**David T. Doot**
Secretary

January 25, 2013

**VIA ELECTRONIC MAIL**

**TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE**

**RE:** Supplemental Notice of February 1, 2013 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, February 1, 2013 at 10:00 a.m. at the Sheraton Framingham Hotel & Conference Center, 1657 Worcester Road, Framingham, MA.** The Participants Committee meeting will be held in the Grand Ballroom for the purposes set forth on the attached agenda. For your information, this meeting is recorded, as are all the NEPOOL Participants Committee meetings.

Directions to the Sheraton Framingham Hotel are included with this notice. Rooms at the Sheraton Hotel for the February 1 meeting are available at the rate of $139.00 per night, on a first-come, first-served basis **UNTIL January 28, 2013**. To take advantage of these arrangements, please contact the hotel directly (1-800-325-3535) and reference the "NEPOOL Participants Committee" block of rooms.

Respectfully yours,

/s/
David T. Doot, Secretary

# FINAL AGENDA

1. To approve the preliminary minutes of the Participants Committee meeting held on January 4, 2013. Preliminary minutes of the January 4 meeting, marked to show changes from the draft previously circulated, are included with this supplemental notice.

2. To adopt and approve an action recommended by the Markets Committee set forth on the Consent Agenda included with this supplemental notice.

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To discuss 2013 Business Priorities. An initial draft of the 2013 Work plan, circulated in advance of the January 4 meeting, is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2013/jan42013/a5_2013_work_plan_hdr.pdf. We have been advised that the ISO is preparing an updated draft for this discussion, and we will circulate that draft as soon as it is available.

5A. To discuss information related to benefits and costs associated with addressing resource performance, including the natural gas challenges. Background material is included with this supplemental notice.

6. To consider and take action, as appropriate, on ISO's proposed revisions to Market Rule 1 in compliance with FERC Order 755. Background material and a draft resolution are included with this supplemental notice.

7. 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 is included with this supplemental notice.

8. To receive reports from committees and subcommittees.

9. To transact such other business as may properly come before the meeting.

**PRELIMINARY**

A meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, January 4, 2013 at the DoubleTree Hotel Boston/Westborough, 5400 Computer Drive, Westborough, MA pursuant to notice duly given. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates attending the meeting.

Mr. Calvin Bowie, Chair, presided and Mr. David Doot, Secretary, recorded. Mr. Bowie welcomed the members, alternates and guests who were present, including Mr. Chris Wilson of the ISO Board, Ms. Sarah Hofmann who was attending for the first time in her capacity as Executive Director of NECPUC, as well as the state representatives in attendance.

Mr. Bowie noted that the Committee was meeting for the first time in Westborough, and planned to meet in Framingham for the next meeting. He explained that these venues reflected the initiative to schedule Participants Committee meetings outside of Boston in an ongoing effort to further minimize the overall costs associated with meetings, both to NEPOOL and to individual members (through, for example, lower costs for lodging, parking, and, for many, travel). He asked that members provide feedback after those meetings outside Boston with respect to the location, amenities, travel, and overall experience associated with the venues to help the Officers decide on future meeting venues.

**APPROVAL OF NOVEMBER 9 AND DEECEMBER 7, 2012 MEETING MINUTES**

Mr. Doot referred the Committee to the preliminary minutes for the November 9, 2012 special meeting and December 7, 2012 annual meeting, as circulated in advance of the meeting. Following motion duly made and seconded, the preliminary minutes for the November 9 and

December 7 meetings were unanimously approved, with an abstention noted by the New Hampshire Office of Consumer Advocate (NH OCA).

**CONSENT AGENDA**

Mr. Doot referred the Committee to the Consent Agenda that was circulated in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved without comment.

**REPORT OF THE ISO CHIEF EXECUTIVE OFFICER**

Mr. van Welie referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the December 7 meeting, circulated in advance of the meeting, and explained he would have more to discuss later in the meeting concerning the 2013 ~~work plan~~Work Plan (Work Plan). There were no questions on the Board meeting summaries and no further report from Mr. van Welie.

**REPORT OF THE ISO CHIEF OPERATING OFFICER**

Dr. Vamsi Chadalavada, ISO Chief Operating Officer, reviewed highlights from the January COO report, which included data only through December 25, 2012, and was circulated in advance of the meeting and posted on the ISO website. Focusing specifically on report highlights, he stated that, with December temperatures 4% higher than average in the major load centers (Hartford and Boston) in December: (i) natural gas prices were 11.4% lower and oil prices were 0.7% higher than November 2012 average values; (ii) Real-Time Hub LMPs were 28.4% lower than November 2012 averages; (iii) Net Commitment Period Compensation (NCPC), totaling $6.3 million, was $3.7 million lower than November 2012 NCPC; (iv) first contingency payments, totaling $3.3 million, were $6 million lower than November's first

contingency payments; (v) second contingency payments totaled $104,000, which was lower than the $1.9 million in November; and (vi) voltage support payments continued to be high and totaled $2.9 million, down $442,000 from November. He reported that, based on a 50/50 load forecast, the lowest Winter Operable Capacity Margin was projected for the week beginning January 19, with the lowest 90/10 Winter Operable Capacity Margin projected for the week beginning January ~~5.~~5, 2013.

Dr. Chadalavada reported that, during the week of the January meeting, New England was experiencing fairly cold temperatures, with gas prices in the $12-$18 MMBtu range. These high prices resulted in a higher utilization of the Portland/Northern natural gas pipeline and Canaport LNG facilities than experienced in prior winters. However, having avoided a prolonged cold snap, and with peak load remaining steady in the 20,000 to 20,500 MW range, the region remained short of the amount anticipated by the 90/10 peak load forecast (22,500 MW). He indicated that, due to the high price of natural gas, all of the coal units had recently been dispatched in merit order.

Dr. Chadalavada then highlighted a slide illustrating a pronounced spike in Real-Time LMPs on December 18, 2012. He explained that the price spike was attributable to a 1,750 MW deficit on the system, caused by loads 400-500 MW over forecasted levels and the loss of a 300 MW unit. He noted that, otherwise, and more consistently than in November, December LMPs generally tracked the price of natural gas.

In response to questions, Dr. Chadalavada indicated that increased voltage payments were attributable to transmission-related activities in West/Central Massachusetts, and were expected to continue through the remainder of 2013. He also indicated that, during 2013 and

into 2014, the ISO hoped to address the impact on Real-Time price formation of additional supplemental reserve commitment by the ISO.

Also in response to questions, Dr. Chadalavada addressed the factors contributing to the recent increase in Minimum Generation (MinGen) Emergencies and Warnings, particularly the relationship between under-forecasted load and resource commitment. He explained that, most often during the morning ramp (12:00 a.m. to 3:00 a.m., but often continuing to 7:00 a.m. during the Winter Period), and less often but also during the afternoon peak for the same reasons, units being committed early in the day to ensure availability later in the day produced energy in excess of that actually required. In those circumstances, he added, the operators were required to follow a series of established procedural steps calling, if need be, on a combination of resources to relieve the MinGen conditions. He clarified that, while circumstances would be evaluated and addressed on a case-by-case basis, operators would generally begin by curtailing hourly external import transactions, and then proceed to curtail self-schedules submitted after the close of the Re-Offer Period (including those submitted by wind resources). That combination of curtailments often cured MinGen conditions. If not, the ISO would take further actions, including asking all resources to go to their Economic Minimum Limits, and in more extreme conditions, to their Emergency Minimum Limits. Dr. Chadalavada noted the role that system flexibility played in creating and addressing these conditions. He confirmed that supplemental commitment choices being made earlier in the day, as well as lower-than-forecasted loads, particularly when temperatures were milder than projected, were contributing to increased MinGen Warnings and Emergencies. He committed to address at a subsequent meeting whether the increased level of MinGen Warnings and Emergencies could be expected to continue in 2013.

**2013 BUSINESS PRIORITIES / WORK PLAN**

Mr. van Welie referred the Committee to the presentation of the 2013 Work Plan ~~(Work Plan)~~, as circulated in advance of the meeting and posted on the ISO website. In introductory remarks, he indicated that the Work Plan was a detailed reflection of the 2013 ISO budget supported by the Committee at the October 2012 meeting, sequenced in a way that reflected the ISO's view of the relative priorities and proposed timing for those activities. He encouraged members to provide feedback as to whether the Work Plan accurately reflected and ordered the anticipated activities. He acknowledged that the Work Plan was aggressive and would require the region to be systematic and organized in its execution, particularly with respect to items addressing the strategic issues that had been under discussion at a conceptual level for the prior 12-24 months. He noted that, unlike prior years where the work plan discussion reflected comments received following an initial presentation to the Officers and NECPUC and NESCOE representatives, the Work Plan was being presented to the Committee without reflecting feedback from that leadership group, which had only just been received the day before, reflecting the urgency of many tasks identified in the Work Plan. Mr. van Welie reported that in response to feedback received the prior day from the Officers, and NECPUC and NESCOE representatives, the ISO would revise the presentation to identify the source driving each activities' inclusion in the Work Plan (e.g. FERC order, NERC standard, ISO-initiated activity, stakeholder-initiated activity) and would try to identify each activity's relative impact from a markets and reliability standpoint.

***Planning/Operations-Related Activities***

Dr. Chadalavada began reviewing the Work Plan by noting that activities on the summary slides colored in green represented those on which operating dollars would be spent;

those in blue, capital dollars; and those in orange identified the work items included in the strategic initiatives previously discussed. He then highlighted the following key planning/-operations-related development priorities:

- Regional Energy-Efficiency Initiative efforts
- FERC Order 1000 Compliance
- Generator Interconnection Studies / Review of Generator Interconnection Process
- Natural Gas Study Phase II (quantifying duration of risk, non-peak winter days, including alignment with NESCOE gas study)
- Gas-Electric Coordination (particularly maintenance scheduling)
- NERC Standards/Tariff Compliance (training of system operating personnel)
- Review and Update Planning Procedures (finalizing transmission planning manual version 1 and revisions thereto)
- Modeling Capacity Zones

Members then commented and asked clarifying questions concerning the Work Plan's planning/operations-related activities. An End User representative commended the ISO for its work on the Energy Efficiency forecasting, which had become a national model and was on a trajectory to save the region a lot of money. He urged continued investment in refinements to Energy Efficiency forecasting, particularly ~~based on~~reflecting experiences and efforts ongoing in other regions around the country.

In response to a member's question concerning the ISO's reliance on the NESCOE gas study, Dr. Chadalavada clarified that the ISO and NESCOE studies would be independent of each other, conducted by different vendors, and independently managed. Should, however, the ISO identify data or information from the earlier NESCOE study that it might find helpful to further explore in connection with its study, the ISO planned to approach those conducting the

NESCOE study for further information. In this spirit of cooperation, Dr. Chadalavada hoped that the earlier NESCOE study would prove helpful to better pace and inform the ISO's gas study.

A member asked how the strategic initiative of aligning planning and markets was incorporated in the Work Plan, if at all. Dr. Chadalavada explained that, although the projected timeframe for fully addressing that initiative was still a few years away (to coincide with FCA10), two of the highlighted activities – (1) the modeling of capacity zones, and (2) finalizing the inputs to the transmission planning process - would help with the alignment of planning and markets.

In response to a question as to which planning/operations-related activities might be passed over or deferred, if necessary, Dr. Chadalavada indicated his expectation that an unavoidable additional effort, such as to address a FERC mandate, would likely result in a slow down in the pace of work and potential inefficiencies with respect to a wide array of activities, rather than lead to an abrupt halt to activities on a specific priority/activity. Referring to the interregional planning and transmission cost allocation components of Order 1000 compliance, Mr. Doot urged the ISO to ensure communications with PJM and NYISO permitted the time and opportunity for meaningful consideration of any stakeholder-identified alternatives to the approach being jointly developed by those system operators.

***Markets-Related Activities***

Dr. Chadalavada then highlighted the following key and interrelated markets-related development priorities:

- FCM Performance Incentives
- Intra-Day Offers (2013 Q2 filing; 2014 Q2 implementation, with primary development by outside vendor Alstom), and NCPC Payments and Cost Allocation revisions (to be developed internally by the ISO)

- Intra-Day Reserves

Dr. Chadalavada emphasized the interdependency of these activities, noting the importance of the sequencing of the priorities, with delays in one activity expected to impact and cascade into others, all of which highlighted the delicate balancing act presented and urgency of the 2013 efforts. Mr. van Welie added that the ISO's corporate goals for 2013 include many of the market design projects, particularly those included in strategic planning initiatives.

Members then commented and asked clarifying questions concerning the Work Plan's markets-related activities. In response to questions, Dr. Chadalavada confirmed that, if need be, the market assessments, rather than the market design projects, would be the first to be delayed. He clarified that the FCM Cost Allocation project identified on the summary slide was a carry over from past years and related to load reconstitution and cost allocation. He indicated that the priority of FCM Cost Allocation was subordinate to that of the strategic initiatives identified, though it would need to be addressed given its relationship to outstanding FERC directives. Addressing improvements to Real-Time Reserve Constraint Penalty Factors (RCPFs), Dr. Chadalavada clarified that "improvements" was intended to capture the development of additional triggers to reflect new products, rather than further increases to existing RCPF triggers.

Members expressed concern with certain descriptions and timing associated with a number of the markets-related activities. Members of the Supplier and End User Sectors identified concerns with the description for the Merchant Transmission Market Implications projects, asking for clarification of types of projects and characteristics that had led the ISO to identify the potential for market changes and how such efforts might interact with the Order 1000 and public policy-related projects. Generation Sector representatives highlighted concerns

related to project sequencing, including the potential adverse effects on fast-responding resources if negative bid pricing was implemented prior to sub-hourly settlements, and concerns with the adverse effect that additional Market Rule changes related to reserve products that anticipate out-of-market actions by operators might have on LMPs and market price signals. An AR Sector representative requested that, if possible, the Wind Dispatch Rules and Intra-Day Offers projects be developed in parallel rather than in series so that the economic impacts of intra-day offers on wind resources could be more fully understood. Another AR Sector representative expressed concerns regarding the timing of the FCM Performance Incentives project, in which demand resources (DR) could not knowledgably participate without an understanding first of ~~what~~ the reserve market opportunities for DR. He asked whether the Intra-Day Offers project would include an opportunity for intra-day offers by DR. In response, Dr. Chadalavada noted that participation of DR in the Real-Time Reserve Market was scheduled for implementation in 2016, well ahead of when FCM Performance Incentives ~~which~~ were planned to go into effect in 2018. He also offered to discuss separately the ISO's thoughts on the interaction between the Reserve Market design changes and FCM Performance Incentives and whether the scope of work for the Intra-Day Offers project could be expanded to include DR intra-day offers.

In response to questions concerning whether and how implementation of Long-Term Financial Transmission Rights (LFTRs) and the consideration of a demand curve for FCM were included in the presentation, Dr. Chadalavada indicated that LFTR efforts were on-going and, subject to confirmation, might be specifically reflected in a revised presentation. He also explained that the FCM demand curve, as well as some of the other unresolved FCM issues, were expected to be considered in connection with the FCM Performance Incentives project. He

added, though, that consideration of these topics might delay the overall efforts, which was of particular concern to the ISO and could influence the sequencing of activities in 2013 or beyond.

***Capital Project Priorities***

Having exceeded the time allotted for the Work Plan discussion, discussion of the Capital Project priorities, as well as any additional and follow-up questions on the planning/operations and markets-related activities, was deferred to the February meeting.

## DAY-AHEAD ENERGY MARKET AND RESERVE ADEQUACY ASSESSMENT TIMELINE REVISIONS

Ms. Allison DiGrande, Chair of the Markets Committee, introduced the Markets Committee's proposed Market Rule changes to modify the Day-Ahead Energy Market (DAM) and Reserve Adequacy Assessment (RAA) timelines. By way of background, she recounted that the ISO had indicated that it wanted to complete the DAM schedule sooner so that gas-fired generators could make arrangements before the gas nomination deadline passed, which would allow the ISO to have better information about the availability of resources early enough to permit it to commit alternative long lead-time resources if needed. Therefore, the ISO proposed changes that included moving the DAM bid deadline to 9:00 a.m. and completing the initial RAA by 4:00 p.m. (ISO Proposal). She described the eight-month Markets Committee process to consider the ISO Proposal and alternatives to that Proposal. She reported that, at its December 11-12, 2012 meeting, the Markets Committee voted on proposed changes to the DAM and RAA timelines, including several amendments to the ISO Proposal and she briefly described those proposed amendments and the Markets Committee votes. She confirmed that an amendment to the ISO Proposal as proposed by Exelon, that set the DAM bidding deadline at 10:00 a.m., the Re-Offer Period from 1:30 p.m. to 2:00 p.m., and had the initial RAA completed by 5:00 p.m.,

was ultimately recommended by the Market Committee for Participants Committee support (MC-Recommended Proposal) with a vote of 84.8%. She said the ISO Proposal was also voted at the ISO's request, but only received 43.05% support, which did not satisfy the 60% vote required for a Markets Committee recommendation. She indicated that, per normal processes, the Markets Committee recommendation that the Participants Committee approve the MC-Recommended Proposal should be presented to the Participants Committee as the main motion to consider proposed revisions to the DAM and RAA timelines. Ms. DiGrande concluded by noting that the ISO still planned to ask for a Participants Committee vote on the unamended ISO Proposal

The following main motion pertaining to the MC-Recommended Proposal was duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Appendices A and F to Market Rule 1, and Section I.2.2 (Definitions), and the deletion of Appendix H to Market Rule 1, as recommended by the Markets Committee and circulated to this Committee in advance of this meeting, together with such non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve; and
>
> FURTHER RESOLVED, that the Participants Committee authorizes and instructs NEPOOL Counsel, in consultation with the NEPOOL Officers, to assemble, prepare and include in filings with the Federal Energy Regulatory Commission such supporting materials (including, if and as appropriate, expert testimony) to support the Market Rule changes if passage of this motion results in a jump ball filing under Section 11.1.5 of the Participants Agreement.

A Supplier Sector representative questioned whether changes to the status quo were justified and invited Committee members, if they were so inclined, to express their own views on the same. Other Supplier and Generation Sector members concurred that the concerns identified as reasons to change the Market Rules may not warrant such dramatic changes in the DAM,

explaining that the ISO proposed such changes based on reliability concerns that really were market concerns that ~~can~~could and should be addressed through effective administration of the markets and possible improvements to price transparency in the markets. Most members, however, acknowledged that changes were nonetheless certain given the ISO's strong desire to move the timelines earlier to address its concerns, and explained why they preferred the MC-Recommended Proposal, including, among other reasons, that NEPOOL needed to send a strong message to FERC of the significant Market Participant concerns ~~of Market Participants~~ with the ISO Proposal.

A number of members, representing multiple NEPOOL Sectors, explained that while the MC-Recommended Proposal may not ~~be~~have been the ideal solution for various/varied reasons, it was a reasonable balancing of competing concerns and was most certainly preferable to the ISO Proposal, which they explained would create problems in the markets. On that note, the Exelon representative that sponsored the MC-Recommended Proposal, while expressing a strong preference for a DAM and RAA schedule closer to bidding at 12:00 p.m. and having an initial RAA at 6:00 p.m., made clear its appreciation for the time currently required by the ISO to accomplish its tasks and for that reason supported the MC-Recommended Proposal as a solution that would allow the ISO to access more long-time lead resources based on the initial RAA schedule, while still ensuring for the DAM market DAM bids and offers that reflect the greater liquidity in the gas markets. In support of the same, a member of the Supplier Sector explained that the MC-Recommended Proposal preserved many of the benefits of the current market structure and also addressed ISO's concerns in ensuring reliability by moving the completion of the initial RAA from the currently effective time of 10:00 p.m. to 5:00 p.m.

Other members noted their concerns about the potentially significant commercial and market efficiency impacts that would occur as the result of the 9:00 a.m. DAM bidding deadline. Some argued that, of all the proposals presented for Participants Committee consideration, 9:00 a.m. was the worst of all options because of the lack of liquidity and price discovery in the gas market before, and including at, that time. That opinion was shared by a number of members, including the EquiPower representative, who advocated for an alternative to the MC-Recommended Proposal that would establish a DAM bidding deadline of 5:00 a.m., similar to the New York markets. Those members, along with many others in the Generation and Supplier Sectors, expressed concern that the 9:00 a.m. deadline would result in an upward pressure on gas prices assumed in the DAM bids, especially on tight days, because without adequate knowledge and transparency on the price of gas, Market Participants would expect high risk premiums and reflect that expectation in their bids. Market Participants would also have to submit offers into the DAM without adequate knowledge and transparency on the price of gas. Discussing the economic impacts of the ISO Proposal, another Participant, this time from the End User Sector, also agreed that 9:00 a.m. bid deadline may raise costs to consumers due to Market Participants adding premiums to their daily bids/offers in the DAM, and would result in the potential disruption in the ability to use the bilateral markets to hedge against this increased risk.

Those members who instead expressed support or a preference for the ISO Proposal, explained generally that they were doing so in deference to the ISO's articulation of the operational and reliability needs and their conclusion that they did not have sufficient basis to disagree with those articulated needs. Members who expressed this overall sentiment were mainly representatives from the Transmission and End User Sectors. A NESCOE representative

also expressed support for the ISO Proposal out of that same respect and deference, but also made clear that NESCOE would not oppose the MC-Recommended Proposal if it were supported by the Participants Committee.

In response to members' comments and concerns, Dr. Chadalavada, for the ISO, clarified that the ISO Proposal was not the result of a scientifically driven approach, but reflected the ISO's best judgment at that time based on its analysis and experience. He explained it was the ISO's conclusion that its proposal best balanced a number of important variables, including: gas nomination timelines for pipelines, gas market trading hours, generators' concern with liquidity in the market, reliability concerns, and ~~its~~the ISO's actual experiences concerning capacity availability given the gas markets. He also noted the ISO's commitment to revisit these changes with stakeholders in the next year and, in any case, the ISO would reevaluate if the results were contrary to expectations (i.e., if market impacts were severe, if reliability was not improved, if further improvements were made on the processing timing itself, etc.).

In final comments, the Exelon representative emphasized the concerns that many expressed with the DAM and RAA timelines proposed by ISO and summarized the purpose and importance to Market Participants of the MC-Recommended Proposal.

After this discussion, but before the Participants Committee vote on the MC-Recommended Proposal, the following two amendments were offered for the Committee's consideration, both of which were offered as motions to amend the MC-Recommended Proposal.

**EquiPower Amendment**

The EquiPower representative reviewed ~~its~~a motion to amend the main motion so as to provide that the DAM bidding deadline would occur at 5:00 a.m., the Re-Offer Period would take place from 8:30 a.m. to 9:30 a.m., and the initial RAA would be completed by 12:30 p.m.

(EquiPower Amendment). He explained that by closing the DAM at 8:30 a.m., gas units would be notified of their DAM commitment in time to buy and schedule gas to meet that commitment. He further noted that the EquiPower Amendment proposed to complete the initial RAA by 12:30 p.m., which would provide the ISO with even more time than under its proposed schedule to access long lead-time resources in order to increase assurance of reliable Real-Time operations.

Following motion duly made and seconded, the EquiPower Amendment was voted and failed by a show of hands.

**Brookfield Amendment**

The Brookfield representative reviewed for the Committee ~~its~~a motion to amend the main motion to change the deadlines in such a way as to ensure that the Re-Offer Period (which in the MC-Recommended Proposal and ISO Proposal was 30 minutes) would last at least one hour, as identified in the materials circulated in advance of the meeting (Brookfield Amendment). A member of the Publicly Owned Entity Sector asked the Brookfield representative whether this amendment also proposed to move the RAA timelines, given that would extend the Re-Offer Period for at least one hour. In response, the Brookfield representative clarified that this amendment did not propose to change any timing in the DAM or RAA schedule other than the duration of the Re-Offer Period.

An Alternative Resources member expressed support for the Brookfield Amendment, noting his view that the currently proposed 30-minute window between the clearing of the DAM and close of the Re-Offer Period may not afford enough time for some demand resources to make re-offers and that the additional time, as proposed by Brookfield, would be an improvement to the MC-Recommended Proposal.

Following motion duly made and seconded, the Brookfield Amendment was voted and failed to pass with a 44.19% Vote in favor, with many abstentions (Generation – 17.1%; Transmission – 0%; Supplier – 10.26%; Alternative Resources – 14.5%; Publicly Owned Entity – 0%; and End User – 2.33%).~~.~~ (See Vote 1 on Attachment 2).

**Vote on Main Motion**

Without further discussion, the main motion was then voted and was approved with a 70.16% Vote in favor (Generation – 17.1%; Transmission – 4.27%; Supplier – 16.3%; Alternative Resources – 10.97%; Publicly Owned Entity – 17.1%; and End User – 4.41%). (See Vote 2 on Attachment 2).

**Vote on the ISO Proposal**

Mr. Bowie explained that, per the requirements of the Participants Agreement, the ISO was entitled to a vote on the unamended ISO Proposal and would accept without the need for a motion and a second the ISO's request for such a vote. Before consideration of that resolution to approve the ISO Proposal, the TransCanada representative raised a concern that the EquiPower Amendment was offered as a motion to amend the MC-Recommended Proposal and not as a motion to amend the ISO Proposal. His concern was that Participants would not have a meaningful way to signal their preference for the EquiPower-proposed DAM bidding deadline of 5:00 a.m. over the ISO Proposal. As a result, he asked whether the question could be placed informally before the Committee so that members could signal their preferences as between the 5:00 a.m. and 9:00 a.m. proposals. Mr. Doot reminded the Committee that procedurally the ISO Proposal was on the table and the ISO was entitled to a vote on its Proposal with any amendments that it found acceptable. He stated further his understanding, which the ISO confirmed, that the ISO would consider the EquiPower-proposed timelines as an acceptable

amendment if ~~it~~they enjoyed sufficient support to minimize or avoid litigation. Under that circumstance, Mr. Doot indicated that the Chair could, if he wished, allow the question to be put to the members without being out of order or exposing the Committee to expansive precedent that could create future procedural challenges. At the direction of the Chair, and without objection, the Committee members were asked to indicate, by a show of hands, whether they preferred or opposed 5:00 a.m. over 9:00 a.m. Mr. Doot indicated that the show of hands demonstrated that the Committee would not support a proposal based on a 5:00 a.m. over a 9:00 a.m. DAM bidding deadline. The ISO confirmed that it would not consider this change to be an acceptable ~~alteration~~amendment to the ISO Proposal. ~~–~~

Accordingly, the Committee considered the following motion:

> RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Appendices A and F to Market Rule 1, and Section I.2.2 (Definitions), and the deletion of Appendix H to Market Rule 1, as recommended by the ISO and circulated to this Committee in advance of this meeting, together with such non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The ISO-supported proposal was voted and failed with a 56.44% Vote in favor, again with many abstentions noted. (Generation – 3.8%; Transmission – 17.1%; Supplier – 0.85%; Alternative Resources – 3.53%; Publicly Owned Entity – 17.1%; and End User – 14.05%). (See Vote 3 on Attachment 2).

Based on the Committee's support for the MC-Recommended Proposal, Mr. Doot indicated that a "jump ball" filing was likely and that NEPOOL Counsel would work with the Officers and interested members to assemble, prepare and include in filings with the FERC such supporting materials (including, if and as appropriate, expert testimony) to support the Participants Committee-supported Proposal (the NEPOOL Proposal).~~.~~

**LITIGATION REPORT**

Mr. Doot referred the Committee to the Litigation Report that had been circulated in advance of the meeting and noted that the report continued to reflect a high level of activity. He highlighted that the FERC had accepted on December 31, 2012, but subject to refund, the proposed Tariff revisions for the recovery of the ISO's 2013 administrative costs to become effective January 1, 2013. He explained that the FERC order established and encouraged settlement judge procedures, and could lead to a hearing if settlement proved unsuccessful. He indicated the expectation that Administrative Law Judge Michael J. Cianci, Jr. would be designated as the Settlement Judge for the proceeding, with a first settlement conference to be held during the third week of January. In response to questions, he confirmed that NEPOOL Counsel would participate in the settlement proceedings and would keep the Committee informed of developments.

With respect to the FCM redesign proceeding, Mr. Doot referred the Committee to the summary of pleadings filed in response to the ISO's December 3 compliance filing that had been circulated with the additional materials for the meeting. He indicated that, although NEPOOL would not be taking a substantive position in the proceeding as a result of the outcome of the November 2 meeting, NEPOOL counsel would continue to monitor the proceeding and to provide updates to the Committee when and as appropriate.

NEPOOL Counsel Patrick Gerity summarized two complaints filed at the end of 2012. One complaint was to further reduce the Transmission Owners' return on equity, already the subject of ongoing litigation. The second complaint was filed by NESCOE and proposed an alternative renewables exemption from the Minimum Offer Price Rule that was included in the ISO's recent FCM filing. He explained that, NESCOE requested that the complaint proceeding

be consolidated with the proceeding to consider the ISO's December FCM filing, which was pending before the FERC. Mr. Gerity noted that responses to and any comments on the NESCOE complaint were due on or before January 17, 2013. He also noted that the settlement judge procedures established in the Information Policy Pipeline Information-Sharing Changes proceeding had been terminated in mid-December following an unsuccessful settlement conference. Subsequently, the ISO requested expedited rehearing and clarification of the December 7, 2012 order accepting but setting the changes for settlement judge procedures, and the New England Power Generators Association had proposed an interim solution to allow the changes to go into effect for the winter period, each of which were pending before the FERC. Anyone with comments or questions on the Litigation Report was encouraged to contact NEPOOL Counsel.

**COMMITTEE REPORTS**

Mr. Joel Gordon, Budget and Finance Subcommittee (Subcommittee) Chairman, reported that the next meeting of the Subcommittee would be held January 18, 2013 at 10:00 a.m., with materials to be posted a week ahead of the meeting. He highlighted that the Subcommittee would at that meeting reinitiate efforts to address and structure financial arrangements to mitigate the risk of, and thereby enable, LFTRs in New England, efforts which he expected to continue at each Subcommittee meeting through at least June. He encouraged all those interested to participate.

**OTHER BUSINESS**

Mr. Doot referred the Committee to the NEPOOL calendar for January and February, highlighting upcoming meetings and events. He reported that the next New England Gas-Electric Focus Group meeting was scheduled for January 23 at the DoubleTree Hotel

Boston/Westborough. Looking to February, Mr. Doot reminded the Committee that the next regularly-scheduled meeting of the Participants Committee would be February 1 at the Sheraton Framingham Hotel & Conference Center.

There being no further business, the meeting adjourned at 2:40 p.m.

Respectfully submitted,

_____
David T. Doot, Secretary

**MEMBERS AND ALTERNATES PARTICIPATING IN**
**JANUARY 4, 2013 PARTICIPANTS COMMITTEE MEETING**

| PARTICIPANT NAME | SECTOR | MEMBER NAME | ALTERNATE NAME | PROXY |
|---|---|---|---|---|
| 511 Plaza LP | End User | William P. Short III | Gus Fromuth | |
| Ashburnham Municipal Light Plant | Publicly Owned | | Gary Will | |
| Bangor Hydro-Electric Company | Transmission | | Stacy Dimou (tel) | |
| Boylston Municipal Light Department | Publicly Owned | | Gary Will | |
| BP Energy Company | Supplier | | | Nancy Chafetz |
| Brookfield Energy Marketing Inc. / CSC | Supplier | Nicolas Bossé | Jose Rotger | |
| Calpine Energy Services, LP | Supplier | John Flumerfelt | | |
| Central Maine Power Company | Transmission | Eric Stinneford (tel) | | |
| Cianbro Companies | End User | Gus Fromuth | | |
| Chicopee Municipal Lighting Plant | Publicly Owned | | Gary Will | |
| Concord Municipal Light Plant | Publicly Owned | | Gary Will | |
| Connecticut Municipal Electric Energy Coop. | Publicly Owned | Brian Forshaw | | Gary Will |
| Connecticut Office of Consumer Counsel (CT OCC) | End User | | | Paul Peterson |
| Conservation Law Foundation (CLF) | End User | Seth Kaplan | | |
| Conservation Services Group (CSG) | AR | Doug Hurley | | |
| Consolidated Edison Energy, Inc. | Supplier | Jeff Dannels | | |
| Corinth Wood Pellets LLC | End User | Gus Fromuth | | |
| CP Energy Marketing (US) Inc. (Capital Power) | Supplier | Michelle Gardner | | |
| DC Energy, LLC | Supplier | Bruce Bleiweis (tel) | | |
| Dominion Energy Marketing, Inc. | Generation | Ronald Hart (tel) | | |
| Dragon Products Company LLC | End User | Gus Fromuth | | |
| Dynegy Marketing and Trade, LLC | Supplier | | | William Fowler |
| Elektrisola, Inc. | End User | Gus Fromuth | | |
| Energy America, LLC | Supplier | Ron Carrier | | Nancy Chafetz |
| EnerNOC, Inc. | AR | Herb Healy | | |
| Entergy Nuclear Power Marketing, Inc. | Generation | Marc Potkin | | |
| EP Energy Massachusetts, LLC | Generation | M.Q. Riding (tel) | | |
| EquiPower Resources Management, LLC | Generation | Jim Ginnetti | William Fowler | |
| Exelon New England Holdings / Constellation | Supplier | Steve Kirk | William Fowler | |
| Fairchild Semiconductor Corporation | End User | Gus Fromuth | | |
| First Wind Energy Marketing, Inc. | AR | | | Bob Stein |
| Food City, Inc. | End User | Gus Fromuth | | |
| Generation Group Member | Generation | Dennis Duffy | Abby Krich (tel) | |
| Granite Ridge/Merrill Lynch | Supplier | | William Fowler | |
| Groton Electric Light Department | Publicly Owned | | Gary Will | |
| Great Bay Energy IV LLC | Supplier | | | Eugene Franco |
| H.Q. Energy Services (U.S.) Inc. | Supplier | | Robert Stein | |
| Hardwood Products Company | End User | | Gus Fromuth | |
| Harvard Dedicated Energy Limited | End User | Mary Smith | | Roger Borghesani |
| Hess Corporation | Supplier | | Marji Philips (tel) | Nancy Chafetz |
| Holden Municipal Light Department | Publicly Owned | | Gary Will | |
| Hudson Light and Power Department | Publicly Owned | | Gary Will | |
| Hull Municipal Lighting Plant | Publicly Owned | | Gary Will | |
| Industrial Energy Consumer Group | End User | Donald Sipe | | Herb Healy |
| IPR-GDF SUEZ Energy Marketing North America | Generation | | | Joe Dalton |
| Ipswich Municipal Light Department | Publicly Owned | | Gary Will | |
| Integrys Energy Services Inc. | Supplier | | | Nancy Chafetz |
| JPMorgan Chase | Supplier | Robert O'Connell (tel) | | |
| Kimberly-Clark Corporation | Supplier | | | Vicki Karandrikas (tel) |
| Linde Energy Services | Supplier | | | Vicki Karandrikas (tel) |
| Littleton (NH) Water & Light Department | Publicly Owned | | Craig Kieny | |
| Long Island Lighting Company (LIPA) | Supplier | William Killgoar | | |
| Macquarie Energy, LLC | Supplier | | | Nancy Chafetz |

**MEMBERS AND ALTERNATES PARTICIPATING IN
JANUARY 4, 2013 PARTICIPANTS COMMITTEE MEETING**

| PARTICIPANT NAME | SECTOR | MEMBER NAME | ALTERNATE NAME | PROXY |
|---|---|---|---|---|
| Maine Public Advocate Office (ME OPA) | End User | | | Paul Peterson |
| Maine Skiing, Inc. | End User | Donald Sipe | | Herb Healy |
| Mansfield Municipal Electric Department | Publicly Owned | | Gary Will | |
| Marblehead Municipal Light Department | Publicly Owned | | Gary Will | |
| Marden's Inc. | End User | Gus Fromuth | | |
| Mass. Attorney General's Office | End User | Fred Plett | P. Tarmey | |
| Mass. Municipal Wholesale Electric Company (MMWEC) | Publicly Owned | Gary Will | | |
| Mercuria Energy America Inc. | Supplier | | | Nancy Chaftez |
| Middleborough Gas and Electric Department | Publicly Owned | | Gary Will | |
| Middleton Municipal Electric Department | Publicly Owned | | Gary Will | |
| Millennium Power Partners | Generation | | Ken Dell Orto | |
| MoArk, Inc. | End User | Gus Fromuth | | |
| New England Building Materials | End User | Gus Fromuth | | |
| New England Power Company (National Grid) | Transmission | Timothy Brennan | | |
| New Hampshire Office of Consumer Advocate (NH OCA) | End User | Paul Peterson | | |
| NextEra Energy Resources, LLC | Generation | Fernandno DaSilva | | |
| NU / NSTAR | Transmission | James Daly | Calvin Bowie | Joe Staszowski |
| NRG Power Marketing, Inc. | Generation | Peter Fuller | | |
| PalletOne of Maine | End User | Gus Fromuth | | |
| Paxton Municipal Light Department | Publicly Owned | | Gary Will | |
| Peabody Municipal Light Plant | Publicly Owned | | Gary Will | |
| PowerOptions, Inc. | End User | Cindy Arcate (tel) | | Paul Person |
| PPL EnergyPlus (PPL) | Supplier | | Sharon Weber (tel) | |
| Praxair, Inc. | End User | | | Vicki Karandrikas (tel) |
| Princeton Municipal Light Department | Publicly Owned | | Gary Will | |
| PSEG Energy Resources & Trade LLC | Supplier | Joel Gordon | | |
| RJF-Morin Brick LLC | End User | Gus Fromuth | | |
| Rowley Municipal Lighting Plant | Publicly Owned | | Gary Will | |
| Rumford Paper Company | End User | Donald Sipe | | Herb Healy |
| Russell Municipal Light Dept | Publicly Owned | | Gary Will | |
| Shipyard Brewing LLC | End User | Gus Fromuth | | |
| Shrewsbury Electric & Cable Operations | Publicly Owned | | Gary Will | |
| Small Distributed Generation Group Member | AR | Doug Hurley | | |
| Small Load Response Group Member | AR | Doug Hurley | | |
| Small Renewable Generation Group Member | AR | Erik Abend (tel) | | |
| South Hadley Electric Light Department | Publicly Owned | | Gary Will | |
| St. Anselm College | End User | Gus Fromuth | | |
| St. Joseph Health Services of Rhode Island | End User | | Gus Fromuth | |
| Sterling Municipal Electric Light Department | Publicly Owned | | Gary Will | |
| Taunton Municipal Light Department | Publicly Owned | | Brian Forshaw | |
| Templeton Municipal Lighting Plant | Publicly Owned | | Gary Will | |
| Texas Retail, LLC | Supplier | Chris Hendrix (tel) | | |
| The Energy Consortium | End User | | Mary Smith | |
| TransCanada Power Marketing Ltd. | Generation | | Mike Hachey | |
| Union of Concerned Scientists (UCS) | End User | Paul Peterson | | |
| United Illuminating Company, The (UI) | Transmission | | Alan Trotta | |
| Utility Services Inc. | End User | | | Paul Peterson |
| Vermont Electric Cooperative | Publicly Owned | Craig Kieny | | |
| Vermont Electric Power Company, Inc. (VELCO) | Transmission | Frank Ettori | Bill Ryan (tel) | Mark Sciarrotta |
| Vermont Energy Investment Corporation | AR | | Doug Hurley | |
| Vermont Public Power Supply Authority (VPPSA) | Publicly Owned | David Mullett | | |
| Vitol, Inc. | Supplier | Joe Wadsworth | | |
| Wakefield Municipal Gas and Light Department | Publicly Owned | | Gary Will | |

**MEMBERS AND ALTERNATES PARTICIPATING IN**
**JANUARY 4, 2013 PARTICIPANTS COMMITTEE MEETING**

| PARTICIPANT NAME | SECTOR | MEMBER NAME | ALTERNATE NAME | PROXY |
|---|---|---|---|---|
| West Boylston Municipal Lighting Plant | Publicly Owned | | Gary Will | |
| Westerly Hospital | End User | | Gus Fromuth | |
| Westfield Gas & Electric Light Department | Publicly Owned | | Gary Will | |
| ZTECH, LLC | End User | | Gus Fromuth | |

**VOTES TAKEN AT**
**JANUARY 4, 2013 PARTICIPANTS COMMITTEE MEETING**

**TOTAL**

| Participant Name | VOTE 1 | VOTE 2 | VOTE 3 |
|---|---|---|---|
| GENERATION | 17.10 | 17.10 | 3.80 |
| TRANSMISSION | 0.00 | 4.27 | 17.10 |
| SUPPLIER | 10.26 | 16.30 | 0.86 |
| ALTERNATIVE RESOURCES | 14.50 | 10.97 | 3.53 |
| PUBLICLY OWNED ENTITY | 0.00 | 17.10 | 17.10 |
| END USER | 2.33 | 4.41 | 14.05 |
| **% IN FAVOR** | **44.19** | **70.15** | **56.44** |

**GENERATION SECTOR**

| Participant Name | VOTE 1 | VOTE 2 | VOTE 3 |
|---|---|---|---|
| Dominion Energy Marketing, Inc. | A | F | O |
| Entergy Nuclear Power Marketing LC | A | F | O |
| EP Energy Massachusetts LLC | F | F | O |
| EquiPower Resources Management | A | A | O |
| Generation Group Member | A | F | A |
| IPR-GDF SUEZ Energy Marketing NA | A | A | F |
| Millennium Power Partners | A | F | O |
| NextEra Energy Resources, LLC | F | F | O |
| NRG Power Marketing, LLC | A | A | F |
| TransCanada Power Marketing Ltd. | A | A | O |
| | | | |
| IN FAVOR (F) | 2 | 6 | 2 |
| OPPOSED (O) | 0 | 0 | 7 |
| TOTAL VOTES | 2 | 6 | 9 |
| ABSTENTIONS ( A) | 8 | 4 | 1 |

**TRANSMISSION SECTOR**

| Participant Name | VOTE 1 | VOTE 2 | VOTE 3 |
|---|---|---|---|
| Bangor Hydro-Electric Company | O | A | F |
| Central Maine Power Company | O | A | F |
| New England Power Company | O | O | F |
| NU / NSTAR | O | O | F |
| The United Illuminating Company | O | O | F |
| Vermont Electric Power Company | O | F | F |
| | | | |
| IN FAVOR (F) | 0 | 1 | 6 |
| OPPOSED | 6 | 3 | 0 |
| TOTAL VOTES | 6 | 4 | 6 |
| ABSTENTIONS (A) | 0 | 2 | 0 |

**ALTERNATIVE RESOURCES SECTOR**

| Participant Name | VOTE 1 | VOTE 2 | VOTE 3 |
|---|---|---|---|
| **Renewable Generation Sub-Sector** | | | |
| First Wind Energy Marketing | A | F | O |
| Small RG Group Member | A | F | O |
| **Distributed Generation Sub-Sector** | | | |
| Conservation Services Group | A | A | A |
| Small DG Group Member | A | F | O |
| **Load Response Sub-Sector** | | | |
| EnerNOC, Inc. | F | F | O |
| Vermont Energy Investment Corp. | A | O | F |
| Small LR Group Member | A | A | A |
| | | | |
| IN FAVOR (F) | 1 | 4 | 1 |
| OPPOSED | 0 | 1 | 4 |
| TOTAL VOTES | 1 | 5 | 5 |
| ABSTENTIONS (A) | 6 | 2 | 2 |

**SUPPLIER SECTOR**

| Participant Name | VOTE 1 | VOTE 2 | VOTE 3 |
|---|---|---|---|
| BP Energy Company | A | F | O |
| Brookfield Energy Marketing Inc. / CSC | S | S | S |
| Brookfield Energy Marketing Inc. | F | A | O |
| Cross-Sound Cable Co. | F | F | O |
| Calpine Energy Services | A | A | F |
| Consolidated Edison Energy, Inc. | F | F | O |
| CP Energy Marketing (US) Inc. | A | F | O |
| DC Energy, LLC | A | O | O |
| Dynegy Marketing and Trade, LLC | A | F | O |
| Energy America, LLC | A | F | O |
| Exelon / Constellation | A | F | O |
| Granite Ridge/Merrill Lynch Commodities | A | F | O |
| Great Bay Energy IV, LLC | A | A | O |
| H.Q. Energy Services (U.S.) Inc. | O | F | O |
| Hess Corporation | A | F | A |
| Integrys Energy Services, Inc. | A | F | A |
| JP Morgan Ventures Energy | O | F | O |
| Kimberly-Clark Corporation | A | F | A |
| Linde Energy Services, Inc. | A | F | A |
| LIPA | A | F | O |
| Macquarie Energy, LLC | A | F | O |
| Mercuria Energy America, inc. | A | F | O |
| PPL EnergyPlus, LLC | A | F | O |
| PSEG Energy Resources & Trade LLC | F | F | O |
| Texas Retail, LC | A | F | O |
| Vitol Inc. | A | F | O |
| | | | |
| IN FAVOR (F) | 3.0 | 20.3 | 1.0 |
| OPPOSED | 2.0 | 1.0 | 19.0 |
| TOTAL VOTES | 5.0 | 21.3 | 20.0 |
| ABSTENTIONS (A) | 19.0 | 2.7 | 4.0 |

**PUBLICLY OWNED ENTITY SECTOR**

**VOTES TAKEN AT**
**JANUARY 4, 2013 PARTICIPANTS COMMITTEE MEETING**

| Participant Name | VOTE 1 | VOTE 2 | VOTE 3 |
|---|---|---|---|
| Ashburnham Municipal Light Plant | O | F | A |
| Boylston Municipal Light Department | O | F | A |
| Chicopee Municipal Lighting Plant | O | F | A |
| Concord Municipal Light Plant | O | F | A |
| Conn. Municipal Electric Energy Coop. | O | F | F |
| Groton Electric Light Department | O | F | A |
| Holden Municipal Light Department | O | F | A |
| Hudson Light and Power Department | O | F | A |
| Hull Municipal Lighting Plant | O | F | A |
| Ipswich Municipal Light Department | O | F | A |
| Littleton (NH) Water & Light Dept. | A | F | A |
| Mansfield Municipal Electric Dept. | O | F | A |
| Marblehead Municipal Light Dept. | O | F | A |
| Mass. Municipal Wholesale Electric Co. | O | F | A |
| Middleborough Gas and Electric Dept. | O | F | A |
| Middleton Municipal Electric Dept. | O | F | A |
| Paxton Municipal Light Department | O | F | A |
| Peabody Municipal Light Plant | O | F | A |
| Princeton Municipal Light Department | O | F | A |
| Rowley Municipal Lighting Plant | O | F | A |
| Russell Municipal Light Department | O | F | A |
| Shrewsbury's Electric & Cable Ops | O | F | A |
| South Hadley Electric Light Dept. | O | F | A |
| Sterling Municipal Electric Light Dept. | O | F | A |
| Taunton Municipal Lighting Plant | O | F | A |
| Templeton Municipal Lighting Plant | O | F | A |
| Vermont Electric Cooperative | A | F | A |
| Vermont Public Power Supply Authority | O | F | A |
| Wakefield Municipal Gas & Light Dept. | O | F | A |
| West Boylston Municipal Lighting Plant | O | F | A |
| Westfield Gas & Electric Light Dept. | O | F | A |
| | | | |
| IN FAVOR (F) | 0 | 31 | 1 |
| OPPOSED | 29 | 0 | 0 |
| TOTAL VOTES | 29 | 31 | 1 |
| ABSTENTIONS (A) | 2 | 0 | 30 |

| Participant Name | VOTE 1 | VOTE 2 | VOTE 3 |
|---|---|---|---|
| 511 Plaza, LP – | O | O | F |
| Cianbro Companies | O | O | F |
| Connecticut Office of Consumer Counsel | A | O | F |
| Conservation Law Foundation | A | F | A |
| Corinth Wood Pellets, LLC | O | O | F |
| Dragon Products Company | O | O | F |
| Elektrisola, Inc. | O | O | F |
| Fairchild Semiconductor Corporation | O | O | F |
| Food City, Inc. | O | O | F |
| Hardwood Products Company | O | O | F |
| Harvard Dedicated Energy Limited | A | F | O |
| Industrial Energy Consumer Group | F | F | O |
| Maine Public Advocate Office | A | O | F |
| Maine Skiing, Inc. | F | F | O |
| Marden's Inc. | O | O | F |
| Mass. Attorney General's Office | O | O | F |
| MoArk, LLC | O | O | F |
| New England Building Materials, LLC | O | O | F |
| NH Office of Consumer Advocate | A | O | F |
| PalletOne of Maine | O | O | F |
| PowerOptions, Inc. | A | O | F |
| Praxair, Inc. | A | F | A |
| RJF – Morin Brick LLC | O | O | F |
| Rumford Paper Company | F | F | O |
| St. Anselm College | O | O | F |
| St. Joseph Health Services of RI | O | O | F |
| Shipyard Brewing Co., LLC | O | O | F |
| The Energy Consortium | A | F | O |
| Union of Concerned Scientists | F | F | A |
| Utility Services Inc. | A | A | A |
| Westerly Hospital, The | O | O | F |
| Z-TECH, LLC | O | O | F |
| | | | |
| IN FAVOR (F) | 3 | 8 | 23 |
| OPPOSED | 19 | 23 | 5 |
| TOTAL VOTES | 22 | 31 | 28 |
| ABSTENTIONS (A) | 10 | 1 | 4 |

**END USER SECTOR**

# CONSENT AGENDA

From the notice of actions of the ***Markets Committee***[1] meeting dated January 10, 2013 which has been previously circulated:

1. **Revisions to MR 1 and Tariff (FCM Demand Asset Auditing)**

   Support revisions to Market Rule 1 and Tariff Section I.2.2 to implement a mechanism which allows, under controlled situations, for the auditing of new demand response assets without auditing the entire demand resource, as recommended by the Markets Committee at its January 9, 2013 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.

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

# Summary of ISO New England Board and Committee Meetings

## February 1, 2013 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee met on January 10 via conference call. The Audit and Finance Committee, Compensation and Human Resources Committee, Markets Committee, System Planning and Reliability Committee, and the Board of Directors all met on January 17 in Holyoke.

**The Audit and Finance Committee** was provided with an update regarding 2012 and 2013 budget performance. The Committee received an overview on cyber security, including the security model, tools and activities, and training for staff. The Committee was also updated on the project related to third party clearing of financial transmission rights and implementation schedule of the clearing process. In executive session, the Committee discussed the protest by various state agencies of the Company's 2013 operating budget, and also reviewed the summary results for 2012 of the Internal Audit Department.

**The Compensation and Human Resources Committee** met by teleconference in executive session on January 10 to discuss corporate goals for 2013. The Committee also met on January 17 and reviewed updated survey data regarding employers' proposed 2013 compensation budgets. The Committee reviewed the data and agreed that there was insufficient data to warrant changing the previously budgeted amounts for the Company's merit and promotional increases. The Committee also discussed corporate performance for 2012 and officer compensation for 2013.

**The Markets Committee** received reports from the internal and external market monitors, and the COO's report on reliability costs. The Committee was briefed on the outcome of the stakeholder review process concerning the proposed changes to the day-ahead market timeline, and reviewed the differences between the company's proposal and the alternative proposal that stakeholders voted to support. The Committee supported management's recommendation to make a jump ball filing at FERC, presenting both proposals. The Committee discussed the results of a review of its existing responsibilities,

and recommended edits to a proposed meeting schedule and committee responsibilities for the upcoming year. The Committee also received an update on the Federal Energy Regulatory Commission's recent order on the proposed rules to conform the FCM rules to the price-responsive demand rules that will become effective in 2017. In executive session, the Committee discussed the work of the Internal Market Monitor in 2012 and the proposed work plan for 2013, as well as corporate performance in 2012 on goals within the Committee's purview.

**The System Planning and Reliability Committee** received an overview of the scope of work for the 2013 Regional System Plan, and reviewed the report schedule and format for the annual meeting. The Committee was provided with an update on anticipated system planning and operations activities for the present quarter, and reviewed the activities during the previous quarter. The Committee discussed compliance with FERC Order 1000 regarding interregional planning, and received a compliance update regarding North American Electric Reliability Corporation (NERC) audit activities, including the results of two successful on-site audits during 2012, and the future workload generated by NERC and FERC in the area of compliance. The Committee was also briefed on the generator interconnection queue process in the region and discussed inquiries regarding the use of elective projects to address deliverability issues. In executive session, the Committee considered corporate performance in 2012 on goals within the Committee's purview.

**The Board of Directors** received the standing committees' reports. The Board discussed and approved the proposed 2013 corporate goals. In executive session, the Board discussed the protest by various state agencies of the Company's 2013 operating budget.

ISO New England

2013 Regional Electricity Outlook

## Reliability is the core of ISO New England's mission, fulfilled by three interconnected and interdependent responsibilities.

Overseeing the day-to-day operation of New England's electric power generation and transmission system

Managing comprehensive regional power system planning

Developing and administering the region's competitive wholesale electricity markets

ISO new england

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## About ISO New England

ISO New England is the independent, not-for-profit corporation responsible for overseeing the day-to-day reliable operation of New England's power generation and transmission system; designing, administering, and monitoring the region's competitive wholesale electricity markets; and managing comprehensive regional power system planning. The company's workforce of power system engineers, economists, computer scientists, and other professionals fulfill these three critical responsibilities that together ensure New England has reliable, competitively priced electricity today and into the future.

ISO New England's board of directors and 550 employees have no financial interest in any company doing business in the region's wholesale electricity marketplace. ISO New England serves the six-state region of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont and is regulated by the Federal Energy Regulatory Commission (FERC).


+3 MW/min

# From the Chairman

**In 1997, ISO New England was established to help bring new efficiencies to the way the region produces, buys, sells, and transports electricity. The task set out before us was equal in both scope and complexity. Now with 15 years of operation under our belt, we can clearly see the signs of progress: New England's power grid is more resilient than ever before. Competitive wholesale electricity markets have attracted over 500 buyers and sellers and encouraged the development of cutting-edge, lower-cost resources and technological advancements. Thanks to the hard work of many, we have enhanced grid operations and regional planning to solve a number of reliability issues.**

Over 14,000 megawatts (MW) of new power plant projects have been interconnected to the grid since ISO New England began operations. That's an average of almost 1,000 MW per year—the equivalent of a power plant large enough to provide electricity to 800,000 homes. More than 2,000 MW of demand resources are available to reduce demand and bolster the grid's reliability. And $5 billion in private transmission investment has been made, reenergizing New England's high-voltage infrastructure and nearly eliminating congestion and its associated costs. The combined effect of these improvements, along with low natural gas prices, have created substantial savings for the region, helping reduce the value of the wholesale electric energy markets by over 40% in four years—from $12 billion in 2008 to approximately $5 billion in 2012.

New England's progress also can be measured in environmental gains. Over the past decade, the region's power system has successfully reduced air emissions by up to 60%. This achievement is made all the more impressive by the fact that the total system generation increased by 11% for the same period. As economics, government policy, and technology shape New England's stance on environmental issues, ISO New England's role is to oversee a competitive marketplace that enables these forces to bring about significant, positive change.

Looking back on the milestones New England has achieved in 15 years, it is truly impressive to see the effects of collaboration on a regional scale. The framework we've built together will enable New England to develop new strategies to meet our electricity needs in the most efficient way possible. Working with state and federal policymakers and industry stakeholders, the ISO continues to move forward on many initiatives to prepare and plan for the integration of new types of resources and engineering advancements and to continuously improve the wholesale electricity markets, operations, and planning processes.

As always, we strive to complete our projects in priority order and meet our extensive day-to-day responsibilities while ensuring that business operations are well-managed, fiscally responsible, and responsive to New England's electricity stakeholders. I thank you for your support, your insights, and your contributions to the evolution of New England's power system.

Sincerely,

**David Vitale**
Chairman of the Board

# From the CEO

**Risk is not a welcome factor in any organization, let alone one charged with ensuring a reliable supply of electricity to 6.5 million homes and businesses. The electricity that keeps hospitals operating and traffic signals lit isn't optional after all, it's a necessity. That fact, however, doesn't make us immune to risk.**

In reality, as a power system operator, ISO New England tackles uncertainty every day—fluctuations in supply and demand because of weather or an unexpected outage of a power plant or transmission line can make it challenging for the ISO to balance the needs of the power system. Our control room relies on the performance and flexibility of a wide variety of resources on the grid to navigate any event. By following rigorous procedures and establishing a fair, effective operating environment for resources, the ISO has been able to consistently keep the lights on in some of the toughest situations. Today, however, a unique convergence of economic and environmental factors is having a serious impact on the diversity, flexibility, and performance of the region's resource mix—risks that threaten the reliable supply of electricity for New England's homes, businesses, and public services.

In late 2010, the ISO launched a Strategic Planning Initiative to analyze, understand, and address these risks. Over the course of 18 months, we collaborated with New England states and market participants to identify the greatest threats to grid reliability as well as the changes needed to mitigate them.

We have found that the region's dependency on natural gas to fuel a large percentage of its generators is the most pressing concern. While low-cost natural gas from the Marcellus shale has been a boon to New England—resulting in billions of dollars of lower cost electricity—the transportation of this fuel through pipelines from the west into the region is frequently constrained, and the low cost of this fuel has reduced the more expensive imports of Canadian gas and liquefied natural gas. As a result, the region is highly dependent on an aging and relatively inflexible fleet of oil- and coal-fired generators to maintain reliability during peak demand periods or when the gas pipeline system is limited.

New England's oil- and coal-fired power plants are already facing significant financial stress from this confluence of market economics and stringent environmental standards. These pressures are forcing many owners of these assets to consider retiring them in the short to medium term. Furthermore, New England policymakers are seeking to increase the amount of renewable energy in the region, resulting in a clear need for a flexible and responsive companion resource base on the grid to provide electricity when the wind doesn't blow or the sun doesn't shine. We also have observed that as a general matter, overall resource performance isn't what we expect during power system contingencies, such as large generator or transmission line outages.

Because the ISO does not own the power plants or transmission lines, we cannot directly address the infrastructure and resource performance problems facing the region. However, we do have a responsibility to develop the market incentives and operating rules to address these concerns—courses of action that would ensure that these resources exist, are available, and run as our operators need to effectively manage the system.

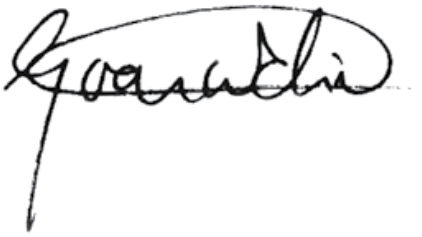
In the fall of 2012, the ISO and stakeholders shifted emphasis from collecting and analyzing information to designing solutions. Our comprehensive study and discussion of the issues at hand have led us to conclude that the region must continue to build on and enhance the wholesale electricity markets to create stronger financial incentives for generators and demand resources. These enhancements will work to ensure that the ISO has access to the resources it needs to operate the grid reliably and that the provision of these services is valued efficiently through a competitive marketplace.

This *Regional Electricity Outlook* provides an overview of the challenges and describes immediate-, short-, and long-term solutions underway or under consideration through our stakeholder process. The proposals being developed are driving ISO New England's business plan for each of its areas of responsibility: designing and administering the wholesale electricity markets, operating the grid, and planning the power system. Documents that provide a more technical, in-depth explanation of the issues and strategies are available at www.iso-ne.com/spi.

It is clear that resolving these challenges will not be simple, and it will take several years to realize the benefits of the solutions. While immediate action by the ISO is necessary to preserve grid reliability, support also will be required across states, regions, and even industries—by federal and state regulators, generators, and natural gas pipeline owners/operators. We look forward to working with our stakeholders as part of this ongoing process. It is important to remember that, often, the best ideas are born out of necessity. Today the power system faces significant and formidable obstacles. But tomorrow, it will be smarter, stronger, and more environmentally sound because of our collective efforts.

Sincerely,

**Gordon van Welie**
Chief Executive Officer

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# Built to Succeed

## What is reliability?

In almost every piece of literature you read about the power grid, you will see reliability listed as Priority Number One. What does reliability mean for most of us? It is the fact that when we start the coffeemaker or turn on the television in the morning, the coffee will flow and banter between lively news anchors will fill the room. You can expect your morning routine to unfold with comfortable predictability in large part because the wholesale side of the power system is making sure that the right amount of electricity is always available to all corners of the grid.

## Diversity, flexibility, performance

To balance electricity supply and demand every moment of the day, ISO New England system operators need a portfolio of resources across the grid that can offer a range of capabilities under a variety of conditions. This includes power plants that can run constantly to meet the required minimum amount of generation, resources that can start up quickly or dial back in response to changes in consumer demand or unexpected events, and generators that use a range of fuels should the region face a shortage in supply of, or access to, any one fuel source.

These resources have to react to the ISO control room's instructions precisely as directed. Their consistent performance—following through on commitments and delivering required services—is what helps your day start and finish just as you planned. When a resource does not perform in accordance with its specifications or obligations, grid operators are forced to depart from efficient and reliable dispatch of the system. This increases both the cost of operations and the chances of unintended power system outages—and puts the ISO in jeopardy of violating federal reliability standards.

# Strengthening our core

Over the past few years, ISO grid operators experienced numerous events during stressed system conditions when the performance and flexibility of power plants and demand resources were insufficient to correct these situations in a timely manner. This has led to growing concerns that as the power system continues to evolve, the mix of supply resources may be unable to operate when and as needed to maintain the grid's present level of reliability. These concerns arise from several different circumstances taking place in New England:

**Challenge 1:** Increasing reliance on natural gas as a fuel source for power plants and the potential for reduced operational performance during stressed system conditions

**Challenge 2:** The large number of aging, economically-challenged oil- and coal-fired generators that provide fuel diversity to the resource mix

**Challenge 3:** Greater future needs for flexible supply resources to balance variable, renewable resources that have operating characteristics markedly different from those of traditional generating resources

New England has made great strides to implement a thriving wholesale electricity marketplace, advanced grid operations, and successful regional planning processes. Today, the region's wholesale electric power industry has reached its next stage of maturity in which existing rules, processes, and systems need to be refined to improve resource performance and dispatch, better meet current and future operational needs, and shore up the long-term reliability of the system.

The following sections of the REO explore each of the three challenges in order of urgency, with Challenge One being the most immediate. It is important to note that the solutions presented are likely to adjust over time. Because New England's power grid is a tightly interconnected network, each resource addition, retirement, or change, can affect the makeup of the grid as a whole. Analyzing challenges and developing solutions must therefore be an ongoing, iterative process.

## Transmission advancements

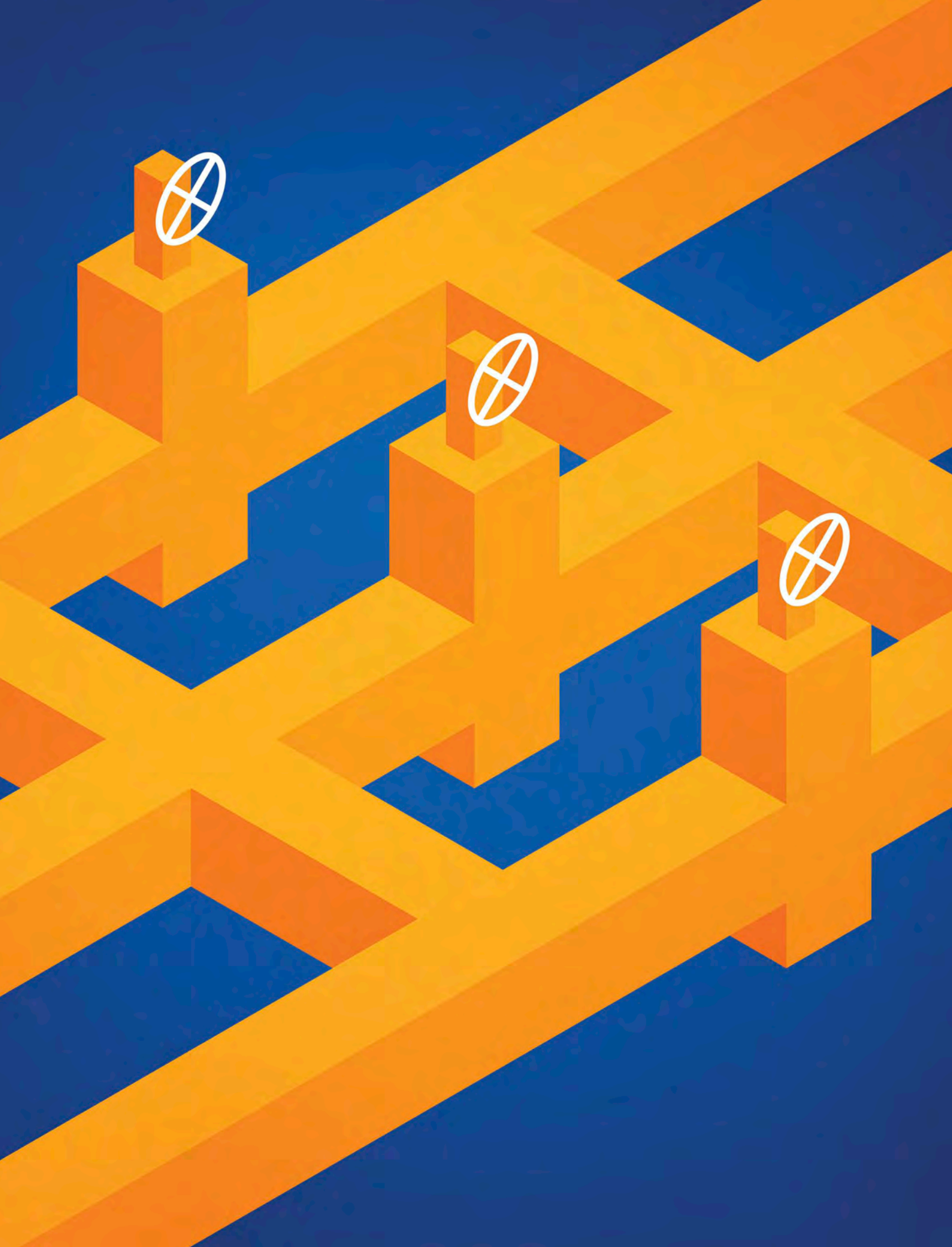
In addition to needing a diverse fleet of high-performing supply and demand resources, system operators also count on the ability to move wholesale electricity freely and efficiently within the region and with neighboring grids. A comprehensive, secure high-voltage infrastructure provides the foundation of reliability, accommodates the integration of new types of resources, and enables greater access to lower-cost power, therefore offsetting costs. Not long ago, insufficient transmission infrastructure was a high-priority concern for the region; however, nearly $5 billion in transmission investment has been made over the past decade as a result of the region's comprehensive system planning process—and another $5 billion is in development over the coming five years. This extensive expansion of the system gives the ISO the latitude and tools needed to better address the current strategic planning challenges.

## Why efficiency matters

Efficiency is about minimizing the cost of producing and delivering electricity while maintaining the high level of reliability consumers require. Markets deliver efficiency by pricing wholesale electricity competitively, motivating suppliers to find the most cost-effective ways to produce it. Efficient, high-performing resources are more likely to be selected to generate electricity and to have the flexibility to meet changing power demand over the course of the day. In turn, markets hasten the retirement of resources that are inefficient, more costly, and less reliable.

## Learn more about the grid, wholesale markets, and the challenges we face

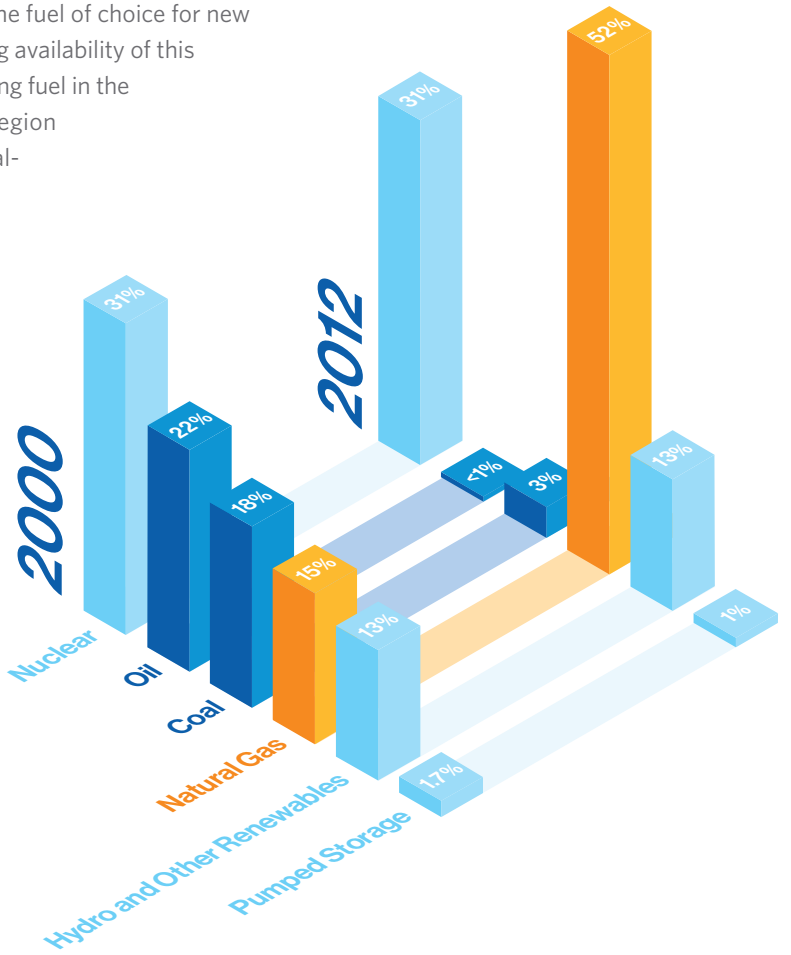
The *Regional Electricity Outlook*, together with the *Regional System Plan* and *Wholesale Markets Project Plan*, form a collection of documents designed to help provide stakeholders critical information about the current state of the grid, issues affecting the future of New England's power system, and the near- and long-term solutions designed to resolve them. All are available on ISO New England's website, www.iso-ne.com.



# Challenge 1

## Mitigating the risks of New England's dependence on natural gas

Natural gas has become the dominant fuel used to produce electricity in New England. Approximately 12,000 of the 14,000 MW of generating capacity built over the past 15 years are natural gas combined-cycle units, and gas continues to be the fuel of choice for new power plant construction. The growing availability of this relatively inexpensive and clean-burning fuel in the eastern part of the US benefits the region in many ways. The increase in natural-gas-fired generation has resulted in a significant decrease in both power plant emissions and the wholesale cost of electricity.




**Dramatic changes in the energy mix**

**The fuels used to produce New England's electric energy have shifted as a result of economic and environmental factors.**

Today, however, the lack of dependable fuel arrangements by generators, limited on-site fuel storage or alternate fuel arrangements, and increasing constraints on the pipeline system have hindered the performance of New England's natural gas generators, creating serious, immediate risks to grid reliability. In various instances, natural gas generators have not provided electric energy because they were unable to procure either the fuel or its transportation, or because they determined the price of gas was too expensive to purchase in real time. The ISO currently is managing these situations by using inefficient and more expensive oil- and coal-fired plants—yet these resources are also at risk (see Challenge Two).

The region's growing dependence on natural gas and its related issues have been a consistent concern during winter, when the priority for natural gas supplies goes to heating New England's homes and businesses. But as the use of natural gas has increased, this dependence has become a major challenge for managing the electric grid throughout the year. As older coal- and oil-fired plants retire and new gas-fired plants are built to replace them, it is likely the region will come to rely even more on this fuel. In addition, gas-fired plants can provide much of the flexibility needed to balance intermittent wind power resources, so it is expected that gas-fired resources will be needed on line as wind resources are built and interconnected (see Challenge Three).

The ISO is exploring with stakeholders improvements designed to ensure and create the incentives for the availability, performance, and flexibility of resources such as natural-gas-fired power plants. These improvements can be categorized as near-term changes that can be implemented quickly; intermediate-term changes that could be implemented in the next year or two; and longer-term changes that could be implemented over the course of the next three to five years. Each of the proposed changes is taken through comprehensive stakeholder and federal approval processes before being implemented.

## Natural gas next door

New ways to extract natural gas have resulted in the recent influx of affordable gas from the Marcellus Formation. Even though this source is located on New England's doorstep, the region is still faced with a number of factors that affect the reliability of fuel supplies.

The pipelines delivering New England's natural gas have to supply a wide variety of customers, some of whom contract for priority delivery. Natural gas supply to power plants can be interrupted to serve these customers. At times, constraints on pipelines can jeopardize a power plant's ability to run. This can be due to physical limitations on the pipeline or pipeline maintenance.

Moving additional natural gas into New England will require investment in pipeline infrastructure. However, additional pipeline capacity is built only if customers commit to long-term contracts, and it is unclear who in the region, other than local gas distribution companies, would find such contracts economically attractive.

# Current operations and near-term market fixes

## Dispatching with Better Visibility, Flexibility

ISO New England has taken several immediate actions during 2012 and 2013 to help system operators better understand the performance limitations of gas-fired plants and more effectively accommodate these resources during system dispatch. These include:

- Monitoring generator fuel inventories closely and reinforcing dispatch obligations of all resources
- Proposing rules that would enhance the ability to audit the operating characteristics of power plants so control room operators have greater visibility into a resource's reserve capability
- Increasing the amount of reserve requirements for real-time system operation so more resources can be ready when called on during stressed system conditions
- Proposing to increase the amount of reserves acquired through the Forward Reserve Market to support the availability of resources to meet those increased real-time requirements

## Enhancing Information and Coordination

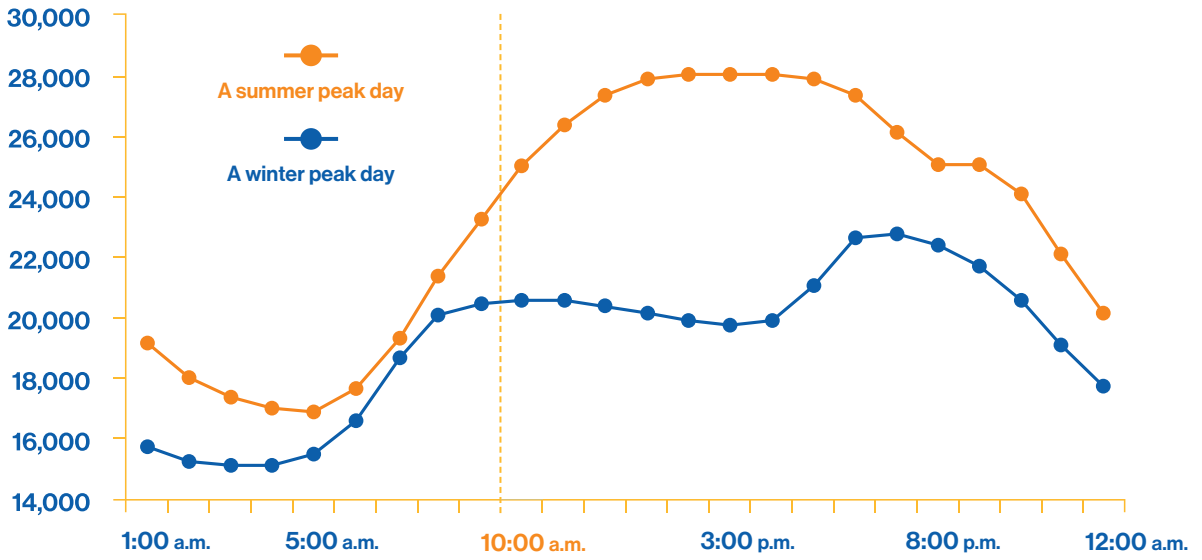
New England is at the forefront to improve operational coordination between the electric industry and pipeline operators. Since the 2004 cold snap, New England's Electric/Gas Operations Committee has facilitated essential communications that have helped maintain power system reliability. More recently, the ISO is pursuing changes to its Information Policy to share generator-specific information with the gas pipelines and for the pipeline operators to in turn share their gas availability information. Should gas supply be insufficient for all generators to meet their schedules, this information would help ISO operators better anticipate and address potential reliability problems. The electric- and gas-sectors also are working to improve coordination of maintenance on both systems.

## Aligning Gas and Electric Market Timing

The natural gas and wholesale electricity markets have different schedules, making it difficult for some gas-fired generators to participate in both markets effectively and for system operators to determine when to call on non-gas resources for the operating day. A proposal underway currently seeks to move up the Day-Ahead Energy Market timeline to help address this issue. In doing so, gas-fired generators would have more time to arrange fuel for the operating day and make fuel-switching decisions should they have dual-fuel capability. This also would give ISO operators more flexibility when determining which non-gas resources to call on line, better accommodating resources that require a long time to start up.

**New England hourly demand (MW)**

**The gas operating day starts at 10:00 a.m. when electricity demand is growing and additional generation is needed.**



## Global factors, local consequences

The global price of liquefied natural gas (LNG) plays an important role in New England's electricity production. Because domestic natural gas prices are currently low and LNG prices in Europe and Asia are currently high, LNG suppliers are selling their fuel outside the US market. As a result, LNG supplies in New England have been greatly reduced, leading to underutilization of the gas pipeline infrastructure in northern New England, which connects LNG facilities, and overutilization of gas pipeline infrastructure in central and southern New England, which connects domestic natural gas sources.

What's more, recent disruptions to global pipeline and tanker deliveries of LNG also have created significant challenges for some of New England's power plants. Operational contingency plans; swift communication; and coordination with state officials, affected generation facilities, and natural gas companies, alleviated concerns with LNG disruptions in the summer of 2012. Nevertheless, the future reliability of LNG supplies to the region is uncertain.

# Medium-term market enhancements

### Tightening the Shortage-Event Trigger

A shortage event is a period when the power system is stressed and using nearly all available resources to satisfy electricity demand. The term "shortage" means the total amount of available generation is less than (or short of) the normal target level to maintain reliable operations. This target level is always set higher than current power demand to ensure reliable power supply continues uninterrupted even if a large generation or transmission facility suddenly has an outage.

The current Forward Capacity Market (FCM) offers provisions that provide financial incentives for resources to perform and minimize the chance of generation outages during shortage-event periods. However, these financial provisions apply only during situations when available generation is far below the normal target level (i.e., a deficiency in the system's 10-minute generation reserves, for a period of a half hour or more). This provision has proven to be not sensitive enough to indicate when the system is entering a heightened "at risk" period. Because this financial incentive is rarely used, the ISO doesn't have assurance the resources will perform. To correct this, in 2013, market rules will be proposed to initiate a shortage-event trigger earlier—during periods when the grid has a deficiency in *total* operating reserves rather than a deficiency only in 10-minute reserves. By triggering shortage events sooner, resources will have the incentive to perform during at-risk periods over a wider range of at-risk situations that can occur in New England's power system.

## Changing Electric Market Offers in Real-Time to Reflect Fuel Prices

Natural gas prices fluctuate throughout the day, but currently market participants can only update their offers to buy and sell in the Day-Ahead Energy Market during limited hours and not during the actual operating day. Any changes to a generator's fuel costs after that time cannot be reflected in the resource's offer. This restriction can cause operators to dispatch generators using "stale" power supply offers that are below a generator's actual production cost, or alternatively, can prevent a generator from lowering its power supply offer if its actual cost is less than anticipated the previous day. Both situations are becoming more common because of the increased volatility in fuel prices, particularly for natural gas.

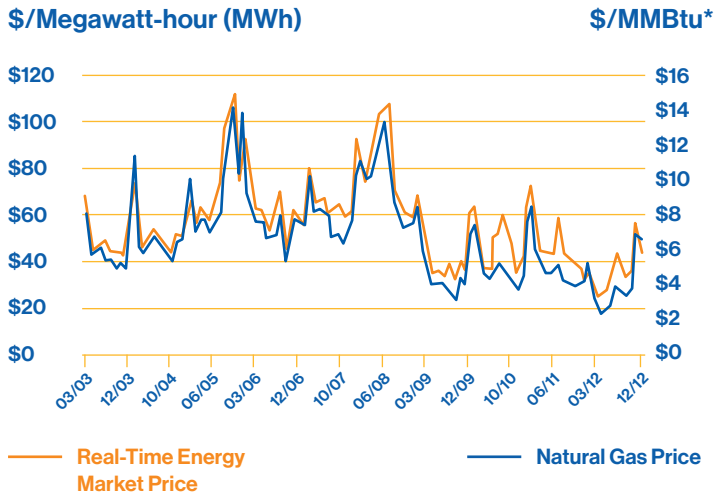
In summer 2013, the ISO will work with stakeholders to propose market rule changes that would allow participants to submit time-dependent (i.e., hour varying) power supply offers in the Day-Ahead Energy Market, as well as to submit updated power supply offers during the operating day. This will improve a resource's ability to reflect the actual costs of fuel and operations in their offer, which can vary during the operating day. This step also will improve how prices are set in the energy market. More accurate pricing provides the necessary signals or incentives for resources to perform, thus ensuring reliability.

## Changing Reserve Needs throughout the Day

The ISO and stakeholders are considering whether to enable additional reserve resources to be committed and dispatched within the operating day. Doing so would give control room operators greater flexibility to more effectively respond to intraday fuel contingencies, reduce the costs of out-of-merit dispatch, and more efficiently value the reliability sought through real-time energy prices.

### Natural gas and wholesale electricity prices are linked

**Because of New England's heavy reliance on this single fuel source, natural gas typically sets the price for wholesale electricity.**




*MMBtu stands for Millions of British thermal units

# Longer-term market development

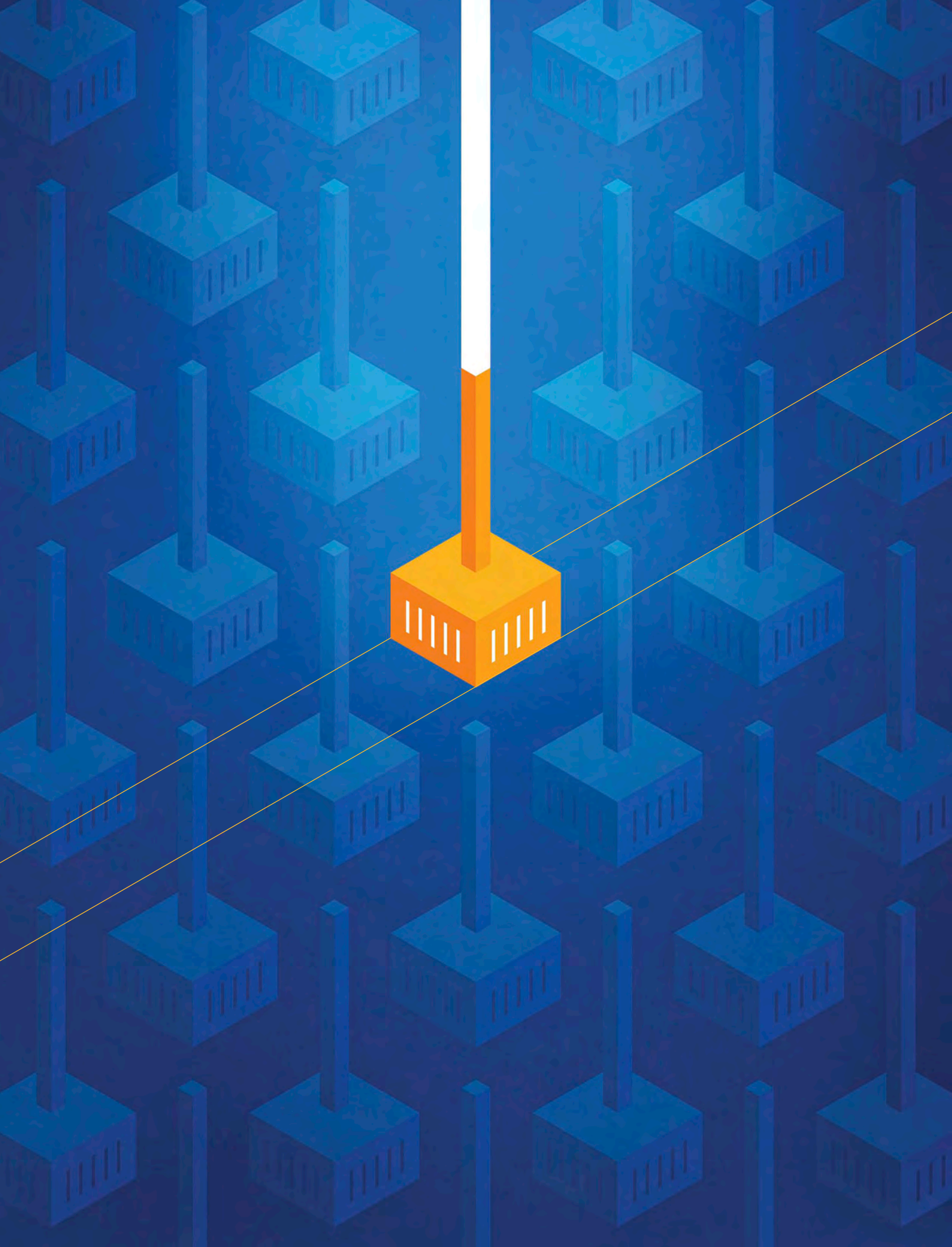
## Performance Incentives

In New England, wholesale electric power is bought and sold day to day through the energy markets. Reserve markets support the energy markets by ensuring the grid has enough resources ready to come on line should demand spike or a power plant or transmission line experience a sudden outage. Capacity markets complement both the energy and reserve markets by ensuring that sufficient resources are designed and built to provide energy and reserves each day. Capacity markets send price signals that attract new investment and encourage the availability of existing resources.

Enhancements to the Forward Capacity Market are being considered so that it further complements the energy and reserve markets by providing stronger financial incentives for all resources to perform during stressed system conditions. For the natural-gas-related challenges, one goal of these enhancements is to stimulate generation resources to make investments that ensure a reliable fuel supply. Presently, gas-fired resources rely on a "just in time" fuel delivery system using interstate pipelines that, in general, must be scheduled in advance of the operating day to ensure adequate fuel. When unforeseen problems in the natural gas supply chain occur during the operating day, flexible resources that have the fuel to maintain the power system's reliability are needed. As the region's reliance on natural gas grows, greater private investment in hardware, fuel arrangements, or other supplier-selected solutions to ensure resource performance and availability is essential. Changes to the Forward Capacity Market will improve suppliers' incentives to undertake these investments.

Other long-term enhancements to the Forward Capacity Market include a "pay-for-performance" incentive structure that increases the financial reward to suppliers whose resources deliver energy or reserves during stressed system conditions. This performance incentive design will result in financial transfers from resources that perform poorly to resources that perform well, providing strong incentive for each resource to perform as needed. Resources that can meet the system's needs by exceeding their capacity market obligations will benefit by doing so. Mirroring the current capacity market's features that reduce consumer price risk, the transfers will be structured so that New England's consumers will continue to pay a forward price, determined by a competitive auction three years in advance, and will not bear the short-run risk of covering performance-incentive payments.

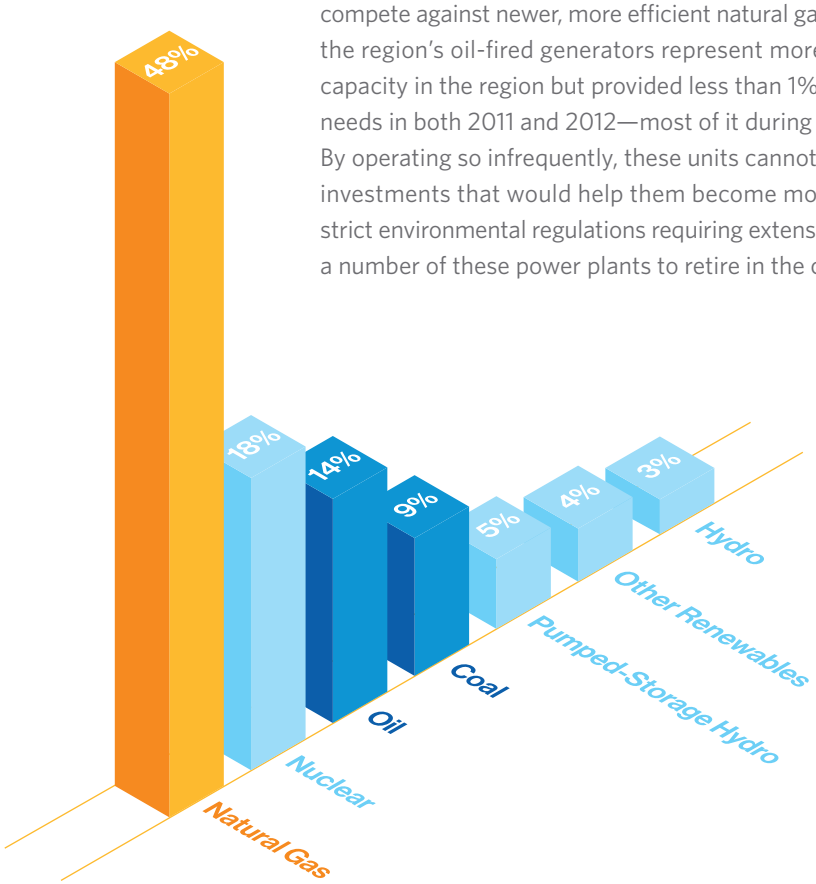
Ultimately, these enhancements are expected to change market participants' long-term investment incentives and produce a more reliable and more flexible fleet of power supply resources at the lowest possible cost. In the interim, the enhanced performance incentives will lead to increased operational-related investments by existing facilities, including more reliable fuel supply arrangements that can improve resource performance and availability during stressed system conditions. The ISO anticipates filing market rule changes for the ninth annual Forward Capacity Market's auction in 2014, which determines suppliers' obligations for the 2018–2019 delivery years.



# Challenge 2

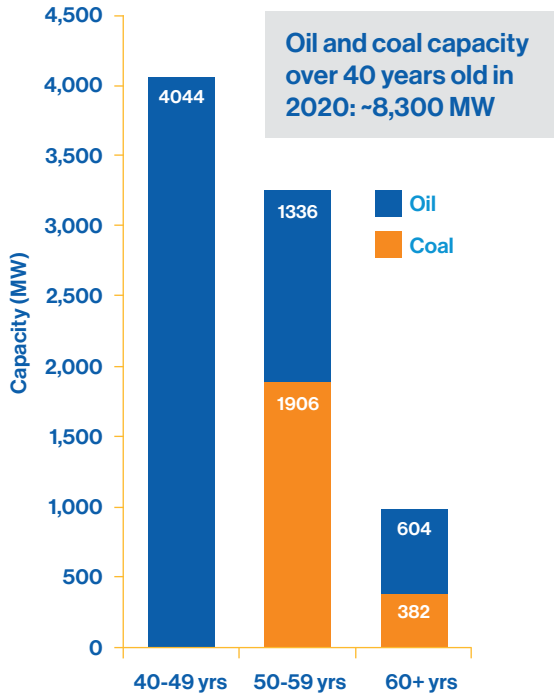
## Planning for retirement: How New England can prepare for an aging generator fleet

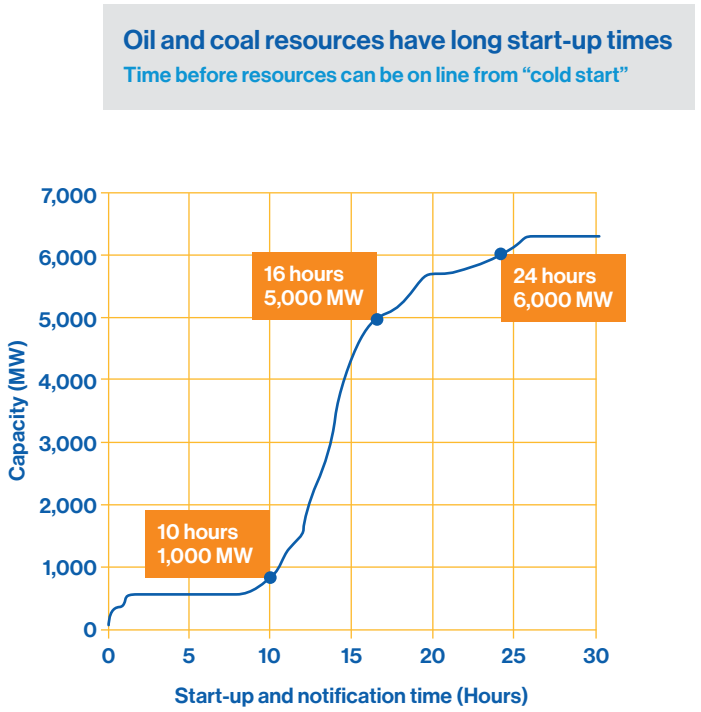
The rising costs associated with oil and coal, and the declining costs of natural gas, have made it difficult for older oil and coal power plants to compete against newer, more efficient natural gas generators. For example, the region's oil-fired generators represent more than 20% of existing capacity in the region but provided less than 1% of the region's electricity needs in both 2011 and 2012—most of it during periods of peak demand. By operating so infrequently, these units cannot recover costs for capital investments that would help them become more efficient. In addition, strict environmental regulations requiring extensive investment may force a number of these power plants to retire in the coming years.




### What's powering New England through the peak?

**Look at fuel usage during high electricity demand on the peak of a summer day in 2011. Oil-fired resources produced 14% of electric energy during the peak but produced only 1% of electricity over the entire year.**




Long start-up times—up to 24 hours to reach full power production—make it challenging to rely on older plants for backup generation. Many of these units were originally designed to provide baseload electricity but are being relied on now for peaking service, ramping, or reserves when the natural-gas plants are constrained.

While it is an expected market outcome for uneconomic plants to retire, the potential magnitude of retirements in a relatively short timeframe poses a serious reliability risk to the region. The loss of each coal- or oil-fired power plant reinforces New England's dependence on natural gas and weakens the ability to weather operational issues caused by the lack of availability of gas generators.

In early 2013, the ISO published the *Strategic Transmission Analysis—Generation Retirement Study*, an assessment of system reliability risks stemming from potential resource retirements. The study analyzed the transmission system impacts if 28 oil- and coal-fired generators, representing nearly 8,300 MW of capacity, were to retire by the end of the decade. In 2020, if all the at-risk units in the region seek to retire, over 6,000 MW of resources would need to be replaced, repowered, or retained to satisfy both generation and transmission reliability requirements. Because of the favorable economics of natural gas, a significant portion of the replacement resources will likely be natural-gas-fired generation.

# Near-term solutions

The region faces a systemic risk if too many units cannot perform simultaneously. To manage this, the ISO has at times had to rely on some near-term strategies, such as retaining resources that want to leave the capacity market, dispatching resources out of merit, procuring emergency capacity, and proposing backstop transmission investments. While necessary for the short-run reliability, these fixes are costly and inefficient.

As described in Challenge One, several constructive immediate actions are helping system operators better manage the system. These include closely monitoring generator fuel inventory, reinforcing current dispatch obligations, enhancing the ISO's ability to audit the operating characteristics of power plants so the control room has a clearer window into a resource's reserve capabilities, and increasing the amount of required reserves so that it has more resources ready to call on during system events.

# Longer-term incentives for a more reliable resource mix

Potential changes to the Forward Capacity Market, as described in Challenge One, are being considered to encourage investments by existing resources to improve performance and availability, such as reducing start-up times and improving operational flexibility. The FCM would reward resources delivering least-cost solutions and performing well during stressed system conditions. These FCM enhancements also would draw investment in new, flexible resources, trending toward a more reliable resource mix over time.

In addition, FCM improvements will help better align market responses with system planning processes so that market resources (i.e., generation, demand resources, merchant transmission) can be considered on equal footing with cost-of-service transmission solutions. In late 2013, the ISO anticipates filing market rule changes that will substantially increase performance incentives, taking effect in 2018–2019. Thereafter, the ISO will focus on the issue of improving the alignment between the FCM and the system planning processes.

## The risks ahead

In 2020, nearly 8,300 MW of generation are expected to be older than 40 years. Representing more than 25% of total generating capacity, a significant portion of New England's generator fleet faces retirement. That creates serious risks for the region, including:

- Markets and reliability rules may not be well-suited to efficiently manage the sheer magnitude of retirements.
- As the oldest generators in New England, many of the at-risk units are located at critical locations on the transmission grid. If they retire without repowering, transmission security challenges could be created on both the local and regional scale.
- The loss of fuel diversity will amplify the region's dependence on natural gas outlined in Challenge One.

# The big picture: Fitting the pieces of the grid puzzle

Many of the region's older oil- and coal-fired generators were built at or near major electricity demand centers, such as the Boston area, to best meet peak consumer demand. The replacement of a large number of these resources could alter the makeup of the grid and create transmission reliability and security issues, depending on where the new resources are located.

The *Strategic Transmission Analysis—Generation Retirement Study* found that the replacements for the 28 at-risk oil-and coal-based resources do not necessarily need to be located in those same demand centers. In fact, repowering all existing sites at their existing locations would likely result in congestion and actually increase the amount of capacity that would need to be replaced.

Transmission development expected between now and 2020 will significantly expand and fortify the area of the grid known as the region's energy hub and the connections to it from other areas of the grid. Based on the study findings, adding 5,000 MW of the 6,000 MW of the replacement capacity to that area of the grid may best serve most of the region's demand and maintain transmission reliability and security.

The remainder of the replacements for the oil- and coal-fired capacity must be developed in specific locations, such as the southeast section of Massachusetts and areas in Connecticut, because of transmission constraints. These areas require local capacity or transmission reinforcements to address transmission reliability concerns.

Depending on the pattern of unit retirements and the timing of new, major transmission projects, the needs of the New England system may change dramatically. Consequently, the ISO and stakeholders will need to consider the solutions developed carefully.

## Forecasting efficiency

Energy efficiency (EE) has seen remarkable growth in recent years. ISO New England has developed the nation's first multistate energy-efficiency forecast to track this growth and measure the impact of state-sponsored EE programs on the region's electricity needs. The forecast shows EE initiatives will see investment totaling nearly $5.7 billion from 2015 through 2021. The projected energy and demand savings shown in the forecast, as well as some transmission upgrades and a changing load forecast, reveal the region was able to defer $260 million of proposed transmission upgrades. This level of savings is expected to continue or increase in the future. And as energy efficiency continues to be added, the region can expect to defer or eliminate the construction of expensive power system infrastructure.

# Challenge 3

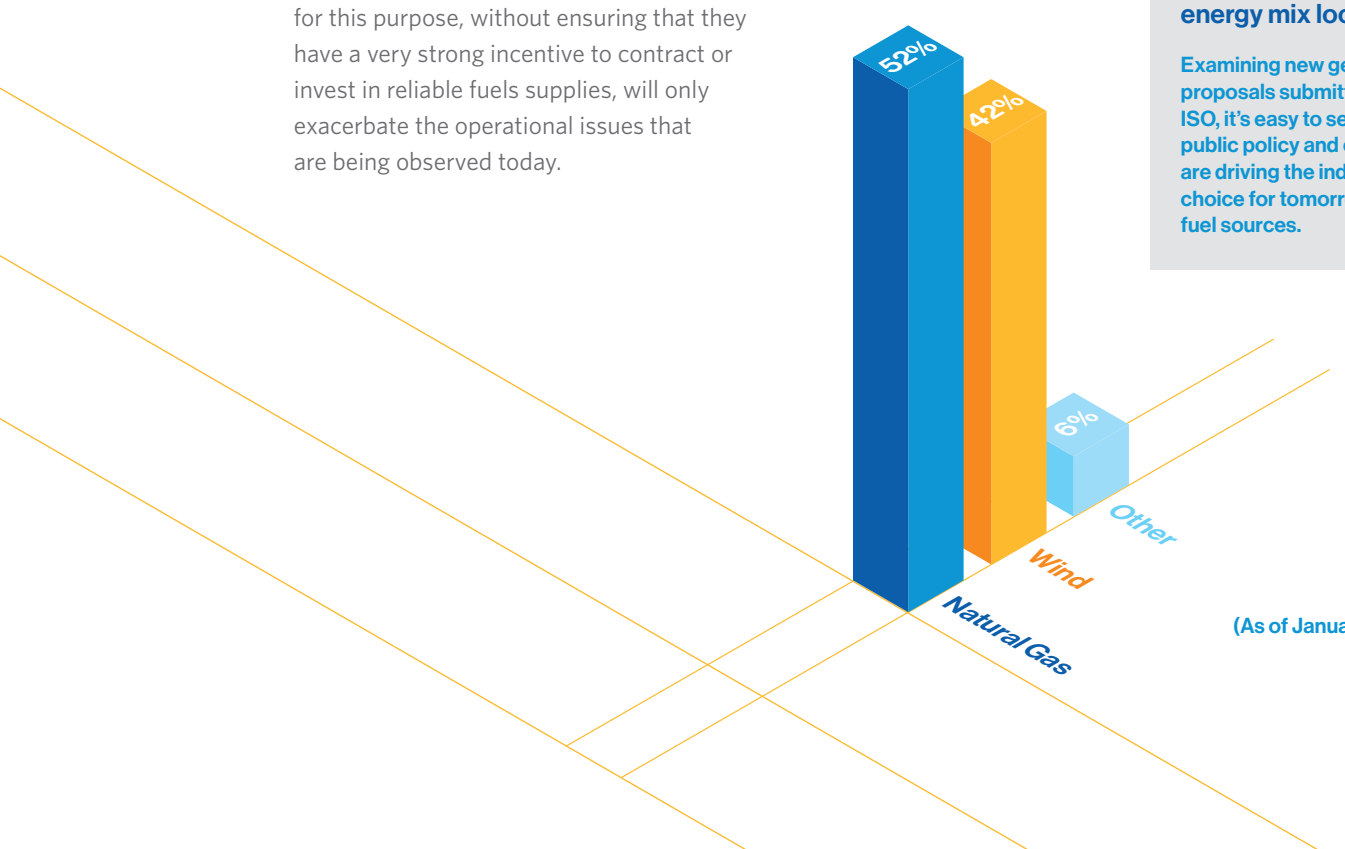
## Integrating variable resources while maintaining reliability

New England has multiple wind-rich areas ripe for development, making renewable energy an exciting possibility for the region's future. With zero emissions and no fuel costs, the addition of significant amounts of wind energy will help achieve federal and state environmental goals, mitigate wholesale electricity price volatility caused by wide-ranging prices of traditional fuels, and help alleviate fuel diversity concerns under normal system operating conditions.

However, renewable resources such as wind are not always capable of producing electricity at times when the need for diverse resources is most important. Wind speeds can be at their lowest levels in the summer, when New England's demand is peaking, and in the winter during extreme cold conditions when demand is high. Adding large amounts of this variable resource also would increase the complexity and decrease the flexibility of control room operations. If this wind potential is realized, system operators must be prepared to manage dispatch with resources that can have rapid and sizeable swings in output. To balance these potential swings by variable resources, the system must hold more capacity in reserve that can come on line quickly. While the short startup times of natural gas power plants provide a suitable complement, relying on natural gas generators for this purpose, without ensuring that they have a very strong incentive to contract or invest in reliable fuels supplies, will only exacerbate the operational issues that are being observed today.

**What will tomorrow's energy mix look like?**

**Examining new generator proposals submitted to the ISO, it's easy to see how public policy and economics are driving the industry's choice for tomorrow's fuel sources.**




(As of January 2013)

# Accommodating a potential influx of wind resources

Regionwide, Renewable Portfolio Standards and other environmental targets call for 30% of New England's projected total electric energy needs in 2020 to be met by renewable resources and energy efficiency. Today, approximately 40% of the proposed projects in the ISO's generator Interconnection Queue are wind-powered.

These variable resources will have a greater impact on system reserve, regulation, and ramping needs as they assume a larger percentage of the grid's total capacity. In the near term, ISO New England is working to integrate wind forecasting into resource commitment and dispatch. The ISO is enhancing the accuracy and range of its forecast with greater insight into variable resources and taking steps to ensure these entities have incentives to follow dispatch orders quickly. Considerable investment in smart grid technologies will be needed to provide system operators with the tools to manage the unpredictability of wind because its output can vary over relatively short time periods.

The 2010 New England Wind Integration Study (NEWIS) analyzed various factors associated with the planning, operating, and market aspects of wind integration. The ISO will continue to implement the strategies outlined in NEWIS as wind projects proposed in the interconnection queue enter service.

## How supercomputers are helping build tomorrow's grid

Unlike power plants that rely on stockpiles or pipelines that ensure a constant supply of fuel, wind farms cannot schedule their electricity generation with complete certainty. That uncertainty creates significant challenges for the grid operator. Planning for real-time and day-ahead energy needs is difficult when a large percentage of generating resources might be off line because the wind isn't blowing.

ISO New England is teaming up with scientists from the Lawrence Livermore National Laboratory (LLNL) to find more efficient ways of integrating variable resources into the grid. LLNL selected the ISO in March 2012 to participate in a one-year program using high-performance computing (HPC) to model and simulate a new robust unit commitment (UC) solution used to dispatch generators.

Relying on LLNL's expertise in high-performance computing, ISO New England is running simulations on the new UC solution and examining its economic and operational benefits to real-time dispatch and pricing.

# Market changes to reflect variability, flexibility

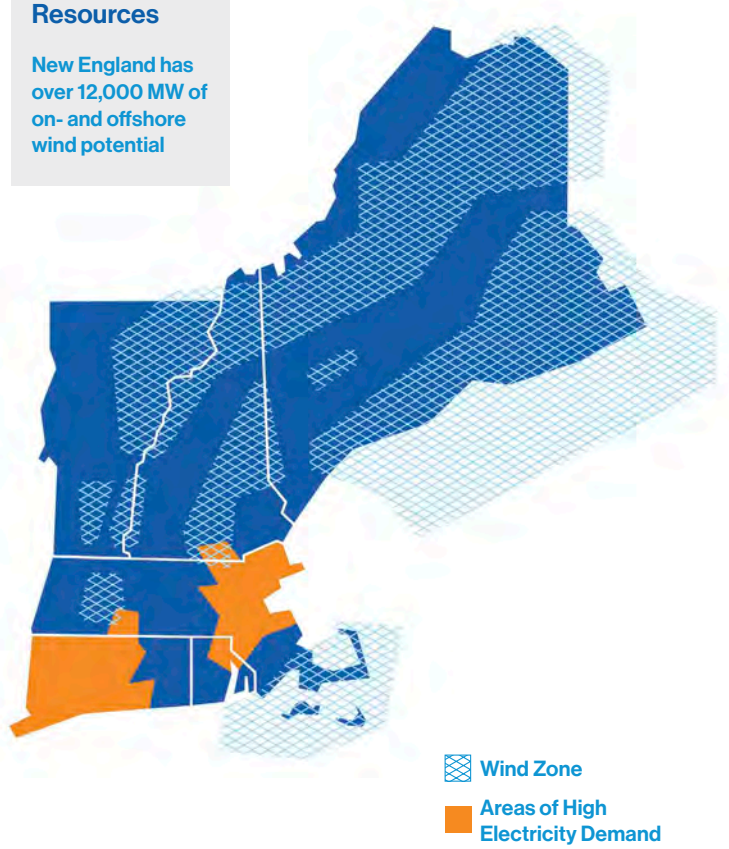
Because renewable resources such as wind power run when the wind blows and cannot easily shut down, system conditions could result during which too much electricity is flowing on the grid, causing the market price to drop to zero. When the price drops to zero, the ISO cannot dispatch in economic merit order. Currently, resources such as wind or even nuclear plants cannot reflect in their supply offers a preference to avoid shutting down. If they are not selected to run, they face inefficient start-up and shut-down expenses. The ISO is examining whether to allow resources to submit negative offers in the energy markets as a solution to this problem. In this situation, generators would pay to operate, which would be less expensive than for them to shut down and restart. This would also send a strong market signal that additional reductions in generation or an increase in demand is needed to ensure reliability.

Changes to the Forward Capacity Market as described in Challenge One that improve incentives for resource flexibility and availability are being developed to better secure investment in resources that can balance intermittent power supply. While the risks associated with this challenge are a longer-term concern, addressing FCM changes now to improve incentives for resource flexibility will facilitate investment planning decisions by the private sector. Other considerations include allowing variable resources to be paid five-minute locational marginal prices in the energy market, which could provide more appropriate compensation and promote efficient performance.

Market design changes are long-term solutions that require time, stakeholder input, and thoughtful planning to achieve successful implementation.

**Untapped Resources**

**New England has over 12,000 MW of on- and offshore wind potential**



# Bringing renewable energy to market

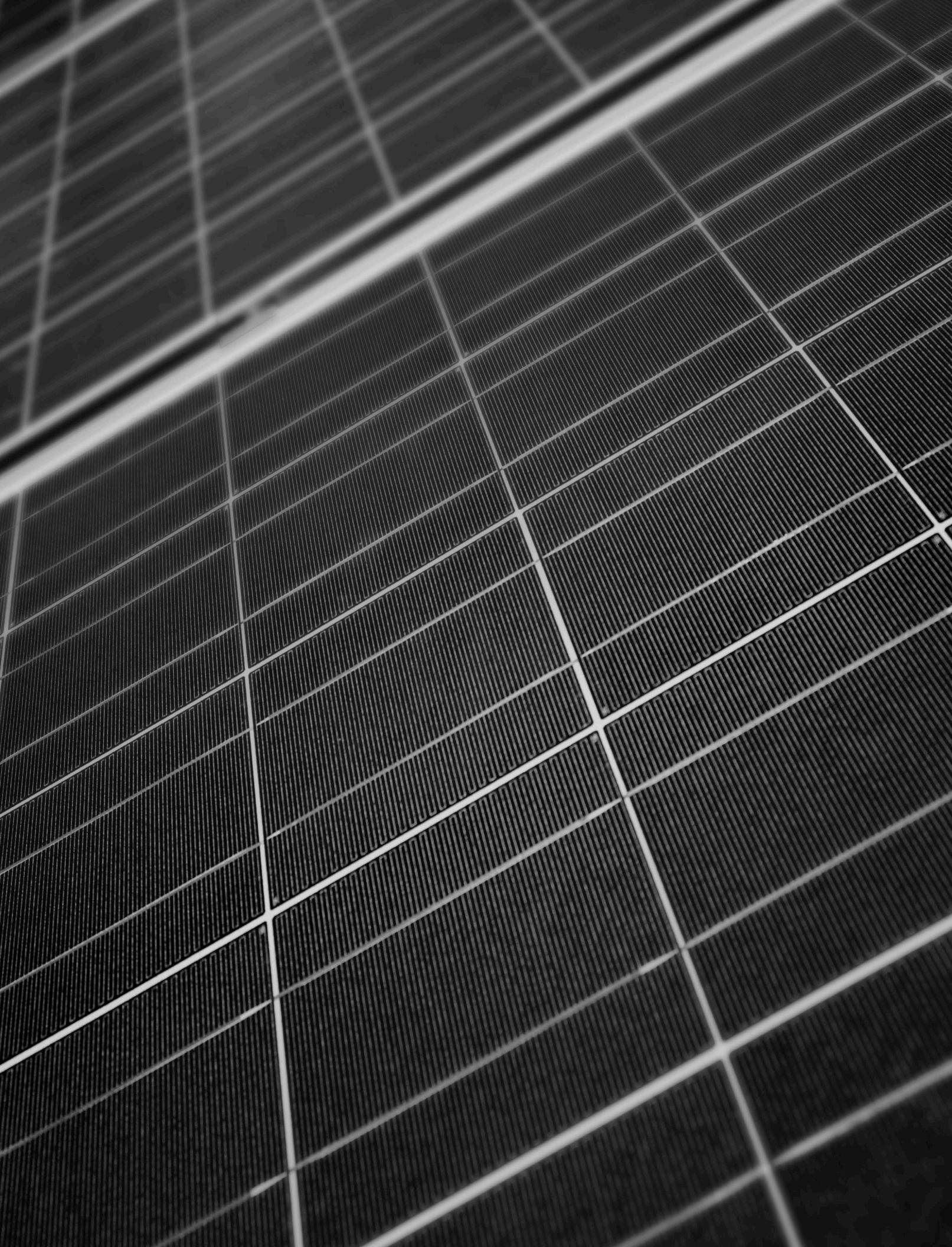
The extent to which wind energy will be developed will depend on the region's readiness to fund large-scale transmission investment to connect remote wind farms to demand centers. An analysis conducted at the request of the six New England governors found that the cost to interconnect from 2,000 MW to 12,000 MW of wind power would be between $1.6 billion to $25 billion in transmission upgrades.

While new wind resources are being added to the system, substantial increases are not expected for several years. The pace of growth may be mitigated by sustained, low natural gas prices; a delay at the federal level in developing clean energy and carbon legislation; or a reconsideration in some parts of the region of Renewable Portfolio Standards. Accommodating a high percentage of variable resources will require careful assessment of the timing of resource development and transmission development. Preparing for the challenge now will ensure that the region has the infrastructure, markets, and strategies in place to properly integrate these resources into the grid.

## Shaving peak demand

New England's active demand resources reduce electric consumption during system peaks or periods of high prices when called on by the ISO. In so doing, demand resources contribute to the diversity and flexibility of resources on the grid. They help defer the need to build expensive power system infrastructure to support infrequent system peaks, lower emissions, decrease reliance on expensive fuels, balance variable resources, and reduce New England's "out-of-market" costs by eliminating the need to start up additional power plants on peak demand days.

The ISO is working on the next step in the evolution of demand resources: the full integration of these resources into the energy market so they can be dispatched, just like supply resources, when it makes economic sense to do so.



# ISO-Metrics

## Accountability and transparency

Open, fair, and independent actions are the defining characteristics of ISO New England's operation. To ensure the highest levels of transparency, industry stakeholders are an integral part of its decision-making process. They include the New England Power Pool (NEPOOL), the voluntary association of the participants in New England's wholesale electricity marketplace; state regulators, including those who form the New England Conference of Public Utilities Commissioners (NECPUC); state and federal legislators, attorneys general, consumer advocates, and environmental regulators; and the six governors, including the New England States Committee on Electricity. They are heavily involved in its budget and business planning processes, regional system planning, and market development. Each year, ISO New England management and its board of directors develop the company's business plan and budget through an open process. The process incorporates input from the states and market participants so that the ISO can accurately align its workplan with regional priorities and so that all industry stakeholders have a clear understanding of the company's goals and objectives.

**As a not-for-profit corporation, ISO New England's performance can be measured not only by the reliability of New England's power grid but by the effectiveness of the services it offers.**

Our stakeholders have regular access to ISO staff and directors, participating in dozens of committees and working groups, and even taking part in the nomination of its board of directors. In 2012, for example, the ISO held approximately 60 Markets, Reliability, Transmission, and NEPOOL Participants committee meetings and nearly 20 Planning Advisory Committee meetings.

The Consumer Liaison Group, formed in 2009, meets quarterly to share information about the economic impacts of New England's power system and wholesale electricity markets on consumers. In early 2011, ISO New England formed the Information Requests Group, a quarterly, ad-hoc forum for stakeholders to provide input to the ISO on prioritizing requests it receives for providing new or enhanced market and power-system information to the wholesale electricity marketplace.

This type of collaboration and teamwork has been the critical factor driving the region's success over the past decade in developing power system infrastructure and a competitive suite of wholesale markets.

# Results on a budget

ISO New England's budget is determined in an open and inclusive process that involves stakeholders, including input from NECPUC and the states' consumer advocates, a review and advisory vote from NEPOOL, review and approval by its independent board of directors, and final approval by the Federal Energy Regulatory Commission (FERC).

The 2013 budget addresses three key categories that reflect ISO New England's ongoing efforts and growing responsibilities: the cost of continued operations and projects in the queue, activities related to the Strategic Planning Initiative, and changes in accounting estimates associated with pension costs, vacancy rate, and depreciation. The company's total operating budget for 2013 is $165 million. Excluding changes in accounting estimates, the 2013 budget is a 4.8% increase over 2012. The range of services and benefits the ISO provides will cost the average New England electricity consumer $0.83 a month in 2013. For more information, the ISO's financial statements are available on its website.

# Customer satisfaction

Stakeholder feedback is an excellent indicator of the quality of the products and services the ISO offers, as well as areas that need improvement. Each year, the ISO asks market participants to rate their overall satisfaction. The 2012 survey, released in early 2013, revealed high overall satisfaction levels. If the percentage of respondents with no opinion is eliminated from the calculation of overall satisfaction, net positive satisfaction with ISO New England is 96%.

# Achieving compliance

## Standards

ISO New England takes pride in fulfilling its responsibilities to the highest standards and strives to maintain compliance with Federal Energy Regulatory Commission, North American Electric Reliability Corporation (NERC), and Northeast Power Coordinating Council (NPCC) directives. These standards are not only mandatory, they carry civil penalties for failure to perform. Its teams dedicate themselves to the safe, reliable operation of the grid through extensive training and continuous process improvement to ensure ISO New England achieves compliance.

In March 2012, the ISO underwent a compliance audit conducted by NPCC. The audit team evaluated ISO New England for compliance with 32 standards from the 2012 NERC Compliance Monitoring and Enforcement Program plus other NERC and regional reliability standards. NPCC reported the ISO complied with all applicable standards and identified zero violations or areas of concern.

## Orders

The ISO developed several major initiatives in 2012 to comply with FERC orders, such as Orders 1000 and 755. FERC Order 1000, *Transmission Planning and Cost Allocation*, addresses several complex issues related to regional planning and cost allocation for transmission projects. Order 1000 is designed to promote open, transparent, and efficient transmission planning. ISO New England is on track to meet the last of the Order 1000 deadlines in April 2013. Order 755, *Frequency Regulation Compensation in Organized Wholesale Power Markets*, requires several changes to the design of ISO New England's Regulation Market expected to be implemented in 2014. Regulation is a critical component of New England's power grid; it balances load, generation, imports and exports, maintains frequency, and keeps the system operating normally through a continuous process of minor corrections.

## Backup Control Center

A key project for the ISO over the next two years will be the construction of a new Backup Control Center (BCC) designed to meet pending requirements from NERC. The existing BCC facility complies with current NERC standards but has no room for expansion and cannot satisfy the demands of the ISO's new Business Continuity Plan. The new BCC, to be located in Connecticut, will ensure continuous reliable operation of all critical functions, including operations, markets, and settlements. This will enable the ISO to meet NERC and FERC requirements that specify a BCC should resume operations within two hours and be capable of prolonged operation in compliance with all reliability standards. Through analysis and discussion with the ISO board, the NEPOOL Budget and Finance Committee, and other stakeholders, the ISO developed plans for a facility that will provide capabilities comparable to the BCC of other ISOs and RTOs. The preliminary capital budget (excluding capitalized internal labor) is $32.7 million. Construction is scheduled to begin in early 2013, with expected completion in 2014.

# Providing information anytime, anywhere

## *ISO Express* and *ISO to Go*

ISO New England launched a redesigned data portal, *ISO Express*, in late December 2011. This portal provides stakeholders with convenient access to grid conditions and wholesale electricity market information. Throughout 2012, the ISO made improvements to the new site, providing enhanced real-time data, detailed historical report generation, and web-based notifications of changing system conditions. Customer feedback drives development of the site, and the ISO will continue to make enhancements in 2013 to provide users with greater functionality. Over the coming year, the ISO also plans to redesign its primary website, making it easier for stakeholders to quickly and easily find the tools and information they seek.

In September 2012, the ISO released *ISO to Go*, a mobile application for smartphones aimed at educating New England's electricity users about the power grid and wholesale electricity markets. The app provides an overview of the grid and markets, conservation tips, up-to-date system conditions, and real-time information on the region's wholesale electricity prices.

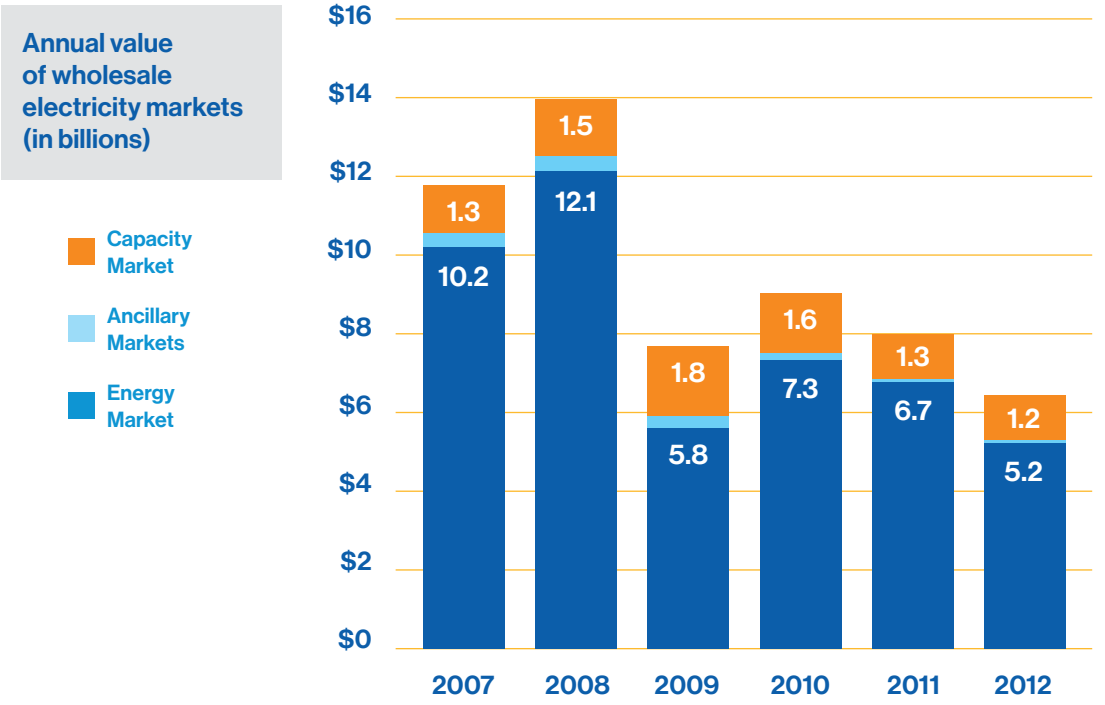
**View and learn more at:**

**isoexpress.iso-ne.com**
**iso-ne.com/isotogo**

# Results at a Glance

**In a relatively short time, the combined functions of competitive electricity markets, centralized system operations, and a dynamic and transparent regional planning process have guided the development of the regional power system that is more reliable, cost-effective, and environmentally sound.**

**Wholesale electricity costs:** The markets are working as designed, producing competitive prices that accurately reflect suppliers' costs of delivering power to the grid to meet consumer demand. The average wholesale electric energy price dropped almost 23% in 2012, driven down by lower natural gas prices and lower demand. Additionally, the 2012 price was nearly 26% lower than the average price set in 2003, the year that ISO New England introduced wholesale competitive markets in their current form. The magnitude of the price decline is illustrated in the total amount paid for electric energy, which fell by more than a billion dollars, from $6.7 billion in 2011 to approximately $5.2 billion in 2012.



**Supply:** More than 14,400 MW of new, efficient, low-carbon-emitting supply have been added to the power system since 1997; with another 5,000 MW proposed. Because this investment is made by private firms and not public utilities, consumers are shielded from the investment risks they had been exposed to under the previous, regulated system. Moreover, in competitive electric energy markets, power plants are paid for performance and therefore have incentives to operate more efficiently, contributing to the grid's overall reliability and controlling power costs.

**Demand-side resources:** Demand resources, such as load management, distributed generation, and energy-efficiency projects, have increased from 100 MW in 2003 to more than 2,000 MW in 2012. This translates into thousands of individual demand assets integrated into the power system. More than 3,600 MW of demand resources are expected to be available by 2015.

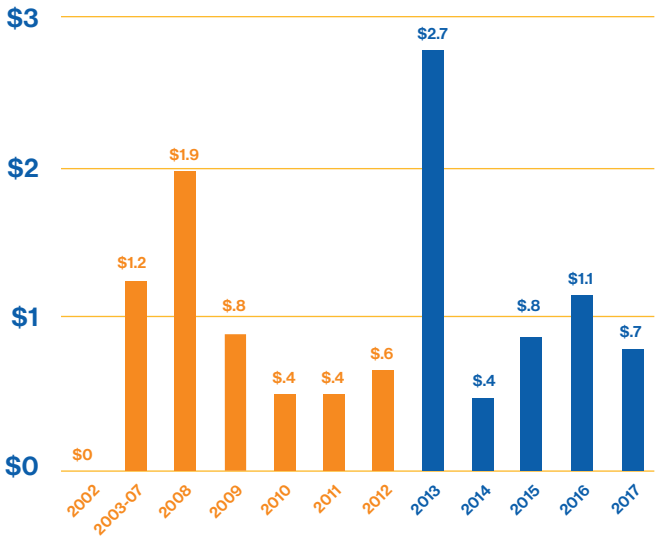
**Environment:** From 2001 to 2010, average emission rates for nitrogen oxides ($NO_x$), sulfur dioxide ($SO_2$), and carbon dioxide ($CO_2$) have declined by 54%, 64%, and 11%. This can be attributed to the increased use of new, more efficient natural-gas-fired power plants, the decline in the cost of that fuel, and the implementation of emission controls on some of the region's oil- and coal-fired power plants.

**Technology:** Markets are stimulating technological innovations that are modernizing the regional power system. Smart grid projects will result in a more efficient, responsive, and reliable system that can incorporate greater amounts of demand resources and alternative energy resources. For example, the final installation of 40 phasor measurement units (PMUs or synchrophasers) and associated computer systems for collecting and analyzing data is on schedule for June 2013. PMUs enhance system operators' ability to monitor and measure performance of the grid, broadening their ability to detect and promptly address problems. This will improve reliability and enable operators to reduce congestion and create other efficiencies that have the potential to lower wholesale electricity costs. The technology also will help accommodate the variable nature of wind resources. The project is funded in part by a grant from the US Department of Energy. The ISO also actively participates in smart grid research, education, and standards development.

**Transmission:** Since 2002, over 400 transmission upgrades totaling $5 billion have been put in service in all six New England states, virtually eliminating congestion on the system. Based on the results and needs described in the ISO's *Regional System Plan*, New England's transmission owners have constructed transmission projects throughout the region that reinforce transmission facilities serving areas that have experienced load growth, such as Vermont, southern Maine, and the New Hampshire seacoast area. Projects also have reinforced the system's critical load pockets, such as Southwest Connecticut and Boston, allowing the import of power from other parts of the system. New interconnections with neighboring power systems also have been placed in service. Approximately $5 billion in transmission investment is planned over the next five years to meet reliability requirements, improve the economic performance of the system, and position the region to integrate renewable resources and alternative technologies.

ISO New England is seeking to align the transmission planning process and wholesale markets. One of the steps includes the evaluation of market resource alternatives to transmission upgrades needed for reliability. In 2011, the ISO completed a pilot project to analyze the megawatts of resources that would be needed at specific locations in Vermont and New Hampshire to reduce the need for transmission investment in these areas. The ISO has applied the lessons learned from this study to the next pilot study underway of the Greater Hartford and Central Connecticut area.

**New transmission investment in New England (in billions)**



# Key Facts

- 6.5 million households and businesses; population 14 million
- Approximately 350 generators
- More than 8,000 miles of transmission lines
- 13 interconnections to power systems in New York and Canada
- More than 32,000 MW of generating capacity

- More than 2,000 MW of demand resources
- All-time peak demand of 28,130 MW set on August 2, 2006
- $5 billion in transmission investment since 2002; another $5 billion planned over next five years
- $5 billion total energy market value in 2012
- More than 500 buyers and sellers in the markets

# ISO New England Board of Directors and Senior Management

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Chairman

**Gordon van Welie**
President and Chief Executive Officer

**Kathleen Abernathy**

**Roberta S. Brown**

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**Paul F. Levy**

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**Stephen J. Rourke**
Vice President, System Planning

*As of January 2013

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ISO new england

1 Sullivan Road Holyoke, Massachusetts 01040

ISO new england

# NEPOOL Participants Committee Report

*February 2013*

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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# Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions*
  - January natural gas prices over the period were 65% higher while oil prices were 2.3% higher than December 2012 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were 100% higher from December 2012 averages
- Average January 2013 natural gas price and RT Hub LMP, respectively, were up 107% and 137% from January 2012 averages.

***LMP and fuel price data through January 29.**
**Market data through January 27, unless noted.**

Underlying natural gas data furnished by:

ICE Global markets in clear view

# Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)*
  - January payments totaled $20.1M, up $11.9M from December
  - First Contingency payments totaled $17.8M, up $12.6M from December
    - $17.8M paid to internal resources, up $12.6M from December
      - $1.3M charged to DALO, $16.5M to RT Deviations
    - $37K paid to resources at external locations, up $13K from December
      - $34K charged to DALO at external locations, $3K to RT Deviations
  - Second Contingency payments totaled $95K, down $41K from the December total of $136K
  - Voltage payments totaled $1.9M, down $1.1M from December
  - Distribution payments totaled $372K, up $372K from December
  - NCPC payments over the period as percent of Energy Market value were 2.0%

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

# Highlights , cont.

- The lowest 50/50 and 90/10 Winter Operable Capacity Margin is being calculated for the week beginning February 9th .
- The lowest 50/50 and 90/10 Spring Operable Capacity Margin is being calculated for the week beginning May 11th .
- Assumptions have been updated for generation at risk due to gas supply as a result of LNG fuel delivery concerns;
- Repositioned select outages of non-gas fired generation from the winter peak load exposure to shoulder months.
- Gas at Risk Outages have been subtracted from the Gas at Risk MW to prevent duplication.

# Highlights , cont.

- ISO is working with NYISO and PJM to update the interregional planning protocol. Tariff changes are being coordinated with the Transmission Committee in preparation for the April 2013 FERC Order 1000 filing
- The seventh Forward Capacity Auction (FCA) for 2016/2017 is scheduled to be held the week of February 4. ISO is expecting to make the FCA #7 results filing with FERC by the end of February
- 2013 Economic Study Requests are due to be submitted by April 1

# WINTER OPERATIONS SUMMARY

*Cold Weather – January 2013*

# Summary

- The week ending January 26, 2013 had the coldest 5 consecutive days since the week of January 19, 2009
- Overall peak load 20,822 MW
- Significant natural gas flow from the north on the Maritimes & Northeast and Portland Natural Gas Transmission Pipelines
- Natural Gas Pipeline restrictions from the west contributed to high gas prices
- High gas prices resulted in oil units being in merit on some days
- Cold weather conditions were experienced throughout the northeast including eastern Canada
- Hydro Quebec experienced all time peak load which limited exports to their neighbors

# Summary, cont.

- Driven by economics some generators switched from gas to oil
- Overall system performance:
  - Cold weather issues delayed generator start-ups
  - Some units experienced forced outages due to mechanical failures
  - Some units experienced emission related restrictions
  - The ISO had to posture pump storage units extensively
  - Tight and uncertain gas supplies to generators in New England
  - Supplement commitment increased as the temperature decreased, gas prices increased and less load cleared in the day-ahead market
  - Generators used the “Limited Energy Resource” option to manage unit availability
  - Even with the loads under the forecast 50/50 peak of 21,392 MW and high utilization of the gas pipelines from the west and the north, the ISO still had difficulty maintaining capacity to meet load and operating reserve requirements
- ISO will continue to update and evaluate fuel surveys to track oil inventory levels

# Summary, cont.

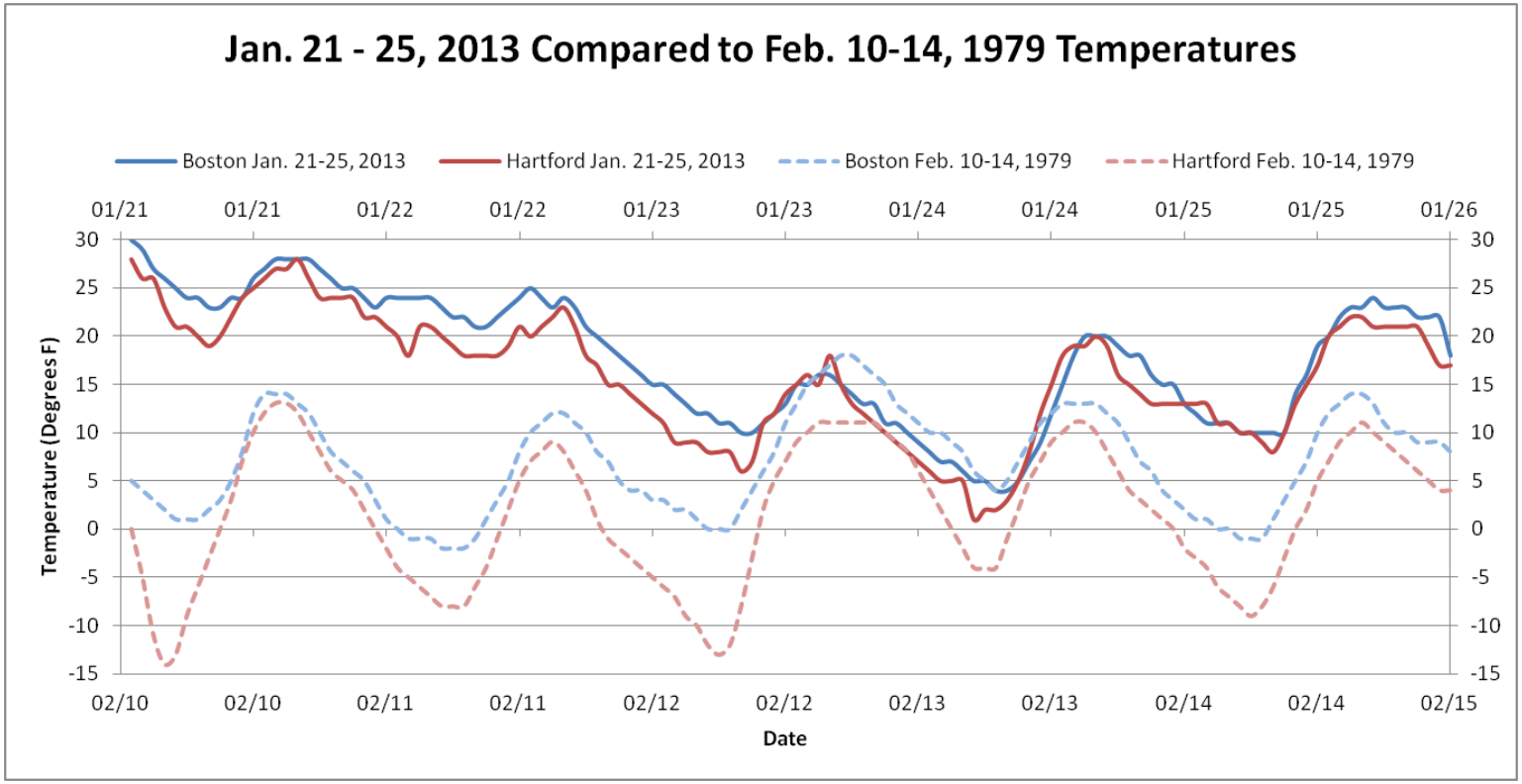
- The ISO implemented OP#4 “Action During a Capacity Deficiency” on Monday, January 28

| | Implemented | Canceled |
|---|---|---|
| Action 1 | 17:30 | 21:30 |
| Action 2 | 17:30 | 21:00 |

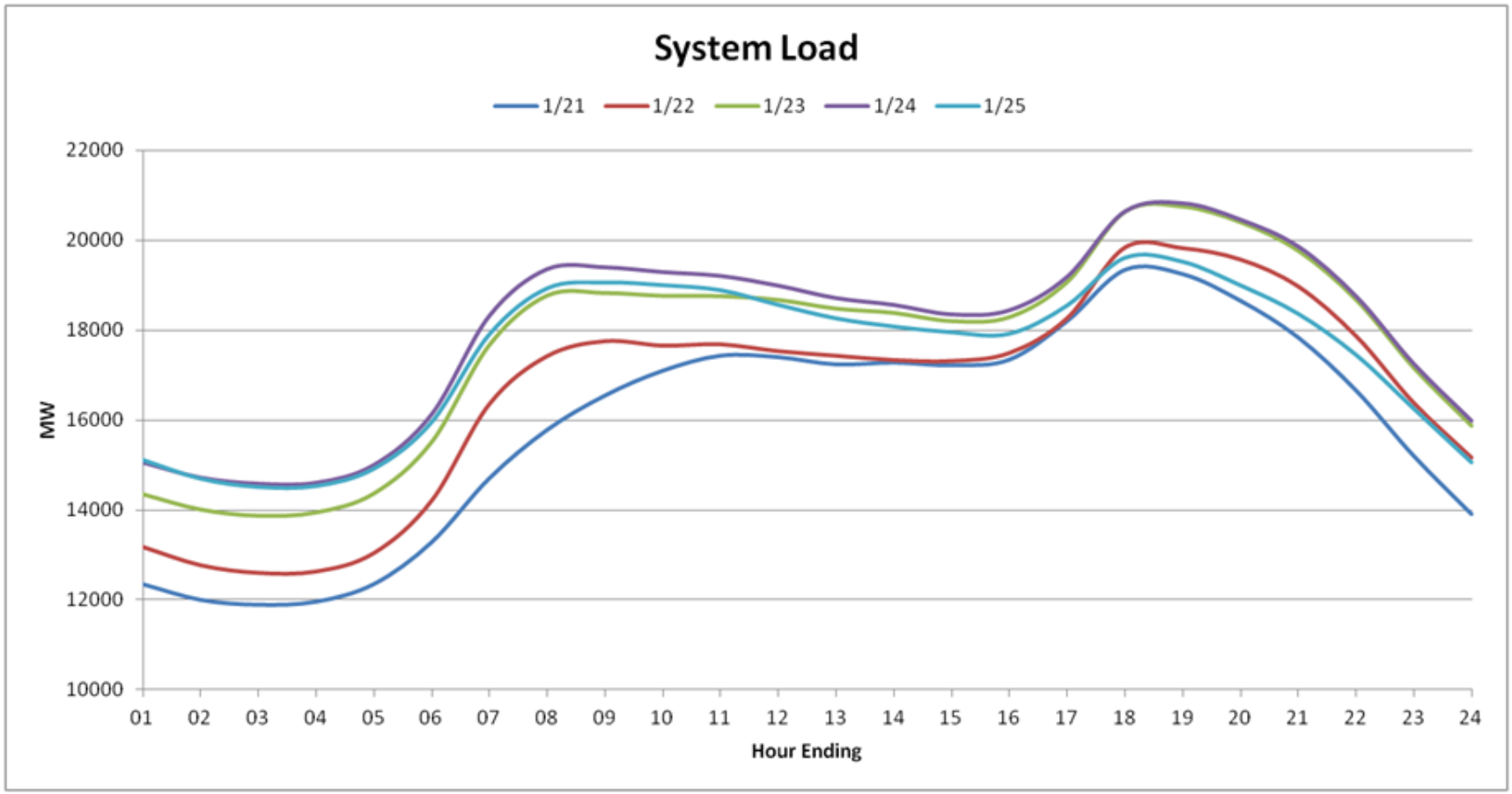
- Capacity Deficiency driven by unit outages and loads higher than forecast
- Initial indication is that the system wide load relief from Demand Response performed well
  - More detail on performance by area should be available in the next few days

# Hourly Temperatures

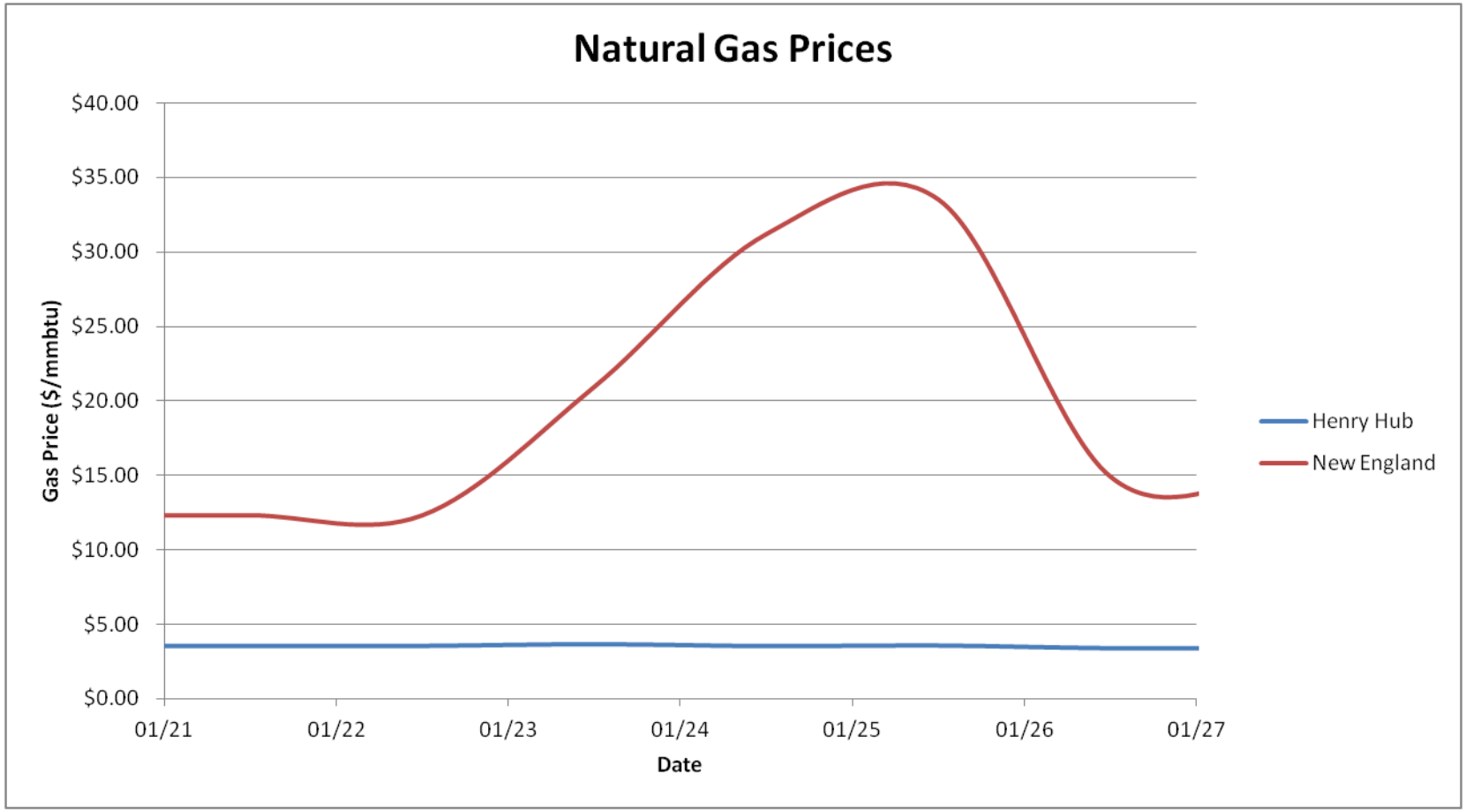
- The temperatures in Boston and Hartford on the days of January 21 – 25, 2013, are compared to the temperatures on the days of February 10 – 14, 1979 (the coldest five days since 1970) in the graph below.



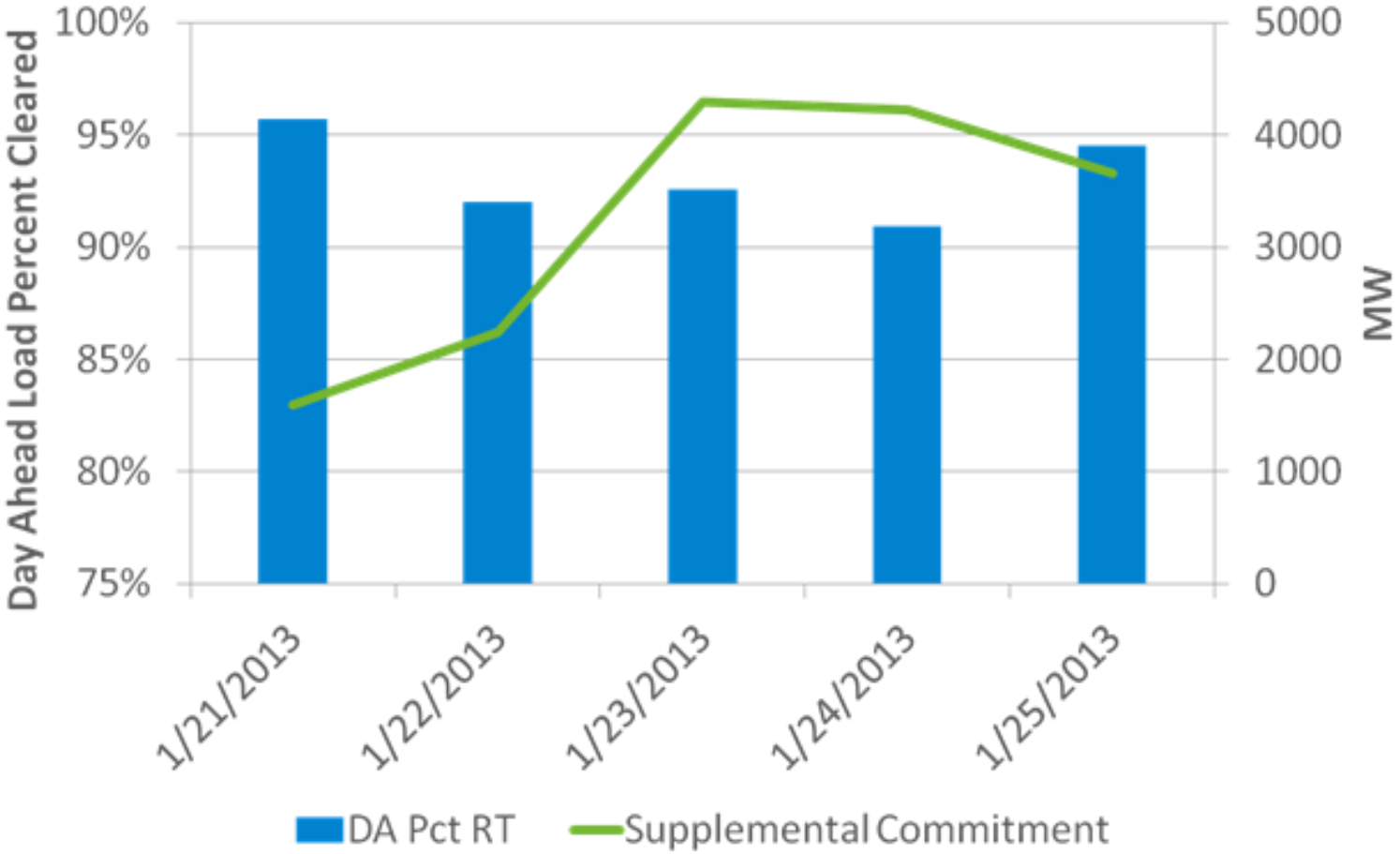
# New England Load



# Comparison of Gas Prices at Henry Hub and in New England



# Day Ahead Load Percent Cleared With Supplemental Commitment



# SYSTEM OPERATIONS

# System Operations

| | | | | |
|---|---|---|---|---|
| **Weather Patterns** | Boston | Temperature – Average<br>Precipitation – Below Normal (2.92“) | Hartford | Temperature – Above Average (1 degree)<br>Precipitation – Normal (4.89”) |

| | | | |
|---|---|---|---|
| **Peak Load:** | 20,822 MW | Jan 24,2013 | 19:00 |

**M/LCC2:** Declared 01/13/2013 Capacity Deficiency Due to Cold Weather - Start Time 09:30 - End Time 21:00

**OP-4** : None

| **NPCC Simultaneous Activation of Reserve Events**: | | |
|---|---|---|
| 01/10/13 | ISONE | 683 MW |

# System Operations

Minimum Generation Emergencies Declared :

| | | |
|---|---|---|
| **Minimum Generation Emergency** | **1/10/13** | **Start-04:00, Expired-06:00 1/10/13 Interchange cuts and self schedules denied** |
| **Minimum Generation Emergency** | **1/18/13** | **Start-04:00, Expired-06:00 1/18 13 Interchange cuts and self schedules denied** |

# System Operations

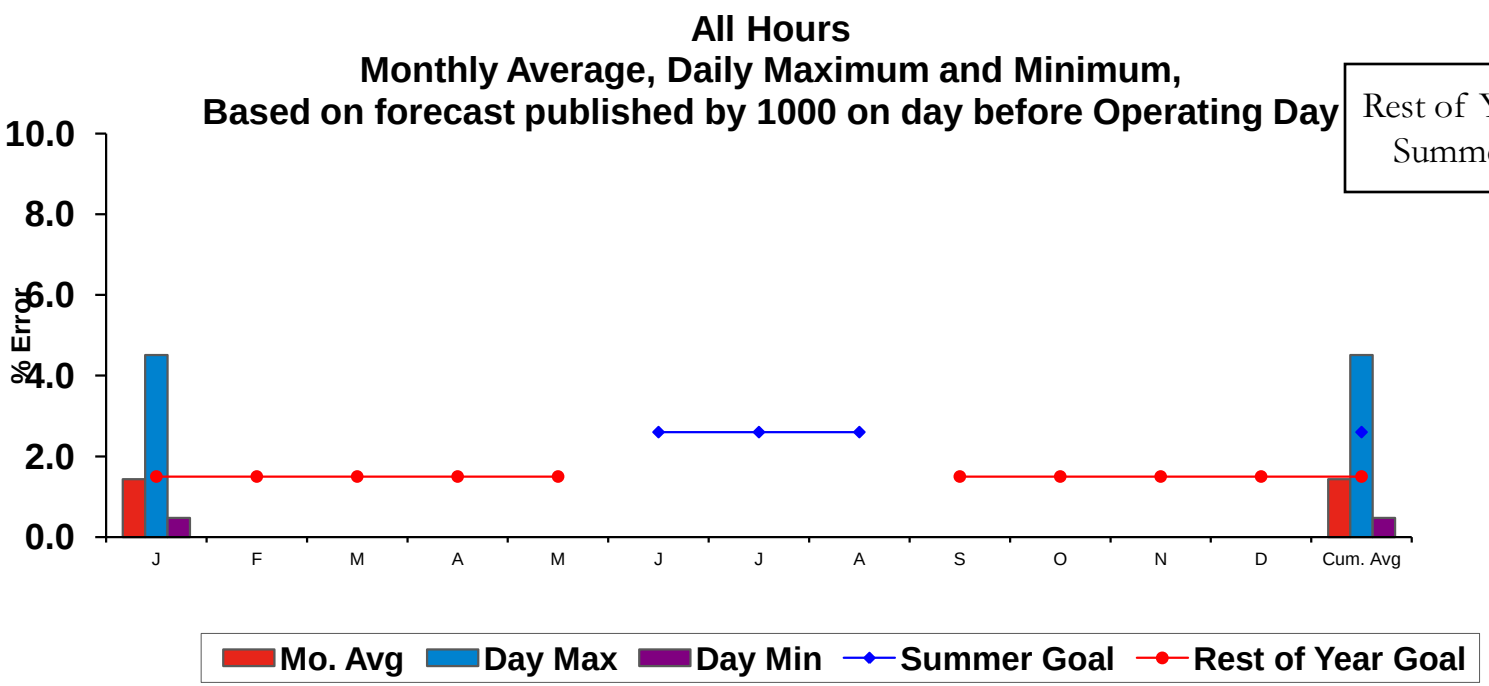
Minimum Generation Emergency Warnings:

| | | |
|---|---|---|
| **Minimum Generation Warning** | **1/1/13** | **Start-05:00, Expired-11:00<br>Interchange cuts** |
| **Minimum Generation Warning** | **1/8/13** | **Start-02:00, Expired-06:00<br>Interchange cuts** |
| **Minimum Generation Warning** | **1/8/13** | **Start-23:00, Expired-23:59<br>Interchange cuts** |
| **Minimum Generation Warning** | **1/9/13** | **Start-22:00, Expired-23:59<br>Interchange cuts** |
| **Minimum Generation Warning** | **1/9/13** | **Start-01:00, Expired-07:00<br>Interchange cuts** |
| **Minimum Generation Warning** | **1/10/13** | **Start-00:01, Expired-07:00<br>Interchange cuts and self schedules denied** |
| **Minimum Generation Warning** | **1/17/13** | **Start-01:00, Expired-07:00** |
| **Minimum Generation Warning** | **1/18/13** | **Start-01:00, Expired-07:00<br>Interchange cuts and self schedules denied** |
| **Minimum Generation Warning** | **1/20/13** | **Start-03:00, Expired-10:00<br>Interchange cuts** |
| **Minimum Generation Warning** | **1/20/13** | **Start-11:00, Expired-17:00<br>Interchange cuts** |
| **Minimum Generation Warning** | **1/20/13** | **Start-21:00, Expired-23:59<br>Interchange cuts** |

# 2013 System Operations – Load Forecast Accuracy

Dashboard Indicator

Rest of Year Goal < 1.5%
Summer Goal < 2.6%




| | J | F | M | A | M | J | J | A | S | O | N | D | Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mo Avg | 1.43 | | | | | | | | | | | | 1.43 |
| Day Max | 4.51 | | | | | | | | | | | | 4.51 |
| Day Min | 0.47 | | | | | | | | | | | | 0.47 |
| 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 | 1.43 | | | | | | | | | | | | 1.43 |
| Summer Actual | | | | | | | | | | | | | |

Sponsor - John Norden

Contact – William Callan

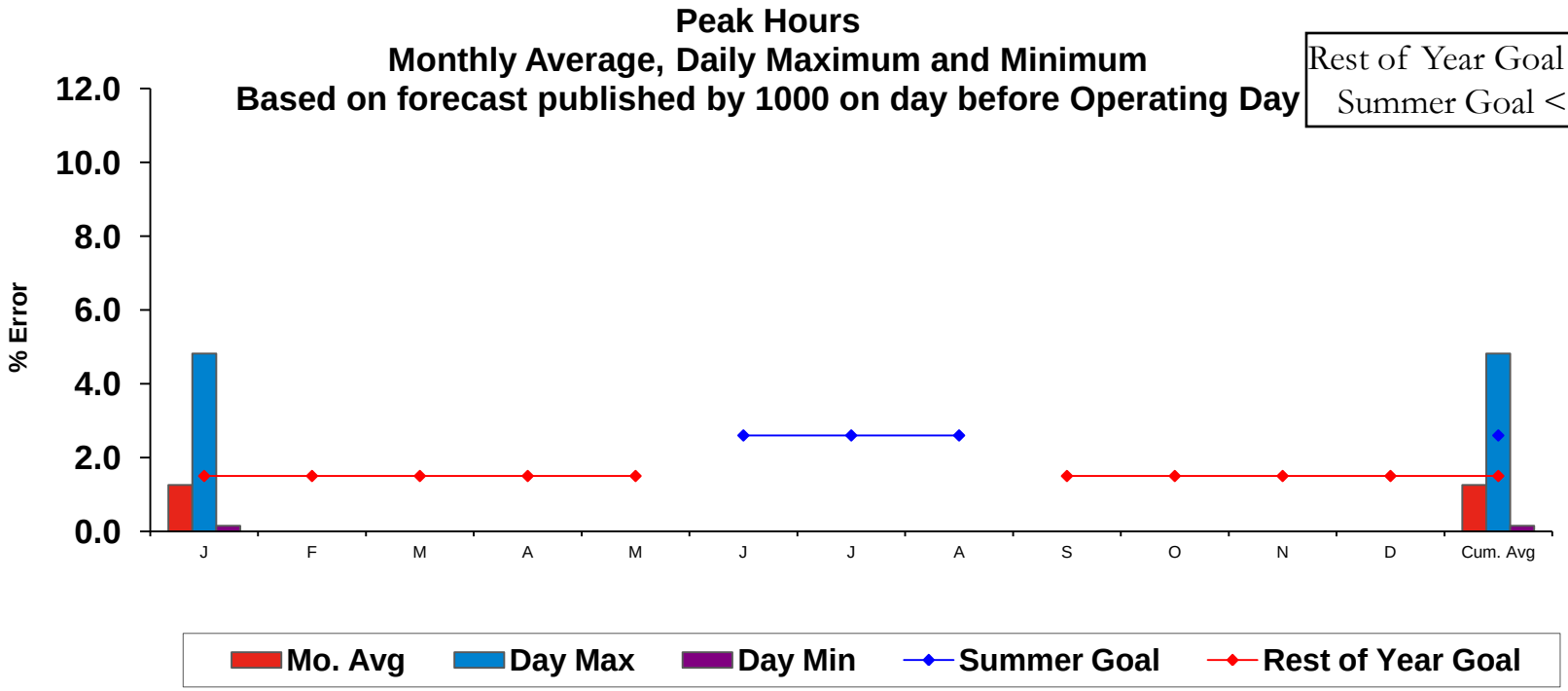
Summer Goal - 2.6%, Rest of Year Goal - 1.5%

Summer consists of June, July & August

# 2013 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator

Rest of Year Goal < 1.5%
Summer Goal < 2.6%




| | J | F | M | A | M | J | J | A | S | O | N | D | Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mo Avg | 1.26 | | | | | | | | | | | | 1.26 |
| Day Max | 4.82 | | | | | | | | | | | | 4.82 |
| Day Min | 0.15 | | | | | | | | | | | | 0.15 |
| 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 | 1.26 | | | | | | | | | | | | 1.26 |
| Summer Actual | | | | | | | | | | | | | |

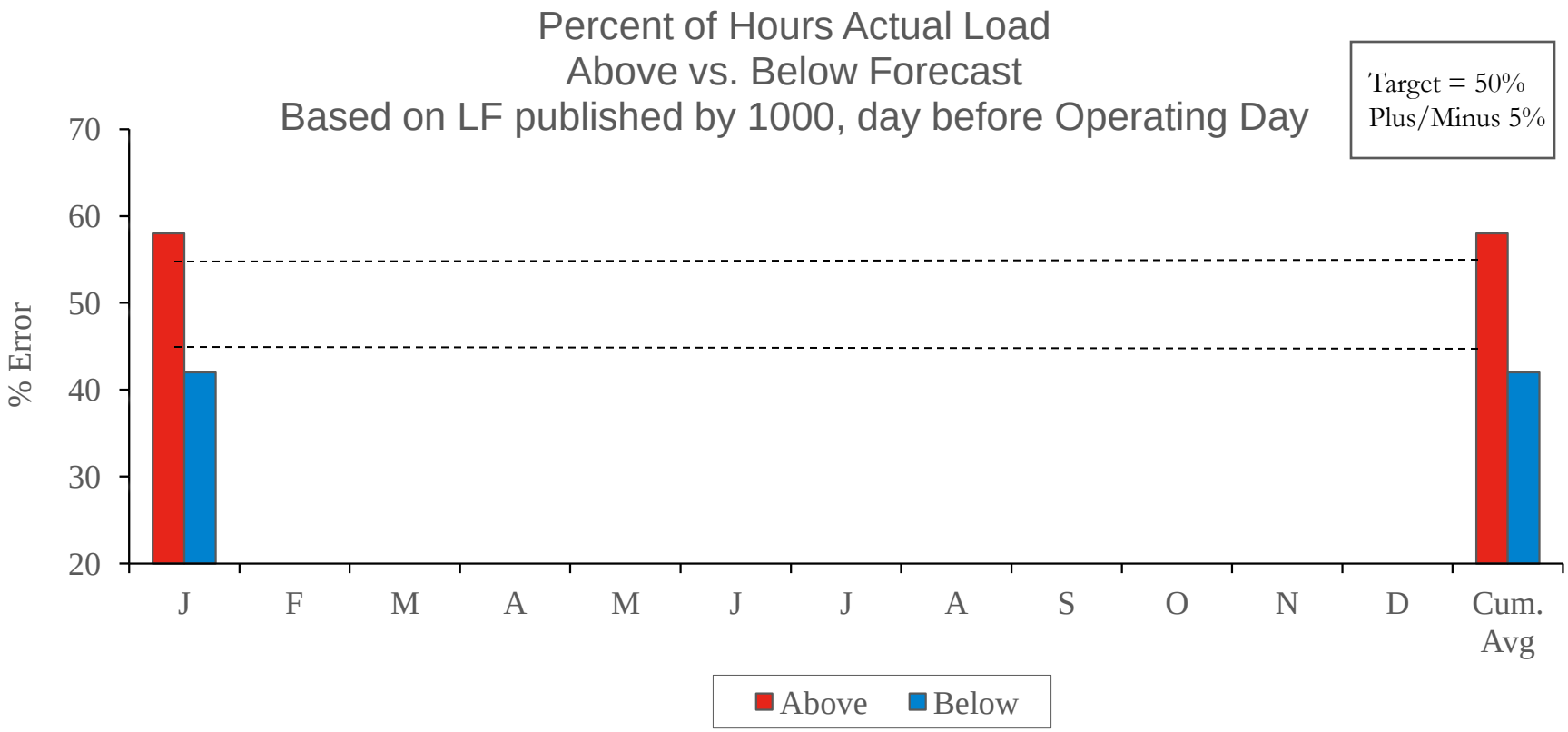
Sponsor - John Norden

Contact - William Callan

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

Summer consists of June, July & August

# 2013 System Operations - Load Forecast Accuracy



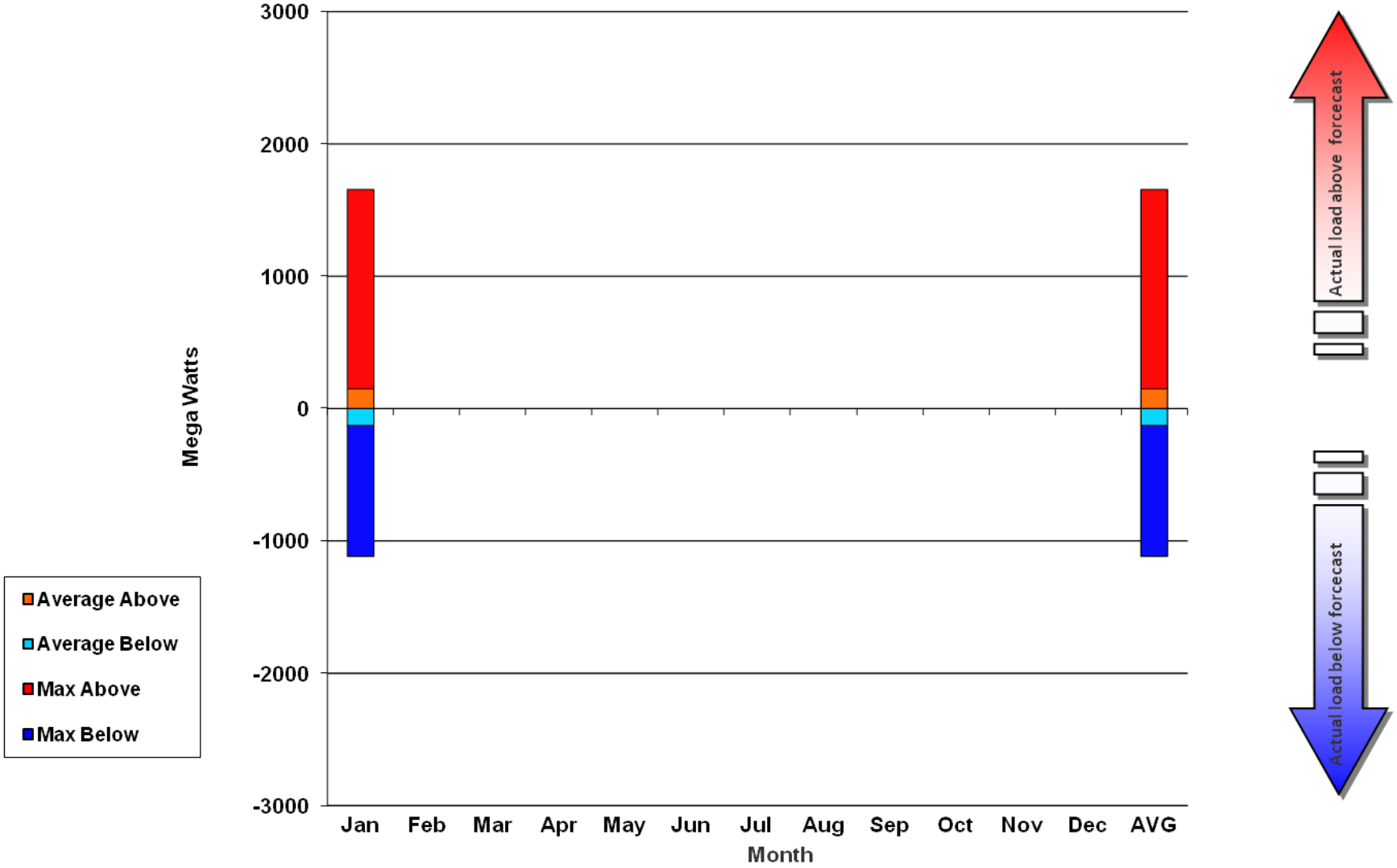

| | J | F | M | A | M | J | J | A | S | O | N | D | Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Above % | 58.0 | | | | | | | | | | | | 58.0 |
| Below % | 42.0 | | | | | | | | | | | | 42.0 |
| Avg Above | 150.0 | | | | | | | | | | | | 150.0 |
| Avg Below | -128.0 | | | | | | | | | | | | -128.0 |
| Avg All | 13.0 | | | | | | | | | | | | 13.0 |

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

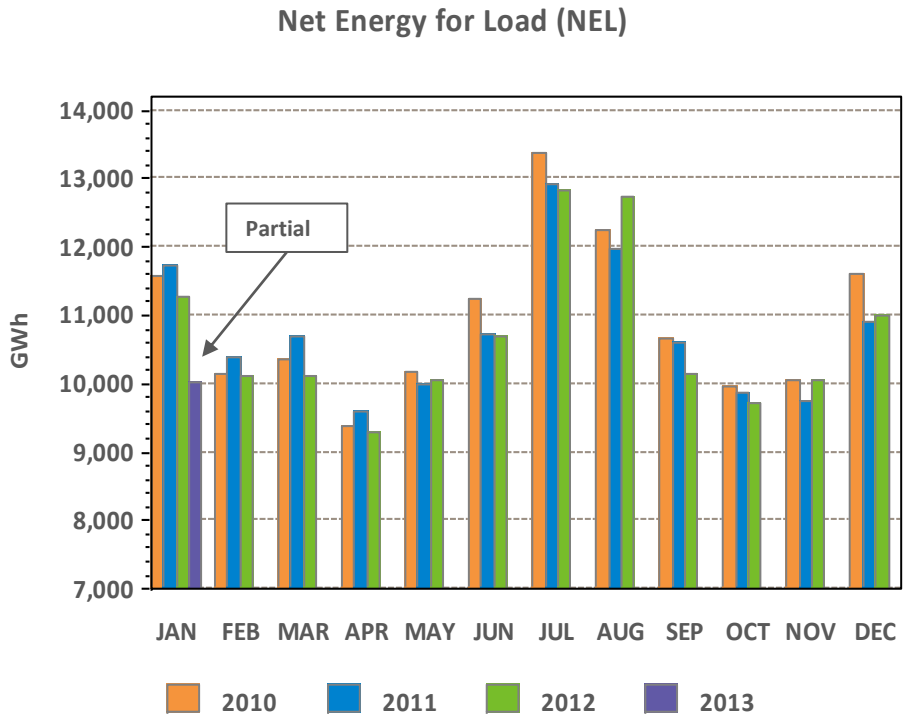
**Sponsor – John Norden**
**Contact – William Callan**

# 2013 System Operations - Load Forecast Accuracy

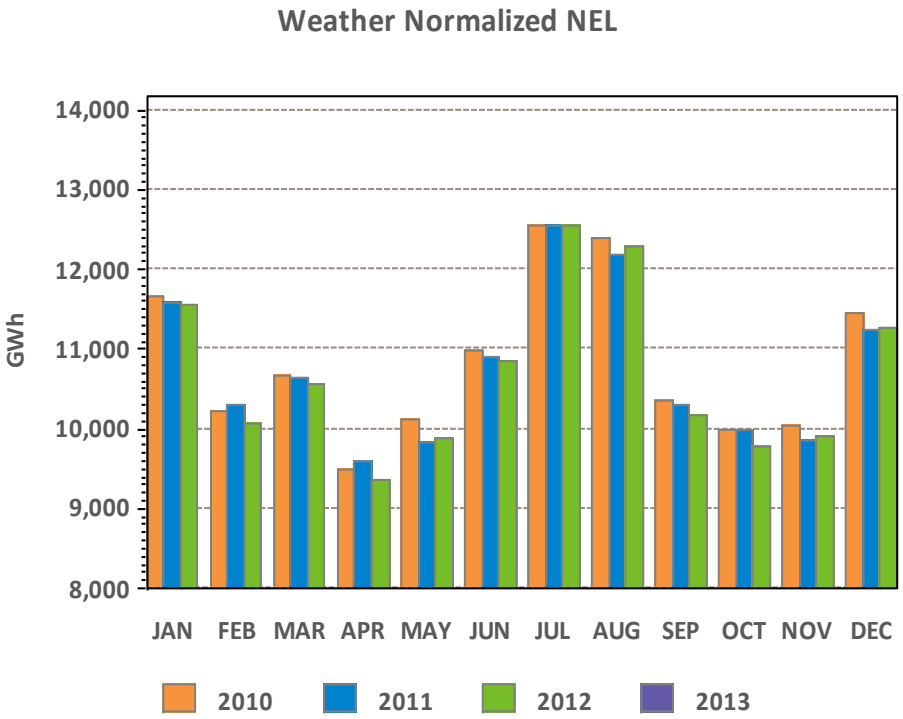
Deviation of Actual Load from Forecasted Load Year to Date 2013



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



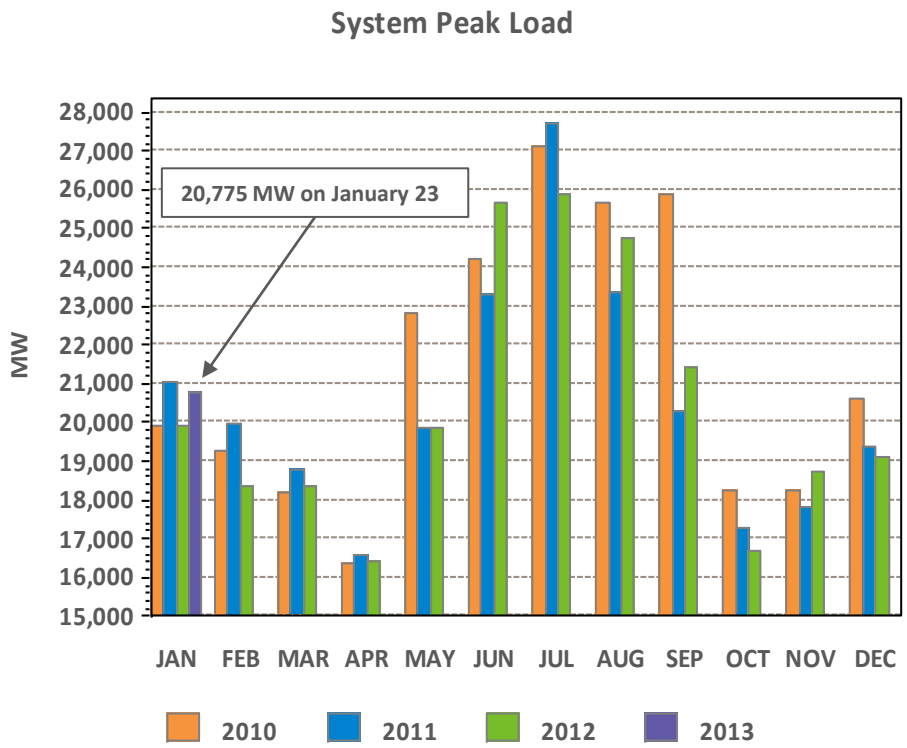

Ann Tot (TWh): 130.8 129.2 128.0 10.0

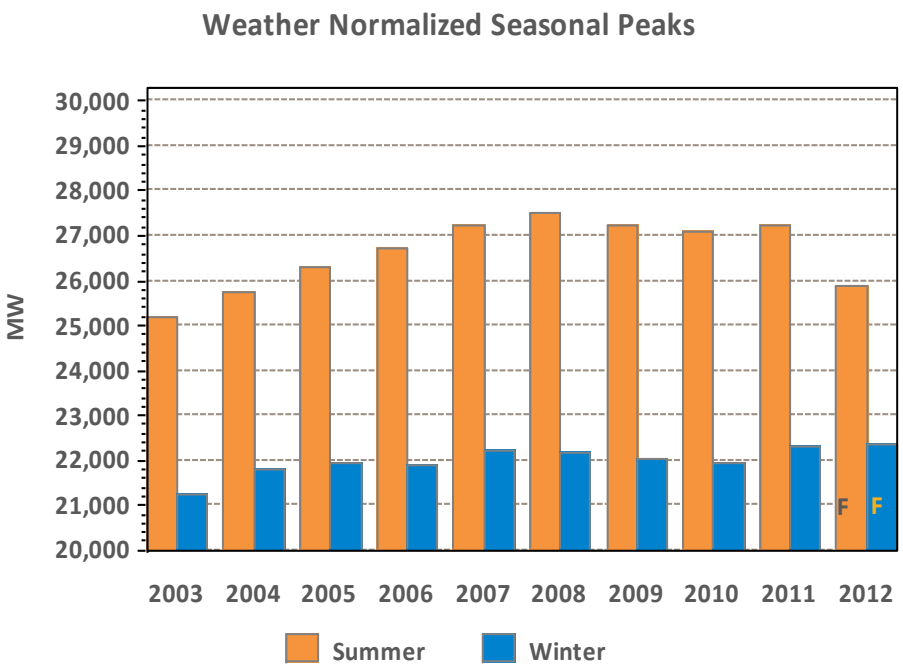



Ann Tot (TWh): 129.9 129.0 128.2 .

NEPOOL NEL is the total net energy required to serve load for the month, in GWh. NEL is calculated as: Generation – pumping load + net interchange. 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



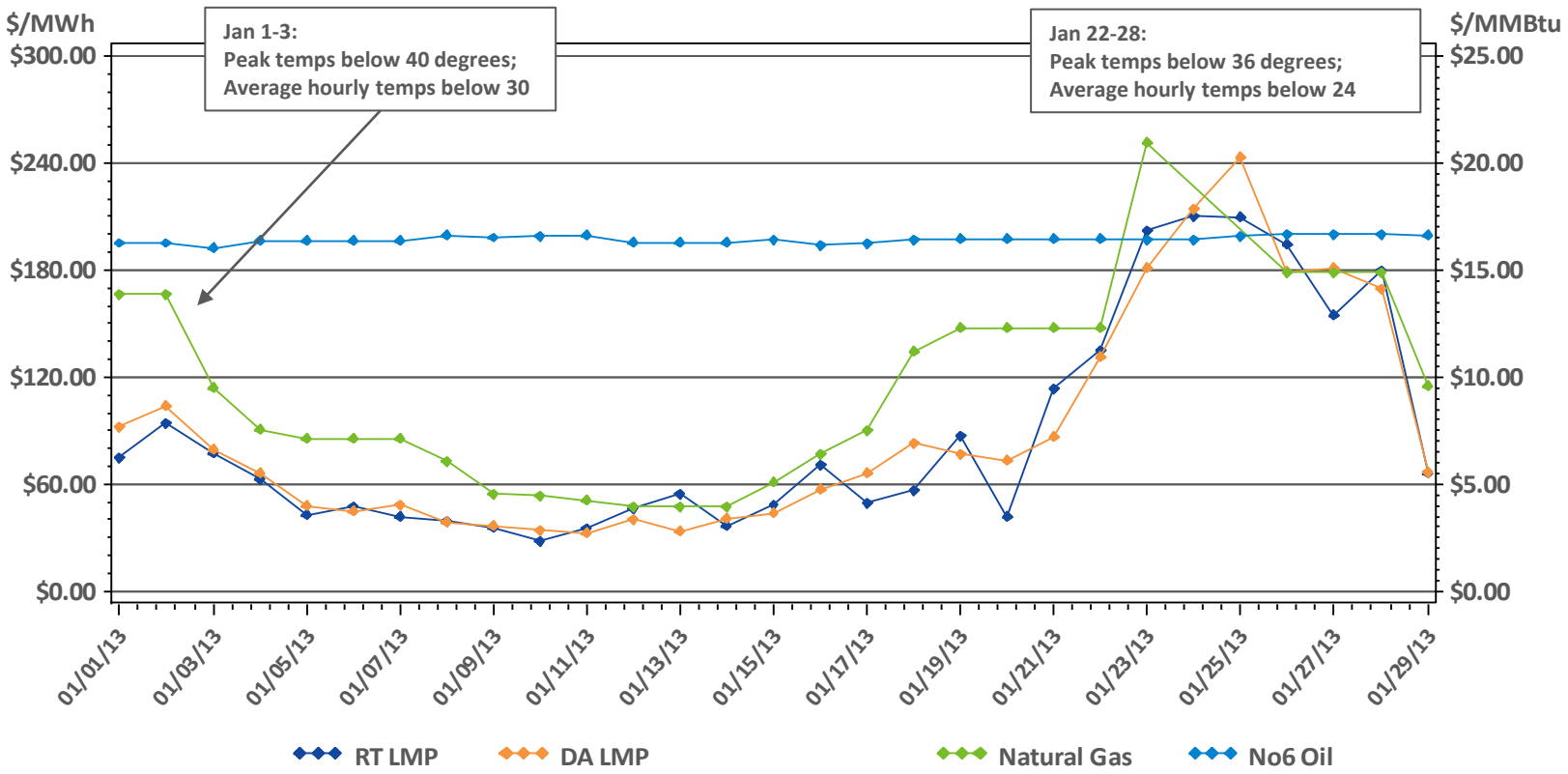




Winter beginning in year displayed

*** F – designates forecasted values, which are updated in mid-April of the following year.**

# MARKET OPERATIONS

# DA and RT ISO-NE Hub Prices and Input Fuel Prices: January 1-29, 2013

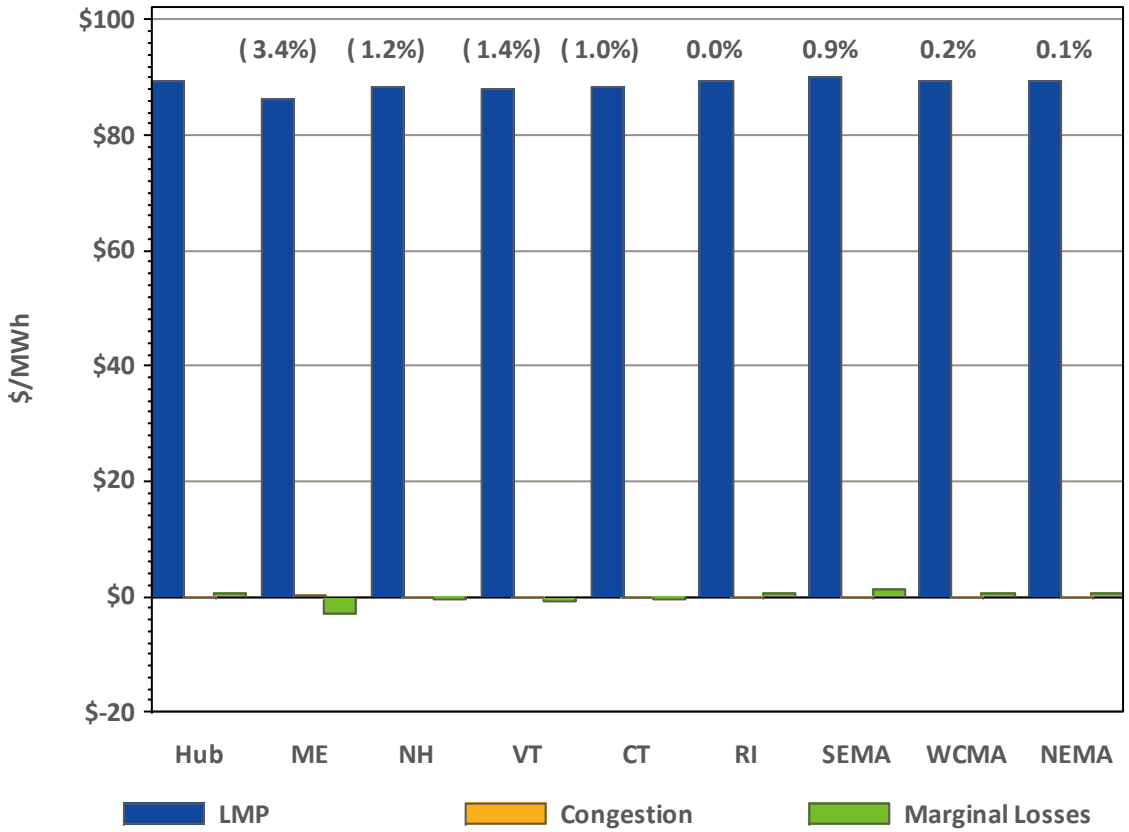



Underlying natural gas data furnished by:

ICE Global markets in clear view

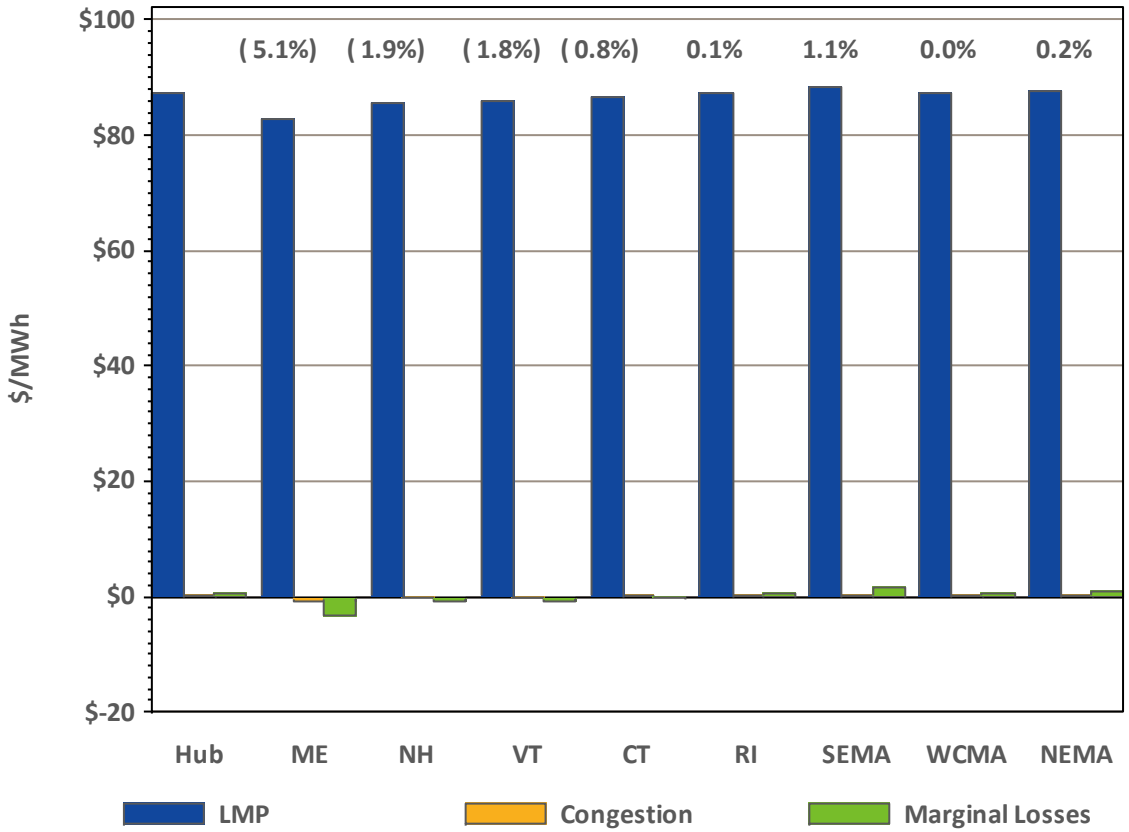
Average price difference over this period (DA-RT): $1.95
Average price difference over this period ABS(DA-RT): $11.49
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 13%
Gas price is average of Massachusetts delivery points; No6 Oil is New York Spot Price from DOEs Energy Information Administration

# DA LMPs Average by Zone & Hub January 2013

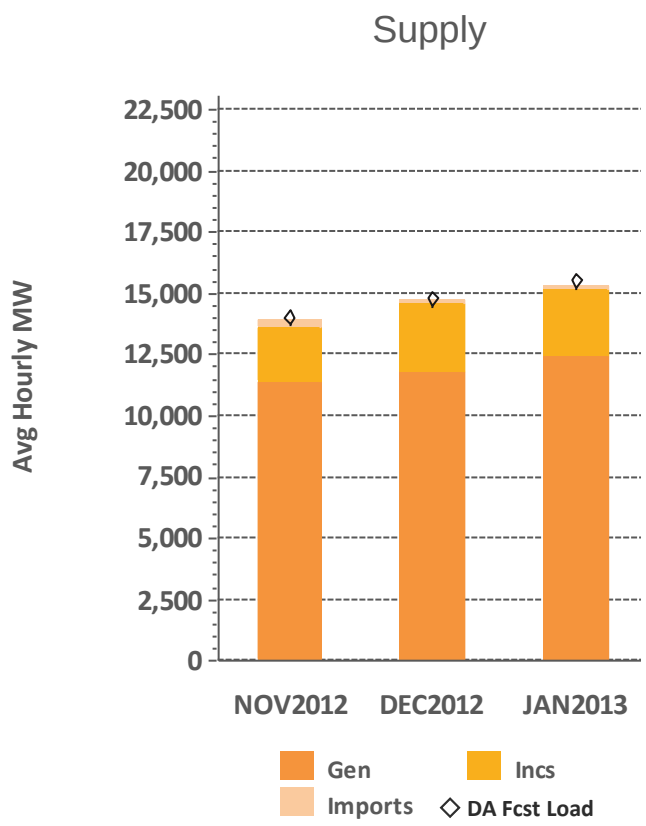



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

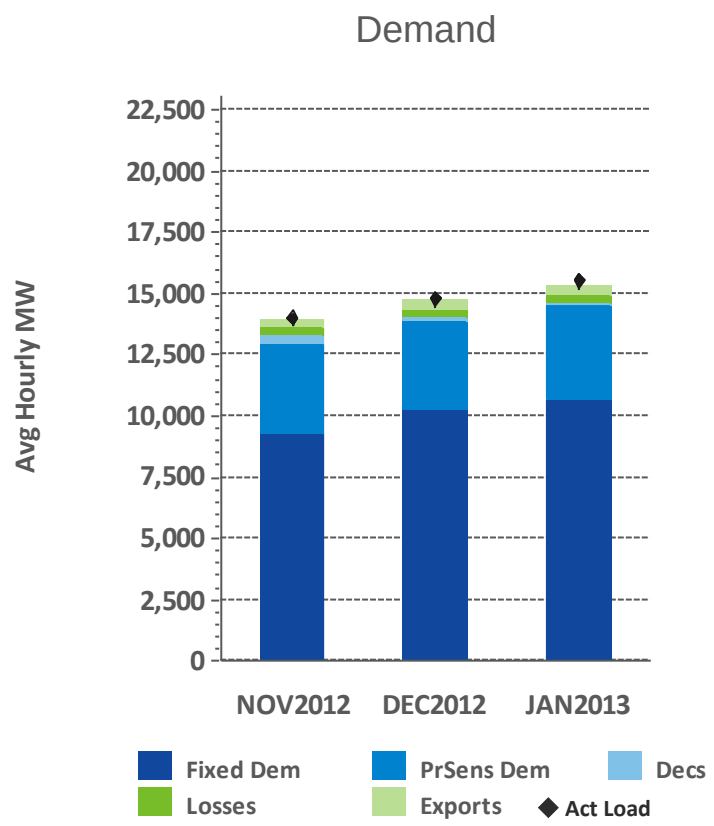
# RT LMPs Average by Zone & Hub January 2013



# Components of Cleared DA Supply and Demand – Last Three Months

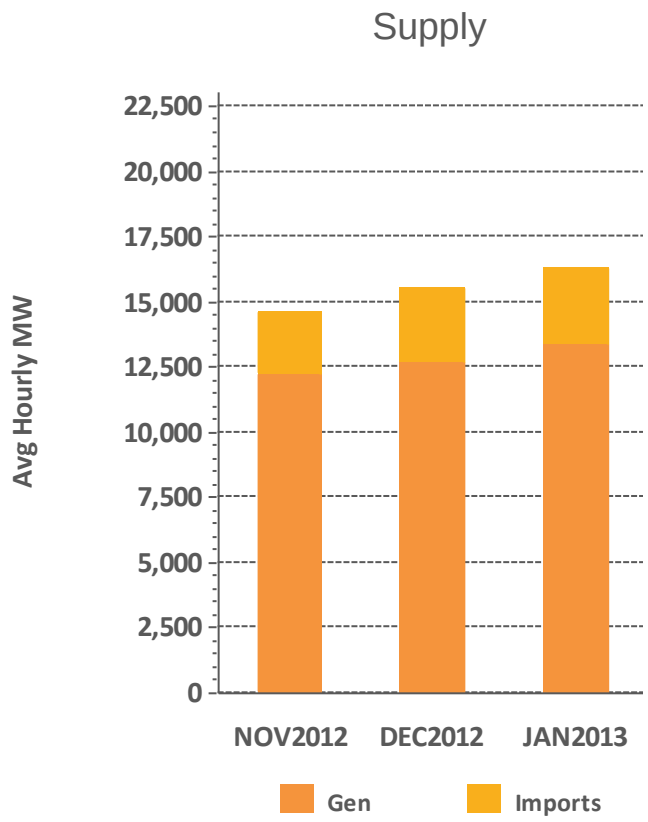


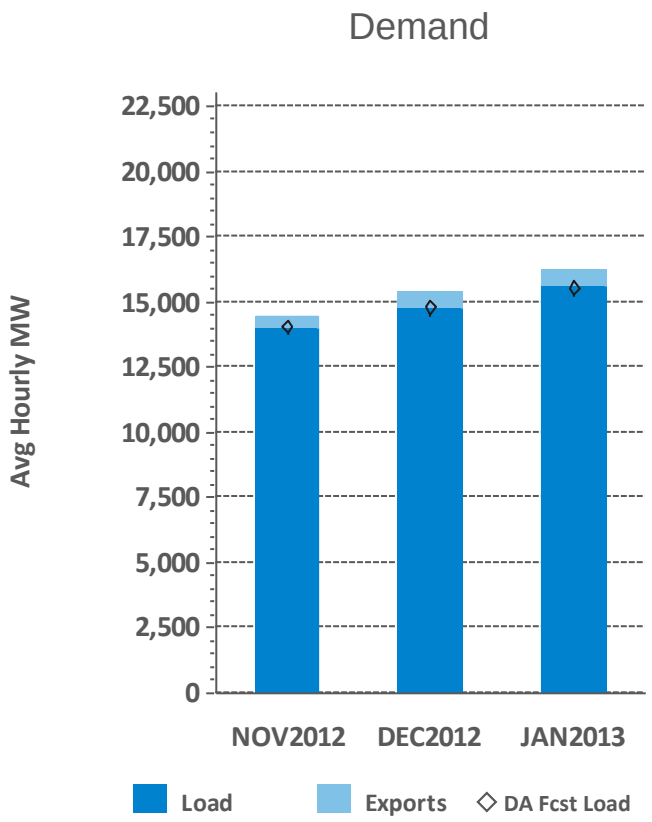

Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



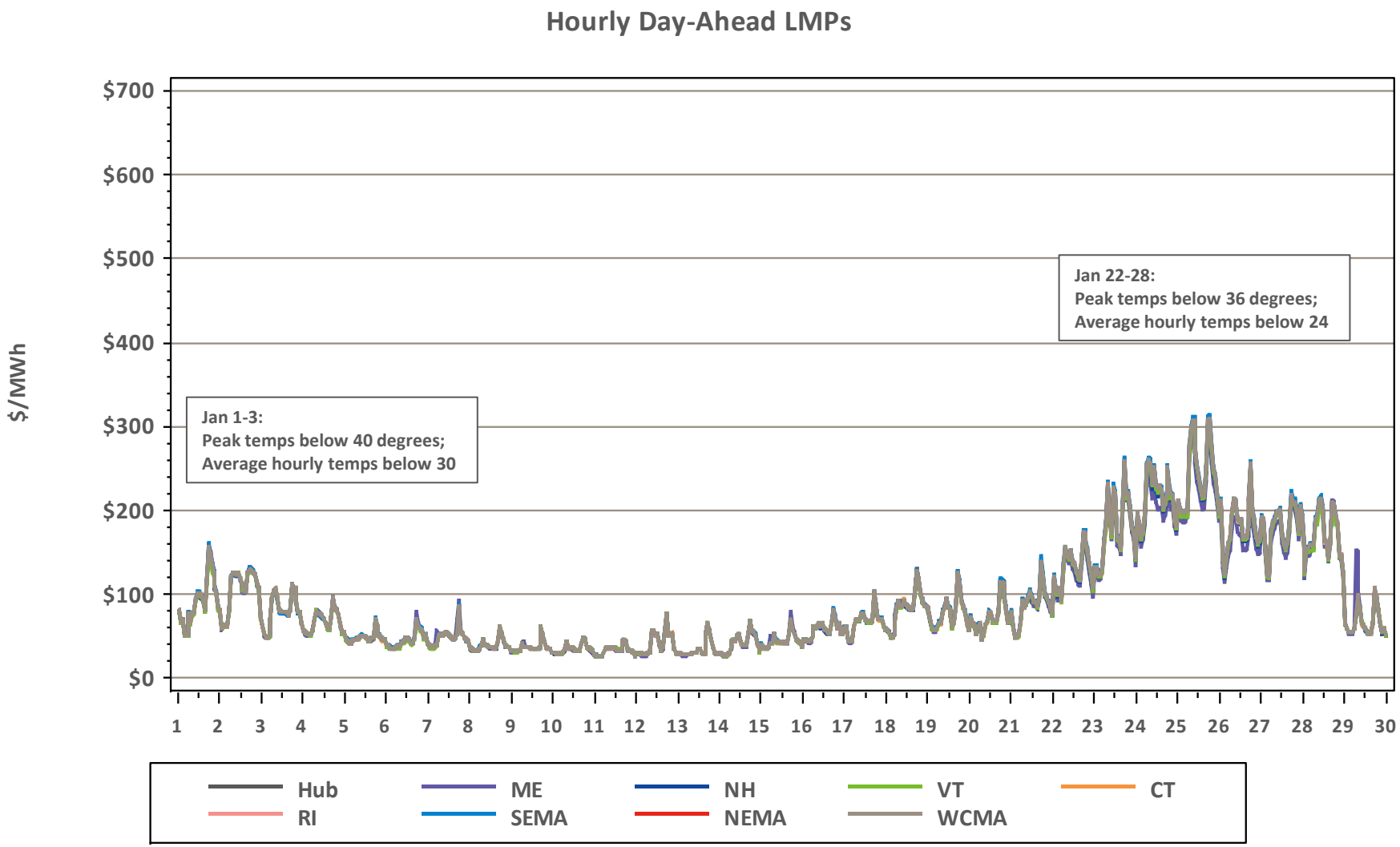

Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

# Components of RT Supply and Demand – Last Three Months

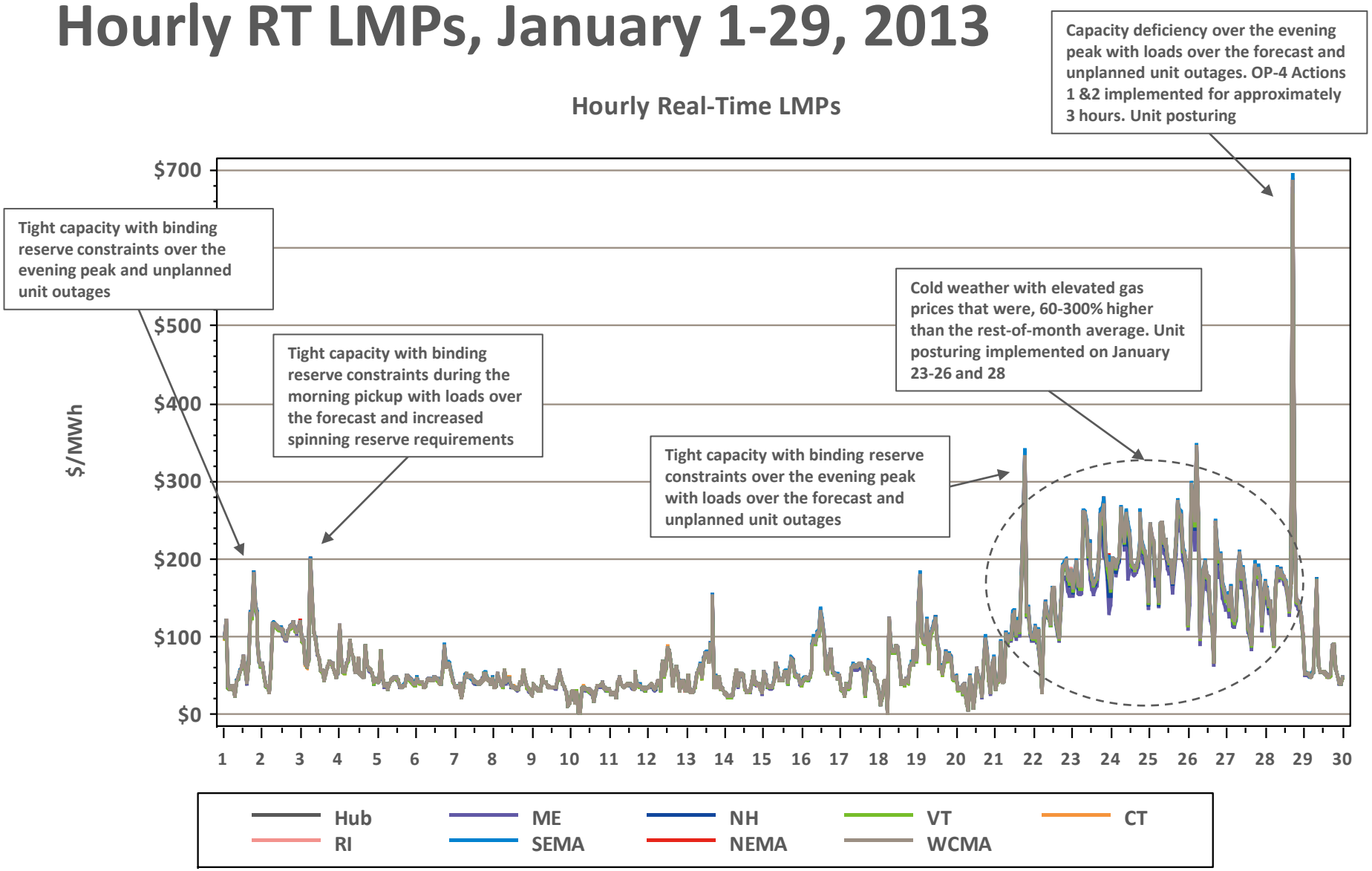


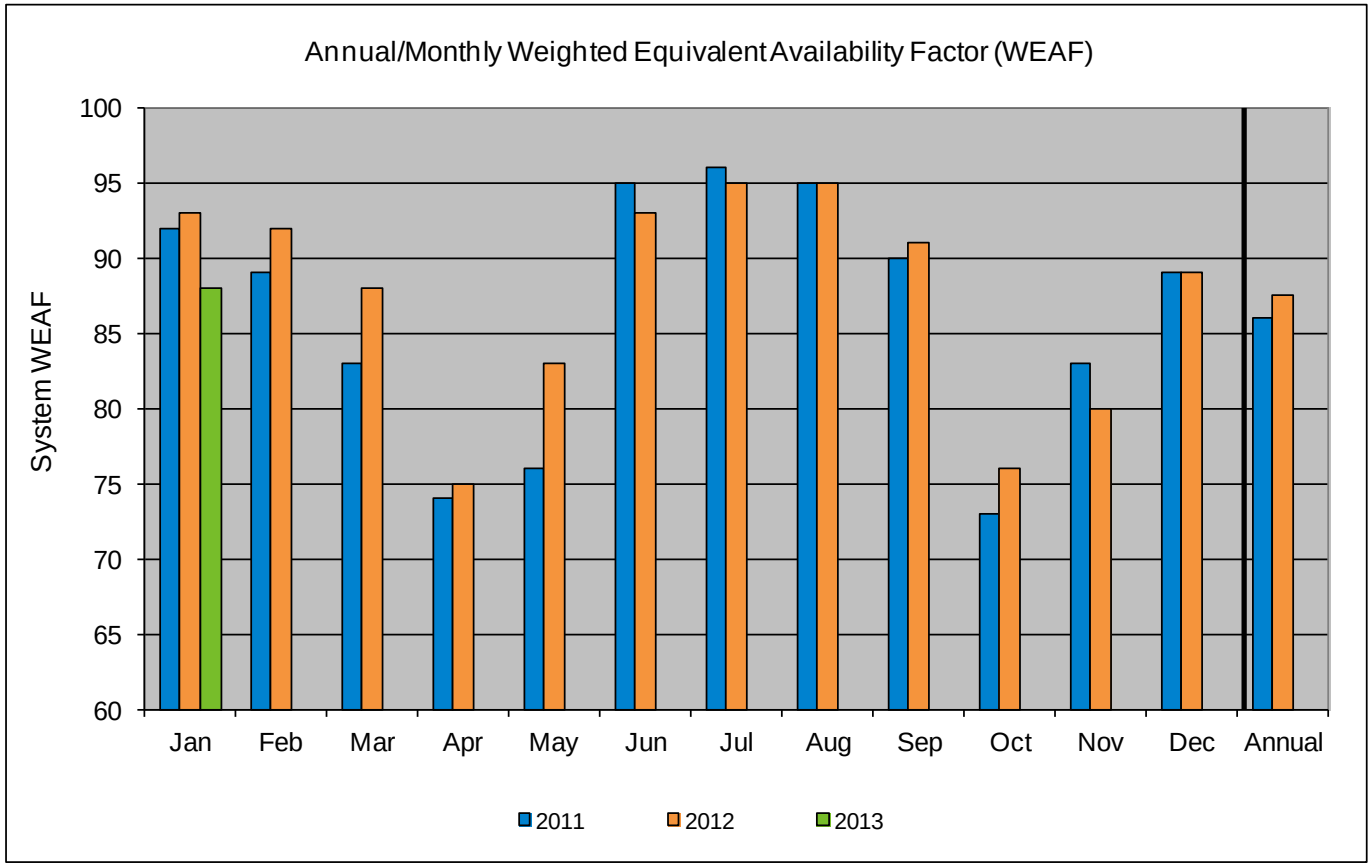
# Hourly DA LMPs, January 1-29, 2013



# Hourly RT LMPs, January 1-29, 2013



# System Unit Availability




| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2013** | 88 | | | | | | | | | | | | 88 |
| **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 |
| **2010** | 91 | 93 | 90 | 83 | 74 | 93 | 93 | 93 | 86 | 77 | 81 | 91 | 87 |

Data as of 1/25/13

# BACK-UP DETAIL

# LOAD RESPONSE

# Capacity Supply Obligation (CSO) MW by Demand Resource Type for February 2013

| Load Zone | RTDR* | RTEG** | On Peak | Seasonal Peak | Total |
|---|---|---|---|---|---|
| ME | 160.90 | 11.84 | 66.39 | 0.00 | 239.12 |
| NH | 25.31 | 24.23 | 60.09 | 0.00 | 109.63 |
| VT | 40.53 | 5.98 | 70.69 | 0.00 | 117.20 |
| CT | 63.03 | 125.28 | 78.61 | 246.10 | 513.02 |
| RI | 20.96 | 21.78 | 63.67 | 0.11 | 106.51 |
| SEMA | 13.59 | 20.06 | 108.24 | 0.21 | 142.10 |
| WCMA | 55.99 | 35.66 | 100.53 | 17.20 | 209.37 |
| NEMA | 21.58 | 37.95 | 178.78 | 0.00 | 238.31 |
| **Total** | **401.89** | **282.77** | **726.98** | **263.62** | **1,675.26** |

* 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

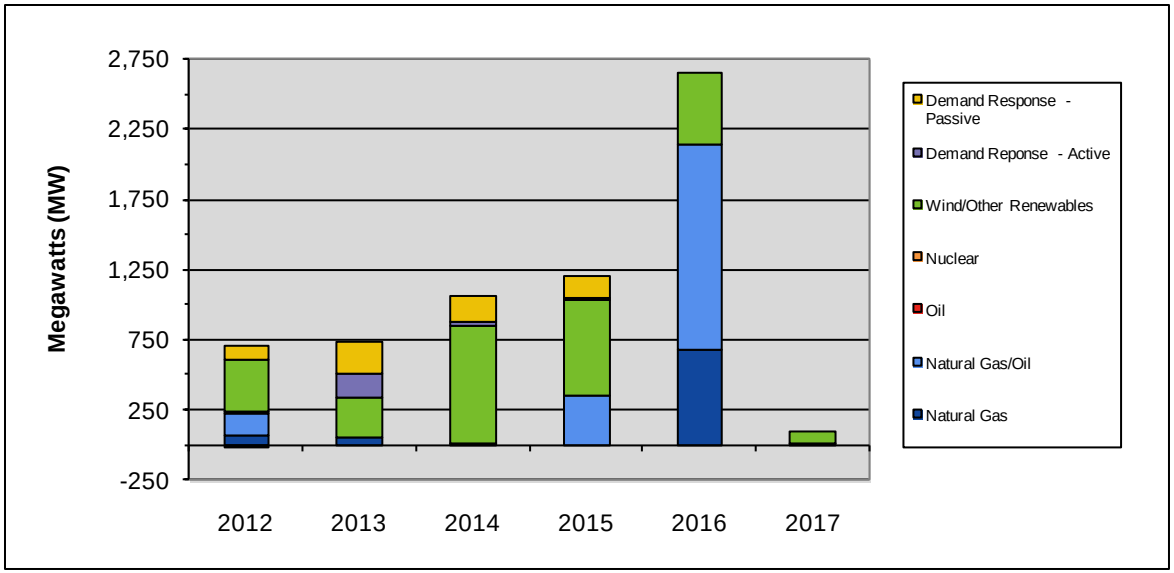
# New Generation Update

***Based on 1/25/13 Interim Queue update***

- One new project has applied for interconnection study since the last update
- One project was withdrawn, resulting in a net increase in new generation projects of 20 MW
- In total, 55 generation projects are currently being tracked by the ISO, totaling 5,000 MW

# Actual and Projected Annual Capacity Additions

## *By Supply Fuel Type and Demand Resource Type*



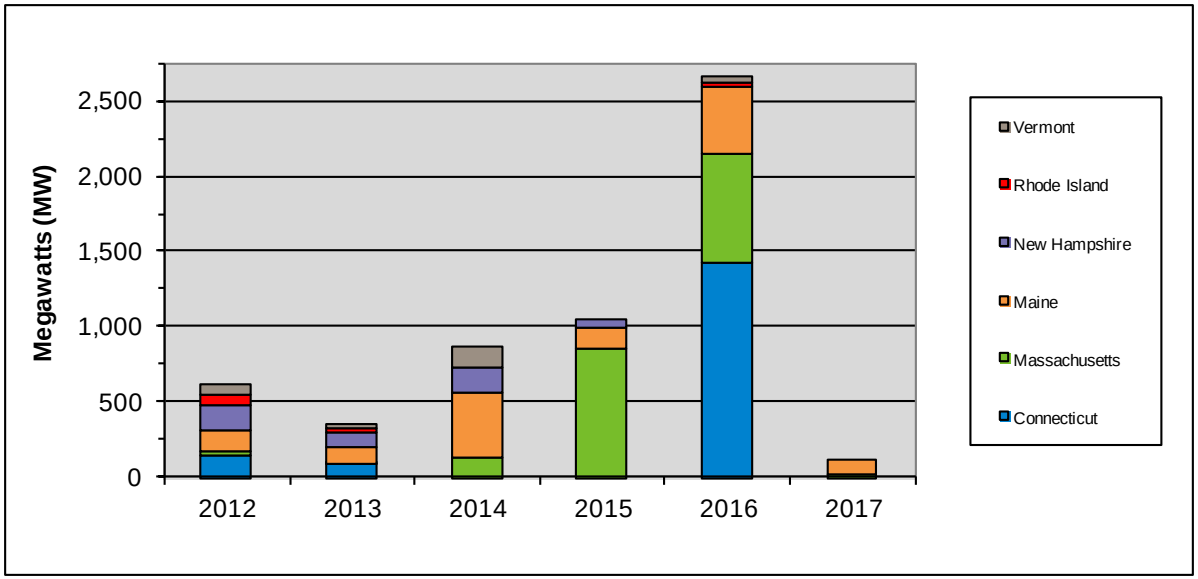

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total MW | % of Total* |
|---|---|---|---|---|---|---|---|---|
| **Demand Response - Passive** | 95 | 225 | 188 | 157 | 0 | 0 | 665 | 10.3 |
| **Demand Response - Active** | -6 | 169 | 19 | 3 | 0 | 0 | 185 | 2.9 |
| **Wind & Other Renewables** | 376 | 290 | 849 | 692 | 513 | 90 | 2,810 | 43.5 |
| **Nuclear** | 13 | 0 | 0 | 0 | 0 | 0 | 13 | 0.2 |
| **Oil** | 0 | 0 | 0 | 0 | 0 | 14 | 14 | 0.2 |
| **Natural Gas/Oil** | 156 | 0 | 8 | 350 | 1,461 | 0 | 1,975 | 30.6 |
| **Natural Gas** | 66 | 53 | 0 | 0 | 680 | 0 | 799 | 12.4 |
| **Totals** | **700** | **737** | **1,064** | **1,202** | **2,654** | **104** | **6,461** | **100.0** |

*** Sum may not equal 100% due to rounding**

- 2012 values consist of the 611 MW of generation that went commercial in 2012
- 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*




| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | Total MW | % of Total* |
|---|---|---|---|---|---|---|---|---|
| **Vermont** | 75 | 30 | 142 | 0 | 33 | 0 | 280 | 5.0 |
| **Rhode Island** | 66 | 28 | 0 | 0 | 29 | 0 | 123 | 2.2 |
| **New Hampshire** | 169 | 96 | 163 | 58 | 0 | 0 | 486 | 8.7 |
| **Maine** | 141 | 108 | 435 | 132 | 451 | 90 | 1,357 | 24.2 |
| **Massachusetts** | 30 | 5 | 117 | 852 | 716 | 14 | 1,734 | 30.9 |
| **Connecticut** | 130 | 76 | 0 | 0 | 1,425 | 0 | 1,631 | 29.1 |
| **Totals** | **611** | **343** | **857** | **1,042** | **2,654** | **104** | **5,611** | **100.0** |

*** Sum may not equal 100% due to rounding**

- 2012 values consist of the 611 MW of generation that went commercial in 2012

# 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 | 5 | 194 | 2 | 106 | 3 | 88 |
| Hydro | 7 | 76 | 1 | 8 | 6 | 68 |
| Landfill Gas | 1 | 28 | 1 | 28 | 0 | 0 |
| Natural Gas | 6 | 733 | 1 | 9 | 5 | 724 |
| Natural Gas/Oil | 4 | 1,819 | 0 | 0 | 4 | 1,819 |
| Oil | 1 | 14 | 0 | 0 | 1 | 14 |
| Solar | 3 | 16 | 2 | 10 | 1 | 6 |
| Wind | 28 | 2,120 | 0 | 0 | 28 | 2,120 |
| Total | 55 | 5,000 | 7 | 161 | 48 | 4,839 |

- 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 | 8 | 246 | 4 | 143 | 4 | 103 |
| Intermediate | 13 | 2,540 | 1 | 8 | 12 | 2,532 |
| Peaker | 6 | 94 | 2 | 10 | 4 | 84 |
| Wind Turbine | 28 | 2,120 | 0 | 0 | 28 | 2,120 |
| Total | 55 | 5,000 | 7 | 161 | 48 | 4,839 |

- 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 | 5 | 194 | 5 | 194 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 7 | 76 | 0 | 0 | 6 | 26 | 1 | 50 | 0 | 0 |
| Landfill Gas | 1 | 28 | 1 | 28 | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas | 6 | 733 | 2 | 24 | 3 | 695 | 1 | 14 | 0 | 0 |
| Natural Gas/Oil | 4 | 1,819 | 0 | 0 | 4 | 1,819 | 0 | 0 | 0 | 0 |
| Oil | 1 | 14 | 0 | 0 | 0 | 0 | 1 | 14 | 0 | 0 |
| Solar | 3 | 16 | 0 | 0 | 0 | 0 | 3 | 16 | 0 | 0 |
| Wind | 28 | 2,120 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 2,120 |
| Total | 55 | 5,000 | 8 | 246 | 13 | 2,540 | 6 | 94 | 28 | 2,120 |

# Capacity Supply Obligation (CSO) FCA 1

| Resource Type | Resource Type | FCA | Proration | | ARA 2 | | ***Delisted MW Released | | Annual Bilateral | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | *CSO | CSO | Change | CSO | **Net Change | CSO | Change | CSO | **Net Change | CSO | **Net Change |
| | | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW |
| Demand | *Active Demand* | *1,850.074* | *1,818.402* | *-31.672* | *1,817.152* | *-1.250* | *1,817.152* | *0.000* | *1,515.593* | *-301.559* | 1,498.628 | *-16.965* |
| | *Passive Demand* | *703.488* | *689.729* | *-13.759* | *666.729* | *-23.000* | *666.729* | *0.000* | *654.078* | *-12.651* | *654.078* | *0.000* |
| **Demand Total** | | **2,553.562** | **2,508.131** | **-45.431** | **2,483.881** | **-24.250** | **2,483.881** | **0.000** | **2,169.671** | **-314.210** | **2,152.706** | **-16.965** |
| Generator | *Non-Intermittent* | *29,798.358* | *28,659.952* | *-1,138.406* | *28,768.138* | *108.186* | *28,600.138* | ***-168.000*** | *29,406.161* | ***806.023*** | *29,480.502* | *74.341* |
| | *Intermittent* | *1,066.571* | *1,050.517* | *-16.054* | *1,046.581* | *-3.936* | *1,046.581* | *0.000* | *999.947* | *-46.634* | *976.099* | *-23.848* |
| **Generator Total** | | **30,864.929** | **29,710.469** | **-1,154.460** | **29,814.719** | **104.250** | **29,646.719** | **-168.000** | **30,406.108** | **759.389** | **30,456.600** | **50.492** |
| **Import Total** | | **933.583** | **898.542** | **-35.041** | **818.542** | **-80.000** | **818.542** | **0.000** | **373.363** | **-445.179** | **339.836** | **-33.527** |
| **** Extraordinary Items | | **N/A** | **N/A** | **N/A** | **0.000** | **N/A** | **N/A** | **N/A** | **N/A** | **N/A** | **-242.442** | **-242.442** |
| **Grand Total** | | **34,352.074** | **33,117.142** | **1,234.932** | **33,117.142** | **0.000** | **32,949.142** | **-168.000** | **32,949.142** | **0.000** | **32,706.700** | **-242.442** |

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

** **The Net Change is the total MW change by resource type (the total CSO reduced vs. the total CSO increased). The value includes Extraordinary Items where applicable.**

*** Capacity that was previously held for reliability was released in accordance with Market Rule 1, Section 13.2.5.2.

**** Extraordinary Items - Extraordinary Items: changes for items that are both unusual in nature and infrequent in occurrence which includes but is not limited to ISO Buy Back, Terminations, etc.

# Capacity Supply Obligation FCA 2

| Resource Type | Resource Type | FCA | Proration | | Annual Bilateral Period 1 for ARA 2 | | ARA 2 | | *** Delisted MW Released | | Annual Bilateral Period 2 for ARA 2 | | Annual Bilateral 3 Period | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | *CSO | CSO | Change | ARA 2 | **Net Change | CSO | **Net Change | CSO | Change | CSO | **Net Change | CSO | **Net Change | CSO | **Net Change |
| | | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW |
| Demand | *Active Demand* | 1,953.383 | 1,803.981 | *-149.401* | 1,854.262 | *50.281* | 1,824.682 | -29.580 | 1,824.682 | 0.000 | 1,821.397 | -3.285 | 1,711.529 | -109.868 | 1,525.433 | -186.096 |
| | *Passive Demand* | 983.230 | 909.889 | *-73.341* | 909.889 | *0.000* | 909.889 | 0.000 | 909.889 | 0.000 | 913.174 | 3.285 | 928.254 | 15.080 | 908.858 | -19.396 |
| **Demand Total** | | **2,936.613** | **2,713.870** | **-222.742** | **2,764.151** | **50.281** | **2,734.571** | **-29.580** | **2,734.571** | **0.000** | **2,734.571** | **0.000** | **2,639.783** | **-94.788** | **2,434.291** | **-205.492** |
| Generator | *Non-Intermittent* | 31,122.642 | 27,558.878 | -3,563.764 | 28,512.876 | 953.998 | 28,635.412 | 122.536 | 28,635.412 | 0.000 | 28,635.412 | 0.000 | 28,738.961 | 103.549 | 28,853.900 | 114.939 |
| | *Intermittent* | 1,084.621 | 994.770 | -89.851 | 993.899 | -0.871 | 936.781 | -57.118 | 936.781 | 0.000 | 936.781 | 0.000 | 928.020 | -8.761 | 893.587 | -34.433 |
| **Generator Total** | | **32,207.263** | **28,553.648** | **-3,653.615** | **29,506.775** | **953.127** | **29,572.193** | **65.418** | **29,572.193** | **0.000** | **29,572.193** | **0.000** | **29,666.981** | **94.788** | **29,747.487** | **80.506** |
| **Import Total** | | **2,297.930** | **2,137.661** | **-160.269** | **1,134.253** | **-1,003.408** | **1,098.415** | **-35.838** | **1,098.415** | **0.000** | **1,098.415** | **0.000** | **1,098.415** | **0.000** | **1,223.401** | **124.986** |
| **** Extraordinary Items | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | -82.740 | -82.740 |
| **Grand Total** | | **37,441.806** | **33,405.179** | **-4,036.626** | **33,405.179** | **0.000** | **33,405.179** | **0.000** | **33,405.179** | **0.000** | **33,405.179** | **0.000** | **33,405.179** | **0.000** | **33,322.439** | **-82.740** |

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

** The Net Change is the total MW change by resource type (the total CSO reduced vs. the total CSO increased) The value includes Extraordinary Items where applicable.

*** Capacity that was previously held for reliability was released in accordance with Market Rule 1, Section 13.2.5.2.

**** Extraordinary Items - Extraordinary Items: changes for items that are both unusual in nature and infrequent in occurrence which includes but is not limited to ISO Buy Back, Terminations, etc.

# Capacity Supply Obligation FCA 3

| Resource Type | Resource Type | FCA | Proration | | Annual Bilateral Period 1 for ARA 2 | | ARA 2 | | *** Delisted MW Released | | Annual Bilateral Period 2 for ARA 2 | | Annual Bilateral 3 Period | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | *CSO | CSO | Change | ARA 2 | **Net Change | CSO | **Net Change | CSO | Change | CSO | **Net Change | CSO | **Net Change | CSO | **Net Change |
| | | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW |
| Demand | *Active Demand* | 1,824.775 | 1,677.575 | *-147.200* | 1,677.575 | *0.000* | 1,543.419 | -134.156 | 1,512.473 | 0.000 | 1,512.473 | 0.000 | 1,378.422 | -134.051 | 1,127.377 | -251.045 |
| | *Passive Demand* | 1,072.863 | 968.521 | *-104.342* | 968.521 | *0.000* | 968.521 | 0.000 | 959.728 | 0.000 | 959.728 | 0.000 | 962.318 | 2.590 | 978.233 | 15.915 |
| **Demand Total** | | **2,897.638** | **2,646.096** | **-251.542** | **2,646.096** | **0.000** | **2,511.940** | **-134.156** | **2,472.201** | **0.000** | **2,472.201** | **0.000** | **2,340.740** | -131.461 | **2,105.610** | **-235.130** |
| Generator | *Non-Intermittent* | 31,133.943 | 27,560.503 | -3,573.440 | 27,620.769 | 60.266 | 28,094.370 | 473.601 | 28,091.870 | 0.000 | 28,103.490 | 11.620 | 28,813.405 | 709.915 | 29,190.369 | 376.964 |
| | *Intermittent* | 1,094.318 | 1,003.263 | -91.055 | 1,004.140 | 0.877 | 837.304 | -166.836 | 837.304 | 0.000 | 825.684 | -11.620 | 821.807 | -3.877 | 781.374 | -40.433 |
| **Generator Total** | | **32,228.261** | **28,563.766** | **-3,664.495** | **28,624.909** | **61.143** | **28,931.674** | **306.765** | **28,929.174** | **0.000** | **28,929.174** | **0.000** | **29,635.212** | **706.038** | **29,971.743** | **336.531** |
| **Import Total** | | **1,900.000** | **1,672.548** | **-227.452** | **1,611.405** | **-61.143** | **1,438.796** | **-172.609** | **1,438.796** | **0.000** | **1,438.796** | **0.000** | **857.244** | **-581.552** | **755.843** | **-101.401** |
| **** **Extraordinary Items** | | **N/A** | **N/A** | **N/A** | **N/A** | **N/A** | **-42.239** | **-42.239** | **N/A** | **N/A** | **-6.975** | **-6.975** | **N/A** | **N/A** | **N/A** | **N/A** |
| **Grand Total** | | **37,025.899** | **32,882.410** | **-4,143.489** | **32,882.410** | **0.000** | **32,840.171** | **-42.239** | **32,840.171** | **0.000** | **32,833.196** | **-6.975** | **32,833.196** | **0.000** | **32,833.196** | **0.000** |

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

** **The Net Change is the total MW change by resource type (the total CSO reduced vs. the total CSO increased) The value includes Extraordinary Items where applicable.**

*** Capacity that was previously held for reliability was released in accordance with Market Rule 1, Section 13.2.5.2.

**** Extraordinary Items - Extraordinary Items: changes for items that are both unusual in nature and infrequent in occurrence which includes but is not limited to ISO Buy Back, Terminations, etc.

# Capacity Supply Obligation FCA 4

| Resource Type | Resource Type | FCA | Proration | | Annual Bilateral Period 1 for ARA 2 | | ARA 2 | | *** Delisted MW Released | | Annual Bilateral Period 2 for ARA 2 | | Annual Bilateral 3 Period | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | *CSO | CSO | Change | ARA 2 | **Net Change | CSO | **Net Change | CSO | Change | CSO | **Net Change | CSO | **Net Change | CSO | **Net Change |
| | | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW |
| Demand | *Active Demand* | 2,051.536 | 1,860.060 | *-191.476* | 1,681.032 | *-171.841* | 1,482.357 | -198.675 | 1,482.357 | 0.000 | 1,367.357 | -115.000 | 1,043.762 | -323.595 | | |
| | *Passive Demand* | 1,297.906 | 1,154.626 | *-143.280* | 1,135.705 | *-12.525* | 1,163.465 | 27.760 | 1,163.465 | 0.000 | 1,163.465 | 0.000 | 1,132.232 | -31.233 | | |
| **Demand Total** | | **3,349.442** | **3,014.686** | **-334.756** | **2,816.737** | **-184.366** | **2,645.822** | **-170.915** | **2,645.822** | **0.000** | **2,530.822** | **-115.000** | **2,175.994** | **-354.828** | | |
| Generator | *Non-Intermittent* | 31,161.578 | 27,655.349 | -3,506.229 | 27,839.237 | 191.388 | 28,454.380 | 615.295 | 27,782.33 | -604.250 | 27,890.197 | 107.822 | 28,370.164 | 479.967 | | |
| | *Intermittent* | 1,085.585 | 979.117 | -106.468 | 972.120 | -7.022 | 857.931 | -114.189 | 857.931 | 0.000 | 865.064 | 7.178 | 839.925 | -25.139 | | |
| **Generator Total** | | **32,247.163** | **28,634.466** | **-3,612.697** | **28,811.357** | **184.366** | **29,312.311** | **501.106** | **29,244.511** | **0.000** | **28,755.261** | **115.000** | **29,210.089** | **454.828** | | |
| **Import Total** | | **1,992.600** | **1,726.449** | **-266.151** | **1,726.449** | **0.000** | **1,396.258** | **-330.191** | **1,396.258** | **0.000** | **1,396.258** | **0.000** | **1,296.258** | **-100** | | |
| **** Extraordinary Items | | **N/A** | **-21.058** | **-21.058** | **N/A** | **N/A** | **-67.800** | **-67.800** | **N/A** | **N/A** | **0.000** | **0.000** | **-45.333** | **-45.333** | | |
| **Grand Total** | | **37,589.205** | **33,354.543** | **-4,234.662** | **33,354.543** | **0.000** | **33,286.591** | **-67.800** | **32,682.341** | **-604.250** | **32,682.341** | **0.000** | **32,637.008** | **-45.333** | | |

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

** **The Net Change is the total MW change by resource type (the total CSO reduced vs. the total CSO increased) The value includes Extraordinary Items where applicable.**

*** Capacity that was previously held for reliability was released in accordance with Market Rule 1, Section 13.2.5.2.

**** Extraordinary Items - Extraordinary Items: changes for items that are both unusual in nature and infrequent in occurrence which includes but is not limited to ISO Buy Back, Terminations, etc.

# Capacity Supply Obligation FCA 5

| Resource Type | Resource Type | FCA | Proration | | Annual Bilateral Period 1 for ARA 2 | | ARA 2 | | *** Delisted MW Released | | Annual Bilateral Period 2 for ARA 2 | | Annual Bilateral 3 Period | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | *CSO | CSO | Change | ARA 2 | **Net Change | CSO | **Net Change | CSO | Change | CSO | **Net Change | CSO | **Net Change | CSO | **Net Change |
| | | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW | MW |
| Demand | *Active Demand* | 2,104.141 | 2,001.126 | *-103.015* | | | | | | | | | | | | |
| | *Passive Demand* | 1,485.713 | 1,397.586 | *-88.127* | | | | | | | | | | | | |
| **Demand Total** | | **3,589.854** | **3,398.712** | **-191.142** | | | | | | | | | | | | |
| Generator | *Non-Intermittent* | 30,560.408 | 28,339.669 | -2,220.739 | | | | | | | | | | | | |
| | *Intermittent* | 878.549 | 825.616 | -52.933 | | | | | | | | | | | | |
| **Generator Total** | | **31,438.957** | **29,165.285** | **-2,273.672** | | | | | | | | | | | | |
| **Import Total** | | **2,011.001** | **1,831.372** | **-179.629** | | | | | | | | | | | | |
| **** Extraordinary Items | | **N/A** | **-18.114** | **-18.114** | | | | | | | | | | | | |
| **Grand Total** | | **37,039.812** | **34,377.255** | **-2,662.557** | | | | | | | | | | | | |

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

** **The Net Change is the total MW change by resource type (the total CSO reduced vs. the total CSO increased) The value includes Extraordinary Items where applicable.**

*** Capacity that was previously held for reliability was released in accordance with Market Rule 1, Section 13.2.5.2.

**** Extraordinary Items - Extraordinary Items: changes for items that are both unusual in nature and infrequent in occurrence which includes but is not limited to ISO Buy Back, Terminations, etc.

# Capacity Supply Obligation FCA 6

| Resource Type | Resource Type | FCA | Proration | | Annual Bilateral Period 1 for ARA 2 | | ARA 2 | | *** Delisted MW Released | | Annual Bilateral Period 2 for ARA 2 | | Annual Bilateral 3 Period | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | *CSO | CSO | Change | ARA 2 | **Net Change | CSO | **Net Change | CSO | Change | CSO | **Net Change | CSO | **Net Change | CSO | **Net 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* | | | | | | | | | | | | |
| | *Passive Demand* | 1,643.334 | 1,553.054 | *-90.280* | | | | | | | | | | | | |
| **Demand Total** | | **3,644.844** | **3,471.716** | **-173.128** | | | | | | | | | | | | |
| Generator | *Non-Intermittent* | 29,866.098 | 27,957.613 | -1,908.485 | | | | | | | | | | | | |
| | *Intermittent* | 891.069 | 840.563 | -50.506 | | | | | | | | | | | | |
| **Generator Total** | | **30,757.167** | **28,798.176** | **-1,958.991** | | | | | | | | | | | | |
| **Import Total** | | **1,924.000** | **1,768.111** | **-155.889** | | | | | | | | | | | | |
| **** Extraordinary Items | | N/A | N/A | N/A | | | | | | | | | | | | |
| **Grand Total** | | **36,326.011** | **34,038.003** | **-2,288.008** | | | | | | | | | | | | |

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

** **The Net Change is the total MW change by resource type (the total CSO reduced vs. the total CSO increased) The value includes Extraordinary Items where applicable.**

*** Capacity that was previously held for reliability was released in accordance with Market Rule 1, Section 13.2.5.2.

**** Extraordinary Items - Extraordinary Items: changes for items that are both unusual in nature and infrequent in occurrence which includes but is not limited to ISO Buy Back, Terminations, etc.

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

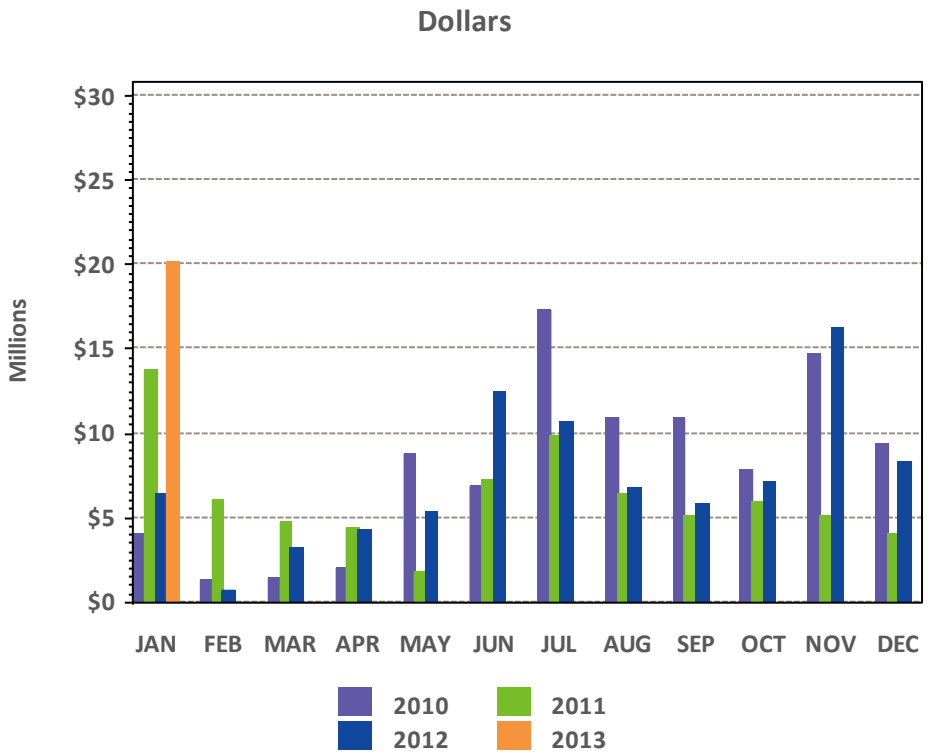
# What are Daily NCPC Payments?

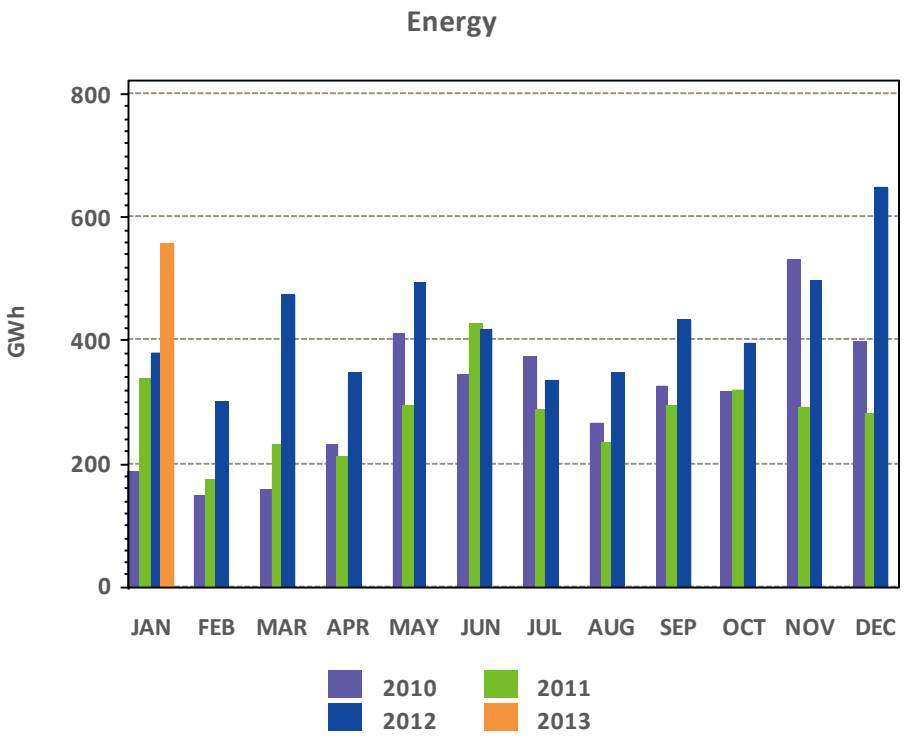
- “Make-whole” payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource’s offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day
- Typically, this is the result of some out-of-merit 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

| | |
|---|---|
| Voltage NCPC Payments | Reliability costs paid to resources operated by ISO-NE to provide voltage 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 |
| 1st Contingency NCPC Payments | Reliability costs paid to eligible resources that are not providing 2nd Contingency, Voltage, or Distribution requirements. These resources may have been providing first contingency coverage (system-wide or locally) |
| 2nd Contingency NCPC Payments | Reliability costs paid to resources providing adequate capacity in constrained areas to respond to a local second contingency. They are committed based on 2nd Contingency protocols |
| 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 |

# Year-Over-Year Total NCPC Dollars and Energy

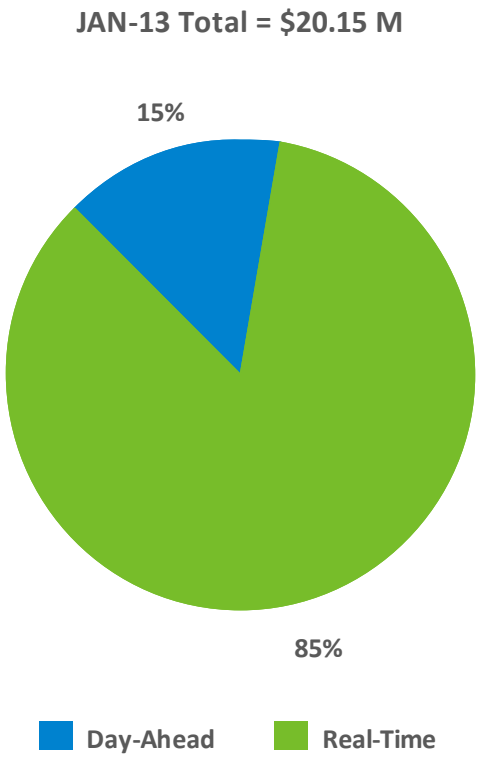


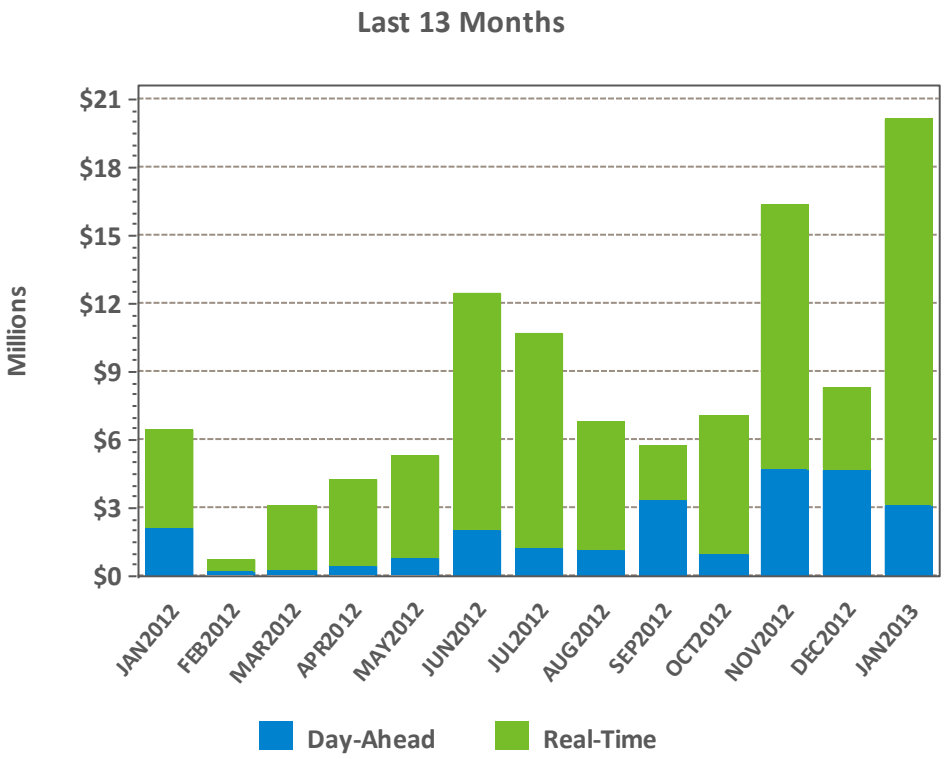




Note:

- Overall Reliability Cost MWh includes out of merit DA and RT 1st Contingency, 2nd Contingency, Voltage, and RT Distribution components.
- Energy includes daily totals of cleared DA energy and RT energy from resources receiving NCPC payments.

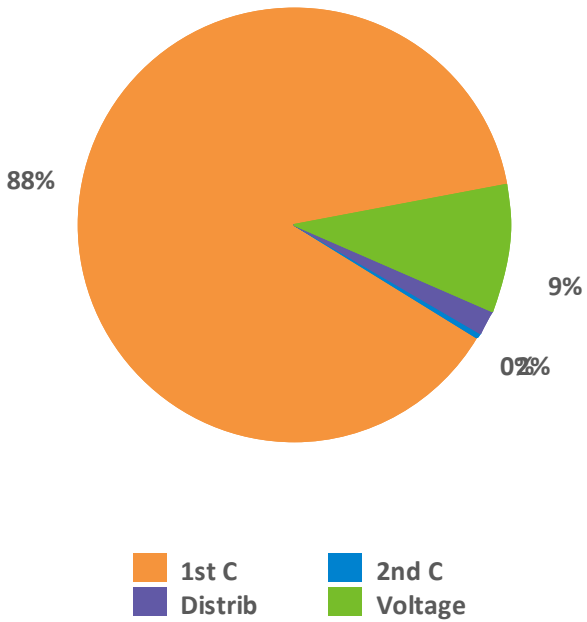
# DA and RT NCPC Payments



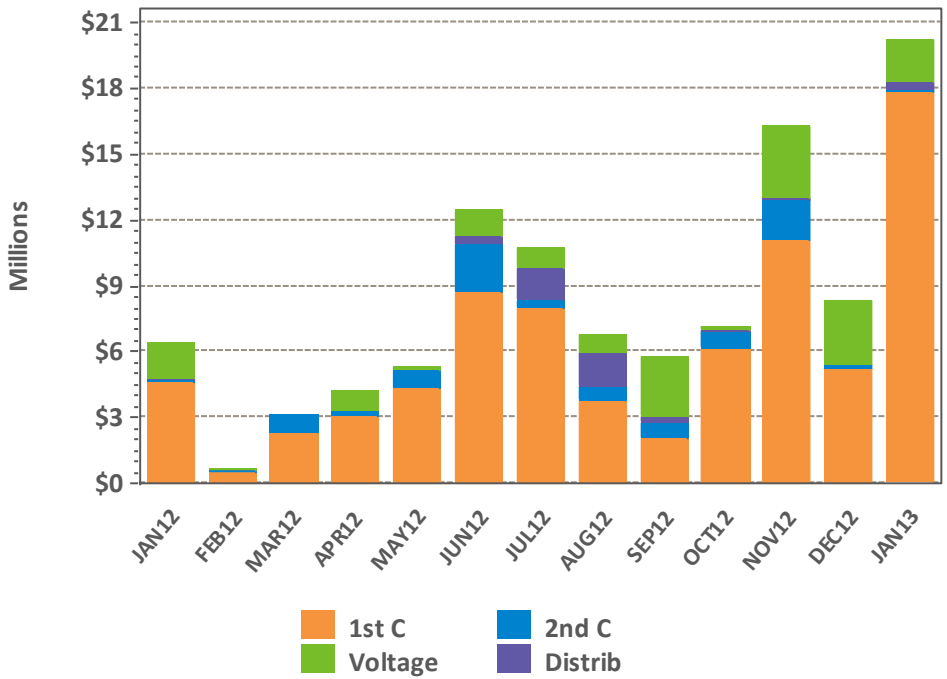



# NCPC Payments by Type

JAN-13 Total = $20.15 M



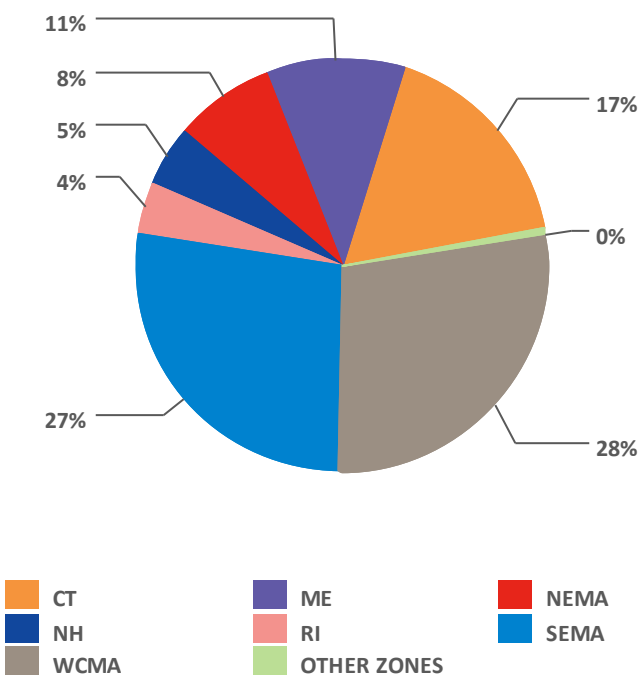

Last 13 Months



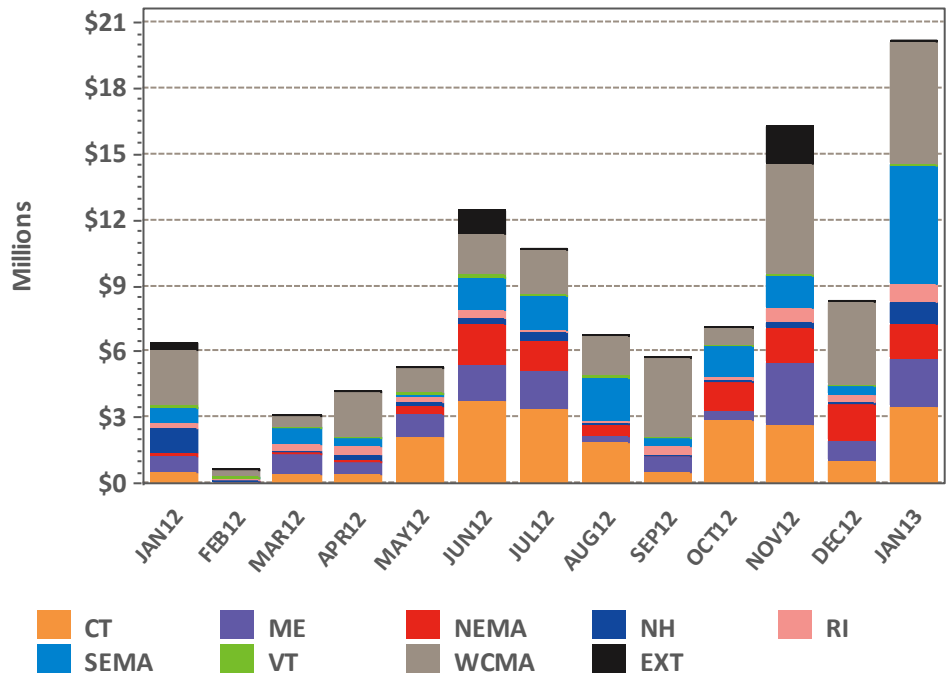

1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

# NCPC Payments by Location

JAN-13 Total = $20.15 M




Last 13 Months

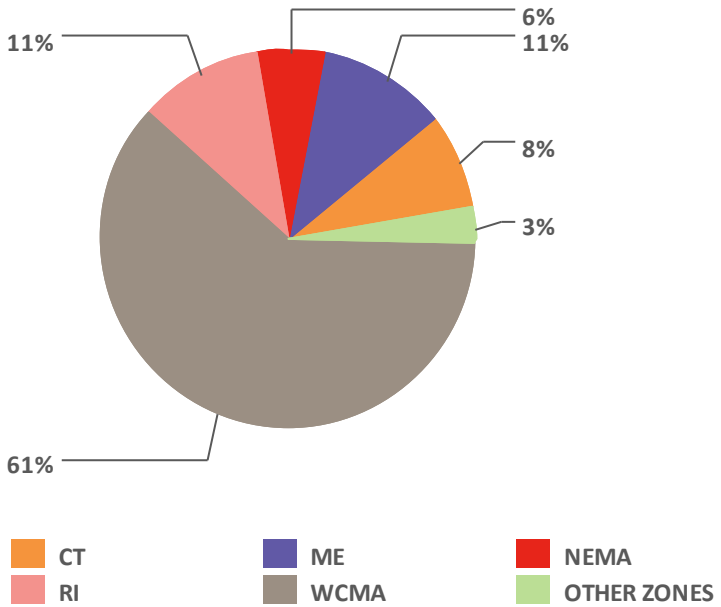



CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

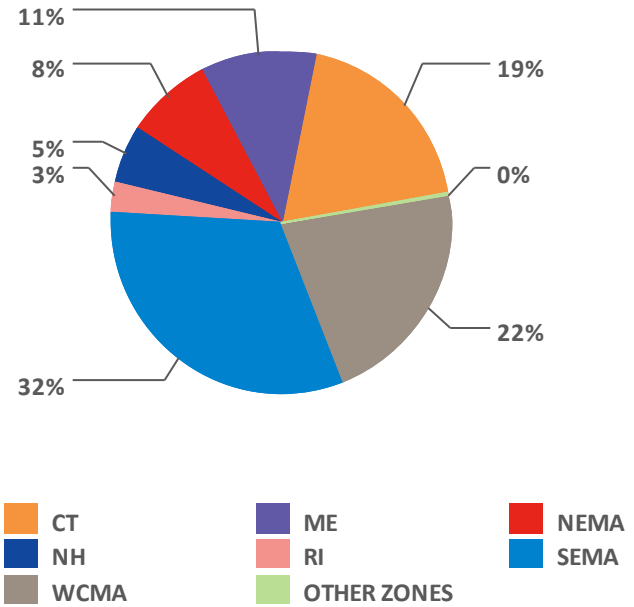
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

# DA and RT NCPC Payments by Location

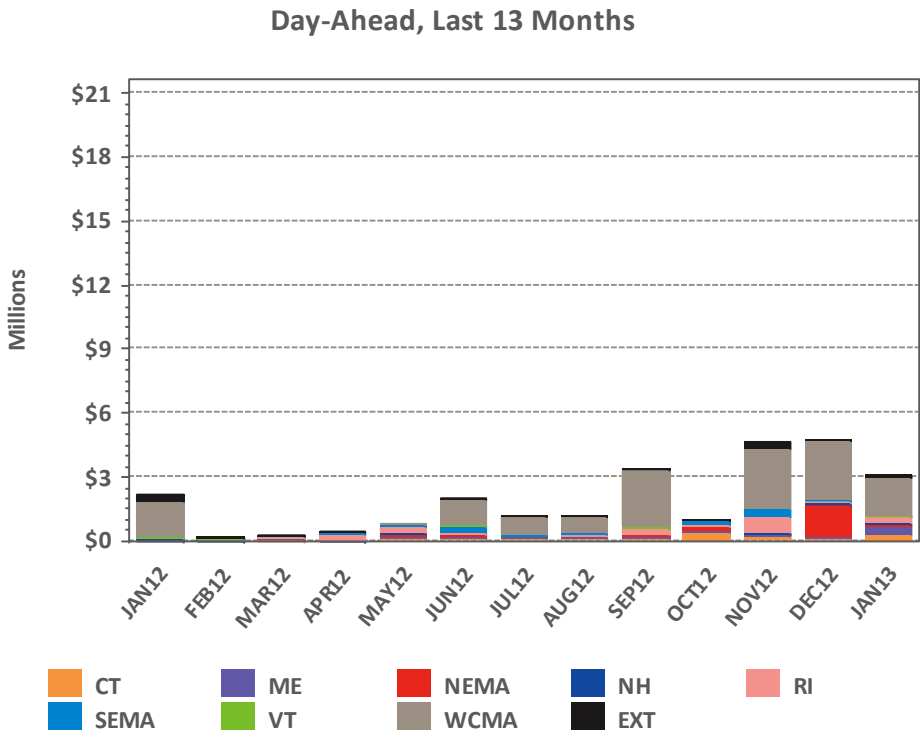
JAN-13 Day-Ahead Total = $3.07 M

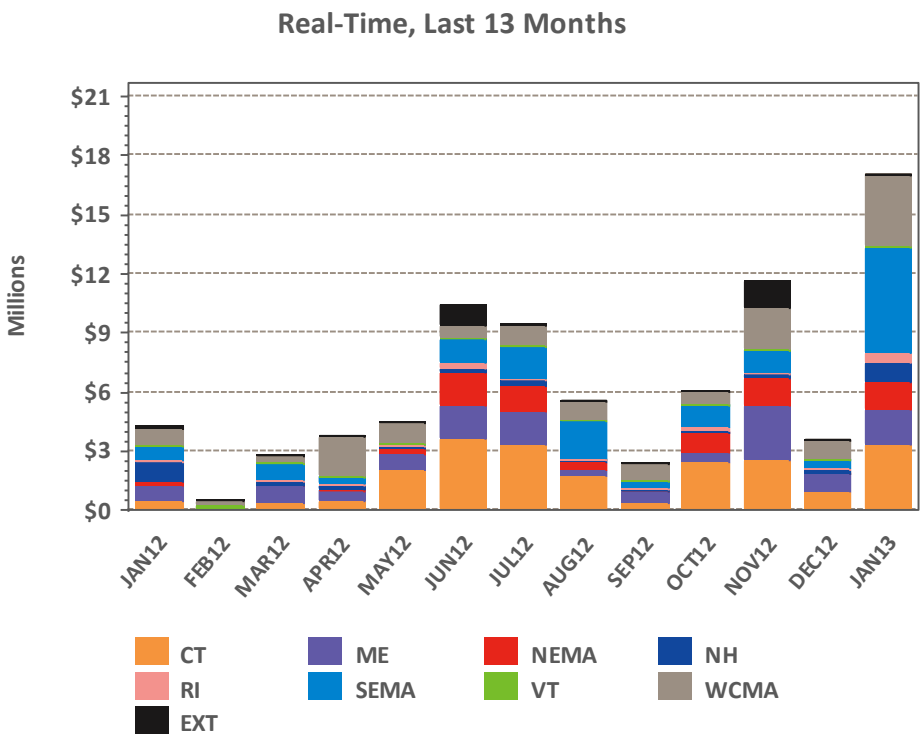



JAN-13 Real-Time Total = $17.08 M

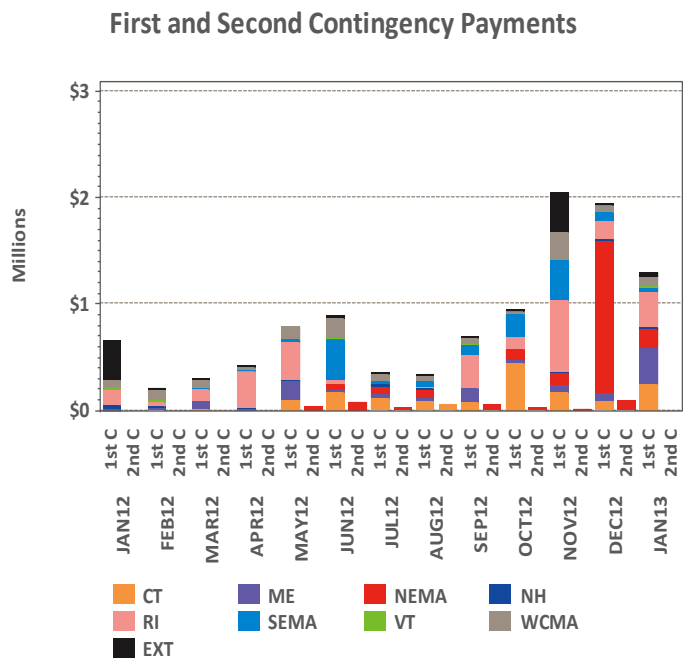


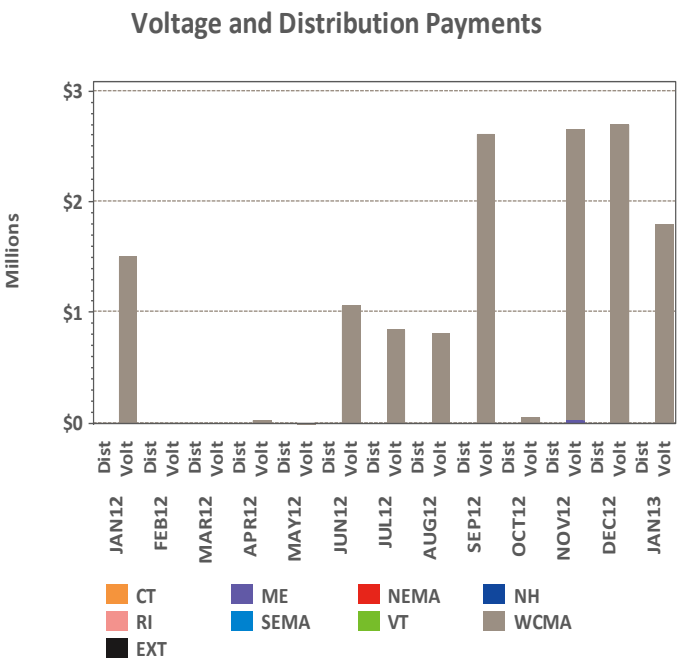
# DA and RT NCPC Payments by Location Last 13 Months



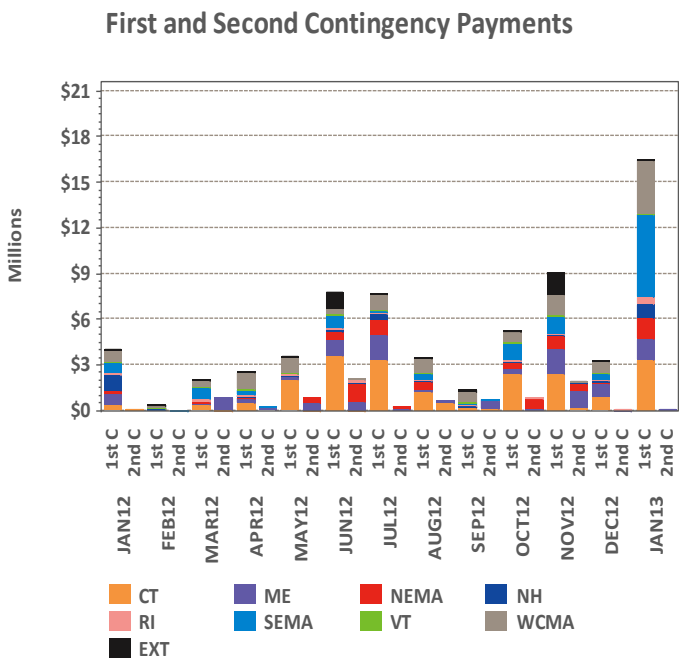



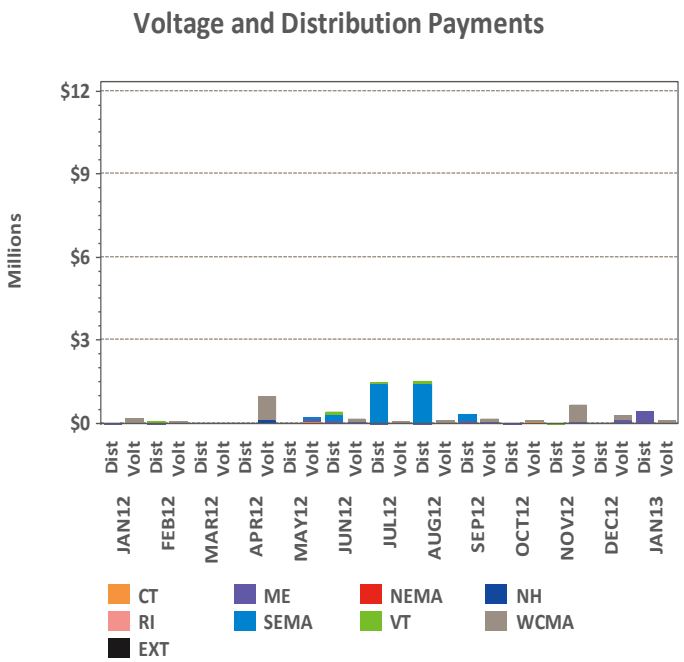
# DA NCPC Payments by Type and Location



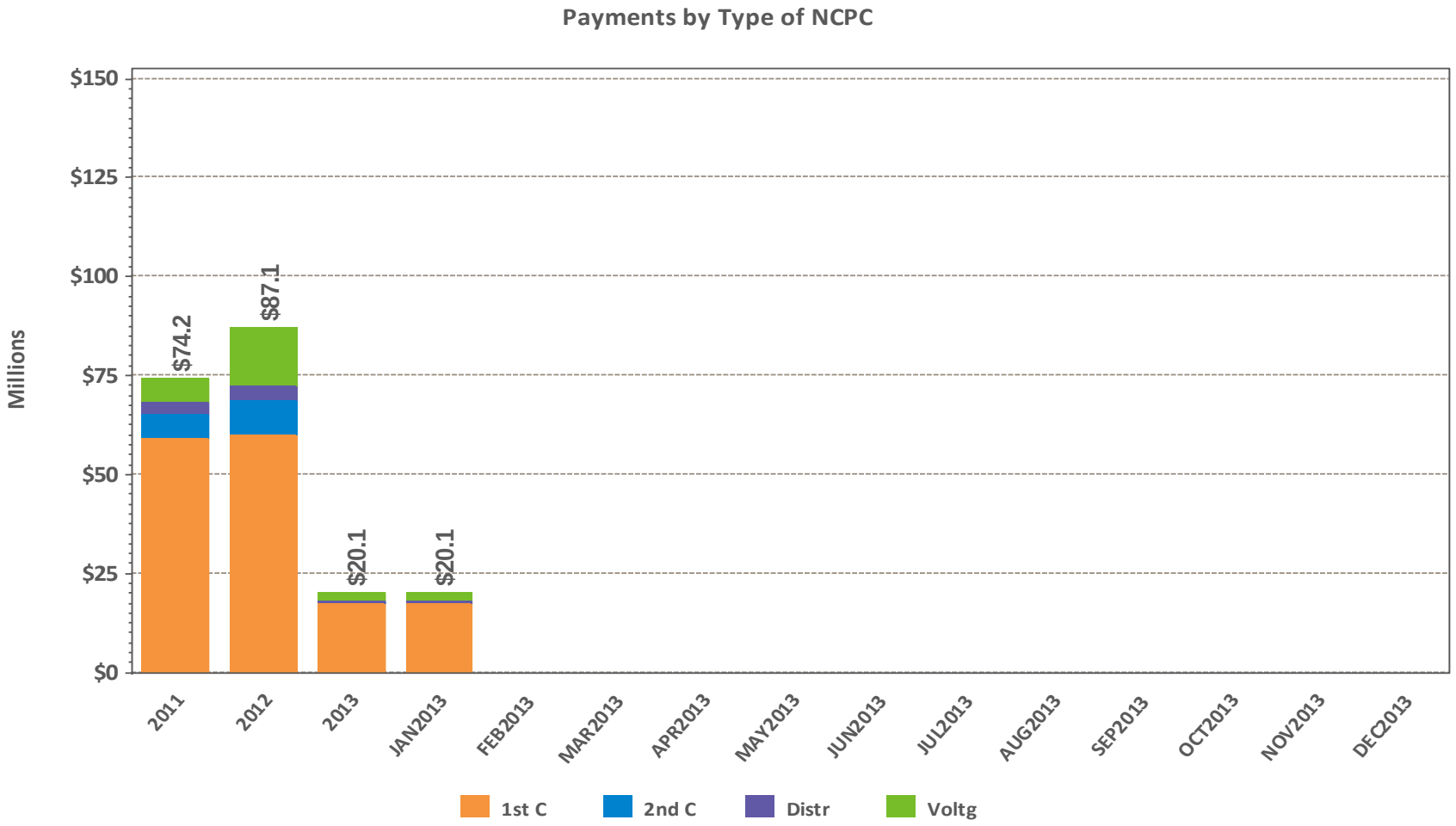



# RT NCPC Payments by Type and Location

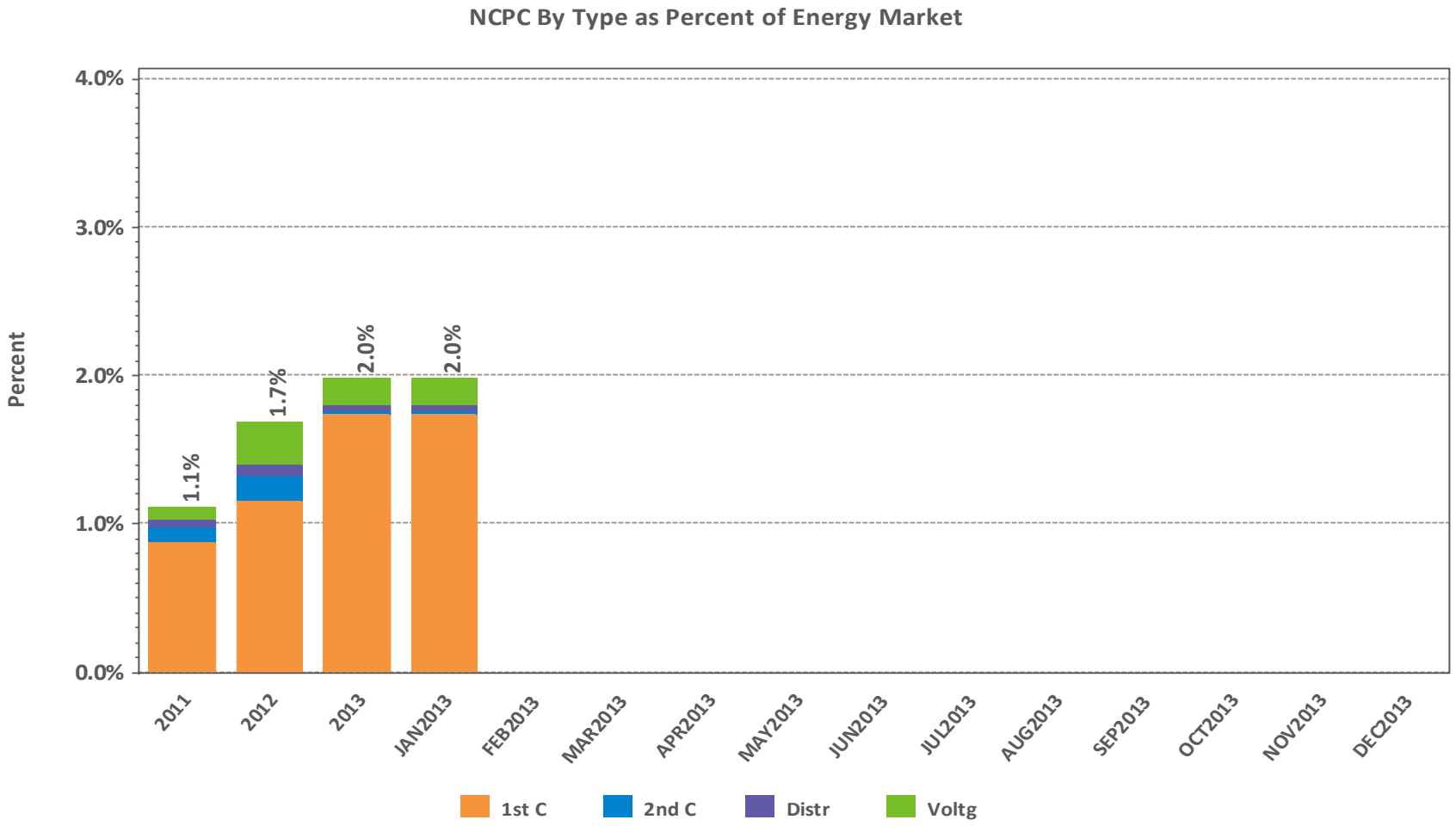


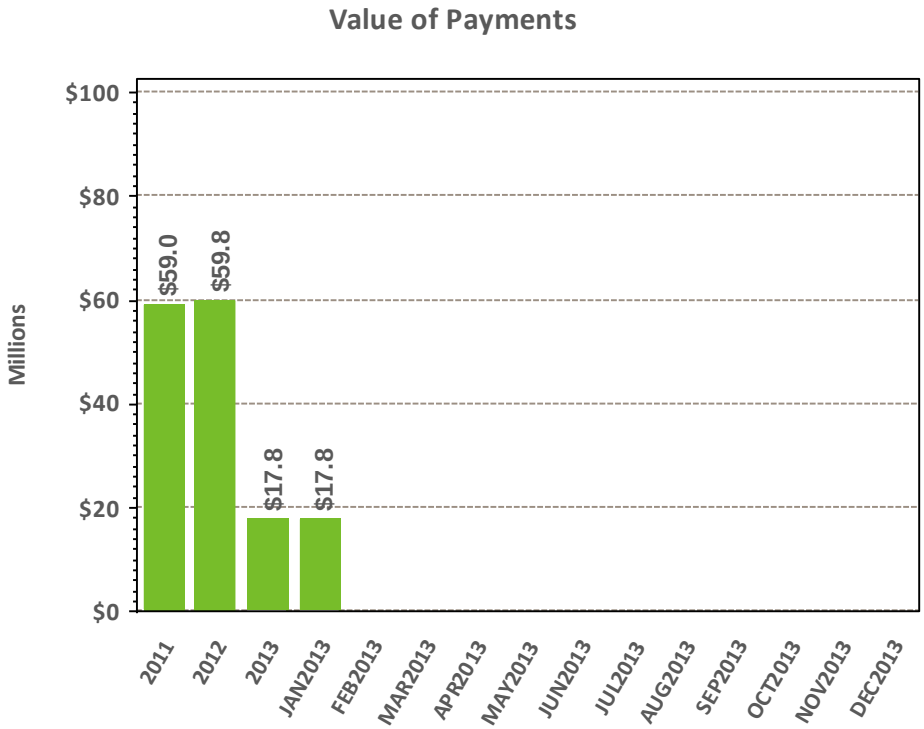
# NCPC Payments by Type

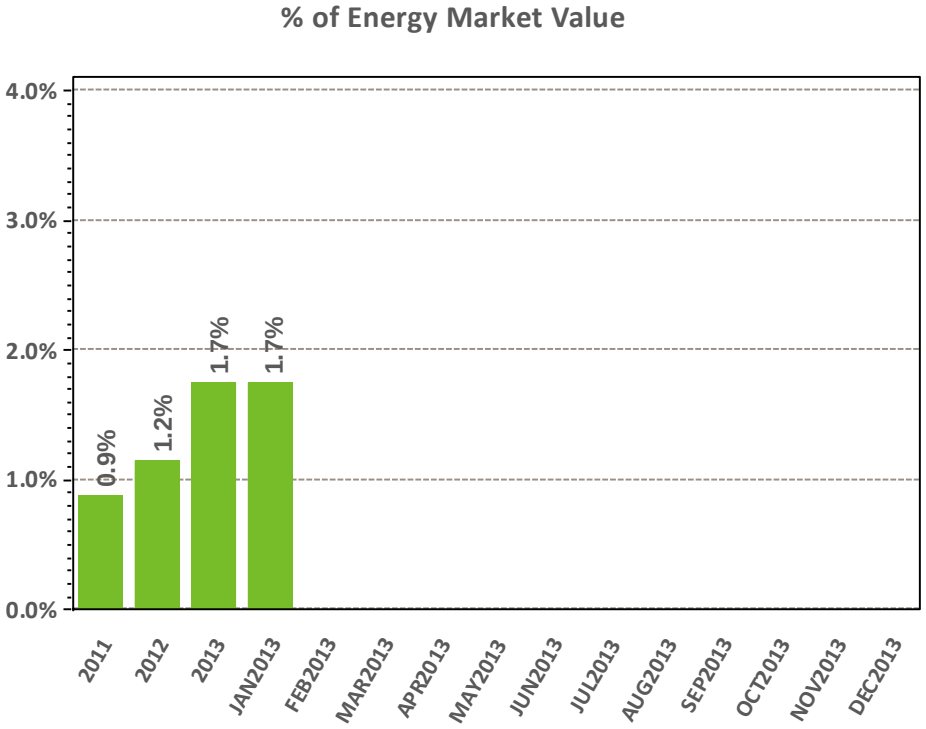


# NCPC Payments by Percent of Energy Market



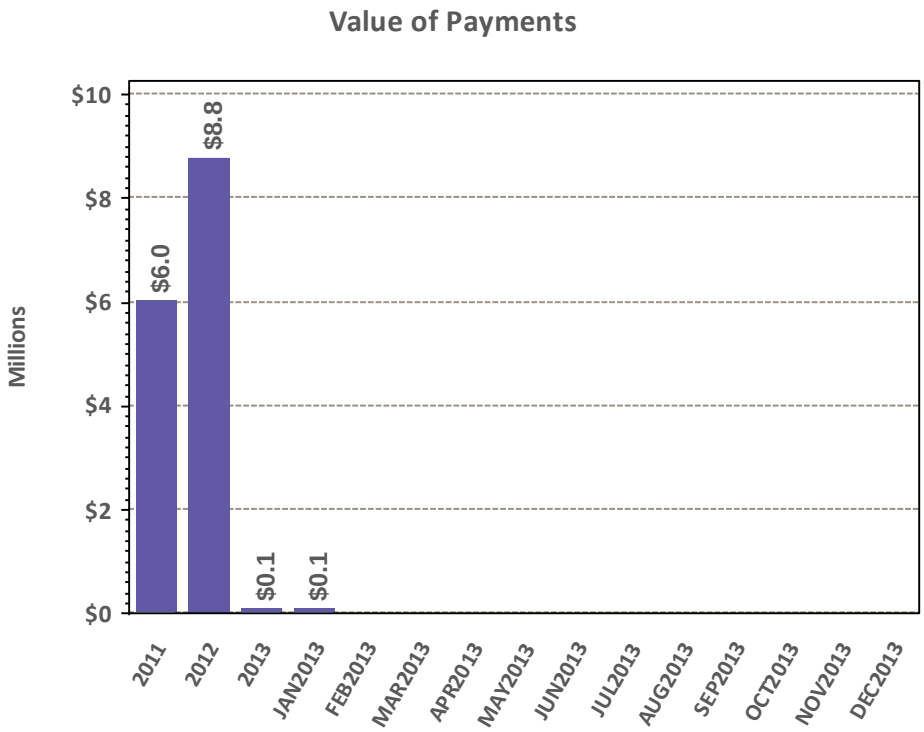
# First Contingency NCPC Payments

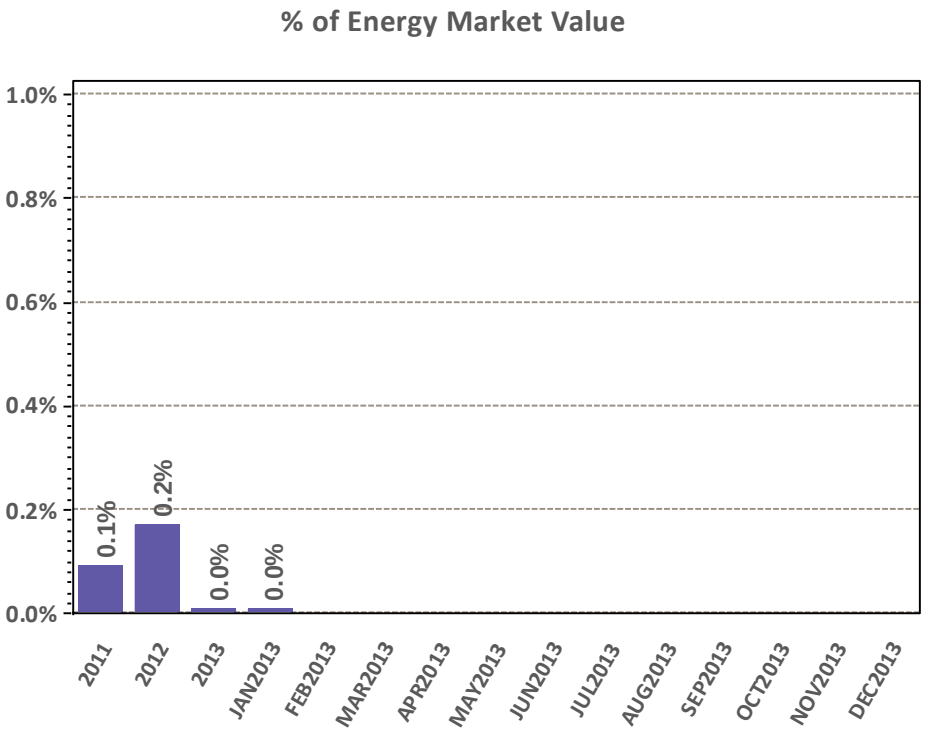



**Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market**

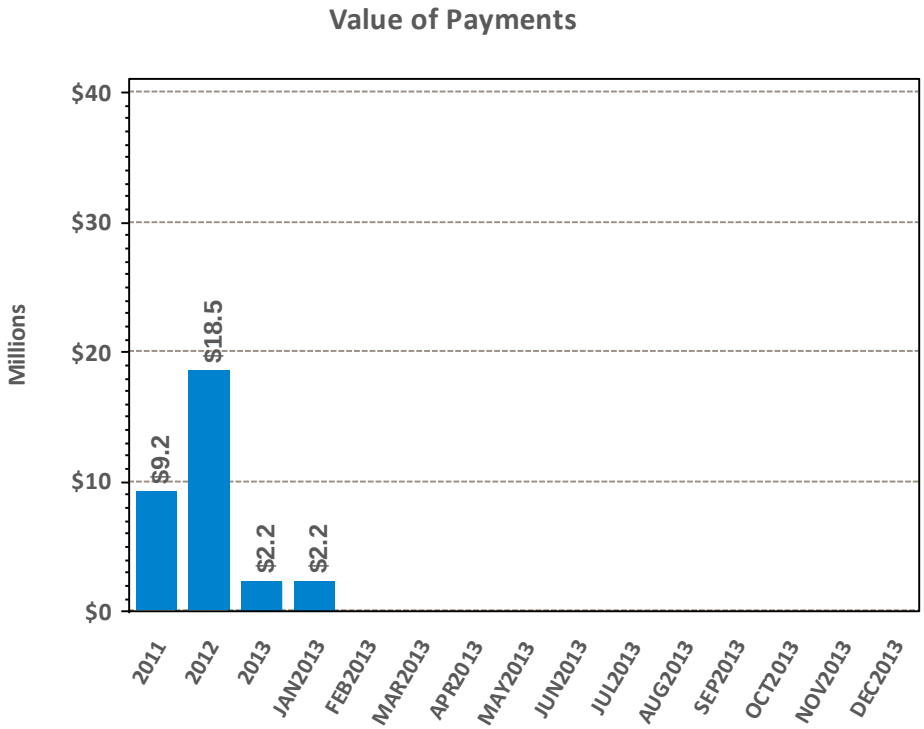
# Second Contingency NCPC Payments

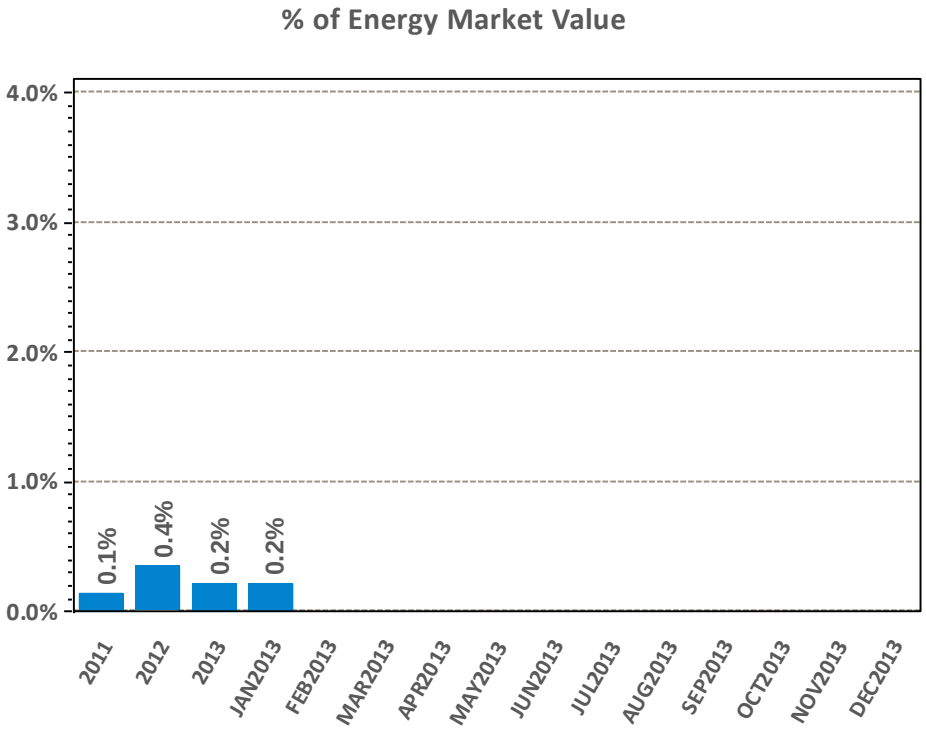



**Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market**

# Voltage and Distribution NCPC Payments




**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

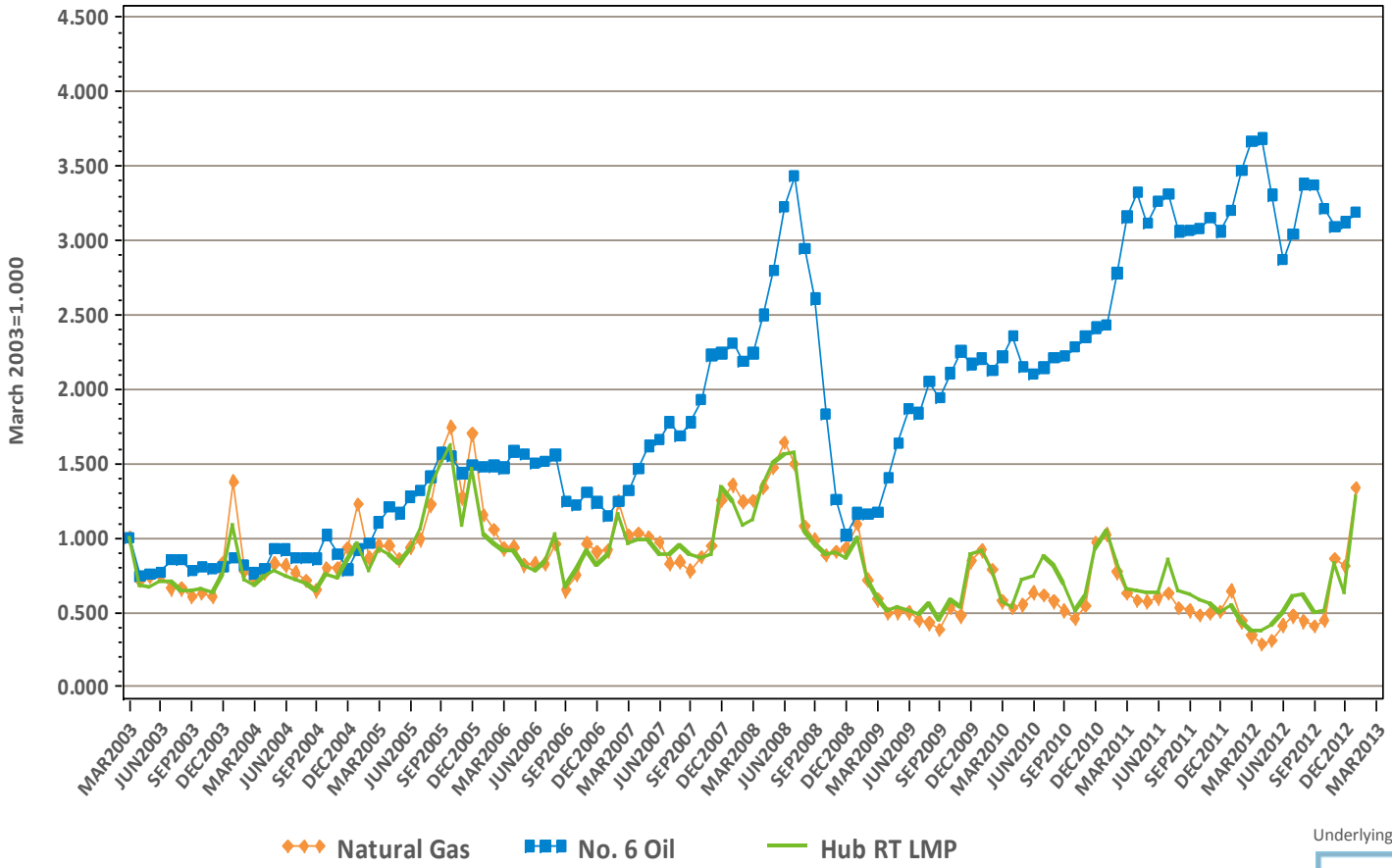
# DA vs. RT LMPs ($/MWh)

Arithmetic Average

| Year 2011 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
|---|---|---|---|---|---|---|---|---|---|
| Day-Ahead | $46.14 | $47.47 | $45.58 | $45.94 | $46.67 | $45.78 | $46.19 | $46.92 | $46.38 |
| Real-Time | $46.57 | $47.95 | $44.95 | $46.07 | $46.57 | $46.14 | $46.58 | $47.23 | $46.68 |
| RT Delta % | 0.9% | 1.0% | -1.4% | 0.3% | -0.2% | 0.8% | 0.9% | 0.7% | 0.6% |
| **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% |

| January-12 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
|---|---|---|---|---|---|---|---|---|---|
| Day-Ahead | $40.37 | $40.88 | $39.76 | $39.98 | $40.31 | $40.42 | $40.58 | $40.96 | $40.59 |
| Real-Time | $36.98 | $37.37 | $35.98 | $36.54 | $36.85 | $36.89 | $37.12 | $37.27 | $37.10 |
| RT Delta % | -8.4% | -8.6% | -9.5% | -8.6% | -8.6% | -8.7% | -8.5% | -9.0% | -8.6% |
| **January-13** | **NEMA** | **CT** | **ME** | **NH** | **VT** | **RI** | **SEMA** | **WCMA** | **Hub** |
| Day-Ahead | $89.46 | $88.49 | $86.33 | $88.30 | $88.11 | $89.38 | $90.13 | $89.55 | $89.36 |
| Real-Time | $87.61 | $86.73 | $82.94 | $85.74 | $85.84 | $87.46 | $88.36 | $87.43 | $87.41 |
| RT Delta % | -2.1% | -2.0% | -3.9% | -2.9% | -2.6% | -2.2% | -2.0% | -2.4% | -2.2% |
| **Annual Diff.** | **NEMA** | **CT** | **ME** | **NH** | **VT** | **RI** | **SEMA** | **WCMA** | **Hub** |
| Yr over Yr DA | 121.6% | 116.5% | 117.1% | 120.9% | 118.6% | 121.1% | 122.1% | 118.6% | 120.1% |
| Yr over Yr RT | 136.9% | 132.1% | 130.5% | 134.6% | 133.0% | 137.1% | 138.0% | 134.6% | 135.6% |

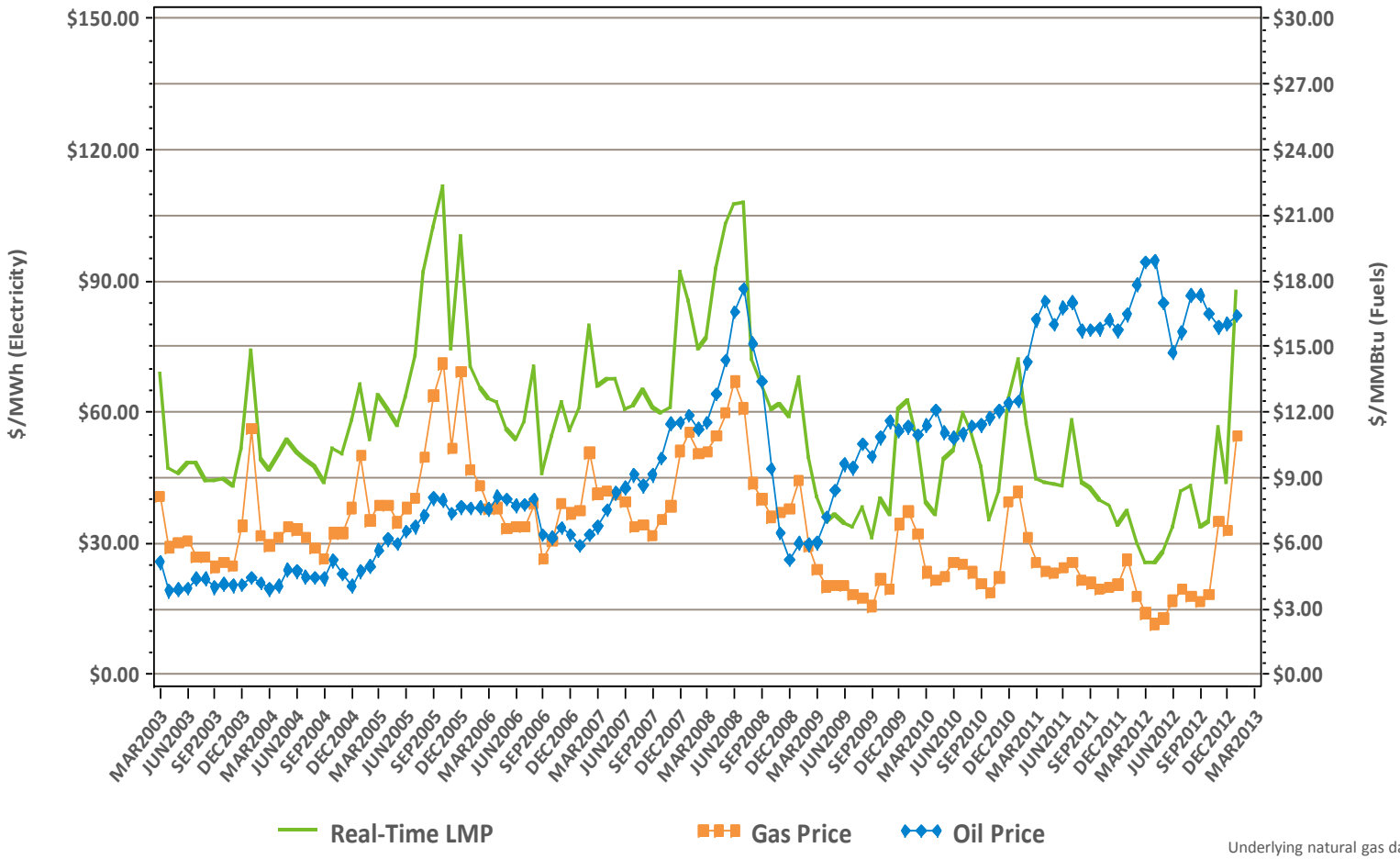
# Monthly Average Fuel Price and RT Hub LMP Indexes




Underlying natural gas data furnished by:

ICE Global markets in clear view

# Monthly Average Fuel Price and RT Hub LMP




Underlying natural gas data furnished by:

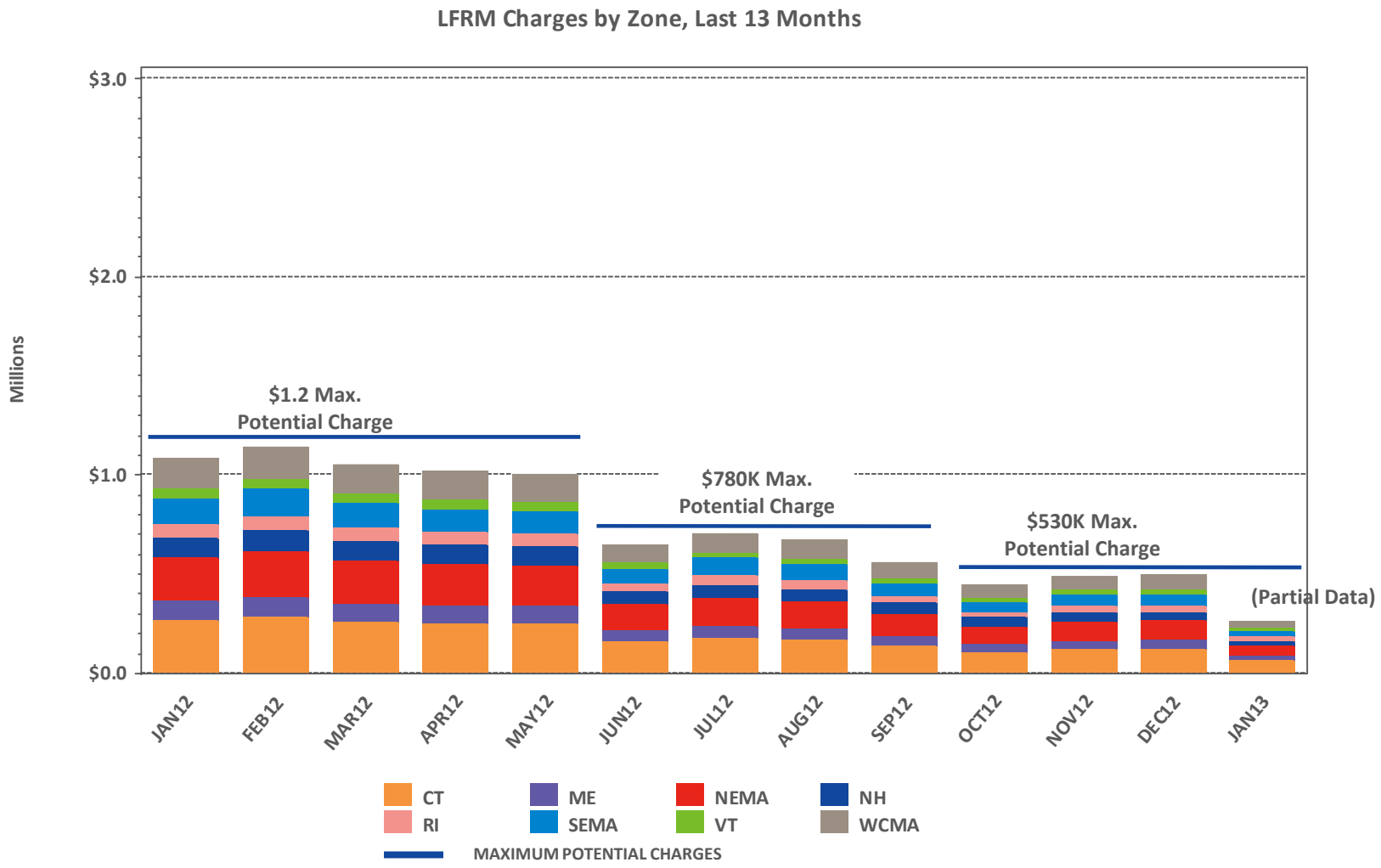
ICE Global markets in clear view

# Reserve Market Results – January 2013

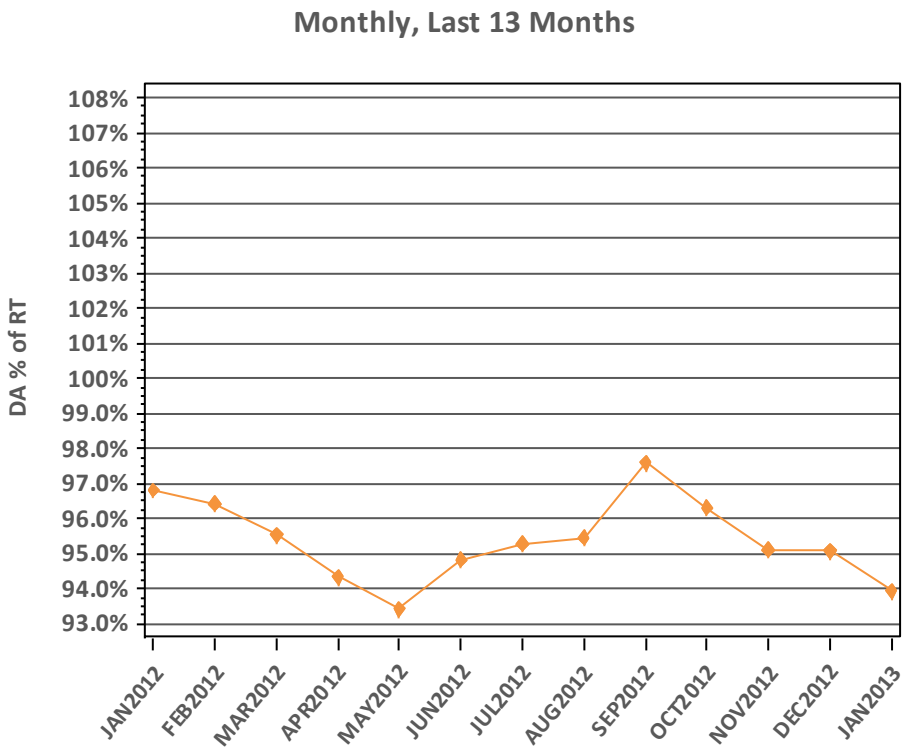
- Maximum potential Forward Reserve Market payments of $455K were reduced by credit reductions of $77K, failure-to-reserve penalties of $116K and failure-to-activate penalties of $0K, resulting in a net payout of $262K or 58% of maximum
  - Rest of System: $157K/$187K (84%)
  - Southwest Connecticut: $39K/$48K (81%)
  - Connecticut: $66K/$219K (30%)
  - NEMA: n/a
- $1.7M total Real-Time credits were reduced by $187K in Forward Reserve Energy Obligation Charges for a net of $1.6M in Real-Time Reserve payments
  - Rest of System: 100 hours, $914K
  - Southwest Connecticut: 100 hours, $398K
  - Connecticut: 100 hours, $167K
  - NEMA: 100 hours, $70K

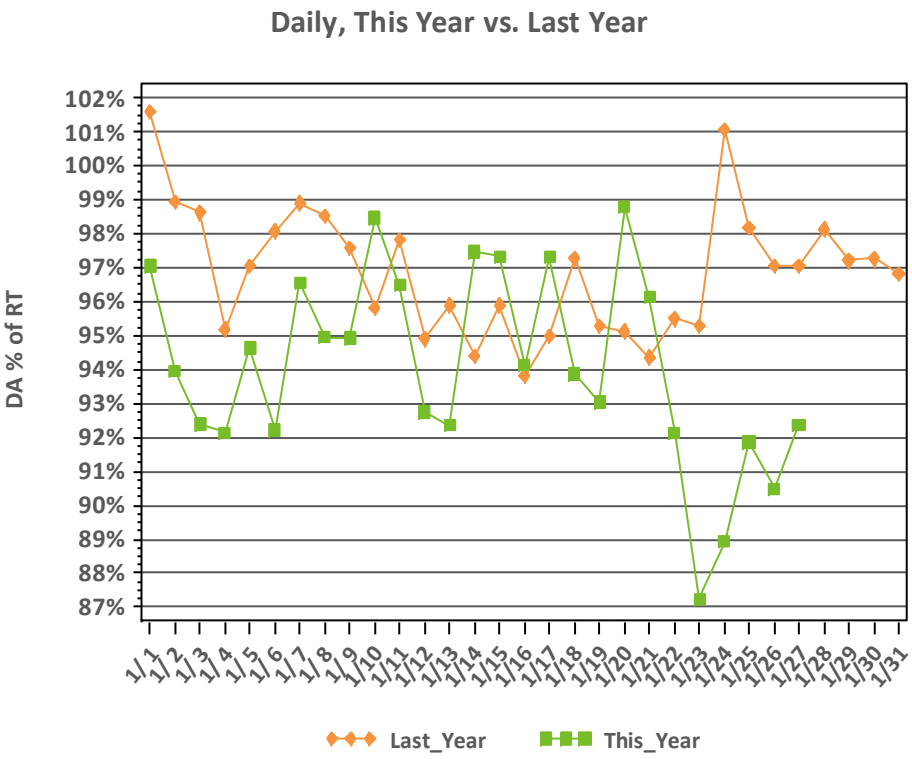
*** "Failure to reserve" results in both reductions in credits and penalties in the Locational Forward Reserve Market.**

# LFRM Charges to Load by Load Zone ($)

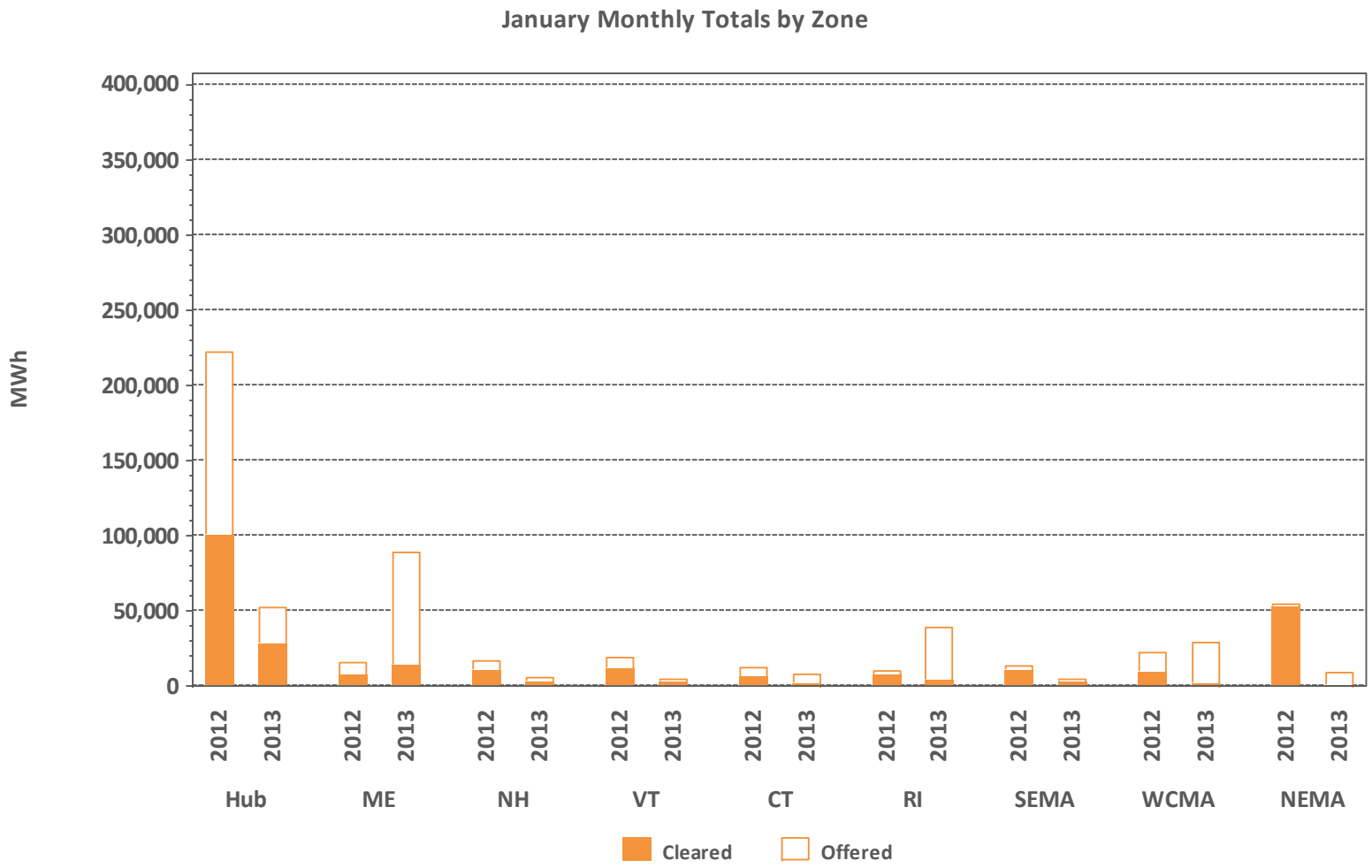


# DA Load Obligation Percent of RT Load Obligation

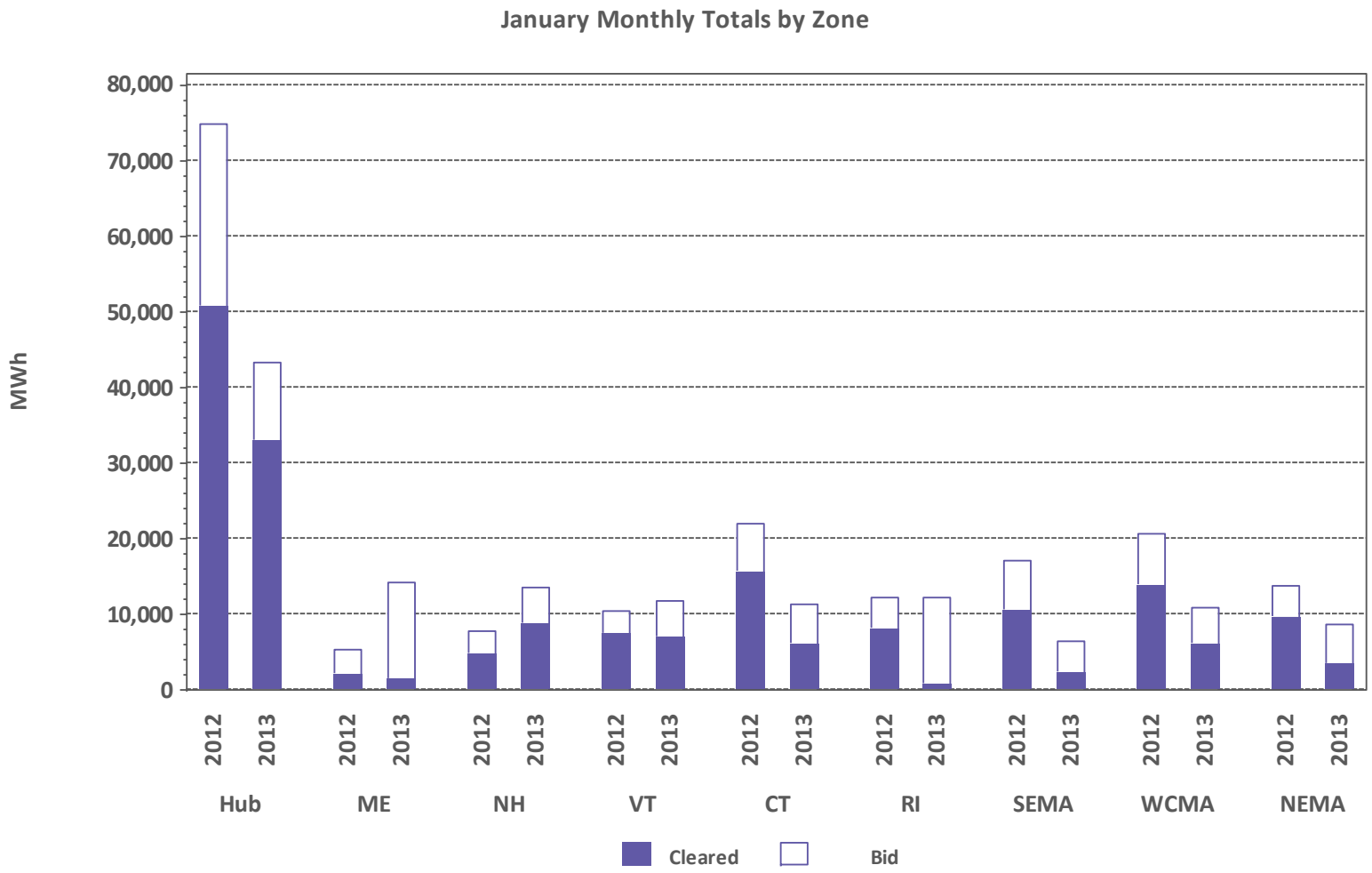


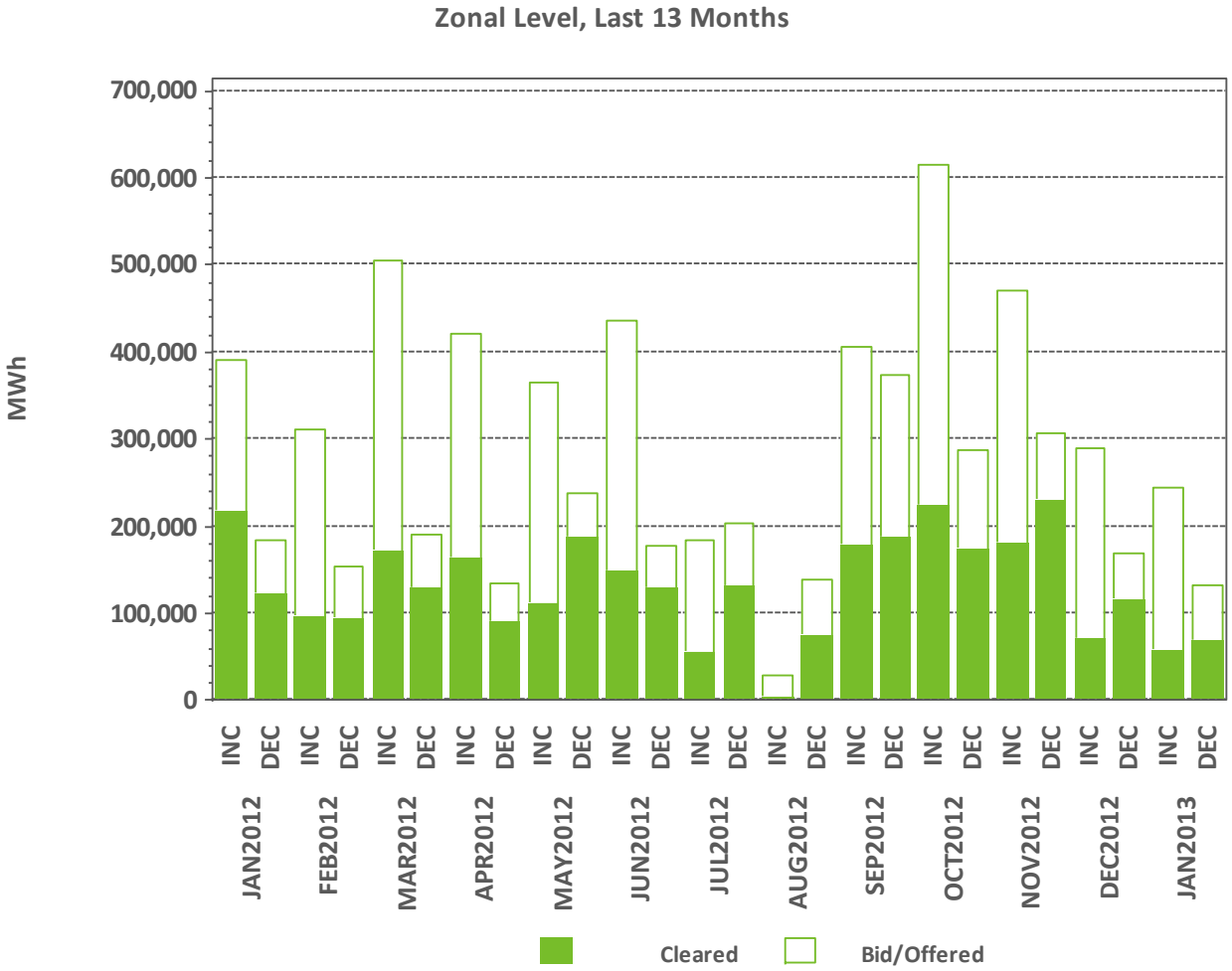
# Zonal Increment Offers and Cleared Amounts



# Zonal Decrement Bids and Cleared Amounts

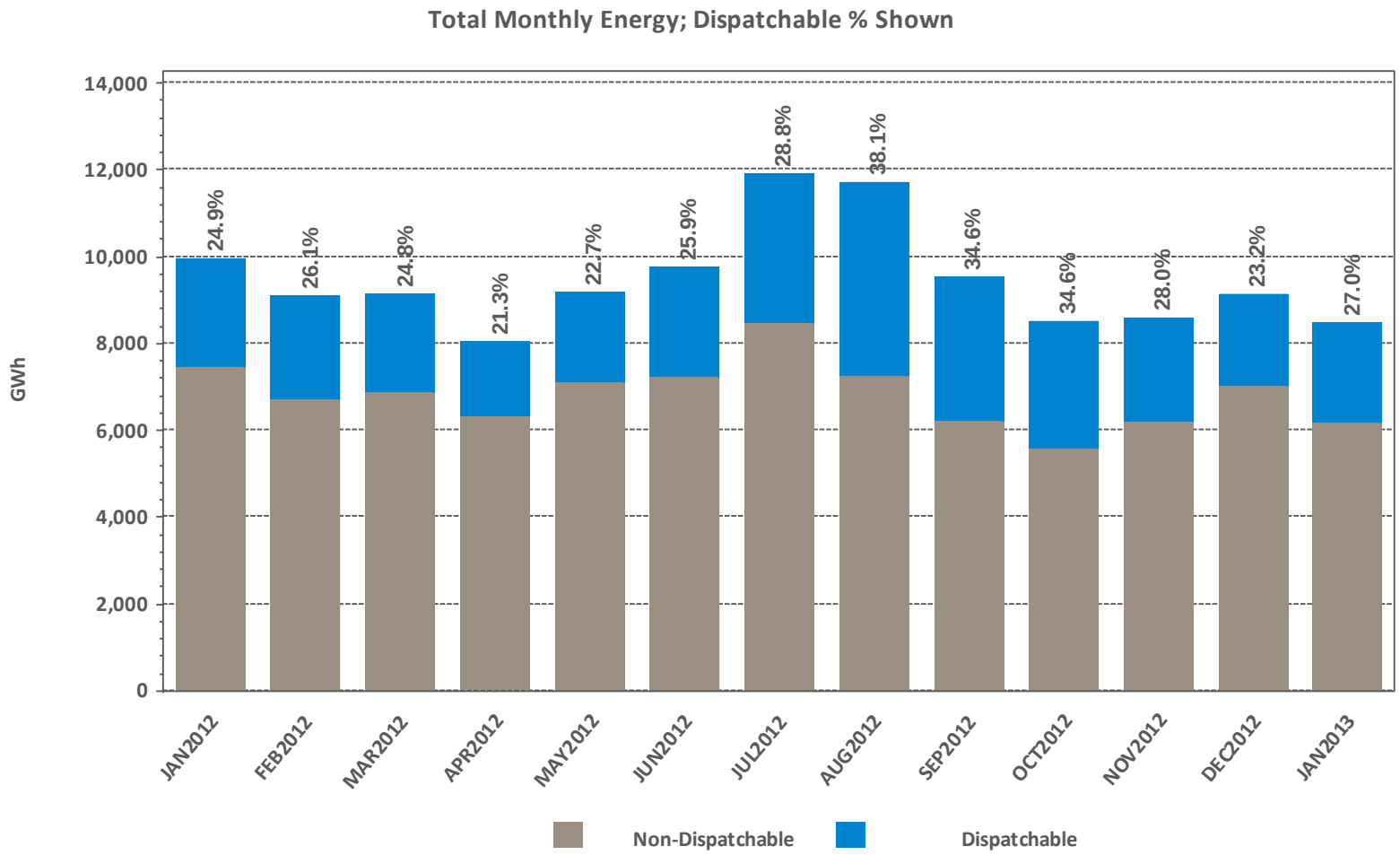


# Total Increment Offers and Decrement Bids

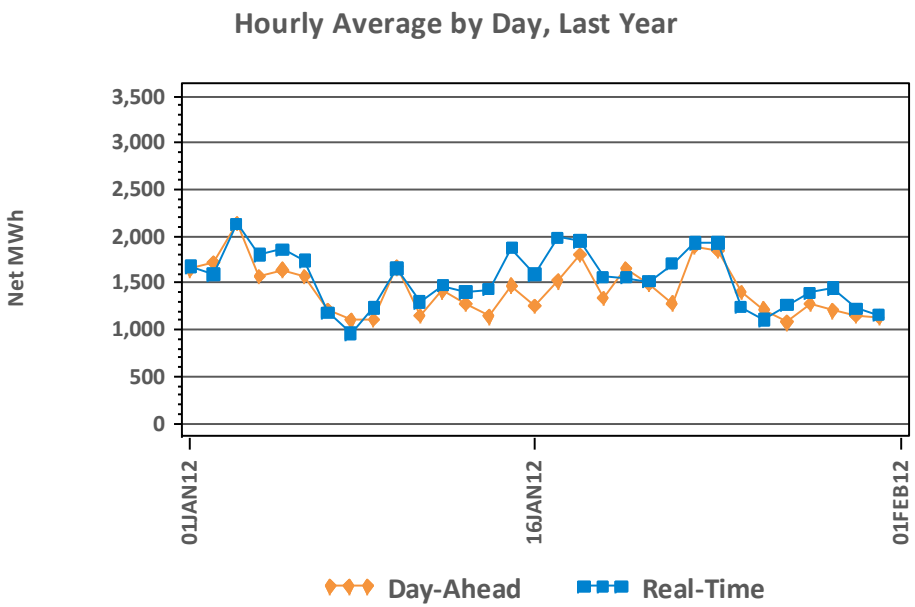


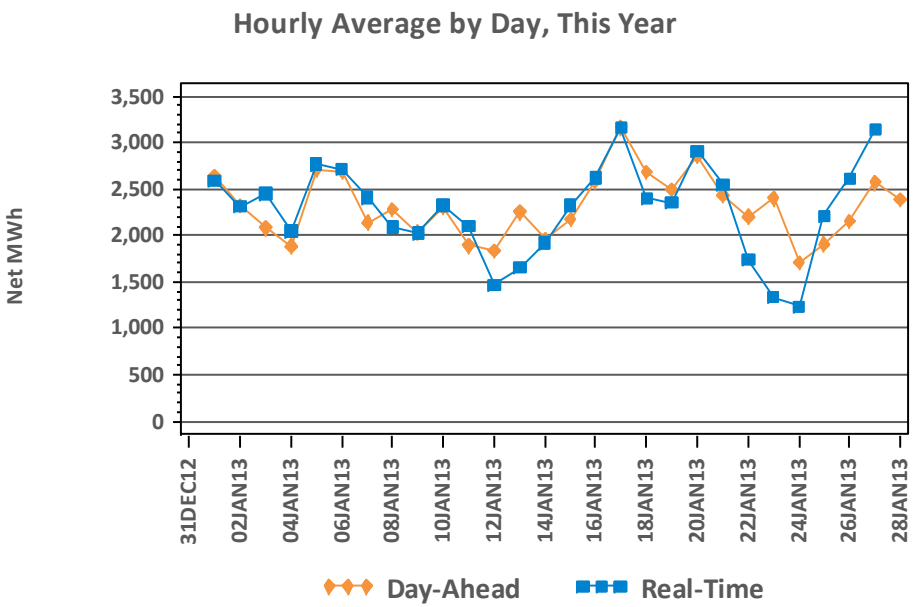

Data excludes nodal offers and bids

# Dispatchable vs. Non-Dispatchable Generation



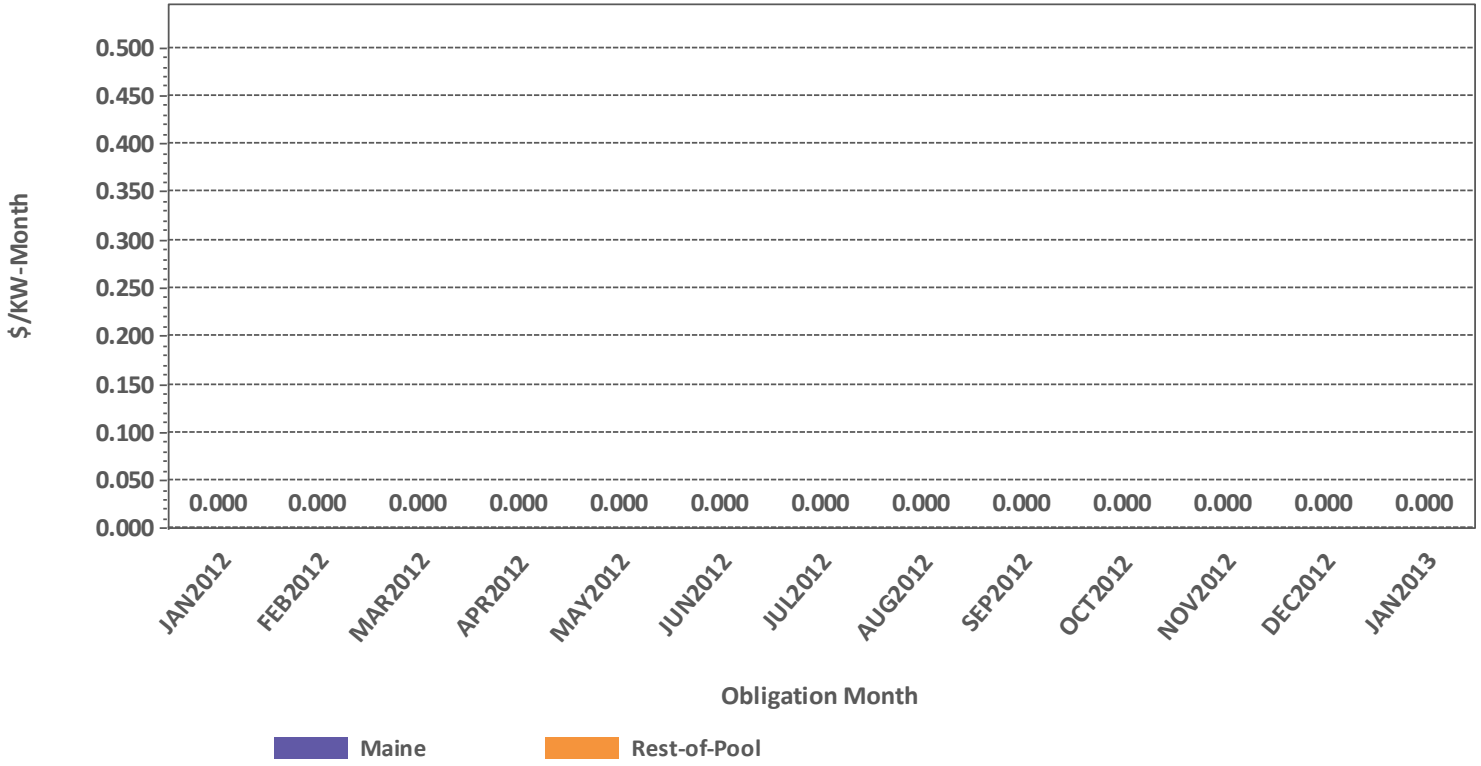
# DA vs. RT Net Interchange
# January 2013 vs. January 2012




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

# 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.

# REGIONAL SYSTEM PLAN (RSP) AND INTERREGIONAL PLANNING

# Planning Advisory Committee (PAC)

- February 12 meeting to include:
  - RSP13 Scope of Work
  - Review of the Process for Submitting Economic Studies
  - New England Load Forecast Update
  - Review of the Scope of Work for the Maine Area Assessment
  - Update on the Greater Boston Study
  - First look at the portion of the draft Planning Manual that discusses the planning process

# Strategic Planning – Studies

- ISO is also supporting the development of a multi-regional gas study, with participants from NYISO, PJM, IESO (Ontario), TVA and MISO. The scope of work is still being finalized. Discussions between this group and the U.S. DOE - EIPC are ongoing for assistance in funding of the study. The release of an RFP is targeted for early February
- Watch PAC notices for strategic planning study updates that will be discussed with stakeholders
  - 2012/2013 Natural Gas Study (1st quarter 2013)
  - Economic Study Updates (January 17 update provided to PAC)
  - Strategic Transmission Analysis - Wind Integration (March PAC)
  - Strategic Transmission Analysis - Unit Retirement (April PAC)
  - Market Resource Alternative Analysis (December 13 update provided to PAC)

# Inter-Area Planning Stakeholder Advisory Committee (IPSAC) – January 28

| | |
|---|---|
| 9:00 | Agenda and Administrative Items |
| 9:15 | Order 1000 Compliance Update and the Northeastern ISO/RTO Planning Coordination Protocol |
| 10:15 | Back-to-Back HVDC Converters at Hudson |
| 11:15 | Interregional Production Cost Study Update |
| 11:30 | Multi-regional Gas/Electric Study Update |
| 11:50 | Next Steps |
| 12:15 | Adjourn |

- For details and to register for the meeting, please use the PJM link below. Upon registering, you will receive confirmation containing dial-in and passcode information
  - http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/ipsac-ny-ne.aspx

# Inter-Area Planning

- PJM is considering conversion of the 345 kV Hudson - Farragut ties to HVDC with the goal of reducing short-circuit availability in the PSE&G service area
  - ISO worked with NYISO and PJM to coordinate the scope of work, system modeling, and draft study results
  - To date, studies show the conversion does not have an adverse impact on New England loss-of-source contingencies
  - ISO stakeholders are encouraged to participate in the PJM Transmission Expansion Advisory Committee (TEAC) and Inter-Area Stakeholder Advisory Committee open stakeholder meetings
  - The studies will be discussed at the January 28 IPSAC meeting

# Environmental Issues

- Stakeholders are encouraged to participate in the EAG meeting scheduled for February 8
  - Agenda to include discussions of environmental regulations affecting the region and the 2011 Annual Emissions Report
  - Registration link will be posted to the ISO calendar

# 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 |

# North Shore Upgrades – Merrimack Valley

*Status as of 1/25/13*

*Project Benefit: Maintains system reliability for the North Shore area*

| Upgrade | Expected In-service | Present Stage |
|---|---|---|
| **Wakefield Junction/Merrimack Valley** | | |
| 115 kV Overhead Reconductor (G133E) | Feb-08 | 4 |
| Reconductor Wakefield Junction - Golden Hills Tap 115 kV | Sep-08 | 4 |
| 30 MVAR 115 kV Capacitor at Revere | Oct-08 | 4 |
| Wakefield Junction Substation | Nov-09 | 4 |
| Loop 345 kV and 115 kV Lines into Wakefield Substation | Nov-09 | 4 |
| Retirement of Golden Hills Substation | Apr-10 | 4 |
| Add Parallel 115 kV Cable in Mystic-Everett Line | Dec-12 | 4 |
| Add King Street - W. Amesbury 115 kV Line | Apr-11 | 4 |
| Reconductor Overhead Portion of Mystic-Everett 115 kV Line | Dec-12 | 3 |

- Received Reliability Committee (RC) recommendation for I.3.9 approval on 3/27/08.
- Final costs presented at 11/19/08 PAC meeting and at 12/18/08 RC meeting (for future vote).
- Transmission Cost Allocation (TCA) application presented at special stakeholder meeting on 1/29/09.
- TCA recommended for approval by RC at March 2009 meeting.

# North Shore Upgrades – Salem Harbor Non-Price Retirement

*Status as of 1/25/13*

*Project Benefits: Allows for the Non-Price Retirement of the Salem Harbor Plant*

| Upgrade | Expected In-service | Present Stage |
|---|---|---|
| Reconductor Y-151 Tewksbury Jct. - West Methuen 115 kV | Dec-13 | 2 |
| Reconductor B-154N King St. - South Danvers 115 kV | Jan-13 | 3 |
| Reconductor C-155N King St. - South Danvers 115 kV | Jan-13 | 3 |
| Reconductor S-145 Tewksbury - North Reading 115 kV | Mar-14 | 2 |
| Reconductor T-146 Tewksbury - North Reading 115 kV | Mar-14 | 2 |

- ISO I.3.9 approval 7/28/11

# Lower Southeastern Massachusetts (SEMA) Proposed Long-term Upgrades

*Status as of 1/25/13*

*Project Benefit: Improves system reliability for the Lower SEMA area*

| Upgrade | Expected In-service | Present Stage |
|---|---|---|
| Expand the Carver Substation | Jun-13 | 3 |
| 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 | 3 |
| Construct New 115 kV Substation with 345-115 kV Autotransformer and Loop Line 115 into the new substation | Jun-13 | 3 |
| Upgrade the 115 kV Bell Rock to High Hill D21 Line | Sep-13 | 3 |
| Separate the 345 kV (342 / 322) Double Circuit Tower Lines | Jun-13 | 3 |

- ISO I.3.9 approval 7/2011.
- Full status update (needs, preferred solution, needs reassessment) given at 4/27/10 PAC.
- Final needs and solutions reports are posted.
- TCA application approval on 12/16/11.
- Project approved by MA EFSB on 4/27/12.

# Maine Power Reliability Program (MPRP)

*Status as of 1/25/13*

*Project Benefit: Addresses long-term system needs of Bangor Hydro Electric 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 | April-13 | 3 |
| Construct New Section 3024 Albion Road to Coopers Mills | Mar-14 | 2 |
| Construct New Section 3025 Coopers Mills to Larrabee Road | Jul-14 | 3 |
| Construct New Section 3026 Larrabee Road to Surowiec | Dec-12 | 4 |
| Construct New Section 3020 Surowiec to Raven Farm | May-13 | 3 |
| Construct New Section 3021 South Gorham to Maguire Road | Nov-13 | 2 |
| Construct New Section 3022 Maguire Road to Eliot | Dec-13 | 2 |

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

# Maine Power Reliability Program, *cont.*

*Status as of 1/25/13*

*Project Benefit: Addresses long-term system needs of Bangor Hydro Electric 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 | May-14 | 3 |
| Construct New Section 243A Livermore Falls to Junction Section 243 | Dec-13 | 3 |
| Construct New Section 251 Livermore Falls to Larrabee Road | Nov-13 | 3 |
| Construct New Section 255 Larrabee Road to Middle Street | April-13 | 2 |
| Construct New Section 86A Tap to Belfast | Jun-14 | 2 |
| Construct New Section 256 Middle Street to Lewiston Lower | May-14 | 1 |

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

# Maine Power Reliability Program, *cont.*

*Status as of 1/25/13*

*Project Benefit: Addresses long-term system needs of Bangor Hydro Electric 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 66 Detroit to Wyman Hydro | May-11 | 4 |
| Rebuild Section 67 Detroit to Albion Road | May-13 | 3 |
| Rebuild Section 203 Detroit to Bucksport | Apr-12 | 4 |
| Rebuild Section 257 (formerly 67) Coopers Mills to Albion Road | May-13 | 2 |
| Rebuild Section 258 (formerly 84) Coopers Mills to Albion Road | Feb-14 | 2 |
| Rebuild Section 166 Surowiec to Spring Street | Nov-11 | 4 |
| Rebuild Section 167 Surowiec to Moshers | Nov-11 | 4 |

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

# Maine Power Reliability Program, *cont.*

*Status as of 1/25/13*

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

| 115 kV Lines Rebuilds (continued) | Expected In-Service | Present Stage |
|---|---|---|
| Rebuild Section 60 Coopers Mills to Bowman Street | May-14 | 3 |
| Rebuild Section 88 Coopers Mills to Augusta East Side | Jun-14 | 3 |
| Rebuild Section 89 Livermore Falls to Riley | Dec-13 | 2 |
| Rebuild Section 229 Riley to Rumford IP | May-13 | 3 |
| Rebuild Section 212 Monmouth to Larrabee Road | Feb-13 | 3 |
| Rebuild Section 269 Bowman Street to Monmouth | May-12 | 4 |
| Rebuild Section 238 Louden to Maguire Road | Feb-12 | 4 |
| Rebuild Section 250 Maguire Road to Three Rivers | May-13 | 2 |

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

# Maine Power Reliability Program, *cont.*

*Status as of 1/25/13*

*Project Benefit: Addresses long-term system needs of Bangor Hydro Electric 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 | 3 |
| Install One 345/115 kV Autotransformer at Coopers Mills | Mar-14 | 2 |
| Install One 345/115 kV Autotransformer at Larrabee Road | Dec-12 | 4 |
| Install One 345/115 kV Autotransformer at Maguire Road | Nov-13 | 2 |
| Install One 345/115 kV Autotransformer at South Gorham | Nov-09 | 4 |

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

# NEEWS: Greater Springfield Reliability Project

*Status as of 1/25/13*

*Plan Benefit: Improves reliability by eliminating greater Springfield and north-central Connecticut area criteria violations*

| Upgrade | Expected In-service | Present Stage |
|---|---|---|
| Construct New 345 kV Ludlow - Agawam Line | Dec-13 | 4 |
| Construct New 345 kV Agawam - North Bloomfield Line | Dec-13 | 3 |
| Expand Existing 115 kV Agawam Station & Construct New 345 kV Yard | Dec-13 | 4 |
| Expand 345 kV North Bloomfield Station | Dec-13 | 3 |
| Expand & Reconfigure 345 kV Ludlow Station | Dec-13 | 4 |
| Rebuild 115 kV Agawam - Piper Line | Dec-13 | 4 |
| Rebuild 115 kV Agawam - Chicopee Line | Dec-13 | 4 |
| Construct New 115 kV Cadwell Switching Station | Dec-13 | 4 |
| Reconductor 115 kV Ludlow - Orchard Line | Dec-13 | 4 |
| Rebuild 115 kV Orchard - Cadwell Line | Dec-13 | 4 |
| Rebuild 115 kV Ludlow - Cadwell Line | Dec-13 | 4 |

# NEEWS: Greater Springfield Reliability Project, *cont.*

*Status as of 1/25/13*

*Plan Benefit: Improves reliability by eliminating greater Springfield and north-central Connecticut area criteria violations*

| Upgrade | Expected In-service | Present Stage |
|---|---|---|
| Build New 115 kV Fairmont Switching Station | Dec-13 | 3 |
| Rebuild 115 kV Fairmont - Piper Line | Dec-13 | 4 |
| Rebuild 115 kV Fairmont - Chicopee Line | Dec-13 | 3 |
| Rebuild 115 kV Fairmont - Cadwell Line | Dec-13 | 3 |
| Rebuild 115 kV Fairmont - Shawinigan Line | Dec-13 | 3 |
| Rebuild 115 kV Ludlow - Shawinigan Line | Dec-13 | 4 |
| Reconfigure 115 kV South Agawam Switching Station | Dec-13 | 3 |
| Reconfigure 115 kV Southwick - South Agawam Line | Dec-13 | 3 |
| Rebuild Two 115 kV South Agawam - Agawam Lines | Dec-13 | 4 |
| Terminate Two 115 kV East Springfield - Cadwell Lines | Dec-13 | 3 |

# NEEWS: Manchester – Meekville Project

*Status as of 1/25/13*

*Plan Benefit: Improves reliability by eliminating greater Springfield and north-central Connecticut area criteria violations*

| Upgrade | Expected In-service | Present Stage |
|---|---|---|
| Build New 345 kV Manchester to Meekville Junction Line | Dec-12 | 4 |
| Separate 3-Terminal 345 kV 395 Line at Meekville Junction | Dec-12 | 4 |
| Reterminate 345 kV North Bloomfield Line to Manchester Substation | Dec-13 | 4 |

# NEEWS: Rhode Island

*Status as of 1/25/13*

*Plan Benefit: Improves reliability by eliminating Rhode Island criteria violations*

| Upgrade | Expected In-service | Present Stage |
|---|---|---|
| Construct New West Farnum - Kent County 345 kV Line | Apr-13 | 3 |
| Install 3rd Kent County 345-115 kV Autotransformer | Sep-11 | 4 |
| Kent County Substation Upgrades | May-12 | 4 |
| Reconductor Kent County - Drumrock 115 kV Line | Jul-11 | 4 |
| Reconductor Short Segments of West Farnum - Hartford Avenue - Drumrock 115 kV Lines | Jan-13 | 3 |

# NEEWS: Interstate & Central Connecticut

*Status as of 1/25/13*

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

| Upgrade | Expected In-service | Present Stage |
|---|---|---|
| Interstate Reliability Project (Interstate)[1] | Dec-15 | 1 |
| Central Connecticut Reliability Project (CCRP)[2] | Jun-17 | 1 |

[1] ISO findings which show continued need for NEEWS Interstate were presented and discussed at the 8/12/10, 11/16/10 and 11/30/10 PAC meetings. The preferred solution was presented at the 11/30/10 PAC meeting. CL&P filed its siting application in December 2011 and National Grid filed its application in June 2012 for MA and July 2012 for RI. Updated needs assessment report posted 5/2/11. Expanded need for Sherman Road switching station was presented to PAC on 9/21/11. The draft solutions study report was posted to the ISO website on 11/22/11 and the final solutions study report was posted on 2/3/12. PPA approval was received on 5/4/12. ISO updated the needs assessment and solution study with the latest load, resource and transmission information and posted the draft follow-up needs assessment analysis on 7/9/12 and follow-up solution study analysis on 7/23/12. The final reports were posted on 9/21/12.

[2] The needs reassessment analysis for NEEWS CCRP has now been combined with the Greater Hartford, Middletown, Northwest CT and Barbour Hill area studies. Scope presented at the 3/16/11 PAC meeting. Special meeting with NESCOE and NECPUC to discuss the scope was held on 10/13/11. GHCC needs assessment and MRA were presented to PAC on 8/9/12. Updated MRA analyses were presented to PAC in both November and December of 2012.

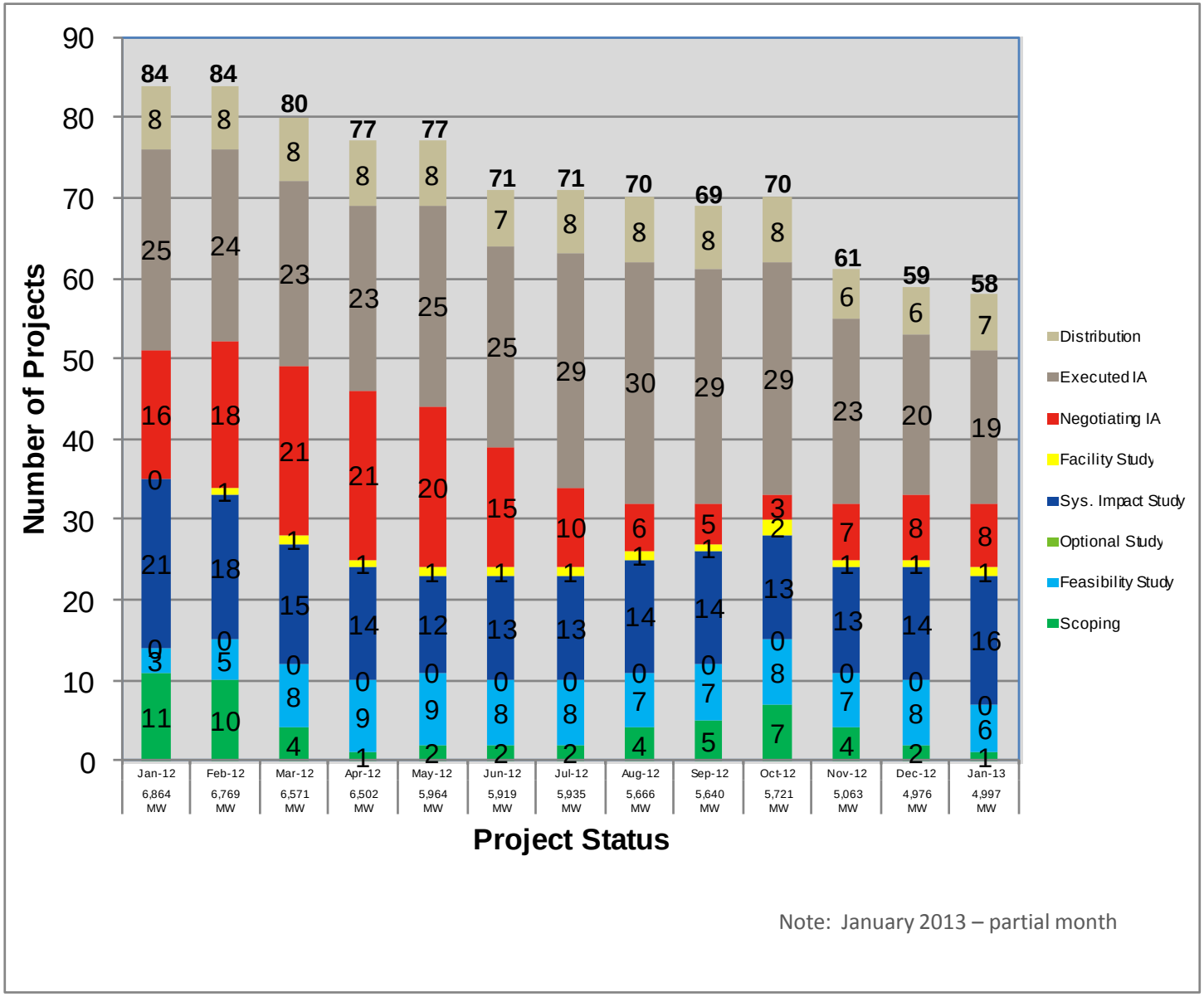
# Transmission Siting Update

- NEEWS
  - Rhode Island Reliability Project
    - Received siting approval from Rhode Island authorities
  - Greater Springfield Reliability Project
    - Received siting approval from both Connecticut and Massachusetts authorities
  - 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
- 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 continue on some portions of the project (Lewiston Loop, Three Rivers, Surowiec-Raven Farm)
  - TCAs are being revised to reflect the new version of the project

# Transmission Siting Update, cont.

- Lower SEMA
  - Energy Facilities Siting Board (EFSB) application filed September 2010
  - Hearings began 5/9/11 and are completed
    - ISO witnesses testified on 6/8/11
  - Initial brief filed 7/29/11
  - Reply brief filed 8/19/11
  - EFSB staff distributed an “Issues Memorandum” on 12/22/11
  - EFSB held a hearing on the “Issues Memorandum” on 1/12/12
  - EFSB issued tentative decision approving the project on 3/30/12
  - EFSB issued its final decision approving the project on 4/27/12

# Status of Tariff Studies




Note: January 2013 – partial month

# OPERABLE CAPACITY ANALYSIS

*Winter/Spring 2013*

# Winter 2013 Operable Capacity Analysis

| 50/50 Load Forecast (Reference) | February-2013 [2] CSO Reduced LNG | February-2013 [2] SCC Reduced LNG |
|---|---|---|
| Generator Operable Capacity MW [1] | 30,754 | 34,274 |
| OP CAP From OP-4 RTDR (+) | 600 | 600 |
| OP CAP From OP-4 RTEG (+) | 400 | 400 |
| Operable Capacity Generator with OP-4 DR and RTEG | 31,754 | 35,274 |
| External Node Available Capacity – CSO Only (+) | 337 | 337 |
| Non Commercial Capacity (+) | 41 | 41 |
| Non Gas-fired Planned Outage MW (-) | 2,228 | 2,228 |
| Allowance for Unplanned Outages (-) | 3,100 | 3,100 |
| Gas Generator Outages MW (-) | 803 | 803 |
| Generation at Risk Due to Gas Supply (-) [4] | 2,092 | 3,747 |
| Net Capacity (NET OPCAP SUPPLY MW) [3] | 23,909 | 25,774 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 20,891 | 20,891 |
| Operating Reserve Requirement MW | 2,375 | 2,375 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 23,266 | 23,266 |
| Operable Capacity Margin [3] | 643 | 2,508 |

[1] Generator Operable Capacity is based on data as of January 24, 2013 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 February 9th 2012

[3] Includes OP4 actions associated with RTEG and RTDR

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

# Winter 2013 Operable Capacity Analysis

| 90/10 Load Forecast (Extreme) | February-2013 [2] CSO Reduced LNG | February-2013 [2] SCC Reduced LNG |
|---|---|---|
| Generator Operable Capacity MW [1] | 30,754 | 34,274 |
| OP CAP From OP-4 RTDR (+) | 600 | 600 |
| OP CAP From OP-4 RTEG (+) | 400 | 400 |
| Operable Capacity Generator with OP-4 DR and RTEG | 31,754 | 35,274 |
| External Node Available Capacity – CSO Only (+) | 337 | 337 |
| Non Commercial Capacity (+) | 41 | 41 |
| Non Gas-fired Planned Outage MW (-) | 2,228 | 2,228 |
| Allowance for Unplanned Outages (-) | 3,100 | 3,100 |
| Gas Generator Outages MW (-) | 803 | 803 |
| Generation at Risk Due to Gas Supply (-) [4] | 3,747 | 3,747 |
| Net Capacity (NET OPCAP SUPPLY MW) [3] | 22,254 | 25,774 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 21,594 | 21,594 |
| Operating Reserve Requirement MW | 2,375 | 2,375 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 23,969 | 23,969 |
| Operable Capacity Margin [3] | (1,715) | 1,805 |

[1] Generator Operable Capacity is based on data as of January 24, 2013 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 February 9th 2013

[3] Includes OP4 actions associated with RTEG and RTDR

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

# Spring 2013 Operable Capacity Analysis

| 50/50 Load Forecast (Extreme) | May-2013 [2] CSO Reduced LNG | May-2013 [2] SCC Reduced LNG |
|---|---|---|
| Generator Operable Capacity MW [1] | 30,125 | 34,274 |
| OP CAP From OP-4 RTDR (+) | 600 | 600 |
| OP CAP From OP-4 RTEG (+) | 400 | 400 |
| Operable Capacity Generator with OP-4 DR and RTEG | 31,125 | 35,274 |
| External Node Available Capacity – CSO Only (+) | 555 | 555 |
| Non Commercial Capacity (+) | 41 | 41 |
| Non Gas-fired Planned Outage MW (-) | 4,803 | 4,803 |
| Allowance for Unplanned Outages (-) | 3,400 | 3,400 |
| Gas Generator Outages MW (-) | 0 | 0 |
| Generation at Risk Due to Gas Supply (-) [4] | 0 | 0 |
| Net Capacity (NET OPCAP SUPPLY MW) [3] | 23,518 | 27,667 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 20,973 | 20,973 |
| Operating Reserve Requirement MW | 2,375 | 2,375 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 23,348 | 23,348 |
| Operable Capacity Margin [3] | 170 | 4,319 |

[1] Generator Operable Capacity is based on data as of January 24, 2013 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 May 11th 2013

[3] Includes OP4 actions associated with RTEG and RTDR

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

# Spring 2013 Operable Capacity Analysis

| 90/10 Load Forecast (Reference) | May-2013 [2] CSO Reduced LNG | May-2013 [2] SCC Reduced LNG |
|---|---|---|
| Generator Operable Capacity MW [1] | 30,125 | 34,274 |
| OP CAP From OP-4 RTDR (+) | 600 | 600 |
| OP CAP From OP-4 RTEG (+) | 400 | 400 |
| Operable Capacity Generator with OP-4 DR and RTEG | 31,125 | 35,274 |
| External Node Available Capacity – CSO Only (+) | 555 | 555 |
| Non Commercial Capacity (+) | 41 | 41 |
| Non Gas-fired Planned Outage MW (-) | 4,803 | 4,803 |
| Allowance for Unplanned Outages (-) | 3,400 | 3,400 |
| Gas Generator Outages MW (-) | 0 | 0 |
| Generation at Risk Due to Gas Supply (-) [4] | 0 | 0 |
| Net Capacity (NET OPCAP SUPPLY MW) [3] | 23,518 | 27,667 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 22,724 | 22,724 |
| Operating Reserve Requirement MW | 2,375 | 2,375 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 25,099 | 25,099 |
| Operable Capacity Margin [3] | (1581) | 2,568 |

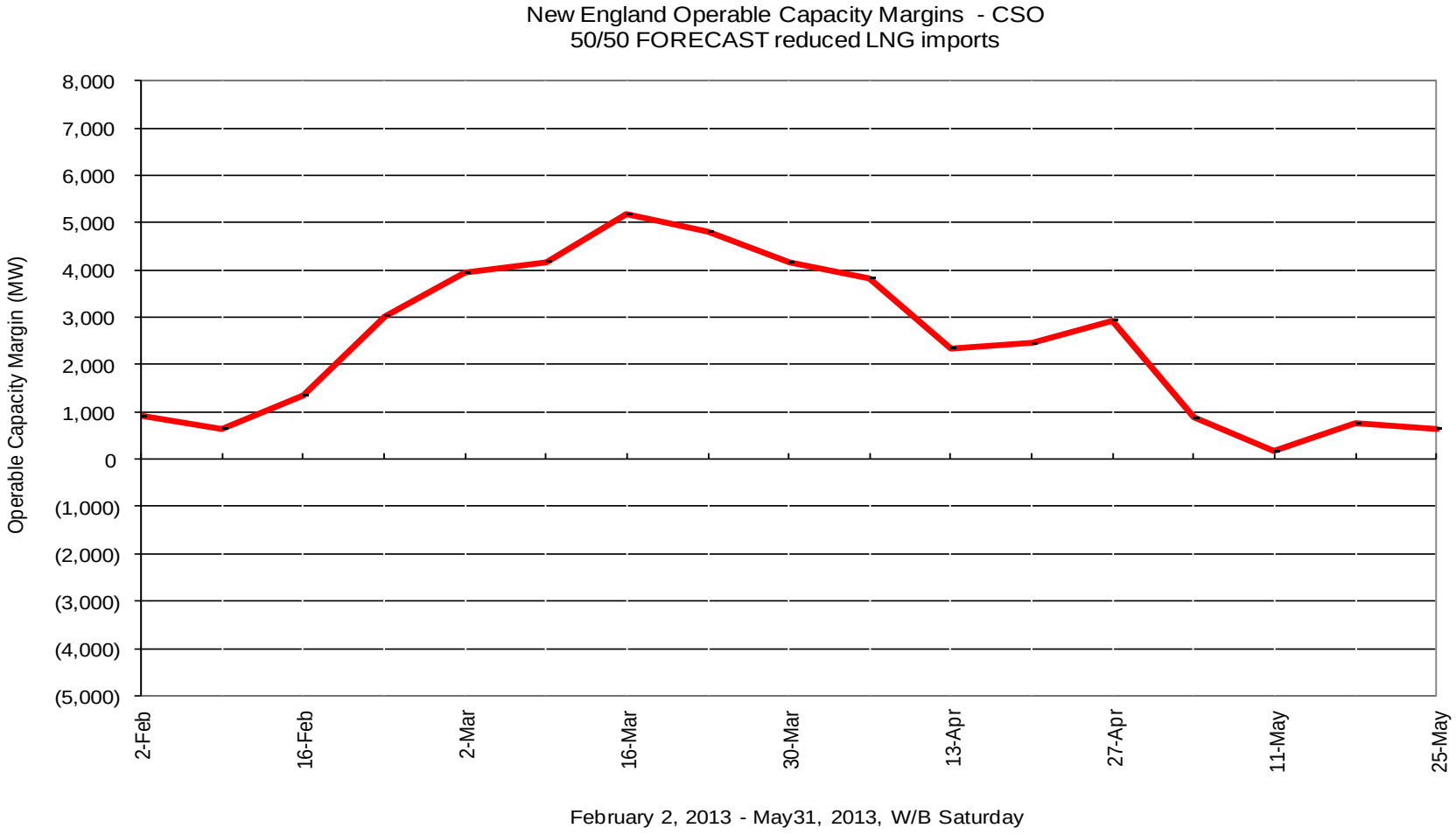
[1] Generator Operable Capacity is based on data as of January 24, 2013 and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, week beginning May 11th 2013

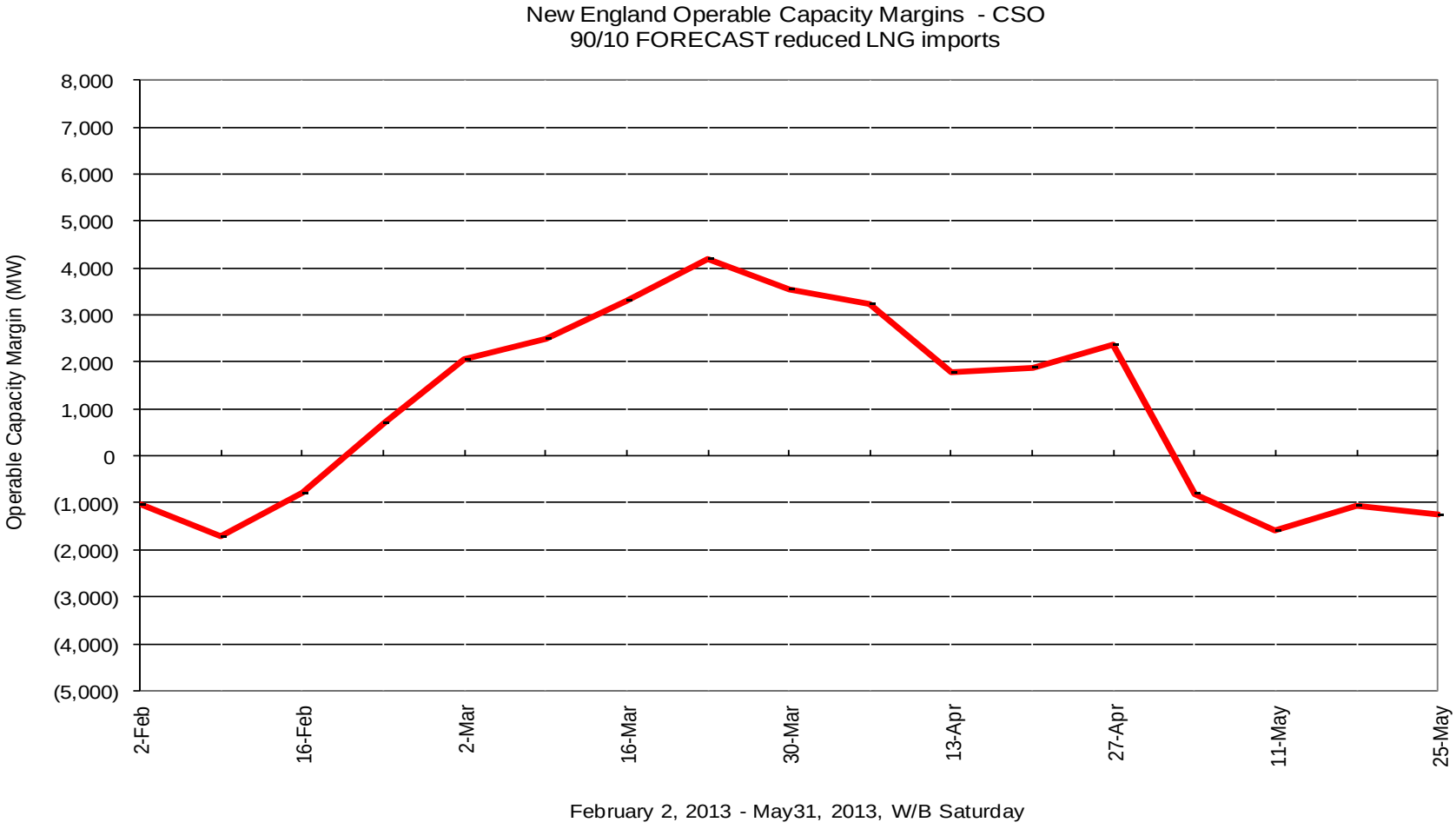
[3] Includes OP4 actions associated with RTEG and RTDR

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

# Winter/Spring 2013 Operable Capacity Analysis(MW) 50/50 Forecast (Reference) –CSO Reduced LNG imports



# Winter/Spring 2013 Operable Capacity Analysis(MW) 90/10 Forecast (Extreme) – Reduced LNG imports



# Winter/Spring 2013 Operable Capacity Analysis(MW) 50/50 Forecast (Reference) – Reduced LNG imports

## ISO-NE 2013 OPERABLE CAPACITY ANALYSIS

### January 28 2013 - 50/50- FORECAST - CSO_Reduced LNG Available

nalysis is a tabulation of w eekly assessments show n in one single table. The information show s the operable capacity situation under assumed conditions for each w eek. It is not expected that the system peak w ill occur every w eek during June, July, and August and Mid Septe

| | OPCAP SUPPLY | | | | | | | | LOAD OBLIGATIONS | | | OPCAP MARGINS | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STUDY WEEK (Week Beginning, Saturday) | AVAILABLE OPCAP MW | EXTERNAL NODE AVAIL CAPACITY MW | NON COMMERCIAL CAPACITY MW | NON-GAS PLANNED OUTAGES CSO MW | ALLOWANCE FOR UNPLANNED OUTAGES MW | GAS GENERATOR OUTAGES CSO MW | GAS AT RISK MW | NET OPCAP SUPPLY MW | PEAK LOAD FORECAST MW | OPER RESERVE REQUIREMEN T 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] |
| 2/2/2013 | 30,754 | 337 | 41 | 1,517 | 3,100 | 551 | 2,757 | 23,207 | 20,920 | 2,375 | 23,295 | (88) | 600 | 512 | 400 | 912 |
| **2/9/2013** | **30,754** | **337** | **41** | **2,228** | **3,100** | **803** | **2,092** | **22,909** | **20,891** | **2,375** | **23,266** | **(357)** | **600** | **243** | **400** | **643** |
| 2/16/2013 | 30,754 | 337 | 41 | 2,204 | 3,100 | 551 | 1,930 | 23,347 | 20,627 | 2,375 | 23,002 | 345 | 600 | 945 | 400 | 1,345 |
| 2/23/2013 | 30,754 | 337 | 41 | 2,134 | 3,100 | 394 | 1,467 | 24,037 | 19,633 | 2,375 | 22,008 | 2,029 | 600 | 2,629 | 400 | 3,029 |
| 3/2/2013 | 30,396 | 485 | 41 | 2,676 | 2,200 | 461 | 986 | 24,599 | 19,282 | 2,375 | 21,657 | 2,942 | 600 | 3,542 | 400 | 3,942 |
| 3/9/2013 | 30,396 | 485 | 41 | 3,053 | 2,200 | 284 | 750 | 24,635 | 19,085 | 2,375 | 21,460 | 3,175 | 600 | 3,775 | 400 | 4,175 |
| 3/16/2013 | 30,396 | 485 | 41 | 2,828 | 2,200 | 284 | 336 | 25,274 | 18,718 | 2,375 | 21,093 | 4,181 | 600 | 4,781 | 400 | 5,181 |
| 3/23/2013 | 30,396 | 485 | 41 | 2,830 | 2,200 | 1,554 | 0 | 24,338 | 18,150 | 2,375 | 20,525 | 3,813 | 600 | 4,413 | 400 | 4,813 |
| 3/30/2013 | 30,125 | 555 | 41 | 3,308 | 2,700 | 1,544 | 0 | 23,169 | 17,638 | 2,375 | 20,013 | 3,156 | 600 | 3,756 | 400 | 4,156 |
| 4/6/2013 | 30,125 | 555 | 41 | 3,452 | 2,700 | 1,985 | 0 | 22,584 | 17,385 | 2,375 | 19,760 | 2,824 | 600 | 3,424 | 400 | 3,824 |
| 4/13/2013 | 30,125 | 555 | 41 | 6,173 | 2,700 | 1,248 | 0 | 20,600 | 16,873 | 2,375 | 19,248 | 1,352 | 600 | 1,952 | 400 | 2,352 |
| 4/20/2013 | 30,125 | 555 | 41 | 6,338 | 2,700 | 1,247 | 0 | 20,436 | 16,607 | 2,375 | 18,982 | 1,454 | 600 | 2,054 | 400 | 2,454 |
| 4/27/2013 | 30,125 | 555 | 41 | 5,853 | 3,400 | 574 | 0 | 20,894 | 16,580 | 2,375 | 18,955 | 1,939 | 600 | 2,539 | 400 | 2,939 |
| 5/4/2013 | 30,125 | 555 | 41 | 4,652 | 3,400 | 424 | 0 | 22,245 | 19,998 | 2,375 | 22,373 | (128) | 600 | 472 | 400 | 872 |
| **5/11/2013** | **30,125** | **555** | **41** | **4,803** | **3,400** | **0** | **0** | **22,518** | **20,973** | **2,375** | **23,348** | **(830)** | **600** | **(230)** | **400** | **170** |
| 5/18/2013 | 30,125 | 555 | 41 | 2,802 | 3,400 | 251 | 249 | 24,019 | 21,878 | 2,375 | 24,253 | (234) | 600 | 366 | 400 | 766 |
| 5/25/2013 | 30,125 | 362 | 41 | 1,509 | 3,400 | 731 | 0 | 24,888 | 22,872 | 2,375 | 25,247 | (359) | 600 | 241 | 400 | 641 |

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 external Capacity Supply Obligations, CSO .
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. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
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 per data included in the 2012 CELT Report adjusted for Other Demand Resources.
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).

# Winter/Spring 2013 Operable Capacity Analysis(MW) 90/10 Forecast (Reference) – Reduced LNG imports

## ISO-NE 2013 OPERABLE CAPACITY ANALYSIS

### January 28 2013 -90/10- FORECAST - CSO_Reduced LNG Available

alysis 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 Septe

| | OPCAP SUPPLY | | | | | | | | LOAD OBLIGATIONS | | | OPCAP MARGINS | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| STUDY WEEK (Week Beginning, Saturday) | AVAILABLE OPCAP MW | EXTERNAL NODE AVAIL CAPACITY MW | NON COMMERCIAL CAPACITY MW | NON-GAS PLANNED OUTAGES CSO MW | ALLOWANCE FOR UNPLANNED OUTAGES MW | GAS GENERATOR OUTAGES CSO 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] |
| 2/2/2013 | 30,754 | 337 | 41 | 1,517 | 3,100 | 551 | 3,999 | 21,965 | 21,624 | 2,375 | 23,999 | (2,034) | 600 | (1,434) | 400 | (1,034) |
| **2/9/2013** | **30,754** | **337** | **41** | **2,228** | **3,100** | **803** | **3,747** | **21,254** | **21,594** | **2,375** | **23,969** | **(2,715)** | **600** | **(2,115)** | **400** | **(1,715)** |
| 2/16/2013 | 30,754 | 337 | 41 | 2,204 | 3,100 | 551 | 3,378 | 21,899 | 21,321 | 2,375 | 23,696 | (1,797) | 600 | (1,197) | 400 | (797) |
| 2/23/2013 | 30,754 | 337 | 41 | 2,134 | 3,100 | 394 | 3,121 | 22,383 | 20,296 | 2,375 | 22,671 | (288) | 600 | 312 | 400 | 712 |
| 3/2/2013 | 30,396 | 485 | 41 | 2,676 | 2,200 | 461 | 2,227 | 23,358 | 19,933 | 2,375 | 22,308 | 1,050 | 600 | 1,650 | 400 | 2,050 |
| 3/9/2013 | 30,396 | 485 | 41 | 3,053 | 2,200 | 284 | 1,784 | 23,601 | 19,730 | 2,375 | 22,105 | 1,496 | 600 | 2,096 | 400 | 2,496 |
| 3/16/2013 | 30,396 | 485 | 41 | 2,828 | 2,200 | 284 | 1,577 | 24,033 | 19,351 | 2,375 | 21,726 | 2,307 | 600 | 2,907 | 400 | 3,307 |
| 3/23/2013 | 30,396 | 485 | 41 | 2,830 | 2,200 | 1,554 | 0 | 24,338 | 18,765 | 2,375 | 21,140 | 3,198 | 600 | 3,798 | 400 | 4,198 |
| 3/30/2013 | 30,125 | 555 | 41 | 3,308 | 2,700 | 1,544 | 0 | 23,169 | 18,237 | 2,375 | 20,612 | 2,557 | 600 | 3,157 | 400 | 3,557 |
| 4/6/2013 | 30,125 | 555 | 41 | 3,452 | 2,700 | 1,985 | 0 | 22,584 | 17,976 | 2,375 | 20,351 | 2,233 | 600 | 2,833 | 400 | 3,233 |
| 4/13/2013 | 30,125 | 555 | 41 | 6,173 | 2,700 | 1,248 | 0 | 20,600 | 17,447 | 2,375 | 19,822 | 778 | 600 | 1,378 | 400 | 1,778 |
| 4/20/2013 | 30,125 | 555 | 41 | 6,338 | 2,700 | 1,247 | 0 | 20,436 | 17,172 | 2,375 | 19,547 | 889 | 600 | 1,489 | 400 | 1,889 |
| 4/27/2013 | 30,125 | 555 | 41 | 5,853 | 3,400 | 574 | 0 | 20,894 | 17,145 | 2,375 | 19,520 | 1,374 | 600 | 1,974 | 400 | 2,374 |
| 5/4/2013 | 30,125 | 555 | 41 | 4,652 | 3,400 | 424 | 0 | 22,245 | 21,672 | 2,375 | 24,047 | (1,802) | 600 | (1,202) | 400 | (802) |
| **5/11/2013** | **30,125** | **555** | **41** | **4,803** | **3,400** | **0** | **0** | **22,518** | **22,724** | **2,375** | **25,099** | **(2,581)** | **600** | **(1,981)** | **400** | **(1,581)** |
| 5/18/2013 | 30,125 | 555 | 41 | 2,802 | 3,400 | 251 | 249 | 24,019 | 23,702 | 2,375 | 26,077 | (2,058) | 600 | (1,458) | 400 | (1,058) |
| 5/25/2013 | 30,125 | 362 | 41 | 1,509 | 3,400 | 731 | 0 | 24,888 | 24,775 | 2,375 | 27,150 | (2,262) | 600 | (1,662) | 400 | (1,262) |

**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 external Capacity Supply Obligations, CSO .**
**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. 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.**
**6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.**
**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 per data included in the 2012 CELT Report adjusted for Other Demand Resources.**
**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<br>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.<br>Begin to allow depletion of 30-minute reserve. | 0[1]<br><br>600 |
| 2 | Dispatch real time Demand Resources. | 600 [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<br>Dispatch real time Emergency Generation | 130 [4]<br>400 [3] |
| 7 | Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes | 0 |
| 8 | Voltage Reduction requiring 10 minutes or less | 260 [4] |
| 9 | Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency.<br>Voluntary Load Curtailment by Large Industrial and Commercial Customers. | 5<br><br>200 [2] |

# 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) |
|---|---|---|
| 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 | | 3,535 |

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 MW values are reviewed on a quarterly basis; actual available MW amounts can be viewed using the demand response dispatch software.
4. The MW values are based on a 26,462 MW system load and the most recent voltage reduction test % achieved.

FEBRUARY 1, 2013


# Discussion of the 2013 Work Plan – Second Draft

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

# Objective and Highlights

- The primary objective of this presentation is to provide the highlights of the 2013 ISO work plan and seek stakeholder input
- Activities related to the strategic planning initiative are highlighted in each of the planning; operations; markets; and capital  projects category
  - In addition, slides 67-71 list the strategic planning activities that have been completed in 2012 and are planned for 2013
- Market activities are split into Market Design and Market Assessment activities
  - Market Assessment activities serve as a prelude to the Market Design activities

# Planning/Operations Related Activities

| 2013 | | | | 2014 | | | |
|---|---|---|---|---|---|---|---|
| Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| Transmission Planning Studies/Support State Siting (Slides 6-8 ) | | | | | | | |
| Eastern Interconnection Planning Collaborative (Slide 9) | | | | | | | |
| 2012 Economic Studies (Slide 10) | | 2013 Economic Studies (Slide 10) | | | | 2014 Economic Studies | |
| Finalize 2013 Forecast of State EE | | (Slide 11) | | Finalize 2014 Forecast of State EE | | | |
| Interregional Planning (Slide 12) | | | | | | | |
| Transmission Cost Allocation (Slide 13) | | | | | | | |
| FERC Order 1000 (Slide 14) | | Implement Final Compliance Orders (TBD) | | | | | |
| | | 2017/18 ICR and LSR | | (Slide 15) | | 2018/19 ICR and LSR | |
| FCA #7 / Annual Reconfig Auctions | | (Slide 16) | | FCA #8 / Annual Reconfig Auctions | | | |
| Generator Interconnection Studies / Review of Generator Interconnection Process (Slide 17) | | | | | | | |
| RSP 13 (Slide 18) | | | RSP 14 | | | | |
| Natural Gas Study Phase II (Slide 19) | | | | | | | |
| 2013 Winter Plan | Gas-Electric Coordination (Slide 20) | | | 2014 Winter Plan | | | |
| Blackstart Fleet Additions (Slide 21) | | | | | | | |
| NERC Standards/Tariff Compliance; Review and Update Planning Procedures (Slide 22-23) | | | | | | | |
| Interaction Between FCM and Interconection Rights (Slide 24) | | | | | | | |
| | Modeling Capacity Zones (Slide 25) | | | | | | |
| Operating Guide Updates (Slide 26) | | | | | | | |

2013 Strategic Planning Initiative related activities are highlighted in Orange

# Markets Related Priorities

| 2013 | | | | 2014 | | | |
|---|---|---|---|---|---|---|---|
| Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| FCM Performance Incentives (Slide 28) | | | | | | | |
| Intra-Day Offers (Slide 29) | | | | | | | |
| NCPC Payments (Slide 30) | | | | | | | |
| | | NCPC Cost Allocation (Slide 31) | | | | | |
| FCM Shortage Event Trigger | | | | | | | |
| Intra-Day Reserves (Slide 33) | | | | | | | |
| | FCA 8 Changes (Slide 34) | | | | | | |
| | | FCM Cost Allocation (Slide 35) | | | | | |
| | Sub-Hourly Settlement | | (Slide 36) | | | | |
| 3rd Party FTR Clearing | | | | (Slide 37) | | | |
| Order 755 | (Slide 38) | | | | | | |
| | | Wind Dispatch Rules (Slide 38) | | | | | |
| Energy Pricing Enhancements (Slide 40) | | | | | | | |
| | | | Merchant Transmission Projects (Slide 41) | | | | |
| | FCM Non-Commercial Financial Assurance (Slide 42) | | | | | | |
| | Other Market Assessments (Slide 43) | | | | | | |

| |
|---|
| Market Assessment |
| Market Design Project |

2013 Strategic Planning Initiative related activities are highlighted in Orange

# Capital Project Priorities

| 2013 | | | | 2014 | | | |
|---|---|---|---|---|---|---|---|
| Q1 | Q2 | Q3 | Q4 | Q1 | Q2 | Q3 | Q4 |
| FCA 8 Implementation (Slide 45) | | | | | FCA 9 Implementation | | |
| Market System Upgrade (Slide 46) | | | | | | | |
| Backup Control Center (Slide 47) | | | | | | | |
| Day-Ahead Market Move (Slide 48) | | | | | | | |
| | Intra-Day Offers (Slide 49) | | | | | | |
| Intra-Day Reserves (Slide 50) | | | | | | | |
| Generation Control Application Phase II Implementation (Slide 51) | | | | | | | |
| | | Coordinated Transaction Scheduling (Slide 52) | | | | | |
| Synchro-phasor Infrastructure Project (Slide 53) | | | | | | | |
| Web Enhancements Phase II (Slide 54) | | | | | | | |
| Divisional Accounting (Slide 55) | | | | | | | |
| | | Regulation Market (Order 755) Implementation (Slide 56) | | | | | |
| Business Intelligence Phase III (Slide 57) | | | | | | | |
| NX9/NX12D Automation (Slide 58) | | | | | | | |
| Wind Forecasting (Slide 59) | | | | | | | |
| Business Continuity Plan Phase III (Slide 60) | | | | | | | |
| Various Database and Application Enhancements (Slides 61-64) | | | | | | | |
| Issue Resolution 2013 (Slide 65) | | | | | | | |

**2013 Strategic Planning Initiative related activities are highlighted in Orange**

# Transmission Planning Studies

- Updated Needs Assessments will be conducted in 2013 in accordance with the Planning Process
  - Updated regional load forecast and Energy-Efficiency (EE) forecast
  - Resource mix will be adjusted for the results of the first seven Forward Capacity Market Auctions
    - New Resources
    - Non Price Retirements and de-list bids
    - Other resource attrition

# Transmission Planning Studies, cont.

- Several studies are underway or nearing completion
  - Eastern Connecticut Study
  - Southwestern Connecticut Ten-Year Compliance Plan
  - Greater Boston Solutions Study
  - Updated regional transfer limit analysis, including stability limit analysis
  - Greater Hartford area
  - SEMA/RI area
  - Restudy VT/NH

# Transmission Planning Studies, cont.

- Support state siting proceedings for major transmission projects, as necessary
  - NEEWS Interstate Reliability Project (MA, RI)
  - Greater Boston Reliability Project (MA, NH)
  - VT/NH Reliability Project (VT, NH)
- Results of the Wind Integration Study to be presented at PAC in Q1/Q2 2013

# Eastern Interconnection Planning Collaborative (EIPC)

- EIPC analysis under the DOE project was completed in 2012
- EIPC will continue with its regular transmission analysis work in 2013
- 2013 EIPC Work Plan focuses on Model Roll-up and Evaluation (contingency analysis and/or transfer analysis)
  - Select model years (for example, a 10-year case) and build roll-up models
  - Perform model evaluation (contingency and transfer analysis)
  - Identify any gaps and develop enhancements to address those gaps
  - Publish results
  - Provide feedback to regional planning processes
  - With stakeholder input, develop resource expansion scenarios for study in 2014
- 2013 ISO Planning staff effort
  - Continue support for and participation in Technical Team, Economic Analysis Working Group, Coordinating Committee, and Executive Committee
  - Information sharing with stakeholders

# 2012/2013 Attachment K Economic Studies

- 2012 economic study requests submitted by April 2012 for retirement of nuclear power stations and other retirements with replacement by several environmentally friendly technologies
  - Economic analysis complete
  - Stakeholder request to examine follow-up resource expansion scenarios received in late November 2012 – analysis underway
- 2013 economic study requests to be submitted by April 1, 2013
  - Interest has already been expressed in an economic study to look at the impact of solar energy resources and other forms of distributed generation

# State Sponsored Energy-Efficiency Programs

- The Regional Energy-Efficiency Initiative (REEI) efforts have highlighted New England states' activities and investments in energy efficiency
- Data has been gathered to support the development of the 2013 EE forecast, expected to be completed in February 2013
- ISO will continue working with the Energy-Efficiency Forecast Working Group to review and refine the EE forecast process
- Data gathering to support development of the 2014 EE forecast to begin in Q3 2013

# Interregional Planning

- There are a number of forums and activities related to interregional planning efforts beyond EIPC
  - North American Electric Reliability Corporation (NERC)
  - Northeast Power Coordinating Council (NPCC)
  - Inter-Area Planning Stakeholder Committee (IPSAC)
  - Department of Energy (DOE) Congestion Study Support
  - Northeast Gas Association (NGA)

# Transmission Cost Allocation (TCA)

| Transmission Owner | Project | Pool Transmission Facilities (PTF) Cost Estimate | Target Date[1] |
|---|---|---|---|
| VELCO / NU | New Hampshire Solutions | ~$450M | 2013 TCA Submittal |
| NU | Greater Springfield Reliability Project – NEEWS | $720M | 2013 TCA Submittal |
| NGRID | Western MA Reinforcements Groups 2-7 | ~$125M | 2013 TCA Submittal |
| NU | Millstone 345 kV Circuit Separation Project and SLOD Special Protection System Retirement | $38.7M[2] | TCA Determination Q2 2013 |
| NU / NGRID | Pittsfield / Greenfield | ~$135M | 2013 TCA Submittal |

[1] TO's determine when to submit TCA applications
[2] TCA submitted

# FERC Order 1000 – Compliance

- FERC Order 1000 requires a compliance filing for interregional planning and transmission cost allocation by April 11, 2013
  - ISO, NYISO and PJM are updating existing joint planning protocol to be consistent with Order 1000 language
  - ISO to work with the Transmission Committee (TC) on any OATT changes related to the interregional planning issues
- Initial FERC Order 1000 compliance filing was made in October 2012
  - No estimate on when the FERC order will be issued. This could be a major effort for ISO, TO's and the TC

# 2017/2018 Installed Capacity and Local Sourcing Requirements for FCA #8

- PSPC review of ISO recommendation of Installed Capacity Requirement (ICR) values – **June 2013**
- Reliability Committee (RC) review/vote – **August 2013**
- Participants Committee review/vote – **October 2013**
- File with FERC – **November 2013**
- Forward Capacity Auction #8 conducted – **February 2014**

# FCM Auction Key Dates

- Commitment Period #4 (2013-2014)
  - ARA #3 – **March 2013**
- Commitment Period #5 (2014-2015)
  - ARA #2 – **August 2013**
- Commitment Period #6 (2015-2016)
  - ARA #1 – **June 2013**
- Commitment Period #7 (2016-2017)
  - Conduct Auction – **February 2013**
  - Results Filing – **February 2013**
- Commitment Period #8 (2017-2018)
  - Show of Interest Window – **February 14 – 28, 2013**
  - FCA FERC Informational Filing – **November 2013**
  - Conduct Auction – **February 2014**

# Generator Interconnection Queue as of December 1, 2012

- In total, 58 generation projects are currently being tracked by the ISO, totaling approximately 5,700 MW
  - 4 in scoping stage
  - 7 in feasibility study
  - 13 in system impact study/optional interconnection study
  - 1 in facilities study
  - 7 negotiating interconnection agreements
  - 23 with interconnection agreements
  - 6 distribution interconnections

*Note: 2 projects require 2 studies each due to multiple interconnection requests and 1 project has no capacity increase*

# Regional System Plan (RSP) – 2013

- RSP13 and related key Planning Advisory Committee (PAC) meetings
  - RSP scope of work to be presented at the February PAC
  - Environmental and renewable resource updates provided to PAC and Environmental Advisory Group (EAG) on an ongoing basis
  - Initial draft report will be posted for stakeholder review in July
  - RSP review and comment ("page turn") meeting scheduled for August 13
- RSP13 Public Meeting scheduled for September 12

# Natural Gas Study Phase II

- Determine ‘duration of risk’ that the electric system faces with respect to pipeline capacity constraints/deficiencies
- Develop additional cases which study a non-design winter day
- Develop additional cases that incorporate decreases in LNG imports into the region; recent changes to proposed US EPA regulations; energy efficiency forecasts

# Gas-Electric Coordination

- Continue coordination and information sharing with gas pipelines
  - Currently, aggregate hourly forecast of expected gas profiles is shared
  - Increase coordination regarding pipeline maintenance scheduling
  - Further information sharing subject to FERC Order
- Run capacity analysis scenarios across different seasons based on information gathered from fuel surveys and pipelines
  - Periodic fuel surveys depending upon system conditions
- Establish operating plans to deal with different system conditions
- Continue data gathering and analysis
- Communicate with stakeholders and regulators on a regular basis

# Blackstart Fleet Additions

- The ISO has developed a plan that will improve the System Restoration Plan with the objective of improving the response time required to restore the system after a blackout
- With the implementation of the revised Schedule 16 (Blackstart Service) in January 2013, the ISO will continue working with selected generator owners in an effort to add larger Blackstart resources to the fleet

# NPCC/NERC/FERC Compliance

- Ensure compliance with new and existing NERC and FERC orders
  - Conducting a complete internal compliance assessment of all applicable NERC Standards Requirements
  - Working on guiding NERC’s new Reliability Enforcement Initiative
  - Continued interaction with Participants on matters relating to NPCC's administration and auditing of NERC Standards
- Review and update Planning Procedures
- Finalize Transmission Planning manual Version 1

# NPCC/NERC/FERC Compliance

- The Purpose of NERC Standard PER-0005-1 ***System Personnel Training*** is 'to ensure that System Operators performing real-time, reliability-related tasks on the North American Bulk Electric System (BES) are competent to perform those reliability-related tasks'
  - Effective date of April 1, 2013
  - ISO New England is currently, or will be compliant with all requirements of PER-005-1 prior to that date
  - Identified and documented over 2000 learning objectives and over 2400 skill and knowledge related items required to perform all system operator tasks
  - Developed over 850 of approximately 1000 lesson plans and training exercises required to incorporate all identified objectives, skills and knowledge

# Interaction between FCM and Interconnection Rights

- Processing of de-list bids, non-price retirement requests, resource re-powering plans and other necessary resource modifications can all impact resource interconnection rights and associated energy and capacity values
- Several improvements have been identified that will require market rule or OATT changes
- ISO will begin presenting suggested changes in Q1 2013

# Modeling Capacity Zones

- FCM reforms will begin with the modeling of four capacity zones (ME, NEMA/BOS, CT, ROP) in FCA #7
- Strategic transmission planning studies carried out in 2012 will help to identify the longer term nature of zones as they emerge
- A stakeholder process to establish guidelines for zonal composition and requirements will begin in Q2 2013, following the completion of FCA #7

# Operating Guides and Procedures Update

- Review and update Guides due to system transmission and generation changes
  - MPRP; GSRP; Lower SEMA; Addition of Renewable Generators
- Review and update real-time voltage limits
- Develop temporary operating guides for system modification during construction
- Integrate new wind dispatching process into review of system operating limits

# Market Design

# FCM Performance Incentives

- The ISO is evaluating replacing the existing FCM Shortage Event penalty structure with a new pay-for-performance mechanism.
  - The ISO issued a whitepaper detailing the proposed design
- The stakeholder process is underway. These changes are scheduled to be effective for the new capacity show of interest in February 2014 and in place for the 2018 – 2019 (FCA #9) commitment period
  - FERC filing scheduled for December 2013

# Energy Market Offer Flexibility

- The ISO is proposing to allow dispatchable resources to submit hourly energy offers into the Day-Ahead Energy Market and to modify the commitment cost components (start-up and no-load costs) and the incremental energy-offer component of supply offers during the operating day.
  - The ISO also will evaluate the self-scheduling rules in the context of the intraday reoffer changes and the ability for resources to submit negative-priced offers into the market.
- The stakeholder process is underway with implementation scheduled for 2014
  - FERC filing scheduled for Q2 2013

# NCPC Payments

- As part of the *Energy Market Offer Flexibility* market design project, the ISO is required to make conforming changes to the NCPC payment rules that complement the ability of participants to modify their offers throughout the operating day.
- The stakeholder process is underway with implementation scheduled for 2014, coincident with the *Energy Market Offer Flexibility* project
  - FERC filing scheduled for Q3 2013

# NCPC Cost Allocation

- The ISO is assessing whether to continue to allocate real-time NCPC costs to virtual transactions and other types of real-time deviations from schedules established in the Day-Ahead Energy Market.
  - This project includes evaluating the extent to which virtual transactions affect real-time NCPC costs and whether the current real-time NCPC cost-allocation methodology accurately reflects how NCPC costs are incurred.
- The ISO is planning to begin the stakeholder process in Q3 2013 with implementation scheduled for 2014
  - FERC filing scheduled for Q4 2013

# FCM Shortage Event Triggers

- The ISO is proposing to modify the triggers for both system-wide and local shortage events.
  - The system-wide changes would become effective upon FERC approval.
  - The local shortage event changes would become effective on June 1, 2016, when an import-constrained capacity zone will exist in FCM.
  - FERC filing scheduled for Q2 2013
- The FCM Performance Incentives project changes scheduled for the 2018 – 2019 (FCA #9) commitment period will replace the current shortage event penalty structure

# Intra-Day Reserves

- As part of the strategic planning initiative, the ISO is evaluating approaches to dealing with uncertainty of fuel supplies
- The approach currently being evaluated by the ISO includes enhancements to the Locational Forward Reserve Market (LFRM) and real-time reserve market
  - Procurement of additional reserves to ensure that there is sufficient system flexibility to deal with both electric and gas sector contingencies
  - Improvements to real-time Reserve Constraint Penalty Factors
  - Improvements to incentives in the LFRM
  - FERC filing scheduled for Q2 2013

# FCA 8 Changes

- The ISO is evaluating modifications to the eighth Forward Capacity Auction that include (1) changing the objective function of the auction to maximize social welfare and (2) evaluating the impact of “lumpy” offers on procurement and pricing in the FCA
  - The ISO is planning to begin the stakeholder process in Q1 2013
  - These changes are scheduled to be effective for the FCA in February 2014
  - FERC filing on the items listed above scheduled for Q3 2013
  - Other FCA 8 related changes have already been filed at FERC based on their order (MOPR, Floor Price)

# FCM Cost Allocation

- The ISO is evaluating modifications to the methodology for allocating FCM costs associated with meeting the Installed Capacity Requirement. This project also will include a discussion of load reconstitution
  - This ISO is planning  to begin the stakeholder process in Q3 2013
  - These changes are scheduled to be effective for the ninth capacity commitment period

# Sub-hourly Real-Time Settlement

- The real-time markets (energy, reserves and regulation) are all settled hourly, even though resources are dispatched for energy on a five-minute basis
  - The hourly settlement approach, especially for resources that are able to respond quickly, can result in hourly compensation being inconsistent with how the resource performed on a 5-minute basis.
  - The ISO is evaluating allowing for sub-hourly settlement for the real-time markets for, at minimum generation, external transactions, dispatchable asset related demand, and demand response
- The ISO is planning to begin the stakeholder process in Q2 2013 with implementation scheduled after the *Energy Market Offer Flexibility* project

# 3rd Party FTR Clearing

- The objective of this activity is to replace ISO-NE financial assurance requirements for holding FTRs with margining by a third party clearing entity
  - This shifts FTR default risk from ISO New England's FTR Market Participants to the third party
- Address the financial assurance issues that have prevented implementation of Long Term FTRs and BoPP
- Facilitate secondary market trading
- Stakeholder process is currently underway and the ISO anticipates a stakeholder vote in Q3 2013
- FERC filing is scheduled for Q4 2013

# Other Market Projects

- The ISO is currently working with stakeholders to address the requirements under the *Regulation Market (Order 755) Compliance* order
  - The stakeholder process is underway and the ISO will file changes in February 2013
- The ISO is proposing to modify the dispatch rules as they apply to wind resources to ensure reliable system operation while efficiently using wind resources
  - The ISO is planning to begin the stakeholder process in Q2 2013 with implementation scheduled for 2014
  - FERC filing scheduled for Q1 2014

# Market Assessments

# Energy Pricing Enhancements

- The objective of this project is to ensure that LMPs accurately reflect the incremental cost of supplying electric energy and maintaining operating reserves in these markets. The ISO is evaluating the following:
  - Revisions to market rules that govern when a resource is eligible to set the locational marginal price (LMP);
  - The economic logic and algorithm for incorporating the start-up costs of fast-start generation resources into the LMP;
  - Energy price formation when a generating resource is dispatched out of merit for reliability reasons
- The ISO has retained a consultant to assist with this effort

# Merchant Transmission Projects: Market Implications

- The ISO is evaluating operational and market impacts specific to new, merchant transmission projects
  - This assessment will review the integration of these transmission projects into the energy and capacity markets
- The ISO is planning to start the stakeholder process for these changes in Q4 2013

# FCM Non-Commercial Financial Assurance

- As part of this assessment, the ISO is planning to evaluate the rules for both commercial operation determination and resource termination
- The ISO is planning to evaluate any financial assurance reforms in the context of the design proposed in *FCM Performance Incentives* project
- Stakeholder discussion on this topic would parallel the *FCM Performance Incentives* project stakeholder timing

# Other Market Assessments

- The ISO is evaluating whether the implementation of multi-period optimization software as part of the Generator Control Application (GCA) delivery will require tariff changes
- The ISO is evaluating how price-responsive demand can participate in the real-time reserves market
- The ISO is evaluating how outages of demand resources should impact their baseline calculations

# CAPITAL PROJECTS

# FCA 8 Implementation

- Based upon the Market Rules that will be in effect for FCA #8, the ISO has initiated a project to design and develop necessary software and auction infrastructure
- Implementation is scheduled for FCA #8 which will be conducted in February 2014

# Market System Upgrade

- This project is intended to upgrade and enhance the Market System and includes the following
  - Upgrade AIMMS/CPLEX (mathematical models) underlying the energy market
  - Upgrade Simultaneous Feasibility Test (SFT), a network analysis package that is used to perform contingency analysis in the security constrained commitment and dispatch
  - Upgrade data import, export and archiving applications
  - Upgrade market operator interfaces
  - Enhancements that allow market snapshots to be re-executed (similar to a replay function)
  - Various other enhancements to study functions, reserve monitor and other applications
- This project is scheduled for Q1 2014

# Backup Control Center

- This project is an adjunct to the new Back-up Control Center (BCC) that is being constructed
- Specifically, this project includes the transition/cutover process from the old BCC to the new BCC
- Major activities in this project include the relocation of servers, purchasing and installation of core network infrastructure and hardware including cyber security requirements, and testing and cutover
  - The challenge will be to accomplish all of the above without any disruption to the Main Control Center, reliability and wholesale markets
- This project is scheduled for Q2 2014

# Day-Ahead Market Timeline Move

- This project is intended to make the necessary software changes to accommodate changes to the Day-Ahead Market and Resource Adequacy Assessment timeline
- This project is scheduled for Q2 2013

# Intra-Day Offers

- This project is intended to implement the necessary changes to the Market System infrastructure to
  - Allow for submission of hourly energy offers into the Day-Ahead Energy Market
  - Allow the modification of commitment cost components (start-up and no-load costs) and the incremental energy-offer component of supply offers during the operating day
- This project is a major software initiative and the ISO is currently assuming a need for market trials with participants (prior to going live)
- This project is scheduled for Q4 2014

# Intra-Day Reserves

- This project is intended to implement rules filed with FERC with regards to procurement of intra-day reserves (to deal with uncertainty of fuel supplies)
  - This project is expected to include changes to the Locational Forward Reserve Market (LFRM); Real-Time dispatch and Settlement systems
- Based on FERC filing and approval, this project is scheduled for implementation in Q3 2013

# Generation Control Application Phase II

- Phase I of this project included the implementation of a look-ahead commitment and scheduling functionality in a study mode
- As part of Phase II, the ISO plans to implement the Generation Control Application in the control room with the following primary features
  - Fast-Start unit startup and shutdown recommendations for the next several hours based on a co-optimized unit dispatch and commitment to satisfy forecasted load and interchange while satisfying network constraints and reserve requirements and accounting for topology changes over the period
  - Provide real-time Unit Dispatch System (UDS) with constraints to ramp slow moving units early in anticipation of reserve requirements and transmission constraints beyond the 15-minute look-ahead interval
- This project is scheduled for Q2 2014

# Coordinated Transaction Scheduling

- This project is intended to implement that Coordinated Transaction Scheduling project, per the market rules that were filed at FERC in 2011
  - The ISO is currently working with NYISO on various operational protocols
  - This project will be a multi year effort and is scheduled for implementation in 2015

# Synchro-phasor Infrastructure Project

- The ISO and the transmission owners received a grant from the DOE related to Synchro-phasor Infrastructure and Data Utilization in the New England region
  - The DOE approved project cost over three years was $18.09M
- The ISO has been able to recognize several efficiencies across all aspects of the project and will deliver this project for approximately $15M
- The project is in its final year and will be completed in June, 2013
- Under this project, Phasor Measurement Units (PMU's) will be deployed in each of the New England states
  - PMU applications associated with situational awareness will be installed at the ISO

# Web Enhancements Phase II

- This project is intended to continue to enhance the delivery of information to stakeholders and the scope of this project includes the following
  - Replace the current Content Management System (CMS)
  - Reorganize and redesign the site structure/navigation
  - Introduce widget based display management of all content
  - Improve the maintenance of the website via use of improved technologies
  - Implement ad-hoc reports platform that enables users to export ad-hoc reports
- This project is scheduled to be implemented in Q4 2013

# Divisional Accounting

- Several Market participants have requested settlement account for their individual business units
- This project will implement changes, in phases, to various ISO systems to allow participants to create and maintain sub-accounts
- Current target date for the project is Q2 2014

# Regulation Market Implementation

- This project is intended to implement FERC Order 755
- The project will implement modifications to the regulation market resource selection process, Automatic Generation Control (AGC) dispatch and settlement
- The implementation date of this project is subject to the completion of the Intra-day Offers

# Business Intelligence Phase III

- This project is intended to primarily replace Oracle Discoverer, which has been the primary reporting/ad hoc query tool and create a centrally managed data dictionary
- This project will be a continuation of the phase I and II efforts that focused on tool replacement
- Business Intelligence Phase III will rollout the implementation of the new tool to various systems used by Market Monitoring and Forward Capacity Market
- This project is scheduled to be implemented in Q4 2013

# NX9/NX12D Data Integration and Automation

- This project is intended to automate the submission of transmission and generator data and integrate them with other ISO systems
  - NX9 data defines and represents the physical characteristics, ratings and operational data for transmission system equipment
  - NX12D data defines the generator reactive data for those assets
  - Data will be bridged to Energy Management System, Model on Demand and other tools
  - Business processes and operating procedures will also be updated
- Current process uses antiquated technology and relies on significant manual effort
- This project is scheduled to be implemented in Q4 2013

# Wind Forecasting Integration

- This project will incorporate wind forecasting and wind resources into ISO processes, scheduling, and dispatch services
- The project will acquire external wind power forecasting services, create operator situational awareness displays, integrate wind into the real-time dispatch integration and maintain historical wind data for future use of the forecast service, auditing, and other analysis
- The project is scheduled for implementation in Q2 2013

# Business Continuity Project Phase III

- This project is a multi-year effort that allows for business continuity (for reliability and market services) in case the Master Control Center is unavailable for an indefinite period of time
- The first two phases of the project focused on high speed connectivity between the Main and the Backup Control Center to provide for a full transition from the MCC to the BCC less than two hours and a four-way Energy Management System (EMS)
- Phase III (final phase) of the project is focused on the following:
  - Implement a multi-site Markets Database
  - Expand the virtual desktop functionality to production such that ISO personnel can conduct business remotely
- This project is scheduled for completion in Q1 2015

# Various System Enhancements/Upgrades

- Market Database Infrastructure Upgrade
  - This hardware upgrade project will replace the Market System database servers and enhance the clustering architecture
  - This project will be completed in Q3 2013
- Software Testing Tool
  - The purpose of this project is to automate the testing effort for various applications at the ISO, which will result in efficiencies in future project implementations
  - This project is scheduled for implementation in Q4 2013

# Various System Enhancements/Upgrades

- Bilateral Financial Assurance
  - In compliance with FERC Order 741, the ISO will establish itself as a central counterparty for transactions within its markets
  - This project is scheduled for implementation in Q1 2013
- System Restoration and Blackstart Resource Management
  - This project is intended to enhance software tools per changes to the ISO operating procedures and training program
  - This project is scheduled for completion in Q1 2013

# Various System Enhancements/Upgrades

- Generator Audit Tool Implementation
  - This project implements a revised methodology for determining Claim 10 and Claim 30 values (to more accurately represent the true capability of generation units) and includes ongoing monitoring and evaluation of Claim 10, Claim 30, Manual Response Rate and Startup Times
  - This project is scheduled for Q3 2013

# Various System Enhancements/Upgrades

- Quarterly Releases
  - These projects are intended to implement various minor enhancements related to customer asset management system, settlement system, various bridges that connect data within the ISO and control room applications
  - These projects are scheduled for implementation, typically in Q2 and Q4 2013
- Electronic Data Delivery
  - FERC issued Order 760 – “Enhancement of Electricity Market Surveillance and Analysis through Ongoing Electronic Delivery of Data from Regional Transmission Organizations and Independent System Operators”
  - Per this FERC Order, the ISO has to submit various market data in electronic form

# Issue Resolution 2013

- Reduce Backlog in Issues Management
  - In 2010, the ISO introduced an initiative to reduce the backlog of issues that have accumulated while the region implemented large projects
  - The 2013 Issue Resolution Project is intended to continue to improve the resolution pace of issues
  - This will increase operational efficiency and accuracy, provide for minor enhancements and reduce risk
  - This could include both software and hardware infrastructure enhancements
  - This will be implemented as multiple projects and they are scheduled for completion by the end of 2013

# STRATEGIC INITIATIVE

# Strategic Planning Initiative

- In 2010, the ISO initiated a strategic planning initiative with stakeholders to understand the impact of the following issues:
  - Resource performance and flexibility
  - Increased reliance on natural gas-fired capacity
  - Retirement of units
  - Integration of a greater level of variable resources
  - Alignment of markets and planning
- Over the past year, the ISO has focused the strategic planning initiative increasingly on Resource Performance and Flexibility; Increased Reliance on Natural Gas-Fired Capacity; and Retirement of Units

# Strategic Planning: 2012 Completed Initiatives

- Resource Performance and Flexibility
  - Update the System Thirty Minute Operating Reserve (TMOR) Reserve Constraint Penalty Factor values (**Completed in Q2 2012**)
  - Analyze the amount of Ten Minute Non-Spinning Reserve (TMNSR) that needs to be procured in the Locational Forward Reserve Market (LFRM) in order to increase system flexibility (Completed in Q4 2012)
  - Enhance audit tariff provisions related to online and offline response rate and seasonal claim capability of generation (**Completed in Q4 2012**)
- Retirement of units
  - Publish draft transmission study related to unit retirement, to identify transmission security impacts resulting from the retirements (**Completed in Q4 2012**)

# Strategic Initiative: 2012 Completed Initiatives

- Increased reliance on natural gas-fired capacity
  - Complete study of the natural gas system to determine quantities of gas-fired MW available after all firm/priority deliveries are taken into account and to study a future case where retired resources are replaced with new, natural gas resources (**Completed in Q2 2012**)
  - Publish a white paper identifying market solutions for addressing the reliability risks associated with dependency on natural gas (**Completed in Q3 2012**)
- Long-term FCM Design / Alignment between Markets and Planning:
  - Publish a draft conceptual design document that incorporates identified local and system reliability requirements into the resource adequacy markets (**Completed in Q2 2012**)
  - Publish a white paper on the long-term FCM design (**Completed in Q4 2012**)

# 2013 Initiatives to Address the Risks Associated with Dependence on Natural Gas and Resource Performance and Flexibility

## Short-Term (Q4 2012 to Q4 2013):

- Survey to gauge fuel inventory
- Improved operational communications with gas pipelines
- Adjust Resource Adequacy Assessment and Day-Ahead market timeline

# 2013 Initiatives to Address the Risks Associated with Dependence on Natural Gas and Resource Performance and Flexibility

## Medium-Term (Q4 2013 to 2014):

- Change the Shortage Hour definition to move from 10 minute, to 30 minute, reserve shortages
- Implement intra-day offers
- Address gas supply uncertainty via enhanced reserve and real-time energy markets

## Long-Term (2014 and Beyond):

- Improve performance incentives in the Forward Capacity by FCA 9

# ACTIVITY DRIVERS

# Wholesale Markets Activity Drivers

| Activity | Driver | Reliability Impact | Market Efficiency Impact |
|---|---|---|---|
| FCM Performance Incentives | ISO Strategic Planning Initiative | High | High |
| Intra-Day Offers | ISO Strategic Planning Initiative | High | High |
| NCPC Payments (tied to Intra-Day Offers) | ISO Strategic Planning Initiative | High | High |
| NCPC Cost Allocation | Internal / External Market Monitor | Low | Medium |
| FCM Shortage Event Trigger | ISO Initiative | Medium | Medium |
| Intra-Day Reserves | ISO Strategic Planning Initiative | High | High |
| FCA 8 Changes | FERC Order | Medium | High |

# Wholesale Markets Activity Drivers, cont.

| Activity | Driver | Reliability Impact | Market Efficiency Impact |
|---|---|---|---|
| FCM Cost Allocation | ISO Initiative | Low | Medium |
| Sub-Hourly Settlement | ISO Initiative | Medium | Medium |
| Order 755 (Regulation) | FERC Order | Low | Medium |
| Wind Dispatch Rules | ISO Initiative / Public Policy | Medium | Medium |
| Energy Pricing Enhancements | ISO / Market Monitors / Supplier and Generator Sector | High | High |
| Merchant Transmission Projects | ISO / Merchant Transmission Projects | Low | Medium |
| FCM Non-Commercial Financial Assurance | ISO Initiative | Low | Medium |
| Other Market Assessments | ISO / Demand Resource Sector | Medium | Medium |

# Planning/Operations Activity Drivers

| Activity | Driver | Reliability Impact |
|---|---|---|
| Transmission Planning Studies / Support State Siting | NERC and NPCC and Tariff Compliance | High |
| Eastern Interconnection Planning Collaborative | DOE Initiative | Low |
| 2013 Economic Studies | Tariff Compliance; Order 890 | Low |
| 2014 Economic Studies | Tariff Compliance; Order 890 | Low |
| Finalize 2013 Forecast of State EE | Public Policy | Medium |
| Finalize 2014 Forecast of State EE | Public Policy | Medium |

# Planning/Operations Activity Drivers, cont.

| Activity | Driver | Reliability Impact |
|---|---|---|
| Interregional Planning | NERC, NPCC and Tariff Compliance | Medium |
| Transmission Cost Allocation | Tariff Compliance | Low |
| FERC Order 1000 | FERC Compliance | Low |
| 2017/18 ICR and LSR | NERC, NPCC and Tariff Compliance | High |
| 2018/19 ICR and LSR | NERC, NPCC and Tariff Compliance | High |
| FCA #7 / Annual Reconfig Auctions | Tariff Compliance | Medium |
| FCA #8 / Annual Reconfig Auctions | Tariff Compliance | Medium |
| Generator Interconnection Studies / Review of Generator Interconnection Process | Tariff Compliance | Medium |

# Planning/Operations Activity Drivers, cont.

| Activity | Driver | Reliability Impact |
|---|---|---|
| RSP 13 Publication | Tariff Compliance | Low |
| RSP 14 Publication | Tariff Compliance | Low |
| Natural Gas Study Phase II | ISO Strategic Planning Initiative | High |
| 2013 Winter Plan | ISO Strategic Planning Initiative | High |
| Gas-Electric Coordination | ISO Strategic Planning Initiative | High |
| 2014 Winter Plan | ISO Strategic Planning Initiative | High |
| Blackstart Fleet Additions | NERC, NPCC and Tariff Compliance | High |

# Planning/Operations Activity Drivers, cont.

| Activity | Driver | Reliability Impact |
|---|---|---|
| NERC Standards / Tariff Compliance; Review and Update Planning Procedures | NERC and NPCC Compliance | High |
| Interaction Between FCM and Interconnection Rights | ISO Strategic Planning Initiative | Medium |
| Modeling Capacity Zones | FERC Order | High |
| Operating Guide Updates | ISO Operations | High |

# Capital Project Activity Drivers

| Activity | Driver | Reliability Impact | Market Efficiency Impact | Total Implementation Cost* |
|---|---|---|---|---|
| FCA 8 Implementation | FERC Order | Medium | High | $2.4M |
| FCA 9 Implementation | ISO Strategic Planning Initiative | High | High | TBD |
| Market System Upgrade | ISO Operations | High | High | $4.7M |
| Backup Control Center | NERC Compliance | High | Medium | $5.7M |
| Day-Ahead Market Move | ISO Strategic Planning Initiative | High | Medium | $780K |
| Intra-Day Offers | ISO Strategic Planning Initiative | High | High | TBD |
| Intra-Day Reserves | ISO Strategic Planning Initiative | High | High | TBD |

* **Provides costs for chartered projects only; Projects could span multiple years**

# Capital Project Activity Drivers, cont.

| Activity | Driver | Reliability Impact | Market Efficiency Impact | Total Implementation Cost* |
|---|---|---|---|---|
| Generation Control Application Phase II | ISO Operations | High | Medium | TBD |
| Coordinated Transaction Scheduling | External Market Monitor | Medium | Medium | TBD |
| Synchro-phasor Infrastructure Project | DOE Initiative | Medium | Low | $4.3M |
| Web Enhancements Phase II | ISO / Multiple NEPOOL stakeholders | Low | Medium | TBD |
| Divisional Accounting | ISO / Multiple NEPOOL Stakeholders | Low | Low** | TBD |

*** Provides costs for chartered projects only; Projects could span multiple years**

**** Impacts Market Participant and Market Settlement Efficiency**

# Capital Project Activity Drivers, cont.

| Activity | Driver | Reliability Impact | Market Efficiency Impact | Total Implementation Cost* |
|---|---|---|---|---|
| Regulation Market (Order 755) Implementation | FERC Order | Low | Medium | TBD |
| Business Intelligence Ph III** | ISO Operations | Low | Low | $990K |
| NX9/NX12D Automation | ISO Operations | High | Low | $2.3M |
| Wind Forecasting | ISO Operations | Medium | Medium | $2.3M |
| Business Continuity Plan Phase III | NERC Compliance | High | Medium | TBD |
| Various Database / Application Enhancements | ISO Operations | Medium*** | Medium | $4.75M |
| Issue Resolution 2013 | ISO Management | Medium*** | Medium | $1.5M |

*** Provides costs for chartered projects only; Projects could span multiple years**

**** Impacts ISO operating efficiency**

***** Some of the activities in this category have a High Reliability Impact (for example, generator auditing)**

# Capital Projects

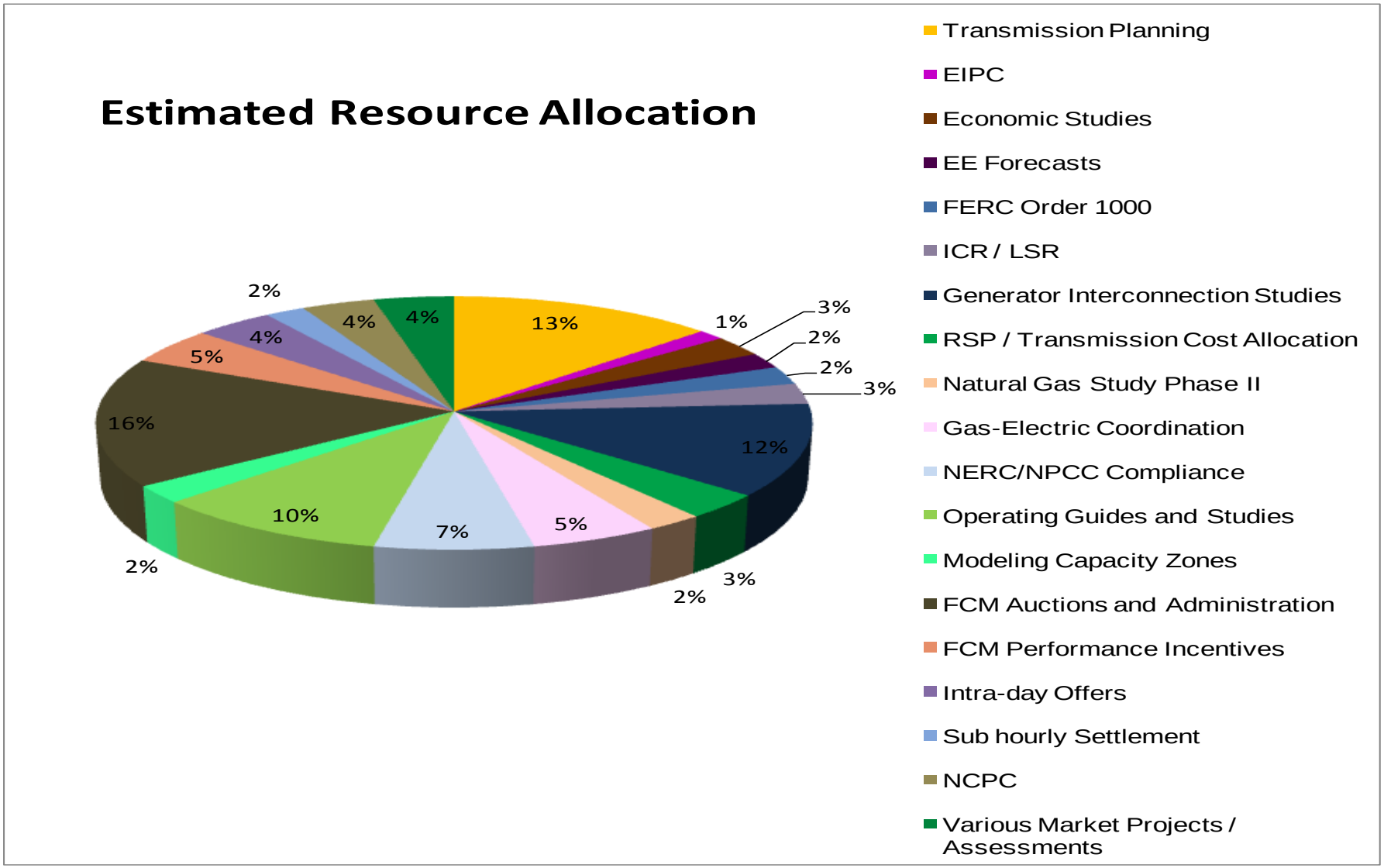
- The ISO discusses changes and updates to its capital budget each quarter (with stakeholders) and files an updated Capital Filing Tariff with the FERC
  - The quarterly CFT captures any changes in the cost of a project
  - The quarterly CFT also notes projects that are completed and new projects that are chartered
- For 2013, the ISO has set aside approximately $5.3M in its capital budget for strategic planning initiative related projects; $2.0M for Regulation Market changes; and $1.8M for Coordinated Transaction Scheduling
  - These projects are estimated to span multiple years and the overall implementation costs will be higher than the 2013 estimate

# ESTIMATED 2013 RESOURCE LOADING

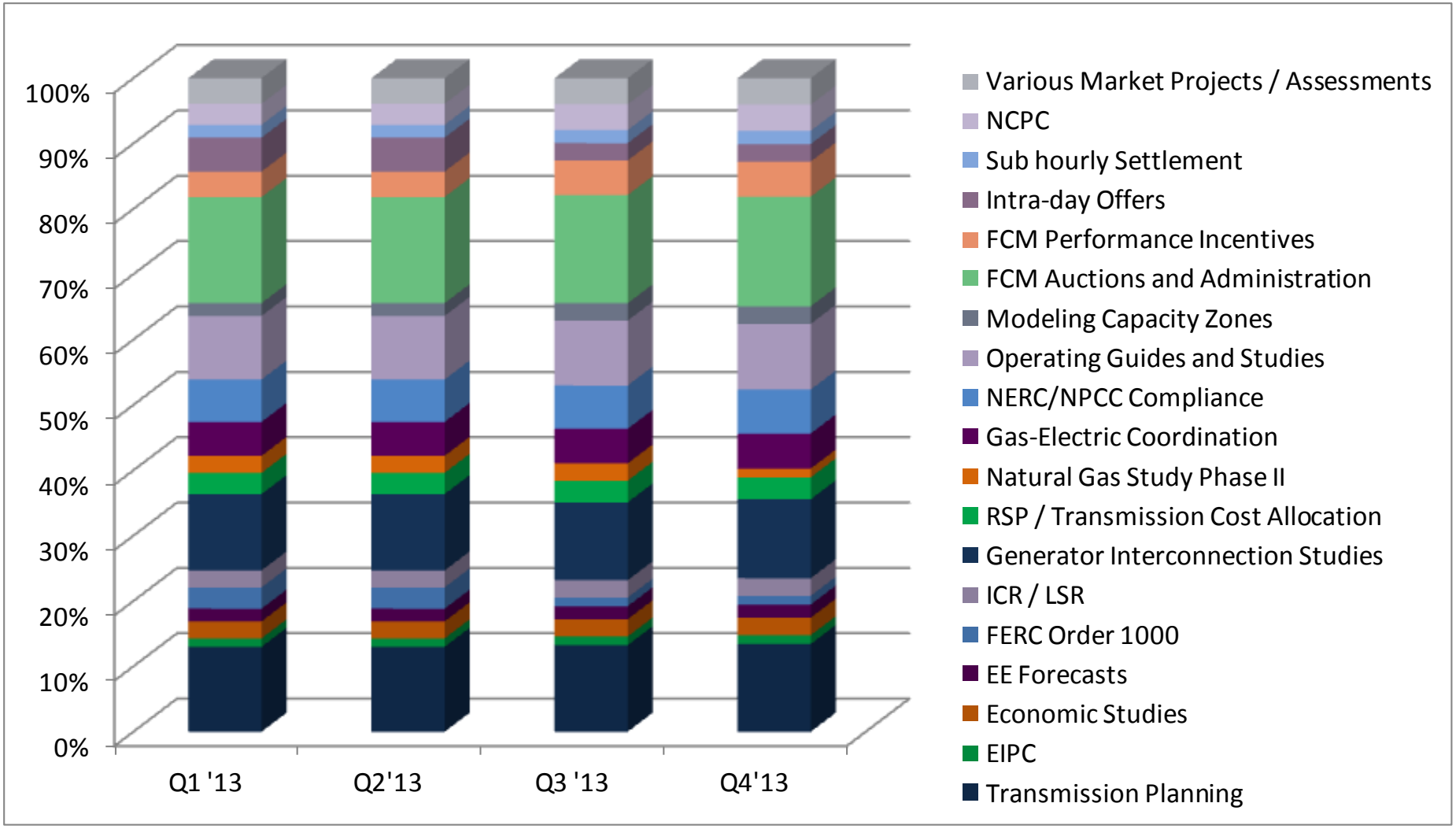
# Resource Estimate

- For the activities identified in the work plan, the estimated ISO resource allocation is as follows:
  - For the capital projects identified in the work plan, the ISO expects an approximate allocation of 105 resources
    - Approximately 55 employees and 50 contractors
  - For the non capital activities identified in the work plan, the ISO expects an approximate allocation of 155 resources
    - Approximately 120 employees and 35 contractors
- Slides 85-88 illustrate the relative resource allocation across activities contained in the work plan
  - The resources are estimates and actual allocation of resources across all activities will change based on final scope and schedule

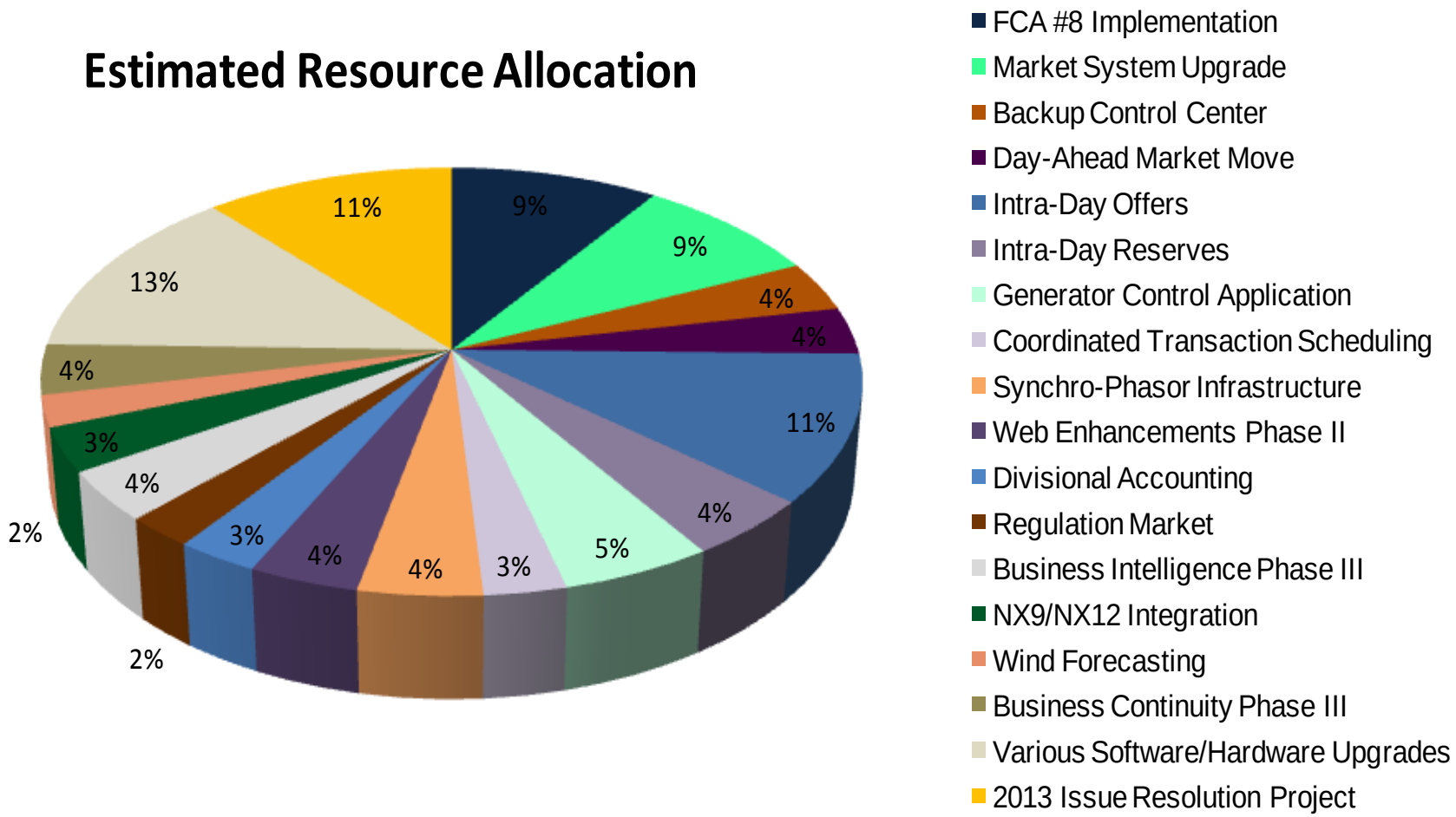
# Estimated Resource Allocation to Non Capital Activities



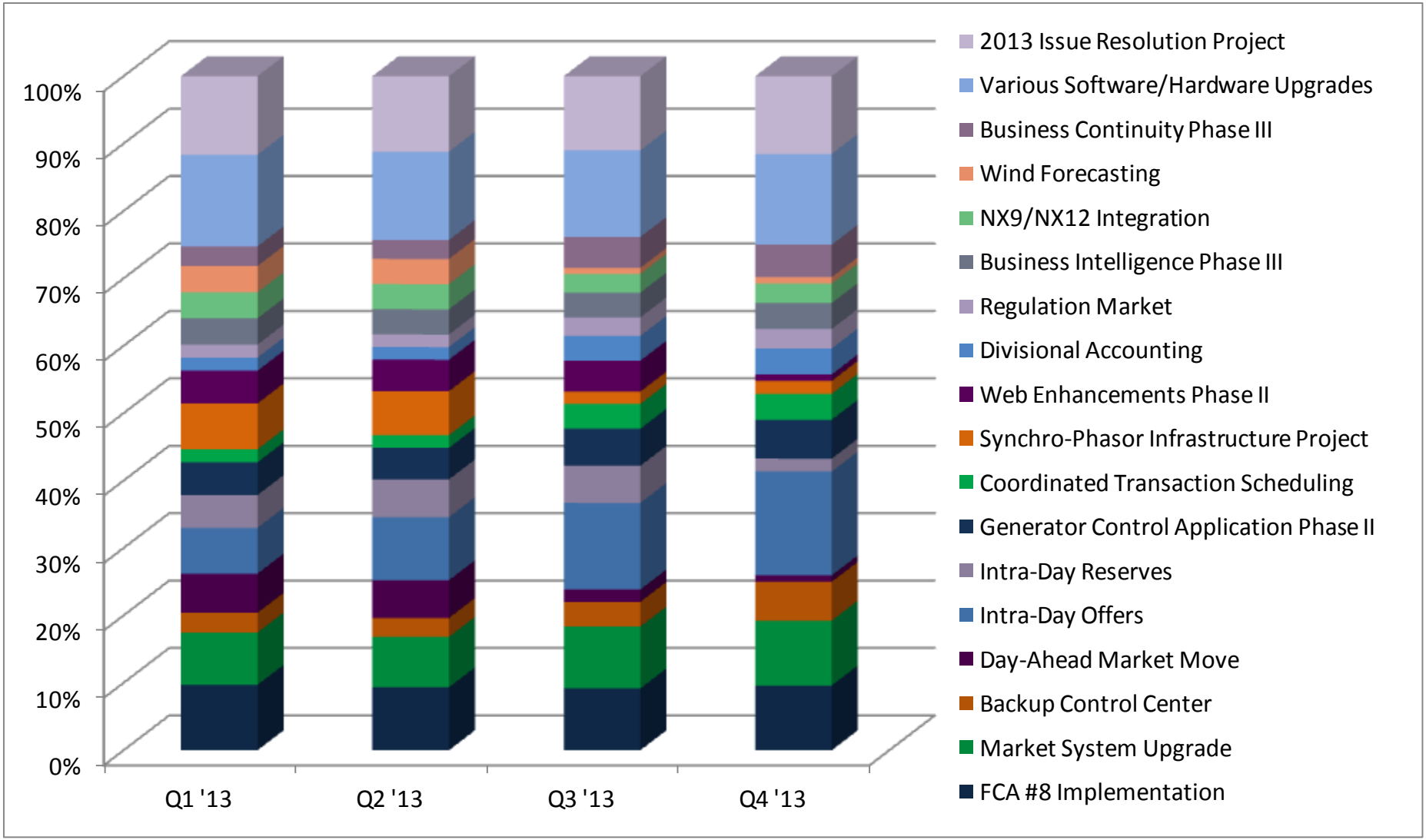
# Estimated Resource Allocation to Non Capital Activities



# Estimated Resource Allocation to Capital Projects



# Estimated Resource Allocation to Capital Projects



ISO new england

memo

**To:** New England Power Pool Participants Committee
New England Conference of Public Utilities Commissioners
New England States Committee on Electricity

**From:** Gordon van Welie

**Date:** January 25, 2013

**Subject:** Information regarding Potential Benefits and Costs of Solutions to Address the Risks Associated with New England's Reliance on Natural Gas

Attached for your consideration are two memos that are intended to provide information to stakeholders and the New England states as they consider the ISO's proposals related to resource performance, including the natural gas challenges. Several stakeholders and the states asked for additional analysis regarding the potential benefits and costs related to the array of market design changes aimed at addressing the natural gas risks. The ISO retained Paul Hibbard of the Analysis Group to assist in the development of categories of potential benefits and costs related to a range of infrastructure options.

It should be noted that this information is outside of the NEPOOL Markets Committee (MC) process as it is intended as background information on the potential benefits and costs of a variety of outcomes resulting from market rule changes. As specific market design proposals are deliberated in the MC, if they are deemed to be "major initiatives," the ISO will perform additional quantitative and qualitative analysis. These memos may be used as inputs to that process.

I look forward to discussing these memos during the Participants Committee meeting on February 1. To that end, I have asked Paul Hibbard to join us for the discussion.

**ISO New England Inc.**
One Sullivan Road, Holyoke, MA 01040-2841
www.iso-ne.com **T** 413 535-4300

**To**: ISO-NE

**From:** Paul Hibbard, Analysis Group

**Date:** January 24, 2013

**Subject:** Information from the Literature on the Potential Value of Measures that Improve System Reliability

## Background

The ISO has identified the region's reliance on natural gas for electricity generation as a key strategic risk. In several documents developed over the past two years as part of its Strategic Planning Initiative, ISO has detailed the potential reliability challenges posed by dependence on natural gas, and has identified a number of short, medium, and longer-term market and operational solutions to address the risks. Implementing the proposed changes is expected to provide substantial reliability and efficiency benefits.

There are a number of areas where implementing changes to address gas dependence risks will provide reliability and/or market efficiency benefits. Shorter-term market changes are designed to create incentives for improved availability and performance at existing generating assets, improve the coordination of natural gas and electricity market transactions, and increase the ability of control room operators to understand system conditions in a timely manner, thereby improving the efficiency of unit commitment and real-time dispatch. Longer-term market changes are designed to create incentives for investment in new capacity with more reliable performance and greater operational flexibility, reducing the power system's vulnerability to challenges associated with natural gas pipeline or electric system infrastructure conditions or contingencies. Over time, implementing such changes will deliver significant power system and market benefits, by:

- Increasing the visibility of electric and natural gas system conditions to control room operators;
- improving the efficiency of market and system operations,
- reducing out of merit commitment and dispatch of generating assets for energy and reserves,
- increasing reliability through reduced loss-of-load probability (LOLP)
- reducing the likelihood of the substantial public safety and economic impacts that flow from power outages, and
- providing financial signals for investment that encourage development of resources that will allow ISO to better manage system operation in the face of fuel uncertainties and greater integration of intermittent, renewable resources.

It is premature to attempt to quantify specific benefits at this time, as the market designs for solutions to the gas dependence risk are not yet complete, and market and system responses are not yet well understood. However, key factors in assessing potential impacts are the degree of vulnerability to the region associated with natural gas infrastructure conditions, and the value of avoiding loss of load through reliability improvements. This memo provides background on Analysis Group's assessment of the vulnerability, and information from economic literature related to estimates of value of lost load (VOLL). The purpose of providing this information at this time is to provide relevant background for policymakers

and stakeholders to consider as market rule changes related to the natural gas dependence risk begin to be discussed in stakeholder and committee meetings.

## Reliability Benefits

There are a number of ways that benefits flow from addressing the gas dependence risk. First, ISO must ensure that system infrastructure development, availability, and performance are sufficient to meet regional, NPCC, and NERC reliability obligations under appropriate load, resource availability, and fuel supply conditions. Failure to comply with these reliability requirements can lead to the imposition of substantial enforcement penalties. In addition to avoiding penalties, thought, there are important benefits associated with the public safety, convenience and economic damages avoided by reducing outage frequency and duration. Finally, the efficiency of regional markets is diminished when ISO has to commit or dispatch generation out of economic merit order due to fuel constraints – e.g., if control room operators are not reasonably certain that gas-fired units will have sufficient fuel for operation in real time if needed.[1]

The degree of uncertainty over fuel availability has become a tangible, challenging concern over the past year for ISO's control room operations.[2] ISO has highlighted in recent documents the drivers of such reliability concerns – namely, the combination of heavy dependence on operation of the region's natural gas-fired generating capacity throughout the year, and the increasingly-frequent constrained conditions for operation of the interstate natural gas pipeline system into and within New England. And while the risks are already present, changing system conditions in the coming years are likely to increase such risks.

The recently-completed ICF Fuel Security Analysis demonstrates the current and future vulnerability of the New England power system to gas-infrastructure related disruptions in both summer and winter peaking periods, under a number of different scenarios. See for example Figure 1 for a summary of winter power surplus/deficiency expectations given available interstate pipeline capacity, net of regional heating and process needs.[3] The solutions that ISO has proposed to address these conditions – whether they improve control room operator knowledge of unit availability, lead to changes in generating unit fuel sources, change fuel procurement practices, increase available pipeline capacity, or lead to unit operational adjustments – will reduce the probability that load will be lost due to constraints or contingencies on the natural gas system.

Reliable electric service is not only important from the perspective of meeting NERC and NPCC standards – it provides public safety and economic benefits by facilitating uninterrupted provision of public support services and by allowing customers to undertake economic and personal activity without disruption. Diminishment of reliable service can include both disruptions to service, and degradation in service quality (voltage changes). By reducing the probability, frequency or duration of bulk power

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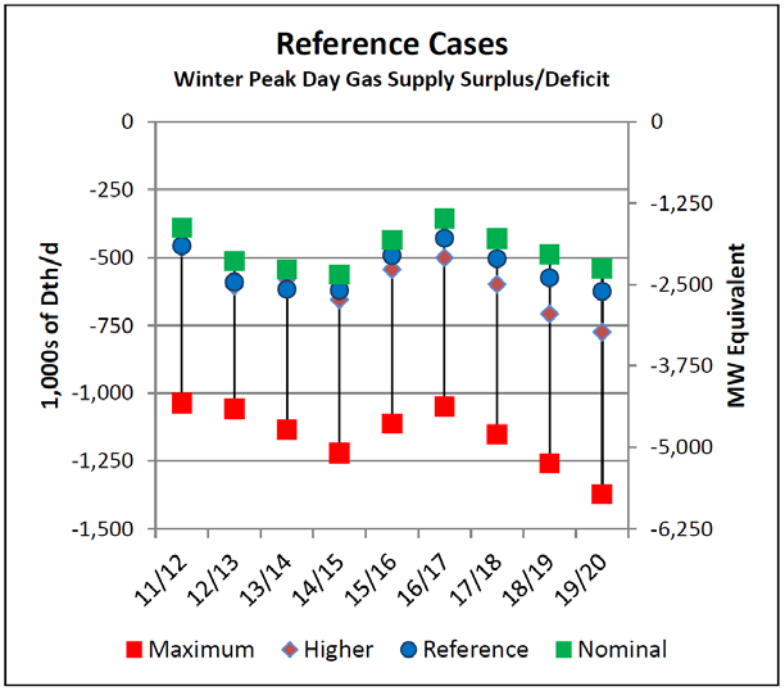
[1] See NEPOOL Participants Committee COO Report by Vamsi Chadalavada, November 2012, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2012/nov22012/coo_report_nov_2012.pdf

[2] See Presentation to New England Restructuring Roundtable by Pete Brandien, June 2012. http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2012/final_roundtable_june2012.pdf. Also, see memo to the NEPOOL Markets Committee by Dennis Robinson and Janine Dombrowski, August 1, 2012. http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/aug782012/a07_iso_memo_08_01_12.pdf

[3] ICF International, *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs*, June 15, 2012, Figure ES-1.

system interruptions, the solutions proposed by ISO to address the reliability impacts of dependence on natural gas can convey potentially large public safety, convenience, and/or economic benefits.[4]

Figure 1

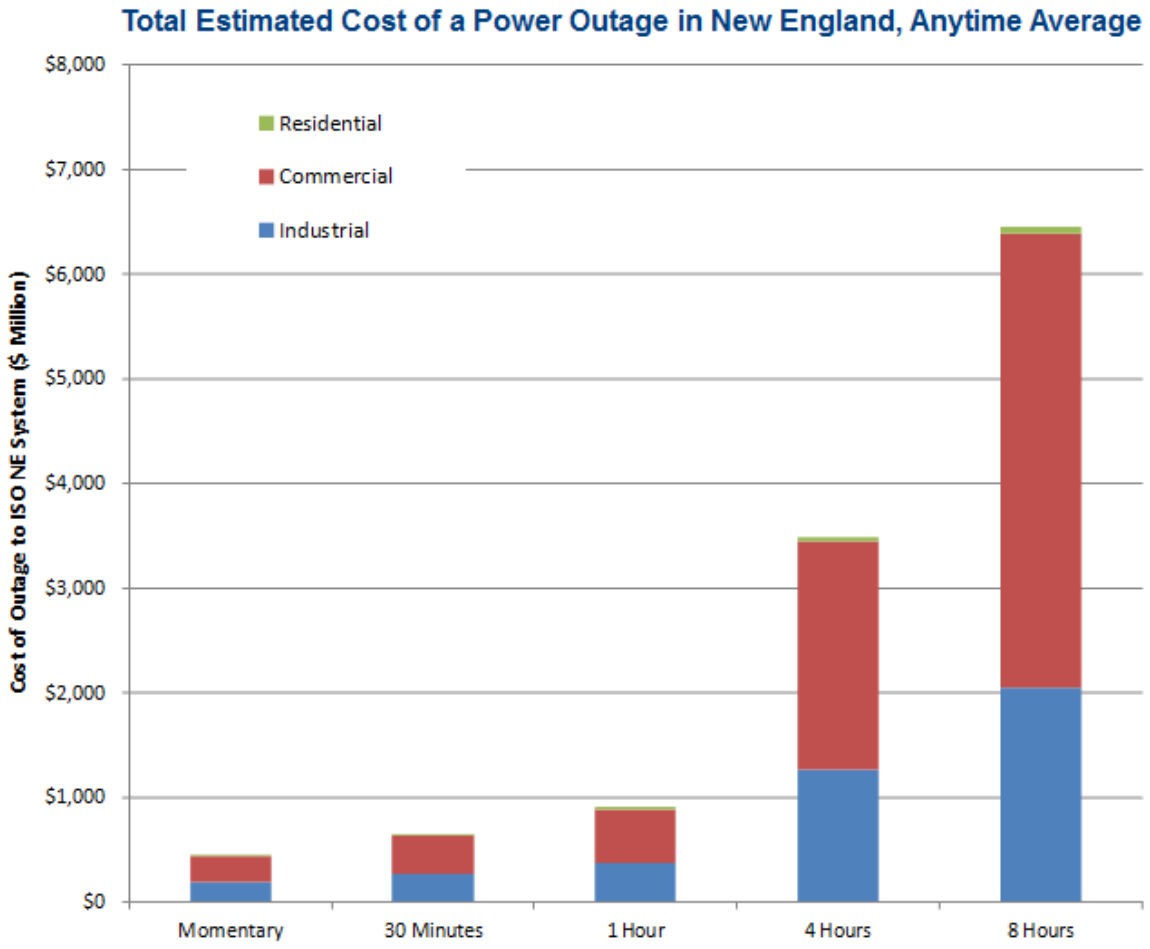



Value of Lost Load (VOLL) is the standard metric used to estimate the economic impact of disruptions in power service to customers, and thus can provide a measure of the magnitude of benefits associated with decreasing the likelihood of power system interruptions. There have been a number of studies completed to estimate VOLL, focused either on estimates of *expected* impacts in particular geographic locations, or on estimates of *damages* resulting from actual loss-of-load events. The studies reviewed for this memo are listed at the end of the memo. Review of these studies reveals that estimates of VOLL can vary significantly depending on what region one is studying; whether an interruption occurs on a weekend or weekday; what type of customer one is (i.e., residential vs. commercial/industrial); and how long the interruption lasts. In order to develop representative VOLL numbers for New England, we selected one of the studies reviewed that represents the middle of the range of all studies,[5] and that contains values that are comparable in magnitude to literature estimates of the costs of the 2003 Northeast blackout (which range from $4 billion to $10 billion (in $2003)).[6] Figure 2 presents numbers for New England based on these VOLL estimates, broken down by customer class and outage duration.

The estimates in this memo are presented for illustration purposes only, and to provide a sense of the potential magnitude of economic impacts of outages. A closer approximation would require assumptions, data and calculations specific to New England states' economic activity, and system conditions and prices consistent with the time frame under review. The public safety and economic impacts of outages experienced across New England states in recent years also provide important indications of benefits of power system reliability, and could serve as benchmarks to inform state- and region-specific analyses. Nevertheless, a review of the literature on VOLL suggests that the range of estimated economic impacts associated with loss of load (and thus benefits of avoiding such interruptions) could reach into billions of dollars for a region the size of New England.

[4] Most customer outages are due to the impact of accidents, storms or other events on local electric utility distribution systems. However, outage also can result from the loss of bulk power system assets – transmission lines or generating units.
[5] Specifically, we constructed New England numbers using the estimates in Sullivan et. al.

Figure 2




Studies reviewed and data used in VOLL estimates include the following:

- Centolella, Paul, et al., "Estimates of the Value of Uninterrupted Service for The Mid-West Independent System Operator", prepared for MISO.
- Electricity Consumers Resource Council (ELCON), "The Economic Impacts of the August 2003 Blackout," February 9, 2004.
- LaCommare, Kristina Hamachi and Joseph Eto, "Understanding the cost of power interruptions to U.S. electricity customers," report no. LBNL-55718, Berkeley, California: Lawrence Berkeley National Laboratory, 2004.
- Primen, "The Cost of Power Disturbances to Industrial & Digital Economy Companies," submitted to the Electric Power Research Institute, June 29, 2001.
- Sullivan, Michael J. et al., "Estimated Value of Service Reliablity for Electric Utility Customers in the United States," report no. LBNL-2132E, Berkeley, California: Lawrence Berkeley National Laboratory, June 2009. (This is the source used for our estimates).
- U.S.-Canada Power System Outage Task Force, "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," April 2004.
- United States Energy Information Administration, Form 826 Data

**To**: ISO-NE

**From:** Paul Hibbard, Analysis Group

**Date:** January 24, 2013

**Subject:** Information on the Range of Costs Associated with Potential Market Responses to Address the Risks Associated with New England's Reliance on Natural Gas

## Background

The ISO has identified the region's reliance on natural gas for electricity generation as a key strategic risk. In several documents developed over the past two years as part of its Strategic Planning Initiative, ISO has detailed the potential reliability challenges posed by dependence on natural gas, and has identified a number of short, medium, and longer-term market and operational solutions to address the risks. Implementing the proposed changes is expected to provide substantial reliability and efficiency benefits.

Implementing the proposed changes may also impose new costs. Some potential costs can be quantified; others may only be identified qualitatively, or may be highly variable or uncertain. For most of the proposed changes it is premature to carry out formal impact analysis or to identify with specificity the benefits and costs that may flow from the proposed rule changes, as the market designs for the solutions are not yet complete, and likely market responses are not yet well understood. Nevertheless, states and stakeholders have sought information and data on the potential drivers of costs related to market rule changes to address gas dependence risks.[1]

This memo provides qualitative and quantitative background information on categories of potential costs associated with new infrastructure alternatives to address gas dependence risks. It is a summary of various studies, reports, and analyses conducted by third parties and available in the public domain, related to natural gas and dual-fuel infrastructure options that could emerge from market rule changes, along with estimates developed by Analysis Group based on information and data provided by ISO-NE or contained in these studies and reports. The list of studies reviewed is presented at the end of this memo. Creating longer-term expectations around fuel certainty and unit performance could lead to such natural gas and/or power system investments, and these investments could in turn be reflected in capacity and reserve market pricing. The degree to which this occurs will depend on the infrastructure options, market need, and the ultimate price of the most competitive resource options that can meet system capacity needs and unit performance obligations.

[1] See, e.g., Memo from New England States Committee on Electricity, *State Feedback and Requests in Connection with ISO-NE's Addressing Gas Dependency Paper*, August 22, 2012, available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/gas_dependency_analysis_request_aug_22_2012.pdf.

## Infrastructure Options and Elements of Cost

There are a number of potential infrastructure responses to market rule changes to address gas dependence risks; cost data for several of these are presented in this memo, including the following:[2]

- Increases in dual-fuel capability or operations
  - From existing dual-fuel capable units
  - From existing units with dual-fuel capability that is currently mothballed or underutilized
  - From newly developed dual-fuel capability at existing gas plants
- New natural gas interstate pipeline capacity
- New in-region LNG storage
- Storage/transportation arrangements tied to existing LNG facilities

The effectiveness and viability of these potential solutions – from reliability and market perspectives – depends on (1) relative costs (fixed and variable), (2) feasibility and timeline for development, and (3) operational characteristics. In the sections that follow, information and data are presented for each of these factors, and for each of the options identified. Specifically, we review:

1. *Costs* – life-cycle costs, including upfront costs and annual operations costs.[3] In order to allow for comparison across options, cost data are reported on a common dollars per kW-month basis. The cost estimates provided are high-level, first-order estimates based on data provided by ISO-NE, and publicly-available information on recent development projects. Figure 1 describes how, in this document, categories of costs are identified and normalized to allow comparison.

**Figure 1**

| | | |
|---|---|---|
| **Capacity (MW)** | 200 | Each facility is sized to serve a quantity of gas-fired capacity |
| **Upfront Cost** | | |
| Project cost ($) | 1,000,000 | **Upfront costs** reflect siting, permit, engineering, facilities, technology and testing |
| Total Upfront Costs ($) | 1,000,000 | |
| **Annual Costs** | | |
| O&M ($) | 1,500,000 | **Annual Costs** include O&M, carrying costs of fuel storage, technology and air permit testing |
| Carrying Cost ($) | 1,000,000 | |
| Total Annual Costs ($) | 2,500,000 | |
| **PV** | | |
| Lifetime | 20 | Present value of lifetime costs of technical option reflect assumed lifetime and discount rate |
| Discount Rate | 9% | |
| **Present Value ($)** | 23,821,364 | |
| **Present Value per MW ($)** | 119,107 | Cost of technical options are normalized in terms of costs per kW-month |
| **Cost per kW-month ($)** | 1.09 | |

2. *Development timeline/feasibility* – the time required between conceptualization and commercialization for the options reviewed varies widely. The analysis presents qualitative assessments of development feasibility and barriers to implementation that would affect when specific alternatives would be available to influence reliability and market outcomes.

[2] It should be noted that there may be additional or alternative outcomes of market rule changes focused on natural gas dependence that are not identified or evaluated in this memo.

[3] In addition to these infrastructure development and operational costs, the integration of such new infrastructure would likely have an impact (positive or negative) on *system costs* over time. Such impacts could arise, for example, from changes in system unit commitment and dispatch in some or all hours of the year given the integration of new resources, and/or changes in system transmission costs. These system cost impacts are not reviewed in this memo.

3. *Operational characteristics* – not all options reviewed provide equal assurance of fuel delivery or generation availability, and so they present different implications for resource availability that may or may not affect market valuation. For example, options differ in their (1) ability to ensure fuel delivery for prolonged or frequent curtailments, (2) ability to support reserve-quality resources, and (3) ability to withstand interstate natural gas pipeline contingencies. The analysis presents qualitative assessments of operational constraints that would affect how specific alternatives would influence reliability and market outcomes.

In the sections that follow, we summarize results for each of the infrastructure options identified above.

**Dual-Fuel Capability**

All natural gas-fired units are capable – in theory – of dual fuel (DF) operation. However, they can differ significantly in the amount of work that would be required to establish operational DF capability, and in the costs that would be incurred to establish and use DF capability. Existing facilities fall into three basic categories:

1. Facilities that currently have DF capability – such units require *on-going* costs to (a) actively maintain alternate fuel burners, including burner and air permit testing, and (b) maintain sufficient fuel supply for an adequate period of operation (from the perspective of reliability needs under natural gas curtailment or contingency circumstances). These annual on-going costs are estimated at roughly $1 million per year. Absent market incentives to maintain this capability and a means to recover these on-going costs, DF capability has been, or likely will be, decommissioned.
2. Facilities with decommissioned DF capability – such units require the same on-going costs as category 1 units, once operational. However, these units would also incur up-front costs including modest technical upgrades, as needed, to bring alternate fuel burners back to operational status, as well as testing to obtain or reinstitute air permits, and to ensure burner operability. These one-time up-front costs are estimated at roughly $2 million for a 250 megawatt (MW) unit.
3. Facilities with no DF capability – such units require the same on-going costs as category 1 units, once operational. However, these units would also incur up-front costs involving major technical upgrades to add alternate fuel burners and fuel storage capability, including testing of new burners and acquiring necessary permits. These one-time up-front costs are estimated at roughly $21 million for a 250 megawatt (MW) unit.

Figure 2 presents a summary of the cost estimates and assumptions used to develop these estimates, including up-front costs, annual costs, and present value cost per kW-month. Results range from approximately $0.48/kW-mth for units with DF capability, to $1.25/kW-mth for units with no DF capability, including levelized capital costs of installing new infrastructure.

There are a number factors related to timing, deployment, and operational characteristics that are important to consider with respect to DF capability, and differences between DF options, including the following:

**Figure 2**

| | Dual Fuel Capable | Under- or Unutilized Duel Fuel Capability | No Dual Fuel Capability |
|---|---|---|---|
| **Capacity (MW)** | 260 | 260 | 260 |
| **Upfront Costs** | | | |
| Unit Cost ($/MW) | | 3,600 | 81,000 |
| Total Development Cost ($) | | 936,000 | 21,060,000 |
| Testing ($) | | 979,050 | 979,050 |
| Total Upfront Cost ($) | 0 | 1,915,050 | 22,039,050 |
| **Annual Costs** | | | |
| O&M ($) | 200,000 | 200,000 | 200,000 |
| Annual Testing ($) | 979,050 | 979,050 | 979,050 |
| Fuel Carrying Cost ($) | 307,862 | 307,862 | 307,862 |
| Days Fuel Supply | 3 | 3 | 3 |
| Fuel Cost ($/MMBtu) | 22.8 | 22.8 | 22.8 |
| Total Annual Costs ($) | 1,486,912 | 1,486,912 | 1,486,912 |
| Lifetime (Years) | 20 | 20 | 20 |
| Discount Rate | 9% | 9% | 9% |
| **Present Value ($)** | 13,573,340 | 15,488,390 | 35,612,390 |
| **Present Value per MW ($)** | 52,205 | 59,571 | 136,971 |
| **Annualized Cost per kW-mth ($)** | 0.48 | 0.54 | 1.25 |

- The actions needed to firm up DF capability with operable or unused capability can likely be performed relatively quickly – burner upgrades are fairly limited in scope; there are relatively few barriers to securing sufficient fuel supply (other than cleaning unused storage tanks and securing cost recovery for fuel carrying costs); and minimum testing time is needed to maintain burner operability and permit status. This means that adding/activating such capability could possibly be completed by winter 2013/2014.
- Actions to install DF capability at units that do not have it are more involved and would require more time – including development, permitting, and construction activities. Such capability would likely not be able to be online until winter 2014/2015 at the soonest.
- In some cases there are or would be variations in output and risk of outage when actively switching from gas- to oil-firing. Some units – in particular those burning heavy fuel oil as a secondary fuel, need to power down before switching, and thus would provide less flexibility than units that can switch on the fly. In addition, there is an increased risk of outage with switching, particularly when alternate fuels are used infrequently.
- It is anticipated that regulatory limits on oil firing to address air quality concerns would generally allow for sufficient operability of DF units to cover electric system reliability needs (while some units may only be allowed to operate on oil when gas is unavailable, most units can operate within permit limits for an annual number of hours equivalent to weeks, a month, or months of continuous operation).
- Finally, storage capacity (relative to burn at continuous full output) and storage refilling methods and rates can be an important element of maintaining resource availability, particularly during winter cold-snap conditions. DF units can have very different capacities and refill rates.

- Generally speaking, facilities served by oil pipelines or rail would be able to maintain burn if needed, and/or refill relatively quickly. But most facilities are served by truck refills, which can require days or weeks to refill to storage representing three days of continuous output.[4] For example, assuming tanker truck capacity of 9,000 gallons (generally on the high end) and representative heat rates, it would take 20 trucks per day to support continuous output of 130 MW.

**New Interstate Pipeline Capacity**

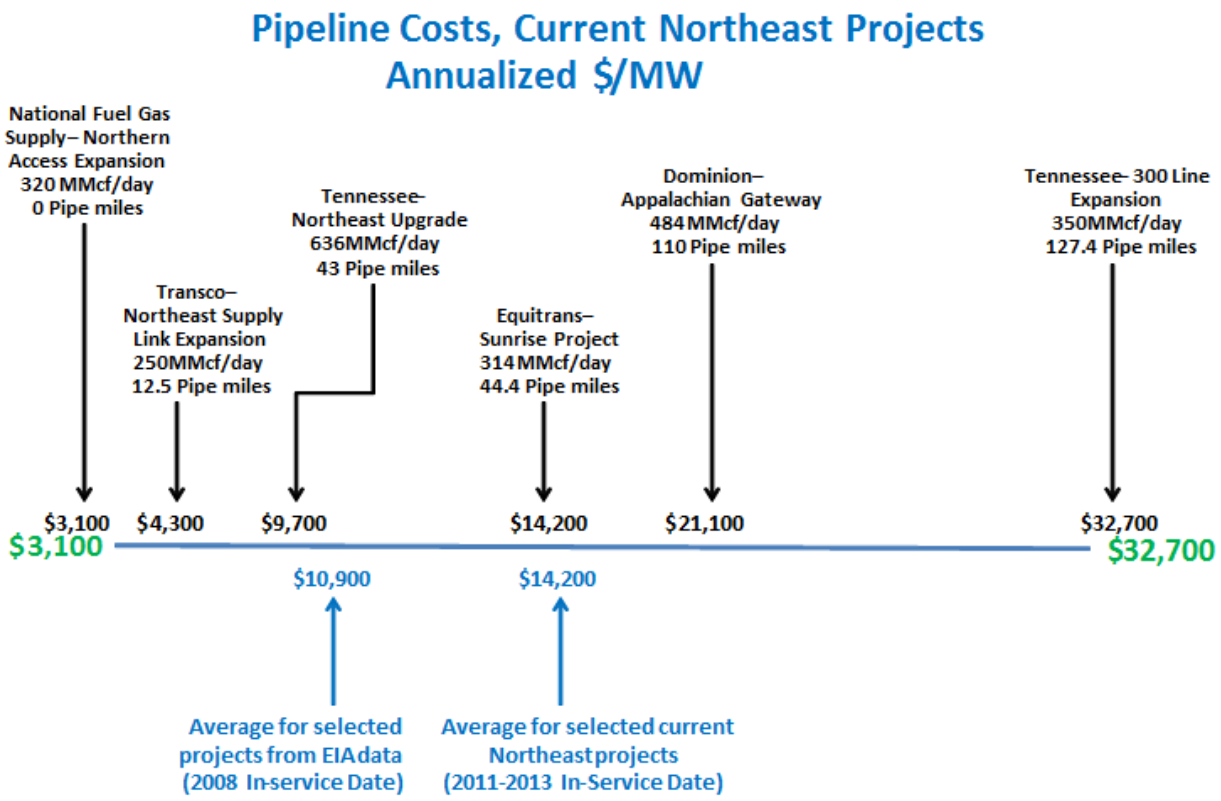
Relatively little firm service is available on the primary pipelines serving New England, so additional firm natural gas supply will likely require the construction of additional pipeline capacity. Increased natural gas pipeline capacity could support the transport of additional fuel supplies to the region, and so would reduce the risk of curtailment to gas-fired generators, relative to current market conditions. Additional pipeline capacity to provide firm gas supply can be achieved through various changes to the interstate pipeline system to relieve pipeline congestion or add incremental capacity, ranging from new compressor stations along existing pipe, to looping, to the construction of new pipelines from key gas sources (e.g., the Marcellus Shale region). The cost of various changes are difficult to identify absent engineering studies, and depend on the extent to which lower-cost technical changes to expand the capacity of the existing pipeline assets have already been exhausted. In recent months, pipeline owners have suggested that most low-cost changes have likely already occurred.

The range of potential upfront costs to increase pipeline capacity from Marcellus and other lower-cost natural gas reserve regions is wide, and depends on the location of constraints being relieved, and/or the overall size and route of the project. See Figure 3.

In addition to up-front costs, annual costs are incurred for operations and maintenance on the pipeline system. In Figure 4 below, estimates of the annualized cost per MW are presented using for the purposes of calculation the average up-front cost of selected current Northeast region projects (based upon the projects reviewed, as presented in Figure 1), and the estimated annual costs for O&M expense. This estimate, based on an assumed increase in pipeline capacity of nearly 400,000 dekatherms per day, is approximately $1.17/kW-mth of equivalent electrical generating capacity.

[4] Three days of continuous output was chosen only to construct a representative calculation. Market performance obligations and/or reliability needs could require less than three days of continuous output.

**Figure 3**




There are a number factors related to timing, deployment, and operational characteristics that are important to consider with respect to the reliability and economic value of increasing pipeline capacity, including the following:

- The timeline for new pipeline capacity siting, permitting, and construction is on the order of several years. Consequently, this is not an option that can provide meaningful power system reliability benefits for several years, at least.
- Under current FERC rules and past practices for funding new pipeline capacity, new projects typically will not go forward without up-front financial commitments from customers to take firm delivery service for all – or most – of the new capacity. Entering into such long-term financial commitments for natural gas transportation is challenging for electric generators under current market conditions.
- Current pipeline capacity firm commitments are held almost entirely by natural gas local distribution companies (LDCs) for the benefit of natural gas ratepayers, and with the guarantee that such capacity will be used to meet the need of LDC end-use customers for heating and process needs as needed, particularly at the time of winter peak conditions. This means that while substantial amounts of such capacity may be released to secondary markets for use by electric

generators throughout the year, it cannot be counted on during winter peak or cold-snap conditions.

- Incremental gas supplies from the Marcellus, at current prices, would result in substantially lower per MWh operating costs than equivalent oil or LNG fuel burns. Increasing pipeline capacity would increase access to lower-cost natural gas reserve regions (e.g., Marcellus) throughout the year, and this could have the effect of decreasing power system costs during any hours when supply from such regions would otherwise be constrained.

**New and Existing LNG Storage Capability**

There are two options tied to liquefied natural gas that have been identified as opportunities to firm up natural gas fuel supply to natural gas-fired generating facilities in New England: (1) the construction of new land-based LNG storage facilities with liquefaction capability dedicated to providing backup gas fuel supply to power plants, [5] and (2) new services associated with spare capacity – to the extent it exists – at the two major LNG terminals serving the region (Distrigas of Massachusetts Corp, or DOMAC, located in Boston, and Canaport, located in Canada).

*New LNG Storage Capacity*

In order to develop cost assessments, we reviewed the costs of three recently-sited facilities of roughly equal storage capacity; the facilities we reviewed offered the best combination of size, performance (vaporization and liquefaction), and cost when utilized as a backup fuel supply.

The cost of a new LNG storage facility includes up-front development costs, annual operating costs, and the carrying cost of the stored fuel. Our estimates are based on the three facilities reviewed, sized to a generic facility with (a) a vaporization rate sufficient to provide backup fuel supply for approximately 540 MW of capacity; (b) 60,000 cubic meters (cm) of storage, equivalent to roughly 14 days of operation at the assumed vaporization rate; (c) a liquefaction rate that would be sufficient to refill enough supply to operate the facility (540 MW) for one day, in 14 days. See Figure 4.

**Figure 4**

| | |
|---|---|
| **Capacity** | |
| LNG Volume (cubic meters) | 60,000 |
| NG Energy Capacity (MMBtu) | 1,262,400 |
| **Flow capabilities** | |
| Maximum discharge rate (MMBtu / day) | 91,300 |
| Maximum liquefaction rate (MMBtu / day) | 6,333 |
| **Variable Operating Costs** | |
| Liquefaction cost ($ / MMBtu) | 1.6 |
| Storage and regasification cost ($ / MMBtu) | 0.4 |
| **Backup Fuel Supply Capability** | |
| MW-Days of Backup Fuel Supply Stored | 7,514 |
| Max MW per Day (given liquefaction rate) | 543 |
| Days to Refill (Liguefy) Sufficient Supply for Max MW per Day | 14 |
| Assumed Heat rate (Btu / kwh) | 7,000 |

Based on the recently-completed facilities, up-front costs range from $1,850 to $2,450 per cm of storage, amounting to approximately $128 million for the generic facility, including siting, permitting,

[5] With respect to new LNG Storage, we focus on on-land facilities with liquefaction capability similar in size to many peak-shaving LNG storage facilities in existence today. We do not review facilities without liquefaction, as refill rates for storage without liquefaction are estimated to be too slow to provide a reliable back up fuel supply. We also do not review new large-scale LNG terminals given the demonstrated and likely barriers to the siting of such facilities within New England.

engineering, and capital costs. Variable costs include fuel carrying costs and operating costs related to liquefaction, storage and regasification. This translates to a cost on the order of approximately $2.47/kW-mth). See Figure 5.

There are a number of factors related to timing, deployment, and operational characteristics that are important to consider with respect to LNG storage capability, including the following:

- Siting and development of a LNG storage facility could require multiple years, even under relatively easy siting conditions. Storage facilities of this size are modest-sized industrial facilities, so in some cases and/or locations opposition to siting at the local level could further lengthen the development timeline.
- The mix of liquefaction and vaporization rates introduces certain constraints on the market value of such facilities, and also on their reliability benefit. At the assumed (and achievable) vaporization rate, it would take between 7 and 20 days to fully discharge the tank. However, the liquefaction rate limits the ability to refill the tank after discharge. Specifically, it could take more than 190 days to fully refill the tank after discharge. Consequently, such a facility could provide backup fuel for an extended curtailment (or multiple shorter curtailments), but that backup capability could be significantly limited for subsequent curtailments after full discharge.

**Figure 5**

| | |
|---|---|
| **Capacity (MW)** | 543 |
| **Upfront Cost** | |
| Project cost ($) | 127,666,667 |
| Cost per cubic meter | 2,128 |
| **Annual Costs** | |
| O&M ($) | 1,500,000 |
| Carrying Cost ($) | 633,920 |
| Initial Fuel Cost (including liquefaction) ($) | 7,043,561 |
| Total Annual Costs ($) | 2,133,920 |
| **PV** | |
| Lifetime | 20 |
| Discount Rate | 9% |
| **Present Value ($)** | 147,146,257 |
| **Present Value per MW ($)** | 270,988 |
| **Annualized Cost per kW-mth ($)** | 2.47 |

*Existing LNG Facilities*

With respect to the existing DOMAC and Canaport facilities, it has been suggested that backup fuel supply to electric generators could be provided through arrangements to essentially store fuel and inject it into the pipelines upon request by electric generators, from these two facilities.[6] Reliance on such services would require excess storage and regasification capacity at the terminal in question, and delivery service on Algonquin or Tennessee to the gas-fired generator's connection point on the pipelines. In addition, for Canaport service there would need to be delivery service on the Maritimes and Northeast pipeline. The stored gas, and the capacity to inject and deliver it, would need to be available as and when needed by the gas generator.

[6] In theory, these same services could be supplied by the offshore Neptune and Northeast Gateway terminals, through tankers "parked" at the intake pipes, or from existing local gas distribution company (LDC) peak shaving storage capacity. However, we did not review this separately given the potentially prohibitive costs of using tankers (on top of the other costs that would be faced by Canaport or DOMAC), and given the dedication of LDC storage facilities to serve natural gas LDC customers on peak.

In this case, there are essentially no up-front costs. All services would be on existing facilities to the extent capacity exists. An estimate of annual costs can be derived by estimating (1) the opportunity cost of storing LNG instead of selling it in higher-value markets (i.e., Europe); (2) the carrying cost reflecting interest on the value of stored fuel; and (3) if firm service is required to meet reliability requirements, a transportation charge for moving gas from storage to delivery point.

We have not attempted to estimate the type and cost of pipeline transportation charges, given the uncertainty around the type of service, and rate that would be charged within the constraints of existing pipeline capacity. However, given the price differential between gas markets in Europe and New England, and the carrying cost of the fuel, we estimate that the price for services would be on the order of $157/MW-day of operation.

List of Sources Reviewed

Sources of information relied on for the Dual Fuel section include the following:

- ESS Group, "Dual-Fuel Generating Capacity and Environmental Constraints Analysis," Interim Report, prepared for ISO-NE, April 1, 2005.
- Settlement between NYISO and TransCanada, Ravenswood for recovery of on-going costs of maintaining dual fuel capability, April, 2011
- PJM Cost of New Entry (CONE), incremental cost for dual fuel capability on new generation units, 2011
- Handy-Whitman Index of Public Utility Construction Costs
- Analysis Group estimates based on these reports, and on data provided by ISO-NE

Sources of information relied on for the New Interstate Pipeline section include the following:

- INGAA publication #17742 (sourced from North American Midstream Infrastructure Through 2035 – A Secure Energy Future, ICF International for INGAA, June 28, 2011)
- "2012 Worldwide Pipeline Construction Report," Pipeline & Gas Journal, January 2012
- "Pipeline Costs in Shale Gas Regions," Ziff Energy Group, June 29, 2011; "Natural Gas Under Siege," Ziff Energy Group, April 2012
- "Gas and Electric Infrastructure Interdependency Analysis," Prepared for MISO by EnVision Energy Solutions, February 2012
- "Jobs & Economic Benefits of Midstream Infrastructure Development, US Economic Impacts Through 2035," Black & Veatch for INGAA, February 15, 2012

Sources of information relied on for the LNG Storage Section include the following:

- "CB&I Awarded Contract for Temple LNG Expansion Project," Pipeline & Gas Journal, December 2009
- UGI LNG company website: http://www.ugilng.com/
- "LNG Facility Brings Positive Economic Change to Former Manufacturing Center," Pipeline & Gas Journal, November 2009
- "LNG Peakshaving Facility, Connecticut, USA," CB&I company website, http://www.cbi.com/markets/project-profiles/lng-peakshaving-facility-connecticut-usa/
- "Mt. Hayes Liquefied Natural Gas Storage Facility, Terasen Gas (Vancouver Island) Inc.," Stakeholder Workshop for the CPCN Application, June 27, 2007
- "Mt. Hayes LNG Storage Facility – In the Matter of an Application by Terasen Gas (Vancouver Island) In. for a Certificate of Public Convenience and Necessity," Submitted to British Columbia Utilities Commission, June 5, 2007"
- "West Coast LNG Projects and Proposals," California Energy Commission, Sept. 2011

- "CB&I Awarded Contract for Temple LNG Expansion Project," Pipeline & Gas Journal, December 2009
- UGI LNG company website: http://www.ugilng.com/
- "LNG Facility Brings Positive Economic Change to Former Manufacturing Center," Pipeline & Gas Journal, November 2009
- "LNG Peakshaving Facility, Connecticut, USA," CB&I company website, http://www.cbi.com/markets/project-profiles/lng-peakshaving-facility-connecticut-usa/
- "Mt. Hayes Liquefied Natural Gas Storage Facility, Terasen Gas (Vancouver Island) Inc.," Stakeholder Workshop for the CPCN Application, June 27, 2007
- "Mt. Hayes LNG Storage Facility – In the Matter of an Application by Terasen Gas (Vancouver Island) In. for a Certificate of Public Convenience and Necessity," Submitted to British Columbia Utilities Commission, June 5, 2007"
- "West Coast LNG Projects and Proposals," California Energy Commission, Sept. 2011
- Repsol, "A Potential LNG Solution for Maintaining Pipeline Deliverability During Peak Demand Periods," ISO NE / NGA Meeting, April 12, 2012
- EIA, "World LNG Shipping Capacity Expanding," Report #DOE/EIA-0637, 2003.
- Massachusetts gas utility resource plans and forecasts
- Analysis Group estimates

# M E M O R A N D U M

**TO:** NEPOOL Participants Committee Members and Alternates

**FROM:** Sebastian M. Lombardi, NEPOOL Counsel

**DATE:** January 30, 2013

**RE:** Update: Revised Order 755 Compliance Proposal (Frequency Regulation Compensation)

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This update is to advise you that the Markets Committee met yesterday and voted unanimously[1] to recommend Participants Committee support for the ISO's revised compliance proposal in response to Order 755 and the FERC's November 8, 2012 order in Docket No. ER12-1643 on the region's initial Order 755 compliance filing.[2] Additional materials, including an earlier NEPOOL Counsel memorandum, background materials from the ISO and a copy of the recommended changes, were circulated with the supplemental notice and are included in the composite set of materials. A copy of the Markets Committee January 29, 2013 notice of actions is included with this memorandum.

Given the Markets Committee recommendation, the following revised form of resolution may be used for Participants Committee action on this matter:

> RESOLVED, that the Participants Committee supports the revisions to Market Rule 1, Appendix F to Market Rule 1 and the Tariff's centralized Definitions, and the deletion of Appendix J to Market Rule 1, proposed in response to FERC's November 8, 2012 order in Docket No. ER12-1643, as recommended by the Markets Committee at it January 29, 2013 meeting 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.

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[1] 5 abstentions were recorded (3 in the Supplier Sector; 1 in the End User Sector; and 1 in the AR Sector).

[2] *ISO New England Inc. et al,* 141 FERC ¶ 61,110 (2012).

ISO new england

memo

**To:** Participants Committee

**From:** Alex Kuznecow, Secretary, Markets Committee

**Date:** January 29, 2013

**Subject:** **ACTIONS OF THE MARKETS COMMITTEE**

This memo is notification to the Participants Committee (PC) of the following action taken by the Markets Committee (MC) at its January 29, 2013 meeting. All Sectors had a quorum.

1. (Agenda Item 3) **REGULATION MARKET (ORDER 755) COMPLIANCE ACTION: RECOMMEND SUPPORT**

The following motion was moved and seconded by the Markets Committee:

> RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Market Rule 1, Appendix F to Market Rule 1, and Tariff Section I.2.2 and deletion of Appendix J to Market Rule 1 in response to the FERC compliance requirements contained in the November 8, 2012 Order for Docket No. ER12-1643-000 as proposed by ISO New England Inc. (the "ISO") and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. Based on a show of hands, the motion passed. 3 abstentions within the Supplier Sector, 1 abstention within the Alternative Resources Sector, and 1 abstention within the End User Sector were recorded.

# M E M O R A N D U M

**TO:** NEPOOL Participants Committee Members and Alternates

**FROM:** Sebastian M. Lombardi, NEPOOL Counsel

**DATE:** January 25, 2013

**RE:** ISO-NE Order 755 Compliance Proposal on Frequency Regulation Compensation

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At its February 1, 2013 meeting, the Participants Committee will be asked to consider supporting changes to Market Rule 1 and the Tariff's centralized Definitions section, proposed by the ISO in response to the FERC's November 8, 2012 Order in Docket No. ER12-1643 (the "*November Order*").[1] The *November Order* requires the ISO to submit by February 6, 2013, modifications to an earlier proposal in response to FERC Order 755 (*Frequency Regulation Compensation in Organized Wholesale Power Markets)* related to the use of clearing prices and several other issues.[2] Included with this memorandum is a copy of the ISO's recommended changes, along with background materials from the ISO that were circulated to the Markets Committee for its meeting on January 29, 2013. We will provide an update on this matter following the Markets Committee's deliberations next week.

By way of brief background, *Order 755* requires organized markets to include in their tariffs a two-part, market-based compensation method for regulation service: (1) a uniform capacity payment, to include opportunity costs, for standing ready to provide frequency regulation service; and (2) a market-based performance payment for regulation service that is actually provided. Last April, the Participants Committee unanimously supported the ISO's proposed *Order 755* compliance changes,[3] which included a simultaneous auction design ("Vickrey design"). The ISO and NEPOOL jointly submitted that proposal to FERC, explaining in their filing why they considered it to comply with *Order 755*.

In the *November Order*, the FERC rejected the jointly-submitted proposal as non-compliant with *Order 755*. The Commission based its order on its conclusions that the proposal did not provide uniform clearing prices and did not provide a two-part payment for both capacity and resource performance.[4] Further, the FERC noted that ISO-NE did not meet the burden of proof required to demonstrate that a deviation from *Order 755*'s requirements was warranted.[5]

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[1] *ISO New England Inc. et al,* 141 FERC ¶ 61,110 (2012).

[2] *Frequency Regulation Compensation in the Organized Wholesale Power Markets,* Order No. 755, 137 FERC ¶ 61,064 (2011) ("*Order 755*").

[3] Abstentions were noted by two End User Participants -- Harvard Dedicated Energy Limited and the Massachusetts Attorney General's Office.

[4] *November Order* at P. 27.

[5] *Id*. at P. 28.

In response to the *November Order*, the ISO has proposed modifications to the earlier proposal. The ISO's modified proposal provides, among other things, for a uniform capacity price and a uniform service (also called "mileage") price. As noted above, the ISO's proposal will be considered next week by the Markets Committee.

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

> RESOLVED, that the Participants Committee supports the revisions to Market Rule 1, Appendix F to Market Rule 1 and the Tariff's centralized Definitions, and the deletion of Appendix J to Market Rule 1, proposed in response to FERC's November 8, 2012 Order in Docket No. ER12-1643, as recommended by [the ISO][the Markets Committee at it January 29, 2013 meeting] 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.

JANUARY 29, 2013 | NEPOOL MARKETS COMMITTEE

# Regulation Market (Order 755) Compliance

*Changes to the April 30th Design to Comply with November 8, 2012 FERC Order*

Jonathan Lowell

PRINCIPAL ANALYST | MARKET DEVELOPMENT

# Background

- FERC Order 755 requires regulation market design changes to provide
  - Two Part Bidding – capacity (MW) and service (mileage)
  - Energy opportunity costs included in market clearing
  - Uniform clearing prices and two-part payment
- Unfortunately, this is not possible without sacrificing economic efficiency (least cost) and/or incentive compatibility (optimal bidding strategy is to offer true costs)
- The ISO filed a design that provided economically efficient outcomes and incentive compatibility
  - The ISO proposed to publish "approximate clearing prices" to enhance market transparency

# FERC Decision

- On 11/8/12 FERC issued an order rejecting the ISO's proposed tariff revisions:
  - Did not provide uniform clearing prices
  - Did not provide a two-part payment
  - Did not meet the burden of proof to demonstrate that a deviation from Order No. 755's requirements was warranted
- ISO must submit a new compliance filing by February 6th
- The rejection did not address economic efficiency or incentive compatibility issues, but rather was narrowly drawn, based on the specific language of the original order.

# ISO Compliance Proposal Objectives

- Meet FERC requirements for uniform clearing prices
- To the extent possible:
  - Minimize potential loss of economic efficiency
  - Preserve incentive compatibility
  - Avoid  bid skewing
  - Avoid potential incentives to not follow AGC dispatch
  - Minimize the need for uplift or make-whole payments
- Make no changes not directly related to the incorporation of clearing prices

# Compliance Design in a Nutshell

| | |
|---|---|
| **UNCHANGED** from the April 30 Filing | Select least cost resources to meet capacity and mileage requirements<br>• Offered capacity and mileage prices<br>• Estimated mileage<br>• Estimated energy opportunity cost included with capacity offer |
| | Calculate incremental cost savings provided by the resource<br>The "Efficient Bundled Payment" for each resource is:<br>EBP = Est. As-Bid Cost + Incremental Cost Savings |
| **NEW** for the Feb. 6 Compliance Filing | Determine uniform mileage price<br>•Maximum of the mileage offers of all selected resources |
| | Determine uniform capacity price<br>•Highest of the capacity prices each selected resource would require in order for its compensation to equal its Efficient Bundled Payment |

# Compliance Design Advantages

- Simple modification to April 30th design
- High confidence the design meets Order 755 requirements, as reinforced in the November 8th order
  - Uniform prices used for settlement
- Largely preserves economic efficiency by selecting least cost resources and compensating those resources at prices based on true value to the system
- Minimizes the need for uplift payments
- Preserves the "no risk to participation" feature of the April 30th design
  - Important for reliability: encourages participation

# Compliance Design – Other Details

- Offer Price caps and floors (New!)
  - Limits potential for bid skewing
- Make-whole payment to ensure compensation for selected resources covers as-bid cost of actual performance and actual energy opportunity cost
- Prices always >= 0
- Publication of market results will include the actual prices
  - No calculation or publication of proxy price information

# Next Steps

- Request MC vote to recommend support January 29th
- PC review at February 1st meeting
- File with FERC on February 6th

# APPENDIX

# Price Calculation Example – Part 1

| | Requirements |
|---|---|
| MW | 70 |
| Miles | 700 |

| | Offered Values | | | | Est. Opp | Eff. |
|---|---|---|---|---|---|---|
| Name | MW | Miles | $/MW | $/Mile | Cost | $/MW |
| A | 17 | 136 | 12 | 0.5 | 1 | 13 |
| B | 42 | 252 | 11 | 0.4 | 2 | 13 |
| C | 27 | 243 | 12 | 1.6 | 3 | 15 |
| D | 18 | 234 | 5 | 0.6 | 1 | 6 |
| E | 31 | 217 | 5 | 1.3 | 2 | 7 |
| F | 12 | 108 | 6 | 1.4 | 1 | 7 |
| G | 31 | 217 | 5 | 0.9 | 1 | 6 |
| H | 33 | 429 | 9 | 1.2 | 5 | 14 |
| I | 51 | 408 | 4 | 0.8 | 4 | 8 |
| J | 31 | 248 | 5 | 1.8 | 2 | 7 |
| K | 54 | 594 | 4 | 0.4 | 1 | 5 |
| L | 43 | 516 | 6 | 1.4 | 3 | 9 |
| M | 10 | 50 | 8 | 1.5 | 4 | 12 |
| N | 51 | 408 | 5 | 1.1 | 4 | 9 |
| O | 24 | 312 | 9 | 1.7 | 3 | 12 |

| Selected Resources | | | |
|---|---|---|---|
| MW | Miles | Bid Cost | Vic Pmt |
| 0 | 0 | 0 | |
| 0 | 0 | 0 | |
| 0 | 0 | 0 | |
| 18 | 234 | 248 | 289 |
| 0 | 0 | 0 | |
| 0 | 0 | 0 | |
| 0 | 0 | 0 | |
| 0 | 0 | 0 | |
| 0 | 0 | 0 | |
| 0 | 0 | 0 | |
| 54 | 594 | 508 | 970 |
| 0 | 0 | 0 | |
| 0 | 0 | 0 | |
| 0 | 0 | 0 | |
| 0 | 0 | 0 | |
| 72 | 828 | 756 | 1259 |

| Total Cost When Excluded | Total Cost When Inlcuded | Increm Cost Savings | As-Bid Cost If Cleared | Vic Pmt = Bid Cost + ICS |
|---|---|---|---|---|
| 756 | 797 | -41 | 289 | 248 |
| 756 | 1154 | -398 | 647 | 248 |
| 756 | 1301 | -545 | 794 | 248 |
| 797 | 756 | 41 | 248 | 289 |
| 756 | 1007 | -251 | 499 | 248 |
| 756 | 938 | -182 | 235 | 53 |
| 756 | 889 | -133 | 381 | 248 |
| 756 | 1484 | -728 | 977 | 248 |
| 756 | 1218 | -462 | 734 | 272 |
| 756 | 1171 | -415 | 663 | 248 |
| 1218 | 756 | 462 | 508 | 970 |
| 756 | 1491 | -735 | 1109 | 375 |
| 756 | 938 | -182 | 195 | 13 |
| 756 | 1391 | -635 | 908 | 272 |
| 756 | 1326 | -570 | 818 | 248 |

Note: Estimate Opportunity Cost included in Effective Capacity Offer Price

# Price Calculation Example – Part 2

| Resource | Offered MW | Offered Miles | Mileage Bid | Mileage Price | Req Capacity Price | Efficient Bundled Payment |
|---|---|---|---|---|---|---|
| D | 18 | 234 | 0.6 | 0.6 | 8.3 | 289.0 |
| K | 54 | 594 | 0.4 | | 11.4 | 969.6 |

Mileage Price = Maximum mileage offer of selected resources = $0.6/Mile

# Price Calculation Example – Part 3

Given a mileage price of $0.6/mile, the capacity price required for resource D to receive expected compensation equal to its Vickrey Payment of $289 is:

18 MW x Capacity Price + 234 miles x $0.6/mile = $289

Therefore, Resource D Capacity Price = $8.3/MW

Similarly, Resource K Capacity Price = $11.4/MW

Uniform Capacity Price = Max[$8.3/MW, $11.4/MW]

= $11.4/MW

| Resource | Compensation at Uniform Prices |
|---|---|
| D | 344.8 |
| K | 969.6 |

# Design Options Considered But Not Pursued

- “Best Fit” pricing over a range of requirements
- “Best Fit” pricing for those resources selected as least cost
- Several compliance options were considered that did not meet threshold criteria
  - Select based on capacity price, dispatch based on mileage price
  - Highest selected prices
  - Include opportunity cost in current pricing design

## I.2 Rules of Construction; Definitions

### I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

**Administrative Sanctions** are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

**ADR Neutrals** are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

**Advance** is defined in Section IV.A.3.2 of the Tariff.

**Affected Party**, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

**Affiliate** is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

**AGC** is automatic generation control.

**AGC SetPoint** is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

**AGC SetPoint Deadband** is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

**Allocated Assessment** is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

**Alternative Capacity Price Rule** is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

**Alternative Dispute Resolution (ADR)** is the procedure set forth in Appendix D to Market Rule 1.

~~**Alternative Technologies Regulation** Pilot Program is the pilot described in Appendix J to Market Rule 1.~~

**Alternative Technology Regulation Resource** is any Resource eligible to provide Regulation that is not registered as a different Resource type.

**Amount Interrupted** is, for purposes of the Load Response Program, the calculated difference between the Customer Baseline and the actual customer load. For generating assets, metered at the generator output, the Amount Interrupted is the generator output.

**Ancillary Services** are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

**Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount** are defined in Section IV.B.2.2 of the Tariff.

**Annual Transmission Revenue Requirements** are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

**Annualized FCA Payment** is used to determine a resource's availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

**Applicants**, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

**Application** is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

**APR-1** means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

**Capacity Load Obligation Acquiring Participant** is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

**Capacity Load Obligation Bilateral** is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

**Capacity Load Obligation Transferring Participant** is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

**Capacity Network Resource (CNR)** is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

**Capacity Network Resource Interconnection Service** is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

**Capacity Rationing Rule** addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

**Capacity Requirement** is described in Section III.13.7.3.1 of Market Rule 1.

**Capacity Supply Obligation** is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

**Capacity Supply Obligation Bilateral** is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

~~**Capacity-to-Service Ratio** is defined in Section III.3.2.2(h) of Market Rule 1.~~

**Demand Response Baseline** is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8.

**Demand Response Capacity Resource** is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

**Demand Response Holiday** is a holiday for which a Market Participant may not submit a Demand Reduction Offer for a Real-Time Demand Response Asset.

**Demand Response Regulation Resource** is a Real-Time Demand Response Resource eligible to provide Regulation.

**Designated Agent** is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

**Designated Blackstart Resource** is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

**Designated Entity** is the entity designated by a Market Participant to receive Dispatch Instructions for generation and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

**Designated FCM Participant** is any Lead Market Participant, including any Provisional Member or DRP-Only Customer that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

**Regional Network Load** is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

**Regional Network Service (RNS)** is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

**Regional Planning Dispute Resolution Process** is described in Section 12 of Attachment K to the OATT.

**Regional System Plan (RSP)** is the plan developed under the process specified in Attachment K of the OATT.

**Regional Transmission Service (RTS)** is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

**Regulation** is the capability of a specific ~~generating unit~~Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.~~increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.~~

**Regulation and Frequency Response Service** is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

**Regulation Capacity** is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

~~**Regulation Capability (REGCAP)** means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.~~

**Regulation Capacity Requirement** is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

~~**Regulation Clearing Price** is defined in Section III.3.2.2(e) of Market Rule 1.~~
**Regulation Capacity Offer** is an offer by a Market Participant to provide Regulation Capacity.

**Regulation High Limit** is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity ~~the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit~~.

**Regulation Low Limit** is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity ~~the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit~~.

~~**Regulation Opportunity Cost** is defined in Section III.3.2.2(i) of Market Rule 1.~~

~~**Regulation Rank Price** is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.~~

~~**Regulation Requirement** is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.~~

~~**Regulation Service Credit** is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.~~

~~**Regulation Service Megawatts** are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.~~

**Regulation Market** is the market described in Section III.14 of Market Rule 1.

**Regulation Service** is the change in output or consumption made in response to changing AGC SetPoints.

**Regulation Service Requirement** is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

**Regulation Service Offer** is an offer by a Market Participant to provide Regulation Service.

**Related Person** is defined pursuant to Section 1.1 of the Participants Agreement.

**Related Transaction** is defined in Section III.1.4.3 of Market Rule 1.

**Reliability Administration Service (RAS)** is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

**Reliability Committee** is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

**Reliability Markets** are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

**Reliability Region** means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

**Reseller** is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

**Reserve Constraint Penalty Factors (RCPFs)** are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

**Reserve Zone** is defined in Section III.2.7 of Market Rule 1.

**Reserved Capacity** is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

**Resource** means a generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction. For purposes of providing Regulation, Resource means a generating unit, a Dispatchable Asset Related Demand, a Demand Response Regulation Resource or an Alternative Technology Regulation Resource.

**Restated New England Power Pool Agreement (RNA)** is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

**Rest-of-Pool Capacity Zone** is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

**Rest of System** is an area established under Section III.2.7(d) of Market Rule 1.

**Retail Delivery Point** is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system.

**Scheduling Service**, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

**Scheduling, System Control and Dispatch Service**, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

**Seasonal Claimed Capability** is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

**Seasonal DR Audit** is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

**Seasonal Peak Demand Resource** is a type of Demand Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

**Section III.1.4 Transactions** are defined in Section III.1.4.2 of Market Rule 1.

**Section III.1.4 Conforming Transactions** are defined in Section III.1.4.2 of Market Rule 1.

**Security Agreement** is Attachment 1 to the ISO New England Financial Assurance Policy.

**Self-Schedule** is the action of a Market Participant in committing and/or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service.

**Self-Scheduled MW** is an amount, in megawatts, that is Self-Scheduled and is equal to the greater of: (i) the Resource's Economic Minimum Limit; or (ii) the Resource's Minimum Consumption Limit~~; or (iii) for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was~~

~~on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating~~.

**Self-Supplied FCA Resource** is described in Section III.13.1.6 of Market Rule 1.

**Senior Officer** means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

**Service Agreement** is a Transmission Service Agreement or an MPSA.

**Service Commencement Date** is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

**Services** means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

**Settlement Financial Assurance** is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

**Settlement Only Resources** are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

**Seven-Day Forecast** has the meaning specified in Section III.H.3.3(a).

**Shortage Event** is defined in Section III.13.7.1.1.1 of Market Rule 1.

**Shortage Event Availability Score** is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

**Through or Out Rate (TOUT Rate)** is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

**Through or Out Service (TOUT Service)** means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

**Tie-Line Asset** is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

~~**Time-on-Regulation Credit** is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.~~

~~**Time-on-Regulation Megawatts** is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.~~

**Total Available Amount** is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

**Total Blackstart Capital Payment** is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

**Total Blackstart O&M Payment** is the annual compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

**Total Blackstart Service Payments** is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

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~~(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 dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the unit's megawatt output level shall be able to change output 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

**III.1.10.1A Day-Ahead Energy Market Scheduling**.

The following actions shall occur not later than 12:00 noon 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 equal to or greater than zero 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 $0.0/MWh; and

(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 $1,000/MWh.

(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. Supply Offers shall be submitted to the ISO in the form specified by the ISO and shall contain the information specified in the ISO's Offer Data specification, as applicable. External Transactions shall be submitted to the ISO according to Section III.1.10.7 of this Market Rule 1. The ISO shall not consider Start-Up Fees, No-Load Fee, notification times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

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 and energy for each hour in the offer period;

(ii) Shall specify the amounts and prices for the entire Operating Day for each Resource offered by the Market Participant to the ISO;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify Start-Up Fees and No-Load Fee equal to the specification of such fees for such unit on file with the ISO (Market Participant changes to the Start-Up Fee and No-Load Fee can only occur during the open periodic bidding enrollment periods (daily));

(iv) Shall set forth any special conditions upon which the Market Participant proposes to supply a Resource increment;

(v) Shall specify a minimum run time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;

(vi) 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 Self-Scheduled Resource, the Economic Minimum Limit may be revised to reflect the Self-Scheduled output level of the Resource and 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 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 be revised 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 or, in the case of a generating Pool-Scheduled Resource continuing to run into the second Operating Day to satisfy its minimum run time, such price or prices being guaranteed by the Market Participant for the period extending into the second Operating Day that satisfies the Resource's minimum run time; and

(ix) Shall not specify an energy offer or bid price below $0/MWh or above $1,000/MWh.

(e) ~~A Market Participant that wishes to make a Resource available to sell Regulation service shall submit a Supply Offer for Regulation that 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.~~**[Reserved.]**

(f) Each Market Participant owning or controlling the output of a resource with a Capacity Supply Obligation shall submit a forecast of the availability of each such resource for the next seven days. A Market Participant may submit a non-binding forecast of the price at which it expects to offer a generating Resource increment to the ISO over the next seven days.

(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.

**III.1.11.4 Emergency Condition.**

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

**III.1.11.5 ~~Regulation.~~[Reserved.]**

~~(a) A Market Participant may satisfy its Regulation obligation from its own Resources capable of performing Regulation service or by purchases from the ISO through the New England Markets at the rates set forth in Section III.3.2.2.~~

~~(b) The ISO shall obtain Regulation service from the least-cost alternatives available from either Pool-Scheduled Resources or Self-Scheduled Resources as needed to meet New England Control Area requirements not otherwise satisfied by the Market Participants. The ISO assigns Regulation to eligible generating units using the ISO Regulation assessment software. The Regulation assessment software calculates, at five minutes after the hour and on demand as needed, the optimal set of generating units required to meet the Regulation Requirement. The software first calculates a Regulation Rank Price, based on estimates of Time-on-Regulation Credits, Regulation Service Credits, estimated Regulation Opportunity Costs, Regulation Capability and other factors, as specified below, that consider the impact of Regulation assignment on the Real-Time Energy Market. An interim Regulation Clearing Price is then calculated and the Regulation Rank Prices are updated using this interim Regulation Clearing Price to recognize that actual payments for Regulation are based upon the Regulation Clearing Price and not the Regulation offer price. The software continues to iterate in this manner until convergence is reached, resulting in an optimal selection of generating units for Regulation assignment. The ISO utilizes the output from this software when evaluating the set of generating units for Regulation assignment. In the event that one or more generating units to be selected have equal Regulation Rank Prices, the ISO shall select the generating unit for Regulation assignment with the largest Regulation Capability. Details of the process and calculations are described below.~~

~~(1) At the start of each operating hour, the ISO calculates an initial Regulation Rank Price for each eligible unit offering to provide Regulation using the ISO's Regulation assignment software. The initial~~

~~Regulation Rank Price for each unit is equal to the sum of the following calculations divided by that unit's Regulation Capability:~~

~~(a) Time-on-Regulation Credit estimate calculated as the product of the Regulation Capability times the Regulation offer price;~~

~~(b) Regulation Service Credit estimate is set equal to the Time-on-Regulation Credit estimate to meet the 50/50 revenue mix objective as determined by the ISO in accordance with procedures specified in the ISO New England Manuals and ISO New England Administrative Procedures;~~

~~(c) Regulation Opportunity Cost estimate calculated as the product of the opportunity cost MW times the opportunity cost price differential where:~~

~~(i) Opportunity cost MW is calculated as the absolute value of the difference between the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by Economic Max and Economic Min, and EstRegGen.~~

~~(ii) EstRegGen is the highest output level corresponding to the most recent Real-Time nodal LMP of the unit when constrained by RSETHI and RSETLO. RSETHI is equal to the Regulation High Limit – Regulation Capability. RSETLO is equal to the Regulation Low Limit + Regulation Capability.~~

~~(iii) To more accurately estimate the actual Regulation Opportunity Cost that will be paid, EstRegGen is further constrained as follows to account for units with large regulating ranges and slow response rates: if actual generation is less than EstRegGen and EstRegGen is greater than RSETLO, then EstRegGen is constrained up by the greater of (actual output + (SlowWideTime * Automatic Response Rate)) and RSETLO; if actual generation is greater than EstRegGen and EstRegGen is less than RSETHI, then EstRegGen is constrained down by the lesser of (actual output – (SlowWideTime * Automatic Response Rate)) and RSETHI. The SlowWideTime is determined by the ISO based upon empirical studies. The initial SlowWideTime value, and subsequent updates, shall be posted on the ISO's website.~~

~~(iv) Opportunity cost price differential is calculated as the absolute value of the difference between the average offer price of the opportunity MW and the Real-Time nodal LMP of the unit.~~

~~(d) Lookahead penalty estimate. The lookahead calculation assigns a cost penalty to units in the selection process if there is a change in energy offer prices near EstRegGen. It is calculated as 0.17 multiplied by the greater of:~~

~~(i) the unit's energy offer price at a higher output level (LookupRegGen as defined below) minus its energy offer price at EstRegGen, multiplied by (LookupRegGen – EstRegGen);~~
~~and~~

~~(ii) the unit's energy offer price at EstRegGen minus its energy offer price at a lower output level (LookdownRegGen as defined below), multiplied by (EstRegGen -LookdownRegGen),~~
~~where,~~

~~LookupRegGen = (EstRegGen + (LookAheadMinutesUp * Automatic Response Rate)) as bounded by Regulation High Limit; and LookdownRegGen = (EstRegGen – (LookAheadMinutesDown * Automatic Response Rate) as bounded by Regulation Low Limit),~~
~~And where the initial values of LookAheadMinutesUp and LookAheadMinutesDown, and subsequent updates, will be posted on the ISO's website.~~

~~(e) A tiebreaker adder is calculated for both pool-scheduled and Self-Scheduled Regulation units. The tiebreaker adder is equal to a tiebreaker multiplier (.000001) times the difference between a tiebreaker megawatt reference value (500 MW) and the Regulation Capability of the unit.~~

~~For Self-Scheduled Regulation, all values calculated under this Section III.1.11.5(b)(1) are set equal to zero except for the tiebreaker adder.~~

~~(2) The ISO's Regulation assignment software creates an initial merit order stack of eligible Regulation Capability by sorting the generating units by the initial Regulation Rank Prices calculated under Section III.1.11.5 (b)(1) in ascending order. Generating units are then selected in rank order until the Regulation Requirement is met. An initial Regulation Clearing Price is then calculated based upon the highest Regulation offer price associated with the initial set of generating units selected to meet the Regulation Requirement. Updated Regulation Rank Prices are then recalculated for generating units with Regulation offer prices that are less than the initial Regulation Clearing Price by substituting the initial Regulation Clearing Price for the generating unit's Regulation offer price, recalculating the Time-On-Regulation Credit and the Regulation Service Credit estimates; adding the originally calculated values~~

~~under Sections III.1.11.5(b)(1)(c), (d) and (e) to these recalculated values and dividing this total by the unit's Regulation Capability. These updated Regulation Rank Prices are utilized along with the initial Regulation offer prices that are greater than or equal to the initial Regulation Clearing Price to create an updated generating unit list sorted by ascending Regulation Rank Prices. An updated Regulation Clearing Price is then calculated and the software continues to iterate in this manner until convergence is reached producing an optimal generating unit rank order list for use in assigning Regulation.~~

~~(3) Shortly after the start of an hour and during the hour as needed, the ISO updates the generating unit rank order list using the ISO's Regulation assignment software based on any changes to Regulation Capability eligibility and other current information, including any changes to Self-Schedule Regulation. The ISO uses this updated Regulation rank order list to assign Regulation for the upcoming hour and to make changes to Regulation assignments within the hour.~~

~~(c) The ISO shall dispatch Resources for Regulation by sending Regulation signals and instructions to Resources from which Market Participants, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, have offered Regulation service. Market Participants shall comply with Regulation dispatch signals and instructions transmitted by the ISO and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources supplying load in the New England Control Area as close to desired output levels as practical, consistent with Good Utility Practice.~~

**III.1.11.6 [Reserved]**

**III.1.12 Dynamic Scheduling.**

Dynamic scheduling can be requested and may be implemented in accordance with the following procedures:

(a) An entity that owns or controls a generating Resource in the New England Control Area may electrically remove all or part of the generating Resource's output from the New England Control Area through dynamic scheduling of the output to load outside the New England Control Area. Such output shall not be available for economic dispatch by the ISO.

(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~~ clearing ~~Prices~~ 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~~ clearing ~~Prices~~ 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~~ clearing ~~Prices~~ 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~~ clearing ~~Prices~~ 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~~ clearing ~~Prices~~ 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~~ clearing ~~Prices~~ 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~~ clearing ~~Prices~~ 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

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.3.2.2** ~~**Regulation.**~~ **[Reserved.]**

~~(a) Each Market Participant shall have an hourly Regulation obligation equal to its pro rata share of the New England Control Area Regulation requirements for the hour, based on the Market Participant's total Real-Time Load Obligation in the New England Control Area for the hour. A Market Participant that does not meet its hourly Regulation obligation through its own Resources shall be charged for Regulation dispatched by the ISO to meet such obligation at the Regulation Clearing Price determined in accordance~~

~~with paragraph (e) of this Section, plus the amounts, if any, described in paragraph (d) and (j) of this Section.~~

~~(b) A Market Participant supplying Regulation at the direction of the ISO in excess of its hourly Regulation obligation shall be credited for Time-On-Regulation Megawatts at the higher of (i) the Regulation Clearing Price or (ii) the Regulation Supply Offer price of the generating Resource supplying Time-On-Regulation Megawatts, plus the unit-specific Regulation Opportunity Cost of the generating Resource supplying the Time-On-Regulation Megawatts, as determined by the ISO in accordance with procedures specified in the ISO New England Manuals and ISO New England Administrative Procedures.~~

~~(c) A Market Participant supplying Regulation at the direction of the ISO shall receive a credit for Regulation Service Megawatts at the higher of (i) the Regulation Clearing Price or (ii) the Regulation Supply Offer price of the generating Resource supplying Regulation Service Megawatts, multiplied by the Capacity-to-Service Ratio. The Capacity-to-Service Ratio is described under Subsection (h).~~

~~(d) Each Market Participant shall be charged its pro rata share of the total Regulation Service Credits for the hour, based upon the Market Participant's total Real-Time Load Obligation in the New England Control Area for the hour.~~

~~(e) The Regulation Clearing Price shall be determined by the ISO. The Regulation Clearing Price for each hour shall be equal to the time-weighted average of all interval based Regulation Clearing Prices calculated within the hour. The Regulation Clearing Price for each interval within the hour shall be equal to the highest Regulation Supply Offer price of any generating Resources selected to provide Regulation in that interval. Regulation Clearing Prices shall be posted and finalized by the ISO in accordance with Section III.2.9A of this Market Rule 1.~~

~~(f) A Market Participant's Regulation Service Megawatts shall be determined by the ISO. A Market Participant's hourly Regulation Service Megawatts for each generating Resource providing Regulation shall be equal to the sum of the absolute value of the generation movement, in megawatts, towards the Regulation set point, such movement calculated in four second intervals based upon the generating Resource's Automatic Response Rate.~~

~~(g) A Market Participant's Time-on-Regulation Megawatts shall be determined by the ISO. A Market Participant's hourly Time-on-Regulation Megawatts for each generating Resource providing Regulation~~

~~shall be equal to the Regulation capability provided multiplied by the minutes of Regulation provision in the hour, divided by sixty.~~

~~(h) The Capacity-to-Service Ratio shall be determined by the ISO. The Capacity-to-Service Ratio is the relationship between Regulation capability provided and Regulation Service Megawatts provided in an hour. Based on historical analysis, on average, one megawatt of Regulation capability will produce ten megawatts of Regulation Service Megawatts. Based on this relationship, the Capacity-to-Service Ratio shall initially be set equal to 0.1 such that the revenue associated with Time-on-Regulation Megawatts and Regulation Service Megawatts associated with a Resource providing Regulation shall be equally split. The revenue split assumption and the Capacity-to-Service Ratio may be changed from time to time and such changes shall be filed with the Commission for approval.~~

~~(i) In determining the credit under subsection (b) to a Market Participant that is selected to provide Regulation and that actively follows the ISO's Regulation signals and instructions, the unit-specific Regulation Opportunity Cost of a generating Resource shall be determined for each hour that the ISO requires a generating Resource to provide Regulation and shall be equal to the product of (i) the deviation of the generating Resource's output necessary to follow the ISO's Regulation signals from the generating Resource's expected output level if it had been dispatched in economic merit order multiplied by (ii) the absolute value of the difference between the Real-Time Price at the generation Node for the generating Resource and the megawatt weighted average Supply Offer price for the energy associated with the deviation of the generating Resource's expected output level if it had been dispatched in economic merit order.~~

~~(j) Amounts credited for Regulation Opportunity Cost in an hour shall be allocated and charged to each Market Participant that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in MWhs during that hour.~~

**III.3.2.3 NCPC Credits.**

The following paragraphs describe the calculation of NCPC Credits and NCPC Charges. Additional information on these calculations may be found in Appendix F of this Market Rule 1.

(a) Except as otherwise provided for under Section III.3.2.3(f), Market Participants' Pool-Scheduled Resources capable of providing Operating Reserve or Replacement Reserve shall be credited as specified below (an "NCPC Credit") based on the prices offered for the operation of such Resources, provided that the Resources were available for the entire time specified in the Offer Data for such Resource.

(b) The following determination shall be made for the Day-Ahead Energy Market:

(i) For each generating Pool-Scheduled Resource that is scheduled in the Day-Ahead Energy Market: the total offered price for Start-Up Fees and No-Load Fee and energy, determined on the basis of the Resource's scheduled output, shall be compared to the total value of that Resource's scheduled energy output as determined by the Day-Ahead Energy Market and the Day-Ahead Prices applicable to the relevant generation Node or External Node in the Day-Ahead Energy Market. Except as otherwise provided in Section III.F.2.3.5 and Section III.F.2.4.5 of Appendix F, if the total offered price summed over all hours for the Operating Day exceeds the total value summed over all hours for the Operating Day, the difference shall be credited to the Market Participant.

(ii) Other Day-Ahead NCPC Credits shall be calculated as specified in Section III.F.2.

(c) Except as otherwise provided for under Section III.F.3, the sum of the foregoing credits calculated in accordance with Section III.3.2.3(b) shall be the "NCPC Charge" in the Day-Ahead Energy Market in each Operating Day.

(d) The NCPC Charge in the Day-Ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its hourly Day- Ahead Load Obligation in for that Operating Day except that, any NCPC Charge associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff, and any economic NCPC Charges associated with External Transactions (purchases and sales), Increment Offers or Decrement Bids at External Nodes in the Day-Ahead Energy Market are charged in accordance Section III.F.3.2.4 of Appendix F.

(e) At the end of each Operating Day, the following determinations shall be made:

(i) for each eligible hour for each synchronized Pool-Scheduled Resource of each Market Participant that operates as requested by the ISO and that is not committed for synchronized condensing: The total offered price, as calculated in accordance with Section III.F.2.1.9, shall be compared to the total value of that Resource's energy in the Real-Time Energy Market, as

calculated in accordance with Section III.F.2.1.13. If the total offered price exceeds the total value, the difference shall be credited to the Market Participant as a Real-Time NCPC Credit.

(ii) For each synchronized Pool-Scheduled Resource or Self-Scheduled Dispatchable Asset Related Demand Resource of each Market Participant that is associated with pumping load and that operates as requested by the ISO in accordance with Section III.3.2.3(f): the total Real-Time costs of energy consumption, as calculated in accordance with Section III.F.2.4.10, shall be compared to the total bid amount of that Resource's energy consumption in the Real-Time Energy Market, as calculated in accordance with Section III.F.2.4.7. If the total Real-Time costs exceed the total bid amount, the difference shall be credited to the Market Participant as a Real-Time NCPC Credit.

(iii) For each pool-scheduled External Transaction sale of each Market Participant that operates as requested by the ISO: the difference between a Market Participant's Real-Time bid price and Real-Time costs as determined pursuant to Section III.F.2 shall be credited to the Market Participant as a Real-Time NCPC Credit.

For purposes of this Section, a Market Participant is deemed to operate as requested by the ISO if it follows dispatch instructions. A generator is considered to be following a dispatch instruction if the actual output of the generator is not greater than 10% above its desired dispatch point and is not less than 10% below its desired dispatch point for each interval in the hour. Generators with an Economic Max less than or equal to 50 MWs are considered to be following a dispatch instruction if the actual output of the generator is not greater than 5 MWs above its desired dispatch point and is not less than 5 MWs below its desired dispatch point for each interval in the hour. If the generator violates this criterion in any interval during the hour, the generator is considered to be not following dispatch instructions for the entire hour.

(f) A Market Participant's Pool-Scheduled Resource or Self-Scheduled generating Resource, the output of which is reduced or suspended at the request of the ISO for the purpose of maintaining appropriate levels of Operating Reserve or for the provision of voltage support, shall be credited in an amount equal to the following:

For generating Resources, the credit for each hour of reduced or suspended operation is:

Posturing Credit = (PAG -AG) x (ULMP -UB) – RC where:

PAG equals the estimated hourly generation had the generator not responded to dispatch orders to reduce or suspend operation taking any limited energy restrictions into account, such estimated hourly generation to be determined in accordance with procedures defined in the ISO New England Manuals;

AG equals the actual output of the generating Resource;

ULMP equals the Real-Time Price associated with the generating Resource that is reduced or suspended for each hour;

UB equals the Supply Offer price associated with PAG for that generating Resource whose output is reduced or suspended;

RC equals any Regulation opportunity cost of generation not produced while providing Regulation credits from Section III.~~3.2.2(i)~~14.8(b)(ii); and where ULMP -UB shall not be negative and Posturing Credit shall not be negative.

The amount, in MW, of a Market Participant's pool-scheduled Dispatchable Asset Related Demand Resource or Self-Scheduled Dispatchable Asset Related Demand Resource that is associated with pumping load which is maintained out of economic merit at the request of the ISO for the purpose of maintaining appropriate levels of Operating Reserve, shall be credited in accordance with Section III.3.2.3(b) and III.3.2.3(e).

(g) Except as otherwise provided for under Section III.F.3, the sum of the foregoing NCPC Credits, plus any Cancellation Fees paid in accordance with Section III.1.10.2(d), such Cancellation Fees to be applied to the Operating Day for which the unit was scheduled, shall be the non-synchronized condensing NCPC Charge for the Real-Time Energy Market in each Operating Day.

(h) The non-synchronized condensing and synchronized condensing NCPC Charge for the Real-Time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day; (ii) generation 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, any NCPC Charge associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff. For the purposes of calculating generation deviations, if a generation resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating Real-Time NCPC Charges. For the purposes of calculating Real-Time NCPC Charges, any difference between the actual consumption (Real-Time Load Obligation) of Dispatchable Asset Related Demand Resources and Dispatchable Asset Related Demand bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation.

(i) At the end of each Operating Day, Market Participants shall be credited on the basis of their offered prices for synchronized condensing for any hydropower or combustion turbine units operated as synchronous condensers but producing no energy.

(j) The sum of the foregoing NCPC Credits as specified in Section III.3.2.3(i) shall be the NCPC Charge for synchronized condensing in the Real-Time Energy Market for the Operating Day in the New England Control Area.

(k) **[Reserved]**

**III.3.2.4 Transmission Congestion.**

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(f) of this Market Rule 1.

**III.3.2.5 [Reserved.]**

**III.14 Regulation Market.**

**III.14.1 Regulation Market System Requirements.**

The Regulation Capacity Requirement and Regulation Service Requirement are determined based on historical control performance and compliance with NERC and NPCC control standards. The Regulation Capacity Requirement and Regulation Service Requirement will be published on the ISO's website.

During abnormal system conditions, the ISO may deviate from the Regulation Capacity Requirement or Regulation Service Requirement to maintain system reliability.

**III.14.2 Regulation Market Eligibility.**

To be eligible to provide Regulation, a Resource must satisfy the following conditions:

(a) Physical Parameters.

(i) Automatic Response Rate.

(1) The minimum Automatic Response Rate is 1 MW/minute.

(ii) Regulation Capacity.

(1) The minimum Regulation Capacity of a generating unit will be determined based on unit size and operating characteristics and must be greater than or equal to: (a) 10 megawatts, and; (b) two times the generating unit's AGC SetPoint Deadband plus one.

(2) The minimum Regulation Capacity of a Resource that is not a generating unit is no less than one megawatt after aggregation.

(b) Regulation Technical Requirements.

A Resource providing Regulation must:

(i) be located within the New England Control Area.

(ii) meet the technical requirements specified in ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands and ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

(iii) be capable of receiving and following AGC SetPoints sent electronically at four-second intervals.

(iv) have a demonstrated capability to reliably follow Dispatch Instructions, consistent with normal operating characteristics and physical offer parameters, including Regulation Capacity and Automatic Response Rate. Resources without an operational history of providing Regulation must establish and demonstrate this capability as follows:

(1) Demand Response Regulation Resources, Dispatchable Asset Related Demand, Alternative Technology Regulation Resources and any Resource with less than one-hour sustainability must participate in the Regulation test environment specified in Section III.14.9.

(2) All Resources must satisfy a minimum responsiveness test that demonstrates that a Resource can follow AGC SetPoints.

(c) Aggregation.

Non-generation sub-resources less than one megawatt in size may be aggregated into a single Resource to meet the Regulation Market eligibility requirements specified in Section III.14.2.

A single AGC SetPoint will be sent every AGC cycle to the aggregated Resource. A Market Participant with an aggregated Resource is responsible for management and control of the individual, aggregated sub-resources to ensure an accurate aggregate response to the AGC SetPoint. The sub-resources may be geographically dispersed, provided:

(i) all of the sub-resources are located within the New England Control Area

(ii) the sub-resources are metered and recorded in a manner that allows real-time performance to be measured against Dispatch Instructions and provides for the retention of the recorded information for purposes of verification, accounting for any performance offsets from other loads, generation or devices under the direct or indirect control of the aggregator as specified in ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

(iii) communications and metering are installed and tested for each sub-resource in accordance with ISO New England Operating Procedure No, 18, Metering and Telemetering Criteria and ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands.

**III.14.3 Regulation Market Offers.**

(a) A Market Participant providing Regulation must submit a Supply Offer. The Supply Offer shall remain effective until cancelled or replaced by the Market Participant. The Supply Offer must specify the following offer parameters:

(i) Regulation unit status (available/unavailable)

Regulation unit status for each hour in an Operating Day must be submitted daily prior to the close of the Re-Offer Period. After initial submission, unit status may be modified at any time.

(ii) Regulation High Limit

For generating units, the Regulation High Limit must be less than or equal to a generating unit's Economic Maximum Limit. For Dispatchable Asset Related Demand, the Regulation High Limit must be greater than or equal to a Dispatchable Asset Related Demand's Minimum Consumption Limit.

(iii) Regulation Low Limit

For generating units, the Regulation Low Limit must be greater than or equal to a generating unit's Economic Minimum Limit. For Dispatchable Asset Related Demand, the Regulation Low Limit must be less than or equal to a Dispatchable Asset Related Demand's Maximum Consumption Limit.

(iv) Automatic Response Rate (MW/minute)

(v) Regulation Capacity Offer ($/MW)

The Regulation Capacity Offer price must be greater than or equal to $0/MW and may not exceed $100/MW.

(vi) Regulation Service Offer ($/MW of instructed movement)

The Regulation Service Offer price must be greater than or equal to $0/MW of instructed movement and may not exceed $10/MW of instructed movement.

(b) Additional Constraints on Offer Parameters.

(i) Regulation offer parameters that exceed recent historical performance for Regulation Capacity or Automatic Response Rate will be constrained to reflect values consistent with the demonstrated performance of the Resource. The Resource of a Market Participant that submits offer parameters inconsistent with demonstrated performance will be disqualified from selection

to provide Regulation until the submitted parameters are modified to be consistent with demonstrated performance.

(ii) A Resource that is dispatchable in the Real-Time Energy Market and providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided as follows: the upper limit of the Resource's energy dispatch range will be reduced by the amount of Regulation Capacity, and the lower limit of the Resource's energy dispatch range will be increased by the amount of Regulation Capacity.

(c) Sustainability.

Regulation Capacity offers for Resources with less than one-hour sustainability will be evaluated in the selection process using a capacity value adjusted to reflect historical performance when dispatched at the non-adjusted value. The adjusted value will account for the Resource's demonstrated ability to follow the AGC dispatch signal over an hour at the offered Regulation Capacity level. The percentage adjustment will be reevaluated periodically to account for changes in the performance of the Resource. Resources with no historical performance record will be evaluated pursuant to the regulation resource test environment specified in Section III.14.9.

Adjusted Regulation Capacity will be used for the purpose of selecting Resources to meet the Regulation Capacity Requirement and for determining Regulation Capacity compensation.

Resources will be dispatched for Regulation in accordance with the unadjusted Regulation Capacity offer parameters.

For a storage-based resource, sustainability is measured based on full rate of charge/discharge starting from a half-full status.

**III.14.4 Regulation Market Administration.**

A Market Participant may modify Regulation offer parameters at any time. The offered parameters will remain in effect until modified by the Market Participant. The most recent offer parameters will be used each time new Resources are selected and until a new selection process is completed.

**III.14.5 Regulation Market Resource Selection.**

Resources are selected to provide Regulation from eligible and available Resources to meet the Regulation Capacity Requirement and Regulation Service Requirement at the least-cost based on Regulation Capacity Offers, Regulation Service Offers, estimated energy opportunity costs, impacts on system production costs, and operational requirements related to reliability, including a minimum aggregated response rate and minimizing short-term changes in the assignment of Resources to provide Regulation. For the purposes of least-cost Resource selection, the following penalty factors are used for any violation of the Regulation requirements constraint: (1) $100/MW plus the Energy Component of the Real-Time Locational Marginal Price at the reference point for each megawatt of Regulation Capacity shortfall, and: (2) $10/MW for each megawatt of Regulation Service shortfall. In addition, selection will consider opportunity cost sensitivities associated with large changes in the estimated opportunity cost of a Resource due to the shape of the Resource's Supply Offer price curve. An eligible Resource may be omitted from providing Regulation due to operational restrictions, including, but not limited to, binding transmission constraints, planned shutdown prior to the end of the settlement interval, or known or anticipated system operating conditions.

The ISO may deviate from the market-based Resource selections to maintain system reliability.

If one or more Resources providing Regulation become unavailable, a new selection process may be conducted to obtain the Resources needed to fulfill the Regulation Capacity Requirement and the Regulation Service Requirement and new clearing prices determined pursuant to Section III.14.8(a).

In the event one or more Resources have equivalent least-cost characteristics in the selection process, the Resource with the larger Regulation Capacity value will be selected or, if the Regulation Capacity value is also equal, the Resource with the earliest Supply Offer submission time will be selected.

**III.14.6 Delivery of Regulation Market Products.**

Resources selected for Regulation are dispatched to reduce the New England Control Area's area control error as needed to ensure reliability and compliance with NERC and NPCC control standards.

Resources that are generating units are dispatched based on relative response rates using multi-valued AGC SetPoints with AGC SetPoint Deadbands. Resources that are not generating units are dispatched using a trinary dispatch that calculates AGC SetPoints equal to one of the following three values: Regulation High Limit, Regulation Low Limit, and a midpoint between the Regulation High Limit and

the Regulation Low Limit. Dispatch will be coordinated with the objective of achieving consistent and non-discriminatory treatment of Resources providing similar offer parameters.

AGC SetPoints will be established to cost-effectively meet reliability criteria based on the current area control error, the Automatic Response Rate and offer parameters of the selected Resources, as well as the current and predicted state of the system.

**III.14.7 Performance Monitoring.**

The performance of a Resource providing Regulation will be monitored in Real-Time. For each settlement interval, a Resource is considered to be non-performing if, after a grace period, the Resource is not responding to AGC SetPoints at a rate at least equal to a percentage of its Automatic Response Rate or outside a tolerance band around the AGC SetPoint that is equal to a percentage of the Regulation Capacity of the Resource. The grace period will be between two and four minutes. The percentage of the Automatic Response Rate will be between 80 and 95 percent. The percentage of the Regulation Capacity of the Resource will be between 5 and 15 percent. The specific values will be published on the ISO's website.

A Resource that changes its direction of movement in a manner inconsistent with the AGC SetPoint is considered non-performing for the remainder of the settlement interval.

Compensation adjustments for non-performing Resources are addressed in Section III.14.8(b)(iv).

**III.14.8 Regulation Market Settlement and Compensation.**

(a) Calculation of Regulation Clearing Prices.

(i) Regulation Service clearing prices.

The Regulation Service clearing price is set equal to the highest Regulation Service Offer of the Resources selected to provide Regulation pursuant to Section III.14.5.

(ii) Regulation Capacity clearing prices.

The Regulation Capacity clearing price is set such that total compensation from the Regulation Service clearing price and the Regulation Capacity clearing price will, based on a uniform clearing price applied to all selected Resources, ensure recovery of as-bid costs for Regulation

Capacity, estimated Regulation Service, estimated energy opportunity costs, and the Resource-specific incremental cost savings payment determined for each Resource for the planned duration of the settlement interval.

The incremental cost savings provided by each Resource is assessed by determining the least-cost selection of Resources as specified in Section III.14.5 both with and without the particular Resource. The incremental cost savings for the settlement interval is the estimated total cost of Regulation without the Resource minus the estimated total cost of Regulation with the Resource, including the application of penalty factors to any violation of the Regulation requirements constraint.

(b) Compensation to Regulation Providers.

(i) A Market Participant with a Resource that is selected to provide Regulation and that complies with the dispatch and performance requirements in Section III.14 shall receive:

(1) A capacity payment equal to the amount of Regulation Capacity selected times the Regulation Capacity clearing price.

(2) A service payment equal to the amount of service provided, while the Resource is considered to be performing as specified in Section III.14.7, as measured by the absolute value of the Resource's scheduled movement at the claimed rate of response without delay, in megawatts, toward the AGC SetPoint in response to AGC dispatch signals times the Regulation Service clearing price.

(ii) Calculation of Actual Energy Opportunity Costs.

A Resource-specific Regulation energy opportunity cost payment for those Resources dispatchable in the Real-Time Energy Market is determined for each settlement interval that the Resource is selected to provide Regulation. The Regulation energy opportunity cost payment shall be equal to the product of (i) the absolute value of the deviation of the Resource's dispatch level necessary to follow the ISO's Regulation signals from the Resource's expected dispatch level if it had been dispatched in economic merit order and (ii) the absolute value of the difference between the Real-Time Price at the Node associated with the Resource and the megawatt weighted average Supply Offer or Demand Bid price for the energy associated with the deviation of the Resource's expected dispatch level if it had been dispatched in economic merit

order. Regulation energy opportunity costs are only incurred when a Resource is providing Regulation.

(iii) Make-Whole Payment

If revenues from the Regulation Capacity clearing price and the Regulation Service clearing price are insufficient to cover a Market Participant's as-bid costs for the actual Regulation Capacity and the amount of Regulation Service provided during a settlement interval plus actual energy opportunity costs as calculated in Section III.14.8(b)(ii), a make-whole payment will be provided for the period that the Resource is considered to be performing as specified in Section III.14.7.

(iv) Performance Adjustments.

A selected Resource's capacity payment will be reduced in proportion to the percentage of four-second AGC cycles during which the Resource was not performing.

(v) Compensation for Replacement Resources

If system conditions require the ISO to designate additional Resources in order to satisfy Regulation requirements for the remainder of a settlement interval without completing the selection process described in Section III.14.5, compensation for replacement Resources will be made according to the Resource's actual performance using the Regulation Capacity clearing price, the Regulation Service clearing price, and any make-whole payments as specified in Section III.14.8(b)(iii).

(c) Regulation Charges.

Each Market Participant shall have a Regulation charge equal to its pro rata share of the Regulation Capacity Requirement and Regulation Service Requirement for the settlement period based on the Market Participant's total Real-Time Load Obligation. The total cost of providing Regulation for each settlement period is charged to Market Participants based on their pro rata share of Real-Time Load Obligation during the period. For the purposes of allocating Regulation charges, the Real-Time Load Obligation of a Dispatchable Asset Related Demand providing Regulation shall be limited to the Minimum Consumption Limit of the Resource.

(d) Net Energy Settlement for Alternative Technology Regulation Resources.

During the asset registration process, a Market Participant with an Alternative Technology Regulation Resource must determine, in conjunction with any interconnecting Transmission Owner, if the

interconnection and metering arrangements for the resource will result in the resource's net energy requirements (energy consumption for the energy settlement interval less energy injections for the energy settlement interval) being separately reported to the ISO as Real-Time Load Obligation or will be included in the Real-Time Load Obligation of a separate LSE. If the Alternative Technology Regulation Resource has separately metered and reported Real-Time Load Obligation, the Market Participant with the resource will pay for the net energy consumed at the Real-Time Price at the resource's Node.

**III.14.9 Regulation Market Testing Environment.**

The ISO administers a regulation resource test environment that allows Market Participants to evaluate or demonstrate the performance of Resources without an operational history of providing Regulation prior to participation in the Regulation Market.

Resources providing Regulation under the regulation resource test environment will be compensated for the Regulation Capacity and Regulation Service provided in response to AGC SetPoints at the lowest of the Regulation Capacity Offer prices and Regulation Service Offer prices offered for any Resource selected during each settlement interval. Resources that are also dispatchable in the Real-Time Energy Market will be compensated for Regulation energy opportunity costs incurred while operating under the regulation resource test environment.

Resources performing a minimal responsiveness test will not be compensated for Regulation.

A Resource may only provide Regulation under the regulation test environment until sufficient operational information has been collected to verify reasonable operating parameters for the Resource or to determine that the Resource does not meet the eligibility requirements necessary to participate in the Regulation Market.

# APPENDIX F

## NCPC ACCOUNTING

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NCPC Credits are calculated for each of the following situations:

(1) Pool-Scheduled Resources (Generators), including Local Second Contingency Protection Resources (Generators) and External Transactions (Day-Ahead and Real-Time Energy Markets); Increment Offers and Decrement Bids cleared at External Nodes.

(2) Pool-Scheduled Resources (Synchronous Condensers and Special Constraint Resources ("SCR") - Real-Time Energy Market)

(3) Canceled Pool-Scheduled Resources (Real-Time Energy Market)

(4) Resources postured for reliability purposes (Real-Time Energy Market)

(5) Dispatchable Asset Related Demand Resources (pumps only) that are postured for reliability purposes in Real-Time.

(6) Self-Scheduled generating Resources providing Operating Reserves by operating in accordance with Dispatch Instructions in non-Self-Scheduled hours or at levels above the Self-Scheduled MW in Self-Scheduled hours during an Operating Day in which they have offered a contiguous block of Self-Scheduled hours, which meet the criteria for such Self-Schedules set forth in Section III.F.1, at least equal to their minimum run times.

**III.F.2.1. Credits for Generating Resources.**

For each Operating Day, the ISO calculates the NCPC Credit due each Market Participant for generating Resources.

In the Day-Ahead Energy Market, eligible generating Resources shall receive Day-Ahead NCPC Credits for all hours that are not Self-Scheduled. Except as otherwise provided in this Appendix F, all eligible generating Resources are eligible except generating Resources that have Self-Scheduled hours that do not meet the criteria set forth in Section III.F.1.1.1 are ineligible for Day-Ahead NCPC Credit. For purposes of the Day-Ahead NCPC Credit calculations, the Self-Scheduled hours shall be the Self-Scheduled hours in the Participant's Supply Offer.

In the Real-Time Energy Market, an eligible generating Resource is eligible to receive Real-Time NCPC Credits for all hours that are not Self-Scheduled and for MW amounts in excess of the Self-Scheduled MW for Self-Scheduled hours when the Resource operates above the Self-Scheduled MWs at the ISO's request. A generating Resource is not eligible to receive Real-Time NCPC Credits for any hour in which the Resource is ramping up from an off-line state prior to being released for dispatch, or ramping down after receiving a shutdown order. Self-Scheduled hours include hours when the Resource is ramping up to a Self-Scheduled hour from an off-line state, or down from a Self-Scheduled hour to an offline state ~~and hours when the Resource is Self-Scheduled for Regulation~~. Eligible generating Resources shall consist of Pool-Scheduled Resources and Self-Scheduled Resources that meet the criteria in Section III.F.1.1.2 and any generating Resources specifically made eligible for Real-Time NCPC Credits in other Sections of this Market Rule 1.

**III.F.2.1.1 Information Retrieved.**

The ISO retrieves the following information:

(a) dispatcher generation scheduling and operations logs;

(b) Generator Offer Data and Supply Offer data;

(c) scheduled MWh for generating Resources cleared in Day-Ahead Energy Market;

(d) metered generation MWh as submitted by Assigned Meter Reader;

(e) operational flags;

- Special Constraint Resource flag;

(f) Generating Resource Desired Dispatch Points and Economic Minimum Limits;

(g) Day-Ahead and Real-Time LMPs; and

(h) Generator flags (for example the Failure to Follow Dispatch Instruction ("FTF") flag) as set using the criterion set forth in Section 2 of the ISO New England Manual for Market Operations, M-11).

**III.F.2.1.2 Hourly Day-Ahead Offer Amount.**

**III.F.2.1.8 Hourly Real-Time MWh**.

The ISO determines the generating Resource's hourly Real-Time MWh based on the values submitted to the ISO by the Assigned Meter Reader for that hour.

**III.F.2.1.9 Hourly Real-Time Energy Offer Amount.**

The ISO calculates the generating Resource's hourly Real-Time energy offer amount based on its prices contained in the Supply Offer (if said Supply Offer has been mitigated, the mitigated Supply Offer shall be used for this calculation) for all eligible hours. For pool-scheduled hours, the Supply Offer price is multiplied by the lesser of the generating Resource's Desired Dispatch Point (provided that any Desired Dispatch Point below the Resource's Economic Minimum Limit will be deemed equal to the Economic Minimum Limit) or its actual metered output for that hour less the Resource's cleared Day-Ahead MWh. For generating Resources operating above their Self-Scheduled MW at the ISO's direction or request during Self-Scheduled hours, the Supply Offer price (excluding the Start-Up Fees and No-Load Fee) is multiplied by the lesser of the DDP or actual metered quantity less the greater of the Resource's Self-Scheduled MW or the Resource's cleared Day-Ahead MWh. ~~Self-Scheduled MW equals the higher of the Resource's Economic Minimum Limit or the output of the unit that is attributable to its submittal of a Self-Schedule for Regulation.~~ For a generating Resource continuing to run into a second Operating Day to satisfy its minimum run time, the Supply Offer prices originally used by the ISO to commit the Resource in the first Operating Day will continue to be binding for the purpose of calculating NCPC Credits into the second Operating Day until such time as the Resource's minimum run time has been satisfied.

**III.F.2.1.10 Application of Start-Up Fee and Hourly No-Load Fee.**

The ISO applies the Start-Up Fee and hourly No-Load Fee if the start-up and no-load switch is set in the Generator Offer Data and if the Start-Up Fee is applicable for the MWh and status of the generating Resource. The Start-Up Fee is not applicable in the case where a Market Participant has initially Self-Scheduled a generating Resource in Real-Time and the ISO subsequently schedules this generating Resource as a Pool-Scheduled Resource once the Self-Schedule is terminated by the Market Participant or if that Participant's Resource was scheduled in the Day-Ahead Energy Market. The No-Load Fee is not applicable in any hour if the total number of hours that the Resource cleared in the Day-Ahead Energy Market is greater than the total number of hours that the Resource had actual generation greater than zero. If the total number of hours that the Resource had actual generation greater than zero is greater than the total number of hours that the Resource cleared in the Day-Ahead Energy Market, the No-Load Fees

would be applicable once the total number of hours that the Resource actually ran in Real-Time exceeded the total number of hours that the Resource cleared in the Day-Ahead Energy Market.

**III.F.2.1.11**

If applicable, when a generating Resource is started during the day at the direction of the ISO, the generating Resource's Real-Time offer amount calculated for that day includes its Start-Up Fee based on the appropriate hot, intermediate, or cold state of the generating Resource. For generating Resources that start generating for the ISO from a condensing state, the applicable Start-Up Fee for that generating Resource shall be the Start-Up Fee submitted that is associated with the hot state of the unit.

**III.F.2.1.12**

If applicable, the generating Resource's Real-Time calculated offer amount includes its hourly No-Load Fee prorated for all hours of operation as follows, using a 10% tolerance:

> If: lesser of (Real-Time MWh or Desired MW) < .9 * (lesser of: Economic Minimum Limit submitted Day-Ahead or any Economic Minimum Limit submitted in Real-Time),
> Then: hourly No-Load Fee is prorated by (lesser of (Real-Time MWh or Desired MW) / (lesser of: Economic Minimum Limit submitted Day-Ahead or any Economic Minimum Limit submitted in Real-Time).

**III.F.2.1.13 Generating Resource Hourly Real-Time Value.**

The ISO calculates the generating Resource's hourly Real-Time value for all eligible hours as:

> ((generating Resource metered value – max (generating Resource cleared Day-Ahead MWh, generating Resource Real-Time Self-Schedule MWh)) * (Real-Time LMP at generating Resource Node)) + generating Resource Regulation ~~Opportunity~~ opportunity ~~Cost~~cost.

**III.F.2.1.14 Generating Resource Daily Real-Time Credits.**

The ISO calculates the daily Real-Time credits for each generating Resource as follows:

(a) Sum hourly Real-Time offer amounts and include applicable No-Load Fees and Start-Up Fees for the day.

economic operation. The ISO credits Postured generating Resources, both pool-scheduled and Self-Scheduled, for responding to the ISO's request to reduce or suspend normal economic operation. A Resource shall be considered postured when it meets the conditions described in the definition of "Postured" in the Tariff. The ISO takes into account any generator Regulation credits associated with the postured generating Resource for the provision of Regulation while postured in calculating the posturing credits for generating Resources. For a Dispatchable Asset Related Demand Resource (pumps only) that is Postured, the posturing credits are calculated in accordance with Section III.F.2.4.

**III.F.2.6.1 Information Retrieved.**

The ISO retrieves the following information:

(a) list of generating Resources reduced or suspended for reliability reasons (dispatcher log)

(b) Generator Offer Data

(c) 5 minute generation data from EMS

(d) Real-Time LMP data

(e) Real-Time Generation Obligation

(f) Generator Regulation credits

**III.F.2.6.2 Posturing Credit Calculation.**

The ISO credits Market Participants for each generating Resource for each hour reduced or suspended based on the following calculation:

(a) *Generating Resources Without Daily Energy Restrictions.* For generating Resources without energy restrictions, the posturing credit for each hour of reduced or suspended operation is:

Posturing Credit = (PAG - AG) x (ULMP - UB) – GRC

Where

PAG equals the estimated hourly generation had the generating Resource not responded to dispatch orders to reduce or suspend operation. Estimated operation for resources following the Day-Ahead schedule prior to posturing will be determined by the Day-Ahead schedules during the posturing event. For generating Resources responding to Real-Time prices prior to posturing, estimates will assume economic operation would have continued;

AG equals the actual output of the generating Resource;

ULMP equals the Real-Time LMP associated with the generating Resource that is reduced or suspended for each hour;

UB equals the Supply Offer price (increment energy price only) associated with PAG for that generating Resource whose output is reduced or suspended;

GRC (Generator Regulation Credits) is the opportunity cost of generation not produced while providing Regulation ~~value~~ calculated under Section ~~4.2.1 of the ISO New England Manual for Market Rule 1 Accounting, M-28~~III.14.8(b)(ii) of Market Rule 1; and

where ULMP - UB shall not be negative and Posturing Credit shall not be negative.

(b) *Generating Resources With Daily Energy Restrictions.* For generating Resources with energy restrictions, a credit is determined based on an estimate of the daily net opportunity cost in the energy market. This daily net amount shall not be negative. The posturing credit is:

Posturing Credit = net of Posturing Hourly Credits as defined below for all hours beginning with the hour that posturing began and ending at the end of the calendar day,

Where:

Posturing Hourly Credit = (PAG - AG) x (ULMP - UB) – GRC

Where:

PAG equals the estimated hourly generation had the generating Resource not responded to Dispatch orders to reduce or suspend operation. Estimated operation for generating Resources following the Day-Ahead schedule prior to the posturing event will be determined by the Day-Ahead schedule. From the start of the posturing event through the end of the calendar day, PAG is set to the Day-Ahead schedule for as long as available energy would have supported the operation. For generating Resources responding to DDP's in Real-Time or operating under Real-Time Self-Schedule changes prior to the posturing event, PAG will be set assuming economic operation would have occurred during

posturing and throughout the day for as long as the available energy would have supported the operation;

AG equals the actual output of the generating Resource;

ULMP equals the Real-Time LMP associated with the generating Resource;

UB equals the Generator Supply Offer price (increment energy price only); and

GRC is the value calculated under Section 4 of the ISO New England Manual for Market Rule 1 Accounting, M-28.

**III.F.2.6.3 Real Time NCPC Credits.**

The Real-Time NCPC Credits for posturing for the Operating Day are equal to the sum of the non-VAR related Real-Time posturing credits associated with reduced or suspended generating Resources for the Operating Day.

**III.F.2.6.4 Real Time VAR Credits.**

The Real-Time VAR credits for posturing for the Operating Day are equal to the sum of the VAR related Real-Time posturing credits associated with reduced or suspended generating Resources for the Operating Day.

**III.F.3. Charges for NCPC**

**III.F.3.1. Allocation.**

The sum of Day-Ahead NCPC Credits for the Day-Ahead Energy Market, excluding the Day-Ahead NCPC credits for External Transactions (purchases and sales), Increment Offers and Decrement Bids at External Nodes, is allocated and charged to Market Participants in proportion to the daily sum of their Day-Ahead Load Obligations. The sum of Real-Time NCPC Credits (excluding Posturing Credits) including those associated with Synchronous Condensers for the Real-Time Energy Market is allocated and charged to Market Participants in proportion to their daily sum of their Real-Time Load Obligation Deviations (excluding any difference between Dispatchable Asset Related Demand Resources that are cleared in the Day-Ahead Energy Market and revenue quality meter readings for Dispatchable Asset Related Demand Resources for the Operating Day that result from operation in accordance with the ISO 's instructions), generation deviations from Day-Ahead amounts and the daily sum of the generation deviations from the greater of the hourly aggregate Desired Dispatch Point or the Resource's Economic Minimum Limit. Real Time NCPC Credits associated with the Posturing of facilities are allocated and

# ~~SECTION III~~

# ~~MARKET RULE 1~~

# ~~APPENDIX J~~

# ~~ALTERNATIVE TECHNOLOGIES REGULATION PILOT PROGRAM~~

# ~~APPENDIX J~~

## ~~ALTERNATIVE TECHNOLOGIES REGULATION PILOT PROGRAM~~

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# ~~ALTERNATIVE TECHNOLOGIES REGULATION PILOT PROGRAM~~

## ~~III.J.1. Purpose~~

~~The Alternative Technologies Regulation Pilot Program has the following purposes:~~

~~i. Evaluate the impact and performance of resources with performance characteristics that are significantly different from the Resources that currently provide regulation service.~~

~~ii. Test alternative control strategies to identify how best to utilize the various technologies to lower the future total cost of regulation.~~

~~iii. Perform the desired evaluations in a manner that does not disrupt the existing Regulation market, or result in non-compliance with relevant NERC standards.~~

~~iv. For each participating Resource, identify the preferred operating parameters that balance system reliability, system-wide costs of regulation service, and the economic performance of the Resource.~~

~~v. Evaluate the potential impact of alternative regulation technologies on the Regulation market and compliance with reliability standards.~~

~~vi. Evaluate the potential impacts on capacity and energy markets.~~

~~vii. Assess the technical and economic feasibility of alternative regulation technologies as market providers of regulation service.~~

~~viii. Provide information necessary to develop appropriate changes to Market Rule 1 to integrate alternative regulating technologies into the Regulation market.~~

## ~~III.J.2. Eligibility and Technical Requirements~~

~~Resources must meet the following requirements to participate in the alternative technologies regulation pilot program:~~

~~i. Pilot program participants must be registered as Market Participants.~~

~~ii. The Resource must provide a response capability greater than or equal to 1 MW/minute.~~

~~iii. The Resource must provide an initial regulating range of at least ±0.1 MW, and no greater than ±5 MW. Increases above ±5 MW may be possible, pursuant to Section III.J.4.~~

~~iv. Each participating Resource must meet all interconnection requirements based on Resource size, and all metering and communication requirements, as described in ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands, Section V.B (Telemetering and Revenue Metering), Section V.C (Communications and Control), and Section V.G (Interconnection), and ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.~~

~~v. The Resource must be capable of receiving and responding to automatic generation control setpoint signals sent electronically by the ISO at four second intervals.~~

~~vi. The Resource must be capable, consistent with its normal operating characteristics, of following dispatch and operating instructions provided by the ISO, whenever the Resource is available to provide regulation services.~~

~~vii. The program participant must provide technology performance data as specified by the ISO from research and development scale or larger demonstration test results to confirm technical feasibility.~~

~~viii. The following generating technology/fuel type resources are eligible to participate in the existing~~

~~Regulation market subject to meeting existing requirements, and are not eligible to participate in the pilot program:~~

- ~~conventional thermal generation – oil, gas, or coal~~
- ~~combined cycle generation – gas or oil~~

- ~~combustion turbine generation – oil or gas~~
- ~~hydro generation with pondage, including pumped storage generation~~

~~Other technology types, including generation using fuel sources other than those listed above, energy storage technologies, load response technologies, and other non-generation technologies are eligible to participate in the pilot program, subject to meeting the remaining requirements of Section III.J.2.~~

~~ix. Resources participating in the pilot program will not be required to meet the minimum regulating range requirements as described in ISO New England Manual 11 Section 3.2.1(4), and will not be required to meet the minimum self-scheduled for regulation duration requirements as described in ISO New England Manual 11 Section 3.2.1(8).~~

~~x. A Resource will not be required to meet any specific sustainability requirement to be eligible to participate in the pilot program.~~

~~xi. A Resource may not commence operations within the pilot program until it is represented in the ISO's energy management systems.~~

**~~III.J.3. Program Duration~~**

~~The pilot program will commence on or after November 18, 2008. To be eligible to participate, the entity that will control and operate the Resource must:~~

~~1. Have executed a Market Participant Service Agreement or have submitted a completed application for New England Power Pool membership, including the required application fee; and~~

~~2. Submit documentation to the ISO identifying the technology proposed to be used to provide regulation services, and the locations where principal facilities and equipment will be installed.~~

~~New Resources that satisfy the eligibility and application requirements may begin providing regulation services at any time prior to the termination of the program, but Resources that can provide at least 12 months of operating experience will be strongly preferred in the event the program's size, described in Section III.J.4, cannot accommodate all the Resources that would like to participate..~~

~~The pilot program will continue through the later of:~~

~~i. the 18th full calendar month of operation; or~~

~~ii. the effective date of the implementation, following acceptance by the Commission, of permanent changes to the Regulation market rules reflecting the results of the pilot program or a filing to terminate the pilot program without implementing any permanent changes to the Regulation market rules.~~

~~Compensation for regulation services under the pilot program will terminate at the end of the program. At that time, pilot program participants that wish to continue to provide regulation services will only be able to do so by meeting the requirements of the Regulation market and participating in the market under the then existing rules and procedures.~~

~~After the pilot program has been in operation for no longer than 12 calendar months, the ISO will evaluate the initial operational results of the pilot program, including Resource performance information, to determine what changes to existing Regulation market rules, if any, are appropriate.~~

**~~III.J.4. Program Size~~**

~~Total program enrollment will be limited to ±13 MW regulating capability. The total program limit of 13 MW represents 10% of the average hourly regulating requirement.~~

~~Within this total, the participation by a single type of technology will be limited to no more than 10 MW, and no individual Market Participant may initially enroll more than 5 MW. These initial limitations may be eased or eliminated over the course of the pilot program, based on participation levels and pilot program results. Any change in program participation limits will not result in decreased participation levels for other participating Resources already accepted into the pilot program, unless the ISO determines through operational testing that an accepted Resource cannot be effectively incorporated at the accepted level. Resources may begin participation in the pilot program at less than their full accepted regulating capability and increase their capability as the pilot program progresses, up to their accepted amount.~~

**~~III.J.5. Selection of Pilot Program Participants~~**

~~Resources interested in joining the pilot program will apply to participate by sending a pilot program participation request letter to the ISO's Customer Service e-mail address (custserv@iso-ne.com) that describes in general terms the technology proposed, interconnection location, regulating capability, performance characteristics, and anticipated commercial operation date. Based on the participation request letters received by the later of October 15, 2008 or the effective date granted by the Commission, the ISO will determine if the program is going to be oversubscribed. The ISO may, at its discretion, request additional information to verify the technical feasibility of any or all of the requests to participate.~~

~~If the ISO determines the pilot program will not be oversubscribed, all participants that meet the pilot program's technical requirements will be accepted. Participants submitting pilot program participation request letters after October 1, 2008 will only be accepted on a space available basis in the order in which the letters were received.~~

~~If the ISO determines the pilot program will be oversubscribed, the ISO will determine a subset of the participation requests that will maximize the useful information to be gained from pilot program, based on the following principles:~~

~~i. Technological diversity~~

~~ii. Potential for the technology to be scalable to "commercial" size, defined for this purpose to be ≥ 1 MW~~

~~iii. Maturity of the proposed technology and the existence of a demonstrated track record indicating the technology is close to commercialization, and not in the early conceptual stages of research and development~~

~~iv. Earliest on-line date~~

~~v. Any unique performance characteristics that offer the greatest potential to reduce the region's future total cost of regulation services.~~

**~~III.J.6. Participant Responsibilities~~**

~~Prior to providing regulation services through the pilot program, each pilot program participant is responsible for, at their own expense, completing all interconnection requirements and installing all~~

~~necessary communication facilities. Arrangements for interconnection, including studies and installation of any required equipment, should be made through the Transmission Owner providing service at the point of interconnection. The ISO's Market Support Services group can provide guidance in initiating the interconnection process and will order the required communication circuits on the pilot program participant's behalf. The pilot program participant must also successfully demonstrate the ability to receive and follow automatic generation control setpoint signals prior to providing regulation services within the pilot program.~~

~~After commencing pilot program commercial operations, the participant is responsible for:~~

~~i. reporting promptly to the ISO any change in availability or ability to perform bidirectional electronic communications;~~

~~ii. reporting promptly the timing and expected duration of any planned or unplanned outages;~~

~~iii. following dispatch and operating instructions provided by the ISO, whether provided electronically or by telephone, whenever the Resource is available to provide regulation services;~~

~~iv. providing the ISO with completed "NX-12" forms, or appropriate pilot program-specific substitute forms prepared by Market Support Services. "NX-9" forms may also be required, depending on where on the transmission system the Resource is located;~~

~~v. meeting all requirements of the ISO New England Financial Assurance Policy; and~~

~~vi. providing, and promptly updating as necessary, the Resource's Automatic Response Rate, Regulation High Limit, Regulation Low Limit, and on/off Regulation status.~~

~~A participant in the pilot program may withdraw from further participation in the program by providing written notification of withdrawal to the ISO's Market Support Services group.~~

**~~III.J.7. Program Design and Management~~**

~~The participation of each Resource in the pilot program will progress through two phases. During the first phase, various regulation dispatch parameters will be adjusted by the ISO in collaboration with the participant to achieve a balance between benefits provided to the Regulation market as identified by the~~

~~ISO and profitable operation of the Resource as identified by the Participant. The ISO will initially send automatic generation control setpoints to each pilot program participant and will observe and monitor the Resource's ability to perform in accordance with the performance specifications provided by the participant.~~

~~When the ISO and the participant agree that the adjusted dispatch parameters achieve the desired balance, the Resource will enter the second phase of operations which continues through the end of the pilot program. Operation during the second phase is intended to approximate how the facility would operate in the competitive Regulation market. Further adjustments to dispatch parameters during the second phase are permitted, but are expected to be less frequent.~~

~~Participants are not guaranteed that operating patterns experienced during the pilot program will necessarily be replicated in the Regulation market after the pilot program has terminated, and there is no guarantee that a participant will be able to operate its Resource profitably during the pilot program. Resources are accepted into the pilot program for the full remaining duration of the program. The participation of a Resource may be terminated at any time by the ISO due to:~~

~~i. Equipment failure or inability to comply with the program's technical requirements;~~

~~ii. Poor reliability or availability; or~~

~~iii. Network reliability problems caused or exacerbated by the Resource that cannot be sufficiently mitigated through adjustments to regulation dispatch parameter settings.~~

~~Program participants may arrange for limited testing of communications and facility operation prior to commencement of the pilot program and prior to the pilot program participant's registration as a Market Participant. There is no compensation for regulation services provided prior to commencement of the pilot program, prior to successful completion of communications testing, or for an unregistered participant.~~

**~~III.J.8. Resource Auditing and Performance Monitoring~~**

~~No explicit auditing of Resource performance is required. The ISO systems used to monitor system status and determine automatic generation control setpoints for Resources in the pilot program will provide automatic performance monitoring. The automatic performance monitoring will identify those time~~

~~intervals during which the actual output of a participating Resource deviates from a device-specific megawatt tolerance about its automatic generation control setpoint. To allow for data transmission latency, inertia, and directional turnaround, a device-specific grace period, specified in seconds, must expire after the automatic generation control setpoint is changed before automatic performance monitoring begins. The device-specific megawatt tolerance and grace period will be established by the ISO for each Resource participating in the pilot program. Intervals identified as non-compliant by automatic performance monitoring are referred to as "fade time" and will be used in the calculation of payments for regulation services provided, as described in Section III.I.9.~~

**~~III.J.9. Market Integration and Participant Compensation~~**

~~The 13 MW of alternative technology regulating resources included in the pilot program will be incremental resources above and beyond the Regulation Requirement amount, as determined periodically by the ISO and acquired through the Regulation market. Pilot program Resources will not submit offers into the Regulation market, will only participate directly in the real time Regulation market as "self-scheduled for regulation," and are not utilized in the determination of the Regulation Clearing Price calculated in accordance with Section III.1.11.5 and Section III.3.2.2(e) of Market Rule 1.~~

~~Hourly payments for regulation services to pilot program Participants shall be calculated as:~~

~~(RCP * Time-on-Regulation Megawatts) + (RCP * Capacity-to-Service Ratio * Regulation Service Megawatts * (time on in minutes – fade time in minutes) / time on in minutes)~~

~~where~~

~~RCP = Regulation Clearing Price,~~

~~Time-on-Regulation Megawatts = Regulation Capability * (time on in minutes – fade time in minutes) / 60 minutes,~~

~~Capacity-to-Service Ratio, as determined in accordance with Section III.3.2.2(h) of Market Rule 1,~~

~~Regulation Service Megawatts = the sum of the absolute value of positive and negative movement that would occur if the Resource responded at its Automatic Response Rate without delay in pursuit of changing AGC setpoints while providing Regulation within the hour, known also as "mileage."~~

~~Pilot program participants are paid for regulation services provided by participating Resources. Pilot program Resources are self-scheduled for regulation and do not receive payment for Regulation Opportunity Costs, as described in ISO New England Manual 11 Section 3.2.5(c).~~

~~Resources participating in the pilot program are not eligible to participate in the ICAP market or the Forward Capacity Market. The Resources shall have no qualified megawatts eligible to receive capacity payments, and shall have no daily Coincident Peak Contribution subject to a capacity payment obligation.~~

~~Program participants do not submit offers into the Day-Ahead Energy Market or the Real-Time Energy Market for participating Resources.~~

~~During the asset registration process for participating Resources, the pilot program participant will determine, in conjunction with any interconnecting Transmission Owner, if the interconnection and metering arrangements for the Resource will result in the Resource's net energy requirements (energy consumption for the hour less energy injections for the hour) being separately reported to the ISO as Real-Time Load Obligation, or will be included in the Real-Time Load Obligation of a separate load serving entity. If the participating Resource has separately metered and reported Real-Time Load Obligation, the pilot program participant will pay for the net energy consumed at the Real-Time Energy Market nodal Locational Marginal Price at the Resource's interconnection point and a proportional share of the following charges, as calculated in accordance with Market Rule 1, that are allocated based on Real-Time Load Obligation:~~

~~i. Inadvertent Energy, as described in ISO New England Manual 28 Section 10.2.2~~

~~ii. Real-time Loss Revenue excess or deficiency, as described in Market Rule 1 Section III.3.2.1(m) and ISO New England Manual 28 Section 7.2.1.~~

~~iii. Real-Time NCPC for Local Second Contingency Protection Resources, as described in Market Rule 1 Appendix F Section III.F.3.2.16.~~

~~iv. Forward Reserve costs, as described in ISO New England Manual 28 Section 2.6.2.~~

~~v. Real-Time Reserve costs, as described in ISO New England Manual 28 Section 2.6.3.~~

~~vi. Schedule 2 Energy Administration Service~~

~~vii. Regulation costs, as described in ISO New England Manual 28 Section 4.3.1.~~

**~~III.J.10. Pilot Program Cost Allocation~~**

~~Pilot program participants must comply with the interconnection requirements under Section II.47 and Schedule 23 of the OATT. Pilot program participants are responsible for the costs of interconnection and metering in accordance with Section II.47, Schedules 11 and 23 of the OATT.~~

~~The ISO's development and implementation costs will be allocated to the ISO capital and expense budget categories as described in Section IV.A Schedules 1, 2, and 3 of the ISO Tariffs as follows:~~

~~i. 20% Scheduling, System Control and Dispatch~~

~~ii. 20% Energy Administration~~

~~iii. 60% Reliability Administration~~

~~Payments for regulation services delivered by pilot program participants will be charged to Market Participants proportionately based on Adjusted Regulation Obligations, which is based on Real-Time Load Obligations and adjusted for bilateral Regulation purchases and sales, as described in Market Rule 1 Section III.3.2.2 and ISO New England Manual 28, Section 4.~~

# M E M O R A N D U M

**TO:** Participants Committee Members and Alternates

**FROM:** NEPOOL Counsel

**DATE:** January 25, 2013

**RE:** UPDATE: Summary of Recent Pleadings in the FCM FCA8 Redesign Proceedings

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This memorandum supplements an earlier NEPOOL Counsel memorandum (dated January 2, 2013) which provided a summary of the initial round of pleadings submitted in response to the ISO's December 3, 2012 filing of proposed FCA8 Tariff revisions in FERC Docket No. ER12-953-001.[1] This update provides a brief summary of: (1) answers to those initial protests and comments submitted in the underlying FCM Redesign docket (ER12-953-001); and (2) pleadings submitted in response to the New England States Committee on Electricity's ("NESCOE") complaint in FERC Docket No. EL13-34, which directly relate to the ISO's December 3 Filing.

If Participants have any questions regarding these FCM Redesign pleadings, please let us know.

## SUMMARY OF PLEADINGS

### I. Answers Submitted in ER12-953-001

***ISO New England*** – In its answer, the ISO generally defended its December 3, 2012 filing and urged the FERC to reject the substance of all the responsive pleadings submitted and accept its proposed FCA8 Tariff revisions without modification. More specifically, the ISO asked the FERC to reject: (1) requests for a categorical exemption from the ISO's proposed buyer-side mitigation construct (i.e., the "MOPR") for state-sponsored or renewable resources and for new self-supplied resources; (2) arguments related to the development and application of the Offer Review Trigger Prices ("ORTPs") used in the offer-floor mitigation mechanism; (3) requests that the FERC reject the ISO's request for waiver of the obligation to implement eight capacity zones for FCA8; and (4) requests to revisit the $1.00/kW-month Dynamic De-List Bid threshold if the FERC were to grant the ISO's requested waiver.

***New England Power Generators Association Inc. ("NEPGA")*** – NEPGA responds to a number of comments and protests[2] seeking specific exemptions to the ISO's proposed MOPR.[3] First,

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[1] The ISO submitted its December 3 Filing in response to several FERC orders on FCM Redesign (the "FCM Redesign Orders"). *See ISO New England Inc. et al*, 135 FERC ¶ 61,029 (2011) ("April 13, 2011 Order"); *ISO New England Inc. et al*, 138 FERC ¶ 61,027 (2012) ("January 19, 2012 Order"); *ISO New England Inc. et al*, 138 FERC ¶ 61,238 (2012) ("March 30, 2012 Order").

[2] Specifically, NEPGA responds to the filings by NESCOE, NU Companies, the Massachusetts Attorney General, *et al.* ("Mass AG"), the Massachusetts Municipal Wholesale Electric Company and New Hampshire Electric Cooperative, Inc., (jointly, "Municipals"), the Connecticut Office of Consumer Counsel, and the Conservation Law Foundation.

NEGPA asserts that the Mass AG and NESCOE requests for an exemption to the MOPR for certain state-sponsored renewable resources represent collateral attacks on prior FERC orders. And even if the FERC were to consider such requests, NEPGA urged the FERC to reaffirm its earlier finding that the ISO must protect against all forms of capacity market price suppression. Second, NEPGA addressed the Municipals' request to exempt new self-supplied resources from the ISO-proposed ORTPs. On this issue, NEPGA stated that self-supplied resources should not be guaranteed to clear in the Forward Capacity Auction ("FCA") by suppressing otherwise competitive outcomes of the FCM.

***H.Q. Energy Services (U.S.) Inc. ("HQUS)*** – In its Answer, HQUS responded to PSEG's[4] protest which, in part, asserted that the ISO's treatment of new import capacity resources under its proposed MOPR is discriminatory. HQUS asked the FERC to reject PSEG's request that the FERC order the ISO to require all importers to specify an External Resource backing their capacity bids because such a request: (1) unduly discriminates against importers of capacity backed by a Control Area, (ii) is an improper collateral attack on the 2006 FCM Settlement and the FERC's FCM Redesign Orders, and (iii) is inappropriate at the compliance phase of this proceeding.

***NEPOOL Participants Committee ("NEPOOL")*** – NEPOOL submitted a brief Answer in response to NRG[5] and PSEG's request that that the FERC direct the ISO to modify the Market Rules to permit the bilateral trading of Capacity Supply Obligations ("CSOs") across capacity zones in certain circumstances. NEPOOL simply asked the FERC to ensure that NRG and PSEG's concerns with unchanged Market Rule provisions are addressed through proper stakeholder and FERC procedures and not in this proceeding.

## II. Pleadings Submitted in EL13-34 (NESCOE Complaint Proceeding)

On December 28, 2012, NESCOE instituted a complaint in response to the ISO's December 3 FCM compliance filing that proposes to implement buyer-side mitigation without an exemption for state-sponsored public policy resources. NESCOE asserted that the ISO's proposed offer floor mitigation construct will 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. In response, NESCOE proposed an alternative renewables exemption (the "Renewables Exemption Proposal"), which it claimed will "establish a path for certain renewable resources to count towards the region's resource adequacy goals while limiting the impact on the FCM clearing price." NESCOE

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[3] NEPGA's answer reiterates the argument expressed in its initial protest in ER12-953-001 that any categorical exemptions to the proposed MOPR would fail to protect against undue market price impacts and thus the FERC should not permit categorical exemptions to the ORTPs proposed by the ISO.

[4] "PSEG" collectively refers to, PSEG Power LLC, PSEG Power Connecticut LLC, and PSEG Energy Resources & Trade LLC.

[5] "NRG" collectively refers to, NRG Power Marketing LLC, GenON Energy Management, LLC, Connecticut Jet Power LLC, Devon Power LLC, GenOn Canal, LLC, GenOn Kendall, LLC, Middletown Power LLC, Montville Power LLC, and Norwalk Power LLC.

requested that the FERC (1) initiate a "paper hearing" proceeding pursuant to Section 206 of the FPA, (2) find the ISO's proposed December 3 FCM Tariff revisions regarding buyer-side mitigation unjust and unreasonable; (3) find NESCOE's Renewables Exemption Proposal just and reasonable; (4) amend the ISO's proposed Tariff revisions to incorporate NESCOE's Renewables Exemption Proposal; and (5) grant NESCOE's motion for consolidation of ER12-953 with EL13-34.

On January 17, 2013, the following pleadings were submitted in response to NESCOE's Complaint.

***ISO New England*** – In its pleading, the ISO opposes NESCOE's motion to consolidate the two FCM proceedings on the ground that the NESCOE Complaint should be dismissed summarily. The ISO asserts that the NESCOE Complaint challenges pending Tariff provisions and since these filed provisions are not final and effective until the FERC takes further action, the ISO's proposed FCA8 Tariff revisions are not "in force," and therefore NESCOE's Complaint does not satisfy the procedural requirements/threshold set forth in Section 206 of the Federal Power Act ("does not lie under the terms of Section 206 of the FPA"). Should the FERC not summarily dismiss the NESCOE Complaint, the ISO argued that it should still be denied because the Complaint was "based on a misreading of the FERC's FCM Redesign Orders."

***NEPGA*** – In its protest, NEPGA asked the FERC to dismiss NESCOE's Complaint and deny the motion to consolidate the proceedings. More specifically, NEPGA asserted: (1) NESCOE's motion to consolidate if granted would cause undue delay in the approval of FERC-directed FCM changes for FCA8; (2) NESCOE's complaint is a collateral attack on prior FERC orders; (3) NESCOE fails to meet its burden under Section 206 of the Federal Power Act to show that the proposed MOPR is unjust and unreasonable; and (4) NESCOE's proposed categorical exemption violates the FERC's primary concern of market price suppression.

***Exelon Corporation*** – Exelon's pleading supported NEPGA's protest (as described above) arguing that the relief sought by NESCOE in its Complaint is a collateral attack on prior FERC orders and that the FERC should approve the ISO's proposed MOPR without modification. In addition, Exelon explained that the FERC should not consolidate the two FCM Redesign proceedings because that could delay the implementation of necessary market mechanisms intended to address price suppression in FCA8.

**Dominion Resources Services, Inc. ("Dominion")** – Dominion supported the comments filed by NEPGA in this complaint docket and urged the FERC to deny NESCOE's motion to consolidate and summarily dismiss the NESCOE Complaint.

***TransCanada Power Marketing Ltd. ("TransCanada")*** – TransCanada submitted a protest[6] asking the FERC to reject NESCOE's proposed Renewables Exemption Proposal for the following reasons: (1) the proposal constitutes a collateral attack on prior FERC orders that denied a categorical exemption to renewable resources; (2) NESCOE's proposed Renewables

[6] TransCanada also submitted this pleading as comments in Docket No. ER12-953-001.

Exemption Proposal is unduly discriminatory because it would permit the participation of uneconomic state-sponsored renewable resources in FCAs to the exclusion of other resources that do not receive out-of-market subsidies from state programs; and (3) the proposal is unjust and unreasonable because it would artificially suppress capacity clearing prices in FCAs and, therefore, harm the efficient operation of ISO markets. In the event that the FERC is inclined to consider the Renewables Exemption Proposal, TransCanada urged the FERC to direct that such proposals should be taken up in the stakeholder process, which would "provide all market participants an opportunity to consider NESCOE's Renewables Exemption Proposal, and its impacts, in conjunction with other proposals in a comprehensive manner, rather than in the piece-meal manner NESCOE seeks to achieve through its complaint."

***Northeast Utilities Companies ("NU Companies")***[7] – Echoing its support of a renewable resource exemption to the MOPR as expressed in its initial comments submitted in the underlying FCM Redesign docket (ER12-953-001), the NU Companies supported NESCOE's request that the FERC initiate a paper hearing process to "consider the negative consequences ISO-NE's over-broad buyer-side mitigation proposal will have on state public policy initiatives and the unnecessary FCM costs that will be imposed on those customers the state programs are intended to benefit."

[7] The "NU Companies" are the Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and NSTAR Electric Company.

# EXECUTIVE SUMMARY
## Status Report of Current Regulatory and Legal Proceedings as of January 24, 2013

The following activity, as more fully described in the attached litigation report, has occurred since the report dated January 2, 2013 was circulated. New matters/proceedings since the last report are preceded by an asterisk '*'. Page numbers precede the matter description.

### I. Complaints

| | | | | |
|---|---|---|---|---|
| | 1 | NESCOE FCM Renewables Exemption Complaint (EL13-34) | Jan 4-17 | NEPOOL, Capital Power, Con Ed, CT PURA, EPSA, GDF Suez, LIPA, MA AG, NextEra, NICC, PSEG intervene |
| | | | Jan 14 | ISO moves to dismiss Complaint, or in the alternative, opposes consolidation and opposes Complaint |
| | | | Jan 17 | NEPGA, Dominion, Exelon, TransCanada move to dismiss Complaint and oppose consolidation; NU supports Complaint |
| | 2 | Base ROE Complaint (2012) (EL13-33) | Jan 8-16 | NEPOOL, AIM, CT AG, CT OCC, CT PURA, EMCOS, MA AG, MOPA, MPUC, TEC, VT DPS intervene |
| | | | Jan 16 | TOs respond to complaint; MMWEC/NHEC submits comments |
| | 2 | HQ US FCA7 Complaint (EL13-25) | Jan 18 | FERC grants HQ US wavier of FCA7 QDN deadline in ER13-335 and dismisses this Complaint as moot |
| | 3 | Brookfield FCA7 Complaint (EL13-23) | Jan 18 | FERC grants Brookfield wavier of FCA7 QDN deadline in ER13-335 and dismisses this Complaint as moot |

### II. Rate, ICR, FCA, Cost Recovery Filings

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|---|---|---|---|---|
| | 4 | ICR-Related Values and HQICCs - 2013/2014 ARA3 and 2014/2015 ARA2 (ER13-495) | Jan 17 | FERC accepts values |
| | 4 | FCA7 Qualification Informational Filing (ER13-335) | Jan 18 | FERC accepts informational filing, effective Jan 18 |
| | 4 | 2013 Administrative Costs Budget (ER13-185) | Jan 4 | Chief Judge Wagner designates Michael J. Cianci, Jr. as the Settlement Judge |
| | | | Jan 24 | 1st settlement conf held |
| | | | Jan 25 | Judge Cianci issues settlement status report; 2nd conf. date Mar 4 |
| | 5 | FCA5 Results Filing (ER11-3891) | Jan 16 | Chief Judge Wagner issues order terminating Settlement Judge procedures and the proceeding, subject to final FERC review |
| | 6 | ISO Issuance of Securities: $40 Million for New Back Up Control Center (ES12-47) | Jan 11 | ISO files "Report of Securities" |

### III. Market Rule Changes, Interpretations and Waiver Requests

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|---|---|---|---|---|
| * | 6 | IMM Information Sharing Revisions (ER13-750) | Jan 11 | ISO and NEPOOL jointly file changes to permit the sharing of confidential information with other ISO/RTOs and their market monitors; comment date Feb 1 |
| * | 6 | CSO Termination: Concord Steam (ER13-735) | Jan 9 | ISO files to terminate Concord Steam's CSO for resource 14666; comment date Jan 30 |
| | | | Jan 11 | NEPOOL intervenes |
| * | 6 | CSO Termination: MATEP (ER13-729) | Jan 8 | ISO files to terminate MATEP's CSO for resource 37090; comment date Jan 29 |
| | | | Jan 11 | NEPOOL intervenes |
| | 6 | FCM Static De-List Bid Changes (ER13-612) | Jan 10-11 | Exelon, NRG, NU intervene doc-lessly |
| | | | Jan 22 | FERC accepts changes, effective Feb 19 |

| | | | |
|---|---|---|---|
| 6 | CSO Bilateral Transaction and Reconfiguration Auction Enhancements (ER13-585) | Jan 7-9 | Exelon, NRG, NU intervene doc-lessly |
| 7 | Corrections to ISO-NE eTariff Section III.A.15.2 (ER13-510) | Jan 9 | FERC accepts corrections |
| 7 | Footprint Power Request for Limited Waiver of New Capacity Qual. Deadlines (ER13-468) | Jan 18 | FERC grants requested waiver of FCA7 QDN deadline |
| 8 | Information Policy Pipeline Information-Sharing Changes (ER13-356) | Jan 14<br><br>Jan 23 | FERC issues tolling order affording it additional time to consider the ISO's request for expedited rehearing of Dec 7 Order<br>FERC conditionally accepts changes on an interim basis (Jan 24-Apr 30, 2013) and denies rehearing of Dec 7 Order |
| 9 | Generator Audit Revisions (ER13-323) | Jan 9 | FERC conditionally accepts revisions, effective Jun 1, 2013 (with 2 weeks' notice of actual effective date) |
| 9 | FCM Conforming Changes Reflecting PRD Full Integration (ER12-1627) | Jan 14 | FERC accepts in part, and rejects in part, proposed changes, effective Jun 1, 2017, and subject to a 60-day compliance filing (Mar 14, 2013) |
| 11 | FCM Redesign Compliance Filing: FCA8 Revisions (ER12-953 et al.) | Jan 14<br>Jan 17 | NEPOOL, ISO, HQ US, NEPGA file answers<br>Danvers intervenes out-of-time |

## IV. OATT Amendments / TOAs / Coordination Agreements

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|---|---|---|---|
| 12 | Order 1000 Compliance Filing (ER13-193; ER13-196, not consolidated) | Jan 7<br>Jan 8<br>Jan 10<br>Jan 17, 18 | VT PSB intervenes out-of-time<br>NESCOE and Five NE States respond to comments and protests<br>RENEW withdraws its intervention<br>PTO AC and ISO file answers to comments and protests |
| 13 | NPC-Supported Revisions to Attachment K and MR1 (ER12-1914) | Jan 18 | FERC accepts second compliance filing, effective Aug 1, 2012 |

## V. Financial Assurance/Billing Policy Amendments

***No Activity to Report***

## VI. Schedule 20/21/22/23 Changes

| | | | |
|---|---|---|---|
| 14 | Schedule 21-BHE: Cancellation of Evergreen Wind LSA (ER13-480) | Jan 9 | FERC accepts cancellation |
| 14 | Schedule 21-FG&E: Corrections, Conforming and Clean Up Changes (ER13-474) | Jan 4 | FERC accepts changes, subject to a compliance filing identifying the effective date of the changes |
| 14 | Schedule 21-GMP: Merger Revisions; Cancellation of Schedule 21-CVPS (ER12-2304) | Jan 9<br><br>Jan 14<br>Jan 24 | Settlement Judge Johnson issues status report and recommends settlement judge procedures be continued<br>Judge Johnson schedules 2nd settlement conf. for Jan 24<br>2nd settlement conf. held |

## VII. NEPOOL Agreement/Participants Agreement Amendments

***No Activity to Report***

## VIII. Regional Reports

| | | | | |
|---|---|---|---|---|
| * | 15 | LFTR Implementation: 17th Quarterly Status Report (ER07-476) | Jan 15 | ISO files its 17th quarterly report |

## IX. Membership Filings

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|---|---|---|---|
| 16 | December 2012 Membership Filing (ER13-493) | Jan 8 | FERC accepts (i) the membership of Iron Energy (Supplier Sector, Dec 1, 2012); and (ii) the termination of SESCO Enterprises (Nov 1, 2012) and Moose River Lumber and MRL Energy (Dec 1, 2012) |

## X. Misc. - ERO Rules, Filings; Reliability Standards

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| 17 | Revised Reliability Standard: EOP-004-2 (RD13-3) | Jan 4 | FERC submits errata to request for approval of Standard merging EOP-004-1 and CIP-001-2a; comment date Feb 4 |
| 17 | Revised Reliability Standard: VAR-002-2b (RD13-2) | Jan 8<br>Jan 23 | AMP intervenes; PPL submits comments<br>FERC responds to PPL comments |
| 18 | NOPR: Geomagnetic Disturbance Reliability Standards (RM12-22) | Jan 10-14 | NERC and Foundation for Resilient Societies file reply comments<br>Additional comments and materials posted on eLibrary |
| 21 | FERC Performance Audit of NERC (FA11-21) | Jan 16 | FERC approves Settlement Agreement comprehensively resolving all outstanding issues related to OE's 2012 performance audit of NERC |

## XI. Misc. - of Regional Interest

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| * | 22 | 203 Application: FPL Energy Maine Hydro/Brookfield (EC13-62) | Jan 14 | Applicants request authorization for indirect disposition of the equity interests in Maine Hydro to Brookfield; comment date Feb 4 |
| | 23 | 203 Application: NEET / NEP (EC13-50) | Jan 15 | FERC authorizes the transfer of the Monroe HVDC Phase I Converter facility from NEET to NEP |
| | 23 | 203 Application: CMP, MEPCO / BHE (EC13-49) | Jan 4<br>Jan 22 | CMP submits clarifying information regarding recovery of transaction costs<br>FERC authorizes transfer of Orrington Assets |
| | 23 | Foley v. UI: Rate Base Complaint (EL12-106) | Jan 7-11 | Foley files additional exhibits |
| | 25 | LGIA – Oakfield (BHE/Evergreen /ISO) (ER13-741; ER13-678) | Jan 10<br>Jan 10 | BHE/ISO withdraw, for technical reasons, LGIA filed in ER13-678<br>BHE/ISO re-file conforming LGIA; comment date Jan 31 |
| | 25 | IA – Fitchburg/Pinetree (ER13-446) | Jan 8 | FERC accepts IA, effective Nov 22, 2012 |
| | 25 | MISO Methodology to Involuntarily Allocate Costs to Entities Outside Its Control Area (ER11-1844) | Jan 17 | MISO and ITC file Brief on Exceptions to Judge Sterner's Initial Decision |
| | 29 | Waiver of Transmission Standards of Conduct: Green Mountain Power Request (TS04-277) | Jan 17 | FERC issues notice of requested waiver; comments date Feb 7 |

## XII. Misc. - Administrative & Rulemaking Proceedings

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| * | 30 | Policy Statement: Allocation of Capacity on New Transmission Projects (AD12-9; AD11-11) | Jan 17 | FERC issues final policy Statement, effective Jan 17 |
| * | 30 | NOPR: Revisions to Pro Forma SGIA and SGIP (RM13-2) | Jan 17 | FERC issues NOPR; comment date 120 days after its publication in the *Federal Register* |
| | 19 | Order 773: Revised "Bulk Electric System" Definition and Procedures (RM12-7; RM12-6) | Jan 22 | APPA, AWEA, Dow Chemical, Holland MI Bd. of Public Works, NARUC, NERC, NRECA, NY PSC, Snohomish County, TAPS, and Utility Services request rehearing and/or clarification |
| | 31 | Order 771: Availability of E-Tag Information to FERC Staff (RM11-12) | Jan 22 | EEI/NRECA, Open Access Tech. Int'l, NRECA (separately), and Southern Companies request clarification and/or rehearing of *Order 771* |

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| 32 | Order 764-A: Variable Energy Resources (RM10-11) | Jan 22 | Iberdrola and Powerex request clarification and/or rehearing of *Order 764-A* |

## XIII. Natural Gas Proceedings

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| 33 | Natural Gas and Electric Market Coordination (AD12-12) | Jan 7 | Nearly 30 parties file comments, including all RTO/ISOs but MISO, as well as the following New England Parties: MMWEC, National Grid, NEPGA (with EPSA), New England LDCs. |
| | | Jan 23 | Gas-electric focus group meeting; next meeting scheduled for Feb 26 |
| 34 | NOI: Enhanced Natural Gas Market Transparency (RM13-1) | Jan 18 | FERC extends date for filing comments to and including Feb 12; comments submitted by Coalition for Renewable Natural Gas |
| 34 | Enforcement Notice of Alleged Violations | Jan 18 | Notice of alleged violations by Michigan Consolidated Gas Co. and Washington 10 Storage Corp. |

## XIV. State Proceedings & Federal Legislative Proceedings

***No Developments to Report***

## XV. Federal Courts (Appeals of FERC Decisions)

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| 36 | Orders 1000 and 1000-A (12-1232 consolidated) | Jan 16 | Intervenors and petitioners file joint unopposed motion to govern further proceedings |
| 36 | FCM Re-Design (12-1060 consolidated) | Jan 7 | FERC files Respondent Brief |
| | | Jan 22 | NEPGA and CT PURA, HQ US, NICC, NSTAR, and NECPUC file Intervenor for Respondent Briefs |
| 37 | Orders 745 and 745-A (11-1486 consolidated) | Jan 15, 17 | Parties file letters advising of additional authorities |
| 38 | Vermont Yankee Complaint (2nd Circuit, 12-707) | Jan 14 | Oral argument held |

**M E M O R A N D U M**

**TO:** NEPOOL Participants Committee Member and Alternates

**FROM:** Patrick M. Gerity, NEPOOL Counsel

**DATE:** January 25, 2013

**RE:** Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures, and Courts

We have summarized below the status through January 24, 2013 of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"), state regulatory commissions, and the Federal Courts and legislatures. If you have questions, please contact us.[1]

## I. Complaints

- **NESCOE FCM Renewables Exemption Complaint (EL13-34)**

On December 28, 2012, NESCOE instituted a complaint in response to the ISO's December 3 FCM compliance filing (*see* ER12-953 in Section III below) that proposes to implement buyer-side mitigation without an exemption for state-sponsored public policy resources. NESCOE asserts that the ISO's proposed offer floor mitigation construct will 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. In response, NESCOE proposes an alternative renewables exemption (the "Renewables Exemption Proposal"), which it claims will "establish a path for certain renewable resources to count towards the region's resource adequacy goals while limiting the impact on the FCM clearing price." NESCOE requests that the FERC (1) initiate a "paper hearing" proceeding pursuant to Section 206 of the FPA, (2) find the ISO's proposed December 3 FCM Tariff revisions regarding buyer-side mitigation unjust and unreasonable; (3) find NESCOE's Renewables Exemption Proposal just and reasonable; (4) amend the ISO's proposed Tariff revisions to incorporate NESCOE's Renewables Exemption Proposal; and (5) grant NESCOE's motion for consolidation of ER12-953 with EL13-34.

Interventions were filed by NEPOOL, Capital Power, Con Ed, CT PURA, EPSA, Exelon, GDF Suez, LIPA, MA AG, NextEra, NICC, and PSEG. NU submitted comments supporting NESCOE's request that the FERC initiate a paper hearing process to consider "the negative consequences that the ISO's over-broad buyer-side mitigation proposal will have on state public policy initiatives and the unnecessary FCM costs that will be imposed on those customers the state programs are intended to benefit." The ISO moved to dismiss the Complaint, opposed consolidation of this proceeding with ER12-953, and, if not dismissed, provided its answer opposing the Complaint. NEPGA, Dominion, and Exelon also asked the FERC to dismiss NESCOE's Complaint and deny the motion to consolidate the proceedings. TransCanada also protested NESCOE's Complaint, urging dismissal, and requesting the FERC, if inclined to consider a proposal exempting renewable resources from mitigation under a MOPR, to direct consideration of such proposals in the stakeholder process. A more detailed summary of the pleadings submitted in this proceeding and the FCM Redesign Compliance Filing proceeding is included with this Report. 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; dtdoot@daypitney.com).

[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. Transmission, Markets and Services Tariff (the "ISO Tariff").

- **Base ROE Complaint (2012) (EL13-33)**

As previously reported, Environment Northeast ("ENE"), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition (the "Complainants") filed an additional complaint regarding the return on equity ("Base ROE") used in calculating formula rates for transmission service in the ISO's Open Access Transmission Tariff ("OATT"), seeking by this complaint to reduce the Base ROE from the still effective 11.14% to 8.7%. Complainants acknowledge that the Base ROE is already the subject of ongoing hearing procedures in EL11-66 (see below) but offer the following six reasons for the docketing of a further complaint addressing the Base ROE: (1) the FERC has held that the pendency of a Section 206 investigation into a public utility's ROE does not immunize that ROE from investigation through a second Section 206 complaint proceeding; (2) promoting the Congressionally-directed symmetry of remedies as between FPA §§ 205 and 206 (i.e. a fair symmetry requires that Complainants be free to file a complaint requesting further rate decreases based on later common equity cost data without regard to the status of prior complaints since TOs could file at any time for an increase); (3) this complaint would ensure the FERC could set an ROE below the 9.2% requested in EL11-66 if the evidence leads there; (4) to reset the New England Transmission Owners ("TOs")[2] zone of reasonableness through updated proxy group analysis; (5) greater assurance that their consent would be required to complete an ROE settlement; and (6) to establish a further 15-month refund period. To the extent the FERC does not summarily grant the reduction to 8.7%, Complainants ask that this matter be set for evidentiary hearing, and that it be consolidated for purposes of hearing and decision with EL11-66.

Interventions were filed by NEPOOL, AIM, CT AG, CT OCC, CT PURA, EMCOS,[3] MA AG, MOPA, MPUC, TEC, and the VT DPS. On January 16, the TOs filed their answer, assert that the FERC should dismiss the Complaint as contrary to Section 206's 15-month refund limitation and that the Complaint fails to show that the TOs' Base ROE is unjust and unreasonable. Alternatively, the TOs argue that the 2011 Complaint (EL11-66) must now be decided solely on the basis of the New England TOs' cost of capital during the locked in period of October 1, 2011 through December 31, 2012, since that is the only refund period to which the 2011 Complaint will apply. TOs argue that evidence relevant to their cost of capital for 2013 and beyond will only be relevant to this Complaint. MMWEC and NHEC filed joint comments supporting the complaint and urging the FERC to grant the relief requested therein and establish the earliest possible refund effective date. Substantively, MMWEC/NHEC provided additional evidence to counter TO arguments that they face substantial payment "risks" in connection either with the provision of transmission service or the construction of new facilities. The request to consolidate this proceeding with EL11-66, as well as the complaint, answer, and comments are 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).

- **HQ US FCA7 Complaint (EL13-25)**

On January 18, the FERC dismissed the H.Q. Energy Services (U.S.) Inc. ("HQUS") FCA7 Complaint as moot [4] As previously reported, HQUS filed a Complaint asking the FERC to direct the ISO to revise the Tariff in time to permit HQUS' import capacity wheeled through NYISO to participate in FCA7 should the FERC (i) determine that the ISO appropriately administered the Tariff and (ii) fail to grant a waiver of the Tariff requirements in these circumstances. In its concurrently issued *FCA7 Qualification Order*,[5] the FERC granted HQUS a wavier of the FCA7 Qualification Determination Notice ("QDN") deadline that allowed HQUS the opportunity to qualify for FCA7. HQ US stated that such a waiver would resolve its Complaint and, accordingly, the FERC dismissed HQ US' Complaint.[6] The FERC also noted that it would not prejudge, and HQUS could raise any concerns with, potential tariff revisions that might be raised through the stakeholder process pursuant to ISO's stated intention to pursue

[2] TOs are Bangor Hydro, CMP, National Grid, New Hampshire Transmission ("NHT"), NSTAR, NUSCO on behalf of its operating company affiliates CL&P, WMECO, and PSNH, UI, Unitil and Fitchburg, and Vermont Transco.

[3] EMCOS or the "Eastern Massachusetts Consumer-Owned Systems" are Braintree, Hingham, Reading, and Taunton.

[4] *H.Q. Energy Services (U.S.), Inc. v. ISO New England Inc.*, 142 FERC ¶ 61,053 (2013) ("*HQUS FCA7 Order*").

[5] *ISO New England Inc. and Footprint Power LLC*, 142 FERC ¶ 61,051 (2013) ("*FCA7 Qualification Order*").

[6] *HQUS FCA7 Order* at P 13.

revisions and clarification of the FCA qualification process.[7] If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Brookfield FCA7 Complaint (EL13-23)**

For similar reasons, the FERC also dismissed the Brookfield Energy Marketing LP ("Brookfield") FCA7 Complaint as moot on January 18.[8] As previously reported, Brookfield alleged that the ISO unjustly and unreasonably disqualified certain Brookfield capacity from participating in FCA7. Specifically, Brookfield alleged that the ISO disqualified Brookfield's capacity based on the application of a deliverability standard for import resources that does not exist in the ISO Tariff. In a December 6, 2012 answer, the ISO indicated that, based on additional information received, it did not oppose the Brookfield waiver request so long as Brookfield provided its financial assurance deposit within five business days of an order granting the waiver. In a footnote to the order dismissing this Complaint, the FERC noted that Brookfield could raise any concerns with the applicable Tariff language during the stakeholder process that the ISO indicated in its answer that it intended to pursue to revise and clarify the FCA qualification process.[9] If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Base ROE Complaint (2011) (EL11-66)**

The FERC issued on May 3, 2012 an order on the Base ROE Complaint, establishing hearing and settlement judge procedures due to identified issues of material fact that could not be resolved based upon the record before it and a finding that the issues would be more appropriately addressed in the hearing and settlement judge procedures ordered.[10] The FERC set the refund effective date at October 1, 2011, as requested. As previously reported, a number of State, consumer, and consumer advocate parties (the "Complainants")[11] filed on September 30, 2011 a complaint against the TOs seeking a FERC order reducing the 11.14 percent Base ROE used in calculating formula rates for transmission service in the ISO's OATT to 9.2 percent. Complainants stated that "due to changes in the capital markets since the *Bangor Hydro* proceeding,[12] the [Base ROE] is no longer just and reasonable." Settlement judge procedures before Judge Judith A. Dowd were ultimately unsuccessful. Chief Judge Wagner issued an order on August 2, 2012 terminating those procedures and designating ALJ Michael J. Cianci as the proceeding's Trial Judge. The current procedural schedule in this case calls for the issuance of an initial decision by September 10, 2013. If you have any questions concerning this matter, please contact Joe Fagan (202- 218-3901; jfagan@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[7] *Id.* at n. 13.

[8] *Brookfield Energy Marketing LP v. ISO New England Inc.*, 142 FERC ¶ 61,052 (2013).

[9] *Id.* at n. 10.

[10] *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.

[11] Complainants are Martha Coakley, Mass. Att'y Gen. ("MA AG"), the Conn. Public Utilities Regulatory Authority ("CT PURA"), Mass. Dep't of Pub. Utils. ("MA DPU"), New Hampshire Pub. Utils. Comm. ("NH PUC"), George Jepsen, Conn. Att'y Gen. ("CT AG"), CT OCC, Maine Off. of the Pub. Advocate ("ME OPA"), New Hampshire Off. of the Consumer Advocate, ("NH OCA"), Rhode Island Div. of Pub. Utils. and Carriers ("RI PUC"), Vermont Dep't of Pub. Srvc ("VT DPS"), MMWEC, AIM, TEC, Power Options, and the IECG.

[12] *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.

## II. Rate, ICR, FCA, Cost Recovery Filings

- **ICR-Related Values and HQICCs - 2013/2014 ARA3, 2014/2015 ARA2, and 2015/2016 ARA1 (ER13-495)**

On January 17, the FERC accepted the jointly filed materials that identify the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL") (collectively, the "ICR-Related Values") and Hydro Quebec Interconnection Capability Credits ("HQICCs") for the third annual reconfiguration auction ("ARA") for the 2013/2014 Capability Year to be held March 1, 2013, the second ARA for the 2014/2015 Capability Year to be held in August 2013, and the first ARA for the 2015/2016 Capability Year to be held in June 2013. The ICR-Related Values and HQICCs were accepted effective January 30, 2013, as requested. Unless the January 17 order is challenged, this proceeding will be concluded. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA7 Qualification Informational Filing (ER13-335)**

On January 18, 2013, the FERC accepted the ISO's informational filing (the "FCA7 Informational Filing") regarding resource qualification for FCA7, effective January 18, 2013.[13] The *FCA7 Qualification Order* resolved the protests filed by HQ US and Brookfield by granting waiver of the QDN deadline to allow the ISO to qualify Brookfield, HQUS, and all similarly-situated denied new import resources west of the Central-East Interface to participate in FCA7.[14] Accordingly, as noted earlier in this report, the separate complaints filed by HQ US and Brookfield were dismissed as moot (*see* Section I above). The *FCA7 Qualification Order* also resolved the protest and request for waiver submitted by Footprint Power in this proceeding and as a stand-alone request (so that its new project could participate in FCA7 at a full capacity of 674 MW, rather than the 570 MWs qualified by the ISO (*see also* Docket No. ER13-468 in Section III below). In granting Footprint's waiver request, the FERC found that the request met its waiver criteria,[15] and disagreed with National Grid that the waiver could harm third parties.[16] Unless the *FCA7 Qualification Order* is challenged, with any challenges due on or before February 19, 2013, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **2013 Administrative Costs Budget (ER13-185)**

As previously reported, the FERC accepted on December 31, 2012 the proposed Tariff revisions for the recovery of the ISO's 2013 administrative costs (the "2013 Revenue Requirement"), but suspended them for a nominal period to become effective January 1, 2013, subject to refund, and established hearing and settlement judge procedures.[17] In setting the 2013 Revenue Requirement for hearing, the FERC encouraged the parties to make every effort to settle their disputes before the hearing procedures are commenced, and indicated that the hearing will be held in abeyance pending the outcome of settlement judge procedures. The FERC rejected as beyond the scope of the proceeding the Joint New England Agencies' proposed reforms to the budget process. However, the FERC stated its expectation that the ISO would fulfill its commitments to schedule a meeting with all interested state agencies on the budgets at least 60 days in advance of its annual budget filings and to include state feedback as part of its future budget filings.[18] The FERC also noted that the ISO may submit its capital and administrative budgets together if it so chooses.

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[13] *FCA7 Qualification Order*. HQ and Brookfield were directed to promptly submit their financial assurance deposits on or before January 28, 2013 within five business days of the date of this order, as requested by the ISO (P 21).

[14] *Id.* at P 19.

[15] The FERC will grant waivers of Tariff requirements where (1) the underlying error was made in good faith; (2) the waiver is of limited scope; (3) granting waiver would remedy a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties. Id. at P 20.

[16] *Id.* at PP 35-38.

[17] *ISO New England Inc.*, 141 FERC ¶ 61,272 (2012) ("*2013 ISO Budget Order*").

[18] *Id.* at P 33.

On January 4, 2012, Chief Judge Wagner designated ALJ Michael J. Cianci, Jr. as the Settlement Judge for this proceeding. A first settlement conference was held on January 24, 2013. On January 25, Judge Cianci issued a settlement status report in which he reported that the parties agreed to use best efforts to exchange information and agreed upon certain target dates, including a telephonic technical conference to be held on February 13, 2013 and to meet for a second formal settlement conference on March 4, 2013. He added that the New England Agencies would use best efforts to submit a counter-offer to the ISO by February 15, 2013 and the ISO its best efforts to respond by February 25, 2013. Accordingly, Judge Cianci recommended that settlement procedures be continued. If there are any questions on this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **FCA5 Results Filing (ER11-3891)**

Subject to final FERC review, this proceeding has now been terminated.[19] As previously reported, the FERC accepted the results of the fifth FCA ("FCA5"), with the exception of Entergy's dynamic de-list bid for Vermont Yankee ("VY") that had been rejected for reliability reasons, which was set for hearing and settlement judge procedures.[20] On September 14, 2012, Entergy Nuclear Power Marketing, Entergy Nuclear Vermont Yankee, the ISO, the MA AG, and the VT DPS (collectively, the "Settling Parties") submitted a Settlement Agreement to resolve the open issues set for hearing. The Settlement Agreement addressed how VY would be treated in FCA5 (and FCA3) under specifically identified scenarios, including two where VY would be relieved of its Capacity Supply Obligation ("CSO") for the 2014-15 Capacity Commitment Period ("CCP") and not subject to capacity replacement costs if it ceases operations in identified instances where it must comply with requirements of state or federal law. NEPOOL and NRG opposed certain aspects of the Settlement Agreement. However, on November 15, 2012, the ISO notified Entergy that the VY FCA5 Dynamic De-list Bid request had, following additional study and analysis, been accepted and VY de-listed. In light of that determination, the VT DPS, on December 31, 2012, requested that the FERC dismiss the Settlement Agreement and terminate the hearing and Settlement Judge procedures, a request NEPOOL supported. As noted above, subject to final FERC review, this proceeding has been concluded.

- **FCA1 Results Remand Proceeding (ER08-633)**

As previously reported, the DC Circuit issued on December 23, 2011, a *per curiam* order[21] that PSEG's May 2010 petition for review be granted, remanding the FERC's orders in this proceeding[22] for further consideration. 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). Since the last report, the ISO filed on October 31 an answer to PSEG's October 15 motion. On November 1, 2012, Connecticut Generators[23] submitted comments supporting PSEG's request and a few of the Connecticut Generators moved to intervene out-of-time. This matter remains pending before the FERC.

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[19] *Order of Chief Judge Dismissing Offer of Settlement, Terminating Settlement Judge Procedures, and Terminating Proceeding Subject to Final Commission Review*, Docket No. ER11-3891 (Jan. 16, 2013).

[20] *ISO New England Inc.*, 137 FERC ¶ 61,056 (2011).

[21] *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).

[22] *ISO New England Inc.*, 123 FERC ¶ 61,290 (2008); *reh'g denied*, 130 FERC ¶ 61,235 (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).

[23] "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.

- **ISO Issuance of Securities: $40 Million for Establishment of New Back Up Control Center (ES12-47)**

On January 11, the ISO filed a "Report of Securities" as required under the FERC's regulations and in connection with the FERC's September 6, 2012 order authorizing the ISO issue up to $40 million in notes in connection with loans from the Connecticut Development Authority and the Connecticut Department of Economic and Community Development to fund the establishment of the new Back-Up Control Center to be located in Windsor, Connecticut. The report indicates that the face value of the principal amount was $36 million. This report will not be noticed for public comment. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

## III. Market Rule Changes, Interpretations and Waiver Requests

- **IMM Information Sharing Revisions (ER13-750)**

On January 11, the ISO and NEPOOL jointly filed changes to the Information Policy and Appendix A to Market Rule 1 to permit the sharing of confidential information with other ISO/RTOs and their market monitors when the exchange of information is necessary for an investigation. A March 13, 2013 effective date was requested. The changes were supported by the Participants Committee by way of the October 3, 2012 Consent Agenda. Comments on this filing, if any, are due on or before February 1, 2013. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CSO Termination: Concord Steam (ER13-735)**

Pursuant to Market Rule 1 § 13.3.4(c), the ISO filed on January 9 to terminate a CSO held by Project Sponsor Concord Steam Corporation ("Concord Steam") for Resource 14666. The ISO indicated that, upon FERC acceptance of the filing, the ISO will draw down the amount of financial assurance provided by Concord Steam with respect to the CSO. NEPOOL submitted a motion to intervene on January 11, 2013. Comments on this filing are due on or before January 30. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CSO Termination: MATEP (ER13-729)**

Pursuant to Market Rule 1 § 13.3.4(c), the ISO filed on January 8 to terminate a CSO held by Project Sponsor MATPE LLC for Resource 37090. The ISO indicated that, upon FERC acceptance of the filing, the ISO will draw down the amount of financial assurance provided by MATEP with respect to the CSO. NEPOOL submitted a motion to intervene on January 11, 2013. Comments on this filing are due on or before January 29. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCM Static De-List Bid Changes (ER13-612)**

On January 22, 2013, the FERC accepted changes jointly filed by the ISO and NEPOOL to the FCM Static De-List Bid provisions on December 21, 2012. Specifically, the changes provide Lead Market Participants with additional flexibility to adjust Static De-List Bids after submission, while preserving the ability of a Lead Market Participant to elect, in the case of Permanent De-List Bids and Export Bids, to have the ISO-determined bid entered into the FCA no later than 15 days after the submission of the informational filing. The changes were accepted February 19, 2013, as requested. Unless the January 22 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0533; pmgerity@daypitney.com).

- **CSO Bilateral Transaction and Reconfiguration Auction Enhancements (ER13-585)**

As previously reported, the ISO and NEPOOL jointly filed, on December 19, 2012, changes to the FCM rules related to CSO Bilaterals and reconfiguration auctions. Specifically, the rule changes will (i) allow Market Participants to submit CSO Bilaterals before the current submission windows open; (ii) move the second annual reconfiguration auction to August (rather than May) each year; and (iii) permit Real-Time Emergency Generation

("RTEG") Resources to shed their CSOs in reconfiguration auctions, with effective dates of September 1, 2013 (upon two weeks' prior notice), April 1, 2013, and April 19, 2013, requested, respectively. The changes were supported by the Participants Committee by way of the November 2, 2012 Consent Agenda. Doc-less interventions were filed by Exelon, NRG, and NU, but no substantive comments on this filing were filed on or before the January 9, 2013 comment date. 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).

- **Corrections to ISO-NE eTariff Section III.A.15.2 (ER13-510)**

On January 9, the FERC accepted a correction to restore to Section 15.2 of Market Rule 1 Appendix A the last clause that was inadvertently dropped when that Section was moved from Section 10.2 and clause (iii) added in a September 15, 2011 filing in Docket No. ER11-4540. As previously reported, the ISO re-submitted on December 4, 2012, a number of corrected eTariff Records to correct each version of Appendix A filed since that time. Unless the January 9 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Footprint Power Request for Limited Waiver of New Capacity Qualification Deadlines (ER13-468)**

In a January 18, 2013 order, the FERC granted the limited waiver of the New Capacity Qualification Deadlines for FCA7 requested by Footprint Power ("Footprint").[24] As previously reported, Footprint requested the waiver so that its new quick-start, gas-fired combined cycle facility in the NEMA/Boston load zone can participate in FCA7 at a FCA Qualified Capacity of 674 MW, rather than the 570 MW identified in its QDN. Subsequent technical analysis had confirmed that needed transmission upgrades could be in service by June 2016 (information unavailable at the time of qualification) and the ISO indicated that it did not have an objection to this waiver request. National Grid submitted comments urging the FERC to consider the implications of Footprint seeking an order from the MA DPU for an out-of-market long-term contract for capacity, while at the same time pursuing its waiver request in this proceeding. In particular, National Grid noted its concerns (i) that, based on comments submitted in a MA DPU proceeding, the possibility that Footprint might simply walk away from an FCM obligation if an out-of-market contract for capacity is not ordered by the MDPU; (ii) that Footprint's approach could end up either double-selling capacity at an unjust and unreasonable rate, or undercutting FCM price signals through an out-of-market subsidy; and (iii) the seriousness of Footprint's allegations regarding the failure of FCM. In granting the waiver, the FERC found that Footprint's requested waiver was of limited scope and would remedy a concrete problem, and the underlying error was made in good faith.[25] In addition, the FERC disagreed with National Grid that the waiver could harm third parties.[26] Unless the *FCA7 Qualification Order* is challenged, with any challenges due on or before February 19, 2013, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **TMNSR Procurement Revision (ER13-465)**

As previously reported, the ISO and NEPOOL jointly filed changes to the procurement of Ten-Minute Non-Spinning Reserve ("TMNSR") in the Forward Reserve Market (the "TMNSR Procurement Revision") on November 27, 2012. The Revision permits the procurement of additional TMNSR if system conditions forecasted for the Forward Reserve Procurement Period indicate an amount of TMNSR equal to 50% of the forecasted largest first contingency would be insufficient, on its own, to meet Real-Time Operating Reserve requirements. A March 1, 2013 effective date was requested. The Revision was supported by the Participants Committee by way of the November 2 Consent Agenda. Doc-less interventions were filed by Dominion, Exelon, and NU. No comments on the Revision were filed, which is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[24] *FCA7 Qualification Order*.

[25] *Id.* at P 34.

[26] *Id.* at PP 35-38.

- **Information Policy Pipeline Information-Sharing Changes (ER13-356)**

On January 23, 2013, the FERC conditionally accepted the changes proposed by the ISO in this proceeding, subject to a 30-day compliance filing in which the ISO is required to reflect additional limitations on the information sharing process, and effective only for the January 24, 2013 through April 30, 2013 period.[27]

***Initial Filing***. On December 7, 2012, the FERC accepted, but suspended for 5 months (to become effective June 14, 2013) the revisions to the Information Policy proposed by the ISO and filed on November 13, 2012, to allow the ISO to disclose, pursuant to a nondisclosure agreement ("NDA") between the ISO and a pipeline company, confidential forecast and Real-Time output information concerning natural gas-fueled generation from resources located within the New England Control Area to operating personnel of the interstate natural gas pipeline companies that serve those resources (the "ISO Changes").[28] As previously reported, although the ISO Changes were supported by the Participants Committee at its November 9 special meeting with an 81.72% vote in favor, an Alternative NDA was also supported by the Participants Committee at the November 9 meeting, by a vote of 95.73% in favor, and was filed by NEPOOL on November 23, 2012. NEPOOL supported the ISO's stated goal to allow the ISO to provide interstate pipeline operators with additional information concerning specific resources for the purpose of maintaining reliability, but asked the FERC to consider the additional protections for affected generators that the Alternative NDA provides, but only so long as the FERC confirms that the ISO and the pipelines are bound to the Alternative NDA. In accepting the changes, the FERC stated that the ISO Changes had "not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" and set the ISO Changes for accelerated settlement judge procedures.[29] The ISO's request for interim action was dismissed as moot.

***Settlement Proceedings***. As previously reported, settlement proceedings established by the *December 7 Order* were terminated on December 14, 2012.

***Requests for Rehearing and Post-Settlement Developments***. As previously reported, the ISO requested expedited rehearing and clarification of the *December 7 Order* on December 19, 2012, asking the FERC (i) to find the ISO Changes just and reasonable or, in the alternative, to reduce the suspension of those tariff changes to one day and replace the references to "refund" with a reference to "further orders in this proceeding"; and (ii) to clarify that the pipelines may engage in information-sharing without violating the Natural Gas Act and other applicable laws and regulations. In a response to the ISO's request, NEPGA recommended that the FERC allow sharing of confidential information per the NDA, subject to the following conditions: (1) allowing the NDA to go into effect for the winter period, without prejudice to parties' future litigation positions; (2) requiring the ISO to notify Market Participants when their confidential information is shared and a brief summary of the information disclosed; and (3) adopting limits on the sharing of information with pipelines to periods when such sharing is operationally necessary. On January 2, 2013 the New England Pipelines submitted a pleading agreeing with the ISO's request for expedited rehearing and clarification of the *December 7 Order* and, in alternatively, if the FERC does not grant the rehearing and clarification proposed by the ISO, supporting the interim solution proposed by NEPGA on December 26. On January 14, 2013, the FERC issued a tolling order affording it additional time to consider the ISO's request for rehearing and clarification.

***Order on Rehearing***. Largely consistent with NEPGA's proposed interim solution, the FERC, on January 23, 2013, conditionally accepted for the January 24, 2013 through April 30, 2013 period the changes proposed by the ISO, subject to a 30-day compliance filing in which the ISO is required to reflect additional limitations on the information sharing process. In accepting the changes, the FERC stated that "in light of the unique facts and circumstances before us, including ISO-NE's statements concerning current LNG supplies to New England, we will accept the [ISO Changes] on an interim basis …. Our action [ ] is intended to address immediate reliability-related concerns for this winter, while providing further opportunity for review of the Information Policy and the NDA

[27] *ISO New England Inc.*, 142 FERC ¶ 61,058 (2013) ("*Pipeline Information Sharing Changes Rehearing Order*").

[28] *ISO New England Inc.*, 141 FERC ¶ 61,196 (2012) ("*December 7 Order*"), *order on Tariff Revisions and denying reh'g*, 142 FERC ¶ 61,058 (2013).

[29] *Id.* at P 31.

accepted on a temporary basis here."[30] Consistent with the ISO's statements in its request for rehearing, the FERC required the ISO to submit "revisions reflecting additional limitations on the information sharing process. Specifically, ISO-NE should specify in the Information Policy that it will share information regarding specific generators only with the pipeline serving that generator directly, or serving the Local Distribution Company that serves that generator, and only when it is operationally necessary, as determined at ISO-NE staff's discretion, to ensure reliability. The Information Policy must also specify that ISO-NE will provide a summary of any disclosed confidential information to the affected market participant within 48 hours following disclosure."[31] The revisions must be submitted on or before February 22, 2013. The FERC reiterated its "desire for the parties to continue to make good faith efforts to resolve their differences with respect to the NDA and make a future filing that provides a more permanent means to promote information sharing," highlighting also that its February 13, 2013 technical conference "will address, among other things, information sharing and confidentiality issues" on Natural Gas and Electric Market Coordination (see Section XIII below). Challenges, if any, to the *Pipeline Information Sharing Changes Rehearing Order* will be due on or before February 22, 2013. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Generator Audit Revisions (ER13-323)**

On January 9, the FERC conditionally accepted changes jointly filed by the ISO and NEPOOL that revise the auditing requirements and procedures for generators participating in the New England Markets ("Audit Revisions").[32] In accepting the revisions, the FERC found "that the Generator Audit Revisions will provide a clearer understanding of the physical capability of generation resources and thereby facilitate resource commitment and real-time operational decisions. The Generator Audit Revisions will also help verify that generators actually have the capability to meet, and are meeting, capacity commitments for which they receive compensation." The revisions will become effective June 1, 2013, as requested, with two weeks' notice of the actual effective date to be provided by the ISO to the FERC, and subject to submission of a compliance filing described below. The FERC rejected a limited protest filed by NRG, finding that the ISO's proposal to allocate costs of both participant-initiated audits and ISO-initiated audits be allocated to Network Load was reasonable (and therefore not necessary to consider NRG's proposal).[33] With respect to NRG's request that the FERC confirm that a Qualifying Audit conducted in 2010/2011 would satisfy the "once in the previous three years" requirement, the FERC indicated that "a generator could use its 2010/2011 winter Seasonal Claimed Capability Audit to satisfy the requirements of a winter Seasonal Claimed Capability Audit for the 2013/2014 Capability Demonstration Year … However, that generator would still need to perform a winter audit during the 2013/2014 Capability Demonstration Year in order to comply with the requirement for the 2014/2015 Capability Demonstration Year."[34] "In the interest of clarity", the FERC directed a 30-day compliance filing (which would be due on or before February 8, "to define and consistently refer to "Capability Demonstration Year," not "Capacity Demonstration Year," in its Tariff provisions."[35] Unless the *Gen Audit Revisions Order* is challenged, with any challenges due on or before February 8, 2013, this matter will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Conforming Changes Reflecting PRD Full Integration (ER12-1627)**

On January 14, 2013, the FERC accepted in part, and rejected in part, the ISO's proposed changes, filed April 26, 2012, to make the FCM Market Rules consistent with the price-responsive demand ("PRD") full integration rules

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[30] *Pipeline Information Sharing Changes Rehearing Order* at P 19.

[31] *Id.* at P 20.

[32] *ISO New England Inc. and New England Power Pool*, 142 FERC ¶ 61,024 (2012) ("*Gen Audit Revisions Order*").

[33] *Id.* at P 36.

[34] *Id.* at P 34.

[35] *Id.* at P 37. The one word change to "Capability" required by the *Gen Audit Revisions Order* is to the consolidated definitions section in Section I.2.2 of the Tariff. Because "Capability", rather than "Capacity" was presented throughout the stakeholder process, the required change is non-substantive and was approved as such by the Chairs and Vice-Chairs of the Markets and Reliability Committees.

(currently scheduled to become effective on June 1, 2017).[36] The FERC also accepted the proposed revisions to Appendix E of Market Rule 1 to become effective June 1, 2017, as requested, and granted the ISO's request to delay implementation of the Fully Integrated rules to June 1, 2017. As previously reported, the conforming changes were considered, but not supported, by the Participants Committee at its February 10, 2012 meeting. In response to the ISO's April 26, 2012 filing, protests were filed by DR Supporters,[37] IECG, and Verso. DR Supporters protested the must offer requirement, including the "absence of any written criteria or rules regarding what constitutes an appropriate offer," and requested that if the rules are accepted, the ISO be required to articulate the mechanisms by which resources "can avoid dispatch with sufficient certainty to maintain the baseline integrity" required under the Market Rules. IECG's limited protests addressed issues related to the reclassification of DR Resources as generation, while Verso challenged the ISO's proposal to prevent demand side resources from receiving capacity payments above their level of purchases. In addition, NECPUC requested that approval of the conforming changes be conditioned upon a requirement that the ISO explore in the stakeholder process "the development of standards or additional rules that provide sufficient definition to demand resources on what qualifies as competitive offering behavior."

As noted above, the FERC accepted in part, and rejected in part, the proposed revisions. The FERC found just and reasonable the "must-offer requirement for demand response resources with a capacity supply obligation in ISO-NE's FCM,"[38] agreed that "the proposal will assist in correcting inefficiencies inherent in the current capacity market design, and will provide substantial benefits to many parties,"[39] and found the "proposal will be beneficial to both demand response providers and wholesale electricity customers".[40] However, the FERC rejected the ISO's proposal regarding net supply (contained in sections III.E.7.3 and III.13.7.1.5.2), without prejudice to a future filing revising Tariff language to clarify its rules regarding demand response resources that provide capacity through both demand reductions and behind-the-meter generation.[41] Noting its concerns with other aspects of the filing, the FERC conditioned its acceptance of certain changes subject to an explanation as to:

- how the Internal Market Monitor will monitor and evaluate offers by demand response capacity resources;[42]
- whether the "3 of last 10 days" baseline refreshment is still a viable element of its methodology to ensure accurate baselines in light of the requirement that demand resources with a Capacity Supply Obligation offer into the energy market in all hours and thus could be dispatched more frequently than under the current FCM market rules[43] (noting its concern about the interaction between the must-offer requirement and the need for demand response resources to refresh their baselines);[44]
- why the removal of using transmission losses in its calculation of demand resource capacity values is justified;[45]
- whether, and if so how, the ISO it will otherwise adjust the total capacity requirement to reflect avoided transmission losses when procuring capacity;[46] and

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[36] *ISO New England Inc.*, 142 FERC ¶61,027 (2012) ("*January 14 Order*").

[37] "DR Supporters" are EnerNOC, Comverge, Viridity Energy, NEPOOL Industrial Customer Coalition ("NICC") and Wal-Mart Stores.

[38] *Id.* at P 27.

[39] *Id.* at P 28.

[40] *Id.* at P 29.

[41] *Id.* at PP 44-46 .

[42] *Id.* at P 36.

[43] *Id.*

[44] *Id.* at P 35.

[45] *Id.* at P 57.

[46] *Id.*

- how considering the duration of a shortage event when evaluating the performance of demand response resources but not generation resources provides for comparable treatment.[47]

The ISO was directed to submit a compliance filing providing these explanations and addressing the changes rejected within 60 days of the date of the order, or on or before March 14, 2013. Any challenges to the *January 14 Order* are due on or before February 13, 2013. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Redesign Compliance Filing: FCA8 Revisions (ER12-953 et al.)**

On December 3, 2012, the ISO and the PTO AC filed revisions to the FCM and FCM-related rules in the Tariff ("FCA8 Revisions") in response to a number of FERC orders,[48] including: (i) implementation of a buyer-side offer-floor mitigation mechanism, (ii) reduction of the Dynamic De-List Bid Threshold to $1.00/kW-month, (iii) elimination of the remaining uses of the Cost of New Entry ("CONE"), and (iv) the complete removal of the FCA administrative price floor. In addition, the ISO asked the FERC to retain, for FCA8 and beyond, the four capacity zones to be used in FCA7, pending further analysis of zonal issues by the ISO and stakeholders in a process that the ISO indicated would begin in the second quarter of 2013. All of the changes were requested to become effective for FCA8, with the Financial Assurance Policy-related changes to become effective February 26, 2013 and the remainder of the changes to become effective February 12, 2013. The package of FCA8 Revisions filed was considered but not supported by the Participants Committee at its November 3, 2012 meeting.

Interventions were filed by: AWEA, CT OCC, Danvers (out-of-time), EMI, EPSA, GDF Suez, HQUS, MPUC, National Grid, NICC, PPL, and RENEW. Comments and protests were filed by: NEPOOL, APPA//NPPA/NRECA, Capital Power, CLF, CT AG, CT OCC, CT PURA, EMCOS, EnerNOC, EPSA, Exelon, Massachusetts,[49] MA AG, MMWEC and NHEC, NEPGA, NESCOE, NRG, NU, PSEG, and TransCanada. A detailed summary of the comments and protests was included with the January 2, 2013 report and is posted with the materials for the January 4, 2013 meeting. On January 14, answers to the protests and comments were submitted by NEPOOL, the ISO, HQ US, and NEPGA. A more detailed summary of the pleadings submitted in this proceeding and the related NESCOE FCM Complaint proceeding is included with this Report. 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), Harold Blinderman (860-275-0357; hblinderman@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **Tie Benefits Calculation and Allocation (ER08-41)**

The ISO's January 14, 2010 update in this proceeding remains pending. As previously reported, the ISO filed, on January 14, 2010, an update to the joint ISO/NEPOOL November 26, 2008 report[50] regarding the plan to study and develop proposals to resolve issues related to the modeling of internal transmission constraints and tie benefits associated with individual lines. In the January 14, 2010 Update, the ISO proposed to comprehensively review and attempt to resolve during 2010 all outstanding and identified tie benefits issues (including the so-called "Reserved Issues", issues raised during 2009 stakeholder meetings, and tie benefits-related issues raised in Docket No. ER10-438) through a NEPOOL stakeholder process and to make a filing with the FERC on or before a date that will allow any related Market Rule or Tariff changes to be effective in time for FCA5 (covering the 2014/2015 Capacity Commitment Period). At its February 5, 2010 meeting, the Participants Committee considered and voted on the ISO's January 14 proposal. The ISO's Proposal received 43.25% support from the Participants Committee. On

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[47] *Id.* at P 58.

[48] *See ISO New England Inc. and New England Power Pool Participants Comm.*, 135 FERC ¶ 61,029 (2011) ("*April 13, 2011 Order*"); *ISO New England Inc. and New England Power Pool Participants Comm.*, 138 FERC ¶ 61,027 (2012) ("*January 19, 2012 Order*").

[49] "Massachusetts" is the MA DPU and MA DOER.

[50] The 2008 Tie Benefits Report indicated that the stakeholder process would begin early during the second quarter of 2009 and would be completed in time for any proposed Market Rule 1 or other Tariff changes to be filed with the FERC before February 1, 2010. *See ISO New England Inc. and New England Power Pool*, 126 FERC ¶ 61,180 (2009).

February 8, 2010, NEPOOL filed comments reflecting the results of that consideration and vote. NESCOE submitted a motion to intervene out-of-time and comments on February 12, 2010. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

## IV. OATT Amendments / TOAs / Coordination Agreements

- **Order 1000 Compliance Filing (ER13-193; ER13-196)**

As previously reported, the ISO and PTO AC ("Filing Parties") submitted an Order 1000 compliance filing for the region on October 26, 2012. The filing consisted of a "Primary Filing" package (ER13-193) and a "Contingent Filing" package (ER13-196) for reliability and market efficiency upgrades. The Primary Filing consists of changes to Attachment K that add a public policy transmission planning process to the existing planning process. Under the Primary Filing, the ISO and the PTOs also seek to retain the PTO exclusive right to build and own reliability and market efficiency transmission upgrades contained in the Regional System Plan ("RSP").

The Contingent Filing, which would only go into effect if the FERC first finds pursuant to a *Mobile-Sierra* analysis that the PTO exclusive right to build and own transmission is contrary to the public interest, consists of revisions that would implement competitive processes for developing, building and owning reliability and market efficiency transmission in the RSP. The Contingent Filing provides for an exception to the competitive, project-based reliability process for identified reliability needs where the year of need is more than five years from the completion of the relevant needs assessment study. Under the exception, the PTO's would retain their exclusive right. Aside from the exclusive PTO right to develop, build and own transmission, the Primary and Contingent Filings contain the same features, including the process for public policy transmission upgrades.

The Filing Parties requested an effective date that is 60 days after a FERC order accepting the filing. The ISO/PTO AC Compliance Filing was supported by only 17.1% of the Participants Committee at its October 3 meeting. An amended package of compliance changes was, however, supported by the Participants Committee and was submitted on an informational basis by NEPOOL on November 16, 2012 (the "NEPOOL Proposal"). Although similar in many respects, the key difference between the NEPOOL Proposal and Filing Parties' Proposal concerns the competitive process for the development, building and owning of reliability and market efficiency transmission upgrades identified as needed in the RSP. The NEPOOL Proposal provides for competitive processes for transmission development, with a narrow exception for reliability upgrades required to be implemented to address an urgent need that must be addressed within three years (subject to certain other conditions). The Filing Parties' Proposal seeks to retain the exclusive right on the part of the incumbent PTOs to build and own reliability and market efficiency transmission upgrades and Proposal provides for competitive processes for transmission development reliability and market efficiency upgrades *only* if the FERC first determines that the PTOs' exclusive right is contrary to the public interest. NEPOOL urged the FERC to take into the results of the stakeholder process as it considers whether the Filing Parties' or the NEPOOL Proposal is more compliant with Order 1000 and consistent with the public interest. NEPOOL asked that FERC, if it agrees that the NEPOOL Proposal is more compliant with Order 1000 and more consistent with the public interest, to direct the ISO and PTOs to revise their Order 1000 compliance filing to reflect the NEPOOL Proposal.

In addition, interventions were filed by CT OCC, Exelon, Iberdrola Renewables, NH OCA, NH PUC, NRECA, NRG, PowerOptions, Transource Energy, and VT PSB. Other comments and protests were filed by AWEA and RENEW, Belmont, CLF, CT DEEP, EMCOS, LS Power Transmission, MMWEC and NHEC, MA AG, MPUC, NESCOE, NHT, Organizations,[51] PSEG, Southern New England States.[52] On January 8, NESCOE and "Five NE States"[53] responded to various comments and protests submitted in this proceeding. On January 10, RENEW

[51] "Organizations" are Environment Northeast, the National Consumer Law Center ("NCLC"), the Natural Resources Defense Council ("NRDC"), and the Sustainable FERC Project.

[52] "Southern New England States" are the MA DPU, RI PUC, and CT PURA.

[53] "Five NE States" are the Southern New England States (*cf* note 27 *supra*) and CT DEEP, NHPUC, VT PSB, and the Vermont Public Service Department ("VPSD").

withdrew its intervention in this proceeding. On January 17 and 18, the PTA ac and the ISO, respectively, filed answers to the NEPOOL and other comments/protests in this proceeding. A NEPOOL counsel memo summarizing those answers in detail was circulated to the Transmission Committee on January 24, 2013. Anyone who did not receive a copy and would like one can request that one be sent by contacting Pat Gerity (860-275-0533; pmgerity@daypitney.com). Otherwise, this matter, including the Filing Parties motion to consolidate the proceedings and the TOs[54] request that the FERC set that date for answers and reply comments 45 days from the date comments are filed, remain pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NPC-Supported Revisions to Attachment K and MR1 – Reliability Review of Rejected De-List Bids (ER12-1914)**

On January 18, 2013, the FERC accepted the ISO's November 26, 2012 compliance filing in this proceeding. As previously reported, the FERC rejected the ISO's first (August 30) compliance filing in this proceeding, and directed a new compliance filing be submitted on or before November 26, 2012[55] to satisfy its condition to the acceptance of the revised package of changes to the regional planning process set forth in Attachment K to the ISO OATT and to Section 13.2.5.2.5(g) of Market Rule 1[56] that the ISO Tariff sheets that expressly reflect FERC's understanding that the reference in Section 4.1(c)(iv) of the Attachment K Revisions to "prior to the start of each new capacity qualification period" means the "show of interest (start)" date included in the FCM Manual's "Master Forward Capacity Market Schedule."[57] Unless the January 18 order is challenged, this proceeding will be concluded.[58] If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Capability Resource Ratings (ER11-2216)**

Action on MMWEC's request for rehearing of the FERC's January 28, 2011 *Capability Clarifications Order*[59] continues to be deferred. As previously reported, the revisions to Tariff accepted by the FERC were described as clarifying the controlling order/hierarchy of documents relied upon by the ISO to establish the energy and capacity output levels for certain Existing Generating Capacity Resources ("Capability Clarifications"). The filing parties (the ISO and the PTO AC) asserted that the Capability Clarifications addressed what the FERC found ambiguous in a July 2010 order in EL10-58,[60] namely, the controlling order of approval documents and data used by the ISO to establish the CNR Capability of an existing generating resource. The Capability Clarifications were considered by the Participants Committee at its October 18, 2010 meeting, but ultimately not supported. In accepting the Capability Clarifications, the FERC addressed protests filed by Dominion, MMWEC, and PSEG. The FERC found that the changes were consistent with, and not a collateral attack on, the FERC's July 2010 order, and provide equal treatment to resources seeking to change capacity limits. In addition, the FERC was also persuaded that interconnection agreements are a more reliable means of determining the CNR Capability ratings, and declined to direct the use of the MW ratings in the CELT Report. MMWEC requested rehearing of the *Capability Clarifications Order* on February 24, 2011, but requested the FERC defer action on the merits of the rehearing request until completion of the process under which the CNR rating for Stony Brook is currently under review. MMWEC stated that if it was able to secure adequate relief, it would so inform the FERC and withdraw the rehearing request; if not, it would ask the FERC to address the merits of its rehearing request. The FERC issued on March 24, 2011 a tolling order affording it additional time to consider the MMWEC rehearing request, which remains pending before the

[54] Bangor-Hydro, CMP, National Grid, NU, UI, and VELCO.

[55] *ISO New England Inc.*, 141 FERC ¶ 61,072 (2012) ("*Compliance Order*").

[56] *ISO New England Inc.*, 140 FERC ¶ 61,088 (2012) ("*July 31 Order*").

[57] *Id.* at P 32.

[58] Neither the *July 31 Order* nor the *Compliance Order* were challenged; both are final and unappealable.

[59] *ISO New England Inc. and the Participating Trans. Owners Admin. Comm.*, 134 FERC ¶ 61,057 (2011) ("*Capability Clarifications Order*"), *reh'g requested*.

[60] *See PSEG Power Conn. LLC v. ISO New England Inc.*, 132 FERC ¶ 61,022 at P 6 (2010).

FERC. If you have any questions concerning this proceeding, 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-NGrid G-33 Line Emergency Switching Instructions Agreement (ER13-623)**

On December 26, 2012, National Grid filed an agreement regarding the Emergency Switching Instructions for the G-33 Line between Brattleboro, VT and Hinsdale, NH between itself and Green Mountain Power. The Letter Agreement is designated as Service Agreement No. TSA-NEP-85 under Schedule 21-NEP of the Tariff. National Grid asked that the FERC waive its requirements, to the extent necessary, to allow the agreement become effective as of April 9, 2012. No comments on this filing were filed on or before the January 16, 2013 comment date and this matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-BHE: Cancellation of Evergreen Wind LSA (ER13-480)**

On January 9, the FERC accepted a notice filed by BHE and the ISO canceling the Local Service Agreement ("LSA") between BHE, Evergreen Wind Power V, LLC and the ISO for long-term conditional Firm Local Point-to-Point Service (previously designated as Original Service Agreement No. 66 under Schedule 21- BHE of the ISO Tariff) as a result of the Point of Receipt becoming PTF. Unless the January 9 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-FG&E: Corrections, Conforming and Clean Up Changes (ER13-474)**

On January 4, 2013, the FERC accepted conforming and non-substantive changes to Schedule 21-FG&E filed by Fitchburg Gas & Electric Company ("FG&E") on November 30, 2012, subject to a compliance filing identifying the effective date of the changes. Specifically, the changes corrected the FERC's eTariff viewer to reflect revisions approved in Docket Nos. ER11-3916 and ER12-145, and otherwise made conforming and non-substantive changes to Schedule 21-FG&E to correct typographical errors, update references and terms, add clarification, and improve usability of Schedule 21-FG&E. Subject to the directed compliance filing, 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 accepted on September 24, 2012, the revised schedules and notices of cancellation filed by Green Mountain Power ("GMP") in this proceeding, but suspended the provisions, subject to refund, and established hearing and settlement judge procedures.[61] In its September 24 order, the FERC stated that its "preliminary analysis indicates that Applicants' proposed Schedules 21-GMP and 20A-GMP and notices of cancellation have not been shown to be just and reasonable, and … raise issues of material fact that cannot be resolved based on the record before us and are more appropriately addressed in the hearing and settlement judge procedures we order."[62] Judge Karen V. Johnson was designated as the settlement judge, and convened a first settlement conference on October 17, 2012. A second settlement conference was held January 24, 2013. Also since the last report, Judge Johnson issued on January 9, 2013, another status report (i) indicating that the participants

[61] *ISO New England, Inc., Central Vt. Pub. Srvc. Corp. and Green Mountain Power Corp.*, 140 FERC ¶ 61,239 (2012) ("*GMP Merger Order*"), *reh'g requested*.

[62] *Id.* at PP 21-22.

continue to negotiate and exchange documents and were optimistic that they will be able to reach a settlement in the near future; and (ii) recommending that settlement judge procedures be continued.

Requests for clarification and/or rehearing of the *GMP Merger Order* requested by VEC and WEC ("Cooperatives") remains pending. In their requests, Cooperatives asserted that the FERC failed to appropriately address the *Mobile Sierra* claim contained in VEC's Protest and further explained in WEC's Answer. WEC separately filed a motion for clarification and/or rehearing requesting that the FERC correct three statements in the *GMP Merger Order* concerning positions taken by WEC. On November 19, 2012, the FERC issued a tolling order affording it additional time to consider the Cooperatives' requests, which remain pending before the FERC.

Cooperatives submitted on November 21 and November 28 pleadings protesting the Notice of Effective Date filed by GMP on October 31, 2012 as to its Schedule 21-GMP, and moving to strike from the record GMP's motion to lodge in this proceeding a 2000 letter order that, according to GMP, has a bearing on the treatment of certain costs in its pending rate case before the FERC. GMP answered the pleading on December 6 and 13, 2012, respectively. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

## VII. NEPOOL Agreement/Participants Agreement Amendments

***No Activity to Report***

## VIII. Regional Reports

- **Quarterly Reports Regarding Non-Generating Resource Regulation Market Participation (ER08-54)**

The ISO filed its seventeenth report on December 19, 2012. 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.[63] In the 17th report, the ISO indicated that it had "continued internal design work and technical evaluation of regulation market changes in light of the issues raised by the February 17, 2011 Notice of Proposed Rulemaking." The ISO stated also that, in accordance with the existing provisions of Market Rule 1, Appendix J, as soon as the Order 755 compliance tariff changes have been implemented, the Pilot Program will terminate and non-generation alternative resources will provide regulation service pursuant to the new tariff provisions. However, the FERC rejected the proposed Order 755 compliance changes and directed that new compliance changes be filed within 90 days. The ISO expects to provide further information on the expected effective date for the Order No. 755 compliance changes (and the changes to end the Pilot Program ) when the new compliance filing is submitted in February 2013. These reports are not noticed for public comment.

- **LFTR Implementation: 17th Quarterly Status Report (ER07-476; RM06-08)**

The ISO filed the seventeenth of its Quarterly Status Reports regarding LFTR implementation on January 15. The ISO reported that, pursuant to tariff changes submitted on June 28, 2012 in Docket No. ER12-2122 and accepted on August 23, 2012, multiple annual auction round rules became effective on October 1, 2012 and monthly reconfiguration auctions will become effective sometime after January 1, 2013 (subject to the ISO providing two weeks' notice of the actual effective date). Conforming changes that incorporate the FTR enhancements submitted in Docket Nos. ER11-3568 and ER12-2122 into the LFTR rules will be filed at a later time, as will changes to the Financial Assurance Policy to reflect any such LFTR enhancements. The ISO reported that the estimated 18-month LFTR implementation process, described in previous reports, would then be initiated once the LFTR and FAP

[63] *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*").

conforming changes are accepted by the FERC. These status reports are not noticed for public comment and no comments were filed.

## IX. Membership Filings

- **January 2013 Membership Filing (ER13-688)**

On December 31, 2012, NEPOOL requested that the FERC accept (i) the memberships of Ethical Energy Benefit Co. (Supplier Sector); Freedom Ring Communications, LLC d/b/a BayRing Communications (Market Participant End User): and HIKO Energy (Supplier Sector), effective January 1, 2013; and (ii) the termination of the Participant status of RLtec and Select Energy (each also January 1, 2013). This matter is pending before the FERC.

- **Negawatt Additional Requirements for Market Participation (ER13-554)**

On December 13, 2012, the ISO submitted, pursuant to Section II.A.1(b) of the Financial Assurance Policy, an informational filing reporting on additional conditions to participation in the New England Markets that will be imposed on Negawatt Business Solutions ("Negawatt"). Those additional conditions, which also apply to Negawatt's membership in NEPOOL, were supported by the Participants Committee at its December 7 annual meeting. A description of the conditions is set forth in the final minutes of the December 7 meeting, and will be included in the NEPOOL membership filing containing Negawatt's materials. The ISO's informational filing was not noticed for public comment.

- **December 2012 Membership Filing (ER13-493)**

On January 8, 2013, the FERC accepted (i) the membership of Iron Energy (Supplier Sector), effective December 1, 2012; and (ii) the termination of the Participant status of SESCO Enterprises (November 1, 2012) and Moose River Lumber and MRL Energy (December 1, 2012).

## 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: December 2012 (RC13-3)**

NERC submitted on December 31, 2012, its Find, Fix, Track and Report ("FFT") informational filing for the month of December 2012. The December FFT resolves 44 possible violations of 13 Reliability Standards that posed a risk minimal risk to bulk power system ("BPS") reliability, but which have since been remediated.[64] The 25 Registered Entities involved each submitted a mitigation activities statement of completion. These filings are for information only and will not be noticed for public comment by the FERC.

- **NERC Compliance Enforcement Initiative (RC11-6)**

As previously reported, FERC conditionally accepted NERC's compliance enforcement initiative and mechanisms described in its filing and summarized in previous reports. In accepting the initiative, the FERC required NERC to make a 60-day compliance filing, and directed NERC to submit 2 informational filings.[65] In the 60-day compliance filing, NERC was directed to explain the principles it will employ in evaluating an entity's compliance history in connection with the FFT process. In addition, NERC was directed to file the 6 and 12-month reports it committed to, with the 6-month report due concurrently with the 60-day compliance filing; the 12-month report,

[64] Only possible violations that pose a minimal risk to Bulk-Power System reliability to be eligible for FFT treatment. *See N. Am. Elec. Reliability Corp.*, 138 FERC ¶ 61,193 (2012) at PP 46-56.

[65] *N. Am. Elec. Reliability Corp.*, 138 FERC ¶ 61,193 (2012), *clarification granted in part and reh'g denied*, 139 FERC ¶ 61,168 (2012).

March 15, 2013. The FERC indicated that it plans to use 12-month report as an opportunity to consider any changes to the FFT process and to any of the limited conditions adopted in the order. In a May 31 order, the FERC clarified that, to be eligible for FFT treatment, an affidavit certifying mitigation of possible violations of Reliability Standards must be verified by a corporate officer or, if no corporate officers exist, an executive or person in an equivalent leadership position, in any case with personal knowledge of the mitigation.[66]

On September 20, 2012, the FERC accepted NERC's 60-day compliance filing.[67] In accepting the filing, the FERC stated its expectation that the Regional Entities will consistently apply the conditions outlined in the FFT Order relating to qualification for FFT treatment, documentation of possible violations as FFTs, accountability and deterrence. Though it refused to mandate the use of standardized processes and forms at that time, the FERC encouraged NERC and the Regional Entities to consider implementation of such processes and/or forms.[68] The September 20 order required NERC to file, and NERC filed on October 12, 2012, its training materials developed to facilitate the implementation of FFT determinations. No comments on the October 12 filing were submitted on or before the November 13, 2012 comment date and this filing is pending before the FERC.

***Yearly Survey of FFTs***. On November 26, the FERC sent letters to each of the Regional Entities requesting, for a random sample of FFTs, "all data, correspondence, and other supporting information used by your staff to evaluate and conclude that these possible violations qualified for FFT treatment. In addition, provide evidence that the issue was successfully remediated, … and a brief narrative explaining the submitted materials." The yearly survey was contemplated by P 73 of the March 15, 2012 order accepting the FFT process.[69] Responses to the survey were due and filed by the Regional Entities on or before December 11, 2012. The survey submissions were not noticed for public comment, but are available on the FERC's eLibrary.

- **Revised Reliability Standard: EOP-004-2(RD13-3)**

On December 31, 2012, as revised on January 4, 2013, NERC filed for approval a Standard that merges EOP-004-1 and CIP-001-2a in order to provide a comprehensive approach to reporting disturbances and events that have the potential to impact the reliability of the BES. The proposed Reliability Standard requires Responsible Entities to have an Operating Plan for reporting applicable events to NERC and others (e.g., Regional Entities, applicable Reliability Coordinators and law enforcement) within 24 hours of the event according to the procedure specified in their Operating Plan. The proposed Reliability Standard provides for timely event analysis and ensures that NERC can develop trends and prepare for a possible next event. The revised Standard is proposed to become effective the first day of the first calendar quarter that is six months following the effective date of a Final Rule in this docket. Comments on this filing are due on or before January 30, 2013; comments on the January 4 errata filing; February 4, 2013.

- **Revised Reliability Standard: VAR-002-2b (RD13-2)**

On November 21, 2012 NERC filed for approval a Standard that clarifies in Requirement R1 that a communication between a Generator Operator and a Transmission Operator is not necessary during start-up or shutdown of a generator. The revised Standard is proposed to become effective the first day of the first calendar quarter following the effective date of a Final Rule in this docket. An intervention was filed by American Municipal Power and comments were submitted by PPL (requesting the FERC to direct that the lower VSL text be revised to permit a registered entity a reasonable period of time of up to 30 minutes to correct an excursion and to confirm that a voltage excursion addressed promptly, such as within the 30 minute window it requested be implemented, should not be considered as triggering a VSL). On January 23, the FEC responded to the PPL comments. This matter is pending before the FERC.

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[66] *N. Am. Elec. Reliability Corp.*, 139 FERC ¶ 61,168 (2012) at PP 7-8.

[67] *N. Am. Elec. Reliability Corp.*, 140 FERC ¶ 61,215 (2012).

[68] *Id.* at P 12.

[69] *N. Am. Elec. Reliability Corp.*, 138 FERC ¶ 61,193 (2012).

- **Interpretation: CIP-002-4 R3 (RD12-5)**

NERC's August 1, request for approval of a proposed interpretation of Requirement R3 to Reliability Standard CIP-002-4 (Critical Cyber Asset Identification) remains pending. As previously reported, the interpretation clarifies (i) that the list of examples provided in Requirement R3 of CIP-002-4 are illustrative, and not an exhaustive list, of the types of Cyber Assets that may be Critical Cyber Assets; and (ii) the meaning of the language "essential to the operation of the Critical Asset". On August 20, NERC submitted an errata filing. No comments on the initial or errata filings were submitted and this matter is pending before the FERC.

- **Interpretation: CIP-006-4 R1.1 (RD12-3)**

On May 23, NERC filed for approval a proposed interpretation of Requirement R1.1 to all versions of Reliability Standard CIP-006 (Cyber Security — Physical Security of Critical Cyber Assets). At highest level, the interpretation clarifies that Requirement R1.1 of CIP-006-4 does not apply to wiring. No comments were filed by the June 13 comment date and this filing is pending before the FERC.

- **NOPR: Geomagnetic Disturbance Reliability Standards (RM12-22)**

As previously reported, the FERC issued on October 18 a NOPR proposing to direct NERC to submit for approval Reliability Standards that address the impact of geomagnetic disturbances ("GMD") on BPS reliability.[70] The FERC proposes a two-staged implementation. In the first stage, the FERC would direct NERC to file, within 90 days of the effective date of a final rule in this proceeding, one or more Reliability Standards that require BPS owners and operators to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the BPS. In the second stage, the FERC would direct NERC to file, within six months of the effective date of a final rule in this proceeding, one or more Reliability Standards that require owners and operators of the BPS to conduct initial and on-going assessments of the potential impact of GMDs, focusing first on the most critical BPS assets. Comments on the NOPR were due December 24, 2012.[71]

58 sets of comments were submitted. Almost uniformly, commenters concurred that the risk to the BPS from GMD was a significant concern that should be addressed, although there was a strong undercurrent at the outset that the FERC's proposal may be at best premature or, at worst, without sufficient technical and/or legal basis to establish the need for one or more new or modified Reliability Standards to address GMD. In general, commenters acknowledged that the current body of science on GMDs does not permit the nature of GMD events to be defined with as much clarity as is desired. In the absence of strong consensus on the technical specifications of a GMD event, some concluded as a threshold matter that there was not yet sufficient basis to conclude a GMD Standard was needed. A number of commenters suggested that industry efforts already underway, particularly NERC's Geomagnetic Disturbance Task Force ("GMDTF"), be completed before much, if any, progress is made towards GMD Standard development. In light of the circumstances, some argued that it would be unwise, if not unlawful, to compel NERC to act on the FERC's proposed rule. Should NERC develop GMD Standards, however, most commenters cautioned against the imposition of a "one-size fits all" approach, favoring instead implementation that accounts for differences in location, function, and risk profile. There was a clear recognition that the benefits of any GMD mitigation mechanism must be cost effective and justified. There is also an acknowledgement that there should be for all Functional Entities a mechanism for recovery of costs incurred in compliance with GMD Standards. Finally, most, but not all, commenters indicated that the NOPR provides insufficient time or unrealistic timeframes in which to develop the GMD Standards, though thoughts on what would be sufficient, realistic, or acceptable varied widely.

Since the last report, reply comments were submitted by NERC and the Foundation for resilient Societies. Additional comments, including those of the Nuclear Regulatory Commission were posted on e-Library. This matter is pending before the FERC.

[70] *Reliability Standards for Geomagnetic Disturbances*, 141 FERC ¶ 61,045 (2012).

[71] The NOPR was published in the *Fed. Reg.* on Oct. 24, 2012 (Vol. 77, No. 206) pp. 64,936-64,943.

- **Revised Reliability Standard: MOD-028-2 (RM12-19)**

On August 24, 2012, NERC filed for approval proposed clarifications to its Area Interchange Methodology (MOD-028-2) Standard. NERC explained that the proposed revisions clarify the timing and frequency of Total Transfer Capability calculations needed for Available Transfer Capability calculations. The revised Standard is proposed to become effective the first day of the first calendar quarter following FERC approval. As of the date of this report, a comment date has not been set.

- **Revised Reliability Standards: FAC-001-1, FAC- 003-3, PRC-004-2.1a, PRC-005-1.1b (RM12-16)**

On July 30, NERC filed for approval proposed revisions to four Reliability Standards, including VRFs, VSLs, and implementation plans, for Facility Connection Requirements (FAC-001-1), Transmission Vegetation Management (FAC-003-3), Analysis and Mitigation of Transmission and Generation Protection System Misoperations (PRC-004-2.1a) and Transmission and Generation Protection System Maintenance and Testing (PRC-005-1.1b). NERC explained that the proposed revisions to the Reliability Standards address the application of Reliability Standards to generator interconnection Facilities (generator tie-lines). The Standards will obviate the need to register all generators as Transmission Owners and/or Transmission Operators with respect to generator interconnection Facilities, unless individual circumstances warrant otherwise. The revised FAC Standards are proposed to become effective the first day of the first calendar quarter that is one year following the effective date of the revisions. As of the date of this report, a comment date has not been set.

- **NOPR: NPCC Regional Reliability Standard: PRC-006-NPCC-1 (RM12-12)**

On September 20, the FERC issued a notice that it proposes to approve the Regional Reliability Standard, including VRFs, VSLs, and an implementation plan, for Automatic Underfrequency Load Shedding in the NPCC region (PRC-006-NPCC-1) submitted by NERC on May 4, 2012, as modified on August 3, 2012. As NERC explained, the proposed NPCC-specific Reliability Standard is to ensure development of an effective automatic underfrequency load shedding ("UFLS") program in order to preserve the security and integrity of the BPS during declining system frequency events, in coordination with the NERC UFLS reliability standard characteristics, PRC-006-1. For New England, the applicable effective dates requested were as follows: for Requirements R1 - R7, the first day of the first calendar quarter following applicable regulatory approval, but no earlier than January 1, 2016; for Requirements R8 - R23, the first day of the first calendar quarter two years following applicable governmental and regulatory approval. Comments on the proposed NPCC Standard were due on or before November 26, 2012[72] and were filed by Dominion, NERC, NYISO, NPCC, and PSEG. Reply comments were filed by NERC and NPCC on December 11, 2012. This matter is pending before the FERC.

- **Order 773: Revised "Bulk Electric System" Definition and Procedures (RM12-7; RM12-6)**

On December 20, 2012, the FERC issued *Order 773*[73] that approved the following:

  - a modified and more detailed definition of "Bulk Electric System" developed by NERC;
  - NERC's contemporaneously filed revisions to its Rules of Procedure, which creates an exception procedure to add elements to, or remove elements from, the definition of "bulk electric system" on a case-by-case basis;
  - NERC's proposed form entitled "Detailed Information to Support an Exception Request" that entities will use to support requests for exception from the "bulk electric system" definition; and
  - NERC's proposed implementation plan for the revised "bulk electric system" definition.

The revised definition of "bulk electric system" removes language allowing for regional discretion in the currently-effective bulk electric system definition. The revised definition establishes a bright-line threshold that includes all facilities operated at or above 100 kV. The modified definition also identifies specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of "bulk electric system."

[72] The NOPR was published in the *Fed. Reg*. on Sep. 26, 2012 (Vol. 77, No. 187) pp. 59,151-59,156.

[73] *Revisions to ERO Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012) ("*Order 773*").

*Order 773* will become effective will become effective March 5, 2013.[74] Requests for rehearing of *Order 773* were filed on January 22, 2013 by APPA, AWEA, Dow Chemical, Holland, Michigan Board of Public Works, NARUC, NERC, NRECA, NY PSC, Snohomish County PUD No. 1, Transmission Access Policy Study Group ("TAPS"), and Utility Services. The requests for clarification and/or rehearing are pending before the FERC, with FERC action required on or before February 21, 2013, or the requests will be deemed denied.

- **NOPR: Revised Reliability Standard: FAC-003-2 (RM12-4)**

On October 18, 2012, the FERC issued a notice that it proposes to approve the Transmission Vegetation Management Reliability Standard (FAC-003-2), including VRFs (with additional revisions to requirement R2), VSLs, implementation plan, and new or revised definitions for Right-of-Way, Vegetation Inspection, and Minimum Vegetation Clearance Distance, as submitted by NERC on December 11, 2011.[75] As FERC explained, FAC-003-2 "would expand the applicability of the standard to include overhead transmission lines that are operated below 200 kV, if they are either an element of an Interconnection Reliability Operating Limit or an element of a Major WECC Transfer Path. In addition, the proposed Reliability Standard incorporates a new minimum annual vegetation inspection requirement, and incorporates new minimum vegetation clearance distances into the text of the standard." Comments on the proposed Standard were due on or before December 24, 2012,[76] and were filed by 20 parties, including EEI, EPRI, NERC, NESCOE, and VELCO. This matter is pending before the FERC.

- **NOPR: Revised Reliability Standard: TPL-001-2 (RM12-1)**

On April 19, 2012, the FERC issued a NOPR in which it proposes to remand this Reliability Standard to NERC for further consideration. The FERC noted its concerns with a provision that would allow a transmission planner to plan for load shedding, following a single contingency provided that the plan is documented and alternatives are considered and subject to review in an open and transparent stakeholder process, which the FERC found vague and unenforceable because the Standard did not adequately define the circumstance in which an entity can plan for non-consequential load loss following a single contingency. Notwithstanding improvements contained in other provisions of proposed Standard, the FERC noted that, pursuant to Section 215 of the FPA, it must remand to NERC any Standard disapproved in whole *or in part*. As previously reported, NERC requested that the FERC approve the Standard[77] on October 19, 2011. Comments were filed by ATC, BPA, EEI, IESO, ISO-NE (jointly with ERCOT, MISO, NYISO PJM, and SPP), ITC Companies, MISO, NERC, and Powerex. This matter remains pending before the FERC.

- **Proposed Clarification to Available Transfer Capability Reliability Standards (RM08-19)**

In compliance with *Order 729*, NERC submitted on December 1, 2010 (in sub-docket -004) proposed VRFs and VSLs for six Available Transfer Capacity ("ATC") Reliability Standards: MOD-001-1a (Available Transmission System Capability); MOD-004-1 (Capacity Benefit Margin); MOD-008-1 (Transmission Reliability Margin Calculation Methodology); MOD-028-1 (Area Interchange Methodology); MOD-029-1a (Rated System Path Methodology); and MOD-030-2 (Flowgate Methodology). No comments were submitted by the January 10, 2011 comment date, and those VRFs and VSLs are pending before the FERC.

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[74] *Order 773* was published in the *Fed. Reg.* on Jan. 4, 2013 (Vol. 78, No. 3) pp. 804-851.

[75] *Revisions to Reliability Standard for Trans. Vegetation Management*, 141 FERC ¶ 61,046 (2012).

[76] The NOPR was published in the *Fed. Reg.* on Oct. 24, 2012 (Vol. 77, No. 206) pp. 64,920-64,935.

[77] In the Oct. 19, 2011 filing, NERC explained that the new Standard (i) a revised Transmission Planning Standard ("TPL") TPL-001-2 (ii) retirement of four existing Reliability Standards: TPL-001-1 (System Performance Under Normal (No Contingency) Conditions ("Category A"); TPL-002-1b (System Performance Following Loss of a Single Bulk Electric System ("BES") Element ("Category B"); TPL-003-1a (System Performance Following Loss of Two or More BES Elements ("Category C"); and TPL-004-1 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements ("Category D"); and (iii) withdrawal of two pending Reliability Standards: TPL-005-0 (Regional and Interregional Self-Assessment Reliability Reports); and TPL-006-0.1 (Data From the Regional Reliability Organization Needed to Assess Reliability).

- **2013-2015 Reliability Standards Development Plan (RM06-16 et al.)**

Pursuant to Section 310 of the NERC's Rules of Procedure, NERC submitted for informational purposes, on December 31, 2012, its Reliability Standards Development Plan ("Plan") for 2013 through 2015. NERC submits its Plan prior to the beginning of each calendar year. The Plan is designed to (i) serve as a management tool to guide and coordinate the development of Reliability Standards and provide benchmarks for assessing progress; (ii) serve as a communications tool for coordinating standards development work with applicable governmental agencies and for engaging stakeholders in Reliability Standards development activities; and (iii) provide a basis for developing annual plans and budgets for the NERC Reliability Standards program. The 2013-2015 Plan includes three areas of work to be completed and covers all currently identified Reliability Standards development projects in the Plan. The 2013-2015 Plan also provides Project schedule and timeline updates, as well as action plans for the Directives, 5-Year Review, and Projects and Emerging Issues Teams. This informational filing was not noticed for public comment.

- **FERC Performance Audit of NERC (FA11-21)**

On January 16, FERC approved a Settlement Agreement between the Office of Enforcement ("OE") and NERC that comprehensively resolved all outstanding issues related to OE's findings and recommendations arising out of its 2012 performance audit of NERC.[78] As previously reported, the Director of OE issued a May 4, 2012 order approving the four (4) *uncontested* audit findings and recommendations made by the Division of Audits following its financial performance audit of NERC that evaluated NERC's budget formulation, administration, and execution covering the August 23, 2006 to March 23, 2012 period. Based on its findings, Audit staff made a total of 42 recommendations. NERC requested rehearing of the May 4 letter order and the FERC ultimately adopted NERC's proposed schedule for a paper hearing with modifications and created a separation of functions among staff for this proceeding.[79] The January 16, 2013 Settlement Agreement provides that, to confirm implementation of the Settlement Agreement, NERC will submit to OE's Division of Audits: (a) a plan for NERC's implementation of the Settlement Agreement and all Audit Report recommendations as revised; (b) quarterly reports detailing NERC's progress toward implementing the Settlement Agreement and all recommendations; and (c) a report describing NERC's final implementation of the Settlement Agreement and all recommendations. The Settlement Agreement also provides that OE will conduct a post-audit review of NERC's implementation of the Settlement Agreement and all recommendations. Finally, the Settlement Agreement specifically indicates that nothing in the Settlement Agreement limits the FERC's ability to determine the sufficiency of the criteria NERC is required to submit to the FERC on February 1, 2013 regarding section 215 of the FPA or whether any NERC activity is or is not eligible for funding under FPA Section 215. The FERC will address those issues in a subsequent order.

## XI. Misc. - of Regional Interest

- **CFTC Exemption Request**

On August 21, 2012, the Commodity Futures Trading Commission ("CFTC") issued a proposed order and request for comment[80] on a February 7, 2012 petition by the RTO/ISOs, including ISO-NE,[81] to exempt FTRs, Energy Transactions (Day-Ahead or Real-Time), Forward Capacity Transactions (Generation, Demand Response, Energy Efficiency), and Reserve or Regulation Transactions (each of which is a class of contract, agreement or transaction authorized under a FERC- or Public Utility Commission of Texas ("PUCT")-approved tariff), from law or regulations administered and enforced by the CFTC:

The proposed order, if finalized without change, would largely confirm the requested exemptions ("Proposed Exemption"), subject to the following conditions:

[78] *N. Am. Elec. Reliability Corp.*, 1429 FERC ¶ 61,042 (2013) ("*NERC 2012 Audit Settlement Order*").

[79] *N. Am. Elec. Reliability Corp.*, 139 FERC ¶ 61,179 (2012) ("*NERC Audit Order*").

[80] The Proposed Order was published in the *Fed. Reg.* on Aug. 28, 2012 (Vol. 77, No. 167) pp. 52,138-52,173.

[81] A copy of the 391-page "Consolidated Request" was circulated to the Committee by the ISO on February 8, and is also available at http://www.iso-ne.com/regulatory/ferc/fed/index.html.

- All parties to the agreements, contracts or transactions that are covered by the Proposed Exemption must be either "appropriate persons"[82] or "eligible contract participants" ("ECPs")[83]; and
  - ***Please note: the CFTC requests comment as to whether there are currently entities engaging in transactions in the ISOs that are neither appropriate persons nor ECPs under the above definitions; if so, on what basis the CFTC may conclude that such entities are appropriate persons or ECPs for the purpose of the Proposed Exemption.***
- Agreements, contracts or transactions covered by the Proposed Exemption must be offered or sold pursuant to a ISO or ERCOT tariff which has been approved or permitted to take affect by FERC or PUCT ("Approved Tariffs"); and
- No Approved Tariff or other governing document may include any requirement that a member be notified prior to an RTO/ISO providing information to the CFTC in response to a subpoena or other request for information or documentation; and
- There must be in full force and effect information sharing arrangements between the CFTC and FERC that are satisfactory to the CFTC (current CFTC-FERC MOU qualifies).

Comments on the August 21 proposed order were filed on September 27, 2012 by NEPOOL (as approved at the September 14 Participants Committee meeting), AB Energy, Financial Marketers Coalition, Tarachand Enterprises, Inc., FERC Staff, Texas Energy Association for Marketers Alliance for Retail Markets, Industrial Customer Coalitions of NEPOOL, PJM, and Coalition of Midwest Transmission Customers, APPA, EPSA/EEI/APP/NRECA/Large Public Power Council, Texas PUC, NY DPS, DC Energy, Financial Institutions Energy Group, Coalition of Physical Energy Companies, Commercial Energy Working Group, and CAISO ERCOT ISO-NE MISO NYISO PJM.

The April 30 ISO-NE request for supplemental order clarifying that the contracts, agreements, and transactions entered into under the ISO's Tariff (including internal bilaterals) are exempt from the Act and CFTC regulations hereunder to the same degree and extent as the relief requested in the February 7 Consolidated Request remains pending.[84]

On October 11, 2012, the CFTC issued a no-action letter that preserves the regulatory status quo "with respect to any of the contracts, agreements or transactions entered into pursuant to a currently (i.e., as of the Effective Date [10/11/12]) [FERC-] Approved Tariff, and any other Subject Transactions that would fall within the scope of the Proposed Order." This status quo will remain in place until the earlier of March 31, 2013 or the date on which the CFTC establishes in a final order on the ISO/RTO petition. The no-action relief applies to the ISOs/RTOs filing the petition and any person who is or would be eligible to participate in their markets under those tariffs.

If there are questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com) or Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **203 Application: FPL Energy Maine Hydro / Brookfield (EC13-62)**

On January 14, 2013, FPL Energy Maine Hydro and Brookfield Power US Holding America Co. ("Brookfield") requested FERC authorization for the indirect disposition of the equity interests in Maine Hydro to Brookfield. Comments on this filing are due on or before February 4, 2013. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[82] "Appropriate persons" are defined in §§ 4(c)(3)(A) through (J) of the Commodity Exchange Act ("CEA") (generally certain specific types of financial institutions, government entities and business entities meeting defined financial standards).

[83] ECPs as defined in section 1a(18)(A) of the CEA and in CFTC regulation 1.3(m).

[84] A copy of the supplemental request was circulated to the Committee on Apr. 30 and is also available at http://www.iso-ne.com/regulatory/ferc/fed/index.html.

- **203 Application: NEET / NEP (EC13-50)**

On January 15, 2013, the FERC authorized, as requested, the transfer of the fully depreciated VAR support equipment associated with the Monroe HVDC Phase I Converter facility from the New England Electric Transmission Corporation ("NEET") to the New England Power Company ("NEP").[85] A notice that the disposition and acquisition of the VAR support equipment has been consummated must be filed with the FERC within 10 days of that transaction. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: CMP, MEPCO / BHE (EC13-49)**

On January 22, 2013, the FERC authorized two transactions:[86] (1) the exchange as between CMP and MEPCO of certain jurisdictional facilities, including easements and parcels of land; and (2) the transfer of 4.87 miles of 345 kV transmission line and related facilities located near the town of Orrington, Maine to BHE (the "Orrington Assets") located in BHE's service territory and part of the larger Maine Power Reliability Program ("MPRP") . As previously reported, the Orrington Assets were energized on November 12, 2012. CMP stated that the total cost of this transaction, including easement transfers and new 115 kV lines may exceed $10 million. On January 4, the Filing Parties, in response to questions from FERC Staff concerning the proposed treatment of the related transaction costs, supplemented their filing with information clarifying that CMP intends to recover transaction costs related to the transfers, estimated to total approximately $78,600, through regional transmission rates. Unless the January 22 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).

- **203 Application: Boston Gen/Constellation Mystic Power (EC10-85)**

Rehearing remains pending of FERC's December 22, 2010 order authorizing Fore River Development, LLC, Mystic I, LLC, Mystic Development, LLC, and Boston Generating, LLC (together, "Boston Gen") and Constellation Mystic Power, LLC ("Mystic Power") to sell five of Boston Gen's generating facilities (Fore River, Mystic 7, 8, and 9, and Mystic Jet) and certain other assets to Constellation Holdings, Inc. or its designee (in this case, its wholly-owned affiliate Mystic Power).[87] As previously reported, the Bankruptcy Court authorized on November 24, 2010 the sale of the generating facilities and other assets to Constellation ("Sale Order"). Mystic Power notified the FERC that the transaction was consummated on January 3, 2011. On January 21, 2011, NSTAR filed a request for rehearing of FERC's order authorizing the transaction to correct the common mode failure reliability condition of Mystic 8 and 9. On February 22, 2011, the FERC issued a tolling order affording it additional time to consider NSTAR's request. On June 3, NSTAR submitted to the FERC additional information to accompany its January 21 request for rehearing. Mystic Power requested on June 20 that the FERC disregard NSTAR's June 3 filing, and affirm its December 22, 2010 order. NSTAR's request for rehearing remains pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Foley v. UI: Rate Base Complaint (EL12-106)**

On September 17, 2012, as amended October 5, 2012, J. William Foley Inc. ("Foley") filed a formal complaint against UI seeking an order to reduce UI's rate base to exclude certain costs which were not reasonably and/or prudently incurred, and/or were not incurred in good faith. In the amended Complaint, Foley challenges "the inclusion of excess costs irresponsibly incurred by UI in connection with the design and execution of the Middletown - Norwalk 345kV Transmission Line Project (the "Overall M-N Project"), as well as the related 115kV interconnects." Foley, who was general the contractor on the Project for the portion known as the Civil Work for 345kV Cable System for Singer-Housatonic West Bank (the "Project"), under the streets of Bridgeport and Stratford, Connecticut and is a UI customer, describes, in part in the public document, and in part under seal, both underground obstacles and contaminated soil issues that Foley alleges were "approached by UI in a manner designed to understate

[85] *New England Power Co. and New England Electric Trans. Corp.*, 142 FERC ¶ 62,032 (2013).

[86] *Central Maine Power Co. and Maine Elec. Power Co., Inc.*, 142 FERC ¶ 62,051 (2013).

[87] *Fore River Dev., LLC*, 133 FERC ¶ 61,248 (2010).

the cost of the Project at the outset, at the expense of substantial additional – and unnecessary – expense at the conclusion of the Project."

On November 5, 2012, UI submitted its answer and motion to dismiss or, in the alternative, to hold proceedings in abeyance. UI moved to dismiss the Complaint on the grounds that (a) the Complaint does not comply with the specificity requirements of Rule 206, (b) the Complaint is premature, (c) the issues raised in the Complaint are not within the FERC's jurisdiction, and, in any event, are being litigated in the CT Superior Court, and (d) the Complaint is insufficient and lacks any evidentiary basis. Alternatively, UI asked the FERC to hold the proceeding in abeyance pending resolution of the related CT litigation, or if not held in abeyance and not dismissed, set for hearing and settlement judge procedures. On November 8, Foley asked for additional time, to and including December 14, to respond to UI's pleading, which UI opposed on November 13. Since that time, Foley submitted on November 22 (as corrected November 23) a memorandum of law in opposition to UI's motion to dismiss, and on December 4, as a second amended complaint, and on December 5, an amended opposition to UI's motion to dismiss. On December 19, 2012, UI submitted its response to the second amended complaint. Since the last report, on January 7 through January 11, 2013, Foley filed additional exhibits. If there are questions on this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Allco Renewable Energy v. National Grid (PURPA Complaint) (EL12-12)**

On November 30, 2011, Allco Renewable Energy Limited ("Allco") filed a complaint against Massachusetts Electric Company d//b/a National Grid (in this summary, "National Grid"). Allco seeks a FERC order that among other things would require National Grid to purchase all of the output from Allco's multiple solar photovoltaic projects in Massachusetts at a rate equal to its long-term avoided cost rate (which it argues includes environmental compliance costs, such as costs of compliance with the MA RPS, RGGI and the MA Global Warming Solutions Act). For timing reasons described in its filing, Allco requested that a settlement judge be appointed in accordance with FERC Rule 603 as soon as possible. On December 21, 2011, National Grid submitted an answer to Allco's complaint urging the FERC to find the complaint is without merit and to deny it in its entirety. One party, the Massachusetts Department of Public Utilities ("MA DPU"), submitted comments by the December 21, 2011 comment date, and on January 5, 2012, the MA DPU also submitted for FERC's reference a letter from the MA DPU to Allco declining to open a rulemaking to amend the MA DPU's regulations with respect to sales of electricity by a renewable energy qualifying facility. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **UI Declaratory Order – Sales to Elm Electric Coop (EL10-67)**

As noted below, these proceedings have been stayed pending CT DPUC action on an agreement before it that would resolve the dispute in this proceeding. As previously reported, on May 12, 2010, the United Illuminating Company ("UI") filed a petition for a declaratory order ("Petition") that its sales to Elm Electric Cooperative ("Elm"), for resale to Elm's members, is a transaction at wholesale subject to FERC jurisdiction. As indicated by UI in the Petition, Elm is a Connecticut electric cooperative formed to sell and distribute electricity to its members, who will be tenants of a large, mixed-use residential and commercial building now under construction in New Haven, Connecticut. Elm will serve its members in part by using a 400 kW fuel cell located at the site, and to the extent the fuel cell production is insufficient to meet the building's load, Elm will purchase electricity from UI that will be re-sold and distributed to its members. Elm also expects to sell the excess power generated by the fuel cell in the New England Market, netting the excess against its UI bill. Elm will install four meters that will handle the building's load and engage a third party to supply sub-meters to each of Elm's members. UI reports that Elm has asserted in CT proceedings that the FERC either does not have jurisdiction or that it would likely disclaim jurisdiction over the matter.[88] On December 7, 2010, UI asked the FERC to stay these proceedings, noting that UI and Elm had negotiated and executed an agreement that, if accepted by the CT DPUC, would resolve the dispute in this proceeding. The motion to stay the proceedings, and the Petition itself, remain pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[88] *See PacifiCorp*, 92 FERC ¶ 61,032 (2000); *Ala. Power Co.*, 95 FERC ¶ 61,002 (2001); *u*, 114 FERC ¶ 61,175 (2006).

- **LGIA – Oakfield (BHE/Evergreen/ISO) (ER13-741; ER13-678)**

On January 10, the ISO and BHE re-filed a conforming, but not fully executed LGIA (LGIA-ISONE/BHE-12-02) under Schedule 22 of the ISO Tariff to govern the interconnection of the 147.6 MW facility of Evergreen Wind Power II ("Evergreen") in Oakfield, Maine. The LGIA was re-filed for technical reasons (the transmittal letter to the original filing in ER13-678 not appearing on the FERC's eLibrary). As previously reported, the filing parties indicated that, though the Oakfield LGIA fully conforms to the FERC-approved *pro forma* LGIA contained in Appendix 6 of Schedule 22 of the OATT, the Oakfield LGIA is non-conforming agreement in that it has not been executed by BHE (which continues to pursue the appropriate clarifications and/or approvals necessary because of its affiliate relationship to Evergreen). A March 2, 2013 effective date was requested. Comments on the re-filed LGIA are now due on or before January 31, 2013. The December 31, 2012 LGIA filing docketed in ER13-678 was withdrawn also on January 10, 2013. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **IA – Fitchburg/Pinetree (ER13-446)**

On January 8, 2013, the FERC accepted an amended interconnection agreement ("IA") between Fitchburg and Pinetree Power-Fitchburg, inc. ("Pinetree") filed by Fitchburg on November 21, 2012 to govern the interconnection of Pinetree's 18 MW cogeneration facility located in Westminster, Massachusetts. The IA was accepted effective November 22, 2012, as requested. Unless the January 8 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).

- **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",[89] 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. Specifically, the issues and findings of the Initial Decision were as follows:

| ***Issue*** | ***Findings*** |
|---|---|
| 1: Whether the FPA and applicable FERC policies thereunder permit MISO and ITC to make, and the FERC to approve, the Oct 20, 2010, filing (as amended on Jan 31, 2012)? | 1. There is no customer or contractual relationship between the Joint Applicants and PJM or NYISO that justifies the proposed cost allocation, as required by FPA section 205.<br>2. The FER has rejected unilateral filings by a utility to impose loop flow costs on neighboring utilities, requiring instead consensual resolution, which is absent here.<br>3. Orders 1000 and 1000-A do not apply, but the policy contained therein predates issuance of those Orders and precludes this filing. |
| 2: Whether the JOA between MISO and PJM precludes allocation of costs associated with the ITC PARs to PJM? | 1. The ITC PARs are like-kind replacement facilities, not new transmission facilities.<br>2. The cost allocation provisions of the JOA apply to the ITC PARs.<br>3. The ITC PARS are not eligible for cross-border cost allocation because they do not qualify as either a Cross-Border Baseline Reliability Project or a Cross-Border Market Efficiency Project.<br>4. The JOA is not the exclusive agreement to address interregional cost allocation between MISO and PJM.<br>5. Although the JOA is not the exclusive vehicle for interregional cost allocation, it is the only relevant customer or contractual relationship in this proceeding and the only one that provides for cross-border cost allocation.<br>6. The Joint Applicants do not meet the *Mobile-Sierra* criteria |
| 3: Whether there are any other customer or contractual relationships or | 1. Other than the JOA, there are no customer or contractual relationships, or interregional plans, between the Joint Applicants and PJM or NYISO |

[89] *Midwest Indep. Trans. Sys..Op., Inc.*, 141 FERC ¶ 63,021 (2012) ("*MISO Initial Decision*") at P 923.

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| interregional plans, or lack thereof, that are relevant to the proposed cost allocation? | that are relevant in this proceeding.<br>2. The lack of a customer or contractual relationship is relevant.<br>3. The lack of an interregional plan is relevant.<br>4. The Joint Applicants' pre-existing contract obligations are relevant.<br>5. The MISO Tariff and applicable policy are relevant<br>6. The MISO-IESO Operating Instruction is relevant. |
| 4. Whether the allocation of the costs of the ITC PARs to NYISO and PJM, and the level of such allocations, is just, reasonable, and not unduly discriminatory or preferential under the FPA and the applicable FERC policies, orders, and precedent thereunder (including but not limited to the policies, if applicable, contained in Order 1000)? | 1. The Joint Applicants' filing violates the FPA and FERC policy.<br>2. The proposed cost allocation violates postage stamp rate and sunken cost recovery policies.<br>3. The Joint Applicants have not met their burden of proving that the proposed rate treatment is just and reasonable.<br>4. The Joint Applicants have not met their burden of proving that the proposed cost allocation is not unduly discriminatory or preferential. |
| 5: Whether any allocation of costs of the ITC PARs to NYISO and PJM and their customers (or others) is appropriate based on cost causation/incurrence and/or beneficiary pays principles or on other considerations and, if so, is the proposed cost allocation roughly commensurate with: (a) the extent to which NYISO and PJM and their customers (or MISO, IESO, or others) caused ITC to incur the costs of the installation and operation of the ITC PARs (and, to the extent relevant, the reasons for which DEC/ITC incurred costs for installation of the Original PAR); and/or (b) the extent to which NYISO and PJM and their customers (or MISO, IESO, or others) will benefit from (or be harmed by) the installation and operation of the ITC PARs? | 1. The Joint Applicants have failed to show that NYISO or PJM caused the harm that resulted in the Joint Applicants' need to install the ITC PARs<br>2. The Joint Applicants have failed to show that NYISO or PJM will be benefitted by the operation of the ITC PARs |
| 6: What is the extent of the contributions to loop flows of MISO, IESO, NYISO, PJM, and others, and do they represent a basis for MISO/ITC to allocate the costs of the ITC PARs to PJM and NYISO? | 1. The Joint Applicants failed to submit credible and persuasive evidence showing NYISO's and PJM's harmful contributions to Lake Erie loop flow.<br>2. The Joint Applicants' failure to account for IESO's contributions to Lake Erie loop flow, whether neutral, negative, or positive, makes the proposal unjust and unreasonable.<br>3. Ignoring PJM's and NYISO's effective loop flow mitigation solutions, while crediting IESO, is unduly discriminatory and preferential. |
| 7. Whether the MISO/ITC DFAX Study provides an adequate basis for the proposed cost allocation? | 1. Joint Applicants' DFAX Study does not provide an adequate basis to support the proposed cost allocation. |
| 8. Whether the filing creates a service obligation of MISO and ITC to NYISO or PJM or their customers and, if so, what is the nature of the obligation? | 1. Joint Applicants assume no service obligation to NYISO or PJM or to their customers pursuant to the filing |
| 9. Whether and to what extent will the PARs control Lake Erie loop flow, including whether, if any of the ITC PARs (or the Hydro One PARs) are unavailable, bypassed, or not being operated in a manner that is consistent with the Presidential Permit issued to ITC by DOE, NYISO, PJM, or their customers nonetheless should be required to pay the charges at issue in this proceeding? | 1. The Joint Applicants have offered no evidence of multi-regional benefits of the ITC PARs<br>2. The arguments that the Michigan-Ontario PARs are prone to failure and will not perform as expected are beyond the scope of this proceeding.<br>3. The doctrine of judicial estoppel does not apply to the facts of this case.<br>4. Addressing the justness and reasonableness of rates is not a collateral attack on the Presidential Permit |
| 10. Whether, if the costs of the ITC PARs are allocated to PJM, the cost | 1. The increased amount assigned to PJM and the decreased amount assigned to NYISO in MISO's January 2012 testimony may not be imposed. |

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| responsibility assigned to PJM by MISO's January 2012 testimony, which increases PJM's allocation above the amount allocated by the MISO/ITC filing, may be imposed on PJM? | 2. A section 206 action is not appropriate. |
| 11. Whether, if the costs of the ITC PARs are allocated to PJM or NYISO, PJM or NYISO is responsible (respectively) for paying MISO in the case of a PJM or NYISO customer's failure to pay PARs-related charges? | Since Judge Sterner found that it is unjust, unreasonable, and unduly discriminatory to allocate the costs of the ITC PARs to NYISO and PJM, Issue 11 is moot and not addressed. |

On January 17, 2013, ITC and MISO challenged the Initial Decision through their Brief on Exceptions. This matter is 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: EnerNOC (IN13-6)**

On December 17, 2012, the FERC approved on a Stipulation and Consent Agreement between OE and EnerNOC, Inc. and Celerity Energy Partners San Diego LLC (together "EnerNOC") that, among other things, levied a ***$820,000 civil penalty*** and required EnerNOC to ***disgorge $656,806*** in unjust profits and interest.[90] OE determined that EnerNOC submitted inaccurate metering data for five assets in 2012 in New England's demand response markets, without exercising due diligence and in violation of the ISO Tariff, being overpaid for two of those assets. OE determined that Celerity unintentionally violated 18 C.F.R. §§ 35.7, 35.37(a)(1), and its market-based rate tariff, by failing to comply with two FERC filing obligations in 2010. EnerNOC also agreed to develop and maintain an effective compliance program focusing on compliance with applicable Tariff and FERC requirements, and to make semi-annual reports to OE for one year following the Effective Date of the Agreement. The December 17 order was preceded on December 14, 2012 by a staff notice of alleged violations.

- **FERC Enforcement Action: Show Cause Order – Richard H. Silkman (IN12-13)**

As previously reported, the Commission issued an order, on July 17, 2012, directing Dr. Silkman to show cause why (i) he should not be found to have violated the FERC's prohibition against Electric Energy Market Manipulation[91] by engaging in fraud in the ISO's Day-Ahead Load Response Program ("DALRP"); and, as a result, (ii) he should not be assessed a ***$1.25 million civil penalty***.[92] OE Staff alleges that, from approximately July 2007 through February 2008, Dr. Silkman advised an industrial load response participant in Rumford, Maine to engage in a fraudulent practice to collect payments in the DALRP. Specifically, Staff alleges that Dr. Silkman advised the participant to curtail on-site generation during DALRP program hours when it enrolled in the DALRP, which Staff believes artificially inflated the participant's baseline load and misrepresented the participant's load profile. Staff also alleges that Dr. Silkman advised and assisted the participant to ensure that its baseline did not appreciably change. The participant was paid for the difference between its inflated baseline load and its normal operational load as a "load reduction" even though no load reduction actually occurred.

On September 14, Dr. Silkman answered and opposed the Show Cause Order. On September 21, FERC Staff filed an unopposed motion for a 30-day extension of time, to November 13, 2012, to reply to the Silkman answer. That request was granted on September 26, and Staff's reply was filed on November 13, 2012. This matter is pending before the FERC.

[90] *EnerNOC, Inc. and Celerity Energy Partners San Diego LLC*, 141 FERC ¶ 61,211 (2012).

[91] 18 CFR § 1c.2 (2011).

[92] *Richard Silkman*, 140 FERC ¶ 61,033 (2012).

- **FERC Enforcement Action: Show Cause Order – Competitive Energy Services ("CES") (IN12-12)**

As previously reported, the Commission issued an order, on July 17 2012, directing CES to show cause why (i) it should not be found to have violated the FERC's prohibition against Electric Energy Market Manipulation by engaging in fraud in the ISO's DALRP; and, as a result, (ii) it should not be assessed a ***$7.5 million civil penalty*** and required to ***disgorge $166,841*** of payments received as a result of participation in the DALRP (plus interest).[93] As previously reported, OE Staff alleges that, from approximately July 2007 through February 2008, CES advised an industrial load response participant in Rumford, Maine to engage in a fraudulent practice to collect payments in the DALRP. Specifically, staff alleges that CES advised the participant to curtail on-site generation during DALRP program hours when it enrolled in the DALRP, which Staff believes artificially inflated the participant's baseline load and misrepresented the participant's load profile. Staff also alleges that CES advised and assisted the participant to ensure that its baseline did not appreciably change. The participant was paid for the difference between its inflated baseline load and its normal operational load as a "load reduction" even though no load reduction actually occurred.

On September 14, CES answered and opposed the Show Cause Order. On September 21, FERC Staff filed an unopposed motion for a 30-day extension of time, to November 13, 2012, to reply to the CES answer. That request was granted on September 26, and Staff's reply was filed on November 13, 2012. This matter is pending before the FERC.

- **FERC Enforcement Action: Show Cause Order – Rumford Paper Company ("Rumford") (IN12-11)**

The Commission issued an order, on July 17 2012, directing Rumford to show cause why (i) it should not be found to have violated the FERC's prohibition against Electric Energy Market Manipulation by engaging in fraud in the ISO's DALRP; and, as a result, (ii) it should not be assessed a ***$13.25 million civil penalty*** and required to ***disgorge*** just under ***$2.9 million*** of payments received as a result of participation in the DALRP (plus interest).[94] As previously reported, OE Staff alleges that, from approximately July 2007 through February 2008, Rumford engaged in a fraudulent practice to collect payments in the DALRP by intentionally curtailing on-site generation during DALRP program hours when it enrolled in the DALRP. Staff believes that this practice artificially inflated Rumford's baseline load and misrepresented its load profile. Staff also alleges that Rumford took actions to ensure that its baseline did not appreciably change for over six months. Rumford was paid for the difference between its inflated baseline load and its normal operational load as a "load reduction" even though no load reduction actually occurred. On August 14, Rumford elected, pursuant to Ordering Paragraph (D), an immediate penalty assessment by the FERC, if the FERC finds a violation, which a United States district court would be authorized to review *de novo*. On September 14, Rumford answered and opposed the Show Cause Order. On September 21, FERC Staff filed an unopposed motion for a 30-day extension of time, to November 13, 2012, to reply to the Rumford answer. That request was granted on September 26, and Staff's reply was filed on November 13, 2012. This matter is pending before the FERC.

- **FERC Enforcement Action: Show Cause Order – Lincoln Paper & Tissue ("LP&T") (IN12-10)**

The Commission issued an order, on July 17 2012, directing LP&T to show cause why (i) it should not be found to have violated the FERC's prohibition against Electric Energy Market Manipulation by engaging in fraud in the ISO's DALRP; and, as a result, (ii) it should not be assessed a ***$4.4 million civil penalty*** and required to ***disgorge*** just under ***$380,000*** of payments received as a result of participation in the DALRP (plus interest).[95] As previously reported, OE Staff alleges that, from approximately July 2007 through February 2008, LP&T engaged in a fraudulent practice to collect payments in the DALRP by intentionally curtailing on-site generation during DALRP program hours when it enrolled in the DALRP. Staff believes that this practice artificially inflated LP&T's baseline load and misrepresented its load profile. Staff also alleges that LP&T took actions to ensure that its baseline did not appreciably change for over six months. LP&T was paid for the difference between its inflated baseline load and its normal operational load as a "load reduction" even though no load reduction actually occurred. On August 14, Lincoln elected, pursuant to Ordering Paragraph (D), an immediate penalty assessment by the FERC, if the FERC

[93] *Competitive Energy Services, LLC*, 140 FERC ¶ 61,032 (2012).

[94] *Rumford Paper Co.*, 140 FERC ¶ 61,030 (2012).

[95] *Lincoln Paper and Tissue, LLC*, 140 FERC ¶ 61,031 (2012).

finds a violation, which a United States district court would be authorized to review *de novo*. On September 14, LP&T answered and opposed the Show Cause Order. On September 21, FERC Staff filed an unopposed motion for a 30-day extension of time, to November 13, 2012, to reply to the LP&T answer. That request was granted on September 26, and Staff's reply was filed on November 13, 2012. On November 28, 2012, LP&T filed an answer to FERC Staff's November 13 reply, with FERC Staff opposing that answer on November 30. Since the last report, LP&T filed supplemental information suggesting that the FERC's decision in the recent *Energy Spectrum* case[96] could not be reconciled with Enforcement Staff's position in this case and requested that the FERC "reject any finding of manipulation against Lincoln and terminate this proceeding." This matter remains pending before the FERC.

- **Waiver of Transmission Standards of Conduct: Bangor Hydro Request (TS11-5)**

Bangor Hydro'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.[97] Bangor Hydro requested a limited waiver from the FERC's Standards of Conduct requirements,[98] 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 can not 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 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 is pending before the FERC.

- **Waiver of Transmission Standards of Conduct: Green Mountain Power Request (TS04-277)**

As previously reported, Green Mountain Power requested on July 27, 2012, a continued waiver of the FERC's Standards of Conduct requirements notwithstanding the material change in facts (its merger with CVPS) upon which the FERC relied in granting Green Mountain a waiver of those requirements. Green Mountain stated that it continues to satisfy the FERC's waiver standards because its control over transmission facilities is limited to small, discrete, stand-alone transmission facilities that are not part of the high voltage grid and are not operated by the ISO and there was no material change in these facts as a result of its merger with CVPS. A notice of this filing was finally issued on January 17, 2013, with comments due on or before February 7, 2013.

## XII. Misc. - Administrative & Rulemaking Proceedings

- **NOI: Open Access and Priority Rights on Interconnection Facilities (AD12-14; AD11-11)**

On April 19, 2012, the FERC issued a notice of inquiry ("NOI") seeking comments on whether, and, if so, how the FERC should revise its current policy concerning priority rights and open access with regard to certain interconnection facilities. The FERC reports that, to date, it has on a case-by-case basis permitted an owner of interconnection facilities to have priority to capacity over its facilities for its existing use at the time of a third-party request for service. In the instance where an owner of interconnection facilities has specific, pre-existing generator expansion plans with milestones for construction of generation facilities and can demonstrate that it has made material progress toward meeting those milestones, the FERC may grant priority rights for the capacity on the interconnection facilities to those future generation projects or expansions as well. Further, an affiliate of the current interconnection

[96] *Energy Spectrum, Inc. v. New York Indep. Sys. Operator Inc.*, 141 FERC ¶ 61,197 (2012) ("*Energy Spectrum*").

[97] *Bangor Hydro-Elec. Co.*, 136 FERC ¶ 61,182 (2011) ("*BHE Standards of Conduct Order*").

[98] *See* 18 C.F.R. § 358 (2011) *et seq*.

facility owner that is developing its own generator projects also may obtain priority rights to the capacity on the interconnection facilities by meeting the ''specific plans and milestones'' standard with respect to future use, provided that the plans include a future transfer of ownership of the interconnection facilities to such an affiliate. More than twenty-five parties filed comments on options for addressing priority rights on interconnection facilities. This matter is pending before the FERC.

- **Policy Statement: Allocation of Capacity on New Transmission Projects (AD12-9; AD11-11)**

On January 17, 2013, the FERC issued a final policy statement to clarify and refine its policies governing the allocation of capacity for new merchant transmission projects and new non-incumbent, cost-based, participant-funded transmission projects ("Policy Statement").[99] Under the Policy Statement, the FERC will allow developers of such projects to select a subset of customers, based on not unduly discriminatory or preferential criteria, and negotiate directly with those customers to reach agreement on the key rates, terms, and conditions for procuring up to the full amount of transmission capacity, when the developers (1) broadly solicit interest in the project from potential customers, and (2) demonstrate to the FERC that the developer has satisfied the solicitation, selection and negotiation process criteria set forth in the Policy. The Policy's clarifications and refinements will be implemented prospectively within the FERC's existing four-factor analysis used to evaluate requests for negotiated rate authority for transmission service.

- **NOPR: Revisions to *Pro Forma* SGIA and SGIP (RM13-2)**

On January 17, 2013, the FERC issued a NOPR[100] proposing to revise the *pro forma* Small Generator Interconnection Procedures ("SGIP") and *pro forma* Small Generator Interconnection Agreement ("SGIA") originally set forth in Order 2006 in order to ensure that the time and cost to process small generator interconnect requests will be just and reasonable and not unduly discriminatory. Specifically, the NOPR proposes modifications to the SGIP to: (1) incorporate provisions that would provide an Interconnection Customer with the option of requesting from the Transmission Provider a pre-application report providing existing information about system conditions at a possible Point of Interconnection; (2) revise the 2 MW threshold for participation in the Fast Track Process included in section 2 of the pro forma SGIP; (3) revise the customer options meeting and the supplemental review following failure of the Fast Track screens so that the supplemental review is performed at the discretion of the Interconnection Customer and includes minimum load and other screens to determine if a Small Generating Facility may be interconnected safely and reliably; and (4) revise the pro forma SGIP Facilities Study Agreement to allow the Interconnection Customer the opportunity to provide written comments to the Transmission Provider on the upgrades required for interconnection. The FERC also proposes to clarify or correct certain sections of the *pro forma* SGIP and SGIA. The FERC indicated that market changes are driving the reevaluation of the SGIP and SGIA. This proceeding will supersede RM12-10 (see below). Comments on this NOPR will be due 120 days after its publication in the *Federal Register*.

- **Request to Update SGIP for Solar Generation (RM12-10)**

In light of the NOPR described immediately above in RM13-2, reporting on the Solar Energy Industries Association ("SEIA") request that the FERC initiate a rulemaking to update its SGIP for solar generation will be discontinued. As previously reported, SEIA filed a petition on February 16, 2012 requesting that the FERC initiate a rulemaking to update its SGIP for solar generation. Specifically, the SEIA urged the FERC to provide an alternative to the "15% rule or screen" that applies to the fast track interconnection of small solar generation, asserting that the 15% rule has become a "major barrier to solar market access". On July 17, 2012, the FERC convened a technical conference to discuss issues related to the petition and comments submitted in response to the technical conference are posted in eLibrary. The FERC granted in its NOPR issued in RM13-2 (*see* immediately above), a Public Utilities Commission of the State of California ("CPUC") motion to lodge in this proceeding (i) its September 13 decision adopting settlement agreement revising distribution level interconnection rules and regulations (Electric Tariff Rule

[99] *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects and Priority Rights to New Participant-Funded Transmission*, 142 FERC ¶ 61,038 (2013).

[100] *Small Generator Interconnection Agreements and Procedures*, 142 FERC ¶ 61,049 (2013) ("*SGIA/SGIP NOPR*").

21), (ii) a revised Rule 21 Tariff; and (iii) an Amended Scoping Memo, all of which CPUC asserted were relevant to the SEIA petition.[101]

- **Order 770: Revisions to EQR Filing Processes (RM12-3)**

On November 15, 2012, the FERC issued *Order 770*[102] amending its regulations to change the process for filing Electric Quarterly Reports ("EQR"s), adopting a web-based approach to filing EQRs that will allow EQRs to be filed directly through the FERC's website, either through a web interface or by submitting an Extensible Mark-Up Language-formatted ("XML") file. *Order 770* follows a June 21, 2012 NOPR which, as previously reported, proposed to discontinue the use of FERC Fox-pro-based software in favor of the web interface or XML-formatted file approach. The implementation of any changes to the EQR filing process will apply to EQR filings beginning with the third quarter 2013 EQR (providing data for July through September 2013). *Order 770* will become effective April 1, 2013.[103] On December 12, 2012, FERC Staff held a technical conference to review the changes in the EQR filing process.

- **NOPR: 3rd-Party Provision of Ancillary Services; New Electric Storage Technology Accounting and Financial Reporting (RM11-24; AD10-13)**

On June 22, 2012, the FERC issued a NOPR that proposes to revise FERC policies governing the sale of ancillary services at market-based rates ("MBR"). The NOPR also proposes to require transmission providers outside of the organized energy markets to explain in their tariffs how they will determine regulation and frequency response reserve requirements, taking into account the speed and accuracy of the resources. Finally, the NOPR proposes revisions to FERC's Uniform System of Accounts and its annual and quarterly forms, statements and reports to better account for and report transactions involving energy storage technologies. Under the NOPR, sellers that pass FERC's existing MBR analyses for energy and capacity would be presumed to lack market power for energy and generator imbalance services in that geographic market. The NOPR also seeks comment on a reporting requirement that would give potential sellers of other ancillary services the information needed to develop market power analyses based on an optional screen designed solely for ancillary services, and it proposes the use of price caps or competitive solicitations to mitigate market power. The NOPR makes a preliminary finding that the proposal to require transmission providers to account for resource speed and accuracy in determining regulation and frequency response reserve requirements is needed to prevent potential undue discrimination against customers that choose to meet their own needs for that ancillary service. It does not mandate a method for meeting this requirement, but proposes that FERC evaluate those determinations on a case-specific basis. Comments on the NOPR were due on or before September 7, 2012.[104] Comments were submitted by, among others, APPA, Beacon Power, EEI, EPSA, Indicated Suppliers,[105] the Federal Trade Commission, NU, and SDG&E. This matter is pending before the FERC.

- **Order 771: Availability of e-Tag Information to FERC Staff (RM11-12)**

On December 20, the FERC issued *Order 771*.[106] *Order 771* grants 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* will require 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* will require that e-Tag information be made available to RTO/ISOs and their Market Monitoring Units, upon request to e-Tag Authors and

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[101] *SGIA/SGIP NOPR* at P 55.

[102] *Revisions to Elec. Quarterly Report Filing Process*, Order 770, 141 FERC ¶ 61,120 (2012) ("*Order 770*")

[103] *Order 770* was published in the *Fed. Reg.* on Nov. 30, 2012 (Vol. 77, No. 231 pp. 71,288-71,312).

[104] The NOPR was published in the *Fed. Reg.* on Jul 9, 2012 (Vol. 77, No. 131) pp. 40,414-40,458.

[105] "Indicated Suppliers" are Exelon, Calpine, Dynegy, GenOn and Tenaska.

[106] *Availability of E-Tag Info. to Comm'n Staff*, Order No. 771, 141 FERC ¶ 61,235 (2012) ("*Order 771*").

Authority Services, subject to appropriate confidentiality restrictions. *Order 771* will become effective February 26, 2013.[107] On January 22, requests for clarification and/or rehearing of *Order 771* were filed by EEI/NRECA, Open Access Technology International, Inc., NRECA (separately), and Southern Companies. EEI/NRECA also requested an expedited extension of the order's March 15, 2013 compliance deadline, to 60 days following FERC action on their requests for rehearing and/or clarification, to provide utilities and their services adequate time to implement *Order 771* as clarified. The requests for clarification and/or rehearing are pending before the FERC, with FERC action required on or before February 21, 2013, or the requests will be deemed denied.

- **Order 764-A: Variable Energy Resources (RM10-11)**

On June 22, the FERC issued *Order 764* that adopts two reforms from its November 2010 NOPR to remove barriers to the integration of Variable Energy Resources ("VERs") into the transmission system by requiring each public utility transmission provider to: (1) offer customers the option of scheduling transmission service at 15-minute intervals; and (2) incorporate provisions into the *pro forma* LGIA requiring interconnection customers whose generating facilities are VERs to provide transmission owners with meteorological and operational data to support power production forecasting.[108] *Order 764* provides guidance on how the FERC will evaluate proposed charges for that service, but does not require a standard approach to (or new schedule for) generator regulation service as proposed in the VER NOPR. The FERC will continue to evaluate proposed charges for generator regulation service on a case-by-case basis, and the Final Rule provides a framework for transmission providers to develop proposed charges. In response to comments on the NOPR by several parties, including the joint comments submitted by NEPOOL and the ISO, the Final Rule explicitly clarified that in its compliance filing, a transmission provider may demonstrate how its existing tariffs, business practices or market rules are adequate to satisfy any requirements of the Final Rule. A more detailed summary was circulated by NEPOOL counsel on June 25 under separate cover. *Order 764* became effective on September 11, 2012.[109] On October 19, EEI requested that the FERC extend for an addition 62 days, to November 12, 2013, the deadline for the compliance filings, so that the initial roll-out and implementation of intra-hour scheduling does not commence during summer peak conditions.

Requests for rehearing and/or clarification of *Order 764* were filed on July 23, 2012 by AWEA, BPA, Iberdrola, NRECA, Powerex, Public Interest Organizations, and Public Power. On August 7, Powerex filed an answer to BPA's request for rehearing. On December 20, 2012, the FERC affirmed its basic determinations in *Order 764*, provided clarification, and granted EEI's request to extend the period for compliance filings.[110] Order 764-A clarified (i) that the intra-hour scheduling reform adopted in the *Order 764* applies to ***all*** transmission customers that schedule transmission service under an OATT;[111] (ii) in the absence of sub-hourly settlement and dispatch, a public utility transmission provider must account for intra-hour imbalances in order to ensure that they are properly factored into the calculation of hourly imbalance charges;[112] and (iii) that schedules for firm transmission service will continue to have curtailment priority over schedules for non-firm transmission service.[113] Remaining requests for clarification and/or rehearing were denied. Requests for clarification and or rehearing of *Order 764-A* were submitted on January 22, 2013 by Powerex and Iberdrola. The requests for clarification and/or rehearing are pending before the FERC, with FERC action required on or before February 21, 2013, or the requests will be deemed denied. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[107] *Order 771* was published in the *Fed. Reg.* on Dec. 28, 2012 (Vol. 77, No. 249) pp. 76,367-76,380.

[108] *Integration of Variable Energy Res.*, 139 FERC ¶ 61,246 (2012) ("*Order 764*"), *order on reh'g*, 141 FERC ¶ 61,232 (2012).

[109] *Order 764* was published in the *Fed. Reg.* on July 13, 2012 (Vol. 77, No. 135) pp. 41,482-41,546.

[110] *Integration of Variable Energy Res.*, 141 FERC ¶ 61,232 (2012) ("*Order 764-A*").

[111] *Id.* at P 15.

[112] *Id.* at P 19.

[113] *Id.* at P 23.

- **NOPR: Incorporation of WEQ DR and Energy Efficiency M&V Standards (RM05-5)**

On April 19, 2012, the FERC issued a NOPR proposing to amend its regulations at 18 CFR § 38.2 to incorporate by reference the business practice standards adopted by the NAESB Wholesale Electric Quadrant ("WEQ") that pertain to the measurement and verification ("M&V") of demand response and energy efficiency resources participating in RTO/ISOs. The FERC states that adoption of the standards is intended to improve the methods and procedures used to accurately measure and compensate demand response and energy efficiency resource performance.

On June 14, 2012, NAESB filed a report informing FERC that it is in the process of revising the relevant energy efficiency business practice standards to remove references to the International Performance Measurement and Verification Protocol. NAESB intends for these minor revisions to create consistency between the WEQ and Retail Electric Quadrant version of the standards. This matter is pending before the FERC.

## 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).

- **Natural Gas and Electric Market Coordination (AD12-12)**

As previously reported, the FERC held a regional technical conference, on August 20, 2012, in Boston, aimed at New England stakeholders to discuss coordination between the natural gas and electric markets. This was one of five regional technical conferences the FERC convened in August to discuss gas-electric interdependence issues. The impetus for these technical conferences were the comments gas and electric stakeholders submitted to the FERC earlier this year in this docket, many of which called for such regional technical conferences. A memo discussing the New England technical conference in more detail was distributed to the Participants Committee on September 7, 2012. On November 15, FERC staff released a report detailing the discussions that took place at the five regional technical conferences. The report is available on the FERC's eLibrary.

On November 15, 2012, the FERC issued an order directing further conferences and reports in the gas-electric coordination initiative.[114] Based on the issues raised during the regional technical conferences in August, this *November 15 Order* directs FERC staff to conduct two technical conferences: one focusing on ways to enhance communication between the two industries; and one focusing on how to design the most efficient scheduling systems for both industries. The *November 15 Order* also requires each ISO and RTO to appear before the FERC on May 16, 2013 and October 17, 2013 to detail their efforts and progress in improving coordination between the industries. At those times, FERC will also want the ISOs and RTOs to discuss any natural gas transportation concerns that arise during the winter heating season and any fuel-related generator outages during the winter and spring. Finally, to monitor the progress made by the two industries, the order directs FERC staff to report to the FERC on natural gas and electric coordination activities at least once each quarter in 2013 and 2014.

In accordance with the *November 15 Order*, FERC staff issued a notice on December 7 that it will hold a technical conference on February 13, 2013 to elicit input pertaining to information sharing and communications issues between the natural gas and electric power industries. FERC staff requested that interested parties file comments on questions set forth in the notice in advance of the technical conference. Responses to these questions were filed on January 7 by nearly 30 parties, with all RTO/ISOs but MISO responding, as well as comments from the following New England Parties: MMWEC, National Grid, NEPGA (with EPSA), and the New England LDCs. As previously reported, these comments will form the basis of the agenda for and discussion at the February 13 technical conference.

Also since the last report, a meeting of the New England Gas-Electric Focus Group was held on January 23, 2013, with the next focus group meeting scheduled for February 26, 2013 (again, all those interested and who wish to

[114] *Coordination Between Natural Gas and Elec. Markets*, 141 FERC ¶ 61,125 (2012) ("*November 15 Order*").

participate directly, if they have not already done so, should let us know so that they can be added to the focus group distribution list).

- **NOI: Enhanced Natural Gas Market Transparency (RM13-1)**

On November 15, the FERC issued a NOI seeking comments 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"). In particular, the FERC is considering the extent to which quarterly reporting of every jurisdictional natural gas transaction that entails physical delivery for the next day (i.e., next day gas) or for the next month (i.e., next month gas) would provide useful information for improving natural gas market transparency. Pursuant to a January 18, 2013 notice, the date for filing comments was extended to and including February 12, 2013.[115] Thus far, comments have been received from the Coalition for Renewable Natural Gas.

- **Enforcement Notice of Alleged Violations**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines. Since the last report, OE issued the following notices that in a nonpublic investigation it has preliminarily determined that there has been a violation of the FERC's regulations:

| ***Company*** | ***Alleged Violation(s)*** |
|---|---|
| Michigan Consolidated Gas Company | 54 back-to-back capacity release transactions without posting the capacity on an Electronic Bulletin Board; multiple flipping transactions. (2001-2006) |
| Washington 10 Storage Corporation ("W10") | 32 firm transportation storage contracts and 72 park and loan ("PAL") contracts misclassified as intrastate (rather than interstate); As a result of misclassification, W10 preliminarily determined to have provided unauthorized service, and failed to have identified contracts in required semi-annual reports. Staff also alleged that W10 failed to file annual reports reflecting hub services in violation of FERC regulations. (2003-2007) |

A Notice of Alleged Violations is not a formal charge, but suggests that the advanced inquiry is likely to move forward.

## XIV. State Proceedings & Federal Legislative Proceedings

- **Connecticut: CT DEEP Study of ISO-NE Impact on Connecticut Ratepayers**

As legislatively directed, the Connecticut Department of Energy and Environmental Protection ("CT DEEP") provided to the CT General Assembly's Energy and Technology Committee on August 28 a report

- reviewing the accountability of ISO-NE to CT ratepayers and energy policymakers;
- considering strategies and mechanisms that might mitigate any adverse impacts Market Rule 1 may have on wholesale generation prices in CT and New England and may reduce CT's reliance on the wholesale power market, including, but not limited to, long-term contracts;
- considering the costs and benefits associated with participating in ISO-NE and any potential benefits of joining another RTO or operating outside of the RTO structure;
- examining the FERC framework that has contributed to CT's high electricity rates, and
- considering methods to foster greater transparency.

[115] The NOI was published in the *Fed. Reg.* on Nov 21, 2012 (Vol. 77, No. 225) pp. 69,780-69,785. The comment date was extended by notice dated Jan. 18, 2013 in this proceeding.

DEEP indicates that it intends to conduct further study of key policy issues highlighted in this preliminary investigation . DEEP notes that the lack of consumer cost accountability in ISO-NE's mission statement requires additional analysis of the wholesale power markets outside of what ISO-NE and FERC have addressed to date. Within available resources, DEEP will engage experts to study the current markets, and determine whether there are alternatives that could improve efficiency, reduce ratepayer costs, and improve the balance of market objective, engaging ISO-NE, FERC, and other New England states when preparing these evaluations. DEEP also indicated that it will continue to participate and advocate for improvements to the regional market design that can further CT's policy objectives. The report reflects comments submitted by NEPOOL and NEPGA on the initial draft. A copy of the report is available on-line at http://www.dpuc.state.ct.us/DPUCservlist.nsf/DocumentSendOut?OpenView. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Massachusetts: DPU Investigation Into Need for Additional NEMA/Boston Generation**

On October 1, 2012, the MA DPU voted to open an investigation into the need for capacity in NEMA/Boston within the next 10 years pursuant to Chapter 209, Section 40 of the Acts of 2012. In making its determination, the DPU must include consideration of ISO findings and of the anticipated function of the FCM. Should the DPU "determines that there is a need for additional electric generating capacity in [NEMA/Boston] within the next 10 years," MA DPU may order distribution companies serving NEMA/Boston to solicit competitive proposals from developers and enter into reasonable, cost-effective long-term contracts to deliver such resources to NEMA/Boston. On September 7, MA DPU asked the ISO to provide by October 22 information about the existing generating capacity and demand response resources in NEMA/Boston, the load forecast for the next ten years, the likelihood of retirements and the implementation of transmission upgrades ("Summary of Information").

MA DPU conducted a technical conference on the Summary of Information on November 8, 2012. Interested parties were provided an opportunity to submit initial and reply comments on the Summary of Information and on the question of whether NEMA/Boston needs additional capacity over the next ten years. Interested persons also may comment on the following questions, which will not be addressed at the technical conference: (1) whether the FCM will send the appropriate price signals to incentivize the necessary electric generating capacity or demand response resources to meet any identified need; and (2) whether MA DPU should order distribution companies to enter into cost-effective long-term contracts if a need is identified. Initial comments were due November 27, 2012; reply comments, December 5, 2012. If you have any questions concerning this development, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Maine: Lewiston Loop CPCN (MPUC 2011-420)**

As previously reported, a petition for a CPCN for the Lewiston Loop Project was submitted to the MPUC on November 18, 2011 in Case No. 2011-420. The most recent hearings were held December 6, 2012. CMP submitted oral data requests on December 31, 2012. The briefing schedule in this case has been suspended pending the MPUC's decision in its Transmission Planning Standards case, 2011-494If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

## XV. Federal Courts (Appeals of FERC Decisions & Others)

The following are NEPOOL-related matters, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the United States Court of Appeals for the District of Columbia Circuit (unless otherwise noted). 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).

- **New England's Order 745 Compliance Filing (12-1306)**
  **Underlying FERC Proceedings: ER11-4336**[116]
  **Appellants: EPSA and NEPGA**

On July 16, 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 course issuance of 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, and 7th Cir. 12-2248)**
  **Underlying FERC Proceedings: RM10-23**[117]
  **Appellants: SC PSA, Coalition for Fair Transmission, PSEG, and Sacramento Municipal Utility District**

Petitions for review of FERC's Order 1000 and 1000-A, as identified in previous reports, remain pending before the DC Circuit. Thus far, docketing statements, statement of issues, and various interventions have been filed. The Court granted a number of motions to intervene on September 9, 2012. On November 6, 2012, the Court dismissed (as premature) Case Nos. 12-1290 and 12-1294, and ordered that remaining cases be held in abeyance pending further order of the Court. On November 14, 2012, MISO Transmission Owners filed a petition for review of Order Nos. 1000, 1000-A and 1000-B (Case No. 12-1448), which was then consolidated on November 15 with the cases consolidated under 12-1232. On December 13, 2012, PPL PJM Companies, filed a motion to intervene. On December 17, 2012, MISO TOs filed their Statement of Issues. On January 16, 2013, intervenors and petitioners filed a joint unopposed motion to govern further proceedings, which is pending before the Court.

- **FCM Re-Design (12-1060 consolidated with 12-1074, 12-1085, and 12-1149) ****
  **Underlying FERC Proceedings: ER10-787; EL10-57; EL10-50**[118]
  **Appellants: NEPGA, NSTAR, MMWEC/NHEC, VT DPS/VT PSB, NRG**

Petitions for review of FERC's orders in the FCM Re-Design proceeding were filed by NEPGA on January 27, 2012; by NSTAR on February 3, 2012; by MMWEC/NHEC on February 10, 2012; by VT DPS/VT PSB on March 1, 2012; and by NRG on March 16, 2012. By orders dated February 7, 2012, February 27, 2012, March 2, and March 22, 2012, the Court consolidated the first four cases, with Case No. 12-1060 remaining the lead Case No. On February 29, 2012, the FERC filed an unopposed motion to hold the NEPGA, NSTAR, MMWEC/NHEC petitions in temporary abeyance pending expiration of the statutory deadline for the filing of petitions for review of the challenged orders. On March 26, 2012, the FERC filed an unopposed motion to allow the parties until April 23, 2012 to negotiate and submit a proposed briefing schedule. On March 27, 2012, the Court granted the FERC's unopposed motion and directed parties to submit proposed formats for the briefing of the cases by April 23, 2012, which were filed. On May 7, 2012, NEPOOL notified the Court of its intent to be aligned as an intervenor in support of NSTAR (12-1074) and MMWEC/NHEC (12-1085), reserving the right to join in an intervenors' brief in support of those petitioners. On October 9, briefs were filed by MMWEC/NHEC, NSTAR, and NEPGA. Supporting petitions were filed on October 23 by NECPUC and PSEG. NEPOOL indicated that it would not join in any intervenor's brief. On January 7, 2013, FERC filed its Respondent Brief. Intervenor for Respondent Briefs were filed on January 22, 2013 by NEPGA and jointly by the CT PURA, HQ US, NICC, NSTAR, and NECPUC. Pursuant to the July 16, 2012 briefing schedule, the next submission will be Reply Briefs for Generator Petitioners and Distribution Utility Petitioners (February 5, 2013) and Final Briefs (March 5, 2013).

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[116] 138 FERC ¶ 61,042 (Jan. 19, 2012); 139 FERC ¶ 61,116 (May 17, 2012).

[117] 136 FERC ¶ 61,051 (Jul. 21, 2011); 139 FERC ¶ 61,132 (May 17, 2012).

[118] 131 FERC ¶ 61,065 (Apr. 23, 2010); 132 FERC ¶ 61,122 (Aug. 12, 2010); 135 FERC ¶ 61,029 (Apr. 13, 2011); 138 FERC ¶ 61,027 (Jan. 19, 2012).

- **Orders 745 and 745-A (11-1486 consolidated with 11-1489, 12-1088, 12-1091 and 12-1093)**
  **Underlying FERC Proceedings: RM10-17-000**[119]
  **Appellants: EPSA, CAISO, ODEC, EEI, CA PUC**

As previously reported, petitions for review of FERC's Order 745 (Demand Response Compensation) were filed by EPSA on December 23, 2011; by CAISO on December 27, 2011; by Old Dominion Electric Cooperative ("ODEC"); and by EEI and the California Public Utilities Commission ("CA PUC") on February 13, 2012. The DC Circuit consolidated the EPSA and CAISO cases on December 28. By orders dated February 13, 2012 and February 15, 2012, the Court consolidated Case Nos. 12-1088, 12-1091 and 12-1093 with 11-1486. All briefing has been completed.

- ***FCM Settlement Appeal Remand* and *Remand Rehearing Orders* (11-1422 and 11-1465 consolidated)****
  **Underlying FERC Proceedings: ER03-563-066, -067**[120] **Appellants: NEPGA and MA AG, CT AG, MPUC**

In continuing litigation arising out of the FCM Settlement, the DC Circuit was requested to review the FERC's 2011 *FCM Settlement Remand Order* and *Remand Rehearing Order* by NEPGA on October 31 and by the MA AG, CT AG and MPUC on November 29, 2011. On November 30, the two cases were consolidated and Petitioners in 11-1465 directed to file their statement of issues by December 30, 2011. On December 28, Petitioners filed their non-binding statement of issues to be raised in proceeding. On December 29, the Court granted the interventions by CT AG, ISO, NEPOOL and NEPGA. On January 13, the Court issued an order that parties and *amicus curiae* submit proposed briefing formats for the cases by February 13, 2012. On February 13, 2012, a joint unopposed motion to govern further proceedings was filed. On March 28, the Court issued an order setting briefing schedule and format, which has since been completed. Oral argument was heard on Nov 15, 2012, and the matter is pending before the Court.

***Background***. As reported for some time, the Supreme Court decided, on January 13, 2010, *NRG Power Marketing, LLC v. Maine Public Utilities Commission*, a case growing out of challenges to the New England Forward Capacity Market settlement agreement. The settlement agreement provides for application of the *Mobile-Sierra* analysis, which creates a presumption that contractual rates are just and reasonable and allows those rates to be set aside only if they are contrary to the public interest, to challenges to the transition rates and the capacity rates that result from the forward capacity auction process. The D.C. Circuit reversed FERC's approval of that provision on the ground that *Mobile-Sierra* protects contract rates only from attack by the signatories to the contract itself. In its decision, the Supreme Court overturned that holding, but it did not decide, whether the transition and auction rates constitute "contract rates" for the purpose of *Mobile-Sierra*, leaving that question to the D.C. Circuit on remand. The D.C. Circuit heard oral argument on these issues on September 20, 2010. On November 5, 2010, the DC Circuit remanded to the FERC for further proceedings the FERC orders approving the settlement agreement's *Mobile-Sierra* provision.[121] The DC Circuit found that the FERC "never articulated in its orders a rationale for its discretion to approve a *Mobile-Sierra* clause outside the contract context, or an explanation for exercising that discretion" in this case. The DC Circuit indicated that the FERC must explain why, if the auction rates are not contract rates, they are entitled to *Mobile-Sierra* treatment.

***FCM Settlement Appeal Remand Order***. As noted above, on March 17, 2011, the FERC issued an order on remand finding that the transition rates and the rates that result from the forward capacity auction in the New England Forward Capacity Market (collectively, the "settlement rates") are not "contract rates" for the purpose of applying the *Mobile-Sierra* analysis, which creates a presumption that contractual rates are just and reasonable and allows those rates to be set aside only if they are contrary to the public interest.[122] The FERC stated, however, that it has the discretion to consider and decide whether future challenges to these settlement rates must overcome a more rigorous application of the statutory just and reasonable standard of review. As part of its ruling, the FERC noted that the settlement rates apply to all suppliers and purchasers of capacity in New England, not just to the settling parties and

[119] 134 FERC ¶ 61,187 (Mar. 15, 2011); 137 FERC ¶ 61,215 (Dec. 15, 2011).

[120] 134 FERC ¶ 61,208 (Mar. 17, 2011); 137 FERC ¶ 61,073 (Oct. 20, 2011).

[121] *ME Pub. Utils. Comm'sn v. FERC*, slip op. (Nov. 5, 2010) at p 11.

[122] *Devon Power LLC*, 134 FERC ¶ 61,208 (Mar. 17, 2011).

that the settlement rates more closely resemble tariff, not contract rates. The FERC also stated that the utilities, or purchasers of capacity, do not participate in the forward capacity auction and are not contracting with the capacity suppliers. The FERC further stated, however, that nothing in the Federal Power Act or in the court opinions relating to this proceeding, precluded it from applying a more rigorous than just and reasonable standard to settlement rate challenges in the future.

***Remand Rehearing Order***. Requests for rehearing, challenging aspects of the FERC's reasoning and conclusions in the FCM Settlement Appeal Remand Order, were filed on April 18, 2011 by NEPGA and a group self-styled as the "Applicants."[123] NEPGA argued that the FERC erred in considering the rates at issue as anything other than contract rates, which would be subject to a *Mobile-Sierra* "public interest" presumption of reasonableness. Applicants argued that the FERC erred in suggesting that the rates at issue, while they are tariff rates, could nevertheless be made subject to the more stringent *Mobile Sierra* "public interest" standard of review. On October 20, 2011, the FERC denied the rehearing requested, rejecting both arguments.[124]

- **Vermont Yankee Complaint (2nd Circuit, 12-707)**
  **Plaintiffs: Entergy Nuclear Vermont Yankee & Entergy Nuclear Operations**
  **Defendants: VT Governor, Attorney General, and PSB Members**

On February 24, Vermont Parties appealed the January 19, 2012 decision of the U.S. District Court for the District of Vermont that, as previously reported, found certain Vermont State Acts were preempted by the Atomic Energy Act and ordered permanent injunctive relief.[125] Appellant and amicus briefs have been filed. Entergy's brief was filed on August 31, 2012. Motions to expedite oral argument were granted on October 3, 2012. Oral argument was held on January 14, 2013, and this matter is pending before the 2nd Circuit.

[123] "Applicants" are the CT and MA Att'y Generals, NSTAR, NEICC, and the IECG.

[124] *Devon Power LLC*, 137 FERC ¶ 61,073 (2011) ("*Remand Rehearing Order*").

[125] *Entergy Nuclear Vt. Yankee, LLC v. Shumlin*, 2012 U.S. Dist. LEXIS 6894 (VT Cir. Jan. 19, 2012).

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Driving directions to the Sheraton Framingham Hotel & Conference Center from major routes throughout the state

**From East**

- Follow the Massachusetts Turnpike (I-90) West to Exit 12.
- Bear Left after the toll (turns into Route 9 West towards Framingham).
- Stay in the right lane. The hotel is the first building on the right.

**From West**

- Follow the Massachusetts Turnpike (Interstate 90) East to Exit 12.
- Bear left after the toll (turns into Route 9 West towards Framingham).
- Stay in the right lane. The hotel is the first building on the right.

**From South**

- Take Interstate 95 North to Exit 6B (Interstate 495 North towards Worcester).
- Continue on I-495 North for about 25 miles. Take Exit 22 (Massachusetts
- Turnpike/Interstate 90
- East) towards Boston.
- Follow the Massachusetts Turnpike (I-90) East to Exit 12.
- Bear left after the toll (turns into Route 9 West towards Framingham).
- Stay in the right lane. The hotel is the first building on the right.

**From North**

- Take Interstate 93 South to Exit 37B (Interstate 95 South/Route 128 South towards
- Waltham).
- Follow I-95/Rte. 128 South to Exit 25 (Interstate 90 West/Massachusetts Turnpike).
- From the Massachusetts Turnpike take Exit 12 and bear left after the toll (turns into
- Route 9 West
- towards Framingham).
- Stay in the right lane. The hotel is the first building on the right.

1657 Worcester Road, Framingham, MA 01701