25 \times \text{FRPR}, \text{applicable nodal RT LMP}))$$

For each participant with FRM obligations, resource level Failure-To-Activate Penalties are summed to determine the participant’s total Failure-To-Activate Penalty.

Section III.9.7.3, Known Performance Limitations, describes the conditions under which Forward Reserve Resources may be subject to actions by the ISO in order to determine their capability to activate (convert capability to energy) Forward Reserve Assigned MWs. This section applies to any Forward Reserve Resource, regardless of resource type (generator, DARD, Demand Response Resource). No changes are required to this section of the Tariff.

Section III.9.8, Forward Reserve Credits, and **Section III.9.9 Forward Reserve Charges**, describe the calculation of Forward Reserve Credits and Forward Reserve Charges respectively. These are participant level calculations and are not impacted by resource type. No changes are required to these sections of the Tariff.

A resource paid in the FRM will have its Real-Time Reserve payment adjusted to prevent double payment for the same MW; more specifically, a resource assigned to meet a Forward Obligation gives up revenue when designated to provide Real-Time Reserves, for which prices are volatile, in exchange for fixed revenue from the FRM. Previously mentioned Tariff changes which allow the calculation of payments and charges to Market Participants with Demand Response Resources participating as Forward Reserve Resources will ensure appropriate FRM values are available for use in the determination of Real-Time Reserve payment adjustments. No changes are required to **Section III.10.4, Forward Reserve Obligation Charges**, which determines a Forward Reserve Obligation Charge such that a Market Participant will not receive double compensation for the provision of both Real-Time Operating Reserve MWs and Forward Reserve MWs.

5) Auditing Demand Response Resources in the Forward Capacity Market

In the Forward Capacity Market, a Market Participant can fulfill a Capacity Supply Obligation with a Demand Response Capacity Resource. The Demand Response Capacity Resource is composed of one or more Demand Response Resources that are located in the same Dispatch Zone. A Market Participant with a Demand Response Capacity Resource fulfills its Capacity Supply Obligation by offering an amount of Demand Response Resources into the co-optimized energy/reserve market that is at least equal to its Capacity Supply Obligation or its resources’ full physical capability if the Capacity Supply Obligation amount is not available. These Demand Response Resources are then dispatched by the ISO in accordance with each resource’s Demand Reduction Offer. The performance of a Demand Response Capacity Resource during the Shortage Event is equal to the sum of the performances of the individual Demand Response Resources associated with the Demand Response Capacity Resource.

Markets Committee Members and Alternates
July 30, 2014
Page 27 of 35

As explained previously, a Demand Response Resource is composed of Demand Response Assets located within the same Dispatch Zone and Reserve Zone. Demand Response Assets are the actual end-use customers (residential, commercial or industrial customers) that reduce energy consumption or provide Net Supply. When the ISO issues a Dispatch Instruction to a Demand Response Resource to reduce demand, the physical instruction goes to the resource's Demand Designated Entity who in turn manages the dispatch of the individual Demand Response Assets that comprises the Demand Response Resource. The performance of each Demand Response Asset during a dispatch event is calculated individually – including both load reduction measured at the Retail Delivery Point and any Net Supply – and the performance of all of the associated Demand Response Assets associated with a Demand Response Resource are summed to determine the performance of the Demand Response Resource.

In the Forward Capacity Market, audits are conducted to establish the capacity of a Demand Response Capacity Resource. These audits serve two purposes. First, the audit establishes the capability, i.e., the Demand Reduction Value, of the resource that is used in the settlement process to the extent the resource was not fully dispatched in a particular month. Second, the audit determines the refund of Financial Assurance, which must be posted by a Market Participant if it offered a New Capacity Resource that cleared an auction in the Forward Capacity Market.²¹ Audits of Demand Response Capacity Resources are conducted by individually dispatching its constituent Demand Response Resources, which participate in the energy market. These audits – known as Seasonal DR Audits – are conducted on a seasonal basis – i.e., summer and winter given that Demand Response Resources with weather-sensitive demands are likely to perform very differently between seasons.

The existing Tariff language could be interpreted to require that all of the Demand Response Resources associated with a Demand Response Capacity Resource with a Capacity Supply Obligation be audited by dispatching all Demand Response Resources simultaneously. However, such a requirement would not reflect the manner in which Demand Response Resources would likely be dispatched in practice once these resources are fully integrated into the energy and reserves markets. Firstly, each Demand Response Resource that is associated with a Demand Response Capacity Resource could have different Demand Reduction Offers, which would place each Demand Response Resource on a different part of the energy market supply curve and would likely result in such resources being dispatched in a non-coincident fashion. Secondly, since Demand Response Resources will be able to provide Operating Reserves, it is possible that during a Shortage Event some Demand Response Resources that are part of a Demand Response Capacity Resource would be dispatched to provide energy and others would be designated to provide Operating Reserve. Accordingly, Section III.13.6.1.5.4.2 of the Tariff was clarified so that Demand Response Resources associated with a Demand Response Capacity Resource would not have to be audited simultaneously.

Further, Section III.13.6.1.5.4.3.3.1 was modified to so that a Market Participant cannot use the performance of a Demand Response Resource during a Shortage Event as a Seasonal DR Audit if any

²¹ Another purpose for auditing Demand Response Resources, which was previously discussed, is to establish a CLAIM10 and/or CLAIM30 value. However, this audit is used exclusively to establish the ability of a Demand Response Resource to provide reserves from an undispached state.

Markets Committee Members and Alternates
July 30, 2014
Page 28 of 35

of the Demand Response Assets associated to the Demand Response Resource is on a forced curtailment or a scheduled curtailment. In calculating the availability score of a resource during a Shortage Event, the Demand Response Resource receives credit for the reduced demand of the Demand Response Asset that is on scheduled or forced curtailment. However, it would not be appropriate to use the performance of a Demand Response Resource with assets on a forced or a scheduled curtailment as its Seasonal DR Audit. This is because the audit's purpose is to measure the performance of the Demand Response Resource in response to dispatch when its assets are in its normal mode of consuming energy from the electric grid. Forced and scheduled curtailments are limited events that do not reflect normal consumption during the vast majority of the year. Since performance during a forced or scheduled curtailment does not accurately reflect the resource's capability in response to dispatch, it would not be appropriate to use that performance as a replacement for a Seasonal DR Audit.

Finally, Section III.13.6.1.5.4.3.3.1 was also modified to permit a Market Participant to establish the Audited Demand Reduction value of the Demand Response Resource equal to its CLAIM10 or CLAIM30 value at the time of a Shortage Event. It is possible for a Shortage Event to occur before a new Demand Response Resource was able to conduct a Seasonal DR Audit to establish an Audited Demand Reduction value. If the resource was not dispatched during the Shortage Event at a level equal to its Maximum Reduction and absent an Audited Demand Reduction value, the assessed availability of the resource during the Shortage Event may be established at a level below its true capability. However, if a CLAIM10 or CLAIM30 value were available at the time of the Shortage Event – which is possible given that the ISO typically conducts CLAIM10/30 audits within five days of the request – the modified market rule would allow the Market Participant to set the Audited Demand Reduction of the Demand Response Resource equal to its CLAIM10 or CLAIM30 value. It should be noted that the ISO would endeavor to coordinate Seasonal DR Audits and CLAIM10/30 audits so a single audit of a Demand Response Resource could be used to establish the resource's Audited Demand Reduction value as well as its CLAIM10 and/or CLAIM30 values.

The sections of the Tariff impacted by clarifying the manner in which Seasonal DR Audits of Demand Response Resources are conducted include Sections III.13.6.1.5.4.2, III.13.6.1.5.4.3.3.1, III.13.6.1.5.4.5, III.13.6.1.5.4.6, and III.13.7.1.5.10.1.1.

6) Related Market Rule Changes

a) Implementation of Recent Demand Response Baseline Changes (that became effective June 1, 2014) for the Market Rules for Full Integration

i) Scheduled and Forced Curtailments (ER14-727-000)

Recently, Section III.8A of the market rules, which governs Demand Response Baselines between now and the time Demand Response Resources are fully integrated into energy and reserve market, was changed to address the accuracy of the Demand Response Baseline during and after days on which an asset is on a scheduled curtailment (e.g., scheduled maintenance of energy consuming equipment) or forced curtailment (e.g., transmission or distribution outage) and to specify how ISO

Markets Committee Members and Alternates
July 30, 2014
Page 29 of 35

New England should be notified of such curtailments.²² The ISO proposes to incorporate the same changes into Section III.8B to be applicable for Demand Response Assets and Real-Time Emergency Generation Assets beginning June 1, 2017.

Baseline accuracy during and immediately following a forced or scheduled curtailment is achieved by requiring the Demand Designated Entity to submit, on the days of the curtailment, meter data values equal to the last unadjusted Demand Response Baseline computed prior to the curtailment instead of actual meter readings. Submitting meter data values equal to the last unadjusted baseline prior to the scheduled or forced curtailment preserves the baseline during the curtailment.

To assess the performance of Demand Response Assets or Real-Time Emergency Generation Assets that are on a forced or a scheduled curtailment, actual meter data values will be submitted by the asset's Demand Designated Entity to the ISO for intervals during which the Demand Response Resource or Real-Time Emergency Generation Resource with which the asset is associated was dispatched to reduce demand pursuant to Section III.13. Similarly, actual meter data values will be submitted to ISO New England for intervals in which a Demand Response Asset, on the first day of an unanticipated forced curtailment, is associated with a Demand Response Resource dispatched in Real-Time pursuant to Section III.E2. The difference between the asset's Demand Response Baseline, which will be equal to the unadjusted baseline calculated for the first day of the forced or scheduled curtailment as described previously, and the asset's actual metered load during the period of dispatch will be used to assess the performance of the asset.

To implement these changes beginning June 1, 2017, **Section III.8B.6.1, Notification of Forced and Scheduled Curtailments**, was modified to include the definition of and parameters for forced and scheduled curtailments. A Market Participant, with a Demand Response Asset or a Real-Time Emergency Generation Asset may notify ISO New England of a forced or scheduled curtailment. A Market Participant may notify the ISO of a scheduled curtailment at least seven calendar days before the start of any reductions. For Demand Response Assets or Real-Time Emergency Generation Assets with a Maximum Interruptible Capacity and/or Maximum Net Supply of five MW or more, notification of a scheduled curtailment must be provided at least 15 calendar days before the start of the curtailment. The length of a scheduled curtailment must be a minimum of a single calendar day and may not exceed a total of 14 calendar days per Capacity Commitment Period.

Further, **Section III.8B.6.2, Submitting Meter Data Values for Days with Forced or Scheduled Curtailments**, was modified to specify the meter data submission requirements for each calendar day on which a Demand Response Asset or a Real-Time Emergency Generation Asset is on a forced or scheduled curtailment. For such days, the Demand Designated Entity of the Demand Response Asset or Real-Time Emergency Generation Asset will submit to the ISO meter data values equal to the

²² *ISO New England Inc. and New England Power Pool, Demand Response Baseline Changes*, Docket No. ER14-727-000, (December 20, 2013); http://www.iso-ne.com/regulatory/ferc/filings/2013/dec/er14-727-000_drbaseline_chg_12-20-2013.pdf

Markets Committee Members and Alternates
July 30, 2014
Page 30 of 35

unadjusted baseline calculated for the first day of the forced or scheduled curtailment for all intervals excluding those intervals in which:

- The Demand Response Resource with which the Demand Response Asset is associated was dispatched during the period of a Shortage Event as defined in Section III.13.7,
- The Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or
- The Real-Time Emergency Generation Resource, with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

Finally, **Section III.8B.6.3, Performance Assessment for Days with Forced or Scheduled Curtailments**, was modified to specify how performance is assessed for Demand Response Assets and Real-Time Emergency Generation Assets that are on a forced or scheduled curtailment. Actual meter data values shall be submitted to the ISO for intervals during which:

- The Demand Response Resource with which the Demand Response Asset is associated was dispatched during a Shortage Event as defined in Section III.13,
- The Demand Response Resource with which the Demand Response Asset is associated was dispatched in Real-Time pursuant to Section III.E2 on the first day of an unanticipated forced curtailment, or
- The Real-Time Emergency Generation Resource, with which the Real-Time Emergency Generation Asset is associated, was dispatched to reduce demand pursuant to Section III.13.

ii) Constraints on the Adjusted Baseline for Net Supply (ER14-1659-000)

Recently, Section III.8A of the market rules was modified to place constraints on the adjusted Demand Response Baseline for assets capable of providing Net Supply.²³ Prior to this change, the floor on the adjusted Demand Response Baseline was zero MW. The majority of demand response assets are not capable of producing Net Supply because they do not have behind-the-meter generation, or because they do not have an interconnection that supports energy injections into the grid. For such assets, the zero MW floor on the adjusted Demand Response Baseline recognizes that these assets are physically incapable of providing Net Supply. However, a zero MW floor on the adjusted Demand Response Baseline of assets capable of Net Supply could result in an over-estimated baseline, and consequently an over-payment. That is, if an asset is capable of Net Supply, but its adjusted Demand Response Baseline is not allowed to go below zero MW, the resulting baseline could overestimate the asset's normal consumption/production activities and consequently overestimate any demand reductions provided in response to Dispatch Instructions.

²³ *ISO New England Inc. and New England Power Pool, Demand Response Baseline Net Supply Changes*, Docket No. ER14-1659-000 (April 4, 2014); http://www.iso-ne.com/regulatory/ferc/filings/2014/apr/er14-1659-000_dr_base_net_sup_chges.pdf

Markets Committee Members and Alternates
July 30, 2014
Page 31 of 35

The issue was addressed by revising market rule language Section III.8A so that the zero MW floor on adjusted Demand Response Baselines only applies to assets that are not capable of providing Net Supply. A new provision was added to Section III.8A to address assets that are capable of providing Net Supply. For these assets, the floor on the adjusted Demand Response Baseline is based on the maximum Net Supply that the asset can push back into the grid, which is defined by the asset's generator interconnection agreement.

The ISO proposes that the same changes be incorporated into Section III.8B, which would be applicable to Demand Response Assets beginning June 1, 2017. Accordingly, **Section III.8B.5(d), Baseline Adjustment**, which specifies the constraints on the adjusted Demand Response Baseline was modified so that:

- For Demand Response Assets that cannot produce Net Supply, the adjusted Demand Response Baseline may not be less than zero, and
- For Demand Response Assets that can produce Net Supply, the adjusted Demand Response Baseline may not be less than the maximum amount in MW that the asset is allowed to push back into the electric system per the applicable generator interconnection agreement, and shall not exceed the asset's Maximum Facility Load.

b) Clarify Metering Requirements for Behind-the-Meter Generators

Under the present Tariff, Real-Time Demand Response Assets may consist of a controllable facility load measured at the Retail Delivery Point of the asset, and may consist of directly-metered Distributed Generation located behind the Retail Delivery Point.²⁴ Accordingly, some complex facilities may have several Real-Time Demand Response Assets located at or behind the same Retail Delivery Point. Accommodating multiple Real-Time Demand Response Assets at the same facility caused the ISO to develop and administer complex metering schemes to ensure that energy generated by a Real-Time Demand Response Asset consisting of directly-metered Distributed Generation was not also being credited to another Real-Time Demand Response Asset located at the Retail Delivery Point.

Many of these issues are resolved when Demand Response Resources are fully integrated into the energy and reserve markets given that all Demand Response Assets must be measured at the Retail Delivery Point. Under full integration, therefore, behind-the-meter Demand Response Assets will not be permitted, and there can be only one Demand Response Asset per Retail Delivery Point. Such a change was reasonable because actions occurring behind the Retail Delivery Point of a Demand Response Asset may have no impact on the electric grid and thus cannot affect the balance of supply

²⁴ For Capacity Commitment Periods commencing before June 1, 2017 – i.e., prior to full integration – Section III.13.1.4.3.2 was clarified to require that the output of generators comprising a Real-Time Demand Response Asset located behind the retail delivery point must be directly metered and reported to the ISO in Real-Time as a single set of interval meter data at an interval of five-minutes or less.

Markets Committee Members and Alternates
July 30, 2014
Page 32 of 35

and demand on the wholesale market.²⁵ Actions of a Demand Response Asset are felt on the electric grid only at the point where that asset is connected to the grid – i.e., at the Retail Delivery Point.

While the market rules will no longer allow a behind-the-meter generator to be registered as a Demand Response Asset, the market rules continue to require that such generators report 5-minute interval meter data to the ISO in Real-Time.²⁶ The purpose of this requirement is to monitor behind-the-meter generation production to ensure that the Demand Response Asset's adjusted Demand Response Baseline, measured at the Retail Delivery Point, is not being manipulated. For example, if a Demand Response Asset with a behind-the-meter generator is scheduled to reduce demand at a specific time, it may reduce generation production just prior to the scheduled dispatch. As discussed previously, the load of an asset 15 minutes (i.e., three, five-minute intervals) prior to dispatch is used to adjust the Demand Response Baseline. By reducing generation during this adjustment period, load at the Retail Delivery Point rises and the Demand Response Baseline is adjusted to this higher level. At the time of dispatch, the generator could resume normal operation, which reduces load at the Retail Delivery Point and makes it appear that it had met its Dispatch Instruction. Without meter data on the operation of such behind-the-meter generation, we would be unable to establish the pattern of normal generation operations so as to verify that generation production was manipulated in Real-Time to produce this outcome.²⁷

Meanwhile, the electric grid is presently witnessing a proliferation of behind-the-meter generation, particularly renewable energy resources such as solar panels at residential, commercial and industrial facilities. As currently written, a Demand Response Asset with a solar panel generating energy behind-the-meter would be required to install five-minute metering on that panel. Not only would the additional expense be likely to discourage the customer from participating in the market as a Demand Response Asset, the requirement appears to be unnecessary for monitoring potential Demand Response Baseline manipulation. To manipulate the Demand Response Baseline as discussed above, the behind-the-meter generator's output must be reduced during the baseline adjustment period. Only those generators whose output can be controlled – i.e., decreased or increased regardless of the facility load – that can affect the adjustment of the Demand Response Baseline. Other generators whose output cannot be controlled – e.g., intermittent resources such as solar or wind, or resources whose electrical output is directly proportional to the energy consumption of the facility – cannot manipulate

²⁵ For example, a behind-the-meter generator that increases production will have no impact on the electric grid if the load at the same facility also increases by the same amount, and vice versa.

²⁶ The only exception to this rule is found in Section III.13.1.4.3.2. This section was clarified to require that Real-Time Emergency Generation Assets must be directly metered and reported to the ISO as a single set of interval meter data – because Real-Time Emergency Generation Assets may be located at a facility with a Demand Response Asset, the emergency generator must be metered directly to establish its performance. However, if there is no other Real-Time Emergency Generation Asset, Real-Time Demand Response Asset or other generator whose output can be controlled at the same facility, this provision allows the Market Participant to instead meter the Real-Time Emergency Generation Asset at the Retail Delivery Point. Meter data associated with the Real-Time Emergency Generation Asset must be recorded and reported by the Market Participant to the ISO in Real-Time at an interval of five minutes or less.

²⁷ It is inadequate to rely on only meter data from the Retail Delivery Point for this purpose. For example, Retail Delivery Point data may reveal an unusual increase in load before a scheduled dispatch, which increases the Demand Response Baseline. However, such an increase could be the result of a legitimate strategy to meet a Dispatch Instruction – e.g., an asset engaged in a pre-cooling or other energy storage strategy.

Markets Committee Members and Alternates
July 30, 2014
Page 33 of 35

the Demand Response Baseline as described above. Further, many customers have emergency generators whose output can be controlled, but that cannot operate synchronized to the grid – i.e., in order to operate the emergency generator, most facilities must also disconnect the load of the facility from the grid (which reduces the load at the Retail Delivery Point to zero MW).

Accordingly, the market rules proposed by the ISO modified the metering requirement for Demand Response Assets with behind-the-meter generation. Rather than requiring that all behind-the-meter generators be metered, the ISO proposes market rule changes that require only those with controllable output, with the exception of emergency generators that cannot operate synchronized to the grid, be metered. Market Participants would report a single set of generator output data to the ISO in Real-Time as an interval of five minutes or less.²⁸ Because the proliferation of behind-the-meter generation – in the form of solar photovoltaics – is presently occurring, the ISO made similar modifications to the current metering rules for Real-Time Demand Response Assets – see Sections III.E1.2.1, III.E1.2.4.

The ISO further clarified its Demand Response Asset metering requirements in Section III.E2.2. In the energy and reserves market, an important distinction is made between telemetry data and revenue quality meter data. Telemetry data is used to monitor the Real-Time status of a Resource – given the importance of the speed by which these data are collected and submitted to the ISO, data quality may be sacrificed. On the other hand, revenue quality meter data is used for settlement – given the importance of data accuracy for settlement, speed is sacrificed (i.e., revenue quality meter data are submitted days after Real-Time and are subject to further corrections in resettlement. Once Demand Response Resources are integrated along with all other Resources participating in the energy and reserves market, the telemetry and metering requirements of Demand Response Resources ought to be comparable to those of other resources.

While the accuracy standard of telemetry data from Demand Response Assets and Resources will continue to be of $\pm 2.0\%$, the market rules for Demand Response Resources were modified to require that all revenue quality meter data meet an accuracy standard of $\pm 0.5\%$.²⁹ Since most Market Participants with Real-Time Demand Response Assets measured from the Retail Delivery Point use the local distribution company meter as the basis for settlement data, and since these meters are revenue quality meters, we believe that increasing the accuracy standard for Demand Response Resources to be comparable to that of other Resources does not pose an unreasonable barrier to market participation.

By differentiating telemetry from revenue quality metering, meter testing and the auditing of meter testing and calibration records have been revised to cover both types of metering. The changed metering requirements are found in Sections III.13.1.4.3.2, III.E1.2.1, III.E1.2.4, III.E2.2.1, III.E2.2.2, and III.E2.2.3.

6) Other Minor Rule Changes

²⁸ The current market rule requires Market Participants to report to the ISO a single set of generator output data in Real-Time at an interval of five minutes or less.

²⁹ The current market rules allow metering with an accuracy of $\pm 2.0\%$ to be used in the settlement process.

Markets Committee Members and Alternates
July 30, 2014
Page 34 of 35

During our comprehensive review of the Tariff to include rule changes that would allow Demand Response Resources to provide Operating Reserves, several non-substantive issues were found that the ISO proposes to correct at this time. These include:

- In Section III.13.1.4.1.1, reference is made to obsolete demand response programs and to an obsolete version of Section III.E – i.e., “... Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1.” The ISO proposes to eliminate this obsolete language.
- Several minor typographical errors were identified and are being corrected. For example, the defined term “Dispatch Instruction” is sometimes modified by the words “ISO issued” or “ISO”. Dispatch Instruction is a defined term in the Tariff, which means directions given by the ISO to Market Participants. Accordingly, the ISO proposes to delete these descriptors wherever found – see Sections III.1.7.7, III.1.7.8, III.1.7.17, and III.1.10.1A.
- At the end of Section III.1.5.2, a number was missing from the last line of the numbered list.
- Because the current Tariff in Sections III.E2.3 and III.E2.4 do not allow Demand Response Resources to Self-Schedule demand reductions, Section III.1.7.8 was clarified to apply this limitation to the procedures that affect Self-Scheduling of Resources.
- Section III.2.4(b)(iii) was modified to make clear that a generating resource operating “at or” above its economic minimum is eligible to set price.
- Section III.2.4(c) was clarified so that the ten percent tolerance range for a generator to be considered following Dispatch Instructions is above “or below” the Desired Dispatch Point. Section III.2.4(d), which applies to Dispatchable Asset Related Demand Resources, was similarly modified. Section III.2.4(e) was added to apply the plus or minus ten percent tolerance range to be considered following Dispatch Instructions to Demand Response Resources.
- Section III.3.2.7 was modified to include Section III.E2 as the source for the charges and credits associated with Demand Response Resources.
- In Section III.8A.4.4, the word “hourly” was deleted because the maximum amount of power that a customer with a behind-the-meter generator is allowed to push back into the electric system per the applicable generator interconnection agreement is stated in MW, not in maximum hourly MW.
- In Section III.9.2.2, Dispatchable Asset Related Demand was missing in a few places where it should have been included. Therefore, Dispatchable Asset Related Demand was incorporated where appropriate.

Markets Committee Members and Alternates
July 30, 2014
Page 35 of 35

- In Section III.9.6.3, a reference to Section III.A.9.4 was corrected to Section III.A.13.4.
- In Section III.9.6.4, the Tariff was clarified by changing the word “by” to “for”, and by deleting the word “Resource” from the end of Dispatchable Asset Related Demand”.
- In Section III.9.6.5, the Tariff was clarified by adding the word “generating” after the term “off-line”; In Section III.9.6.5(c) the words “in megawatts” were deleted since the subject of the sentence is “Forward Reserve Delivered Megawatts.”
- In Section III.10.3, the Tariff was clarified by deleting the word “as” from the first sentence.
- In Section III.11, the obsolete term “load response” throughout this section was replaced with the term “Demand Resources.”
- Sections III.13.1.4.1.1, III.13.6.2.5.1, III.13.7.1.5.10.1, and III.13.7.1.5.10.2 contained typographical errors, which are being corrected. Some examples of these corrections include: replacing “from” with “for“, averge” with “average”, “theamount” with “the amount”, “reduced” with “reduced”, and “.” with a “,”.
- In Section III.13.6.2.5.1, a reference to Appendix E was clarified to reference Appendix E1.
- In Section III.E2.1.3, the word “consumption” was replaced with the more appropriate term “demand reduction capability.”
- In Section III.E2.1.5, an excess space between the words “Response” and “Capacity” was deleted, and the word “that” was corrected to “than”.
- Where appropriate, the terms “Lead Market Participant”, “Lead Market Participant or Designated Entity” were replaced with the more general term “Market Participant” in order to apply to all Resource types.

Please contact me if you have any questions regarding this memo or the proposed market rule changes.

blank

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: September 26, 2014

RE: Tangent Transition to Load Response Sub-Sector Small Group Member and NEPOOL/Participants Agreement Changes to Allow for that Transition

You will be asked at the October 3 meeting to approve for balloting amendments to the NEPOOL Agreement and Participants Agreement (“Amendments”) that will permit the transition of Tangent Energy Solutions, Inc. (“Tangent”) from a Provisional Member to a full member of the AR Sector (the “Transition”). Materials explaining the Transition and the Amendments were circulated with last week’s initial notice. Those materials have been revised to address comments we received and the revised materials are included with this memorandum.

The revisions to the earlier version of the Amendments are solely to ensure that both the AR Sector (the Sector directly impacted) and the Participants Committee, not just the Participants Committee, must approve an entity like Tangent qualifying as an AR Provider. The change in proposed effective date reflects the additional time needed to confirm the ISO Board’s agreement to the Amendments. The revisions to the Amendments and materials are highlighted in yellow. We have been advised that the AR Sector supports Tangent becoming a full member of its Sector.

As noted in last week’s materials, affirmative Participants Committee action and approval of the Amendments will permit Tangent to participate fully in the AR Sector (rather than be moved into the Common Provisional Member Group Seat pursuant to the 126th Agreement). Should there be any further questions in advance of the October 3 meeting, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

The following form of resolution could be used to authorize the balloting of the proposed Amendments and approve the Transition:

RESOLVED that, subject to successful approval of the proposed Amendments to the Second Restated NEPOOL Agreement and the Participants Agreement substantially in the form of the Amendments presented at this meeting, the Participants Committee (1) approves the transition of Tangent Energy Solutions, Inc. to the AR Sector Load Response Sub-Sector Small Group Member (Transition), as previously approved by the AR Sector and recommended by the Membership Subcommittee and presented at this meeting, and (2) authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of agreements amending the New England Power Pool Agreement and Participants Agreement to allow for that Transition, to each Participant for execution by its voting member or alternate on this Committee or such Participant’s duly authorized officer.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: September 19, 2014

RE: Tangent Energy Solutions Transition to Load Response Sub-Sector Small Group Member and NEPOOL/Participants Agreement Changes to Allow for that Transition

We write you now, ahead of the final notice, for your comments and input on a proposal to approve the transition of Tangent Energy Solutions, Inc. (“Tangent”) from a Provisional Member to a full member of the AR Sector (the “Transition”). You will be asked at the October 3 Participants Committee meeting to approve the balloting of changes to the NEPOOL and Participants Agreements to permit the implementation of that Transition (the “Amendments”). Tangent’s Transition and the Amendments were recommended for Participants Committee approval by the Membership Subcommittee at its September 15 meeting.¹ Included with this memorandum for your review is a draft One Hundred Twenty-Seventh Agreement to Amend the NEPOOL Agreement² and a draft Amendment No. 8 to the Participants Agreement to effect the Amendments.

Tangent has been in NEPOOL as a Provisional Member in the AR Sector since February 1, 2012 and its business has grown to a point that it wishes to become a full member.³ It has participated actively in NEPOOL meetings through its designated representative, Brad Swalwell. Since becoming a Provisional Member, its business interests in New England have grown and are now comprised of between two and three MW of Demand Response Resources (as defined in the NEPOOL and Participants Agreements). Those Resources, however, are not enrolled in ISO-NE’s Demand Response Program because Tangent does not yet have in place the required Remote Terminal Units (RTUs) and other infrastructure to satisfy the Demand Response Program’s metering requirements.⁴ The only Demand Response Resources currently that may be taken into account for purposes of determining whether a member qualifies as an “AR Provider,” however, are those “that are enrolled in the Load Response Program and have not been inactive in that Program for a period exceeding six (6) months.” For that reason, unless the currently operative provisions in the NEPOOL and Participants Agreements are changed, even though Tangent has a

¹ See Notice of Actions of NEPOOL Membership Subcommittee (Sep. 15, 2014) available at: http://www.nepool.com/uploads/Memb_Subcomm_NOA_20140915.pdf.

² The One Hundred Twenty-Sixth Agreement (Common Provisional Member Group Seat) was approved in balloting, which concluded Sep. 22, 2014.

³ Tangent has been a member of the AR Sector Load Response Sub-Sector Provisional Group Member. If accepted as a full member, it would participate in the LR Sub-Sector Small Group Seat. Tangent desires this transition notwithstanding the fact that its share of NEPOOL expenses will increase.

⁴ Before making the material investment necessary to meet ISO-NE’s metering infrastructure requirements, Tangent is awaiting further clarity with respect to the participation by Demand Response Resources in the wholesale markets in light of the DC Circuit Court of Appeals actions on Order 745.

very active and current business interest in New England and has regularly attended NEPOOL meetings, it cannot qualify as an AR Provider. The Amendments would allow the Participants Committee in this and similar circumstances to vote to accept on a case-by-case basis business interests like Tangent's as sufficient to qualify the member as an AR Provider rather than a Provisional Member.

Given the circumstances, the Subcommittee would like to respond positively to Tangent's request to participate fully in the AR Sector (rather than be moved into the Common Provisional Member Group Seat).⁵ To that end, the Subcommittee recommended that the Participants Committee support Tangent's Transition and approve the Amendments to allow that Transition to occur. The Amendments would afford the AR Sector and the Participants Committee the latitude to determine the Substantial Business Interests in Alternative Resources, beyond those already specifically identified, that can be taken into consideration for the purpose of determining whether an Entity qualifies as an AR Provider.⁶

Looking forward to the Participants Committee meeting, changes to the NEPOOL and Participants Agreements require a 2/3 NEPOOL Vote achieved in balloting in which the Minimum Response Requirement is satisfied. In accordance with Section 6.10(e)(iii) of the NEPOOL Agreement, because the definition of AR Provider is included in the Participants Agreement, the ISO-NE Board of Directors must also approve the proposed change. The following form of resolution, which would require that 2/3ds vote to pass, could be used to authorize the balloting of the proposed Amendments and approve the Transition:

RESOLVED that the Participants Committee approves the transition of Tangent Energy Solutions, Inc. to the AR Sector Load Response Sub-Sector Small Group Member (Transition), as recommended by the Membership Subcommittee and presented at this meeting, [but with such changes as were discussed and agreed to by the Committee], and authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of agreements amending the New England Power Pool Agreement and Participants Agreement to allow for that Transition, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.

If approved in balloting, the Amendments would be filed with the FERC and NEPOOL would request that the changes be permitted to become effective as of November 1, 2014. Please review these changes and, if there are any questions or comments in advance of the meeting concerning the Amendments, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

⁵ Because of the current size of its Alternative Resources, if it is permitted to become a full member, Tangent would join the Small Group Member in the Load Response Sub-Sector.

⁶ To be clear, such Entities can participate in NEPOOL in either event, but only as either a Provisional Member or possibly an End User if they have load. The requested changes place such Entities more squarely within the Sector that shares their business interest.

**ONE HUNDRED TWENTY-SEVENTH AGREEMENT AMENDING
NEW ENGLAND POWER POOL AGREEMENT
(AR Provider Definition Revisions)**

THIS ONE HUNDRED TWENTY-SEVENTH AGREEMENT AMENDING NEW ENGLAND POWER POOL AGREEMENT, dated as of October 3, 2014 (“One Hundred Twenty-Seventh Agreement”), amends the New England Power Pool Agreement (the “NEPOOL Agreement”).

WHEREAS, effective February 1, 2005 the NEPOOL Agreement was amended by the One Hundred Seventh Agreement Amending New England Power Pool Agreement and restated as the Second Restated NEPOOL Agreement, and has subsequently been amended numerous times; and

WHEREAS, the Participants desire to amend further the Second Restated NEPOOL Agreement to reflect the revision detailed herein.

NOW, THEREFORE, upon approval of this One Hundred Twenty-Seventh Agreement by the NEPOOL Participants Committee in accordance with the procedures set forth in the Second Restated NEPOOL Agreement, the Participants agree as follows:

**SECTION 1
AMENDMENTS**

1.1 Amendment to Section 1.6. Section 1.6 of the Second Restated NEPOOL Agreement is amended so that it reads as follows:

AR Provider is a Participant with a “Substantial Business Interest” in Alternative Resources located within the New England Control Area. For the purposes of this Agreement,

(a) a Participant has a Substantial Business Interest in Alternative Resources if:

(i) either (A) the Participant owns or controls any Alternative Resource and at least 75% of its Energy resources within the New England Control Area are Alternative Resources; or (B) the Participant (1) owns or controls at least 50 MW (or its equivalent) of Alternative Resources within the New England Control Area or (2) has an independently verifiable capital investment in its Alternative Resources in the New England Control Area as of the end of the most recent calendar year of at least \$30,000,000, regardless of the percentage of its business interests those Alternative Resources represent; and

(ii) either (A) the quantity of Alternative Resources (in megawatts) and other generation resources in the New England Control Area owned or controlled by the Participant exceeds the highest quantity of hourly Governance Load responsibility held by the Participant in the prior twelve (12) months; or (B) the quantity of generation (in megawatt hours) in the past twelve months from Alternative Resources

and other generation resources in the New England Control Area that the Participant owns or controls exceeds the total quantity of Governance Load responsibility held by the Participant in the prior twelve months; or (C) the Participant has not held any Governance Load responsibility in the prior twelve (12) months but otherwise meets one of the tests set forth in (i)(A) or (i)(B) above; or

(iii) the Participant is determined by the AR Sector and the Participants Committee to have a Substantial Business Interest in Alternative Resources.

(b) the only Alternative Resources that shall be taken into account for purposes of determining whether an Entity qualifies as an AR Provider pursuant to sections (a)(i) and (a)(ii) above are:

(i) those generating resources that are within the New England Control Area that are (A) currently in operation, (B) under construction, or (C) proposed for operation as generation and that have received approvals under Sections 18.4 and/or 18.5 of the First Restated NEPOOL Agreement between July 1, 2002 and the Effective Date or received approvals on or after the Effective Date under Sections I.3.9 and/or I.3.10 of the Tariff or for which completed environmental air or environmental siting applications have been filed or permits exist; or

(ii) Demand Response Resources that are enrolled in the Load Response Program and have not been inactive in that Program for a period exceeding six (6) months; or

(iii) Energy Efficiency Resources that have not been inactive in an Energy efficiency program of a New England state for a period exceeding six (6) months; or

(iv) ARAlternative Resources that have been offered in a Forward Capacity Auction or Reconfiguration Auction that have been accepted by the ISO.

SECTION 2 MISCELLANEOUS

- 2.1 This One Hundred Twenty-Seventh Agreement shall become effective December 1, 2014, or on such other date as the Commission shall provide that the amendment reflected herein shall become effective.
- 2.2 Capitalized terms used in this One Hundred Twenty-Seventh Agreement that are not defined herein shall have the meanings ascribed to them in the Second Restated NEPOOL Agreement.

**AMENDMENT NO. 8 TO
PARTICIPANTS AGREEMENT
(Revisions to AR Provider Definition)**

THIS AMENDMENT NO. 8 TO PARTICIPANTS AGREEMENT (“Amendment No. 8”) is made and entered into as of this 3rd day of October, 2014 by and between ISO New England Inc. (the “ISO”) and the New England Power Pool, an unincorporated association created pursuant to the New England Power Agreement dated as of September 1, 1971, as amended and restated, acting herein by and through the NEPOOL Participants Committee (“NEPOOL”).

WHEREAS, the Participants Agreement by and among the ISO and NEPOOL became effective as of February 1, 2005 and has subsequently been amended seven times.

WHEREAS, the ISO and NEPOOL desire to amend the Participants Agreement to reflect the revisions detailed herein.

NOW, THEREFORE, upon approval of this Amendment No. 8 by the ISO and by the NEPOOL Participants Committee in accordance with the procedures set forth in the Participants Agreement, the ISO and NEPOOL agree as follows:

1. Amendment to Section 1.1 (Defined Terms).

- 1.1 Amendment to Definition of “AR Provider”. The definition of AR Provider is amended to read as follows:

AR Provider is a Participant with a “Substantial Business Interest” in Alternative Resources located within the New England Control Area. For the purposes of this Agreement,

(a) a Participant has a Substantial Business Interest in Alternative Resources if:

(i) either (A) the Participant owns or controls any Alternative Resource and at least 75% of its Energy resources within the New England Control Area are Alternative Resources; or (B) the Participant (1) owns or controls at least 50 MW (or its equivalent) of Alternative Resources within the New England Control Area or (2) has an independently verifiable capital investment in its Alternative Resources in the New England Control Area as of the end of the most recent calendar year of at least \$30,000,000, regardless of the percentage of its business interests those Alternative Resources represent; and

(ii) either (A) the quantity of Alternative Resources (in megawatts) and other generation resources in the New England Control Area owned or controlled by the Participant exceeds the highest quantity of hourly Governance Load responsibility held by the Participant in the prior twelve (12) months; or (B) the quantity of generation (in megawatt hours) in the past twelve months from Alternative Resources and other generation resources in the New England Control Area that the Participant owns or controls exceeds the total quantity of Governance Load responsibility held by

the Participant in the prior twelve months; or (C) the Participant has not held any Governance Load responsibility in the prior twelve (12) months but otherwise meets one of the tests set forth in (i)(A) or (i)(B) above; or

(iii) the Participant is determined by the AR Sector and the Participants Committee to have a Substantial Business Interest in Alternative Resources.

(b) the only Alternative Resources that shall be taken into account for purposes of determining whether an Entity qualifies as an AR Provider pursuant to sections (a)(i) and (a)(ii) above are:

(i) those generating resources that are within the New England Control Area that are (A) currently in operation, (B) under construction, or (C) proposed for operation as generation and that have received approvals under Sections 18.4 and/or 18.5 of the First Restated NEPOOL Agreement between July 1, 2002 and the Effective Date or received approvals on or after the Effective Date under Sections I.3.9 and/or I.3.10 of the Tariff or for which completed environmental air or environmental siting applications have been filed or permits exist; or

(ii) Demand Response Resources that are enrolled in the Load Response Program and have not been inactive in that Program for a period exceeding six (6) months; or

(iii) Energy Efficiency Resources that have not been inactive in an Energy efficiency program of a New England state for a period exceeding six (6) months; or

(iv) ARAlternative Resources that have been offered in a Forward Capacity Auction or Reconfiguration Auction that have been accepted by the ISO.

4. Effective Date. This Amendment No. 8 shall become effective on December 1, 2014 or on such other date as the Commission shall provide that the amendments reflected herein shall become effective.

5. Counterparts. Counterparts of this Amendment No. 8 may be signed by the parties, each of which shall be an original but both of which together shall constitute one and the same instrument.

6. Governing Law. This Amendment No. 8 shall be governed by and enforced in accordance with the laws of the State of Delaware.

7. Miscellaneous. Terms used in this Amendment No. 8 that are not defined herein shall have the meanings ascribed to them in the Participants Agreement, the Second Restated NEPOOL Agreement, or the ISO's Transmission, Markets and Services Tariff.

[The next page is the signature page.]

IN WITNESS WHEREOF, the ISO and NEPOOL have caused this Amendment No. 8 to be executed by their duly authorized representatives as of the date first written above.

ISO NEW ENGLAND INC.

NEW ENGLAND POWER POOL
acting through the NEPOOL Participants
Committee

By: _____
Name: Gordon van Welie
Title: President and Chief Executive Officer

By: _____
Name: Joel Gordon
Title: Chair, NEPOOL Participants
Committee

EXECUTIVE SUMMARY

Status Report of Current Regulatory and Legal Proceedings as of October 1, 2014

The following activity, as more fully described in the attached litigation report, has occurred since the report dated September 11, 2014 was circulated. New matters/proceedings since the last Report are preceded by an asterisk “*”. Page numbers precede the matter description.

I. Complaints				
* 1	206 Proceeding: Importers’ FCA Offers Review/Mitigation (EL14-99)	Sep 16 Sep 17 Sep 17- Oct 1	FERC initiates 206 proceeding; interventions due Oct 7 FERC notices proceeding; sets Sep 24, 2014 refund effective date NEPOOL, Casco Bay, Champlain VT, CMEEC/MMWEC/NHEC, ConEd, CT PURA, Essential Power, HQ US, MA AG, National Grid, NESCOE, NRG, NU, PSEG intervene	
1	Base ROE Complaint (2014) (EL14-86)	Sep 25 Sep 26	Complainants and Intervenor answer TO’s Sep 10 response EMCOS answer TO’s Sep 10 response	
4	Base ROE Complaint (2012) (EL13-33)	Sep 11 Sep 19 Sep 22 Sep 25-26	TOs move for summary disposition or, alternatively, consolidation with EL14-86 Chief Judge Wagner issues order continuing settlement judge procedures; 2nd Settlement conference scheduled for Oct 9 Judge Wagner issues status report on behalf of Judge Dring Complainant-Intervenor, FERC Trial Staff, EMCOS oppose Sep 11 motion for summary disposition, but support alternative request for consolidation with EL14-86	
II. Rate, ICR, FCA, Cost Recovery Filings				
6	FCA8 Results Filing (ER14-1409)	Sep 16	FCA8 Results Filing becomes effective by operation of law	
III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests				
* 7	Fuel Price Adjustment Changes (ER14-2929)	Sep 23 Sep 24- Oct 1	ISO and NEPOOL jointly file changes to revise the provision addressing automated fuel price adjustments in Market Rule 1; comment date Oct 14 Calpine, Dominion, NRG intervene	
* 7	Regulation Market Dispatch Changes (ER14-2918)	Sep 22	ISO and NEPOOL jointly file Regulation Market Dispatch Changes; comment date Oct 14	
* 8	Waiver Request: Deadline for QDN Challenge (GDF SUEZ) (ER14-2886)	Sep 15	GDF SUEZ requests waiver of deadlines for FCA9 QDN challenges; comment date Oct 6	
8	Waiver Request: New Capacity Qualification Deadlines (MMWEC) (ER14-2771)	Sep 12 Sep 24	ISO intervenes and opposes waiver request FERC denies waiver request	
8	ISO CSO Deferral Proposal (ER14-2440)	Sep 12	FERC accepts proposal, effective Jul 17, 2014	
12	Order 755 Regulation Market Changes (ER12-1643)	Sep 30	FERC accepts tariff sheets extending effective date of new Regulation Market to Mar 31, 2015	
IV. OATT Amendments / TOAs / Coordination Agreements				
13	Order 784 Compliance Filing (ER14-877)	Sep 23	Transmission Committee recommends NPC support for compliance changes	

V. Financial Assurance/Billing Policy Amendments*No Activity to Report***VI. Schedule 20/21/22/23 Changes**

16	Schedule 21-NEP: Centennial Island Hydro SGIA (ER14-2534)	Sep 17	FERC accepts Centennial Island Hydro SGIA filing

VII. NEPOOL Agreement/Participants Agreement Amendments*No Activity to Report***VIII. Regional Reports**

16	Capital Projects Report - 2014 Q2 (ER14-2656)	Sep 25	FERC accepts Q2 2014 Report
* 17	Quarterly Reports Regarding Non-Generating Resource Regulation Market Participation (ER08-54)	Sep 19	ISO files its 24th quarterly report
* 17	Reserve Market Compliance (17th) Semi-Annual Report (ER06-613)	Oct 1	ISO submits 17th semi-annual report

IX. Membership Filings

* 17	October 2014 Membership Filing (ER14-2980)	Sep 30	Memberships: Plant-E, Fisher Road Solar, Nordic Energy Services; Terminations: Blue Pilot; comment date Oct 21
17	September 2014 Membership Filing (ER14-2749)	Sep 29	FERC accepts BlueRock Energy and E.ON Global Commodities North America memberships; SBR Energy, Dragon Products and Dragon Energy LLC terminations
18	August 2014 Membership Filing (ER14-2541)	Sep 18	FERC accepts SFE Energy Connecticut and SFE Energy Massachusetts memberships

X. Misc. - ERO Rules, Filings; Reliability Standards

* 18	FFT Report: Sep 2014 (NP14-50)	Sep 30	NERC files report
* 18	Revised Reliability Standard: PRC-004-3 (RD14-14)	Sep 15	NERC files revised Standard for approval; comment date Oct 20
* 18	Revised Reliability Standard: NUC-001-3 (RD14-13)	Sep 15	NERC files revised Standard for approval; comment date Oct 15
19	NOPR: New Reliability Standard: CIP-014-1 (Physical Security) (RM14-15)	Sep 22	NIPSCO, SmartSenseCom, City of Tallahassee - Electric Utility, and the Foundation for Resilient Societies file reply comments
19	NOPR: Revised Reliability Standard: COM-001-2 and COM-002-4 (RM14-13)	Sep 18	FERC issues NOPR; comment date Dec 1, 2014
20	NOPR: Revised Reliability Standard: MOD-031-1 (RM14-12)	Sep 18	FERC issues NOPR; comment date Dec 1, 2014
20	NOPR: Revised Reliability Standard: PRC-005-3 (RM14-8)	Sep 29	NERC, EEI, Idaho Power Company, ITC, and G&T Cooperatives file comments
21	NOPR: Revised TOP and IRO Reliability Standards (RM13-15, RM13-14, RM13-12)	Oct 1	NERC files 3rd quarterly status report on status of revisions to IRO and TOP Standards

* 23	Revised NPCC Regional Reliability Standards Development Procedure (RR14-7)	Sep 15	NERC files amendments to NPCC's Regional Reliability Standards Development Procedure; comment date Oct 6
24	2015 NERC/NPCC Business Plans and Budgets (RR14-6)	Sep 12 Sep 16	Exelon supports filing Western Interconnection Regional Advisory Body recommends approval of WECC's proposed 2015 budget

XI. Misc. - of Regional Interest

* 24	203 Application: Dynegy/EquiPower (EC14-140)	Sep 11 Sep 24 Sep 25	Dynegy/EquiPower request authorization for transfer of EquiPower's New England and PJM generating assets; comment date Nov 11 PJM IMM requests consolidation with Dynegy/Duke Energy transaction (EC14-141) Dynegy opposes PJM IMM consolidation request
24	PURPA Complaint v. MA DPU (EL14-84 et al.)	Sep 19 Sep 26	MA DPU answers Allco Sep 8 answer FERC issues notice of its intention not to initiate an enforcement action (clearing way for Allco to itself bring an enforcement action against the MA DPU)
25	FirstEnergy PJM DR Complaint (EL14-55)	Sep 22 Sep 25 – Oct 1	FirstEnergy files amended complaint; comments due Oct 22 Environmental Law and Policy Center, EDF, NRDC/Sustainable FERC Project, Dynegy intervene
25	E&P Agreements: Blue Sky West & CMP (ER14-2743; ER14-2744)	Sep 30	CMP supplements its Blue Sky West E&P Agreements filing with redlined agreements

XII. Misc. - Administrative & Rulemaking Proceedings

28	NOPR: MBR Authorization Refinements (RM14-14)	Sep 23-24	Parties submit comments
28	Order 676-H: Incorporation of WEQ Version 003 Standards (RM05-5)	Sep 18	FERC issues final rule, effective Oct 24, 2014

XIII. Natural Gas Proceedings

* 30	Inquiry Into Natural Gas Trading, and Proposal to Establish an Electronic Information and Trading Platform (AD14-19)	Sep 18 Oct 1	Commissioner Moeller convenes meeting to explore ideas to facilitate and improve natural gas trading, and the concept of establishing a centralized natural gas information and trading platform Parties submit written comments
31	NOPR: Scheduling Coordination (RM14-2)	Sep 29	NAESB issues Report
32	Natural Gas-Related Enforcement Actions: BP (IN13-15)	Sep 22	FERC Trial Staff submits pre-filed direct testimony

XIV. State Proceedings & Federal Legislative Proceedings*No Activity to Report***XV. Federal Courts**

34	2013/14 Winter Reliability Program and Bid Results (14-1104 (consol.))	Sep 29	TransCanada, RESA, FERC, ISO-NE, Essential Power MA, PSEG and NEPGA filed proposed joint, unopposed briefing format and schedule
34	Orders 773 and 773-A (2nd Cir., 13-2316)	Sep 24 Sep 25	FERC, NY/NY PSC file final briefs; NY/NY PSC files reply brief NERC, NARUC file intervenor briefs
35	Orders 1000 and 1000-A (12-1232 (consol.))	Sep 29	Large Public Power Council petitions DC Circuit for rehearing <i>en banc</i>

35	<i>Orders 745 and 745-A</i> (11-1486)	Sep 17 Sep 22 Sep 30	Court denies request for rehearing <i>en banc</i> of May 23 Decision FERC and intervenors move for Court to stay issuance of its mandate Petitioners oppose motion to stay mandate
36	PPL EnergyPlus, LLC v. Nazarian (4th Cir., 13-2424)	Sep 15	Supreme Court extends time to file a petition for a writ of certiorari to and including Nov 27, 2014.

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: October 2, 2014

RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures, and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission (“FERC”), state regulatory commissions, and the Federal Courts and legislatures through October 1, 2014. If you have questions, please contact us.¹

I. Complaints

- **206 Proceeding: Importers’ FCA Offers Review/Mitigation (EL14-99)**

On September 16, 2014, the FERC initiated this proceeding, pursuant to Section 206 of the FPA, directing the ISO to either revise its Tariff to provide for the review and potential mitigation of importers’ offers prior to each annual Forward Capacity Auction (“FCA”) or show cause why it should not be required to do so.² The FERC directed the ISO to submit those Tariff revisions or support for why Tariff revisions should not be required on or before October 16, 2014. September 24, 2014 is the refund effective date.³ We understand that the ISO will propose Tariff revisions, and those revisions are to be considered first at the October 8-9 Markets Committee meeting. A special Participants Committee meeting will be scheduled the following week to consider the proposed Tariff changes and Markets Committee developments with respect to those changes. Interventions in this proceeding are due on or before October 7, 2014 and have thus far been filed by: NEPOOL, Casco Bay, Champlain VT, CMEEC/MMWEC/NHEC, ConEd, CT PURA, Essential Power, HQ US, MA AG, National Grid, NESCOE, NRG, NU, and PSEG. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtldoot@daypitney.com), Pat Gerity (860-275-0533; pmgerity@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Base ROE Complaint (2014) (EL14-86)**

The Massachusetts Attorney General (“MA AG”), together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the “2014 ROE Complainants”),⁴ filed a

¹ Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the “Second Restated NEPOOL Agreement”), the Participants Agreement, or the ISO New England Inc. (“ISO” or “ISO-NE”) Transmission, Markets and Services Tariff (the “Tariff”).

² *ISO New England Inc.*, 148 FERC ¶ 61,201 (Sep. 16, 2014) (“September 16 Order”).

³ The Sep. 17 notice of this proceeding was published in the *Fed. Reg.* on Sep. 24, 2014 (Vol. 79, No. 185) p. 57,075.

⁴ “2014 Complainants” are: the MA AG, Connecticut Public Utilities Regulatory Authority (“CT PURA”), Massachusetts Municipal Wholesale Electric Company (“MMWEC”), New Hampshire Electric Cooperative, Inc. (“NHEC”), Massachusetts Department of Public Utilities (“MA DPU”), New Hampshire Public Utilities Commission (“NH PUC”), the Attorney General of the State of Connecticut (“CT AG”), Connecticut Office of Consumer Counsel (“CT OCC”), Maine Office of the Public Advocate (“MOPA”), New Hampshire Office of the Consumer Advocate (“NH OCA”), Rhode Island Division of Public Utilities and Carriers (“RI PUC”), Vermont Department of Public Service (“VT DPS”), Associated Industries of Massachusetts (“AIM”), The Energy Consortium (“TEC”), Power Options, Inc., Western Massachusetts Industrial Group, Environment Northeast (“ENE”), National Consumer Law Center, the Greater Boston Real Estate Board, and the Industrial Energy Consumer Group (“IECG”).

complaint on July 31, 2014 to reduce the current 11.14% Base ROE to 8.84% (but in any case no more than 9.44%) and to cap the Combined ROE for all rate base components at 12.54%. 2014 Complainants state that they submitted this Complaint seeking refund protection against payments based on a pre-incentives Base ROE of 11.14%, and a reduction in the Combined ROE, relief as yet not afforded through the prior ROE proceedings. The TOs responded to the Complaint on September 10, and have requested that this Complaint be dismissed or, in the alternative, consolidated with the 2012 Complaint (EL13-33). In addition, the MPUC submitted comments supporting the Complaint, and interventions were filed by NEPOOL, APPA, and EMCOS. Motions opposing those requests and the TO's answer were filed by Complainants and Intervenor and EMCOS on September 26 and 26, respectively. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

• **206 Investigation: FCM Performance Incentives (Compliance Proceeding) (EL14-52)**

As more fully explained in Section III below (ER14-1050), the FERC instituted this proceeding, pursuant to section 206 of the Federal Power Act ("FPA"), in its May 30 *PI Order*, having concluded in the *PI Order* that the ISO's existing Tariff, specifically the current FCM payment design, "is unjust and unreasonable, because it fails to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits."⁵ The FERC directed the ISO to submit in this proceeding "Tariff revisions reflecting a modified version of its [PFP] proposal and an increase in the Reserve Constraint Penalty Factors, consistent with NEPOOL's proposal."⁶ The FERC-established refund effective date will be June 9, 2014.⁷ Interventions were filed by NEPOOL, CT AG, CT DEEP, CT OCC, CT PURA, Dynegy, Essential Power, Exelon, MPUC, PSEG, RI PUC, and UI. Requests for clarification and/or rehearing of the *PI Order* were filed by: NEPOOL, Connecticut and Rhode Island,⁸ Dominion, MMWEC, Indicated Generators,⁹ NEPGA, NextEra, Potomac Economics, and PSEG/NERG. On July 28, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC. Developments with respect to the ISO's compliance filing will be reported in "FCM PI Jump Ball Compliance Filing (ER14-2419)", Section III below.

• **206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices to be Adopted in Docket RM14-2 (EL14-23)**

As previously reported, on March 20, 2014, the FERC initiated this proceeding, pursuant to Section 206 of the FPA, to ensure that the ISO's scheduling, particularly its Day-Ahead scheduling practices, correlate with any revisions to the natural gas scheduling practices to be ultimately adopted by the FERC in RM14-2 (see Section XIII below).¹⁰ Noting its concern about the lack of synchronization between the Day-Ahead scheduling practices of interstate natural gas pipelines and electricity markets, the FERC directed each

⁵ *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 at P 23 (May 30, 2014) ("*PI Order*").

⁶ *Id.* at P 1.

⁷ The June 3 notice of this proceeding was published in the *Fed. Reg.* on June 9, 2014 (Vol. 79, No. 110) pp. 32,937-89.

⁸ "Connecticut and Rhode Island" are: the Connecticut Public Utilities Regulatory Authority ("CT PURA"), the Conn. Office of Consumer Counsel ("CT OCC"), George Jepsen, Att'y Gen. for the State of Conn. ("CT AG"), the Conn. Department of Energy and Environmental Protection ("CT DEEP"), the United Illuminating Company ("UI") and the Rhode Island Div. of Pub. Utils. and Carriers ("RI PUC").

⁹ "Indicated Generators" are: Exelon Corp. ("Exelon"), EquiPower Resources Management, LLC ("EquiPower"), Essential Power, LLC ("Essential Power"), and Dynegy Marketing and Trade, LLC and Casco Bay Energy Company, LLC (together, "Dynegy").

¹⁰ *Cal. Indep. Sys. Op. Corp. et al.*, 146 FERC ¶ 61,202 (Mar. 20, 2014). The New England 206 proceeding was docketed as EL14-23.

ISO and RTO, including ISO-NE, within 90 days after publication of a Final Rule in Docket RM14-2 in the *Federal Register*:

(1) to make a filing that proposes tariff changes to adjust the time at which the results of its day-ahead energy market and reliability unit commitment process (or equivalent) are posted to a time that is sufficiently in advance of the Timely and Evening Nomination Cycles, respectively, to allow gas-fired generators to procure natural gas supply and pipeline transportation capacity to serve their obligations, or (2) to show cause why such changes are not necessary. In their responses, each ISO and RTO must explain how its proposed scheduling modifications are sufficient for gas-fired generators to secure natural gas pipeline capacity prior to the Timely and Evening Nomination Cycles.¹¹

The Commission expects to issue a final order in this section 206 proceeding within 90 days of the filings required under the March 20 order. Interventions by over 40 parties, including one by NEPOOL, were filed in the New England-specific docket. On April 10, Puget Sound submitted comments addressing the changing of RTO/ISO practices, including a request that RTO/ISOs be required “to adopt consistent timelines that require bids awards to be submitted prior to the natural gas timely and evening scheduling deadlines”. This matter is pending action in RM14-2. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dttdoot@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

• FCM Administrative Pricing Rules Complaint (EL14-7)

Rehearing and clarification remains pending on both of the FERC’s January 24 FCM Administrative Pricing-related orders that (i) granted in part, and denied in part, NEPGA’s Administrative Pricing Rules Complaint in this proceeding,¹² and (ii) accepted changes to the FCM Administrative Pricing Rules in ER14-463 (see Exigent Circumstances Filing – FCM Admin. Pricing Rules (ER14-463) below).¹³ As previously reported, in the *Jan 24 Orders*, the FERC found that the administrative pricing provisions for situations of Inadequate Supply and Insufficient Competition were unjust and unreasonable. While the FERC declined to adopt NEPGA’s proposed revisions, it adopted the revisions proposed by the ISO in its Exigent Circumstances Filing in ER14-463 and also declined to find the existing Capacity Carry Forward Rule unjust and unreasonable.¹⁴ In its request for rehearing and clarification of the *Jan 24 Orders*, NEPGA requested the FERC: (i) require prospective auctions to utilize ORTP-based prices; (ii) direct ISO-NE to implement for FCA9 a sloped demand curve for all aspects of the FCM, including for individual capacity zones; and (iii) require ISO-NE to eliminate the zero-bid requirement and implement the bidding protocols requested by NEPGA in its initial Complaint in this proceeding. On March 24, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dttdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

• NESCOE FCM Renewables Exemption Complaint (EL13-34)

Rehearing of the FERC’s February 12, 2013 order denying NESCOE’s FCM Renewable Exemption Complaint¹⁵ remains pending before the FERC. As previously reported, NESCOE instituted this December 28, 2012 complaint in response to the ISO’s December 3, 2012 FCM compliance filing that implemented

¹¹ *Id.* at P 19.

¹² *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 146 FERC ¶ 61,039 (Jan. 24, 2014) (“*Jan 24 NEPGA FCM Admin Pricing Rules Order*”), *reh’g requested*.

¹³ *ISO New England Inc.*, 146 FERC ¶ 61,038 (Jan. 24, 2014) (“*Jan 24 Exigent Circumstances Order*”, and together with the *Jan 24 NEPGA FCM Admin Pricing Rules Order*, the “*Jan 24 Orders*”), *reh’g requested*.

¹⁴ *Id.* at P 1.

¹⁵ *New England States Comm. on Elec. v. ISO New England Inc.*, 142 FERC ¶ 61,108 (2013), *reh’g requested*.

buyer-side mitigation without an exemption for state-sponsored public policy resources. NESCOE asserted that the ISO's proposed Minimum Offer Price Rule ("MOPR") would likely exclude from the FCM new renewable resources developed pursuant to state statutes and regulations, and thereby result in customers being forced to purchase more capacity than is necessary for resource adequacy and proposed an alternative renewables exemption (the "Renewables Exemption Proposal"). In denying the Complaint, the FERC found that "NESCOE has failed to meet its burden under section 206 to demonstrate that ISO-NE's MOPR is unjust, unreasonable or unduly discriminatory" as applied to the New England Capacity Market.¹⁶ The FERC declined to set the case for hearing, and therefore denied the motion to consolidate this proceeding with the FCA8 Revisions Compliance Filing proceeding (ER12-953),¹⁷ on which it concurrently issued an order conditionally accepting in part and dismissing in part the ISO's proposed compliance filing. Rehearing was requested by NESCOE, the CT PURA, and the MA DPU on March 14, 2013. On March 29, 2013, NEPGA filed an answer challenging NESCOE's request for rehearing. On April 15, 2013, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Dave Doot (860-275-0102; dttdoot@daypitney.com).

• Base ROE Complaint (2012) (EL13-33)

As previously reported, the FERC, on June 19, 2014, established hearing and settlement judge procedures¹⁸ in response to the December 2012 Complaint by Environment Northeast ("ENE"), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"). The 2012 Base ROE Complaint challenged the TOs' 11.14% return on equity ("Base ROE"), and seeks a reduction of the Base ROE to 8.7%. In the *2012 Base ROE Initial Order*, the FERC found that the Complaint "raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures ordered."¹⁹ The FERC rejected Complainants' request to consolidate this proceeding with the 2011 Base ROE Complaint, though it noted the change in its' practice for determining public utilities' ROE announced in that proceeding. Accordingly, the FERC directed the parties to present evidence and any discounted cash flow ("DCF") analyses in accordance with that guidance.²⁰ Hearing in this proceeding has been held in abeyance pending the outcome of settlement judge procedures. On July 21, the TOs requested rehearing of the *2012 Base ROE Initial Order*. On August 20, the FERC issued a tolling order affording it additional time to consider the TOs' rehearing request, which remains pending before the FERC.

Since the last Report, the TOs requested that the FERC admit into evidence in this proceeding the 2014 Base ROE Complaint (EL14-86) and the TOs' September 10, 2014 answer to that complaint, including all testimony and exhibits. The TOs asserted that with that evidence, the FERC would have a full record to address all open substantive issues in this proceeding, and could find just and reasonable a 10.99% base ROE, eliminating the need for the hearing previously directed and being held in abeyance. Alternatively, should the FERC deny summary disposition of this proceeding, the TOs requested that this proceeding be consolidated with the 2014 Base ROE Complaint in EL14-86. In response, Complainants-Intervenors,²¹ FERC Trial Staff and EMCOS all opposed summary disposition but supported consolidation of the proceedings. These motions are pending before the FERC.

¹⁶ *Id.* at P 32.

¹⁷ *Id.* at P 30.

¹⁸ *Environment Northeast, et al. v. Bangor Hydro-Elec. Co., et al.*, 147 FERC ¶ 61,235 (June 19, 2014) ("*2012 Base ROE Initial Order*"), *reh'g requested*.

¹⁹ *Id.* at P 26.

²⁰ *Id.*

²¹ As previously reported, NICC withdrew as a complainant in the case on July 15, explaining that NICC members had decided to disband NICC and cease all functions, including advocacy before the FERC.

As previously reported, Judge John P. Dring was appointed the settlement judge in this case. A first settlement conference was held on July 24; a second settlement conference is scheduled for Thursday, October 9, 2014. On behalf of Judge Dring, Chief Judge Wagner issued a status report on September 22 indicating that the parties were making progress toward settlement. Judge Wagner also issued an order continuing settlement procedures on September 19. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

• **Base ROE Complaint (2011) (EL11-66)**

Also on June 19, 2014, the FERC issued *Opinion 531*,²² affirming in part, and reversing in part, Judge Cianci's Initial Decision²³ in this proceeding. In *Opinion 531*, the FERC announced a new approach that it will use for determining public utilities' base ROE and a change in its' practice on post-hearing ROE adjustments. With respect to the New England TOs', the FERC applied its new that approach to the facts of this proceeding to determine the NETOs' base ROE, and established a paper hearing to allow the participants an opportunity to submit briefs on a limited issue regarding application of the new ROE approach.²⁴

As previously reported, Trial Judge Cianci issued his initial decision on August 6, 2013 finding unjust and unreasonable the 11.14% ROE currently used in calculating formula rates for transmission service in the OATT, and finding that the ROE should be 10.6% for the October 2011 through December 2012 "locked in/refund period" and 9.7% from January 2013 forward, subject to further updating or modification by the FERC.²⁵ By way of reminder, the FERC established hearing and settlement judge procedures²⁶ following a complaint by a number of State, consumer, and consumer advocate parties (the "2011 Complainants")²⁷ seeking a FERC order reducing the 11.14% Base ROE to 9.2% "due to changes in the capital markets since the *Bangor Hydro* proceeding."²⁸ After settlement judge procedures before Judge Judith A. Dowd were ultimately unsuccessful and terminated, these proceedings proceeded to now-completed hearings before Judge Cianci.

In *Opinion 531*, the FERC concluded that it is now appropriate to use the same two-step DCF methodology model for the electric industry as it has used for the natural gas and oil pipeline industries.²⁹ The FERC also made a tentative finding that the required long-term growth projection should be based on projected long-term growth in gross domestic product ("GDP"), but established a paper hearing to permit participants to present evidence on the appropriate long-term growth projection to be used in the two-step DCF methodology.³⁰ Applying the two-step DCF methodology to the facts of this proceeding, the FERC found that the TOs' starting proxy group was consistent with FERC precedent, and after taking official notice of the necessary GDP growth

²² *Martha Coakley, Mass. Att'y Gen. et al.*, 147 FERC ¶ 61,234 (2014) ("*Opinion 531*"), *reh'g requested*.

²³ *Martha Coakley, Mass. Att'y Gen. et al.*, 144 FERC ¶ 61,012 (2013) ("*Initial Decision*").

²⁴ *Opinion 531* at P 1.

²⁵ *See 2011 Base ROE Initial Decision*.

²⁶ *Martha Coakley, Mass. Att'y Gen et al.*, 139 FERC ¶ 61,090 (2012) ("*Base ROE Complaint Order*"). The *Base ROE Complaint Order* was not challenged and is final.

²⁷ Complainants are Martha Coakley, Mass. Att'y Gen. ("MA AG"), CT PURA, Mass. Dep't of Pub. Utils. ("MA DPU"), New Hampshire Pub. Utils. Comm. ("NH PUC"), CT AG, CT OCC, Maine Off. of the Pub. Advocate ("ME OPA"), New Hampshire Off. of the Consumer Advocate, ("NH OCA"), RI PUC, Vermont Dep't of Pub. Svc. ("VT DPS"), MMWEC, AIM, TEC, Power Options, and the IECG.

²⁸ *See Bangor Hydro-Elec. Co. et al.*, 117 FERC ¶ 61,129 (2006) ("*Opinion 489*") at PP 79-81, *order on reh'g*, *Bangor Hydro-Elec. Co. et al.*, 122 FERC ¶ 61,265 (2008) at PP 30-34.

²⁹ *Opinion 531* at P 8.

³⁰ *Id.*

projections, the FERC's analysis produced a zone of reasonableness of from 7.03% to 11.74%.³¹ Accordingly, the FERC found it appropriate, based on record evidence, to place the TOs' base ROE halfway between the midpoint of the zone of reasonableness and the top of that zone (or at the two-thirds point), resulting in a 10.57% Base ROE (subject to adjustment based on the outcome of the paper hearing on long-term growth projections to be used).³² The FERC also indicated that, based on the record in this proceeding and economic trends since 2008 more generally, it would end its practice of updating the ROE based on changes in U.S. bond yields during the proceeding.³³ Several parties requested rehearing and/or clarification of *Opinion 531*, including: the TOs, EMCOS, American Municipal Power ("AMP"), and NRECA/APPA.³⁴ On August 20, the FERC issued a tolling order affording it additional time to consider the requests for rehearing of *Opinion 531*, which remain pending before the FERC.

In other procedural matters since the last Report, On August 5, 2014, the TOs moved to strike evidence submitted in Complainants' July 21 Petition for Rehearing, urged dismissal of the APPA, NRECA and AMP motions to intervene out-of-time, and answered EMCOS' motion for clarification. Also on August 5, Complainants, APPA, NRECA, and NHEC jointly answered the TOs' July 21 motion for clarification. On August 12, NRECA and APPA answered the TOs' Aug 5 dismissal motion. Complainants answered the TOs' August 5 motion to strike the materials provided with their July 21 request for rehearing on August 20, 2014. Also on August 20, the TOs answered Complainants Aug 5 answer. Finally, Complainants, APPA, NRECA, and NHEC jointly answered the TOs' Aug 5 motion for clarification.

Paper Hearing. On August 4, Complainants, TOs, and FERC Trial Staff submitted their initial briefs on the appropriate long-term growth projection to be used in the two-step DCF methodology. On September 4, Complainants, TOs, and FERC Trial Staff each submitted reply briefs. The paper hearing is pending before the FERC.

If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

• FCA8 Results Filing (ER14-1409)

On September 16, 2014, the results of the eighth FCA ("FCA8") held February 3, 2014 and filed February 28 (as amended by the additional information filed July 17, 2014 in response to the FERC's June 27 deficiency letter) became effective by operation of law. Challenges, if any, to the finality of the FCA8 Results must be filed in Federal Court on or before November 17, 2014.

As noted in Section I above (EL14-99), the FERC, in its companion *September 16 Order*, initiated a 206 proceeding directing the ISO to either revise its Tariff to provide for the review and potential mitigation of importers' offers prior to each annual FCA or show cause why it should not be required to do so. In the *September 16 Order*, the FERC also addressed Brayton Point, reporting that the Office of Enforcement ("OE") conducted a limited review of Brayton Point's bidding behavior and found "credible justifications for the owners' retirement decision" and elected not to further investigate Brayton Point. However, OE's non-public investigation into FCA8 bidding behavior, initiated following a non-public referral from the ISO and the IMM,

³¹ *Id.* at P 9.

³² *Id.* at PP 9-10.

³³ *Id.* at P 11.

³⁴ NHEC and MPUC joined as Petitioners in the NRECA/APPA request.

continues.³⁵ If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCA1 Results Remand Proceeding (ER08-633)**

As previously reported, the DC Circuit issued on December 23, 2011, a *per curiam* order³⁶ that PSEG's May 2010 petition for review be granted, remanding the FERC's orders in this proceeding³⁷ for further consideration, which remains to be acted on. In particular, the FERC must (i) determine whether PSEG's position (that it should receive the full (unprorated) floor price for all its resources that it could not prorate) would be an appropriate way to interpret the then-existing Market Rules and, if not, (ii) respond to PSEG's objections that any contrary result would result in "undue discrimination" and would be "inconsistent with the fundamental policy goals" of FCM. On October 15, 2012, PSEG filed a motion requesting that the FERC issue an order on remand directing the ISO to pay PSEG the full FCA floor price without further delay (for PSEG, the difference totaling \$2.8 million plus interest). The ISO filed on October 31, 2012 an answer to PSEG's October 15 motion. On November 1, 2012, Connecticut Generators³⁸ submitted comments supporting PSEG's request and a few of the Connecticut Generators moved to intervene out-of-time. As noted, this matter remains pending before the FERC.

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **Fuel Price Adjustment Revisions (ER14-2929)**

On September 23, the ISO and NEPOOL jointly filed changes to revise the provision addressing automated fuel price adjustments in Section III.A.3.4 of Appendix A to Market Rule 1 and to make a number of clean-up changes (collectively, the "Fuel Price Adjustment Revisions"), in preparation for the December 3, 2014 implementation of the energy market offer flexibility ("EMOF") rules. The Fuel Price Adjustment Revisions expand the types of information Market Participants can provide to support their submitted fuel prices and limit the conditions under which the IMM will restrict a Market Participant from submitting fuel price adjustments through the automated interface. A December 3, 2014 effective date was requested. The Fuel Price Adjustment Revisions were unanimously supported by the Participants Committee at its September 12, 2014 meeting. Comments on the Fuel Price Adjustment Revisions are due on or before October 14. Thus far, interventions have been filed by Calpine, Dominion, and NRG. If you have any questions, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Regulation Market Dispatch Changes (ER14-2918)**

On September 22, the ISO and NEPOOL jointly filed Market Rule changes to provide an energy-neutral dispatch option for non-generation resources ("Regulation Market Dispatch Changes"). This approach addresses the FERC's concerns about the non-discriminatory participation of limited energy resources in the Regulation Market by relying on the use of separate but coordinated dispatch signals. The Regulation Market Dispatch Changes also include additional revisions to the previously-accepted rules to clarify certain provisions, correct errors and to conform the rules to the expected December 3, 2014 implementation of the

³⁵ *September 16 Order* at P 11.

³⁶ *PSEG Energy Res. & Trade LLC and PSEG Power Conn. LLC v. FERC*, No. 10-1103, 2011 U.S. App. LEXIS 25659, (D.C. Cir. Dec. 23, 2011).

³⁷ *ISO New England Inc.*, 123 FERC ¶ 61,290 (June 20, 2008); *reh'g denied*, 130 FERC ¶ 61,235 (Mar. 24, 2010), *remanded*, *PSEG Energy Res. & Trade LLC and PSEG Power Conn. LLC v. FERC*, No. 10-1103, 2011 U.S. App. LEXIS 25659, (D.C. Cir. Dec. 23, 2011).

³⁸ "Connecticut Generators" are CP Energy Marketing (US) Inc. and Bridgeport Energy LLC (collectively, "Capital Power"); Dominion Resources Services ("Dominion"); Milford Power Co. and EquiPower Resources Management (collectively, "EquiPower"); NRG Power Marketing, Conn. Jet Power, Devon Power, Middletown Power, Montville Power, Norwalk Power, and Somerset Power (collectively, "NRG"); and PPL EnergyPlus.

EMOF changes. The Regulation Market Dispatch Changes were unanimously supported by the Participants Committee at its September 12, 2014 meeting. Comments on the Regulation Market Dispatch Changes are due on or before October 14. If you have any questions, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Waiver Request: Deadline for QDN Challenge (GDF SUEZ) (ER14-2886)**

On September 15, GDF SUEZ requested a waiver of the deadline to challenge a portion of an FCA9 Qualification Determination Notification (“QDN”). GDF SUEZ seeks the waiver in order to qualify Northfield Mountain at its full winter capacity (22 MW more than identified in the QDN). Comments on this waiver request are due on or before October 6, 2014. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request: New Capacity Qualification Deadlines (MMWEC) (ER14-2771)**

On September 24, the FERC denied MMWEC’s requested waiver of the FCA9 New Capacity Qualification Deadlines.³⁹ As previously reported, the waiver would have enabled ISO consideration of the 2 MW Ipswich Wind Independence Project qualification package. The ISO, in a September 12 pleading, opposed the waiver request, asserting that the MMWEC request did not meet the FERC’s requirements for waivers. The FERC did not find that MMWEC’s statement that its underlying error was made in good faith a sufficient basis to justify waiving an express deadline. The FERC reiterated that it “will not automatically grant waiver of ISO-NE’s Tariff requirements merely because we are asked to do so – especially given ISO-NE’s objection to waiver of its tariff.” Similarly, the FERC was unpersuaded that the requested waiver was of limited scope or would not have adverse consequences on any third party or the FCM.⁴⁰ Challenges, if any, to the September 24 order must be filed on or before October 24. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Competitive Offer Test Revisions (ER14-2686)**

On August 22, the ISO and NEPOOL jointly submitted revisions to Market Rule 1 Appendix A to ensure the competitive offer test, which is used by the ISO to determine whether Market Participants are exempt from certain Shortage Event availability penalties, functions as intended when the Energy Market Offer Flexibility (“EMOF”) changes are implemented. While a December 3, 2014 effective was requested, the parties requested a FERC order on this filing by October 21 to facilitate implementation of the Competitive Offer Test Revisions software and process changes together with the EMOF changes. The Competitive Offer Test Revisions were unanimously supported by the Participants Committee at its August 1, 2014 meeting. Doc-less interventions were filed by Dominion, NRG and NU. Comments on this filing were due on or before September 12, 2014; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ISO CSO Deferral Proposal (ER14-2440)**

As announced at the last Participants Committee meeting, the FERC accepted on September 12, 2014 revisions to the FCM Market Rules and Financial Assurance Policy to allow a new capacity resource to seek a one-year deferral of the start of its Capacity Supply Obligation (“CSO”).⁴¹ The revisions were accepted without change or condition, effective July 17, 2014, as requested. Unless the September 12 order is challenged, with any challenges due on or before October 14, 2014, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

³⁹ *Mass. Mun. Wholesale Elec. Co.*, 148 FERC ¶ 61,227 (Sep. 24, 2014).

⁴⁰ *Id.* at PP 13-14.

⁴¹ *ISO New England Inc.*, 148 FERC ¶ 61,185 (Sep. 12, 2014).

- **FCM PI Jump Ball Compliance Filing (ER14-2419)**

The ISO's July 14 compliance filing remains pending before the FERC. As previously reported, in response to directives in the FERC's May 30, 2014 *Order on Tariff Filing and Instituting Section 206 Proceeding* (the "*PI Order*"),⁴² the ISO submitted, on July 14, 2014, proposed Market Rule changes to its "pay-for-performance" ("PFP") design. The July 14 compliance filing included changes to address FERC directives in the *PI Order* concerning the treatment of Energy Efficiency resources, higher Reserve Constraint Penalty Factor ("RCPF") values, and exemptions in instances of certain transmission-related constraints ("ISO PI Compliance Changes"). The ISO PI Compliance Changes were considered by the Participants Committee at its July 10 special meeting. Not a single Participant supported the ISO PI Compliance Changes.⁴³ Interventions were submitted by Calpine, Dynegy, Emera, Exelon, GDF SUEZ, MPUC, NRG, and UI. Protests were filed by NEPOOL, Brookfield, CT/RI,⁴⁴ First Wind, NESCOE, NEPGA/EPGA, Public Systems,⁴⁵ NU, PSEG, Renewable Energy New England, Inc. ("RENEW"), and Verso. On August 15, the ISO answered the August 4 protests. On August 28, NEPOOL answered the ISO's August 15 protest. If you have any questions related to this proceeding, please contact Dave Doot (860-275-0102; dtldoot@daypitney.com), Pat Gerity (860-275-0533; pmgerity@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Winter 2014/15 Reliability Program (ER14-2407)**

As previously reported, the FERC conditionally accepted, on September 9, the Tariff revisions jointly filed by the ISO and NEPOOL intended to maintain reliability through fuel adequacy by creating incentives for dual-fuel resource capability and participation, offsetting the carrying costs of unused firm fuel purchased by generators and providing compensation for demand response services ("Winter 2014/15 Reliability Program").⁴⁶ In its *Winter 2014/15 Reliability Program Order*, the FERC required the ISO to initiate a stakeholder process by January 1, 2015 to develop a "market-based" proposal to address reliability concerns for the 2015/16 Winter and future winters, as necessary. As part of those efforts, the FERC also directed the ISO to submit a stakeholder meeting schedule on or before October 9 and progress reports every 60 days thereafter for the next 12 months. No Section 206 proceeding was initiated despite requests made in comments (summarized in previous Reports). The FERC also directed the ISO to continue to analyze the appropriateness of the 1.75 volatility ratio of the higher-priced fuel index (included as part of new market monitoring changes) and include its analysis and recommendations as part of the IMM's Annual Markets Report. The Winter 2014/15 Reliability Program was accepted effective as of December 3, 2014, as requested. Any challenges to the *Winter 2014/15 Reliability Program Order* will be due on or before October 9, 2014. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Demand Curve Changes (ER14-1639)**

As previously reported, the FERC conditionally accepted on May 30, 2014, the April 1 revisions to the FCM rules jointly submitted by the ISO and NEPOOL that establish a system-wide sloped demand curve ("Demand Curve Changes").⁴⁷ The Demand Curve Changes define the shape of the system-wide sloped demand curve (with key points defined by CONE and the 0.1 days/year LOLE target) illustrated below, extend the period

⁴² *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (May 30, 2014) ("*PI Order*"), clarification and reh'g requested.

⁴³ Comments by NEPOOL members during the Participant Processes made clear that there was either no opposition to the other compliance changes filed by ISO-NE or opposition was limited to the ISO's proposed approach to address the issue of inefficient price signals in instances of intra-zonal transmission constraints.

⁴⁴ "CT/RI" are CT PURA, CT OCC, CT AG, CT DEEP, and the RI PUC.

⁴⁵ "Public Systems" are CMEEC, MMWEC, NHEC, and VEC.

⁴⁶ *ISO New England Inc. and New England Power Pool Participants Comm.*, 148 FERC ¶ 61,179 (Sep. 9, 2014) ("*Winter 2014/15 Reliability Program Order*").

⁴⁷ *ISO New England Inc. and New England Power Pool Participants Comm.*, 147 FERC ¶ 61,173 (May 30, 2014) ("*Demand Curve Order*"), reh'g requested.

during which a Market Participant may “lock-in” the capacity price for a new resource from five to seven years, establish a limited renewables, and eliminate, at the system-wide level, the administrative pricing rules that were necessary in certain market conditions under the vertical demand curve construct. The Demand Curve Changes were accepted effective June 1, 2014, as requested, for implementation prior to associated FCA9 deadlines. As a condition to its acceptance, the FERC directed the ISO, in a 60-day compliance filing, to clarify how new resources could qualify for the Renewable Technology Resources MOPR exemption in future auctions.⁴⁸ Requests for rehearing of the *Demand Curve Order* were filed by Exelon/Entergy, MMWEC/NHEC, NextEra, NEPGA, PSEG, and TransCanada. On July 28, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC.

Compliance Filing. On July 11, the ISO submitted the required 60-day compliance filing to clarify how new resources could qualify for the renewables exemption in future auctions. In that filing, the ISO explained that “new resources could qualify for the exemption in future auctions, but only as long as the new resources qualify as a renewable technology project (e.g., solar power) under a renewable standard or goal that was in effect on January 1, 2014.” NEPGA submitted comments supporting the compliance filing on August 1, 2014. The compliance filing is pending before the FERC. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Performance Incentives Jump Ball Filing (ER14-1050)**

As previously reported, the ISO and NEPOOL submitted on January 17, 2014, two alternative versions of Market Rule changes intended to improve the operating performance of capacity resources in New England -- the “ISO-NE Proposal” and the “NEPOOL Proposal”. Both Proposals sought to further address existing reliability, investment and resource performance challenges in New England. However, the two proposals offered fundamentally different approaches. The ISO-NE Proposal would redefine capacity as a different product where payments are affected by whether a resource is providing energy and/or operating reserves in Real-Time three years hence. Through its “pay-for-performance” mechanism, the ISO Proposal abandoned longstanding capacity market principles in New England and the other RTO markets and converts the FCM from a market designed to ensure long-term resource adequacy to one that is driven primarily by prospective and largely unpredictable actual production. Resources not producing energy or reserves at the time of a “Capacity Scarcity Condition” for any reason would be subject to significant penalties, even if that scarcity condition occurs during very low load conditions, or is caused by transmission outages or even by errors in the ISO’s load forecasting. The NEPOOL Proposal, in contrast, built upon a series of Market Rule changes, either made or are pending, proposed changes that would enhance the current market design and achieved the objective of improving the performance incentives for resources in the ISO-NE electricity markets. The Proposals were submitted pursuant to “jump ball provision” of the Participants Agreement (Section 11.1.5).

On May 30, 2014, the FERC issued an order in response to the jump ball filing.⁴⁹ As more fully summarized in the May 31 memorandum circulated to the Committee and posted on the NEPOOL website (http://www.NEPOOL.com/Litigation_Reports.php), the FERC concluded that the existing Tariff, specifically the current FCM payment design, “is unjust and unreasonable, because it fails to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits” and instituted a proceeding under Section 206 of the FPA (see EL14-52 in Section I above). Concluding that neither the ISO-NE Proposal nor the NEPOOL Proposal, standing alone, had been shown to be just and reasonable, the FERC, drawing features from each Proposal, went on to direct the ISO to submit by July 14, 2014 Tariff revisions reflecting a modified version of the ISO-NE Proposal and an increase in the Reserve Constraint Penalty Factors, consistent with NEPOOL’s Proposal. Specifically, the compliance filing was to include (1) changes to implement ISO-NE’s proposed two-settlement capacity market design with certain modifications, and (2) changes to increase the RCPF values for Thirty-Minute Operating Reserves to \$1,000/MWh and for Ten-

⁴⁸ *Id.* at P 88.

⁴⁹ *See PI Order.*

Minute Non-Spinning Operating Reserves to \$1,500/MWh. The FERC established a June 9, 2014 refund effective date.⁵⁰ Requests for clarification and/or rehearing of the *PI Order* were filed by: NEPOOL, Connecticut and Rhode Island, Dominion, MMWEC, Indicated Generators, NEPGA, NextEra, Potomac Economics, and PSEG/NERG. On July 28, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending before the FERC.

Compliance Filing (ER14-2419). On July 14, the ISO submitted a filing in response to the *PI Order*. That filing is summarized under ER14-2419 above.

If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dttdoot@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com), Eric Runge (617-345-4735; ekrunge@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

• **Exigent Circumstances Filing – FCM Admin. Pricing Rules (ER14-463)**

NEPGA's request for rehearing and clarification of the *Jan 24 Exigent Circumstances Order* in this proceeding remains pending. As previously reported, the FERC accepted, on January 24, revisions to the FCM administrative pricing rules that (i) addressed what the ISO identified as a "gap" in the Insufficient Competition rules; (ii) set an administrative rate of \$7.025/kW-month to be applied if there is Insufficient Competition (as the ISO proposed to redefine it) or Inadequate Supply in FCA8; and (iii) made additional clarifying changes to the FCM administrative pricing rules (collectively, the "FCM Pricing Rule Changes").⁵¹ The FCM Pricing Rule Changes became effective January 24, 2014, as requested. In accepting the filing, the FERC established a \$7.025/kW rate, should the administrative pricing provisions trigger, for FCA8, replacing existing Tariff provisions that it found unjust and unreasonable in the Administrative Pricing Rules Complaint order (see EL14-7 in Section I above).⁵² Addressing the ISO's statements about a sloped demand curve as a long-term solution to the issues presented in this proceeding, the FERC, noting its concerns that waiting until Summer 2014 for such a proposal to be filed would not allow sufficient time for implementation by FCA9, the FERC stated

Given ISO-NE's explanation that a sloped demand curve will address the difficult and challenging issues presented here, and based on ISO-NE's statements that its proposal here is intended to be temporary and address concerns for FCA8, we will direct ISO-NE to submit its proposed demand curve by April 1, 2014, to allow sufficient time for implementation prior to FCA9.⁵³

Demand Curve Changes were filed by April 1, as directed, and conditionally accepted (see ER14-1639 above). NEPGA requested clarification and rehearing of the *Jan 24 Exigent Circumstances Order* on February 24, 2014. The FERC issued on tolling order on March 24, 2014 affording it additional time to consider the NEPGA rehearing request, which remains pending before the FERC.

If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dttdoot@daypitney.com), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

⁵⁰ See n. 4 *supra*.

⁵¹ *Jan 24 Exigent Circumstances Order*.

⁵² The order also accepted the ISO's proposed changes to correct the IC Gap and the remaining administrative pricing provisions. Addressing the questions concerning the "Exigent Circumstances" underlying the filing, the FERC found that the ISO had satisfied the prescribed criteria for an Exigent Circumstances filing: "ISO-NE justifiably determined that failing to immediately implement a change prior to FCA 8 could affect the short-term competitiveness and efficiency of the markets and, in the long-term, affect system reliability." *Id.* at P 52.

⁵³ *Id.* at P 30.

- **Order 755 Regulation Market Changes (ER12-1643)**

On September 30, the FERC accepted tariff sheets extending the effective date of the new Regulation Market design to March 31, 2015 (rather than October 1, 2014).⁵⁴ As previously reported, the ISO explained that among the reasons for the March 31, 2015 requested effective date were to allow the ISO time to: (i) receive a FERC order on the Regulation Market Dispatch Changes (*see* ER14-2918 above); (ii) develop the necessary software to accomplish the energy neutral dispatch of Regulation resources; and (iii) not interfere with higher priority market and reliability projects underway now and continuing through Winter 2014/15. Unless the September 30 order is challenged, with any challenges due on or before October 20, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Redesign Compliance Filing: FCA8 Revisions (ER12-953 et al.)**

As previously reported, the FERC, on February 12, 2013, conditionally accepted in part, and rejected in part, revisions to the FCM and FCM-related rules in the Tariff (“FCA8 Revisions”) filed by the ISO and the PTO AC.⁵⁵ The *FCA8 Revisions Order* accepted the following aspects of the FCA8 Revisions as compliant with its prior FCM Orders: the ISO’s offer review trigger prices;⁵⁶ unit specific offer review;⁵⁷ the ISO’s proposal to subject a resource to offer floor mitigation until that resource clears in one FCA; imports’ treatment under MOPR;⁵⁸ no exemptions to MOPR for new Self-Supplied Resources;⁵⁹ the application of mitigation to *all* new resources offering into the FCM, including renewables that are procured pursuant to state policy initiatives;⁶⁰ \$1.00/kW-month Threshold to trigger IMM review of Dynamic De-List Bids;⁶¹ and a number of other additional revisions.⁶² The *FCA8 Revisions Order* rejected: the ISO’s proposed methodology for reducing the offer floor of an uncleared resource that has already achieved commercial operation at the time of an FCA (directing the ISO to submit a revised proposal that subjects a resource to an offer floor until it has demonstrated that it is needed by the market);⁶³ and the ISO’s request to model only 4 capacity zones for FCA8 (the ISO’s Capacity Zones Changes were accepted in *ISO New England Inc.*, 147 FERC ¶ 61,071 (2014)). Two requests for rehearing of the *FCA8 Revisions Order* were filed on March 15, 2013, one by MMWEC, NHEC, APPA, NEPPA, and NRECA; the other, by EMCOS and Danvers. On April 11, NEPGA filed an answer to the MMWEC *et al.* request. On April 15, 2013, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC.

If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Eric Runge (617-345-4735; ekrunge@daypitney.com) or Dave Doot (860-275-0102; dttdoot@daypitney.com).

⁵⁴ *ISO New England Inc.*, 148 FERC ¶ 61,253 (Sep. 30, 2014).

⁵⁵ *ISO New England Inc.*, 142 FERC ¶ 61,107 (Feb. 12, 2013) (“*FCA8 Revisions Order*”).

⁵⁶ *FCA8 Revisions Order* at PP 37-38.

⁵⁷ *Id.* at P 53.

⁵⁸ *Id.* at P 70.

⁵⁹ *Id.* at P 80.

⁶⁰ *Id.* at P 97.

⁶¹ *Id.* at P 126.

⁶² *Id.* at P 127.

⁶³ *Id.* at PP 63-64.

IV. OATT Amendments / TOAs / Coordination Agreements

• **Order 784 Compliance Filing (ER14-877)**

As previously reported, the FERC *rejected* on September 9 the ISO's December 27, 2013 filing in response to *Order 784*.⁶⁴ The September 9 order (i) found (and explained why) the ISO had failed to demonstrate that the ISO Tariff is consistent with or superior to the reforms directed by *Order 784*,⁶⁵ and (ii) denied the ISO's request to waive *Order 784*'s new Area Control Error ("ACE") data posting requirements.⁶⁶ Accordingly, the FERC directed the ISO on or before October 9, 2014 (a) to submit a compliance filing inserting the new *pro forma* Schedule 3 language regarding consideration of the speed and accuracy of resources into Schedule 3 of the Tariff and (b) to post historical one-minute and ten-minute ACE data on its OASIS, consistent with *Order 784*'s requirements. Any challenges to the FERC's September 9 order will also be due on or before October 9, 2014. The Participants Committee will be asked at its October 3 meeting to support Transmission Committee-recommended revisions to Schedule 3 of Section II of the ISO Tariff to respond to the September 9 order (agenda item # 6). If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

• **Order 1000 Interregional Compliance Filing (ER13-1960; ER13-1957)**

On July 10, 2013, the ISO, NEPOOL and the PTO AC jointly filed revisions to Sections I and II of the Tariff to comply with the interregional coordination and cost allocation requirements of *Orders 1000* and *1000-A* (the "*Order 1000* Interregional Compliance Changes") (ER13-1960). In addition, the ISO, on behalf of itself, NYISO and PJM, filed an Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol ("*Amended Protocol*") as part of its compliance changes (ER13-1957). The *Order 1000 Interregional Compliance Changes* include (i) revisions to Attachment K to add provisions describing the interregional coordination provisions included in the Amended Protocol, as well as adding other provisions facilitating the consideration of interregional solutions to regional needs; (ii) a new Schedule 15 reflecting the methodology for allocation among ISO-NE and NYISO of the costs of approved interregional transmission projects; (iii) revisions to Schedule 12 describing the regional cost allocation within New England of the costs of approved interregional transmission projects; and (iv) conforming changes to Tariff Section I. The *Order 1000* Interregional Compliance Changes and the Amended Protocol were supported by the Participants Committee at its June 27 Summer Meeting. On August 7, the FERC extended the comment deadline on these filings to and including September 9, 2013. Doc-less motions to intervene were filed by a number of New England parties in both proceedings, including Dominion, Exelon, PPL, PSEG, and NEPOOL (in the Protocol proceeding (in which it was not a filing party)). On August 26, 2013, NEPOOL filed comments supporting the Protocol. NEPOOL added that "From a stakeholder perspective, stakeholder input into revisions to the Protocol as it evolves over time would be easier and more likely to be taken into account if it were made part of the individual regional tariffs of each of the Northeast ISOs rather than existing solely as a stand-alone three-party agreement". On September 9, NESCOE submitted comments generally supporting the filings, but reserving the right to further comment on these filings should the substance of the changes be modified as a result of further FERC (see ER13-193 and ER13-196 below) or federal court proceedings. Public Interest Organizations⁶⁷ raised concerns that the Protocol and related amendments "do not meet certain of the transparency and cost allocation aspects of [*Order 1000*]'s minimum requirements." On September 24, 2013, the ISO answered Public Interest Organizations' and NEPOOL's

⁶⁴ *ISO New England Inc.*, 148 FERC ¶ 61,180 (Sep. 9, 2014).

⁶⁵ *Id.* at PP 14-15 (explaining why it disagreed that inclusion of the Schedule 3 language was unnecessary or would introduce confusion).

⁶⁶ *Id.* at P 21 ("So long as a market participant in New England may opt to self-supply Regulation Service and access to Area Control Error data may provide some positive value to that participant, we find it appropriate for ISO-NE to post such data")

⁶⁷ "Public Interest Organizations" are Conservation Law Foundation, ENE, Natural Resources Defense Council, Pace Energy and Climate Center, and the Sustainable FERC Project.

comments. These matters remain pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Order 1000 Compliance Filing (ER13-193; ER13-196)**

Rehearing of the FERC's May 17, 2013 order on the region's *Order 1000* compliance filing⁶⁸ (described in previous Reports) remains pending. As previously reported, the *Order 1000 Compliance Order* accepted the ISO-NE/PTO compliance filing as partially complying with *Order 1000*, but required changes to the compliance proposal. The primary change was the elimination of the Right of First Refusal ("ROFR") and the establishment of competitive transmission development for all regional transmission projects (with an exception to the elimination of the ROFR for transmission needed for reliability within three years of the needs assessment determination and subject to certain other limiting criteria). Additionally, the *Order 1000 Compliance Order* required that the public policy transmission proposal be revised to: (i) make the ISO, rather than the New England states, the entity that evaluates and selects which transmission projects will be built to meet transmission needs driven by public policy; and (ii) include an *ex ante* default cost allocation method, transparent to all stakeholders, developed in advance of particular transmission facilities being proposed, rather than leaving it to the states to decide cost allocation on a project-specific basis after particular projects are proposed. While requiring these fundamental changes to the public policy transmission part of the filing, the *Order 1000 Compliance Order* also allowed for the NESCOE-driven proposal for both selection of projects and cost allocation to remain in the tariff as a complementary process for voluntary transmission projects alongside the *Order 1000*-compliant process. A more detailed summary of the *Order 1000 Compliance Order* was circulated to the Participants Committee on May 20, 2013. On June 17, the ISO, LS Power, PTO AC and NESCOE each filed requests for clarification and/or rehearing of the *Order 1000 Compliance Order*. On June 28, the ISO answered LSP Power's request concerning the effective date for the *Order 1000* compliance changes. On July 16, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending before the FERC.

Order 1000 November 15 Compliance Order Changes. On November 15, 2013, the ISO and the PTO AC jointly submitted proposed revisions to Sections I and II of the Tariff and to the Transmission Operating Agreement ("TOA") (the "Compliance Revisions") to comply with the FERC's May 17, 2013 *Order 1000 Compliance Order*. The revisions included planning revisions (addressing competitive processes for developing new regional transmission projects), cost allocation revisions (regarding the allocation of costs for Public Policy Transmission Projects), and TOA revisions. The Planning Revisions and the Cost Allocation Revisions filed by the ISO and PTO AC were considered but not supported by the Participants Committee at its November 8, 2013 meeting.

Comments on the November 15 filing were filed by **NEPOOL** (seeking two sets of changes to the Planning Revisions filed by the ISO and PTO AC (i) limiting the scope of transmission projects that are grandfathered under the old, non-competitive processes, so that Proposed Projects are not grandfathered but instead are open to competition; and (ii) ensuring that all Qualified Transmission Project Sponsors ("QTPS") are on an equal footing regarding consulting with the ISO in assessing regional transmission needs and solutions (together, the "NEPOOL Alternative"); but taking no position on the Cost Allocation revisions); **CLF and The Sustainable FERC Project** (supporting the November 15 filing and its public policy planning and regional cost allocation provisions.); EMCOS/Participating Municipals (request the ISO and TOs be required to revise Section 3.3 of Attachment K to eliminate the grandfathering for proposed Transmission Projects, and to revise Schedule 12 to ensure that public power systems not subject to state Public Policy requirements are exempted from any obligation to pay for Public Policy projects); **Environmental Groups**⁶⁹ (each supporting the Cost Allocation Revisions, but noting continuing concern that the region's planning process fails to produce more cost-effective and efficient planning outcomes); **LSP Transmission** (supporting

⁶⁸ *ISO New England Inc.*, 143 FERC ¶ 61,150 (May 17, 2013) ("*Order 1000 Compliance Order*").

⁶⁹ "Environmental Groups" are ENE, Connecticut Fund for the Environment, Environment Council of Rhode Island, Health Care Without Harm, The Natural Resources Council of Maine, and The Sustainable FERC Project.

NEPOOL's Alternative, requesting a January 1, 2014 effective date for the compliance filing, and protesting the hold harmless provision contained in Attachment O, Section 9.01, the ISO's evaluation process and the proposed study deposit), **MA DPU** (supporting the Cost Allocation Revisions); **NESCOE** (without expressing a position on the Cost Allocation Revisions, affirming its support for NESCOE it having a central role in determining how public policy planning need relates to cost allocation); **New Hampshire Transmission** ("NHT") (protesting the November 15 filing and suggesting specific amendments to the proposal to be submitted a short time after an order on the second compliance filing is issued); **Public Systems**⁷⁰ (requesting that the FERC adopt MMWEC's cost allocation proposal and direct the Filing Parties to include an express right of consumer-owned utilities to opt out of the non-regional allocated costs of projects satisfying policy requirements that do not apply to them); and **VT/RI Parties**⁷¹ (protesting the Cost Allocation Revisions). Answers to the protests and comments were filed on January 15 by the ISO, PTO AC, and MA DPU (to the VT/RI Parties). On February 4, 2014, NHT filed an answer to the January 15 answers by the ISO and PTO AC. The ISO answered the NHT February 4 answer on February 18, 2014.

These matters remain pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

• Schedule 21- NSTAR: MBTA LSA (ER14-2596)

On August 5, as amended September 5, NSTAR and the ISO filed a non-conforming Local Service Agreement ("LSA") by and among NSTAR, Massachusetts Bay Transportation Authority ("MBTA"), and the ISO for Local Network Service under Schedule 21-NSTAR of the ISO OATT (the "MBTA LSA"). The MBTA LSA replaces a long-standing bilateral *pro forma* Service Agreement ("Current Agreement") between MBTA and NSTAR for service under Schedule 21-NSTAR. While the MBTA LSA is based on the form of LSA contained in Schedule 21-Common under the ISO OATT, it is non-conforming and is being filed insofar as it reflects different rates from those set forth in Schedule 21-NSTAR, i.e., a Direct Assignment Charge for the K Street Point of Delivery. A May 1, 2014 effective date was requested. No comments on the initial LSA filing were filed. Comments on the amendments to the LSA were due on or before September 26, 2014; none were filed. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

• Order 792 Compliance Filing (ER14-2583)

On August 4, the ISO, NEPOOL, and the PTO AC jointly submitted revisions to the Small Generator Interconnection Procedures ("SGIP") and Small Generator Interconnection Agreement ("SGIA") set forth in Schedule 23 of the ISO Tariff in response to the requirements of *Order 792*.⁷² The *Order 792* changes were unanimously supported by the Participants Committee at the June 26, 2014 Summer Meeting. Comments on this filing were due on or before August 25, 2014. Doc-less interventions were filed by Dominion, Exelon and NRG,

⁷⁰ In this proceeding, "Public Systems" are MMWEC and NHEC.

⁷¹ "VT/RI Parties" are the State of New Hampshire Public Utilities Commission ("NHPUC"), the Rhode Island Public Utilities Commission ("RIPUC"), the Vermont Public Service Board ("VT PSB"), the Vermont Public Service Department ("VPSD"), Vermont Electric Power Company ("VELCO"), and Vermont Transco ("VT Transco").

⁷² *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159 (Nov. 22, 2013) ("*Order 792*"), *order clarifying compliance procedures*, 146 FERC ¶ 61,214 (Mar. 20, 2014).

but no comments were filed. This matter remains pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 21-NEP Centennial Island Hydro SGIA (ER14-2534)**

On September 17, the FERC accepted a non-conforming SGIA between New England Power Company (“NEP”) and Centennial Island Hydroelectric Company (“Centennial Island Hydro”). The SGIA addresses the interconnection of Centennial Island Hydro’s 0.64 MW hydroelectric generating facility located in Lowell, Massachusetts. The facility is already subject to a 1989 IA with NEP (which will be cancelled upon the acceptance of the SGIA). The SGIA is non-conforming, among other reasons, because the ISO is not a party to the SGIA and this interconnection was not processed under the ISO’s SGIPs. The SGIA was accepted effective as of June 23, 2014, as requested. Unless the September 17 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-GMP: Merger Revisions; Cancellation of Schedule 21-CVPS (ER12-2304)**

As previously reported, the FERC approved, on August 4, 2014, a November 13, 2013 Settlement Agreement and Offer of Settlement (“Settlement”)⁷³ reported to resolve all disputes in these proceedings (related to concerns with Schedules 21-GMP and 20A-GMP and notices of cancellation filed in 2012 by GMP).⁷⁴ On August 22, GMP submitted 2 compliance filings (reflecting 2 separate effective dates), consistent with the approved Settlement. Comments on the compliance filings were due on or before September 12; none were filed. This matter is pending before the FERC. If there are questions on these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- **Capital Projects Report - 2014 Q2 (ER14-2656)**

On September 25, the FERC accepted the ISO’s Capital Projects Report and Unamortized Cost Schedule covering the second quarter (“Q2”) of calendar year 2014 (the “Report”). The ISO is required to file the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Highlights included the following new projects: FCA9 (\$2.064 million); Enhance Control Room Flat Panel Displays (\$169,000); and Financial Assurance Business Intelligence Integration (\$150,000); and Passive Asset Data Repository (\$78,900). Projects reported to have significant changes include: (i) EMOF changes (\$240,000 increase, reflecting removal of Regulation Market changes from EMOF changes to be implemented December 3); (ii) Divisional Accounting (\$417,200 (deferred to 2015)); and (iii) Control Room Visualization (\$328,600 due to underestimation of costs and consultant turnover). NU filed a doc-less motion to intervene on September 3. NEPOOL filed comments on August 27 supporting the filing. Unless the September 25 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

⁷³ *ISO New England Inc., et al.*, 148 FERC ¶ 61,097 (Aug. 4, 2014).

⁷⁴ *See ISO New England, Inc., Central Vt. Pub. Svc. Corp. and Green Mountain Power Corp.*, 140 FERC ¶ 61,239 (Sep. 24, 2012) (“GMP Merger Order”), *reh’g denied*, 142 FERC ¶ 61,146 (Feb. 25, 2013).

- **Quarterly Reports Regarding Non-Generating Resource Regulation Market Participation (ER08-54)**

The ISO filed its twenty-fourth report on September 19, 2014. As previously reported, the ISO committed in the August 5, 2008 Regulation Filing to provide the FERC with quarterly reports on its progress in implementing and carrying out market rule revisions to allow non-generating resources to provide Regulation, including the Alternative Technologies Pilot Program.⁷⁵ In the 24th report, the ISO reported that, it was planning with NEPOOL to jointly submit later in September Tariff changes to adopt an energy-neutral dispatch method and to re-submit non-controversial parts of the Regulation Market Rule changes that were rejected by the May 20, 2014 Order. The ISO said that, assuming the FERC accepts the new tariff changes, including the energy-neutral dispatch method, the ISO expects to implement the new regulation market design that fully complies with *Order 755* on March 31, 2015. These reports are not noticed for public comment.

- **Reserve Market Compliance (17th) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,⁷⁶ as modified,⁷⁷ the ISO submitted its 17th semi-annual reserve market compliance report on October 1, 2014. In the 17th report, the ISO explained, as in its prior compliance reports, that work on the forward TMSR market issues continues to be on hold due to its efforts on other priority projects (e.g. design and implementation of FCM-related changes (specifically, development of zonal sloped demand curve and elective transmission upgrade proposals and review of the Peak Energy Rent mechanism), development of a “do not exceed” dispatch mechanism for intermittent resources and a proposed design for sub-hourly settlement of the Real-Time Energy Markets. Other higher priority projects include demand resources integration into the Energy Market to comply with *Order 745* and Regulation Market enhancements required to comply with *Order 755*. In addition, the ISO expects to focus on Energy and Reserve Market price formation issues during the next year, as well as complete an ongoing review of NCPC cost allocation rules). The ISO reports that it does not expect to have the available resources needed to revisit this issue until at least 2016. As per the May 9, 2011 letter order in this proceeding, the FERC no longer issues public notices, acts on, or issues orders on these informational filings. If there are questions on this matter, please contact Dave Doot (860-275-0102; ddoot@daypitney.com).

IX. Membership Filings

- **October 2014 Membership Filing (ER14-2980)**

On September 30, NEPOOL requested that the FERC accept: (i) the memberships of Fisher Road Solar I (AR Sector, RG Sub-Sector), Nordic Energy Services (Supplier Sector); and Plant-E Corp. (Supplier Sector) (each effective October 1, 2014); and (ii) the termination of the Participant status of Blue Pilot Energy. Comments on this filing are due on or before November 21.

- **September 2014 Membership Filing (ER14-2749)**

On September 29, the FERC accepted: (i) the memberships of BlueRock Energy, Inc. and E.ON Global Commodities North America LLC (Supplier Sector, each effective September 1, 2014); and (ii) the termination of the Participant status of SBR Energy, Dragon Products and Dragon Energy LLC.

⁷⁵ See Market Rule 1 revisions regarding the provision of Regulation by non-generating resources, *ISO New England Inc. and New England Power Pool*, Docket Nos. ER08-54-000 and -001 (filed Aug. 5, 2008) (the “Regulation Filing”).

⁷⁶ See *NEPOOL and ISO New England Inc.*, 115 FERC ¶ 61,175 (2006) (“ASM II Order”) (directing the ISO to provide updates on the implementation of a forward TMSR market), *reh’g denied* 117 FERC ¶ 61,106 (2006).

⁷⁷ See *NEPOOL and ISO New England Inc.*, 123 FERC ¶ 61,298 (2008) (continuing the semi-annual reporting requirement with respect to the consideration and implementation of a forward market for Ten-Minute Spinning Reserve (“TMSR”).

- **August 2014 Membership Filing (ER14-2541)**

On September 18, the FERC accepted the memberships of SFE Energy Connecticut Inc. and SFE Energy Massachusetts Inc. (each effective August 1, 2014).

X. Misc. - ERO Rules, Filings; Reliability Standards

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FFT Report: September 2014 (NP14-50)**

NERC submitted on September 30, 2014 its Find, Fix, Track and Report (“FFT”) informational filing for the month of September 2014. The August FFT resolves 30 possible violations of 20 Reliability Standards that posed a risk minimal risk to bulk power system (“BPS”) reliability, but which have since been remediated.⁷⁸ The 10 Registered Entities involved each submitted a mitigation activities statement of completion. FFT filings are for information only and will not be noticed for public comment by the FERC.

- **Revised Reliability Standard: PRC-004-3 (RD14-14)**

On September 15, 2014, NERC filed for approval changes to PRC-004-3 (Protection System Misoperation Identification and Correction) as well as a revised definition of “Misoperation” and a new definition of “Composite Protection System” for inclusion in the NERC Glossary of Terms, and the retirement of Reliability Standards PRC-004-2.1a (Analysis and Mitigation of Transmission and Generation Protection System Misoperations) and PRC-003-1 (Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System) as listed in the Implementation Plan (“PRC-004 Changes”). NERC stated that the PRC-004 Changes address outstanding Commission concerns and directives related to PRC-004 and PRC-003 and create a single Reliability Standard requiring Transmission Owners, Generator Owners, and Distribution Providers to identify and correct causes of Misoperations of certain Protection Systems for Bulk Electric System Elements. NERC requested that the PRC-004 Changes be approved, and the existing PRC-004-2.1a and PRC-003-1 be retired, effective on the first day of the first calendar quarter that is one year after the date of FERC approval. Comments on the PRC-004 Changes are due on or before October 20, 2014.

- **Revised Reliability Standard: NUC-001-3 (RD14-13)**

Also on September 15, 2014, NERC filed for approval changes to NUC-001-3 (Nuclear Plant Interface Coordination) as well as the associated VRFs and VSLs, and the retirement of NUC-001-2 as listed in the Implementation Plan (“NUC-001 Changes”). NERC stated that the NUC-001 Changes represent the implementation of recommendations made following a Standards Processes Manual-mandated periodic review. NERC requested that the NUC-001 Changes be approved, and existing NUC-001-2 be retired, effective on the first day of the first calendar quarter that is one year after the date of FERC approval. Comments on the NUC-001 Changes are due on or before October 15, 2014.

- **Revised Reliability Standards: FAC-001-2 and FAC-002-2 (RD14-12)**

On August 22, 2014, NERC filed for approval changes to FAC-001-2 (Facility Interconnection Requirements) and FAC-002-2 (Facility Interconnection Studies) (“FAC Changes”). NERC stated that the FAC Changes are designed to eliminate redundancies between the two Standards and to clarify the actions required under each. NERC added that “the proposed revisions are designed to maintain the existing reliability goals, while providing responsible entities with flexibility regarding how they fulfill the actions required.” NERC requested that the FAC Changes be approved, and the existing FAC-001-1 and FAC-002-1 be retired, effective on

⁷⁸ Only possible violations that pose a minimal risk to Bulk-Power System reliability are eligible for FFT treatment. See *N. Am. Elec. Reliability Corp.*, 138 FERC ¶ 61,193 (Mar. 15, 2012) at PP 46-56.

the first day of the first calendar quarter that is one year after the date of FERC approval. Comments on the FAC Changes were due on or before September 25, 2014; none were filed. This matter is pending before the FERC.

- **Revised Reliability Standards: INT-004-3, INT-006-4, INT-009-2, INT-010-2, INT-011-1 (RD14-4)**

As previously reported, the FERC approved, on June 30, 2014, uncontested changes to five Interchange and Coordination Standards (“INT Changes”).⁷⁹ On August 22, 2014, NERC submitted an errata filing replacing the language in the effective date section of the INT Reliability Standards with “See implementation plan” in order to clarify that the implementation plan contains the correct effective date language. Comments on the errata filing were due on or before September 25, 2014; none were filed. This matter is pending before the FERC.

- **NOPR: New Reliability Standard: CIP-014-1 (Physical Security) (RM14-15)**

On July 17, 2014, the FERC issued a NOPR proposing to approve NERC’s proposed Physical Security Reliability Standard (CIP-014-1).⁸⁰ NERC has reported that CIP-014 is designed to enhance physical security measures for the most critical Bulk-Power System facilities and thereby lessen the overall vulnerability of the Bulk-Power System to physical attacks. CIP-014 requires Transmission Owners and Transmission Operators to protect those critical Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or cascading within an Interconnection. CIP-014 also includes requirements for: (i) the protection of sensitive or confidential information from public disclosure; (ii) third party verification of the identification of critical facilities as well as third party review of the evaluation of threats and vulnerabilities and the security plans; and (iii) the periodic reevaluation and revision of the identification of critical facilities, the evaluation of threats and vulnerabilities, and the security plans to help ensure their continued effectiveness. NERC proposed to make CIP-014 effective as of the first day of the first calendar quarter that is 6 months after the date that CIP-014 is approved, as requested. Comments on this NOPR were due on or before September 8, 2014, and were filed by over 30 parties, including a number of industry organizations, Entergy, and NU. Reply comments were due September 22, 2014⁸¹ and were filed by NIPSCO, SmartSenseCom, City of Tallahassee - Electric Utility, and the Foundation for Resilient Societies (“FRS”). This matter is pending before the FERC.

- **NOPR: Revised Reliability Standard: COM-001-2 and COM-002-4 (RM14-13)**

On September 18, 2014, the FERC issued a NOPR proposing to approve changes to COM-1 (Communications) and COM-2 (Operating Personnel Communications Protocols) (together, “COM Changes”).⁸² Proposed COM-001 establishes a clear set of requirements for what communications capabilities various functional entities must maintain for reliable communications. Proposed COM-002 improves communications surrounding operating instructions by setting predefined communications protocols, requiring use of the same protocols regardless of the current operating condition (whether normal, alert, and Emergency operating conditions), and requiring entities to reinforce the use of the documented communication protocols through training, assessment, and feedback. NERC requested that the COM Changes be approved effective as of the first day of the first calendar quarter that is 12 months after the date that the COM Changes are approved by the FERC. Comments on this NOPR are due on or before December 1, 2014.⁸³

⁷⁹ The INT Changes revised: (1) INT-004-3 (Dynamic Transfers); (2) INT-006-4 (Evaluation of Interchange Transactions); (3) INT-009-2 (Implementation of Interchange); (4) INT-010-2 (Interchange Initiation and Modification for Reliability); and (5) INT-011-1 (Intra-Balancing Authority Transaction Identification).

⁸⁰ *Physical Security Reliability Standard*, 148 FERC ¶ 61,040 (Jul. 17, 2014).

⁸¹ The Physical Security NOPR was published in the *Fed. Reg.* on July 23, 2014 (Vol. 79, No. 141) pp. 42,734-42,743.

⁸² *Communications Reliability Standards*, 148 FERC ¶ 61,210 (Sep. 18, 2014).

⁸³ The *Communications Reliability Standards* NOPR was published in the *Fed. Reg.* on Sep. 30, 2014 (Vol. 79, No. 189) pp. 58,709-58,716.

- **NOPR: Revised Reliability Standard: MOD-031-1 (RM14-12)**

On September 18, 2014, the FERC issued a NOPR proposing to approve changes to MOD-31 (Demand and Energy Data) (“MOD-031 Changes”).⁸⁴ The MOD-031 Changes are designed to replace, consolidate and improve upon the “existing MOD-C Standards”⁸⁵ in addressing the collection and aggregation of Demand and energy data necessary to support reliability assessments performed by the ERO and Bulk-Power System planners and operators. Specifically, the MOD-031 Changes, in response to *Order 693*, (1) streamline the MOD Reliability Standards to clarify data collection requirements; (2) include Transmission Planners as applicable entities that must report Demand and energy data; (3) require applicable entities to report weather-normalized annual peak hour actual Demand data from the previous year to allow for meaningful comparison with forecasted values; and (4) require applicable entities to provide an explanation of, among other things: (i) how their Demand Side Management forecasts compare to actual Demand Side Management for the prior calendar year and, if applicable, how the assumptions and methods for future forecasts were adjusted.; and (ii) how their peak Demand forecasts compare to actual Demand for the prior calendar year with due regard to any relevant weather-related variations (e.g., temperature, humidity, or wind speed) and, if applicable, how the assumptions and methods for future forecasts were adjusted. Consistent with FERC’s directives, NERC is also proposing to revise the definition of Demand-Side Management to include activities or programs undertaken by any applicable entity, not just a Load Serving Entity or its customers, to achieve a reduction in Demand. NERC requested that the MOD-031 Changes be approved, and the existing MOD-C Standards be retired, effective on the first day of the first calendar quarter that is 12 months after the date that the MOD-031 Changes are approved by the FERC. Comments on this NOPR are due on or before December 1, 2014.⁸⁶

- **Revised Reliability Standard: BAL-001-2 (RM14-10)**

On May 9, 2014, NERC filed for approval changes to BAL-001-2 (Real Power Balancing Control Performance) (“BAL-001 Changes”). The BAL-001 Changes add a frequency component to the measurement of a Balancing Authority’s Area Control Error (“ACE”) and allows for the formation of “Regulation Reserve Sharing Groups.” NERC requested that the BAL-001 Changes be approved, and the existing BAL-001-1 Standard be retired, effective on the first day of the first calendar quarter that is 12 months after the date that the BAL-001 Changes are approved by the FERC. As of the date of this report, a comment date has not been set for this filing.

- **NOPR: Revised Reliability Standard: PRC-005-3 (RM14-8)**

On July 17, 2014, the FERC issued a NOPR proposing to approve changes to PRC-005-3 (Protection System and Automatic Reclosing Maintenance) (“PRC-005 Changes”).⁸⁷ The PRC-005 Changes include in PRC-005 the maintenance and testing of reclosing relays that can affect the reliable operation of the BPS. The FERC also proposes to approve one new definition and six revised definitions, the assigned VRFs and VSLs, and NERC’s proposed implementation plan. The FERC also proposes to direct NERC to submit a report based on actual performance data, and simulated system conditions from planning assessments, two years after the effective date of the proposed standard (to address whether PRC-005-3 applies to an appropriate set of auto-reclosing relays that can affect BPS reliability. Further, the FERC proposes to direct NERC to modify PRC-005-3 to include maintenance and testing of supervisory relays.⁸⁸ The PRC-005 Changes are to become effective, and the existing PRC-005-2 retired, as of the first day of the first calendar quarter that is 12 months after the date that the PRC-005 Changes are approved by the FERC. Comments on the PRC-005-3 NOPR were due on or before

⁸⁴ *Demand and Energy Data Reliability Standard*, 148 FERC ¶ 61,192 (Sep. 18, 2014).

⁸⁵ The “existing Mod-C Standards” are: MOD-016-1.1, MOD-017-0.1, MOD-018-0, MOD-019-0.1, and MOD-021-1.

⁸⁶ The *Demand and Energy Data Reliability Standard* NOPR was published in the *Fed. Reg.* on Sep. 30, 2014 (Vol. 79, No. 189) pp. 58,716-58,720.

⁸⁷ *Protection System Maintenance Reliability Standard*, 148 FERC ¶ 61,041 (Jul. 17, 2014).

⁸⁸ *Id.* at PP 1-2.

September 23, 2014⁸⁹ and were filed by NERC, EEI, Idaho Power Company, ITC, and the G&T Cooperatives.⁹⁰ This NOPR is pending before the FERC.

• **NOPR: Revised Reliability Standard: MOD-001-2 (RM14-7)**

On June 19, 2014, the FERC issued a NOPR proposing to approve changes to MOD-001-2 (Modeling, Data, and Analysis — Available Transmission System Capability) (“MOD Changes”) proposed by NERC. The MOD Changes replace, consolidate and improve upon the Existing MOD Standards in addressing the reliability issues associated with determinations of Available Transfer Capability (“ATC”) and Available Flowgate Capability (“AFC”). MOD-001-2 will replace the six Existing MOD Standards⁹¹ to exclusively focus on the reliability aspects of ATC and AFC determinations. NERC requested that the revised MOD Standard be approved, and the Existing MOD Standards be retired, effective on the first day of the first calendar quarter that is 18 months after the date that the proposed Reliability Standard is approved by the FERC. NERC explained that the implementation period is intended to provide NAESB sufficient time to include in its WEQ Standards, prior to MOD-001-2’s effective date, those elements from the Existing MOD Standards, if any, that relate to commercial or business practices and are not included in proposed MOD-001-2. The FERC seeks comment from NAESB and others whether 18 months would provide adequate time for NAESB to develop related business practices associated with ATC calculations or whether additional time may be appropriate to better assure synchronization of the effective dates for the proposed Reliability Standard and related NAESB practices. The FERC also seeks further elaboration on specific actions NERC could take to assure synchronization of the effective dates. Comments on this NOPR were due August 25, 2014,⁹² and were filed by NERC, Bonneville, Duke, MISO, and NAESB. The MOD-001-2 NOPR remains pending before the FERC.

• **Order 797: New Reliability Standard: EOP-010-1 (Geomagnetic Disturbance Operations) (RM14-1)**

As previously reported, the FERC approved on June 19, 2014 new Reliability Standard EOP-010-1 (Geomagnetic Disturbance Operations).⁹³ The new Reliability Standard requires BPS owners and operators to develop and implement operational procedures to mitigate the effects of Geomagnetic Disturbances consistent with the reliable operation of the BPS. The FERC also approved the associated VRFs and VSLs, implementation plan, and effective dates proposed by NERC. Accordingly, EOP-010-1 will become effective January 1, 2015. On July 21, 2014, FRS requested rehearing of *Order 797*. On August 20, the FERC issued a tolling order affording it additional time to consider the FRS request, which remains pending before the FERC.

• **NOPR: Revised TOP and IRO Reliability Standards (RM13-15, RM13-14, RM13-12)**

On November 21, 2013, the FERC issued a NOPR⁹⁴ proposing (i) to approve NERC’s proposed revisions to Reliability Standard TOP-006-3 (Monitoring System Conditions) filed in RM13-12, but (ii) to remand changes to the following Interconnection Reliability Operations and Coordination (“IRO”) and Transmission Operating (“TOP”) Reliability Standards filed in RM13-14 and RM13-15:

- IRO-001-3 (Reliability Coordination — Responsibilities and Authorities);

⁸⁹ The PRC-005-3 NOPR was published in the *Fed. Reg.* on July 24, 2014 (Vol. 79, No. 142) pp. 44,475-44,483.

⁹⁰ The “G&T Cooperatives” are Assoc. Elec. Coop., Basin Elec. Power Coop. and Tri-State Generation and Transmission Assoc.

⁹¹ The 6 existing MOD Standards to be replaced by MOD-001-2 are: MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2.

⁹² The MOD-001-2 NOPR was published in the *Fed. Reg.* on June 26, 2014, (Vol. 79, No. 123) pp. 36,269-36,273.

⁹³ *Reliability Standard for Geomagnetic Disturbance Operations*, Order No. 797, 147 FERC ¶ 61,209 (June 19, 2014) (“*Order 797*”), *reh’g requested*.

⁹⁴ *Monitoring System Conditions - Transmission Operations Reliability Standard, Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, 145 FERC ¶ 61,158 (Nov. 21, 2013) (“*Nov 21 NOPR*”).

- IRO-002-3 (Reliability Coordination – Analysis Tools);
- IRO-005-4 (Reliability Coordination – Current Day Operations);
- IRO-0014-2 (Coordination Among Reliability Coordinators);
- TOP-001-2 (Transmission Operations);
- TOP-002-3 (Operations Planning);
- TOP-003-2 (Operational Reliability Data); and
- PRC-001-2 (System Protection Coordination).⁹⁵

As previously reported, the changes to TOP-006-3 filed April 5, 2013 are targeted to address the respective monitoring role and notification obligation of Reliability Coordinators (“RCs”), Balancing Authorities (“BAs”) and Transmission Operators (“TOPs”) by clarifying that TOPs are responsible for monitoring and reporting available transmission resources and that BAs are responsible for monitoring and reporting available generation resources. In addition, the changes confirm that RCs, TOPs, and BAs are required to supply their operating personnel with appropriate technical information concerning protective relays located within their respective areas.

The changes to the IRO Standards were to achieve two important overall reliability benefits: (1) delineate a clean division of responsibilities between the Reliability Coordinator and Transmission Operators; and (2) improve system performance by raising the bar on monitoring of Interconnection Reliability Operating Limits (“IROLs”) and System Operating Limits (“SOLs”) in order to focus monitoring on IROLs and SOLs that are important to reliability.

The changes to the remaining TOP Standards were to upgrade the overall quality of the Standards, eliminate gaps in the requirements, eliminate ambiguity, eliminate redundancies, and address *Order 693* directives. NERC indicated in its April filing that the proposed TOP Standards are also more efficient than the currently-enforceable TOP Reliability Standards because they incorporate the necessary requirements from the eight currently-effective TOP Reliability Standards (TOP-001-1a, TOP-002-2.1b, TOP-003-1, TOP-004-2, TOP-005-2a, TOP-006-2, TOP-007-0, TOP-008-1) and the PER-001-0.2 Reliability Standard into three cohesive, comprehensive Reliability Standards that are focused on achieving a specific result.

Because the proposed TOP and IRO Reliability Standards were interrelated, and because the proposed revisions to Reliability Standard TOP-006-3 involved similar issues raised in the TOP and IRO proposals concerning monitoring of the interconnected transmission network and notification of and by registered entities, the FERC addressed all three proposals together in the one NOPR. Although the FERC acknowledged that the proposed TOP and IRO Reliability Standards contain some improvements over the current Standards, concerns that the changes would create reliability gaps in the Standards that are critical to reliable operation of the BPS resulted in the proposed remand of the proposed TOP Standards.⁹⁶ The FERC went on to explain that

given the interrelationship between the TOP and IRO Reliability Standards and that NERC requests that both sets of standards be addressed together, we believe a remand of the proposed IRO standards in addition to those of the TOP will enable NERC to more comprehensively consider modifications to the standards that would address the reliability concerns identified in this NOPR. This approach, in turn, should allow NERC more flexibility in developing appropriate modifications that address our concerns since changes to the TOP standards might require, in some instances, commensurate changes to the IRO standards.⁹⁷

⁹⁵ The changes in proposed PRC-001-2 were administrative in nature and were limited to removal of three requirements in currently-effective PRC-001-1 that were to be addressed in proposed TOP-003-2.

⁹⁶ *Id.* at P 4.

⁹⁷ *Id.*

Initially, comments are the *Nov 21 NOPR* were due on or before February 3, 2014.⁹⁸ However, on December 20, NERC requested that the FERC defer action in this proceeding to January 31, 2015 to allow NERC time to consider the reliability concerns raised by the FERC in the *Nov 21 NOPR* and by an independent review commissioned by NERC that identified proposed TOP-001-2, PRC-001-2, IRO-001-3, and IRO-005-4 as high risk standards requiring improvement. On January 6, 2014, the ISO/RTO Council and NRECA filed comments supporting NERC's requested deferral. On January 14, 2014, the FERC granted NERC's motion to defer action on the *Nov 21 NOPR* until January 31, 2015, including deferral of the comment due date. Comments were nonetheless submitted on February 3, 2014 by BPA and Idaho Power. On October 1, 2014, NERC submitted the third of its promised quarterly status reports regarding the status of revisions. In the October report, NERC reported that standard drafting team and NERC Staff are diligently working to revise the IRO and TOP Reliability Standards, with a meeting held in late July and a technical conference held in August. NERC reported on ballots of the standards, definitions, and proposed implementation plan taken during the quarter. A drafting team meeting was held September 30 – October 2, 2014.

• **NOPR: BAL-002-1a Interpretation Remand (RM13-6)**

This May 16, 2013 NOPR, which proposes to remand NERC's proposed interpretation of BAL-002 (Disturbance Control Performance Reliability Standard) filed February 12, 2013 (which would prevent Registered Entities from shedding load to avoid possible violations of BAL-002), remains pending.⁹⁹ NERC asserted that the proposed interpretation clarifies that BAL-002-1 is intended to be read as an integrated whole and relies in part on information in the Compliance section of the Reliability Standard. Specifically, the proposed interpretation would clarify that: (1) a Disturbance that exceeds the most severe single Contingency, regardless if it is a simultaneous Contingency or non-simultaneous multiple Contingency, would be a reportable event, but would be excluded from compliance evaluation; (2) a pre-acknowledged Reserve Sharing Group would be treated in the same manner as an individual Balancing Authority; however, in a dynamically allocated Reserve Sharing Group, exclusions are only provided on a Balancing Authority member by member basis; and (3) an excludable Disturbance was an event with a magnitude greater than the magnitude of the most severe single Contingency. The FERC, however, proposes to remand the proposed interpretation because it believes the interpretation changes the requirements of the Reliability Standard, thereby exceeding the permissible scope for interpretations. Comments on the *BAL-002-1a Interpretation Remand NOPR* were due on or before July 8, 2013,¹⁰⁰ and were filed by NERC, EEI, ISO/RTO Council, MISO, NC Balancing Area, Northwest Power Pool Balancing Authorities, NRECA, and WECC. This NOPR remains pending before the FERC.

• **Revised NPCC Regional Reliability Standards Development Procedure (RR14-7)**

On September 15, 2014, NERC requested approval of amendments to NPCC's Regional Reliability Standards Development Procedure ("RRSDP"). The amendments (1) change the name of the RRSDP to the Northeast Power Coordinating Council, Inc. ("NPCC") Regional Standard Processes Manual ("RSPM"), (2) provide organization and clarity to the RSPM by developing separate sections for: (i) the withdrawal of a request for approval of a regional standard before it has been approved, (ii) retirement of an approved NPCC regional standard, (iii) requirements for approval of a process waiver, and (iv) process for correcting errata; (3) incorporate NPCC's Cost Effectiveness Analysis Procedure ("CEAP") into the RSPM; (4) further develop NPCC's clarification process for regional standards, (5) create new appendices for the newly revised RSPM, and (6) recognize the Reliability Standard Audit Worksheet ("RSAW") as necessary to a regional standard developed by the NPCC Standard Drafting Team and the NPCC. Comments on the RRSDP amendments are due on or before October 6, 2014.

⁹⁸ The *Nov 21 NOPR* was published in the *Fed. Reg.* on Dec. 5, 2013 (Vol. 78, No. 234) pp. 73,112-73,128.

⁹⁹ *Electric Reliability Organization Interpretation of Specific Requirements of the Disturbance Control Performance Standard*, 143 FERC ¶ 61,138 (2013) ("*BAL-002-1a Interpretation Remand NOPR*").

¹⁰⁰ The *BAL-002-1a Interpretation Remand NOPR* was published in the *Fed. Reg.* on May 23, 2013 (Vol. 78, No. 99) pp. 30,245-30,810.

- **2015 NERC/NPCC Business Plans and Budgets (RR14-6)**

On August 22, 2014, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2015. FERC regulations¹⁰¹ require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected. NERC reported that its proposed 2015 Funding requirement represents an overall increase of approximately \$10.3 million (18.2%) over NERC's 2014 Funding requirement. NERC reported that a significant portion of its budget increase is for NERC's costs to participate in the Cyber Risk Information Sharing Program ("CRISP"); \$8.94 million of NERC's costs for CRISP will be funded by participating utilities and other entities. The NPCC U.S. allocation of NERC's net funding requirement is \$3.7 million. NPCC requested \$14.78 million in statutory funding (a U.S. assessment per kWh (2013 NEL) of \$0.0000425) and \$1.13 million for non-statutory functions. Comments on this filing were due on or before September 12, 2014. On September 12, Exelon filed comments supporting NERC's requesting NERC's 2015 Business Plan and Budget. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Dynegy/EquiPower (EC14-140)**

On September 11, 2014, Dynegy and EquiPower requested FERC authorization for Dynegy's acquisition of EquiPower's generating assets (Dighton, Elwood, Kincaid, Lake Road, Liberty, MASSPOWER, Milford, Richland-Stryker Generation and Brayton Point). Comments on this filing are due on or before November 11. On September 24, PJM's IMM requested that this proceeding be consolidated with EC14-141 (the acquisition of certain Midwest generating assets from Duke Energy), citing common issues of law and fact and the need to evaluate the impact of the combined transactions on PJM markets. Dynegy opposed that request on September 25. That request is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: Calpine/Constellation (Fore River) (EC14-135)**

On September 5, 2014, Calpine Fore River Energy Center, LLC ("Calpine") and Constellation Mystic Power, LLC ("Constellation") requested FERC authorization for the acquisition by Calpine of the Fore River Generating Station and certain associated assets from Constellation. Comments on this filing were due on or before September 26, 2014; none were filed. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **PURPA Complaint v. MA DPU (Allco Renewable Energy) (EL14-84 et al.)**

As previously reported, Allco Renewable Energy Limited ("Allco") petitioned the FERC on July 28, 2014, to pursue an enforcement action against the MA DPU under the Public Utility Regulatory Policies Act of 1978 ("PURPA").¹⁰² Allco sought a FERC order that would invalidate the MA DPU's regulations that Allco asserted prevented Allco's affiliate QFs from recovering their long-run avoided cost rate (a rate fixed at the outset for the entirety of a QF contract based upon the utility's projected future avoided costs). On August 15, MA DPU requested an extension of time, to November 1, 2014, to respond. National Grid supported the MA DPU's request and Allco indicated it had no objection to an extension that would not prevent the FERC from issuing a decision within the 60-day period provided for in PURPA. On August 18, the FERC granted

¹⁰¹ 18 CFR § 39.4(b) (2014).

¹⁰² Section 210(h)(2) of PURPA permits the FERC to initiate, and for QFs to petition the FERC to initiate, an enforcement action against a State regulatory authority for failure to implement the FERC's PURPA regulations. If the FERC declines to initiate an enforcement action, the petitioning QF then has the right to bring an action in the appropriate U.S. district court to enforce the PURPA regulations.

the extension request, in part, extending the time to file interventions and comments, to and including August 28, 2014. On August 28, the MA DPU filed its protest to the Complaint. Allco answered the MA DPU protest on September 8 and the MA DPU answered the Allco answer on September 19, 2014. On September 26, the FERC issued a notice of its intention not to initiate an enforcement action, clearing the way for Allco to itself bring an enforcement action against the MA DPU in the appropriate court.¹⁰³ If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **FirstEnergy PJM DR Complaint (EL14-55)**

On May 23, 2014, the same day that DC Circuit vacated *Order 745* (see Section XV below), FirstEnergy filed a complaint against PJM requesting that the FERC require the “removal of all portions of the PJM Tariff allowing or requiring PJM to include demand response as suppliers to PJM’s capacity markets”. FirstEnergy also requested that the results of the PJM capacity auction due to be released that same day, to the extent it included and cleared demand response resources, be considered void and legally invalid. PJM’s response, and all comments and interventions were initially due on or before June 12, 2014. However, on June 11, the FERC extended that date to 30 days after the submission by FirstEnergy of an amended complaint. FirstEnergy filed its amended complaint on September 22, 2014. Comments on the FirstEnergy Complaint will be due October 22, 2014. Thus far, more than 60 parties have moved to intervene; no comments or responses have yet been filed. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **E&P Agreements: Blue Sky West & CMP (ER14-2743; ER14-2744)**

On August 29, Central Maine Power (“CMP”) filed Engineering and Procurement (“E&P”) Agreements between CMP and Blue Sky West II, LLC (“Blue Sky West”) to facilitate the interconnection of the Blue Sky West’s 191 MW wind farm in Bingham, Mayfield Township and Kingsbury Plantation, Maine. CMP requested that the Agreements be accepted as follows: (1) the Original E&P Agreement effective October 26, 2012; (2) the First Revised E&P Agreement effective March 20, 2014; and (3) the Second Revised E&P Agreement effective July 17, 2014. Comments on the E&P Agreement filing were due on or before September 19, 2014; none were filed. On September 30, CMP supplemented its filing with marked copies of: the First Revised E&P Agreement, showing differences between the original E&P Agreement and the First Revised E&P Agreement; and the Second Revised E&P Agreement, showing differences between the First Revised E&P Agreement and Second Revised E&P Agreement. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **MISO Methodology to Involuntarily Allocate Costs to Entities Outside Its Control Area (ER11-1844)**

On December 18, 2012, Judge Sterner issued his 374-page initial decision which, following hearings described in previous reports, found at its core that “it is unjust, unreasonable, and unduly discriminatory to allocate costs of Phase Angle Regulating Transformers (“PARs”) of the International Transmission Company (“ITC”) to NYISO and PJM”,¹⁰⁴ which the Midwest ISO (“MISO”) and ITC proposed unilaterally to do (without the support of either PJM or NYISO) in its October 20, 2010 filing initiating this proceeding. For a summary of specific findings, please refer to any of the January to June 2013 Reports.

On January 17, 2013, ITC and MISO challenged the Initial Decision through their Brief on Exceptions. Briefs opposing exceptions were filed by the FERC Trial Staff, MISO TOs, NYISO, NY TOs, PJM, and the PJM TOs. On February 25, Joint Applicants moved to strike a portion of the PJM Brief Opposing Exceptions. On March 12, PJM answered Joint Applicants February 25 motion. MISO (now called “Midcontinent Independent System Operator, Inc.”) moved to lodge a NYISO “Broader Regional

¹⁰³ *Allco Renewable Energy Limited et al.*, 148 FERC ¶ 61,233 (Sep. 26, 2014).

¹⁰⁴ *Midwest Indep. Trans. Sys. Op., Inc.*, 141 FERC ¶ 63,021 (Dec. 18, 2012) (“MISO Initial Decision”) at P 923.

Markets Informational Report” filed March 19, 2014 in ER08-1281 and a related January 16, 2014 “Ontario-Michigan Interface PAR Performance Evaluation Report” (“Evaluation Report”) prepared by MISO, IESO and PJM. Oppositions to that motion to lodge were filed by FERC Staff, NYISO, NY TOs, PJM, and PSEG. This matter remains pending before the FERC. If there are any questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

• **FERC Enforcement Action Pending: Staff Notices of Alleged Violations (IN__-__)**

City Power and K. Tsingas. On August 25, 2014, the FERC issued a notice that Staff has preliminarily determined that (i) City Power Marketing, LLC (“City Power”) and K. Stephen Tsingas violated the FERC’s Anti-Manipulation Rule by engaging in manipulative Up To Congestion trading in PJM during July 2010; and (ii) City Power violated the FERC’s market behavior rules (18 C.F.R. § 35.41 (2014)) by making false statements and omitting material information during the investigation.

Powhatan Energy, HEEP Fund, CU Fund, and H. Chen. On August 5, 2014, the FERC issued a notice that Staff has preliminarily determined that Houlihan (Alan) Chen, HEEP Fund Inc., and CU Fund Inc., and Powhatan Energy Fund, LLC, violated the FERC’s Anti-Manipulation Rule by engaging in manipulative Up To Congestion trading in PJM between June and August 2010. Staff alleges that Chen (on behalf of Powhatan, HEEP Fund, or CU Fund) engaged in Up To Congestion transactions in PJM designed to falsely appear to be spread trades, as a vehicle for collecting Marginal Loss Surplus Allocation (“MLSA”) payments from PJM, by placing millions of megawatt hours of offsetting trades between the same two trading points, in the same volumes and the same hours—an intentional effort to cancel out the financial consequences from any spread between the two trading points while capturing large amounts of MLSA payments. Staff alleges this strategy amounted to wash trading, long prohibited by the FERC.

Twin Cities. On June 12, 2014, the FERC issued a notice that Staff has preliminarily determined that Twin Cities Power-Canada, U.L.C. and certain affiliated companies, including Twin Cities Energy and Twin Cities Power, and individuals Allan Cho, Jason F. Vaccaro, and Gaurav Sharma each violated the FERC’s prohibition of electric energy market manipulation by scheduling and trading physical power in MISO to benefit related swap positions that settle off of real-time MISO prices, including the Cinergy Hub Balance-of-Day Swap traded on IntercontinentalExchange, Inc. (“ICE”), during the period January 1, 2010 through January 31, 2011.

Recall that Notices of Alleged Violations (“NoVs”) are issued only after the subject of an enforcement investigation has either responded, or had the opportunity to respond, to a preliminary findings letter detailing Staff’s conclusions regarding the subject’s conduct.¹⁰⁵ NoVs are designed to increase the transparency of Staff’s nonpublic investigations conducted under Part 1b of its regulations. A NoV does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

• **Waiver of Transmission Standards of Conduct: Emera Maine (f/k/a Bangor Hydro) Request (TS11-5)**

Emera Maine’s October 31, 2011 amended waiver request remains pending before the FERC. As previously reported, the FERC denied, without prejudice, Bangor Hydro’s initial request for waiver of the FERC’s Standards of Conduct requirements.¹⁰⁶ Bangor Hydro requested a limited waiver from the FERC’s Standards of Conduct requirements,¹⁰⁷ to the extent necessary, to permit its transmission function personnel to undertake the actions necessary to re-sell into the New England Market energy from the Rollins Project which the MPUC has mandated it purchase but cannot otherwise sell at retail. The FERC stated that it would revisit its determination if Bangor Hydro brought forward information demonstrating that it met the criteria for waiver set forth in section 358.1(c) and summarized in the order (i.e. a demonstration that Bangor Hydro has

¹⁰⁵ See *Enforcement of Statutes, Regulations, and Orders*, 129 FERC ¶ 61,247 (Dec. 17, 2009), *order on requests for reh’g and clarification*, 134 FERC ¶ 61,054 (Jan. 24, 2011).

¹⁰⁶ *Bangor Hydro-Elec. Co.*, 136 FERC ¶ 61,182 (Sep. 15, 2011) (“*BHE Standards of Conduct Order*”).

¹⁰⁷ See 18 C.F.R. § 358 (2013) *et seq.*

no access to information concerning the operation of the transmission facilities by the ISO and that it obtains information about such matters only by viewing the ISO's OASIS). In response to the *BHE Standards of Conduct Order*, Bangor Hydro amended its waiver request in 2 respects: First, Bangor Hydro revised its request to apply only to the energy required to be purchased from the Rollins Project and the Exeter Agri-Energy Project. Second, Bangor Hydro committed, as a condition of the waiver (if granted), not to engage in any purchases or sales of wholesale electric capacity or energy except for those required under Maine laws and/or regulations or orders of the MPUC. The MPUC filed comments supporting Bangor Hydro's amended waiver request on November 15, 2011. This matter remains pending before the FERC.

XII. Misc. - Administrative & Rulemaking Proceedings

• RTO/ISO Common Metrics Report (AD14-15)

On August 26, 2014, FERC Staff published a "Common Metrics" report, the primary purpose of which is to provide a platform for review of ISO, RTO and utility performance. The Common Metrics Report provides the following two components for a performance review: (1) an analysis of the metrics data to confirm that the data provided by ISOs, RTOs and utilities in regions outside ISO and RTO markets are consistent with the definitions of the common metrics; and (2) an evaluation and confirmation that the common metrics are measuring the same activities and have the same meaning across the industry. FERC Staff determined 30 metrics meeting the criteria for common metrics. FERC Staff reported that further analysis is needed, and indicated that it would request approval for further data collection on performance metrics for the 2008-2012 and 2010-2014 periods from the Office of Management and Budget ("OMB").

• Price Formation in RTO/ISO Energy & Ancillary Services Markets (AD14-14)

On June 19, 2014, the FERC initiated a proceeding to evaluate price formation issues in RTO/ISO energy and ancillary services markets. In its notice, the FERC announced a series of staff workshops to facilitate a discussion with market operators and their stakeholders on the existing market rules and operational practices related to:

- ▶ use of uplift payments;
- ▶ offer price mitigation and offer price caps;
- ▶ scarcity and shortage pricing; and
- ▶ operator actions that affect price.

Sep 8 Workshop. The FERC held its first workshop on September 8, 2014. The September 8 workshop focused on the technical, operational and market issues that give rise to uplift payments and the levels of transparency. The workshop also previewed the scope of the remaining price formation topics. The webcast of the September 8 workshop will be archived and available for 3 months on the FERC's website at <http://ferc.capitolconnection.org/>. Speaker materials have been posted in the FERC's eLibrary. Also posted in eLibrary is a FERC staff report issued August 21 that analyzes "Uplift in RTO and ISO Markets." Since the last report, CME Group filed post meeting comments on October 1.

Oct 28 Workshop. On September 5, the FERC announced that it will hold a second workshop addressing the technical, operational, and market issues related to offer price mitigation and offer price caps, and scarcity and shortage pricing in energy and ancillary services markets operated by RTOs and ISOs, on Tuesday, October 28, 2014 from 8:45 a.m. to 5:00 p.m. The workshop will be open for the public to attend. Further details and a formal agenda will be issued prior to the October 28 workshop. The FERC has established a web page for this issue at <http://www.ferc.gov/industries/electric/indus-act/rto/energy-price-formation.asp>.

- **RTO/ISO Winter 2013-2014 Op and Market Performance (AD14-8)**

On April 1, 2014, the FERC held a technical conference to explore the impacts of and actions taken to respond to recent cold weather events by RTO/ISOs. Discussion focused on: the impact of cold weather events on operational planning and real-time operations, market prices and performance, and regional infrastructure; the actions taken in response to those impacts; gas procurement; and lessons learned that can be shared between regions and applied in future events. ISO-NE's materials were circulated to the Committee on April 1, and are posted with the composite materials for the April 4 meeting. Speaker materials are posted in the FERC's eLibrary as well as at:

<http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=7272&CalType=&CalendarID=116&Date=&View=Listview>.

For those that may have missed the conference, a free recording of the conference will be archived at <http://ferc.capitolconnection.org/> for at least three months. Post-conference comments were filed by over 40 parties, including: ISO-NE, APPA, Dominion, EEI, Entergy, EPSA, Essential Power, Exelon, Macquarie, MMWEC/CMEEC, PSEG, Vitol. The Citizens Utility Board and 202 individuals filed comments on price spikes experienced by energy users during winter 2013/14.

- **NOPR: MBR Authorization Refinements (RM14-14)**

On June 19, the FERC issued a NOPR proposing to revise its current standards, and to streamline certain aspects of its filing requirements, for obtaining market-based rates ("MBR") for sales of electric energy, capacity, and ancillary services.¹⁰⁸ In addition, the FERC clarified certain standards for obtaining and retaining MBR authority. Among other changes, the FERC proposes (i) to permit sellers in RTO/ISO markets with Commission-approved market monitoring and mitigation to include a statement that they are relying on such mitigation to address any potential horizontal market power concerns in lieu of submitting the indicative screens; (ii) to permit sellers to explain that their qualified capacity is fully committed in lieu of including indicative screens in their filings in order to satisfy the FERC's horizontal market power tests and to submit a change in status filing when there is a net increase of 100 MW or more; (iii) to relieve sellers of their obligation to file quarterly land acquisition reports and of the obligation to provide information on sites for generation capacity development in market-based rate applications and triennial updated market power analyses; (iv) to require a change in status filing if there is a 100 MW increase in cumulative nameplate capacity added in any relevant geographic market; and (v) require corporate org charts with all MBR applications and notices of change in status. Comments on this NOPR were due September 23, 2014,¹⁰⁹ and were filed by over 25 parties. This NOPR is pending before the FERC.

- **NOPR: Open Access and Priority Rights on ICIF (RM14-11)**

On May 15, the FERC issued a NOPR proposing to waive the Open Access Transmission Tariff requirements of 18 CFR 35.28 (2013), the Open Access Same-Time Information System requirements of Part 37 of its regulations, 18 CFR 37 (2013), and the Standards of Conduct requirements of Part 358 of its regulations, 18 CFR 358 (2013), for any public utility that is subject to such requirements solely because it owns, controls, or operates Interconnection Customer's Interconnection Facilities ("ICIF"),¹¹⁰ in whole or in part, and sells electric energy from its Generating Facility. The Commission also proposes to find that requiring the filing of an OATT is not necessary to prevent unjust or unreasonable rates or unduly discriminatory behavior with respect to ICIF over which interconnection and transmission services can be ordered. The NOPR also proposes a 5-year safe harbor period during which an ICIF owner subject to the blanket waiver, who initially has excess capacity on its ICIF because it intends to serve its own or its affiliates' future phased generator additions or expansions, may establish a rebuttable presumption for priority right over third parties to use that excess capacity. Comments on this NOPR were due on or before July 29, 2014.¹¹¹ Comments were submitted by over 20 parties, including:

¹⁰⁸ *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Svcs. by Public Utils.*, 147 FERC ¶ 61,232 (June 19, 2014) ("MBR NOPR").

¹⁰⁹ The MBR NOPR was published in the *Fed. Reg.* on July 25, 2014 (Vol. 79, No. 143) pp. 43,536-43,572.

¹¹⁰ ICIF is the term used by the FERC in the NOPR to refer to "generator tie lines".

¹¹¹ The NOPR was published in the *Fed. Reg.* on May 30, 2014 (Vol. 79, No. 104) pp. 31,061-31,072.

APPA, AWEA, EEI, EPSA, First Wind, NextEra, NRECA, and NRG. Since the last Report, the MISO Transmission Owners filed comment replying to the comments of MISO and the ITC Companies. This matter is pending before the FERC.

- **WIRES Request for Policy Statement on ROE for Electric Transmission (RM13-18)**

On June 26, 2013, WIRES¹¹² petitioned the FERC to institute an expedited generic proceeding and to provide such policy and clarifications as necessary to provide “greater stability and predictability regarding regulated rates of return on equity for existing and future investments in high voltage electric transmission infrastructure.” Specifically, WIRES recommended a new policy that (1) standardizes selection of proxy groups; (2) denies complainants a hearing on rates of return for existing facilities unless it is shown that existing returns are at the extremes of the zone of reasonableness; (3) allows consideration of competing infrastructure investments of other industries; (4) permits use of other rate of return methodologies; and (5) supports use of more forward-looking data and modeling. In addition, WIRES urged the FERC to support consideration of a project’s actual and anticipated benefits when a complaint is filed against the ROE for an existing project. Although the WIRES petition has not been noticed for public comments, more than 16 sets of comments have been filed. On October 3, 2013, WIRES submitted a summary of the comments and analysis filed to that point in the proceeding. On October 16, the Organization of PJM States noted its position that the WIRES petition did not present a compelling reason for the FERC to initiate a generic rulemaking proceeding or abandon its Discounted Cash Flow methodology. On November 5, 2013, a letter from US Senator Angus King, urging the FERC to establish a more certain regulatory environment that provide investors the level of confidence necessary to support and encourage needed infrastructure investments, was posted in eLibrary. This matter is pending before the FERC.

- **Order 771: Availability of e-Tag Information to FERC Staff (RM11-12)**

Rehearing of portions of *Order 771* has been requested and remains pending. As previously reported, *Order 771*,¹¹³ issued December 20, 2012, granted the FERC access, on a non-public and ongoing basis, to the complete electronic tags (“e-Tags”) used to schedule the transmission of electric power interchange transactions in wholesale markets. *Order 771* requires e-Tag Authors (through their Agent Service) and Balancing Authorities (through their Authority Service) to take steps to ensure FERC access to the e-Tags covered by this Rule by designating the FERC as an addressee on the e-Tags. The FERC stated that the information made available under this Final Rule will bolster its market surveillance and analysis efforts by helping it detect and prevent market manipulation and anti-competitive behavior. In addition, *Order 771* requires e-Tag information be made available to RTO/ISOs and their Market Monitoring Units, upon request to e-Tag Authors and Authority Services, subject to appropriate confidentiality restrictions. *Order 771* became effective February 26, 2013.¹¹⁴ In response to requests for clarification and/or rehearing of *Order 771* filed by EEI/NRECA, Open Access Technology International, Inc., NRECA (separately), and Southern Companies (collectively, the “Rehearing Requests”), the FERC issued, on March 8, 2013, *Order 771-A*.¹¹⁵ *Order 771-A* addressed only those issues that needed to be answered on an expedited basis to allow affected entities to comply with the requirement to ensure FERC access in a timely manner to the e-Tags covered by *Order 771*.¹¹⁶ The FERC noted that it would issue an additional

¹¹² WIRES, the Working group for Investment in Reliable and Economic Electric Systems, describes itself as a national non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. Information about its principles and members is available on its website www.wiresgroup.com.

¹¹³ *Availability of E-Tag Info. to Comm’n Staff*, Order No. 771, 141 FERC ¶ 61,235 (Dec. 20, 2012) (“*Order 771*”), order on reh’g and clarification, 142 FERC ¶ 61,181 (2013).

¹¹⁴ *Order 771* was published in the *Fed. Reg.* on Dec. 28, 2012 (Vol. 77, No. 249) pp. 76,367-76,380.

¹¹⁵ *Availability of E-Tag Info. to Comm’n Staff*, Order No. 771-A, 142 FERC ¶ 61,181 (Mar. 8, 2013) (“*Order 771-A*”).

¹¹⁶ *Order 771-A* clarified that: (1) Balancing Authorities and their Authority Services will have until 60 days after publication of this order to implement the validation requirements of *Order 771*; (2) validation of e-Tags means that the Sink Balancing Authority, through its Authority Service, must reject any e-Tags that do not correctly include the FERC in the CC field; (3) the requirement for the FERC to be included in the CC field on the e-Tags applies only to e-Tags created on or after

rehearing order, addressing the remaining issues raised on rehearing and clarification, which therefore remain pending before the FERC.

- **Order 676-H: Incorporation of WEQ Version 003 Standards (RM05-5)**

On September 18, 2014, the FERC issued *Order 676-H*,¹¹⁷ which proposes to amend FERC regulations by incorporating by reference, with certain enumerated exceptions, **Version 003** of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant (“WEQ”) of the North American Energy Standards Board (“NAESB”). The Version 003 Standards update earlier versions of these standards previously incorporated by reference into FERC regulations at 18 CFR 38.2. The Version 003 standards include modifications to support Order Nos. 890, 890-A, 890-B and 890-C, including the standards to support Network Integration Transmission Service on an Open Access Same-Time Information System (“OASIS”), Service Across Multiple Transmission Systems (“SAMTS”), standards to support FERC policy regarding rollover rights for redirects on a firm basis, standards that incorporate the functionality for transmission providers to credit redirect requests with the capacity of the parent reservation and standards modifications to support consistency across the OASIS-related standards. The Version 003 Standards also include modifications to the OASIS-related standards that NAESB states support *Order Nos. 676, 676-A, 676-E and 717* and add consistency. In addition, there are modifications to the Coordinate Interchange standards to compliment recent updates to e-Tag specifications, modifications to the Gas/Electric Coordination standards to provide consistency between the two markets, and re-organized and revised definitions to create a standard set of terms, definitions and acronyms applicable to all NAESB WEQ standards. The Version 003 Standards include the Standards addressed in *Order 676-G* and the recent Smart Grid Standards. Order 676-H will become effective October 24, 2014.¹¹⁸

XIII. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jennifer Galiette (860-275-0338; jgaliette@daypitney.com).

- **Inquiry Into Natural Gas Trading, and Proposal to Establish an Electronic Information and Trading Platform (AD14-19)**

On September 18, 2014, Commissioner Moeller convened a meeting to discuss issues related to how transactions are conducted on the natural gas system and potential transactional improvements to address the needs of electric generators for natural gas. The meeting included representatives/speakers from various sectors of the natural gas and electric industries (load, suppliers, marketers, exchanges, gas associations, and ISOs) and environmental interests. Representatives from NYISO and PJM were among the speakers on the electric side (ISO-NE was not present). A summary of that meeting is posted on the Litigation Updates & Reports webpage (http://nepool.com/uploads/Lit_Supp_AD14-19_20140918_Mtg_Summary.pdf). Written comments on issues discussed at the meeting, limited to 5 pages, were due on or before October 1, 2014. Comments were filed by nearly 30 parties.

March 15, 2013; (4) the FERC will deem all e-Tag information made available to the FERC pursuant to *Order 771* as being submitted pursuant to a request for privileged and confidential treatment under 18 CFR 388.112; (5) the FERC is to be afforded access to the Intra-Balancing Authority e-Tags in the same manner as interchange e-Tags; and (6) the requirement on Balancing Authorities to ensure FERC access to e-Tags pertains to the Sink Balancing Authority and no other Balancing Authorities that may be listed on an e-Tag.

¹¹⁷ *Standards for Bus. Practices and Communication Protocols for Pub. Utils.*, Order No. 676-H, 148 FERC ¶ 61,205 (Sep. 18, 2014) (“*Order 676-H*”).

¹¹⁸ *Order 676-H* was published in the *Fed. Reg.* on Sep. 24, 2014 (Vol. 79, No. 185) pp. 56,939-56,955.

• **NOPR: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (RM14-2)**

On March 20, 2014, the FERC issued a series of orders addressing gas-electric coordination. At the forefront, was this NOPR, in which the FERC proposes to revise its natural gas act regulations in order to better coordinate the scheduling of natural gas and electricity markets and to provide additional flexibility to natural gas shippers.¹¹⁹ Specifically, the NOPR proposes to: (i) start the Gas Day earlier, at 4:00 a.m. Central Clock Time (“CCT”)¹²⁰ rather than 9:00 a.m., in order to ensure that gas-fired generators are not running short on gas supplies during the morning electric ramp periods; (ii) institute a later start to the first day-ahead gas nomination opportunity (called the Timely Nomination Cycle), from 11:30 a.m. to 1 p.m. The FERC said that because the Timely Nomination Cycle is the most liquid of the gas nomination cycles, this change will allow electric utilities to finalize their scheduling before gas-fired generators must make gas purchase arrangements and submit nomination requests for natural gas transportation service to the pipelines; and (iii) modify the current intraday nomination timeline to provide 4 (rather than 2) intraday nomination cycles in order to provide greater flexibility to all pipeline shippers. The NOPR adds an early morning nomination cycle with a mid-day effective flow time and a new late-afternoon nomination cycle during which firm nominations would have precedence over or be permitted to bump already scheduled interruptible service. Ultimately, the standard cycles will be 8:00 a.m. CCT (bump), 10:30 a.m. CCT (bump), 4:00 p.m. CCT (bump) and 7:00 p.m. CCT (no-bump).

To provide shippers additional flexibility, the NOPR also proposes to: (i) clarify its policy with respect to the “No-Bump” Rule for Pipelines with Enhanced Nomination Services (the ability of a pipeline to permit firm shippers to bump an interruptible shipper’s nomination during any enhanced nomination opportunity proposed by the pipeline (beyond the standard nomination opportunities). The FERC indicated that under the revised intraday nomination timelines proposed here, pipelines offering enhanced nomination services should be permitted to bump interruptible shippers at least until the time when the bumping notice under the newly proposed Intra-Day 3 schedule is provided (in the Commission’s proposal 6:00 p.m. CCT); and (ii) require Multi-Party Transportation Contracts; and (ii) FERC proposes to require all interstate pipelines to offer multi-party service agreements, providing multiple shippers the flexibility to share interstate pipeline capacity to serve complementary needs in an efficient manner.

Noting that the natural gas and electricity industries are best positioned to work out the details of how changes in scheduling practices can most efficiently be made and implemented, consistent with the policies discussed in the NOPR, the FERC provided the industries 6 months to reach consensus on standards, consistent with FERC’s guidance in the NOPR, including any revisions or modifications to the proposals provided herein. Comments are due November 28, 2014¹²¹ and should include the consensus standards or notifying the FERC of their inability to reach consensus on any revisions to the FERC’s proposals. The FERC also noted its expectation that the electric industry (particularly the ISO/RTOs) would participate in these efforts to help ensure that the resulting consensus reasonably accommodates the interests of both industries.

On September 29, NAESB submitted a status report and record of its activities in response to Gas-Electric Scheduling Coordination NOPR. In that report, NAESB identified the modifications to the NAESB Wholesale Gas Quadrant (WGQ) Business Practice Standards specific to the NOPR. The modified NAESB WGQ Business Practice Standards propose revisions to the nomination timeline that result in three intra-day nomination cycles in addition to the timely and evening nomination cycles. The nomination cycles are not dependent upon a specific start time to the gas day and are implementable with whichever time the FERC chooses as a start of the gas day.

• **NOI: Enhanced Natural Gas Market Transparency (RM13-1)**

On July 9, 2014, the FERC issued a notice that, in order to assess better whether the reporting requirement described in the NOI would enhance natural gas transparency, the FERC will seek additional

¹¹⁹ *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 146 FERC ¶ 61,201 (Mar. 20, 2014).

¹²⁰ CCT, pursuant to the NAESB WGQ standards, reflects daylight savings changes.

¹²¹ The NOPR was published in the *Fed. Reg.* on Apr. 1, 2014 (Vol. 79, No. 62) pp. 18,223-18,243.

information from certain natural gas marketers regarding what portion of their total natural gas sales are jurisdictional natural gas sales. To obtain that information, OE will send data requests to certain natural gas marketers who, in turn, will have 15 days to respond. The FERC indicated that, after those responses are received, it will consider what, if any, further action in this docket will be necessary and/or appropriate. As previously reported, in a November 15, 2012 NOI, the FERC sought input on what changes, if any, should be made to the regulations under the natural gas market transparency provisions of section 23 of the Natural Gas Act (“NGA”) to improve natural gas market transparency. Comments in response to the NOI were received from over 30 parties.

• Posting of Offers to Purchase Capacity (Section 5 Proceeding) (RP14-442)

Similar to the ISO/RTO 206 Order in EL14-22 et al. (see Section I above), the FERC also instituted a proceeding under Section 5 of the Natural Gas Act to examine whether interstate natural gas pipelines are providing notice of offers to purchase released pipeline capacity in accordance with section 284.8(d) of the Commission’s regulations.¹²² On or before May 19, natural gas pipelines must either revise their respective tariffs to provide for the posting of offers to purchase released capacity, or otherwise demonstrate that they are in full compliance with FERC regulations.¹²³ The FERC also requested that NAESB develop business practice and communication standards specifying: (1) the information required for requests to acquire capacity; (2) the methods by which such information is to be exchanged; and (3) the location of the information on a pipeline’s website. Each pipeline must explain in its compliance filing how it will fully comply with 18 CFR § 284.8(d) until NAESB develops, and the FERC implements, the requested standards, including how the pipeline will provide shippers the ability to post offers to purchase capacity on the Informational Posting section of its website.¹²⁴

• Natural Gas-Related Enforcement Actions

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines. Since the last Report, there was a great deal of activity in the following on-going, gas-related enforcement proceeding:

<u>Company</u>	<u>Alleged Violation(s)</u>	<u>Civil Penalty/Disgorgement</u>
BP America Inc. BP Corp. N. Amer. BP Amer. Production BP Energy Co. (together, “BP”) (IN13-15)	The FERC established a hearing to determine whether BP violated section 4A of the Natural Gas Act and the FERC’s Anti-Manipulation Rule as alleged by OE Staff. OE Staff alleged that BP traded physical natural gas at Houston Ship Channel (“HSC”) to increase the value of BP’s financial position at HSC, uneconomically using BP’s transportation capacity, making repeated early uneconomic sales at HSC, taking steps to increase BP’s market concentration at HSC. In doing so, OE staff alleged, BP suppressed the HSC Gas Daily index with the goal of increasing the value of BP’s financial position at HSC. The activity occurred from mid-September 2008 through November 2008.	Show Cause Order ¹²⁵ \$28 million (civil penalty) \$800,000 (disgorgement)

¹²² *Posting of Offers to Purchase Capacity*, 146 FERC ¶ 61,203 (Mar. 20, 2014).

¹²³ *Id.* at P 6.

¹²⁴ *Id.*

¹²⁵ *BP America Inc. et al.*, 144 FERC ¶ 61,100 (Aug. 5, 2013).

- **New England Pipeline Proceedings**

The following New England pipeline projects are pending before the FERC:

- ***Algonquin Incremental Market Project (AIM Project) (CP14-96)***

- ▶ Algonquin Gas Transmission filed for Section 7(b) and 7(c) certificate Feb. 28, 2014
- ▶ 342,000 dekatherms/day of firm capacity to NY, CT, RI and MA.
- ▶ 37.6 miles of take-up, loop and lateral pipeline facilities in NY, CT, and MA and system modifications in NY, CT and RI. The system upgrades would also require the removal of some facilities.
- ▶ 10 firm shippers: Yankee Gas, NSTAR, Connecticut Natural Gas, Southern Connecticut, Narragansett Electric, Colonial Gas, Boston Gas, Bay State, Norwich Public Utilities, and Middleborough Gas and Electric (eight LDCs and two municipal utilities).
- ▶ Authorization Requested by Jan 1, 2015.
- ▶ Construction to begin Mar 2015 (anticipated).
- ▶ In-service: Nov 2016 (anticipated).

- ***Connecticut Expansion Project (CP14-529)***

- ▶ Tennessee Gas Pipeline filed for Section 7(c) certificate July 31, 2014
- ▶ 72,100 dekatherms/day of firm capacity.
- ▶ 13.26 miles of three looping segments and facility upgrades/modifications in NY, MA and CT.
- ▶ Three firm shippers: Connecticut Natural Gas, Southern Connecticut Gas, and Yankee Gas.
- ▶ Authorization requested by July 31, 2015.
- ▶ Construction to begin Winter 2015/2016.
- ▶ In-service: Nov 2016 (anticipated).

- ***Constitution Pipeline (CP13-499)***

- ▶ Constitution Pipeline Company filed for Section 7(c) certificate July 31, 2014.
- ▶ 650,000 dekatherms/day of firm capacity from Susquehanna County, PA through NY to Iroquois/Tennessee interconnection.
- ▶ New 122-mile interstate pipeline.
- ▶ Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
- ▶ EIS to be completed by Oct 24, 2014.
- ▶ Authorization requested by Nov 25, 2014; Construction to begin Feb 2015.

- ***Wright Interconnect Project (with Constitution) (CP13-502)***

- ▶ Iroquois Gas Transmission filed application Jun 13, 2014.
- ▶ 650,000 dekatherms/day of firm capacity interconnect between Constitution and Iroquois/Tennessee.
- ▶ New receipt point with Constitution, new facilities at Wright and modifications to Iroquois/Tennessee metering system.
- ▶ All capacity to be leased to Constitution.
- ▶ Authorization requested by May 1, 2014.
- ▶ In-service: Mar 31, 2015.
- ▶ Revised FERC schedule indicates FERC authorization in Jan. 2015.
- ▶ FERC Aug 18, 2014 revised schedule calls for EIS completion by Oct 24, 2014.

- ***Salem Lateral Project (CP14-522)***

- ▶ Algonquin Gas Transmission filed application Jul 10, 2013.

- ▶ 115,000 dekatherms/day of firm capacity.
- ▶ 1.2 miles of pipeline to 630 MW Salem Harbor Station and other Salem, MA facilities.
- ▶ Footprint Power sole firm customer.
- ▶ Authorization requested by Apr 17, 2015.
- ▶ In-Service: Nov 2015 (anticipated).

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit). An “**” following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2013/14 Winter Reliability Program (14-1104, 14-1105, 14-1103 (consolidated))**
Underlying FERC Proceedings: ER13-1851¹²⁶ and ER13-2266¹²⁷
Appellants: TransCanada and RESA

On June 6, 2014, TransCanada and the Retail Energy Supply Association filed petitions for review of the FERC’s orders on the 2013/14 Winter Reliability Program (14-1104 and 14-1105, respectively). Also on June 6, 2014, TransCanada filed a petition for review of FERC’s orders on the 2013/14 Winter Reliability Program Bid Results Filings (ER14-1103). On July 3, 2014, these proceedings were consolidated. On July 7, the FERC requested a minimum of 60 days after Petitioners’ opening briefs to file its brief. On July 23, leave to intervene was granted to ISO-NE, NEPGA, PSEG and Essential Power. On September 29, TransCanada, RESA, FERC, ISO-NE, Essential Power MA, PSEG and NEPGA filed a proposed joint, unopposed briefing format and schedule.

- **Orders 773 and 773-A (2nd Cir., 13-2316)**
Underlying FERC Proceedings: RM12-6 and RM12-7¹²⁸
Appellants: NY PSC and People of the State of New York

The NY PSC and the People of the State of New York have petitioned the Second Circuit Court of Appeals for review of FERC’s orders on *Orders 773 and 773-A* (Revised “Bulk Electric System” Definition and Procedures). Briefs have thus far been filed as follows: NYPSC/State of NY (May 2, 2014); NARUC (May 28); FERC (August 22); NERC (August 27); NERC reply brief (September 10, 2014); FERC and NY/NY PSC final briefs (September 24); NERC and NARUC intervenor briefs.

¹²⁶ 144 FERC ¶ 61,204 (Sep. 16, 2013); 147 FERC ¶ 61,026 (Apr. 8, 2014).

¹²⁷ 145 FERC ¶ 61,023 (Oct. 7, 2013); 147 FERC ¶ 61,027 (Apr. 8, 2014).

¹²⁸ 141 FERC ¶ 61,236 (Dec. 20, 2012); 143 FERC ¶ 61,053 (Apr. 18, 2013).

- **New England's Order 745 Compliance Filing (12-1306)**
Underlying FERC Proceedings: ER11-4336¹²⁹
Appellants: EPSA and NEPGA

On July 16, 2012, EPSA and NEPGA filed a petition for review of FERC's orders on New England's *Order 745* (Demand Response Compensation) filings. On August 16, 2012, EPSA and NEPGA filed a statement of issues as well as an unopposed motion to hold case in abeyance pending the final resolution of Case Nos. 11-1486, et al. (*EPSA et al. v. FERC*) (see Orders 745 and 745-A below). On August 23, 2012, the Court granted the motion to hold the case in abeyance. Motions to govern future proceedings will be due 30 days following the issuance of the mandate in the *Order 745* appeal.

- **Orders 1000 and 1000-A (12-1232 consolidated with 12-1233, 12-1250, 12-1276, 12-1279, 12-1280, 12-1285, 12-1292, 12-1293, 12-1296, 12-1299, 12-1300, 12-1304, 12-1448, 12-1478, and 7th Cir. 12-2248)**
Underlying FERC Proceedings: RM10-23¹³⁰
Appellants: SC PSA, Coalition for Fair Transmission, PSEG, and Sacramento Municipal Utility District

Petitions for review of FERC's Orders 1000, 1000-A, and 1000-B, as identified in previous reports, were denied by the DC Circuit in an August 15, 2014 order.¹³¹ The Court issued a companion order indicating that it would withhold issuance of the mandate until seven days after disposition of any timely petition for rehearing or petition for rehearing *en banc*. On September 29, Large Public Power Council petitioned the Court for rehearing *en banc*. That request is pending before the Court.

- **Orders 745 and 745-A (11-1486 consolidated with 11-1489, 12-1088, 12-1091 and 12-1093)**
Underlying FERC Proceedings: RM10-17-000¹³²
Appellants: EPSA, CAISO, ODEC, EEI, CA PUC

As previously reported, the DC Circuit vacated *Order 745*¹³³ in its entirety as impermissibly encroaching on "states' exclusive jurisdiction to regulate the retail market" in a 2-1 decision ("Decision") issued on May 23, 2014. The DC Circuit vacated *Order 745* on two separate and independent grounds. First, it held that the FERC does not have jurisdiction to regulate demand response. The Court reasoned that: (i) the states retain exclusive authority to regulate the retail market; (ii) absent an express statutory grant of authority, the FERC cannot regulate areas left to the states; (iii) the FPA provides the FERC with authority over wholesale sales of electricity, but demand response is not such a sale; (iv) the authority of the FERC to regulate wholesale power rates under the FPA cannot be read so broadly as to allow direct regulation of demand response; and (v) demand response, while not necessarily a retail sale, is part of the retail market, involving retail customers, their decision whether to purchase at retail, and the levels of retail electricity consumption. Therefore, the Court concluded, the FERC has no authority to directly regulate demand response. "FERC's authority over demand response resources is limited: its role is to assist and advise state and regional programs."

As an alternative and secondary basis for its decision against *Order 745*, the Court concluded that the FERC order was "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." The Court found that the FERC failed to reasonably consider and address arguments that *Order 745* will result in

¹²⁹ 138 FERC ¶ 61,042 (Jan. 19, 2012); 139 FERC ¶ 61,116 (May 17, 2012).

¹³⁰ 136 FERC ¶ 61,051 (Jul. 21, 2011); 139 FERC ¶ 61,132 (May 17, 2012).

¹³¹ *S. Car. Pub. Serv. Auth. v. Federal Energy Regulatory Commission*, 2014 U.S. App. LEXIS 15674 (Aug. 15, 2014).

¹³² 134 FERC ¶ 61,187 (Mar. 15, 2011); 137 FERC ¶ 61,215 (Dec. 15, 2011).

¹³³ *Order 745* required RTOs and ISOs to include provisions in their tariffs that assured demand response would be paid at LMP for interrupting their loads when such interruption was cost effective.

over-compensation of demand response resources, resulting in unjust and discriminatory rates. The Court further found that the FERC failed to demonstrate how its proposed pricing construct would result in just compensation. The Decision and preliminary implications of the Decision were summarized in more detail in the memo included with the supplemental materials circulated and posted for the June 6 meeting.

On July 7, the FERC petitioned the Court for rehearing *en banc* of the May 23 Decision. On July 18, the Court, on its own motion, directed EPSA, APPA, NRECA, Old Dominion and EEI (“Petitioners”) to file a joint response to the FERC petition for rehearing. That response was filed on August 4, 2014. The petition for rehearing *en banc* was denied on September 17, 2014.

On September 22, the FERC and a group of intervenors¹³⁴ filed motions to stay the issuance of the mandate for at least a 90-day period, to accommodate the time during which they may file a petition for a writ of certiorari in the Supreme Court of the United States. On September 30, Petitioners filed a motion opposing the request for stay. The request for stay is pending before the Court of Appeals for the DC Circuit.

• **PPL EnergyPlus, LLC v. Nazarian (4th Cir., 13-2424)**

On June 2, 2014, the 4th Circuit Court of Appeals affirmed the September 30, 2013 decision of the United States District Court for the District of Maryland¹³⁵ which found that a Maryland Public Service Commission (“MD PSC”) order directing three Maryland distribution utilities to enter into a ‘contract for differences’ for capacity and energy in the PJM control area (the “CfD”) with a gas-fired merchant generator selected by the MD PSC (the “MD PSC Order”) violated the Supremacy Clause of the United States Constitution and cannot be enforced.¹³⁶ In affirming the District Court decision, the 4th Circuit found the MD PSC Order both field¹³⁷ and conflict pre-empted.¹³⁸

With respect to field pre-emption, the 4th Circuit stated that a “wealth of case law confirms FERC’s exclusive power to regulate wholesale sales of energy in interstate commerce, including the justness and reasonableness of the rates charged.”¹³⁹ It found the federal scheme (i.e. the PJM Market) “carefully calibrated to protect a host of competing interests” (representing “a comprehensive program of regulation that is quite sensitive to external tampering”),¹⁴⁰ and leaving “no room either for direct state regulation of the prices of interstate wholesales of [energy], or for state regulations which would indirectly achieve the same result.” Accordingly, the

¹³⁴ Intervenors include: Coalition of MISO Transmission Customers; PJM Industrial Customer Coalition; EnerNOC, Inc.; Viridity Energy, Inc.; American Forest & Paper Association; EnergyConnect, Inc.; Wal-Mart Stores, Inc.; and Steel Producers.

¹³⁵ *PPL EnergyPlus, LLC v. Nazarian*, 974 F.Supp. 2d 790 (D. Md. Sep. 30, 2013); 2013 U.S. Dist. LEXIS 140210, 2013 WL 5432346 (“*District Court Decision*”). The *District Court Decision* was summarized in past Litigation Reports.

¹³⁶ *PPL EnergyPlus, LLC v. Nazarian*, 2014 U.S. App. LEXIS 10155.

¹³⁷ “Field preemption” is a doctrine based on the Supremacy Clause of the U.S. Constitution that holds that any federal law, including regulations of a federal agency, takes precedence over any conflicting state law. Preemption can be implied when federal law/regulation “occupies the field” in which the state is attempting to act/regulate. Field preemption occurs when there is “no room” left for state regulation. Accordingly, a state may not pass a law or take any action in a field, like the regulation of wholesale power sales, pervasively regulated by federal law/regulation.

¹³⁸ “Conflict preemption” occurs where there is a conflict between a state law and a federal law. (“[E]ven if Congress has not occupied the field, state law is naturally preempted to the extent of any conflict with a federal statute.”). Such a conflict occurs when “the challenged state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress. The court must look to “the entire scheme of the statute” and determine “[i]f the purpose of the [federal] act cannot otherwise be accomplished—if its operation with its chosen field [would] be frustrated and its provisions be refused their natural effect. Where a state law conflicts with a federal law, the Court does not balance the competing federal and state interests. Any state law, however clearly within a State’s acknowledged power, which interferes with or is contrary to federal law, must yield.”

¹³⁹ Slip op. at p. 14.

¹⁴⁰ *Id.* at p. 10.

4th Circuit concluded that the MD PSC Order “field preempted because it functionally sets the rate that CPV receives for its sales in the PJM auction.”¹⁴¹ The MD PSC Order “compromises the integrity of the federal scheme and intrudes on FERC’s jurisdiction” because the MD PSC Order “effectively supplants the rate generated by the auction with an alternative rate preferred by the state.” The 4th Circuit rejected arguments that the CfD payments “represented a separate supply-side subsidy implemented entirely outside the federal market.”¹⁴² And, even if the presumption against preemption were to apply, the Court found that that it was “overcome by the text and structure of the FPA, which unambiguously apportions control over wholesale rates to FERC.”¹⁴³

With respect to conflict pre-emption, the 4th Circuit found that the MD PSC Order “presents a direct and transparent impediment to the functioning of the PJM markets, and is therefore preempted”.¹⁴⁴ Preemption was appropriate because of the “extensive and disruptive” impact of the MD PSC Order on matters within federal control (the PJM markets). It found that the MD PSC Order had “the potential to seriously distort the PJM’s auction’s price signals, thus ‘interfer[ing] with the method by which the federal statute (i.e. the PJM Markets) was designed to reach its goals.’”¹⁴⁵ “Maryland’s initiative disrupts [the PJM scheme] by substituting the state’s preferred incentive structure for that approved by FERC.”¹⁴⁶ “Maryland has sought to achieve through the backdoor of its own regulatory process what it could not achieve through the front door of FERC proceedings. Circumventing and displacing federal rules in this fashion is not permissible.”¹⁴⁷

Petitions for rehearing *en banc* were filed by MD PSC and CPV Maryland on June 16, 2014. On June 17, 2014, the 4th Circuit stayed the mandate pending the *en banc* ruling on the Petitions. On June 30, 2014, the 4th Circuit denied the petitions for rehearing *en banc*. On September 15, the Supreme Court extended the time to file a petition for a writ of certiorari to and including November 27, 2014.

• **PPL EnergyPlus, LLC v. Hanna (3d Cir., 13-4330)**

On September 11, 2014, the 3rd Circuit Court of Appeals affirmed¹⁴⁸ the analogous October 11, 2013 decision of the United States District Court for the District of New Jersey declaring unconstitutional (and therefore null and void) New Jersey’s Long Term Capacity Agreement Pilot Program Act (“LCAPP”).¹⁴⁹ In affirming the New Jersey District Court’s decision, the 3rd Circuit concluded:

LCAPP compels participants in a federally-regulated marketplace to transact capacity at prices other than the price fixed by the marketplace. By legislating capacity prices, New Jersey has intruded into an area reserved exclusively for the federal government. Accordingly, federal statutory and regulatory law preempts and, thereby, invalidates LCAPP and the Standard Offer Capacity Agreements.¹⁵⁰

¹⁴¹ *Id.* at p. 16.

¹⁴² *Id.* at pp. 18-19.

¹⁴³ *Id.* at p. 20. The Court noted the limited scope of its holding, which “is addressed to the specific program at issue” and did not “express an opinion on other state efforts to encourage new generation.” *Id.* at p. 21.

¹⁴⁴ *Id.* at p. 27.

¹⁴⁵ *Id.* at p. 23.

¹⁴⁶ *Id.* at p. 24. (“Two features of the Order render its likely effect on federal markets particularly problematic. First, as noted, the CfDs are structured to actually set the price received at wholesale. They therefore directly conflict with the auction rates approved by FERC. Second, the duration of the subsidy -- twenty years -- is substantial.”)

¹⁴⁷ *Id.* at p. 25.

¹⁴⁸ *PPL EnergyPlus, LLC v. Hanna*, __ F.Supp.2d __ (D. NJ. Oct. 11, 2013); 2013 U.S. Dist. LEXIS 147273, (“*NJ Order*”).

¹⁴⁹ *PPL EnergyPlus, LLC v. Hanna*, 2014 U.S. App. LEXIS ____ (Sep. 11, 2014).

¹⁵⁰ *Id.* slip op. at 31.

Any petition for rehearing or rehearing *en banc* must be filed on or before September 25, 2014. If no petition for rehearing is filed, any petition for *certiorari* to the U.S. Supreme Court must be filed on or before December 10, 2014.

INDEX

Status Report of Current Regulatory and Legal Proceedings as of October 1, 2014

I. Complaints

206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices to be Adopted in Docket RM14-2	(EL14-23)	2
206 Investigation: FCM Performance Incentives (Compliance Proceeding).....	(EL14-52)	2
206 Proceeding: Importers' FCA Offers Review/Mitigation	(EL14-99)	1
Base ROE Complaint (2011).....	(EL11-66)	5
Base ROE Complaint (2012).....	(EL13-33)	4
Base ROE Complaint (2014).....	(EL14-86)	1
FCM Administrative Pricing Rules Complaint.....	(EL14-7)	3
NESCOE FCM Renewables Exemption Complaint.....	(EL13-34)	3
PURPA Complaint v. MA DPU (Allco Renewable Energy).....	(EL14-84 et al.).....	24

II. Rate, ICR, FCA, Cost Recovery Filings

Base ROE Complaint (2011).....	(EL11-66)	5
Base ROE Complaint (2012).....	(EL13-33)	4
Base ROE Complaint (2014).....	(EL14-86)	1
FCA1 Results Remand Proceeding	(ER08-633)	7
FCA8 Results Filing	(ER14-1409)	6

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices to be Adopted in Docket RM14-2	(EL14-23)	2
206 Investigation: FCM Performance Incentives (Compliance Proceeding).....	(EL14-52)	2
206 Proceeding: Importers' FCA Offers Review/Mitigation	(EL14-99)	1
Competitive Offer Test Revisions	(ER14-2686)	8
Demand Curve Changes	(ER14-1639)	7
Exigent Circumstances Filing – FCM Admin. Pricing Rules	(ER14-463)	11
FCM Administrative Pricing Rules Complaint.....	(EL14-7)	3
FCM Performance Incentives Jump Ball Filing	(ER14-1050)	10
FCM PI Jump Ball Compliance Filing	(ER14-2419)	9
FCM Redesign Compliance Filing: FCA8 Revisions.....	(ER12-953 et al.)	12
Fuel Price Adjustment Revisions.....	(ER14-2929)	7
ISO CSO Deferral Proposal.....	(ER14-2440)	8
NESCOE FCM Renewables Exemption Complaint.....	(EL13-34)	3
Order 755 Regulation Market Changes.....	(ER12-1643)	12
Regulation Market Dispatch Changes	(ER14-2918)	7
Waiver Request: New Capacity Qualification Deadlines (MMWEC).....	(ER14-2771)	8
Waiver Request: QDN Challenge Deadlines (GDF SUEZ)	(ER14-2886)	8
Winter 2014/15 Reliability Program.....	(ER14-2407)	9

IV. OATT Amendments/Coordination Agreements

Order 784 Compliance Filing.....	(ER14-877)	13
Order 1000 Compliance Filing.....	(ER13-193; ER13-196).....	14
Order 1000 Interregional Requirements Compliance Filing	(ER13-1960; ER13-1957).....	13
Order 1000 November 15 Compliance Order Changes.....	(ER13-193; ER13-196).....	14

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Updates

Order 792 Compliance Filing.....	(ER14-2583)	15
Schedule 21- GMP: Merger Revisions; Cancellation of Schedule 21-CVPS	(ER12-2304)	16
Schedule 21- NEP: Centennial Island Hydro SGIA	(ER14-2534)	16
Schedule 21- NSTAR: MBTA LSA	(ER14-2596)	15

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

Capital Projects Report - 2014 Q2.....	(ER14-2656)	16
Quarterly Reports Regarding Non-Generating Resource Regulation Market Participation ..	(ER08-54)	17
Reserve Market Compliance (17th) Semi-Annual Report	(ER06-613)	17

IX. Membership Filings

August 2014 Membership Filing	(ER14-2541)	18
October 2014 Membership Filing.....	(ER14-2980)	17
September 2014 Membership Filing.....	(ER14-2749)	17

X. Misc. - ERO Rules, Filings; Reliability Standards

2015 NERC/NPCC Business Plans and Budgets.....	(RR14-6).....	24
FFT Report: September 2014	(NP14-50)	18
NOPR: BAL-002-1a Interpretation Remand	(RM13-6)	23
NOPR: New Reliability Standard: CIP-014-1 (Physical Security).....	(RM14-15)	19
NOPR: Revised Rel. Standard: COM-001-2 and COM-002-4	(RM14-13)	19
NOPR: Revised Rel. Standard: MOD-001-2	(RM14-7)	21
NOPR: Revised Rel. Standard: MOD-031-1	(RM14-12)	20
NOPR: Revised Rel. Standard: PRC-005-3.....	(RM14-8)	20
NOPR: Revised TOP and IRO Reliability Standards	(RM13-15, -14, -12)	21
Order 797: New Reliability Standard: EOP-010-1 (Geomagnetic Disturbance Operations).....	(RM14-1)	21
Revised NPCC Regional Reliability Standards Development Procedure.....	(RR14-7).....	23
Revised Reliability Standard: BAL-001-2.....	(RM14-10)	20
Revised Reliability Standards: FAC-001-2 and FAC-002-2	(RD14-12).....	18
Revised Reliability Standards: INT-004-3, INT-006-4, INT-009-2, INT-010-2, INT-11-1 ..	(RD14-4).....	19
Revised Reliability Standard: NUC-001-3	(RD14-13).....	18
Revised Reliability Standard: PRC-004-3	(RD14-14).....	18

XI. Misc. Regional Interest

203 Application: Calpine/Constellation (Fore River).....	(EC14-135)	24
203 Application: Dynegy/EquiPower	(EC14-140)	24
E&P Agreements: Blue Sky West & CMP	(ER14-2743; ER14-2744)....	25
FERC Enforcement Action Pending: Staff Notice of Alleged Violations –Twin Cities		26
FirstEnergy PJM DR Complaint.....	(EL14-55)	25
MISO Methodology to Involuntarily Allocate Costs to Entities Outside Its Control Area ..	(ER11-1844)	25
PURPA Complaint v. MA DPU (Allco Renewable Energy).....	(EL14-84 et al.).....	24
Waiver of Transmission Standards of Conduct: Bangor Hydro Request.....	(TS11-5).....	26

XII. Misc: Administrative & Rulemaking Proceedings

NOPR: MBR Authorization Refinements	(RM14-14).....	28
NOPR: Open Access and Priority Rights on ICIF	(RM14-11).....	28
<i>Order 676-H</i> : Incorporation of WEQ Version 003 Standards	(RM05-5).....	30
<i>Order 771</i> : Availability of E-Tag Information to FERC Staff	(RM11-12).....	29
Price Formation in RTO/ISO Energy & Ancillary Services Markets	(AD14-14)	27
RTO/ISO Common Metrics Report.....	(AD14-15)	27
RTO/ISO Winter 2013-2014 Op and Market Performance	(AD14-8)	28
WIRES Request for Policy Statement on ROE for Electric Transmission	(RM13-18).....	29

XIII. Natural Gas Proceedings

206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices to be Adopted in Docket RM14-2	(EL14-23)	2
Enforcement Actions: BP	(IN13-15).....	32
Inquiry Into Natural Gas Trading, and Proposal to Establish an Electronic Information and Trading Platform.....	(AD14-19)	30
NOI: Enhanced Natural Gas Market Transparency	(RM13-1).....	31
NOPR: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities	(RM14-2).....	31
Posting of Offers to Purchase Capacity (Section 5 Proceeding).....	(RP14-442)	32

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

2013/14 Winter Reliability Program and Bid Results	14-1104 (consol.).....	34
New England's <i>Order 745</i> Compliance Filing	12-1306.....	35
<i>Orders 1000/1000-A</i>	12-1232 (consol.).....	35
<i>Orders 745/745-A</i>	11-1486 (consol.).....	35
<i>Orders 773/773-A</i>	(2nd Cir., 13-2316)	34
<i>PPL EnergyPlus, LLC v. Nazarian</i>	(4th Cir., 13-2424)	36
<i>PPL EnergyPlus, LLC v. Hanna</i>	(3d Cir., 13-4330)	37

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates
FROM: Pat Gerity, NEPOOL Counsel
DATE: September 19, 2014
RE: 2015 Participants Committee Officer Elections

In order to ensure that the selection process requirements in the Participants Committee Bylaws for next year's Participants Committee officers can be timely completed, we need each Sector to indicate, no later than **Friday, October 24, 2014**, who the Sector has selected to serve as its 2015 Vice-Chair and, as a result, a nominee to be the 2015 Chair for the Participants Committee. A description of the qualifications, responsibilities, and expectations of the Sector officers selected has been included with this memorandum. We urge each of you to work within your Sectors to select your Sector's 2015 Vice-Chair.

By way of reminder, the Bylaws require that one voting member from each Sector be selected by a majority of all the voting members in its Sector (i) to serve as a nominee for Chair of the Participants Committee and (ii) if not elected Chair, to serve as a Committee Vice-Chair. A secret written balloting process will then be conducted to elect the 2015 Chair from among the Vice-Chair nominees. We have asked for your input by October 24, 2014 to allow adequate time for the full balloting process contemplated under the Bylaws to be completed, if necessary, by the December 5 Annual Meeting.

If any Sector needs assistance in conducting the vote for its Sector representative, please let us know (preferably no later than October 15). We would be pleased to help however we can. Also, if you have any questions, please feel free to contact me (pmgerity@daypitney.com; (860) 275-0533).

Participants Committee Sector Officer Qualifications, Responsibilities, and Expectations

Qualifications: A Participants Committee Chair or Vice-Chair must be a voting member of the Participants Committee. Per the Participants Committee bylaws, one voting member from each active Sector of the Participants Committee is to be selected to serve as the Vice-Chair of the Sector “by a majority of all the voting members in its Sector.” The Chair is selected from among the nominated Vice-Chairs using the balloting procedures in the bylaws.

Responsibilities and Expectations of Participants Committee Sector Vice-Chairs:

1. Help to build and maintain a collegial and productive working relationship with other Committee officers and members, ISO management, and state regulatory representatives participating in Committee activities.
2. Communicate routinely and effectively with other members of the Sector:
 - a. To help ensure that members have the information needed to support informed and active Committee participation;
 - b. To ensure that the officer has sufficient information to provide to the other officers, ISO management and staff, and state and federal regulators a fair and objective report of Sector members’ positions and sensitivities on regional matters; and
 - c. To report objectively to Sector members information, questions, positions, perspectives, and sensitivities of or from the other Sectors, the ISO, and regulators that are provided to the Officer to be shared with the Sector.
3. Attend and lead or support planning for and participation in Participants Committee meetings, including (a) participation in pre-planning conference calls and in-person meetings to identify and confirm discussion and consent agenda topics and materials, meeting logistics and orderly flow of business at Committee meetings, and (b) serving as Chair if and as needed for a meeting or portions of a meeting at which the Chair is not able to preside.
4. Coordinate and organize Sector members when appropriate, including for meaningful participation by the Sector members in the semi-annual meetings with the ISO Board of Directors and regulators.
5. Ensure that the Sector is fairly and objectively represented at other committee and working group meetings and meetings among Officers, ISO management and state regulatory representatives, and that the Officer or representative is reasonably informed as to the perspectives and sensitivities of the Sector members.
6. With the other NPC Officers, review and comment on NEPOOL filing or pleadings, raising awareness of any Sector-specific sensitivities.
7. Serve on the Joint Nominating Committee that recommends to the Participants Committee a slate of candidates for membership on the ISO Board of Directors.