NEPOOL
NEW ENGLAND POWER POOL

David T. Doot
Secretary

April 28, 2017

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of May 5, 2017 NEPOOL Participants Committee Teleconference 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 Participants Committee will be held **by teleconference on Friday, May 5, 2017, at 10:00 a.m.** The Participants Committee meeting will be held for the purposes set forth on the attached final agenda and posted with the meeting materials at http://nepool.com/NPC_2017.php. For your information, this meeting is recorded, as are all the NEPOOL Participants Committee meetings. The dial-in number for the meeting, to be used only by those who otherwise attend NEPOOL meetings, is 1-866-803-2146; Passcode: 7169224. For your information, this meeting will be recorded, as are all NEPOOL Participants Committee meetings.

PLEASE NOTE: The June 2, 2017 Participants Committee meeting has been cancelled. The next scheduled in-person Participants Committee meeting is scheduled for Tuesday, June 27, which is the first day of the NEPOOL Summer Meeting and the day set aside to conduct NEPOOL General Business.

Looking ahead to the Summer Meeting on June 27-29, 2017 at the Chatham Bars Inn, Chatham, MA (coffee & dessert on Monday evening, June 26), we encourage you to register early, both for meeting-related activities and for rooms at Chatham Bars. Meeting registration can be accessed at http://nepool.com/Summer_Mtg_Info_Page.php. Hotel reservations can be accessed through the hotel link on the NEPOOL Summer Meeting webpage or through the Chatham Bars hotel link at NEPOOL, or by contacting Chatham Bars directly at 1-800-527-4884 and identifying yourself as part of NEPOOL. The NEPOOL group discounted room rate at Chatham Bars is $379.00 per room, per night (single/double occupancy). As with past summer meetings, the rooms at the discounted rate have gone quickly, so we urge you to make your reservations early if you wish to stay at the Chatham Bars Inn. We ask that you **make your reservations no later than June 2, 2017** in order to receive the group discounted rate. After that date, Chatham Bars will try to accommodate you on a first-come, first-served basis based on availability and at the rate available at that time. Information regarding additional activities at the 2017 NEPOOL Summer Meeting will be circulated as it becomes available and posted on the NEPOOL Website Summer Meeting page and provided in future notices.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the Participants Committee meeting held on April 7, 2017. The preliminary minutes of the April 7 meeting, marked to show changes from the draft circulated on April 24, 2017, are included and posted with the meeting materials.

2. To adopt and approve all actions recommended by the Technical Committees set forth on the Consent Agenda included with this notice.

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts. The litigation report will be circulated and posted in advance of the meeting.

5A. To receive a report on the status of GIS discussions. Background materials will be circulated and posted in advance of the meeting.

6. To receive reports from Committees, Subcommittees and other working groups:

   - Markets Committee
   - Reliability Committee
   - Transmission Committee
   - Budget & Finance Subcommittee
   - GIS Agreement Working Group
   - Others

7. To receive a report on administrative matters.

8. 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, April 7, 2017, at the Colonnade Hotel, Boston, 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 who attended the meeting.

Mr. Thomas Kaslow, Chair, presided and Mr. David Doot, Secretary, recorded. Mr. Kaslow welcomed the members, alternates and guests who were present. Mr. Kaslow began by congratulating Ms. Anne George, ISO Vice President, External Affairs and Corporate Communications, for the Achievement Award she received the evening before from the New England Women in Energy and the Environment.

APPROVAL OF MARCH 3, 2017 MEETING MINUTES

Mr. Kaslow referred the Committee to the preliminary minutes for the March 3, 2017 teleconference meeting, as circulated in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the March 3 meeting were unanimously approved without change.

CONSENT AGENDA

Mr. Kaslow 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, with abstentions noted by BP, Cross-Sound Cable~~,~~ and Mercuria. Their representatives stated the abstentions related to concerns identified with respect to Consent Agenda Item 7 (Capping Adjusted Energy Offers for Use in Fast-Start Pricing).

NEPOOL COMMENTS ON INTERCONNECTION REFORM NOPR (RM17-8-000)

Ms. Mariah Winkler, Transmission Committee Chair, referred the Committee to the materials posted in advance of the meeting concerning NEPOOL Comments on the Notice of Proposed Rulemaking (NOPR) in Docket No. RM17-8-000, regarding Reform of Generator Interconnection Procedures and Agreements (NEPOOL Comments). She summarized those materials, noting that the NEPOOL Comments in the distributed materials included certain non-substantive changes that had been reviewed and approved by herself and Mr. José Rotger, as the elected Officers of the Transmission Committee.

The following motion was duly made, seconded, and unanimously approved, without discussion:

> RESOLVED, that the Participants Committee approves the filing of the NEPOOL Comments in the Interconnection Reform NOPR proceeding, as recommended by the Transmission Committee at its March 28, 2017 meeting and as reflected in the materials distributed to the Participants Committee for its April 7, 2017 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

CONFORMING REVISION TO ISO TARIFF SECTION II.44

Ms. Winkler then referred the Committee to the materials posted in advance of the meeting concerning a revision to Section II.44 of the ISO Tariff to conform that Section to Day-Ahead Energy Market scheduling deadline Market Rule changes. She summarized those materials and the following motion was duly made, seconded, and unanimously approved, without discussion:

> RESOLVED, that the Participants Committee supports the revision to Section II.44 of the ISO-NE Tariff, as recommended by the Transmission Committee at its March 28, 2017 meeting and as reflected in the materials distributed to the Participants Committee for its April 7, 2017 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the two ISO Board ~~and Board~~ Committee meetings that had occurred since the March 3 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

He then provided an update on the status of the ISO's near-term proposal under development as part of the Integrating Markets and Public Policy (IMAPP) process. In light of the May 1-2 FERC Technical Conference on IMAPP-related issues, the ISO planned to release an executive summary of its proposal on April 17. The details concerning that proposal would be discussed with the ISO Board, with a plan, if possible, to release details before the May 1-2 FERC Technical Conference.

In response to a question, he confirmed his expectation that the agenda for the Technical Conference would include as speakers representatives from the ISO, PJM and NYISO ~~as speakers~~.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the April COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. Focusing on report highlights, which he explained reflected data through March 29, 2017, he reported for March that: (i) Energy Market value was $382 million, which was up $78,000 from February 2017 and up $162 million from March 2016; (ii) average natural gas prices were 22% higher than February 2017 average prices; (iii) average Real-Time Hub LMPs ($35.43/MWh) were 26% higher than February 2017 LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 96.4% in March, down from 97.2% in February; (v) daily Net Commitment Period Compensation (NCPC) for March (through March 28) totaled $5.4 million, down $1.7 million from February 2017 and up $1.3 million from March 2016; (vi) first contingency payments, totaling $3.7 million, were $273,000 higher than February's; (vii) second contingency payments totaled $760,000, down $2.3 million from February; (viii) voltage support payments totaled $988,000, up $282,000 from February's; and (ix) NCPC payments were 1.4% of the total Energy Market value.

Dr. Chadalavada highlighted the 1% decline in Day-Ahead cleared physical Energy during peak hours over each of the previous three months. He explained that a persistent mismatch raises the potential need for supplemental commitments. He stated that it was too early to understand the exact cause of the decline, but observed that average Real-Time prices had been comparatively lower than average Day-Ahead prices, offering some explanation as to why some load obligations were being moved directly to the Real-Time market. He indicated that the ISO would continue to study these results and respond as appropriate.

Providing a power system spring maintenance update, Dr. Chadalavada reported that there was a planned maintenance outage in NH for the next 45 days and a forced transmission outage, which would require out-of-merit commitments to control high voltage during April and May. He reported that CT would require out-of-merit commitments in April. He said that scheduled upgrades in NEMA were unlikely to require out-of-merit commitments in April and May. In response to questions, Dr. Chadalavada stated that NH outages were unlikely to require out-of-merit commitments in NEMA because of recent system upgrades.

Dr. Chadalavada then provided a final update on the 2016/17 Winter Program. He reported that approximately 100,000 barrels of oil were burned. On March 15, the end of the Winter Period, 3,034,668 barrels of oil were eligible for payments under the program. He reported that total expected program costs were $30.9 million for oil, $291,000 for liquefied natural gas (LNG), and $126,000 for Demand Response (DR) (including energy payments for dispatch on January 10). He noted that performance-based reductions for oil payments were not included in the report, but were expected to be approximately $400,000 to $500,000, subject to confirmation.

Reviewing FCM highlights, Dr. Chadalavada reported that when the June 2017-May 2018 Capacity Commitment Period (CCP) starts, on June 1, 2017, Footprint (roughly 700 MW) would still be in the commissioning stage. The ISO expected to have procedures in place, similar to those established for Summer 2016, to address any potential reliability issues. Those procedures, again to be established in collaboration with the Transmission Owners, would include switching procedures to address potential post-first contingency situations. He explained in response to questions, that extraordinarily hot temperatures and/or heavy loads might refine procedures and other operational changes beyond those used in past summers.

Turning to FCA12, Dr. Chadalavada reported that Retirement De-List Bids and Permanent De-List Bids totaling approximately 521 megawatts (MW) were received by the March 24 deadline. The FCA12 Show of Interest window would be open April 14-28 and the Renewable Technology Resource election cap would be approximately 514 MW. In response to a member's request, ~~rather than system aggregate of MW proposed to be retired,~~ Dr. Chadalavada agreed to consider having the ISO provide a zonal breakdown of proposed retirements rather than just system aggregates, if and as permitted under the Tariff. He also explained that neither IMAPP proposals (to be implemented after the CCP12 period) nor the Winter Reliability Program (which would end prior to CCP12) should impact FCA12.

Dr. Chadalavada then provided an update on operable capacity. He said that the lowest 50/50 and 90/10 Summer Operable Capacity Margins were projected for the weeks beginning June 3, 10, and 17, 2017 with shortages expected for both the 50/50 and 90/10 margins because of the June 1, 2017 retirement of Brayton Point ~~effective June 1, 2017~~ and delays in commercial operation of new resources.

In response to how the peaker pricing mechanism activated on March 1, 2017 was working, Dr. Chadalavada reported it had been activated numerous times and that the mechanism was affecting prices in 12-15% of the intervals. He opined that the mechanism was performing as intended.

Addressing a question related to decreased monthly recorded Net Energy for Load (NEL) and weather-normalized NEL during the winter months, Dr. Chadalavada confirmed his speculation during his March report that overperformance by Energy Efficiency, particularly the lighting (light-emitting diode (LED)) component, was a major factor in driving down NEL during the winter months.

Dr. Chadalavada then reported on operations during the March 14, 2017 winter storm. He said the storm was the biggest of the season, with significant snow in New York and Southern Vermont, mixed precipitation in southwest New England, and near blizzard conditions throughout the rest of the region. He reported that an equipment failure at a major Eastern Massachusetts substation caused the loss of five major transmission elements at about 12:00 p.m. The Transmission Owners (TOs) cleared the damaged equipment at the substation during the storm and restored four lines within two-three hours and the last line by about 4:00 p.m. Simultaneously, at about 1:00 p.m. there was a loss of a distribution feeder to Distrigas, which the TOs restored at about 2:15 p.m. The ISO called up several additional units in SEMA for reliability. He explained that the transmission event was caused by an initial equipment failure that compromised special protection systems. He stated the ISO followed up with the TOs and was confident that the steps they we~~a~~re taking would serve the region well in the future.

Dr. Chadalavada concluded his report by reviewing ~~a~~ prices experienced on March 2, 2017. He noted negative pricing experienced throughout the day, most notably in the morning and around noon. As the load ramped up sharply from mid-afternoon, there were binding reserve constraints on the system. He reported key drivers impacting prices were Real-Time generation supply above Day-Ahead cleared amounts, loads ~~were~~ under forecast during the day's early hours and over ~~the~~ forecast during peak hours, and binding reserve constraint raises pricing over peak hours. He reviewed LMPs at three key points during the day~~, including~~:

- Around 6:00 a.m. - ($28.26)/MWh; negative offers were marginal; over 1,000 MWh offered below $0/MWh;
- 12:00-1:00 p.m. - ($49.58)/MWh; mid-day loads at 13,000 MW (500 MW below forecast; negative offers were marginal; 700 MWh offered below $0/MWh; and
- 7:00 p.m. - $65.07/MWh; load pick-up over peak hours caused a binding Ten-Minute Spinning Reserve constraint from 6:05 p.m. until 9:35 p.m.

He noted ~~that~~ that, under low-load conditions, the market would be ~~senstive~~sensitive to small deviations in supply. He added that, with roughly 10,700 MW of non-dispatchable or must-run resources on the system, negative prices were very likely when system load was at or near that level.

ISO UPDATE ON OPERATIONAL LOAD FORECASTING

Dr. Chadalavada provided a report on the ISO's operational load forecast improvement effort, summarized in a presentation circulated in advance of the meeting and posted on the NEPOOL and ISO websites. He explained that the report focused exclusively on the operational side, noting how the impact of the rapid and increasing amount of photovoltaic generation (PV) (roughly 2,000 MW, of which 95% was behind-the-meter (BTM)) was being understated and was adding unacceptable unpredictability to the load forecast process. The ISO's load forecast did not yet reflect reliable inputs on PV, which was increasing performance error by as much as 3-5% on some days, and thereby impacting system dispatch and pricing.

He explained how the ISO's load forecasting models were incorporating some, but not all, of the PV impacts and the challenges encountered as a result. The ISO concluded that, to address those challenges, PV data would be separated completely from the load forecast models. He then reviewed a series of slides outlining the steps to improve BTM PV load forecast modeling.

In response to whether the ISO ran into a similar situation with E~~e~~nergy E~~e~~fficiency or wind forecasting, Dr. Chadalavada stated the wind forecast was~~is~~ still a relatively marginal amount and the ISO was ~~we are now~~ able to put the wind forecast into its ~~our~~ dispatch models, ~~but the wind only~~ affecting~~s us from a~~ dispatch, but with ~~standpoint and~~ less impact on load forecasts. He stated the Energy Efficiency wa~~i~~s typically 100% across the entire day. What distinguished ~~and the difference with~~ PV was ~~is the~~ its remarkable over-performance on a sunny day versus a cloudy day, and with hundreds of thousands of installations, the challenges associated with identifying ~~hundreds of thousands of installations that make it very challenging to know~~ how any particular town might perform relative to the rest of the New England profile.

~~–~~Concerning data publishing, Dr. Chadalavada stated that once the ISO untrained~~s~~ the load forecast model and had a~~s the~~ BTM PV model, the ISO would ~~will~~ initially aggregate and publish the forecasts together ~~and publish~~ and as ~~the~~ ISO automation became ~~gets into~~ more sophisticated~~ automation~~, maybe sometime in 2018, they would ~~will~~ publish the forecasts ~~aggregate~~ separately if members would find ~~found~~ that valuable, which several members expressed ~~that~~ they would.

Dr. Chadalavada reported as part of its ongoing pilot project with VELCO, the ISO compared the statistically sampled production data for Vermont~~T~~ to VELCO's data, which included~~s~~ more than 90% of Vermont's total BTM PV production~~ in the state~~. He stated the results demonstrated that the ISO's BTM PV production estimation method closely matche~~s~~d VELCO's data.

He concluded his update reporting on process, noting that, once~~as~~ the ISO's ~~makes improvements on infrastructure and improving~~ load forecast infrastructure and accuracy sufficiently improved, he ha~~s~~d asked System Operations to come to provide an update to the ~~a~~ Reliability Committee, ~~meeting to provide an update~~ likely to occur sometime in 2018. He stated the ISO wa~~i~~s ~~currently~~ collecting ~~the~~ Real-Time data so it could ~~can~~ get an hourly BTM PV output and make that ~~have it~~ available to operators. He was hopeful ~~and believes~~ that in 2018 the ISO would will be able to automate and decouple ~~the~~ load from ~~the~~ PV, so that they could be separately identified and netted~~and have them as two separate things that it would net~~. He explained ~~stated~~ how this topic ~~this also~~ tied~~s~~ into the Work Plan, as there we~~a~~re still several major projects in 2018 that would ~~are~~ take~~ing~~ some of the ISO's implementation resources away. Mr. van Welie identified the importance of addressing this issue before it impacted ~~reviewed that if we do not get a handle on this it might start effecting~~ commitments and ~~the~~ Day-Ahead/~~-~~Real-Time clearing.

ISO UPDATE ON 2017/18 WORK PLAN

Dr. Chadalavada provided an update on the 2017/18 Work Plan, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. He stated that the update reflected changes to the Work Plan since its release in September 2016. He then highlighted and provided updates regarding the following five primary efforts in the Work Plan:

IMAPP – Noting u~~U~~ncertainty as to pace and intensity of effort when first reflected in the Work P~~p~~lan, certain clarity had since emerged. Proposed Market Rule changes arising out of the ISO's near-term IMAPP proposal we~~a~~re planned for ~~to be~~ filing~~ed~~ with the FERC by the end of 2017/early 2018 in order to permit implementation for FCA13.

Fuel Security – The ISO wa~~i~~s studying fuel security beyond 2022 given the expected resource mix. Of most immediate concern were the implications potential oil unit retirements could have on gas pipelines, LNG deliveries into New England, and dual-fuel units. The ISO wa~~i~~s working to understand, for a variety of projected 2025 resource portfolio scenarios, whether there would be sufficient fuel available to system resources needed to meet winter loads. He explained that the planned study wa~~i~~s to look at winter operations in the 2025 time frame and not to focus on any specific solutions. Stakeholder discussion on the ISO's assessment would begin in the September/October timeframe, which would allow for ~~the~~ data and assumptions from the "2017-2026 Forecast Report of Capacity, Energy, Loads, and Transmission" to be incorporated.

Dr. Chadalavada explained that place~~-~~holders would be used in the 2017/18 Work Plan to account for the need to respond following stakeholder discussion of the fuel security study. Mr. van Welie suggested any impact on the 2018 budgets would likely be covered in contingency, rather than separately budgeted.

FERC Rulemaking Proceedings - Referring to a list of the numerous FERC NOPRs and final rules issued since the 4th quarter of 2016, Dr. Chadalavada explained the significant time and effort required by the ISO to review and to respond to the proposed rules, not all of which had been contemplated in the 2017/18 Work Plan. He confirmed that resource availability would change based on the timing and scope of final rules resulting from the NOPRs. He reminded the Committee that rulemaking proceedings and new market designs also impact "committed" work. He reported that the ISO was working to raise the FERC's awareness of those impacts by identifying approved changes yet to be implemented and the scope of work associated with implementation.

Cyber Security - ISO -preparations were underway for an audit in 2018 by the Northeast Power Coordinating Council, Inc. (NPCC) on the ISO's~~its~~ compliance with NERC's critical infrastructure protection (CIP) cybersecurity standards Preparations were requiring significant effort to ensure that the ISO was auditably compliant. A member, whose company had been impacted by the CIP standards and Interconnection Reliability Operating Limits (IROLs), explained that these would require significant expense. He asked the ISO to consider and include in its Work Plan discussion on compensation for these reliability obligations. Dr. Chadalavada indicated that such compensation was not yet contemplated and he encouraged Participants to re-raise the issue for consideration during 2018 budget/W~~w~~ork P~~p~~lan discussions in September/October.

Ramp Pricing – Dr. Chadalavada reported that the ISO would accelerate work on ramp pricing, with discussion planned to begin in the fourth quarter of 2017 rather than be sequenced after work on Day-Ahead co-optimization of energy and reserves, as previously suggested. The ISO planned to open ~~there~~ discussion by reviewing surveys it had completed and its design expectations. He noted that benefits of ramp pricing would include: (1) pricing efficiencies (as additional PV ~~photovoltaic~~ penetration increasingly accelerates ramps between midday and evening peaks), and (2) resource benefits (offering the ISO resource commitment flexibility).

CLEAN-UP CHANGES TO NEPOOL AND PARTICIPANTS AGREEMENTS

Mr. Patrick Gerity, NEPOOL Counsel, referred the Committee to the materials circulated and posted in advance of the meeting concerning approving for balloting two sets of amendments. He stated that the first set of amendments were proposed clean-up changes to both the Second Restated NEPOOL Agreement (2d RNA) and the Participants Agreement (PA), primarily to conform the PA to the 2d RNA's currently effective Provisional Member arrangements (Clean-Up Changes). In addition, the Clean-~~up~~ Up Changes included a change to the 2d RNA to make the application fee applicable to Data-Only Participants the same as their annual fee amount.

The following main motion was then duly made, seconded and approved unanimously, without discussion:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of agreements amending the Second Restated New England Power Pool Agreement and Participants Agreement, to reflect the Clean-Up Changes presented at this meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chairs of the Participants Committee and Membership Subcommittee, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.

SMALL STANDARD OFFER PROVIDER PROPOSAL

Mr. Gerity then reviewed that the second set of amendments to the 2d RNA that would allow any Entity that qualified as a "Small Standard Offer Service Provider" the option of participating in the Pool either as a member of the Supplier Sector, as some do now, or as a member in the Provisional Member Group Seat until its business grew to the point where it no longer qualified as "small" (Small Standard Offer Provider Proposal or Proposal). Rather than create a Supplier Sector group seat arrangement for Small Standard Offer Service Providers as had previously been proposed and discussed, the Proposal would allow such Providers to be members of the Provisional Member Group Seat for governance purposes and to pay an application and annual fee of $5,000 each, which would satisfy their financial responsibilities for

Participant Expenses. There had been no consensus on either the earlier proposal or the current Small Standard Offer Provider Proposal (although the latter Proposal appeared to have more support than the earlier proposal). The proponent, Maine Power LLC, had requested Participants Committee action on the Proposal.

Mr. Gerity stated that the motion to ballot the Small Standard Offer Provider Proposal must be approved by a two-thirds NEPOOL Vote. If approved, the ballots would be circulated for execution and approval in balloting, which would also require a two-thirds NEPOOL Vote and sufficient returns to satisfy the Minimum Response Requirement to be approved. Any changes to the PA or 2d RNA approved in balloting would be filed with the FERC, with a May 1, 2017 effective date requested.

The following motion was duly made and seconded:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of agreements amending the New England Power Pool Agreement, to effect the Small Standard Offer Provider Proposal, as presented at this meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chairs of the Participants Committee and Membership Subcommittee, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.

The Maine Power representative then summarized the history behind and reasons for supporting the Proposal, as explained in his memorandum to the Committee that had been circulated and posted in advance of the meeting. He explained that the Proposal was designed to facilitate participation in the Pool and the New England Markets by entities serving relatively small amounts of standard offer load by reducing NEPOOL expenses for such entities. He stated that the Proposal was offered as a compromise to earlier proposals, acknowledged continued concerns by some with respect to the Proposal, and asked for members' support for the Proposal, which he said would aid small entities to serve small quantities of standard offer load.

Members then asked clarifying questions and discussed the Proposal. In response to ~~a~~ comments and clarifying questions, Mr. Gerity confirmed that the Proposal would potentially increase the permanence of the membership of some in the Provisional Member Group Seat. He explained that the definition of Small Standard Offer Service Provider was broadly worded but its current application was very limited given the existing standard offer mechanisms in each of the New England states. He confirmed that the Proposal would not change the arrangements for membership in the Supplier Sector, but would expand qualification for membership in the Provisional Member Group Seat. Members clarified comparisons made between governance arrangements in other organized markets and those in New England.

Those opposing the Proposal identified the following concerns: the potential for competitive advantage to Small Standard Offer Service Providers (not available previously to and at the expense of other load serving entities (LSEs)); the explicit limited applicability of the proposed arrangements; the potential impact on Participant Expense allocation if the resulting participation in the proposed arrangements was not limited or would otherwise be expanded to include others; and whether the Proposal was necessary at all given that some current members of NEPOOL that would meet the definition of Small Standard Offer Service Provider, including the proponent, could and did participate in the Supplier Sector. Some suggested that the circumstances prompting arrangements for other Market and non-Market Participants were not sufficiently present in these circumstances.

Those supporting the Proposal viewed it as consistent with NEPOOL's history of implementing appropriate arrangements to facilitate, and make as inclusive as practical, participation in the New England Markets and stakeholder processes, including permitting ~~some~~

graduated fees and expenses in proportion to their voting share in five of the six Sectors. They contended that the Small Standard Offer Provider Proposal minimized the impact on all existing members by~~of~~ allowing new, small members to join NEPOOL. They viewed Provisional Member treatment as addressing in compromise objections raised over the impact of prior proposals on existing members.

Following final comments from the Maine Power representative on his Proposal, the Committee voted to ballot the Amendments with a 70% Vote in favor (Generation Sector – 2.86%; Transmission Sector – 17.12%; Supplier Sector – 3.21%; AR Sector – 12.57%; Publicly Owned Entity Sector – 17.12%; and End User Sector – 17.12%). (See Vote 1 on Attachment 2).

Mr. Doot reviewed that, following the meeting, NEPOOL Counsel, as balloting agent, would circulate two sets of ballots -- the first set of ballots for the Clean-up Changes, which passed unanimously, without discussion; the second, for the Small Standard Offer Provider Proposal. Both sets of ballots required the Minimum Response Requirement to be satisfied, with 70% in favor required for the Clean-Up Changes, and 66.67% in favor required for the Small Standard Offer Provider Proposal. He stated that both sets of changes would need to be filed with the FERC and expected that the Clean-Up Changes would be filed independently of the Small Standard Offer Provider Changes.

LITIGATION REPORT

Mr. Doot referred the Committee to the April 5 Litigation Report that had been circulated and posted in advance of the meeting. He reported that activity continued to be on the lighter~~d~~ side given the continued absence of a FERC quorum. He highlighted the May 1-2 FERC Technical Conference mentioned earlier in the meeting and expected additional details to be issued soon in a supplemental notice for that meeting.

In response to questions regarding the timing of the filing of previously-supported interconnection clustering revisions, Mr. Hepper stated that the ISO had decided to wait to file the revisions until there was a high probability of a FERC quorum. He indicated that the ISO fully expected that there would be protests submitted in response to any filing of the interconnection clustering revisions given the experience with those revisions in the NEPOOL process. He explained that deferring filing until the FERC could take an action would mitigate potential difficulties associated with undoing actions taken in response to an interim order addressing a contested filing during the absence of a FERC quorum (e.g. changing queue positions and deposit requirements).

GIS AGREEMENT WORKING GROUP STATUS REPORT

Mr. David Cavanaugh referred the Committee to the memorandum from NEPOOL Counsel circulated and posted in advance of the meeting regarding Generation Information System (GIS) Agreement Working Group discussions concerning future GIS arrangements. He began by reviewing the history and status of GIS Working Group efforts. He reported that the Working Group had considered issuing a request for proposals for the development and administration of the GIS, as well as extending and restating the agreement with the current GIS administrator, APX, Inc. (APX). During this exploration and evaluation process, he reported that the existing agreement with APX automatically renewed for a twelve-month term, then set to expire on December 31, 2017. Based on those deliberations, and a preliminary agreement in principle with APX, the Working Group proposed to amend and restate the existing GIS Development and Administration Agreement for a three-year term (from January 1, 2018 through December 31, 2020). He stated the agreement in principle reduced~~s~~ aggregate GIS costs for GIS services, provided for greater services, and improved flexibility of the GIS application.

Thanking Mr. Cavanaugh for the report, Mr. Kaslow indicated that, absent alternative direction from the Participants Committee, the Working Group would, between then and the NEPOOL Summer Meeting, negotiate a final agreement consistent with the preliminary agreements in principle, and cease exploration of alternative GIS providers for now.

Responding to a request for more detail on the way GIS costs would be allocated under the new agreement, Mr. Cavanaugh summarized that there would be lower costs to NEPOOL ~~Load Serving Entities (~~LSEs~~)~~. New fees would be assessed to non-Participant generators that are subscription holders and to traders that are not being charged fees under the existing agreement. In response to further questions and requests, Mr. Doot stated that a separate meeting among NEPOOL Participants would be scheduled to answer further questions, and additional materials in connection with that meeting would be provided to members on request. He encouraged all interested to participate in that meeting, notice of which would be provided to all Participants Committee members.

COMMITTEE REPORTS

Markets Committee. Mr. William Fowler reported that the next Markets Committee meeting was scheduled for April 12 as a one-day meeting. He also reported that, on April 20, there would be a special joint WebEx meeting of the NEPOOL Markets Committee and NYISO Market Issues Working Group to receive a report from Potomac Economics on the performance of Coordinated Transaction Scheduling (CTS) following the first year of CTS implementation.

Transmission Committee. Mr. ~~José~~ Rotger reported that the Transmission Committee was scheduled to meet on April 25 via teleconference, with the agenda including ISO-proposed revisions to the Tariff definition of *Force Majeure*.

Reliability Committee. Mr. Robert Stein reported that the Reliability Committee was scheduled to meet on April 18 in Westborough, MA.

Budget & Finance Subcommittee. Mr. Ken Dell Orto reported that the Budget & Finance Subcommittee meeting scheduled for April 17, 2017 had been cancelled. The next Subcommittee meeting was scheduled for May 12, 2017.

OTHER BUSINESS

Mr. Fowler reminded the Committee that the next IMAPP meeting was scheduled for May 17 at the Doubletree Hotel in Westborough and encouraged people that had already presented proposals to update them and present any new ideas. Ms. Heather Hunt stated that the states had been developing feedback on long-term solutions discussed in the IMAPP process and would be issuing a document summarizing that feedback very soon.

Mr. Doot reported that, in the absence of a FERC quorum, and due to lack of NEPOOL Technical Committee agenda items for consideration by the Participants Committee, the May 5 and June 2 Participants Committee meetings would likely be held by teleconference or cancelled. He urged Participants to pay close attention to notices for those meetings. He reported that the NEPOOL Summer Meeting was scheduled for June 27-29 at the Chatham Bars Inn in Chatham, MA, and encourage all to participate. Registration and reservation blocks for that meeting would open within a week. He noted that the schedule for that meeting called for general business of the Participants Committee to be conducted on Tuesday, June 27, with a later start time of 10:30 a.m. to accommodate anyone wanting to travel to the meeting that morning. Sector meetings with the ISO Board and state representatives would be held on Thursday, June 29.

There being no further business, the meeting adjourned at 12:40 p.m.

Respectfully submitted,

David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 7, 2017 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
American PowerNet Management	Supplier			Mary Smith
Anbaric Management LLC	Provisional Group	Steve Conant		
Ashburnham Municipal Light Plant	Publicly Owned		Brian Thomson (tel)	
AVANGRID (CMP/UI)	Transmission	Eric Stinneford (tel)		
Belmont Municipal Light Department	Publicly Owned		Tim Hebert	
Boylston Municipal Light Department	Publicly Owned		Brian Thomson (tel)	
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier		Brett Kruse	Bill Fowler
Chester Municipal Electric Light Department	Publicly Owned		Tim Hebert	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson (tel)	
Citigroup Energy Inc.	Supplier	Barry Trayers (tel)		
CLEAResult Consulting, Inc.	AR	Doug Hurley		
Competitive Energy Services, LLC	Supplier			Glenn Poole (tel)
Concord Municipal Light Plant	Publicly Owned		Tim Hebert	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User			Dave Thompson
Conservation Law Foundation	End User	Jerry Elmer		
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
CPV Towantic, LLC	Generation	Dan Pierpont		
Cross-Sound Cable	Supplier		Jose Rotger	
Danvers Electric Division	Publicly Owned		Tim Hebert	
DC Energy	Supplier	Bruce Bleiweis (tel)		
Direct Energy Business, LLC	Supplier	Ron Carrier		Nancy Chafetz
Dominion Energy Marketing, Inc.	Generation	Jim Davis		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier	`		Bill Fowler
Elektrisola, Inc.	End User			Stacy Dimou
Emera Maine/Emera Energy Services	Transmission		Sandi Hennequin	Jeff Fenn (tel)
Entergy Nuclear Power Marketing, LLC	Generation	Ken Dell Orto		Bill Fowler
EnerNOC, Inc.	AR	Sarah Griffiths		Doug Hurley
Essential Power, LLC	Generation		Bill Fowler	
Eversource Energy	Transmission	James Daly	Cal Bowie	Vandan Divatia
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
Fairchild Semiconductor Corporation	End User			Stacy Dimou
Farhad Aminpour	End User		Roland Scott	
FirstLight Power Resources Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	Bob Stein
Georgetown Municipal Light Department	Publicly Owned		Tim Hebert	
Groton Electric Light Department	Publicly Owned		Brian Thomson (tel)	
Groveland Electric Light Department	Publicly Owned		Tim Hebert	
H.Q. Energy Services (U.S.) Inc.	Supplier		Bob Stein	Abby Krich
Harvard Dedicated Energy Limited	End User	Mary Smith		Paul Peterson Doug Hurley
High Liner Foods (USA) Incorporated	End User		William P. Short III (tel)	Stacy Dimou
Hingham Municipal Lighting Plant	Publicly Owned		Tim Hebert	
Holden Municipal Light Department	Publicly Owned		Brian Thomson (tel)	
Hull Municipal Lighting Plant	Publicly Owned		Brian Thomson (tel)	
Industrial Energy Consumer Group	End User	Don Sipe		
Ipswich Municipal Light Department	Publicly Owned		Brian Thomson (tel)	
Long Island Lighting Company (LIPA)	Supplier		Bill Killgoar	
Littleton (MA) Electric Light & Water Department	Publicly Owned		Tim Hebert	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
APRIL 7, 2017 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Littleton (NH) Water & Light Department	Publicly Owned	Craig Kieny (tel)		
Maine Power, LLC	Supplier	Jeff Jones		
Maine Public Advocate Office	End User			Paul Peterson
Maine Skiing, Inc.	End User	Don Sipe		
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson (tel)	
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson (tel)	
Marble River, LLC	Supplier		John Brodbeck (tel)	
Massachusetts Attorney General's Office (MA AG)	End User	Fred Plett		
Mass. Development Finance Agency	Publicly Owned		Tim Hebert	
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned	Brian Thomson (tel)		
Mercuria Energy America, Inc.	Supplier			Nancy Chafetz
Merrimac Municipal Light Department	Publicly Owned		Tim Hebert	
Middleborough Gas and Electric Department	Publicly Owned		Brian Thomson (tel)	
Middleton Municipal Electric Department	Publicly Owned		Tim Hebert	
National Grid	Transmission		Tim Martin	
New Hampshire Electric Cooperative (NHEC)	Publicly Owned	Steve Kaminski (tel)		Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
NRG Power Marketing LLC	Generation	Dave Cavanaugh		
Pascoag Utility District	Publicly Owned		Tim Hebert	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson (tel)	
Peabody Municipal Light Plant	Publicly Owned		Brian Thomson (tel)	
Princeton Municipal Light Department	Publicly Owned		Brian Thomson (tel)	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned			Brian Forshaw
Rowley Municipal Lighting Plant	Publicly Owned		Tim Hebert	
Russell Municipal Light Department	Publicly Owned		Brian Thomson (tel)	
Saint Anselm College	End User			Stacy Dimou
Shipyard Brewing LLC	End User		Stacy Dimou	
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson (tel)	
Small Load Response Group Member	AR	Doug Hurley	Brad Swalwell (tel)	
Small Renewable Generation Group	AR	Erik Abend		
South Hadley Electric Light Department	Publicly Owned		Brian Thomson (tel)	
Sterling Municipal Electric Light Department	Publicly Owned		Brian Thomson (tel)	
Stowe Electric Department	Publicly Owned		Tim Hebert	
SunEdison Companies (First Wind Energy Marketing)	AR			Bob Stein, Abby Krich
Taunton Municipal Light Department	Publicly Owned		Tim Hebert	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson (tel)	
The Energy Consortium	End User		Mary Smith	
Union of Concerned Scientists	End User		Francis Pullaro	
Utility Services Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny (tel)		
Vermont Electric Power Company	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR		Doug Hurley	
Verso Maine Energy LLC	Generation	Glenn Poole (tel)		
Vitol Inc.	Supplier	Joseph Wadsworth (tel)		
Wakefield Municipal Gas and Light Department	Publicly Owned		Brian Thomson (tel)	
Wallingford DPU Electric Division	Publicly Owned		Tim Hebert	
Wellesley Municipal Light Plant	Publicly Owned		Tim Hebert	
West Boylston Municipal Lighting Plant	Publicly Owned		Brian Thomson (tel)	
Westfield Gas & Electric Light Department	Publicly Owned		Tim Hebert	
Wheelabrator North Andover Inc.	AR	Bill Fowler		
Z-TECH, LLC	End User			Stacy Dimou

ATTACHMENT 2

ROLL CALL VOTE TAKEN AT
APRIL 7, 2017 NEPOOL PARTCIPANTS COMMITTEE MEETING

TOTAL

Sector/Group	Vote 1
GENERATION	2.86
TRANSMISSION	17.12
SUPPLIER	3.21
ALTERNATIVE RESOURCES	12.57
PUBLICLY OWNED ENTITY	17.12
END USER	17.12
% IN FAVOR	**70.00**

GENERATION SECTOR

Participant Name	Vote 1
CPV Towantic, LLC	O
Dominion Energy Marketing	O
Entergy Nuclear Power Marketing	A
Essential Power, LLC	A
FirstLight Power Resources	A
Generation Group Member	O
NextEra Energy Resources, LLC	O
NRG Power Marketing, LLC	O
Verso Maine Energy LLC	F
IN FAVOR (F)	1
OPPOSED (O)	5
TOTAL VOTES	6
ABSTENTIONS (A)	3

TRANSMISSION SECTOR

Participant Name	Vote 1
AVANGRID (CMP/UI)	F
Emera Maine	S[1]
Emera Maine	F
Emera Energy Services Subsidiaries	F
Eversource Energy	F
National Grid	F
Vermont Electric Power Co.	F
IN FAVOR (F)	5
OPPOSED	0
TOTAL VOTES	5
ABSTENTIONS (A)	0

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1
Renewable Generation Sub-Sector	
SunEdison (FirstWind)	A
Wheelabrator North Andover Inc.	O
Small RG Group Member	F
Distributed Generation Sub-Sector	
CLEAResult Consulting, Inc.	F
Load Response Sub-Sector	
EnerNOC, Inc.	A
VT Energy Investment Corp.	F
Small LR Group Member	F
IN FAVOR (F)	4
OPPOSED	1
TOTAL VOTES	5
ABSTENTIONS (A)	2

SUPPLIER SECTOR

Participant Name	Vote 1
American PowerNet Management	A
BP Energy Company	O
Brookfield Energy Marketing Inc.	A
Calpine Energy Services	O
Citigroup Energy Inc.	O
Competitive Energy Services, LLC	F
Consolidated Edison Energy, Inc.	O
Cross-Sound Cable Company	F
DC Energy, LLC	O
Direct Energy Business, LLC	O
DTE Energy Trading, Inc.	O
Dynegy Marketing and Trade, LLC	A
Exelon Generation Company	O
Galt Power, Inc.	O
H.Q. Energy Services (U.S.) Inc.	O
Long Island Power Authority (LIPA)	A
Maine Power, LLC	F
Marble River, LLC	A
Mercuria Energy America, Inc.	O
PSEG Energy Resources & Trade	O
Vitol Inc.	O
IN FAVOR (F)	3
OPPOSED	13
TOTAL VOTES	16
ABSTENTIONS (A)	5

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[1] Pursuant to Section 6.2 of the NEPOOL Agreement, Participants and their Related Persons are for voting purposes together permitted to join only one Sector to which any of them is eligible to join, but are permitted to split the vote in that Sector as they see fit. Emera Maine and the Emera Energy Services Subsidiaries, as Related Persons, are collectively members of the Transmission Sector, but sometimes split their vote evenly between the companies' transmission (Emera Maine) and generation (Emera Energy) interests.

ROLL CALL VOTE TAKEN AT
APRIL 7, 2017 NEPOOL PARTCIPANTS COMMITTEE MEETING

END USER SECTOR

Participant Name	Vote 1
Conn. Office of Consumer Counsel	F
Conservation Law Foundation	F
Elektrisola, Inc.	F
Fairchild Semiconductor Corporation	F
Farhad Aminpour	A
Harvard Dedicated Energy Limited	F
High Liner Foods (USA) Inc.	F
Industrial Energy Consumer Group	F
Maine Public Advocate Office	F
Maine Skiing, Inc.	F
Mass. Attorney General's Office	F
NH Office of Consumer Advocate	F
St. Anselm College	F
Shipyard Brewing Co., LLC	F
The Energy Consortium	F
Union of Concerned Scientists	F
Utility Services Inc.	F
Z-TECH, LLC	F
IN FAVOR (F)	17
OPPOSED	0
TOTAL VOTES	17
ABSTENTIONS (A)	1

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1
Ashburnham Municipal Light Plant	F
Belmont Municipal Light Dep't	F
Boylston Municipal Light Dep't	F
Chester Municipal Light Dep't	F
Chicopee Municipal Lighting Plant	F
Concord Municipal Light Plant	F
Conn. Mun. Electric Energy Coop.	F
Danvers Electric Division	F
Georgetown Municipal Light Dep't	F
Groton Electric Light Department	F
Groveland Electric Light Dep't	F
Hingham Municipal Lighting Plant	F
Holden Municipal Light Dep't	F
Hull Municipal Lighting Plant	F
Ipswich Municipal Light Dep't	F
Littleton (MA) Electric Light Dep't	F
Littleton (NH) Water & Light Dep't	F

PUBLICLY OWNED ENTITY SECTOR cont'd

Participant Name	Vote 1
Mansfield Municipal Electric Dep't	F
Marblehead Municipal Light Dep't	F
Mass. Development Finance Agc'y	F
Mass. Mun. Wholesale. Elec. Co.	F
Merrimac Municipal Light Dep't	F
Middleborough Gas & Elec. Dep't	F
Middleton Municipal Electric Dep't	F
New Hampshire Electric Coop.	F
Pascoag Utility District	F
Paxton Municipal Light Dep't	F
Peabody Municipal Light Plant	F
Princeton Municipal Light Dep't	F
Reading Municipal Light Department	F
Rowley Municipal Lighting Plant	F
Russell Municipal Light Dep't	F
Shrewsbury's Elec. & Cable Ops.	F
South Hadley Electric Light Dep't	F
Sterling Mun. Elec. Light Dep't	F
Stowe (VT) Electric Department	F
Taunton Municipal Lighting Plant	F
Templeton Mun. Lighting Plant	F
Vermont Electric Cooperative	F
Wakefield Mun. Gas & Light Dep't	F
Wallingford (CT) Div. Pub. Utils.	F
Wellesley Municipal Light Plant	F
West Boylston Mun. Lighting Plant	F
Westfield Gas & Elec. Light Dep't	F
IN FAVOR (F)	44
OPPOSED	0
TOTAL VOTES	44
ABSTENTIONS (A)	0

CONSENT AGENDA

From the notice of actions of the April 12, 2017 ***Markets Committee***[1] meeting, dated April 12, 2017, which has been previously circulated:

1. Revisions to MR1 and Tariff (*Order 831* Compliance)

Support revisions to Market Rule 1 and Tariff Section I.2.2 that address the compliance requirements contained in FERC Order No. 831 (Offer Caps in RTO/ISO markets, Docket No. RM16-5), as recommended by the Markets Committee at its April 12, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously, with one abstention noted (in the Supplier Sector).

2. Revisions to MR1and Manual M-RPA (Enabling Sub-Hourly Revenue Quality Metering Submittals)

Support revisions to Market Rule 1 and Manual M-RPA (Registration and Performance Auditing) to allow the ISO to enable software functionality to accept five-minute data from meter readers for use in sub-hourly Real-Time settlement, as recommended by the Markets Committee at its April 12, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

From the notice of actions of the April 18, 2017 ***Reliability Committee***[2] meeting, dated April 20, 2017, which has been previously circulated:

3. Revisions to OP-2 (Instituting Time Requirement for Computer/Communication Equipment Outages; Editorial Changes)

Support revisions to Operating Procedure (OP) No. 2 (Maintenance of Communications, Computers, Metering and Computer Support Equipment), including changes to institute a time requirement for reporting outages on computer and communications equipment in accordance with NERC Reliability Standard TOP-001-3 and other minor editorial changes, as recommended by the Reliability Committee at its April 18, 2017 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

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[1] Markets Committee Notices of Actions are posted on the ISO-NE website at: https://iso-ne.com/committees/markets/markets-committee.

[2] Reliability Committee Notices of Actions are posted on the ISO-NE website at: http://iso-ne.com/committees/reliability/reliability-committee.

Summary of ISO New England Board and Committee Meetings

May 5, 2017 Participants Committee Meeting

Since the last update, the Markets Committee, the System Planning and Reliability Committee, and the Board of Directors met on April 20 and 21 in Boston.

The Markets Committee reviewed reports on market monitoring, mitigation and reliability costs and discussed key issues in the seasonal market reports. Next, the Committee reviewed the Company's discussion paper entitled "Competitive Auctions with Subsidized Policy Resources" which discusses the conceptual approach for integrating states' policies and the wholesale markets in the near term. The Committee also reviewed the Internal Market Monitor's draft annual markets report for the 2016 calendar year and discussed the methods used to evaluate the competitiveness of the markets, and the analysis of structural competitiveness and market outcomes.

The System Planning and Reliability Committee was provided with a summary of activities that were a major focus during the first quarter of 2017. Those activities included: summer preparedness, implementation of Order 1000, updated transmission planning criteria and assumptions, the 2016 economic planning study, and enhancements to the generator interconnection process. The Committee also previewed issues likely to be a focus during the second quarter. Next, the Committee discussed forecasts for long-term peak and energy requirements, energy efficiency, and the impact of solar photovoltaics. The Committee also discussed highlights of the Forward Capacity Auction #11 and outlook for FCA #12. Finally, the Committee reviewed the Regional System Plan project list, and key messages for the 2017 Regional System Plan and upcoming Annual Meeting in September.

The Board of Directors received a report from the CEO including a quarterly update on corporate goal achievement. The Board also received committee reports, approved the 2016 audited financial statements, and approved a proposed amendment to the Participants Agreement related to an administrative matter relevant to NEPOOL operations in order to conform the Participants Agreement with the Restated NEPOOL Agreement’s Provisional Member arrangements. Next, the Board reviewed the Company’s five-year business plan and discussed a variety of issues affecting the business plan, including fuel security and the Company’s discussion paper entitled “Competitive Auctions with Subsidized Policy Resources” which discusses the conceptual approach for integrating states’ policies and the wholesale markets in the near term. Next, the Board prepared for its meeting with NECPUC, which occurred the next day. Finally, the Board was joined by the Acting Chairman of FERC, Cheryl LaFleur, to talk about the strategic, policy and regulatory implications of the issues discussed.

NEPOOL PARTICIPANTS COMMITTEE
05/05/17 MEETING, AGENDA ITEM #4

NEPOOL Participants Committee Report

May 2017

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value was $246M, down $160M from March 2017 and down $27M from April 2016
    - April natural gas prices over the period were 28% lower than March 2017 average values
    - Average RT Hub Locational Marginal Prices ($31.42/MWh) over the period were 9.7% lower than March 2017 averages
    - Average April 2017 natural gas prices and RT Hub LMPs over the period were up 10% and 12%, respectively, from April 2016 averages
  - Average DA cleared physical energy at the peak hour as percent of forecasted load was 97.2% during April, up from 96.5% during March

Data are through April 26 (RT NCPC through April 25), 2017 unless otherwise noted.

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

Underlying natural gas data furnished by:

ICE Global markets in clear view

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - April NCPC payments totaled $2.4M over the period, down $3.1M from March 2017 and down $1.5M from April 2016
    - First Contingency* payments totaled $2.1M, down $1.7M from March
      - $1.9M paid to internal resources, down $1.6M from March
        - $874K charged to DALO, $467K to RT Deviations, $580K to RTLO
      - $179K paid to resources at external locations, down $107K from March
        - $22K charged to DALO at external locations, $157K to RT Deviations
    - Voltage payments totaled $306K, down $681K from March
    - Second Contingency payments were $0, down $760K from March
  - NCPC payments as percent of Energy Market value over the period were 1%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $191K; Rapid Response Pricing (RRP) Opportunity Cost - $167K; Posturing - $221K

Winter Reliability Program Costs & Billing

- Final Program Costs were $30.7M*:
  - Oil: $30.3M
  - LNG: $277K
  - DR: $126K
    - $70K fixed cost; $56K energy costs from Jan. 10 dispatch event
- Billing/Payment Schedule:
  - Initial Billings were based on 75% of initial inventory
  - Trued-up charges for unused fuel were issued on April 18, 2017
  - Payment to generators for unused fuel inventory will be in May 15, 2017 bill

* Final program costs reflect performance adjustments of $674K (Oil Program) and $13K (LNG Program)

Highlights, cont.

- 2016 Economic Study - NEPOOL Scenario Analysis
  - Phase I observations and key messages are complete, and the report is expected to be issued in the second quarter
  - Phase II is underway, reviewing certain market and operations impacts
- Load, Energy Efficiency, and Photovoltaic Forecasts have been updated and included in the 2017 CELT Report

Forward Capacity Market (FCM) Highlights

- CCP #8 (2017-2018)
  - Approximately 700 MW of new resources will not be commercial for June 1
    - ISO Operations has developed procedures to mitigate potential reliability impacts due to new resources not being in service
- CCP #9 (2018-2019)
  - Second bilateral window will be May 1-5
  - Second reconfiguration auction will be August 1-3

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #10 (2019-2020)
  - First bilateral transaction window will be April 3-7
  - First reconfiguration auction will be June 5-7
- CCP #11 (2020-2021)
  - First bilateral transaction window will be April 4-6, 2018
  - First reconfiguration auction will be June 1-5, 2018
- CCP #12 (2021-2022)
  - Show of Interest window closed April 28 and participation by new resources is similar to FCA #11
  - Existing resource static delist bids are due June 5
  - New Resource Qualification Packages are due June 19
  - The Renewable Technology Resource election cap is approximately 514 MW

FERC Order 1000

- Interregional Planning
  - Interregional Planning Stakeholder Advisory Committee (IPSAC) webinar is scheduled for May 19
- Intraregional Planning
  - Several parties submitted information to be considered as Qualified Transmission Project Sponsors, and 16 companies have been approved
- Public Policy
  - Public Policy process was initiated on January 11
  - Stakeholders made presentations regarding Public Policy Requirements at the February 23 PAC meeting
  - Submitted Stakeholder input was made available to NESCOE on March 1
  - NESCOE provided communication to the ISO regarding Public Policy on May 1

Highlights, cont.

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 6, 2017

- The lowest 50/50 and 90/10 Summer Operable Capacity Margins are projected for week beginning June 3, 2017

- New England is forecasting a net peak demand of 26,482 MW for week beginning July 15, 2017

- Forecasted summer outages/reductions:
  - Seasonal Claimed Capability (SCC) margins reflect generator retirements at Brayton Point
  - Capacity Supply Obligation (CSO) values reflect delays in commissioning of ~700 MW

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (2.1°F) Max: 86°F, Min: 33°F Precipitation: 5.84” – Above Normal Normal: 3.60”	Hartford	Temperature: Above Normal (3.0°F) Max: 88°F, Min: 30°F Precipitation: 3.85” - Normal Normal: 3.86” Snow: 0.08”

Peak Load:	15,649MW	Apr 06, 2017	HE18

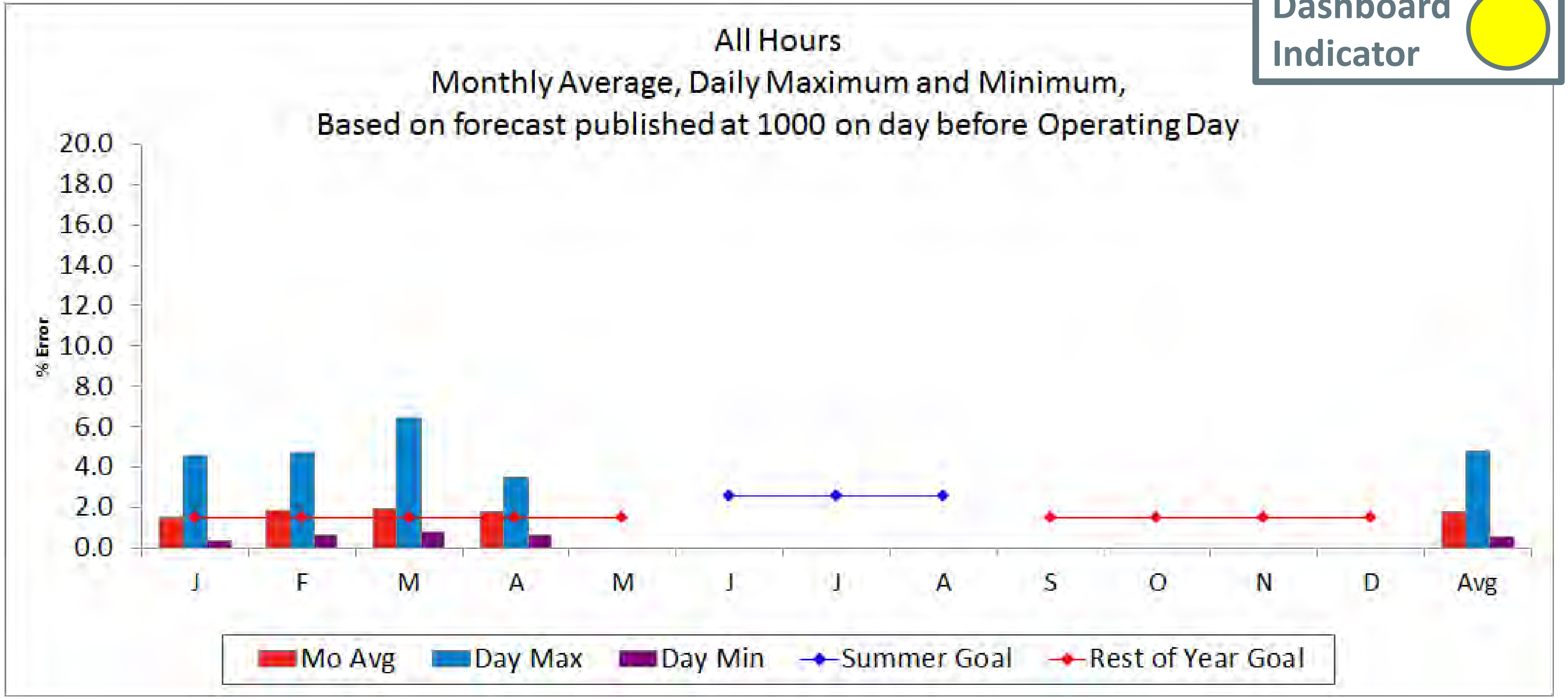
MLCC2: None		
OP-4 : None		
NPCC Simultaneous Activation of Reserve Events:		
4/4	ISONE	1250MW
4/14	NBSO	400MW
4/30	NBSO	400MW

Minimum Generation Warnings & Events:

Minimum Generation Warning		None
Minimum Generation Events		None

2017 System Operations - Load Forecast Accuracy

Dashboard Indicator ●

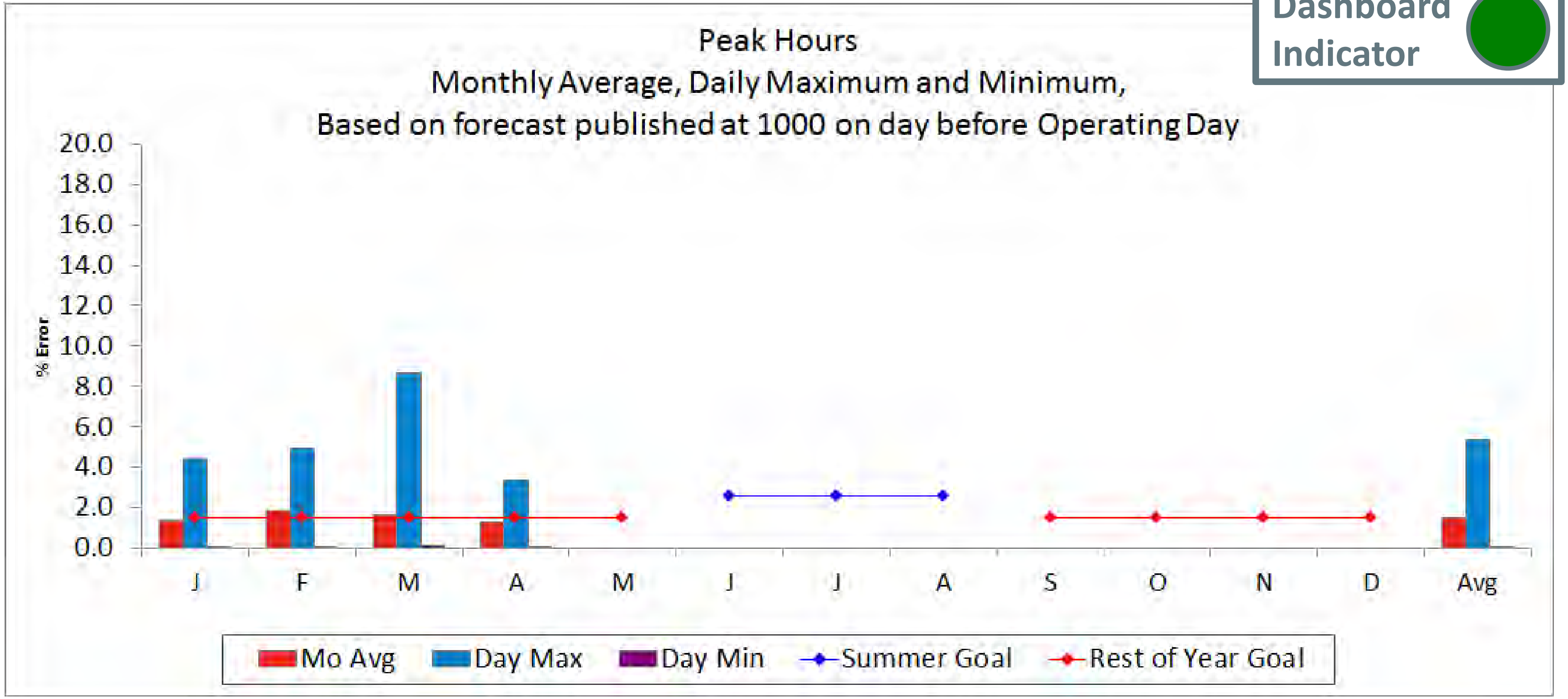


Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.51	1.84	1.95	1.81									1.78
Day Max	4.58	4.72	6.43	3.53									4.83
Day Min	0.33	0.62	0.77	0.65									0.59
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.51	1.84	1.95	1.81									1.78
Summer Actual													

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

2017 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator ●

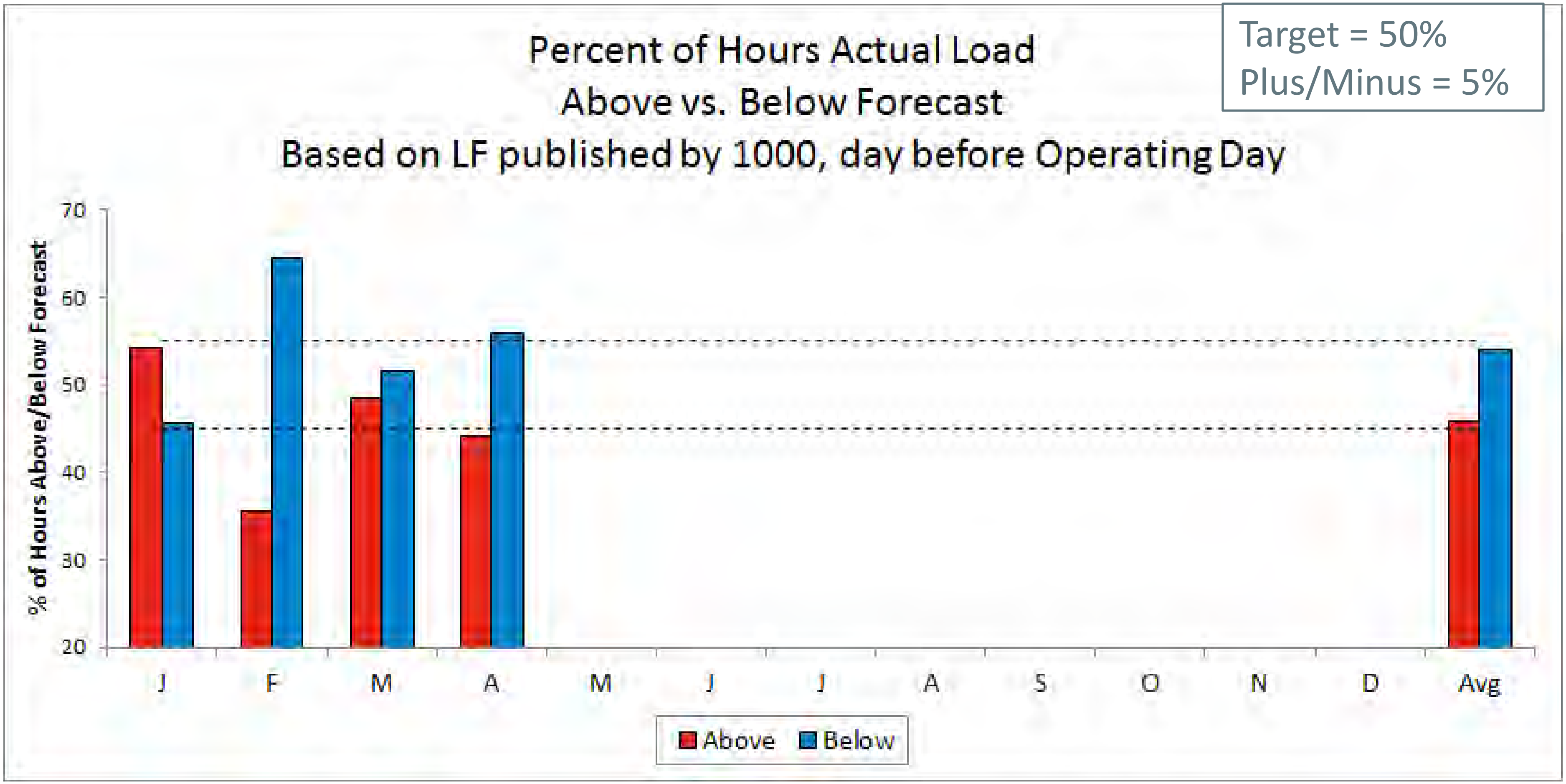


Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.38	1.83	1.63	1.26									1.52
Day Max	4.41	4.91	8.70	3.39									5.38
Day Min	0.01	0.05	0.14	0.01									0.05
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.38	1.83	1.63	1.26									1.52
Summer Actual													

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

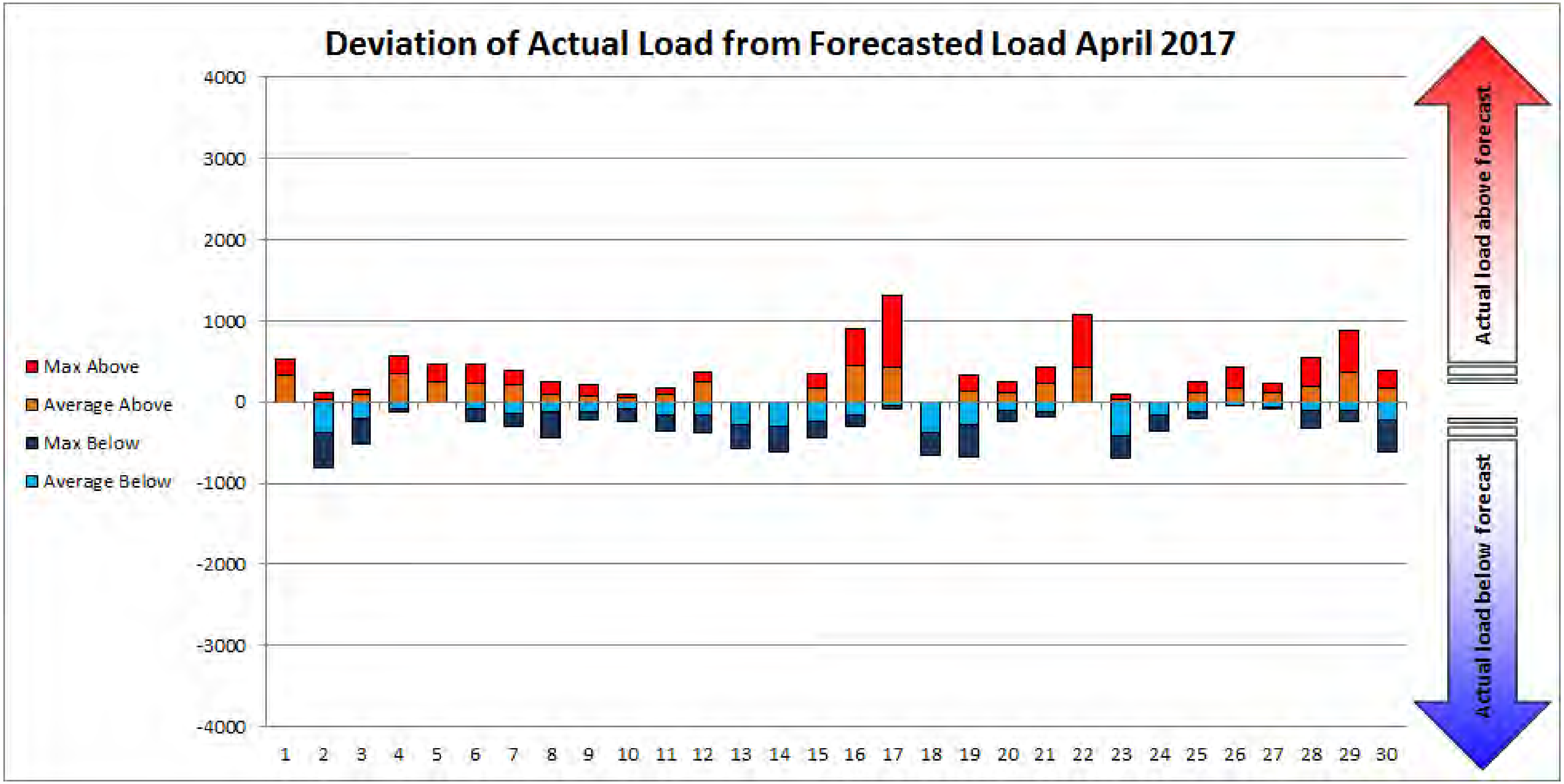
2017 System Operations - Load Forecast Accuracy cont.

Target = 50%
Plus/Minus = 5%

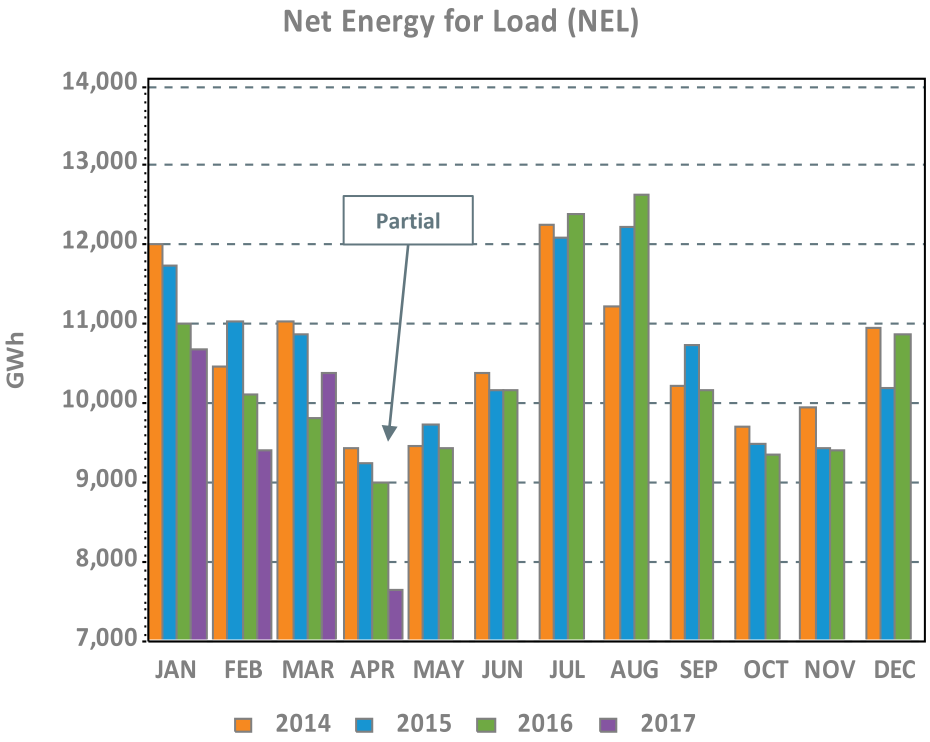


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	54.3	35.6	48.5	44.2									46
Below %	45.7	64.4	51.5	55.8									54
Avg Above	175.5	137.4	192.2	171.9									170
Avg Below	-174.1	-209.5	-206.6	-156.8									-186
Avg All	20	-76	-32	-4									-22

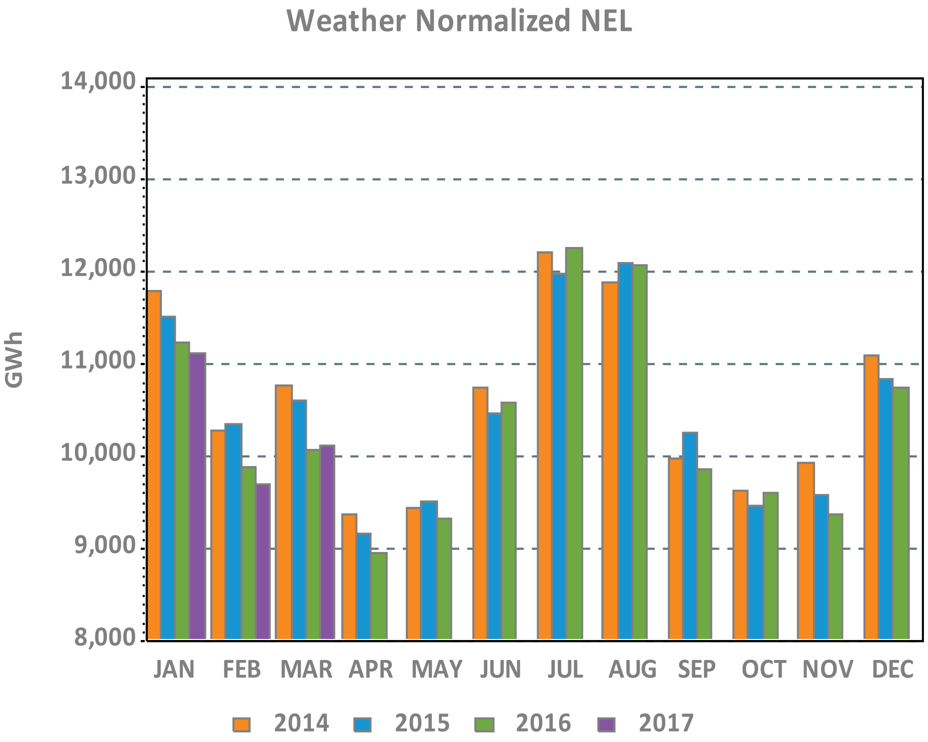
2017 System Operations - Load Forecast Accuracy cont.



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



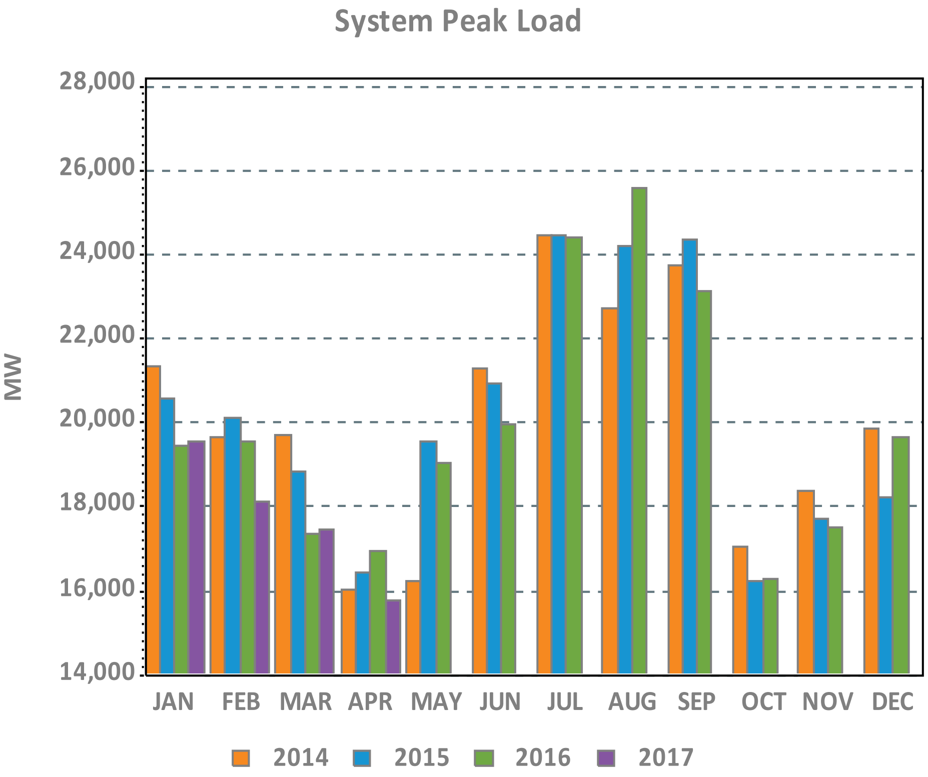
Ann Tot (TWh): 127.2 127.0 124.4 38.1



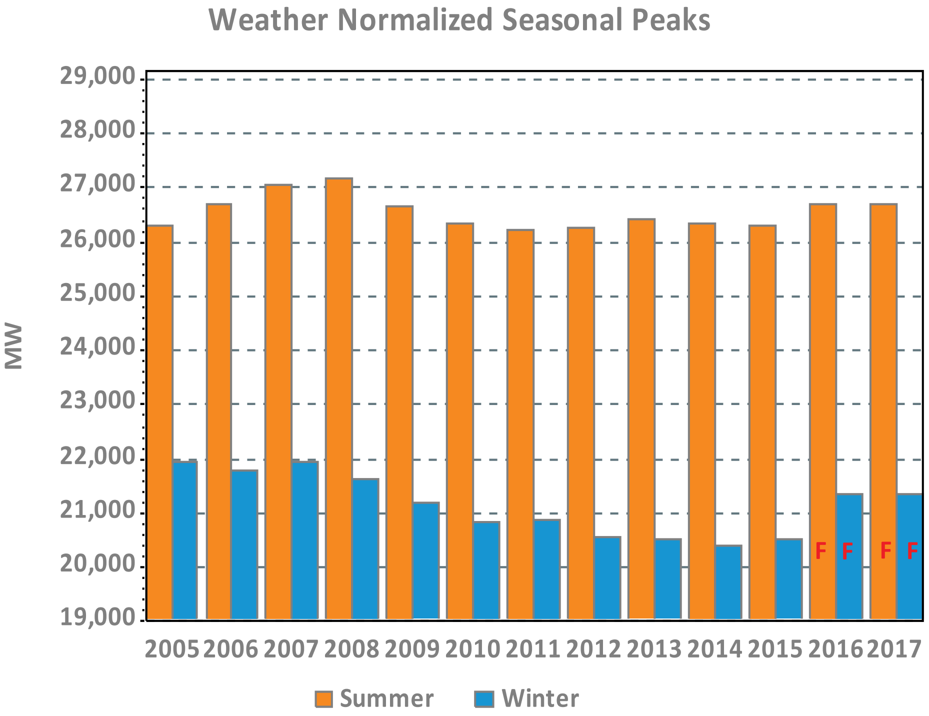
Ann Tot (TWh): 127.1 125.8 124.0 30.9

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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



*Revenue quality metered value

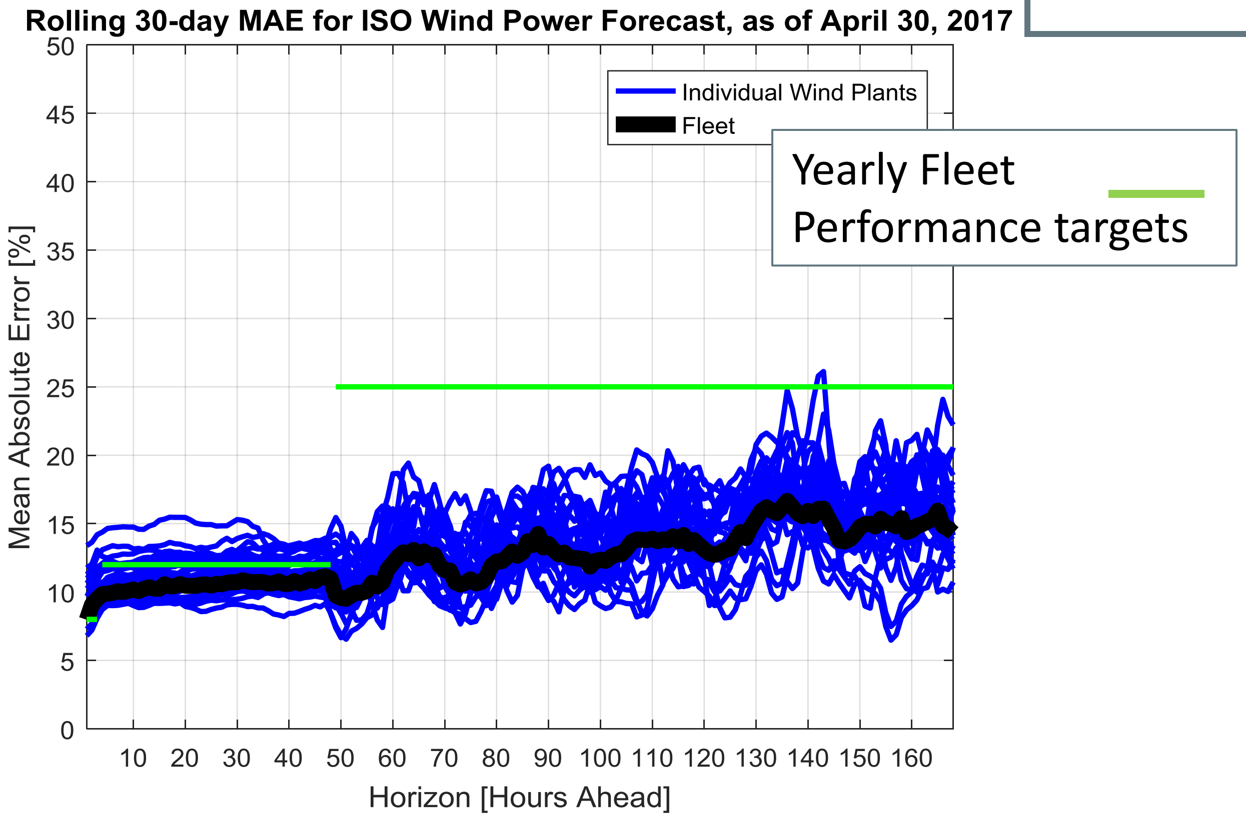


Winter beginning in year displayed

F – designates forecasted values, which are updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts MAE

Dashboard Indicator 🟢

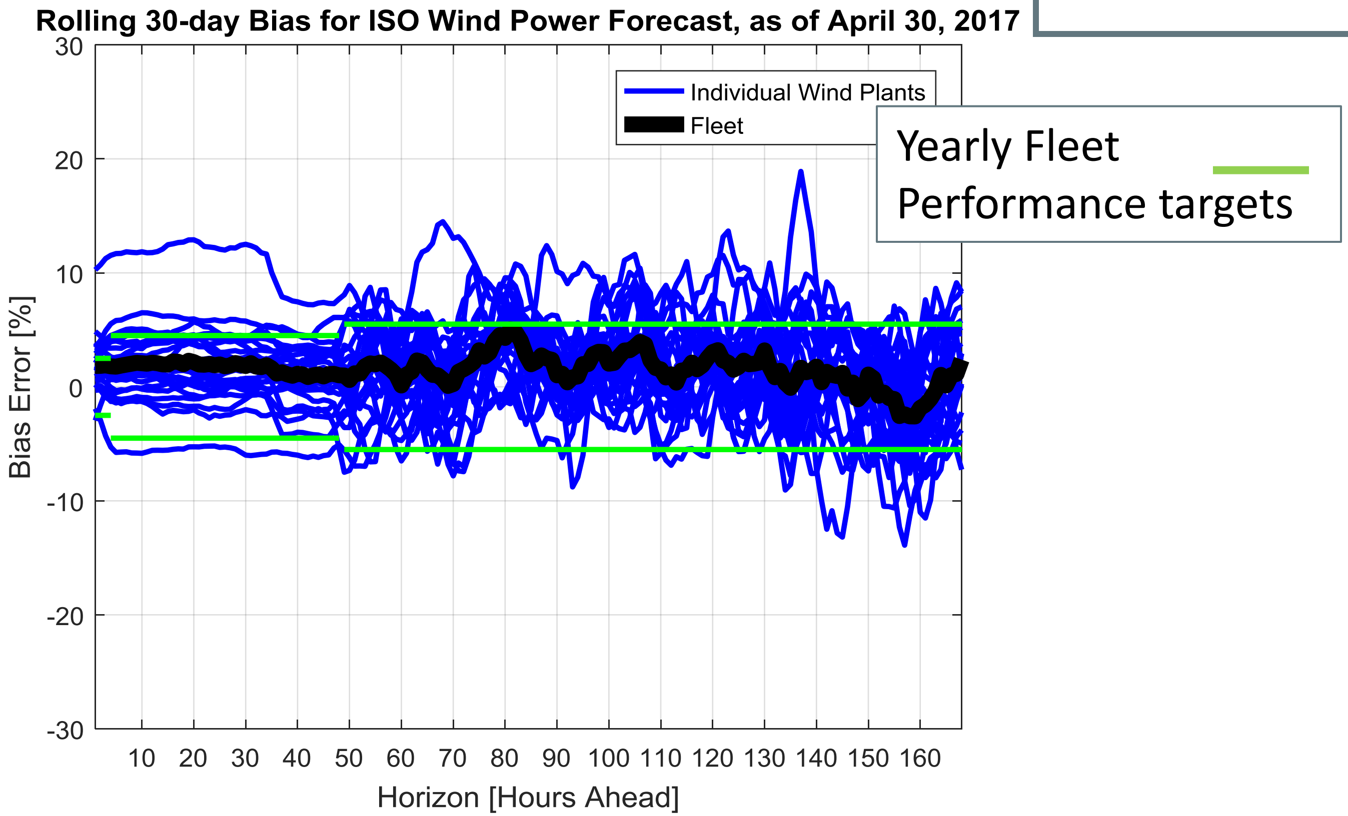


Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Medium and Long Term Forecasts Bias

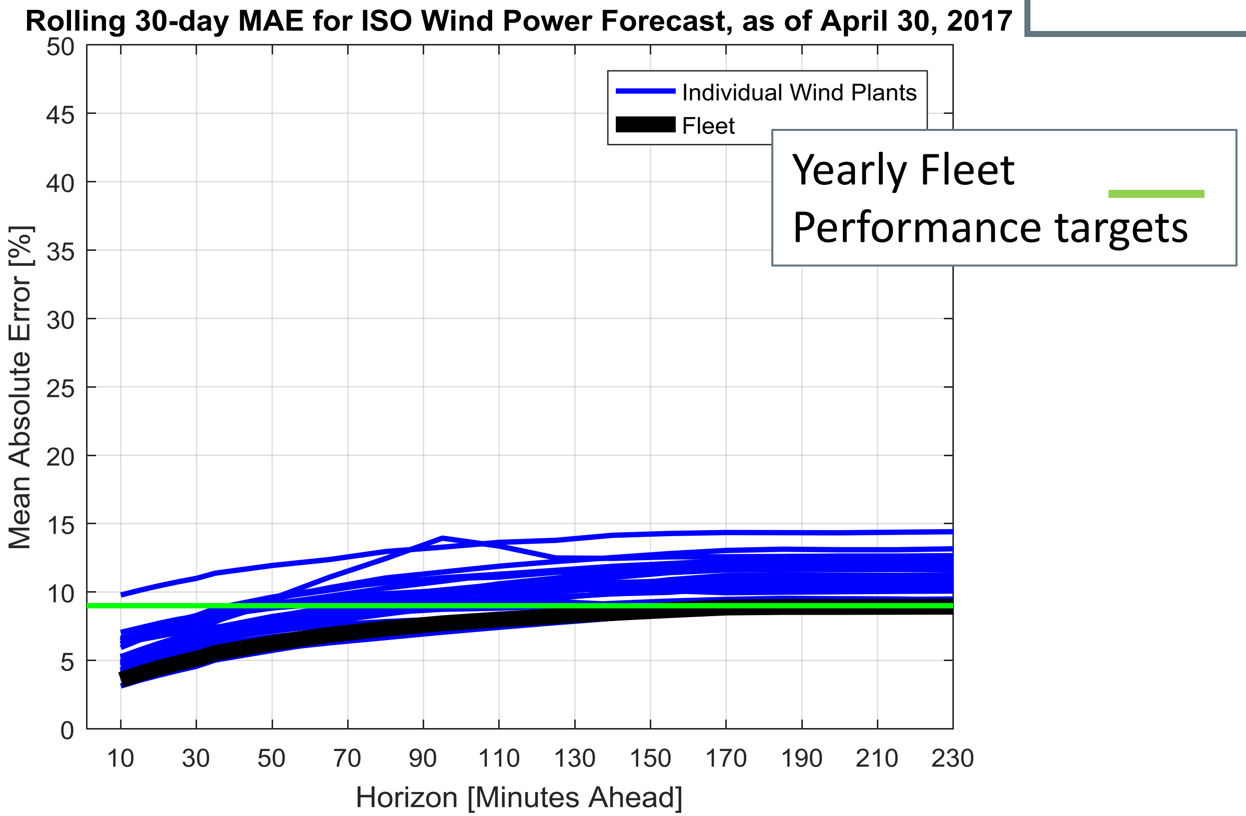
Dashboard Indicator ●



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-GL forecast compares well with industry standards, and monthly Bias is within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator ●



Yearly Fleet Performance targets

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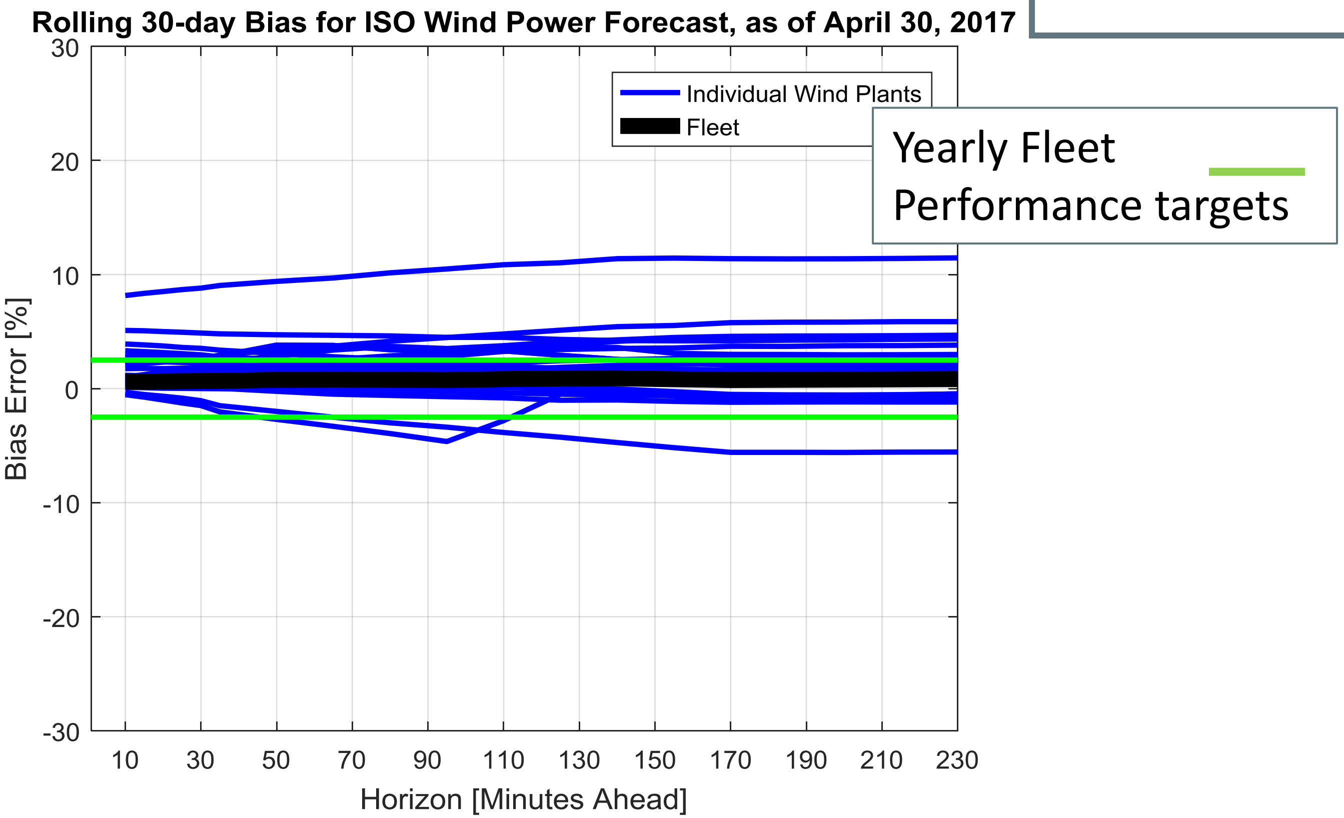
Wind Power Forecast Error Statistics: Short Term Forecast Bias

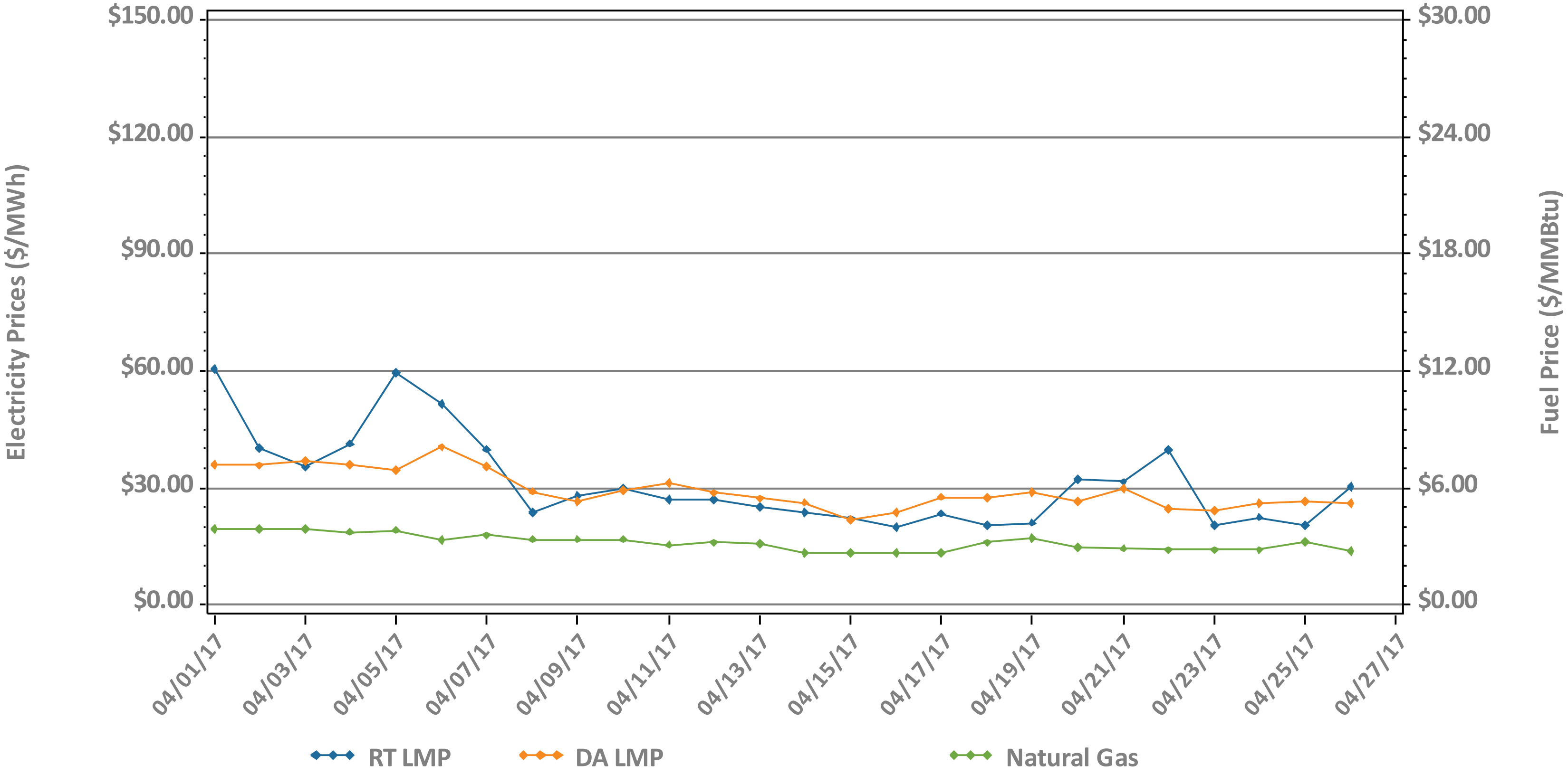
Dashboard Indicator ●



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-GL forecast compares well with industry standards, and monthly Bias is within yearly performance targets.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: April 1-26, 2017

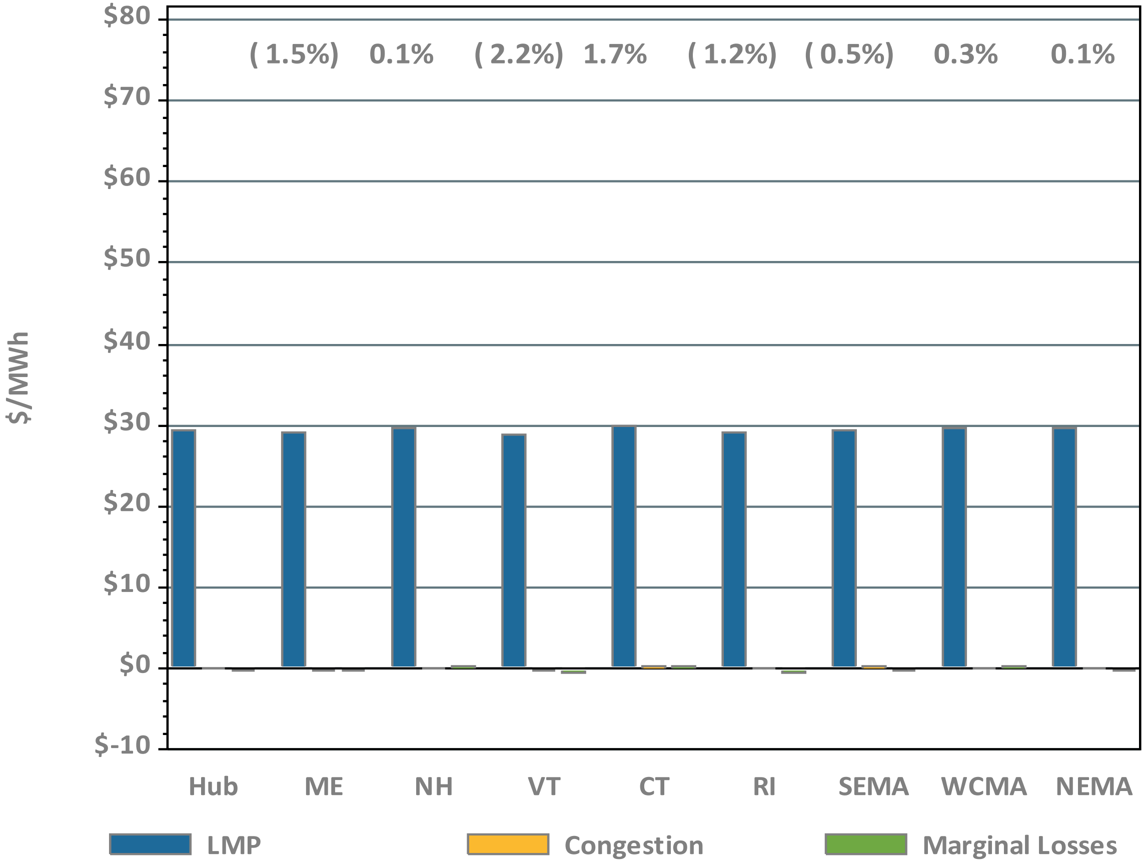


Underlying natural gas data furnished by:

ICE Global markets in clear view

Average price difference over this period (DA-RT): $-1.94
Average price difference over this period ABS(DA-RT): $6.02
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%
Gas price is average of Massachusetts delivery points

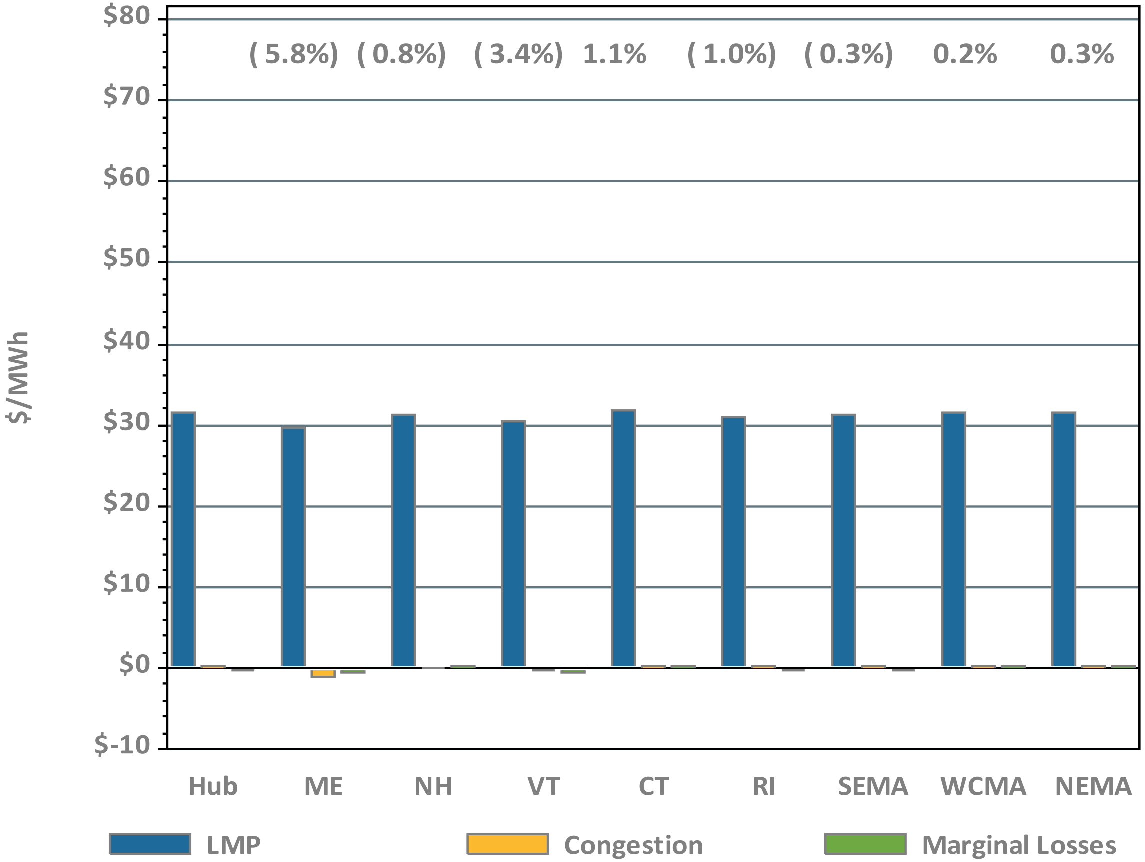
DA LMPs Average by Zone & Hub, April 2017



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

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

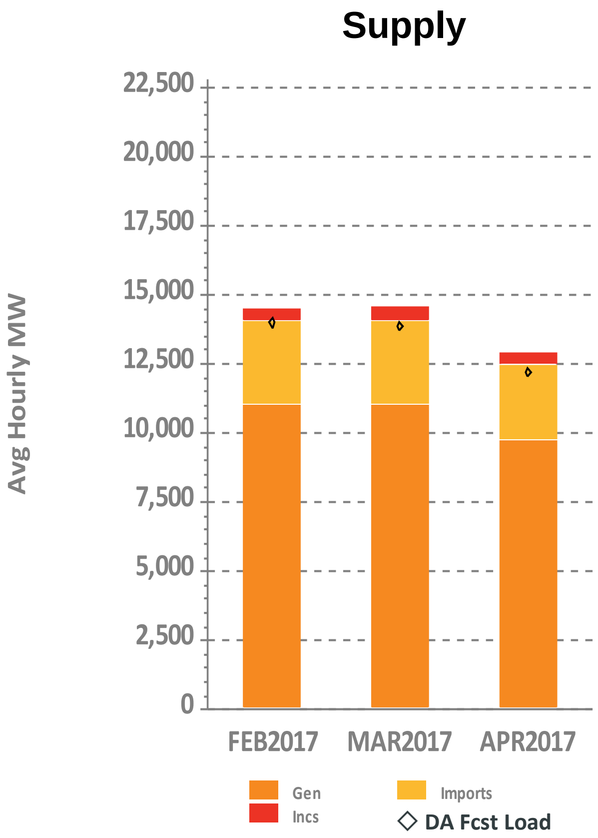
RT LMPs Average by Zone & Hub, April 2017



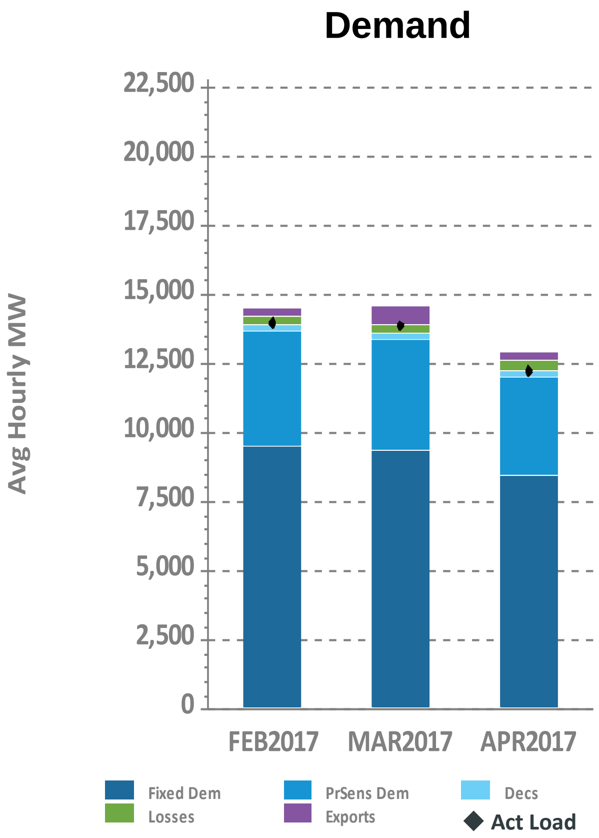
Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

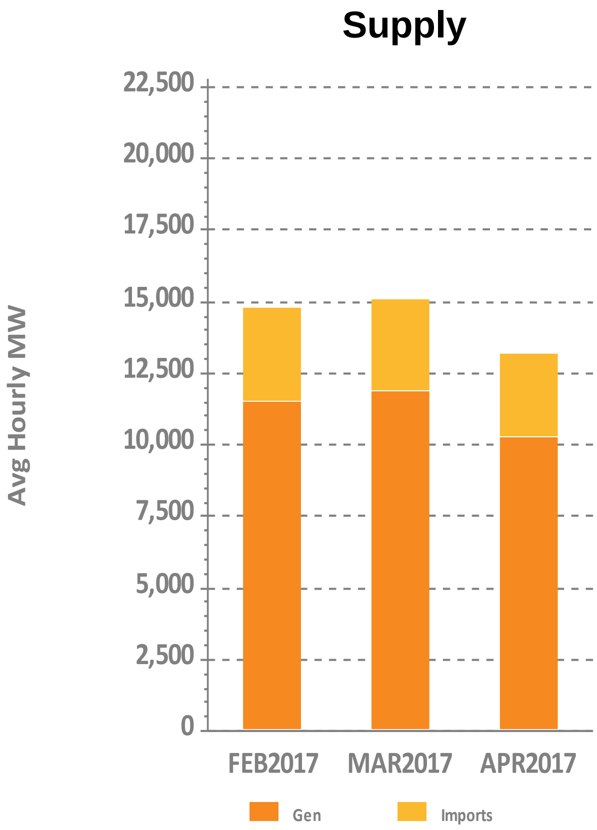


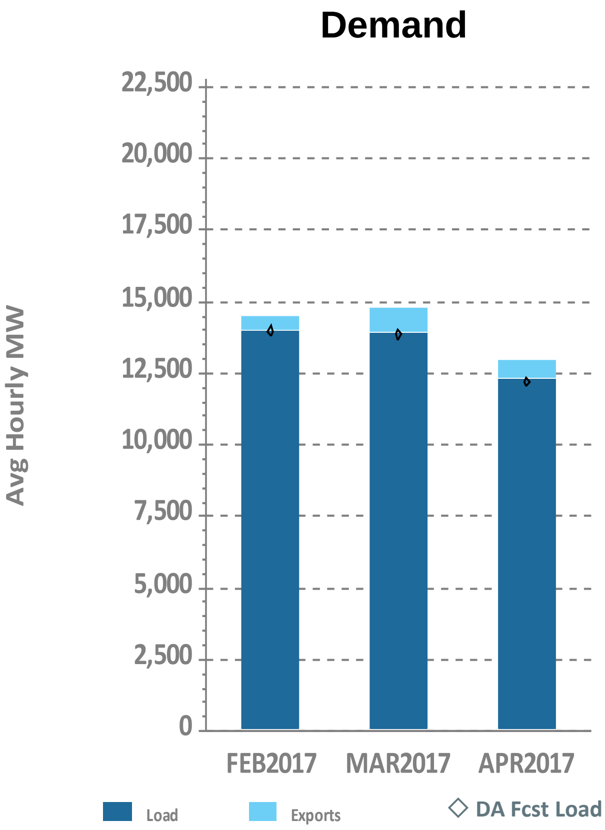
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load



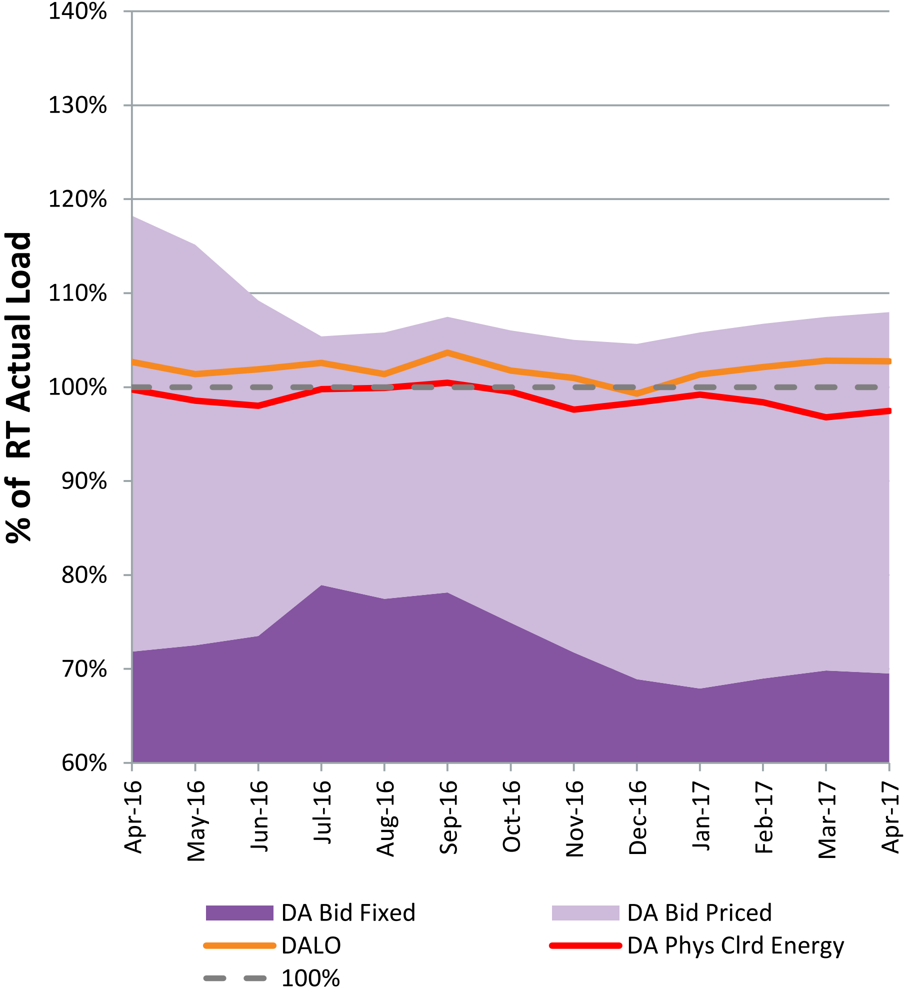
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

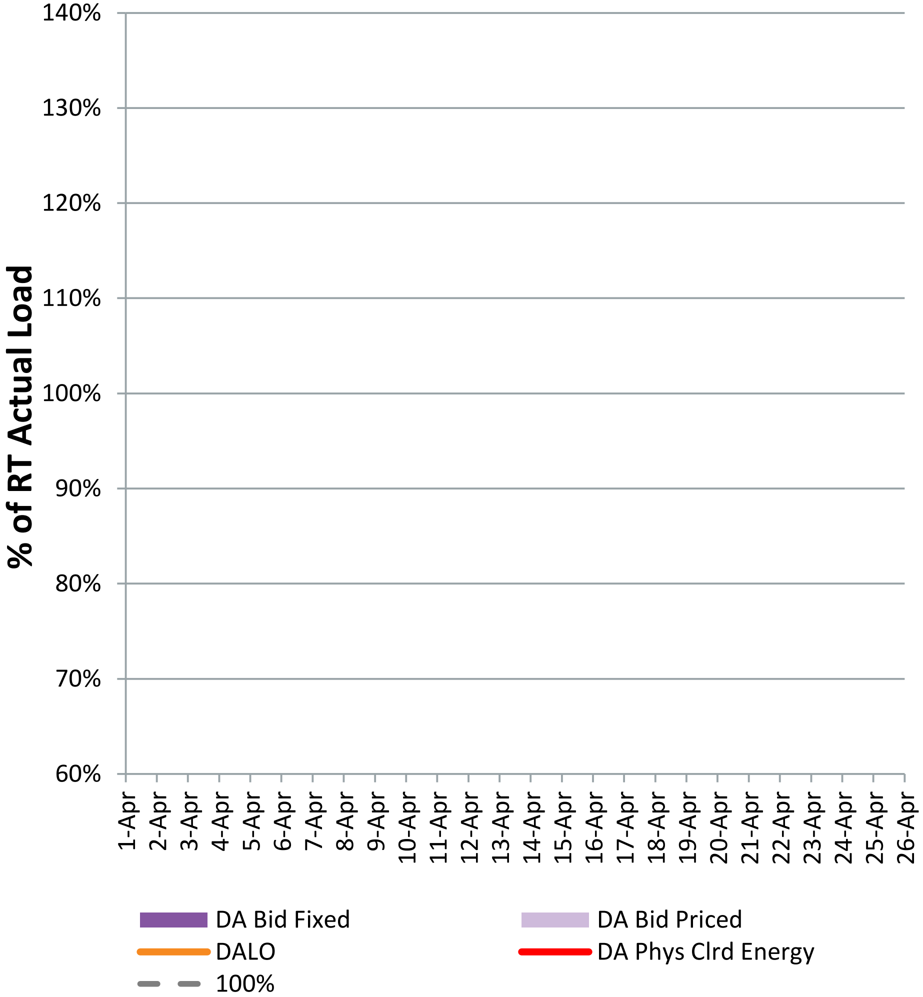
Components of RT Supply and Demand – Last Three Months





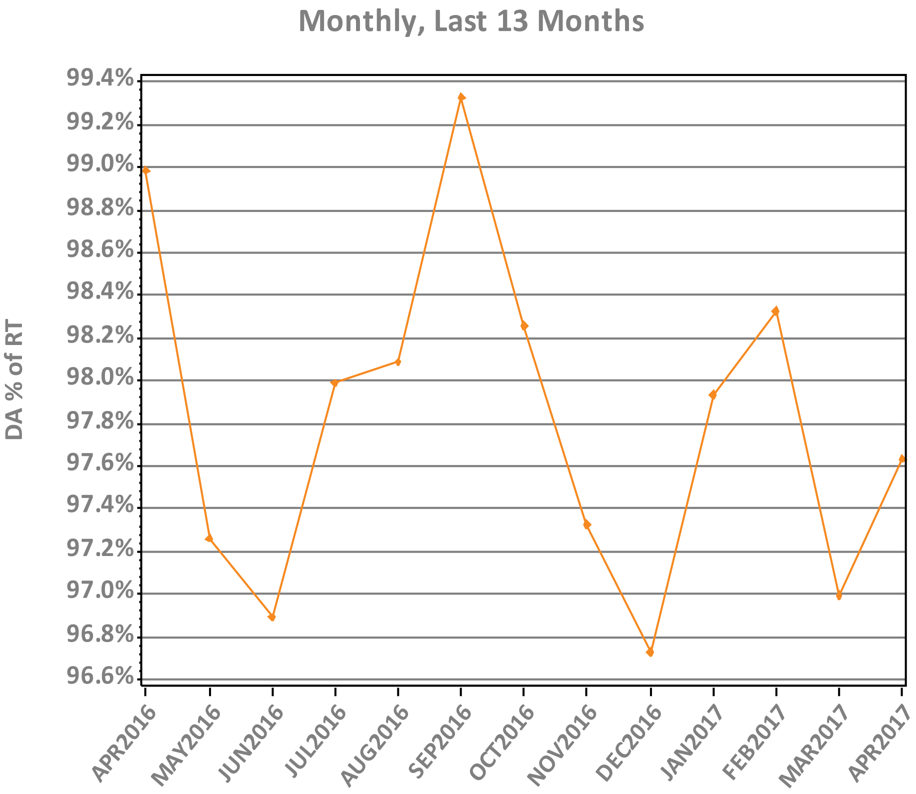
DAM Volumes as % of RT Actual Load (Peak Hour)

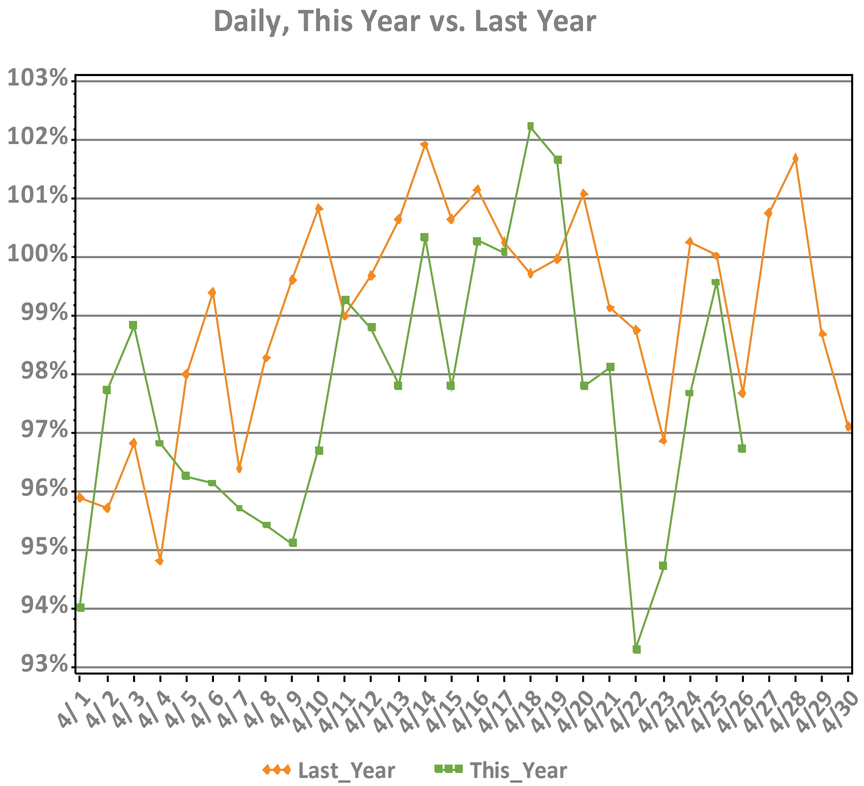




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

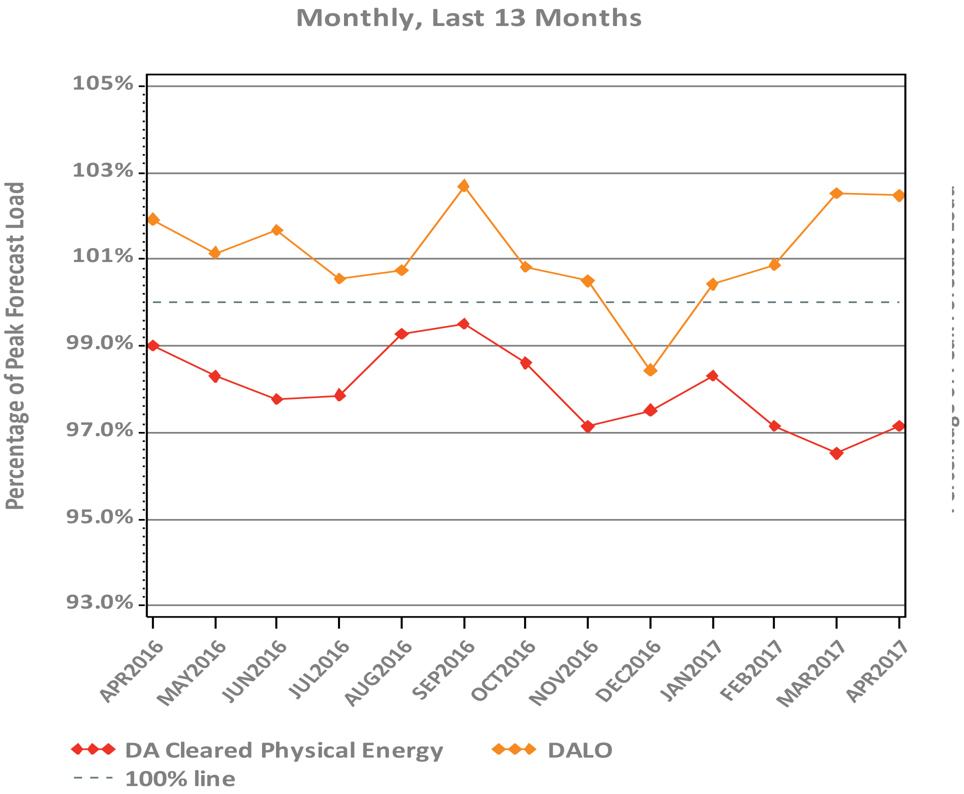
DA vs. RT Load Obligation: April, This Year vs. Last Year

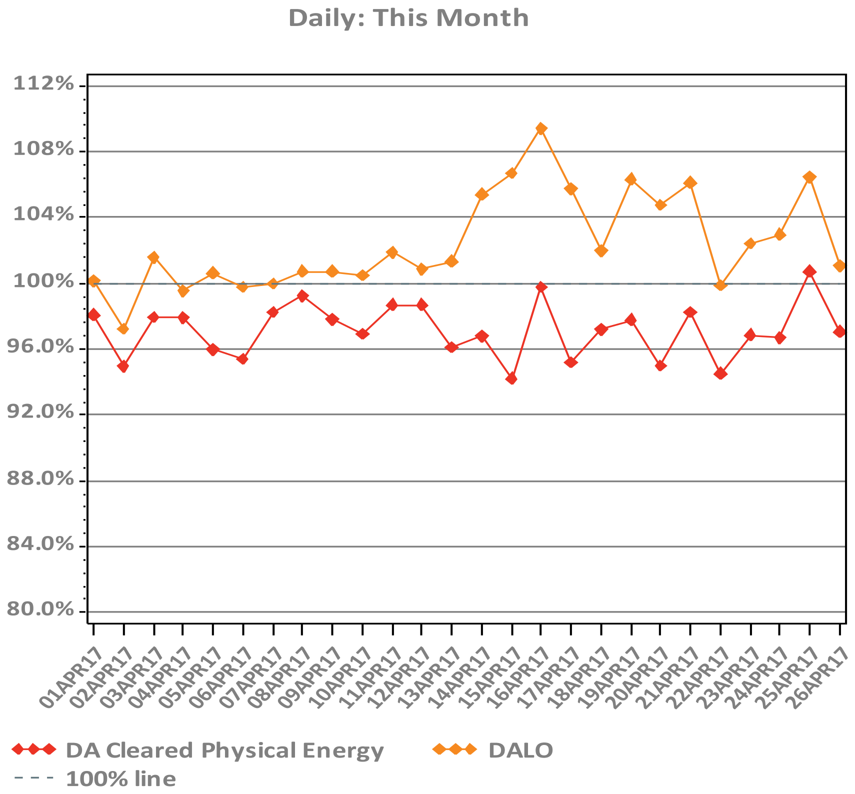




*Hourly average values

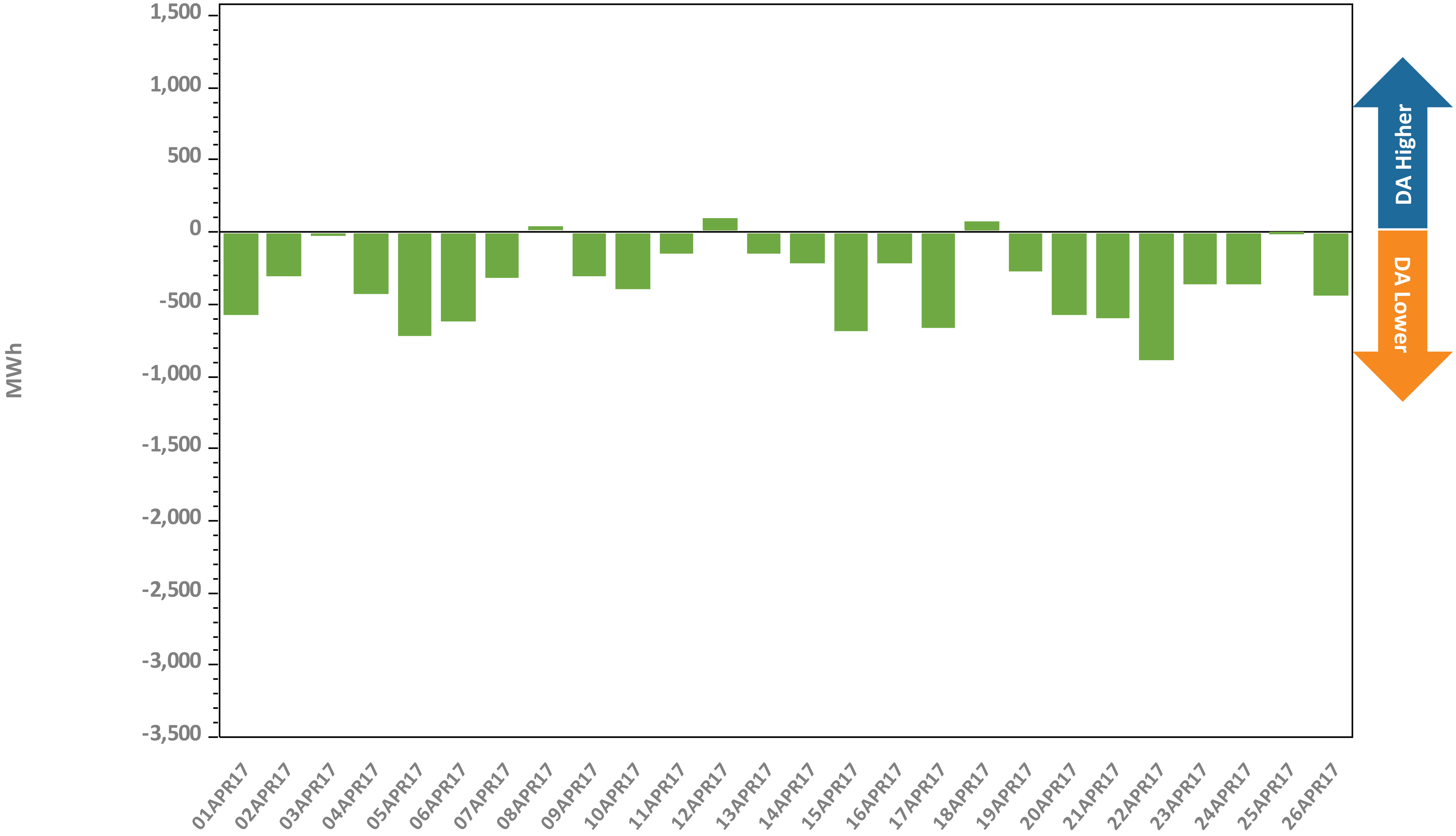
DA Volumes as % of Forecast in Peak Hour





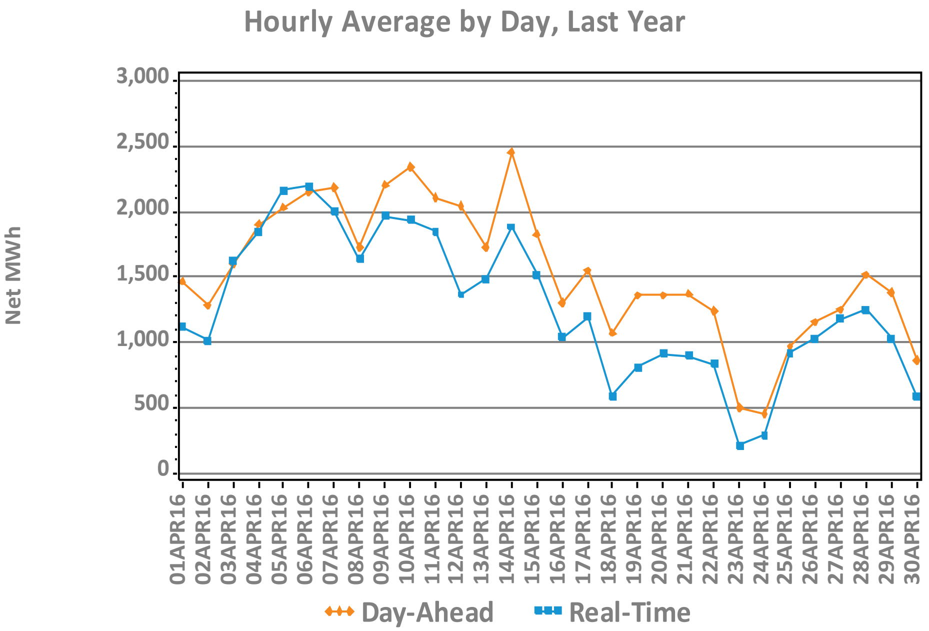
***Supplemental commitments for capacity during the Reserve Adequacy Assessment (RAA) process during April were *zero*.**

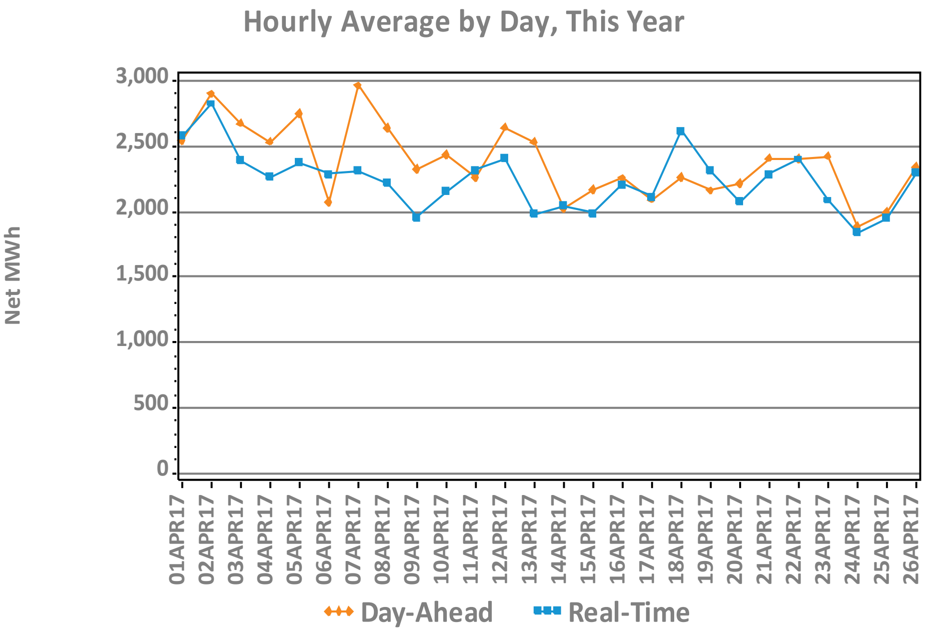
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

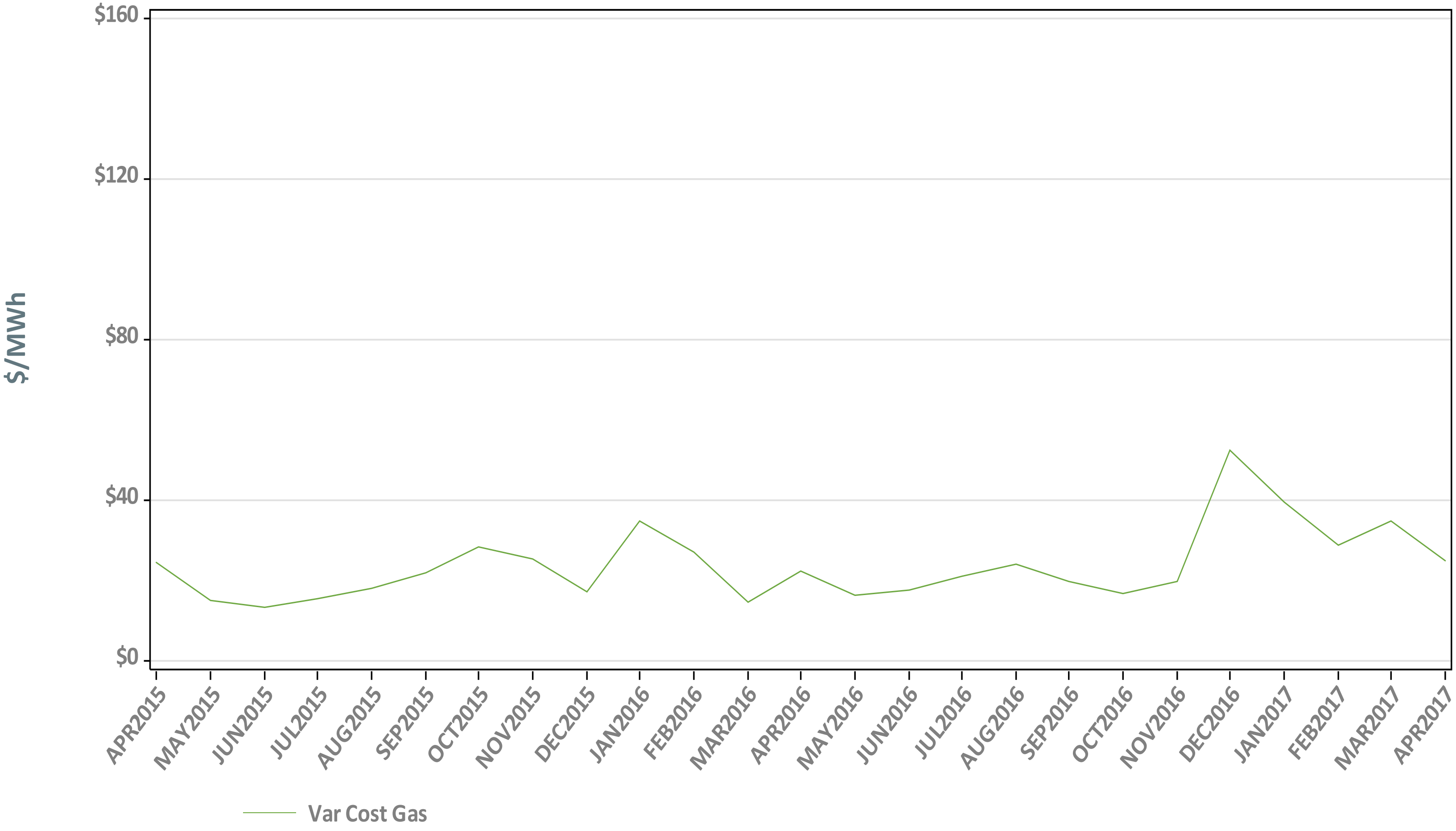
DA vs. RT Net Interchange April 2017 vs. April 2016





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

Variable Production Cost of Natural Gas: Monthly

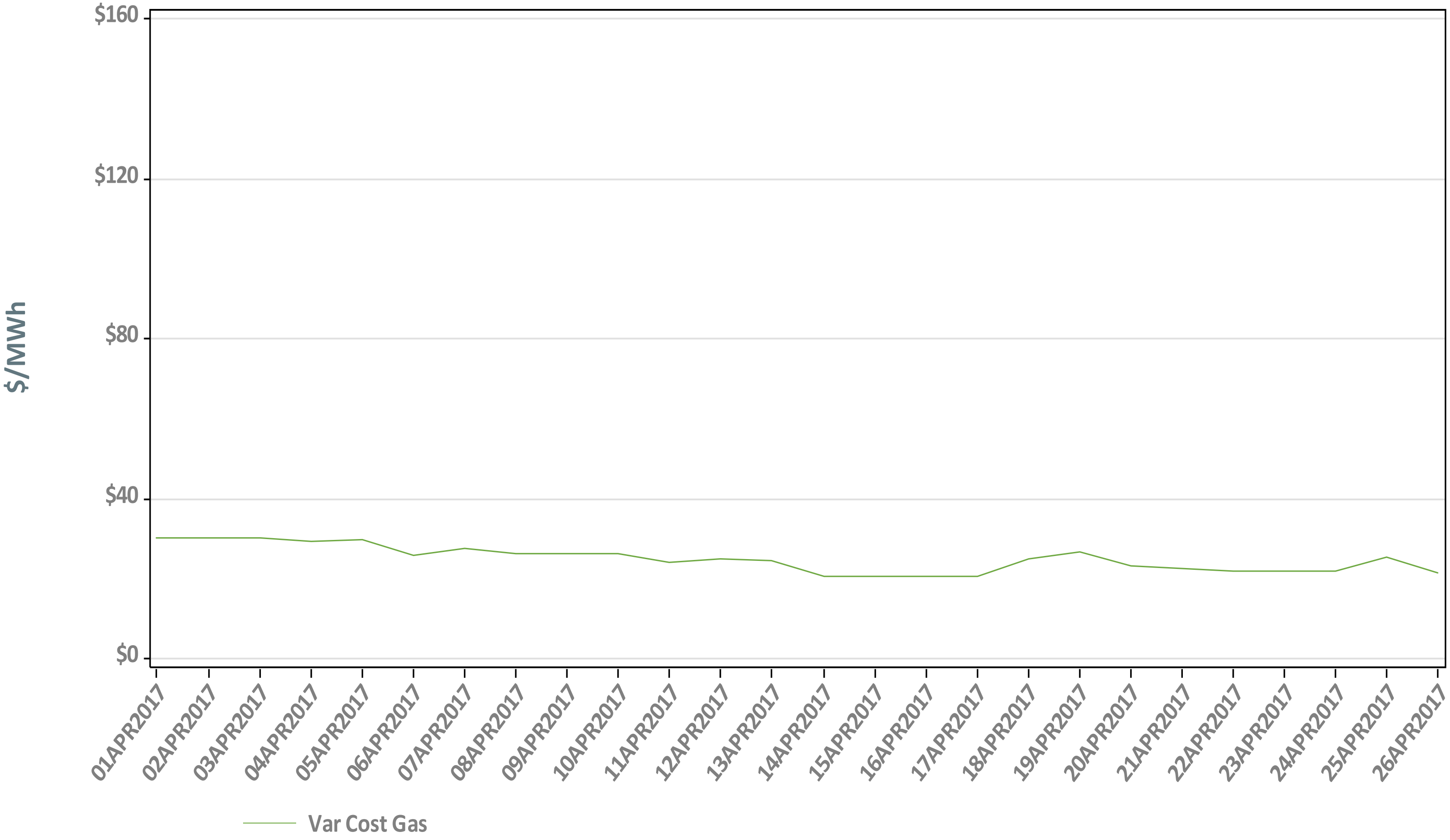


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

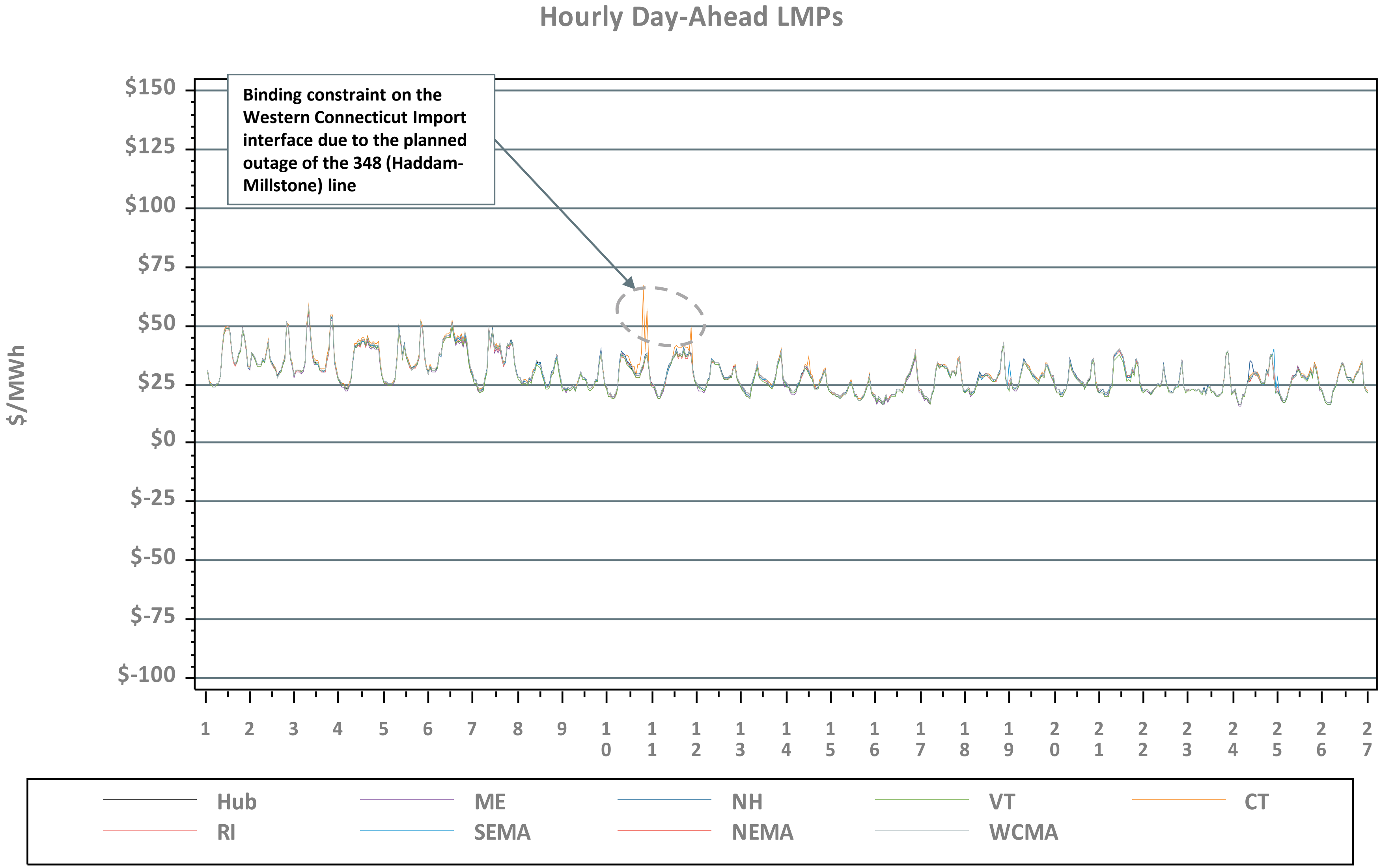


Underlying natural gas data furnished by:

ICE Global markets in clear view

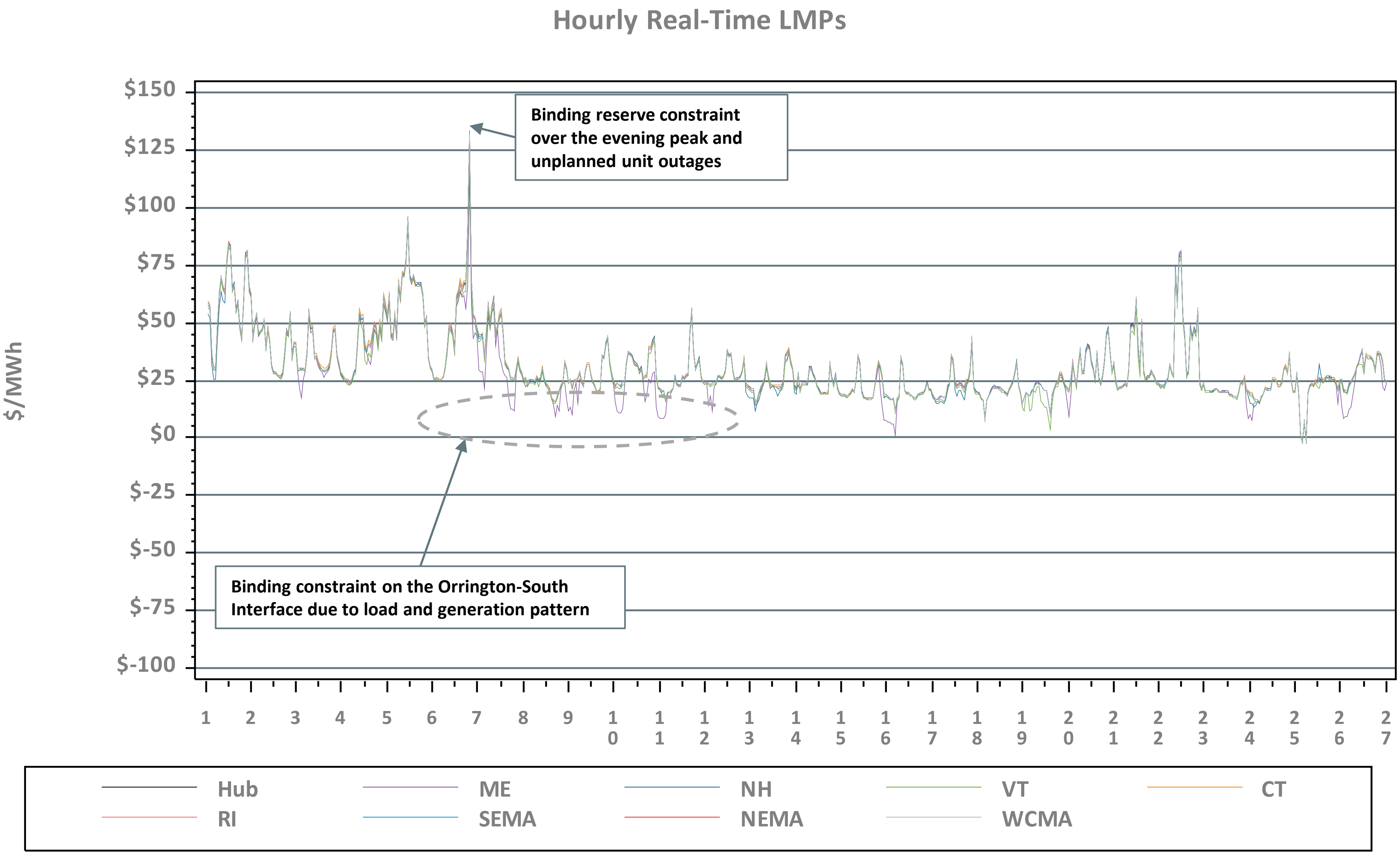
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Hourly DA LMPs, April 1-26, 2017



Binding constraint on the Western Connecticut Import interface due to the planned outage of the 348 (Haddam-Millstone) line

Hourly RT LMPs, April 1-26, 2017

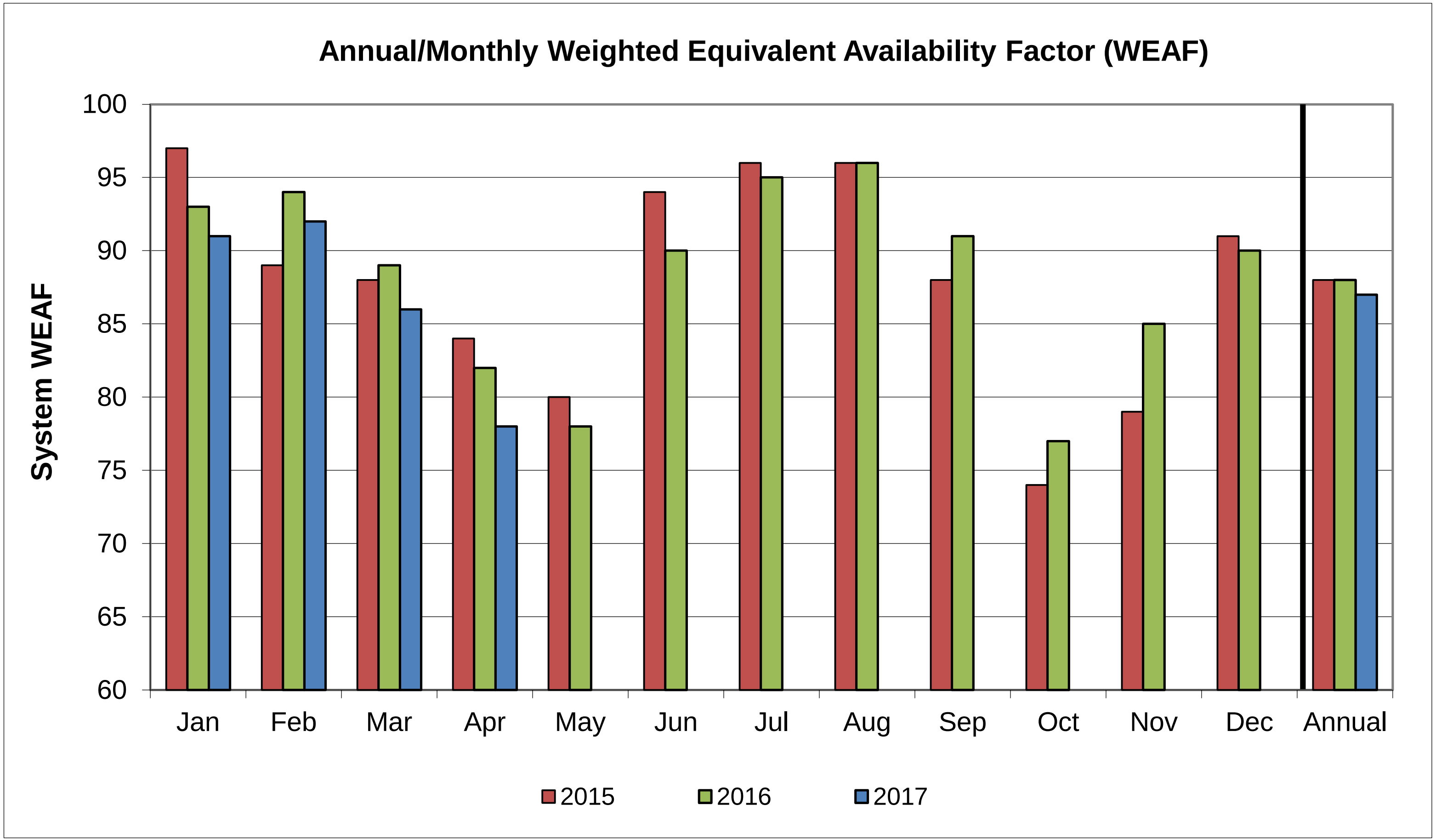


Binding reserve constraint over the evening peak and unplanned unit outages

Binding constraint on the Orrington-South Interface due to load and generation pattern

* No Minimum Generation Emergencies were declared in March.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2017	91	92	86	78									87
2016	93	94	89	82	78	90	95	96	91	77	85	90	88
2015	97	89	88	84	80	94	96	96	88	74	79	91	88

Data as of 4/30/17

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for June 2017

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	77.2	0.0	133.3	0.0	210.6
NH	10.5	0.0	81.1	0.0	91.6
VT	24.7	0.0	104.7	0.0	129.4
CT	57.2	1.5	61.2	355.4	475.3
RI	11.2	0.0	176.9	0.0	188.2
SEMA	10.8	0.0	246.7	0.0	257.4
WCMA	27.8	0.0	228.1	52.5	308.4
NEMA	33.7	11.1	486.5	0.0	531.3
Total	**253.2**	**12.6**	**1,518.5**	**407.9**	**2,192.2**

*** Real Time Demand Response**

**** Real Time Emergency Generation**

NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

New Generation Update

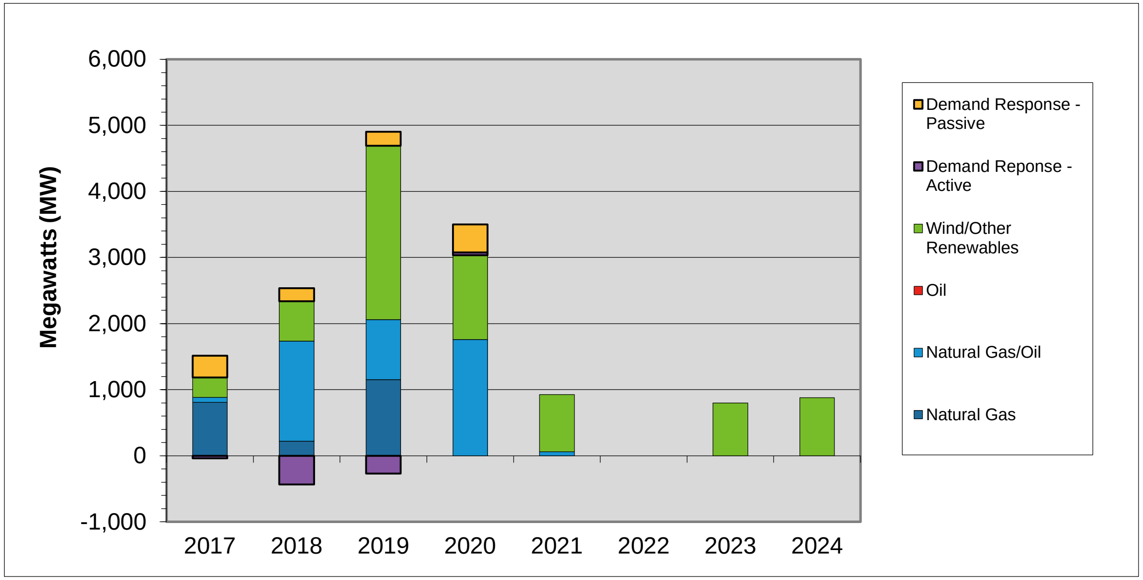
Based on Queue as of 5/1/17

- Nine new projects, with a total rating of 1,074 MW, have applied for interconnection study since the last update*
  - The projects consist of two simple cycle gas turbines, three photovoltaic plants, two wind facilities, a cogeneration plant, and an increase to an existing municipal solid waste plant, with expected in-service dates ranging from 2017 to 2024
- Two projects withdrew from the queue and no projects went commercial, resulting in a net increase in new generation projects of 918 MW
- In total, 83 generation projects are currently being tracked by the ISO, totaling approximately 13,800 MW

* One project has an alternate which, if pursued, would change the total rating to 1,025 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2017	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Demand Response - Passive	330	196	212	422	0	0	0	0	1,160	8.1
Demand Response - Active	-37	-433	-270	42	0	0	0	0	-697	-4.9
Wind & Other Renewables	304	603	2,634	1,279	866	0	800	880	7,366	51.4
Oil	0	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	75	1,519	904	1,757	58	0	0	0	4,313	30.1
Natural Gas	808	218	1,154	0	0	0	0	0	2,180	15.2
Totals	**1,480**	**2,103**	**4,635**	**3,501**	**924**	**0**	**800**	**880**	**14,322**	**100.0**

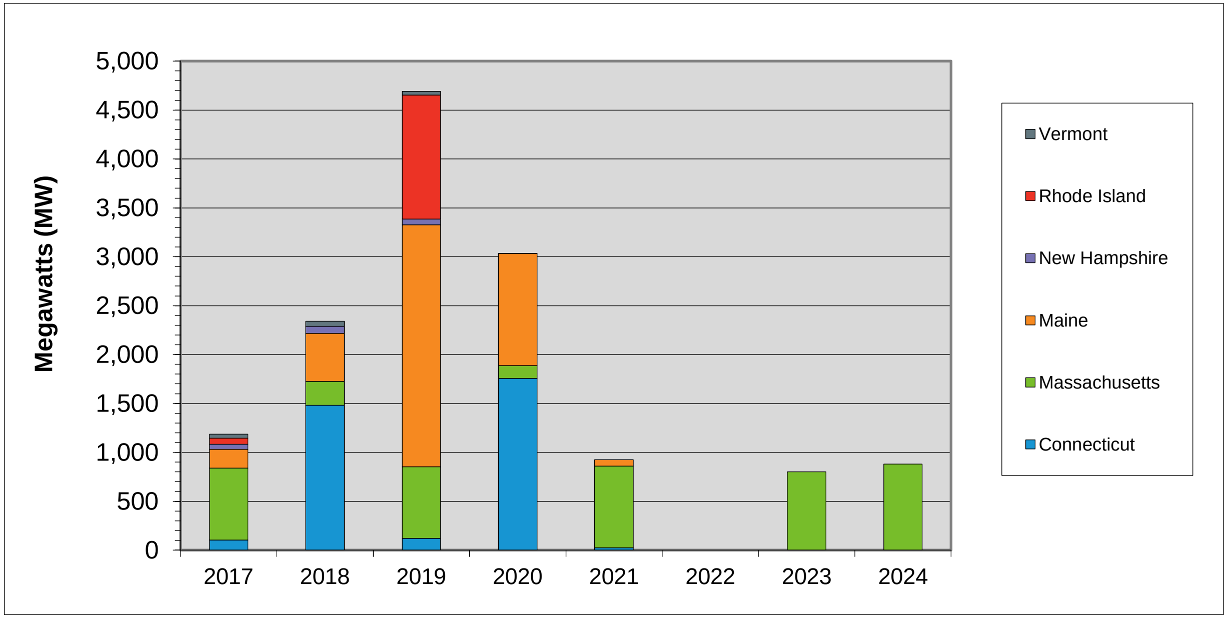
[1] Sum may not equal 100% due to rounding

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

- 2017 values include the 16 MW of generation that has gone commercial in 2017
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2017	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Vermont	42	50	40	0	0	0	0	0	132	1.0
Rhode Island	61	0	1,268	0	0	0	0	0	1,329	9.6
New Hampshire	51	73	58	5	0	0	0	0	187	1.3
Maine	195	491	2,474	1,145	66	0	0	0	4,371	31.5
Massachusetts	736	245	730	128	835	0	800	880	4,354	31.4
Connecticut	102	1,481	122	1,758	23	0	0	0	3,486	25.2
Totals	**1,187**	**2,340**	**4,692**	**3,036**	**924**	**0**	**800**	**880**	**13,859**	**100.0**

[1] **Sum may not equal 100% due to rounding**

- 2017 values reflect the 16 MW of generation that has gone commercial in 2017

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Fuel Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	2	39	0	0	2	39
Hydro	4	101	0	0	4	101
Landfill Gas	1	2	0	0	1	2
Natural Gas	14	2,243	1	100	13	2,143
Natural Gas/Oil	14	4,313	2	1,009	12	3,304
Oil	0	0	0	0	0	0
Solar	18	855	0	0	18	855
Wind	28	6,213	1	23	27	6,190
Battery Storage	2	77	0	0	2	77
Total	83	13,843	4	1,132	79	12,711

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Baseload	5	109	0	0	5	109
Intermediate	19	5,429	1	801	18	4,628
Peaker	31	2,092	2	308	29	1,784
Wind Turbine	28	6,213	1	23	27	6,190
Total	83	13,843	4	1,132	79	12,711

- 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

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Fuel Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	2	39	2	39	0	0	0	0	0	0
Hydro	4	101	1	5	2	30	1	66	0	0
Landfill Gas	1	2	1	2	0	0	0	0	0	0
Natural Gas	14	2,243	1	63	10	1,999	3	181	0	0
Natural Gas/Oil	14	4,313	0	0	7	3,400	7	913	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	18	855	0	0	0	0	18	855	0	0
Wind	28	6,213	0	0	0	0	0	0	28	6,213
Battery Storage	2	77	0	0	0	0	2	77	0	0
Total	83	13,843	5	109	19	5,429	31	2,092	28	6,213

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 6

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	2,001.510	1,918.662	-82.848	1,368.608	-550.054	1,271.984	-96.624	1,085.347	-186.64	842.791	-242.56	789.366	-53.425	638.393	-150.973
	Passive Demand	1,643.334	1,553.054	-90.280	1,521.535	-31.519	1,521.535	0.000	1,516.504	-5.03	1,700.586	184.08	1,694.766	-5.82	1,687.458	-7.308
Demand Total		**3,644.844**	**3,471.716**	**-173.128**	**2,890.143**	**-581.573**	**2,793.519**	-96.624	**2,601.851**	**-191.67**	**2,543.377**	**-58.47**	**2,484.132**	**-59.245**	**2,325.851**	-158.281
Generator	*Non-Intermittent*	29,866.098	27,957.613	-1,908.485	28,121.731	164.118	28,343.440	221.709	28,442.424	98.98	28,727.16	284.73	28,881.019	153.859	**28,971.511**	90.492
	Intermittent	891.069	840.563	-50.506	827.047	-13.516	828.252	1.205	829.219	0.97	820.743	-8.48	777.924	-42.819	**754.101**	-23.823
Generator Total		**30,757.167**	**28,798.176**	**-1,958.991**	**28,948.778**	**150.602**	**29,171.692**	222.914	**29,271.643**	**99.95**	**29,547.9**	**276.26**	**29,658.943**	**111.043**	**29,725.612**	66.669
Import Total		**1,924.000**	**1,768.111**	**-155.889**	**1,768.111**	**0.000**	**1,641.821**	-126.290	**1,616.821**	**-25.00**	**1,399.037**	**-217.78**	**1,337.037**	**-62**	**1,337.037**	0
*****Grand Total**		**36,326.011**	**34,038.003**	**-2,288.008**	**33,607.032**	-430.971	**33,607.032**	0.000	**33,490.315**	**-116.72**	**33,490.32**	**0.00**	**33,480.112**	**-10.208**	**33,388.5**	-91.612
Net ICR (NICR)		**33,456**	**33,456**	**0**	**33,456**	**0**	**33,456**	**0**	33,114	**-342**	**33,114**	**0.00**	**33,391**	**277**	**33,391**	**0**

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

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

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

Capacity Supply Obligation FCA 7

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,116.698	1,043.719	-72.979	944.27	-99.45	932.721	-11.549	781.206	-151.52	671.28	-109.926	575.63	-95.65	556.453	-19.177
	Passive Demand	1,631.335	1,519.740	-111.595	1,519.311	-0.43	1,543.793	24.482	1,544.276	0.48	1,544.119	-0.157	1,607.705	63.586	1,884.902	277.197
Demand Total		**2,748.033**	**2,563.459**	**-184.574**	**2,463.581**	**-99.88**	**2,476.514**	**12.933**	2,325.482	-151.03	2,215.399	-110.083	2,183.335	-32.064	2,441.355	258.02
Generator	*Non-Intermittent*	30,704.578	28,146.837	-2,557.741	28,127.044	-19.79	28,523.002	395.958	28,307.339	-215.66	28,791.131	483.792	28,948.677	157.546	29,152.793	204.116
	Intermittent	936.913	893.710	-43.203	903.244	9.53	913.083	9.839	838.626	-74.46	824.833	-13.793	800.286	-24.547	735.174	-65.112
Generator Total		**31,641.491**	**29,040.547**	**-2,600.944**	**29,030.288**	**-10.26**	**29,436.085**	**405.797**	29,145.965	-290.12	29,615.964	469.999	29,748.963	132.999	29,887.967	139.004
Import Total		**1,830.000**	**1,606.862**	**-223.138**	**1,606.862**	**0.00**	**1,616.401**	**9.539**	1,576.401	-40.00	1,576.401	0	1,440.401	-136	1,162.202	-278.199
*****Grand Total**		**36,219.524**	**33,210.868**	**-3,008.656**	**33,100.731**	**-110.14**	**33,529.000**	**428.269**	33,047.848	-481.15	33,407.764	359.916	33,372.699	-35.065	33,491.524	118.825
Net ICR (NICR)		**32,968**	**32,968**	**0**	33,529	561	33,529	0	33,529	0.00	33,529	0	33,152	-377	33,152	0

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

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

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

Capacity Supply Obligation FCA 8

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	**CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	1,080.079	887.493	-192.59	891.604	4.111	772.352	-119.252	601.852	-170.5	400.487	-201.365	381.941	-18.546
	Passive Demand	1,960.517	1,958.874	-1.64	1,956.663	-2.211	2025.383	68.72	2,036.906	11.523	2,112.758	75.852	2,308.73	195.972
Demand Total		**3,040.596**	**2,846.367**	**-194.23**	**2,848.267**	**1.9**	**2,797.735**	**-50.532**	**2,638.758**	**-158.977**	**2,513.245**	**-125.513**	2,690.671	177.426
Generator	*Non-Intermittent*	28,547.813	28,523.796	-24.02	28,666.87	143.074	28,658.35	-8.52	28,863.752	205.402	28,888.84	25.092	28,833.605	-55.235
	Intermittent	876.925	898.955	22.03	922.173	23.218	918.782	-3.391	920.037	1.255	916.51	-3.527	823.162	-93.348
Generator Total		**29,424.738**	**29,422.751**	**-1.99**	**29,589.043**	**166.292**	**29,577.132**	**-11.911**	**29,783.789**	**206.657**	**29,805.35**	**21.565**	29,656.767	-148.583
Import Total		**1,237.034**	**1,237.034**	**0.00**	**1,375.53**	**138.496**	**1,375.53**	**0**	**1314.43**	**-61.1**	**1,394.43**	**80**	1,345.998	-48.432
*****Grand Total**		**33,702.368**	**33,506.152**	**-196.22**	**33,812.84**	**306.688**	**33,750.397**	**-62.443**	**33,736.977**	**-13.417**	**33,713.03**	**-23.948**	33,693.436	-19.594
Net ICR (NICR)		**33,855**	**34,061**	**206.00**	**34,061**	**0**	**33,442**	**-619**	**33,442**	**0**	**33,138**	**-304**	33,138	**0**

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

** Change columns contain the changes in CSO amount resulting from, but not limited to, the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

*** Grand Total reflects both CSO Grand Total and the net total of the Change Column. The Grand Total for FCA 8 does not reflect a Supplemental Information filing in March of 2014.

Capacity Supply Obligation FCA 9

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	647.26	596.701	-50.559	553.857	-42.844								
	Passive Demand	2,156.151	2153.94	-2.211	2150.196	-3.744								
Demand Total		**2,803.411**	**2,750.641**	**-52.77**	**2,704.053**	**-46.588**								
Generator	*Non-Intermittent*	29,550.564	29,558.181	7.617	29,783.831	225.65								
	Intermittent	891.616	864.924	-26.692	872.425	7.501								
Generator Total		**30,442.18**	**30,423.105**	**-19.075**	**30,656.256**	**233.151**								
Import Total		**1,449**	**1449**	**0**	**1449**	**0**								
*****Grand Total**		**34,694.591**	**34622.746**	**-71.845**	**34,809.309**	**186.563**								
Net ICR (NICR)		**34,189**	**33,883**	**-306**	**33,883**	**0**								

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

** Change columns contain the changes in CSO amount resulting from, but not limited to, the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

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

Capacity Supply Obligation FCA 10

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	377.525												
	Passive Demand	2,368.631												
Demand Total		**2,746.156**												
Generator	*Non-Intermittent*	30,520.433												
	Intermittent	850.143												
Generator Total		**31,370.576**												
Import Total		**1,449.8**												
*****Grand Total**		**35,566.532**												
Net ICR (NICR)		**34,151**												

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

** Change columns contain the changes in CSO amount resulting from, but not limited to, the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

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

Capacity Supply Obligation FCA 11

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	**CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	419.928												
	Passive Demand	2,791.019												
Demand Total		**3,210.947**												
Generator	*Non-Intermittent*	30,494.8												
	Intermittent	894.217												
Generator Total		**31,389.02**												
Import Total		**1,235.4**												
*****Grand Total**		**35,835.368**												
Net ICR (NICR)		**34,075**												

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

** Change columns contain the changes in CSO amount resulting from, but not limited to, the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/ Passive	Existing	New	Grand Total
2010-11	Active	1246.399	603.675	1850.074
	Passive	119.211	584.277	703.488
	Grand Total	1365.61	1187.952	2553.562
2011-12	Active	1768.392	184.99	1953.382
	Passive	719.98	263.25	983.23
	Grand Total	2488.372	448.24	2936.612
2012-13	Active	1726.548	98.227	1824.775
	Passive	861.602	211.261	1072.863
	Grand Total	2588.15	309.488	2897.638
2013-14	Active	1794.195	257.341	2051.536
	Passive	1040.113	257.793	1297.906
	Grand Total	2834.308	515.134	3349.442
2014-15	Active	2062.196	41.945	2104.141
	Passive	1264.641	221.072	1485.713
	Grand Total	3326.837	263.017	3589.854
2015-16	Active	1935.406	66.104	2001.51
	Passive	1395.885	247.449	1643.334
	Grand Total	3331.291	313.553	3644.844
2016-17	Active	1116.468	0.23	1116.698
	Passive	1386.56	244.775	1631.335
	Grand Total	2503.028	245.005	2748.033
2017-18	Active	1066.593	13.486	1080.079
	Passive	1619.147	341.37	1960.517
	Grand Total	2685.74	354.856	3040.596
2018-19	Active	565.866	81.394	647.26
	Passive	1870.549	285.602	2156.151
	Grand Total	2436.415	366.996	2803.411
2019-20	Active	357.221	20.304	377.525
	Passive	2018.201	350.43	2368.631
	Grand Total	2375.422	370.734	2746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2236.727	554.292	2791.019
	Grand Total	2571.361	639.586	3210.947

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

What are Daily NCPC Payments?

- Payments made to resources whose 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 during 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
- NCPC payments are intended to make a resource that follows the ISO’s operating instructions “no worse off” financially than the best alternative generation schedule

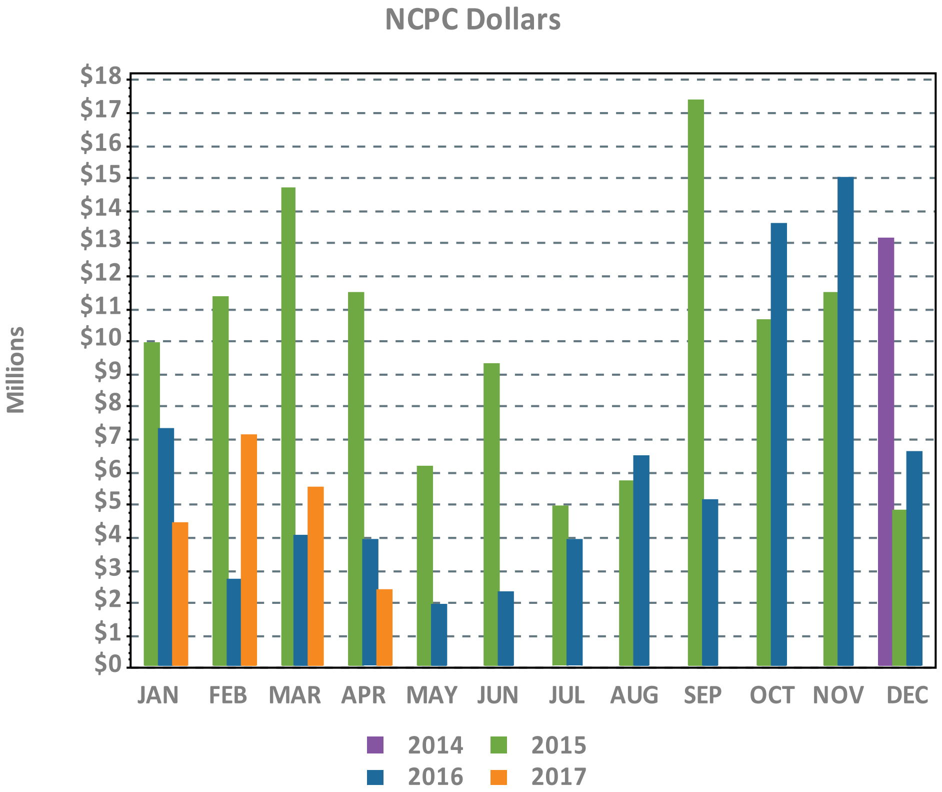
Definitions

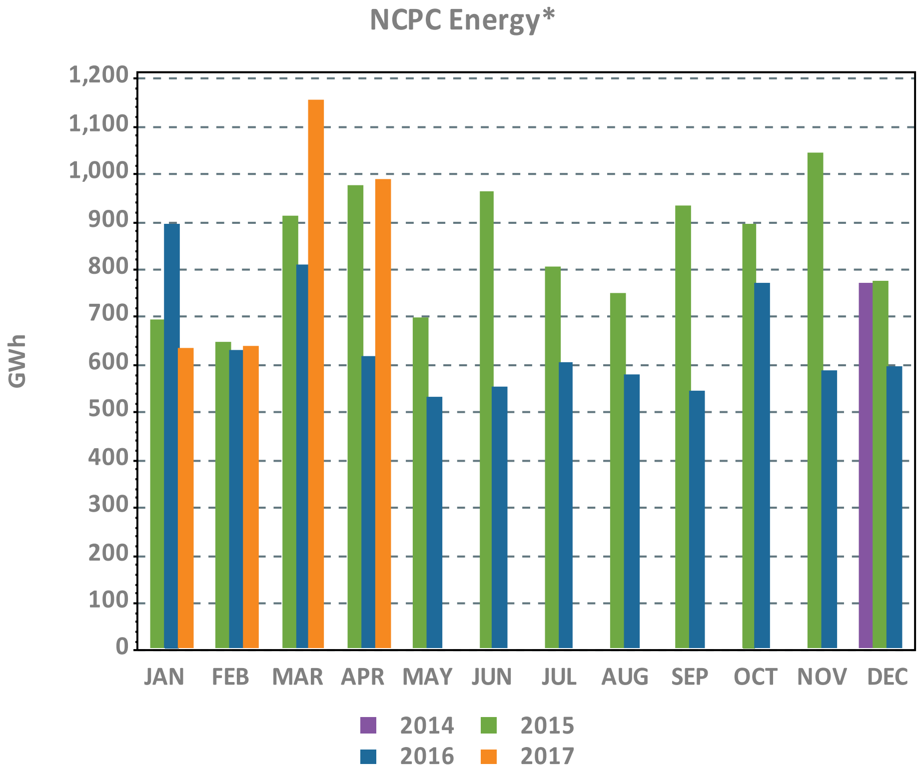
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1st Contingency	Market	DA 1st C (excluding at external nodes) is allocated to system DALO. RT 1st C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1st Contingency	Market	DA 1st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2nd Contingency	Market	DA and RT 2nd C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service
System – Other	Market	Includes GPA, Economic Generator/DARD Posturing, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost NCPC (allocated to RTLO); and Min Generation Emergency NCPC (allocated to RTGO).

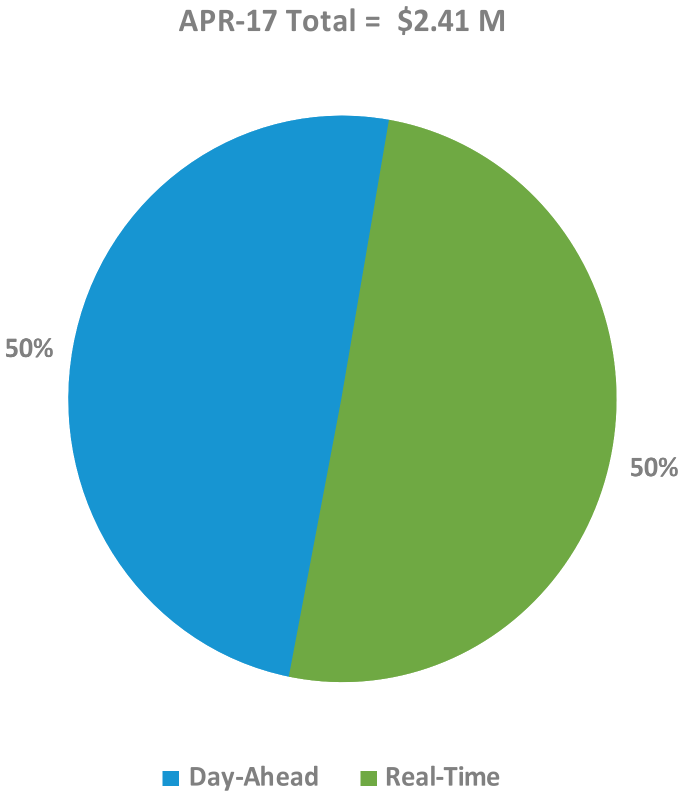
Year-Over-Year Total NCPC Dollars and Energy

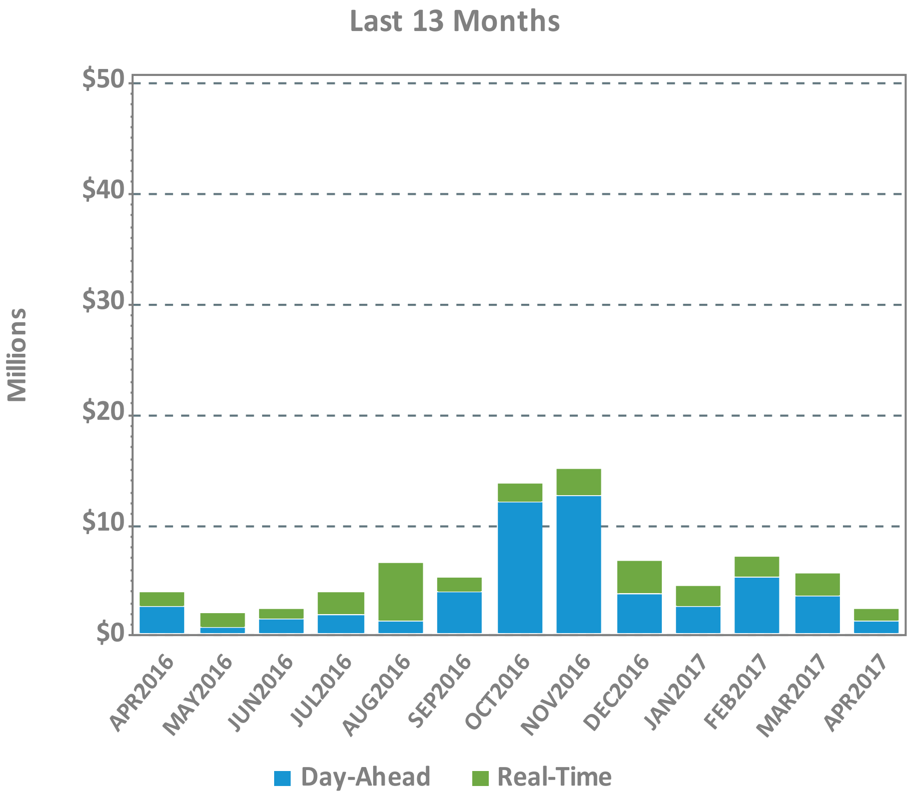




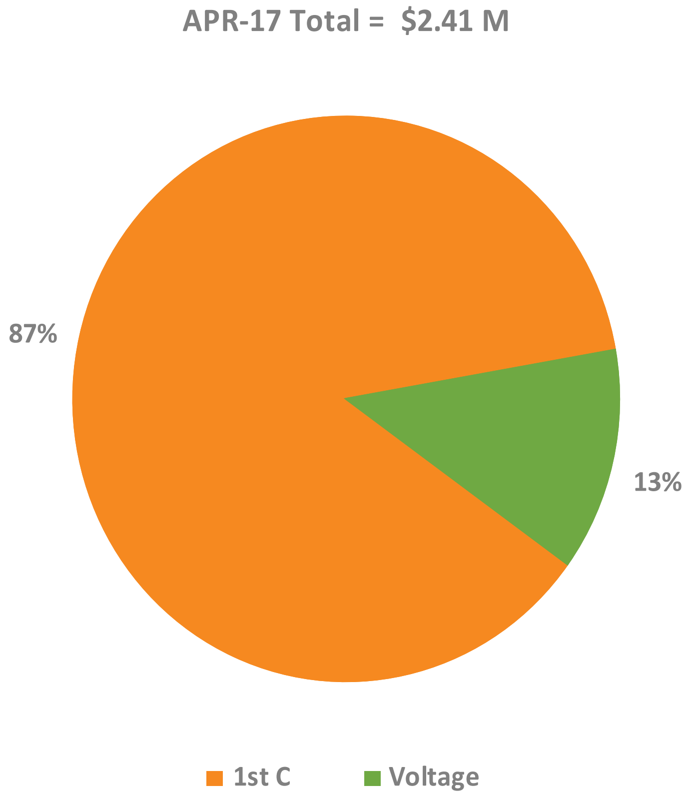
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.**

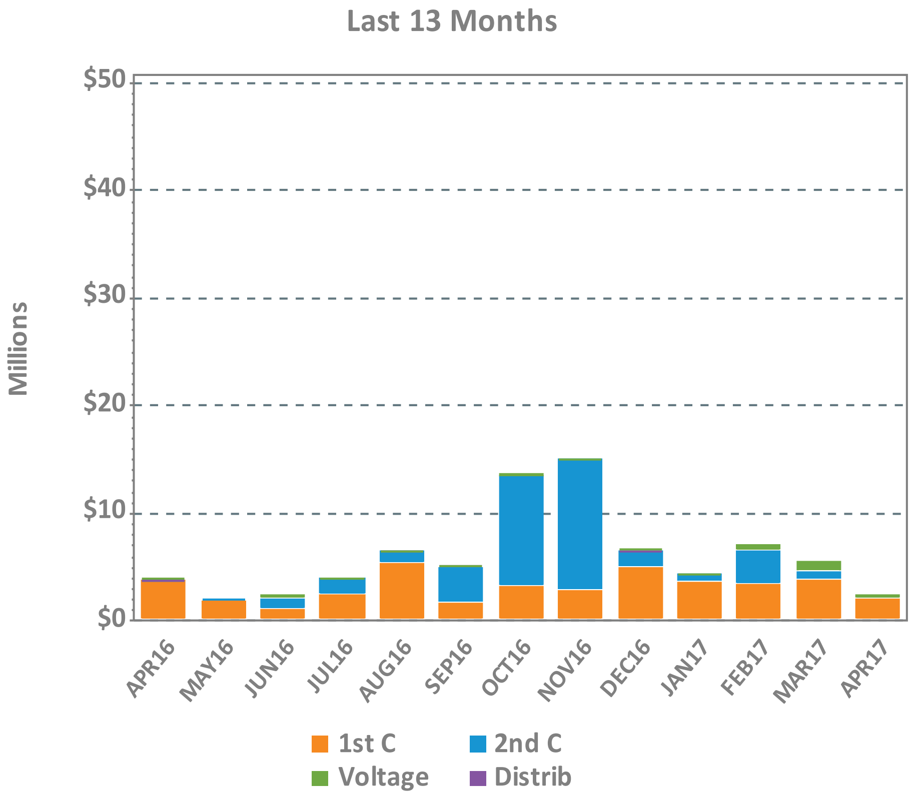
DA and RT NCPC Charges





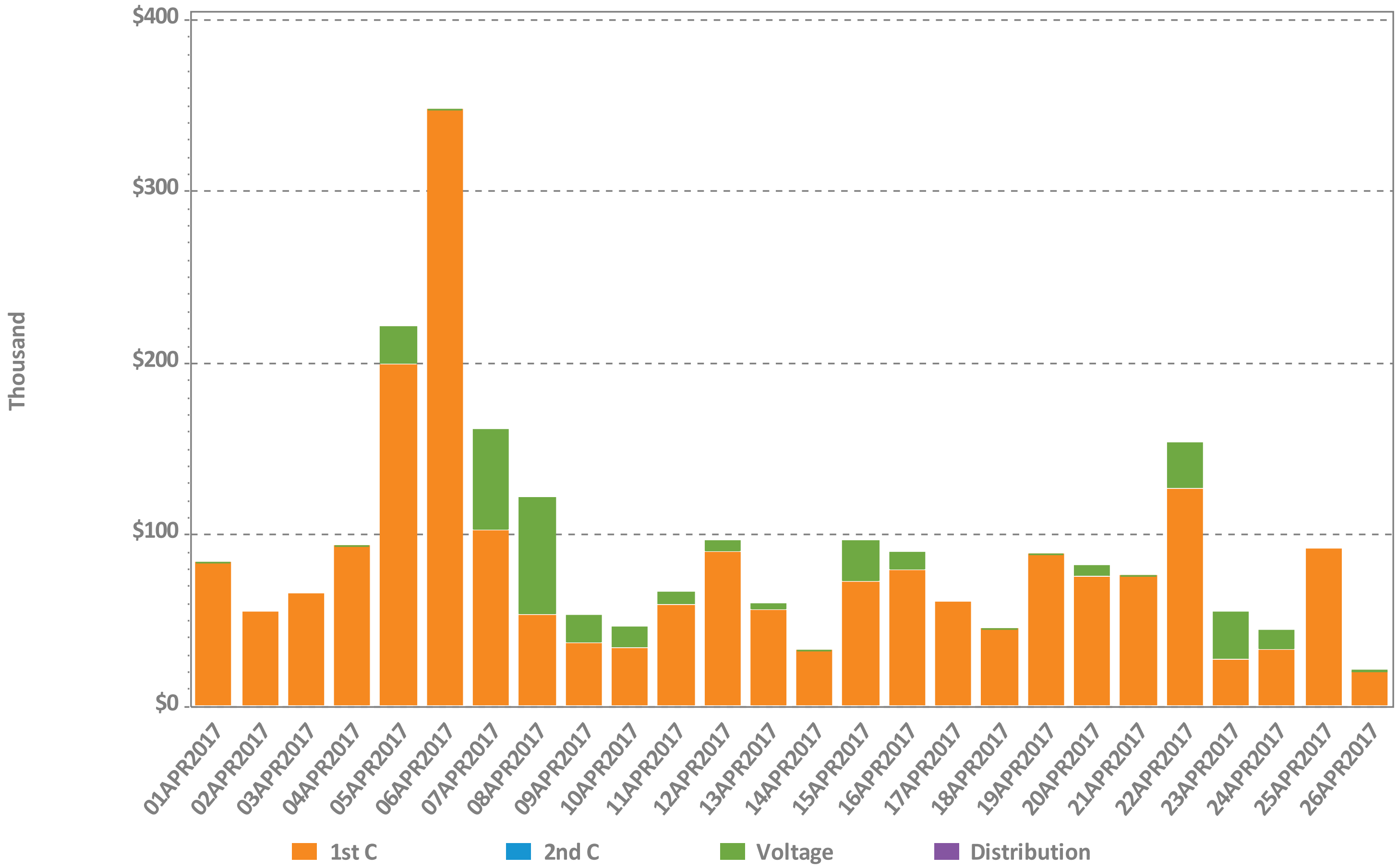
NCPC Charges by Type





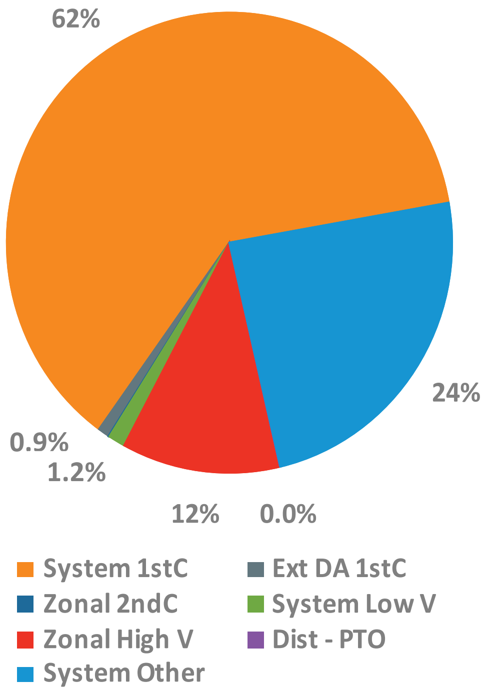
1^{st} C – First Contingency
2^{nd} C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

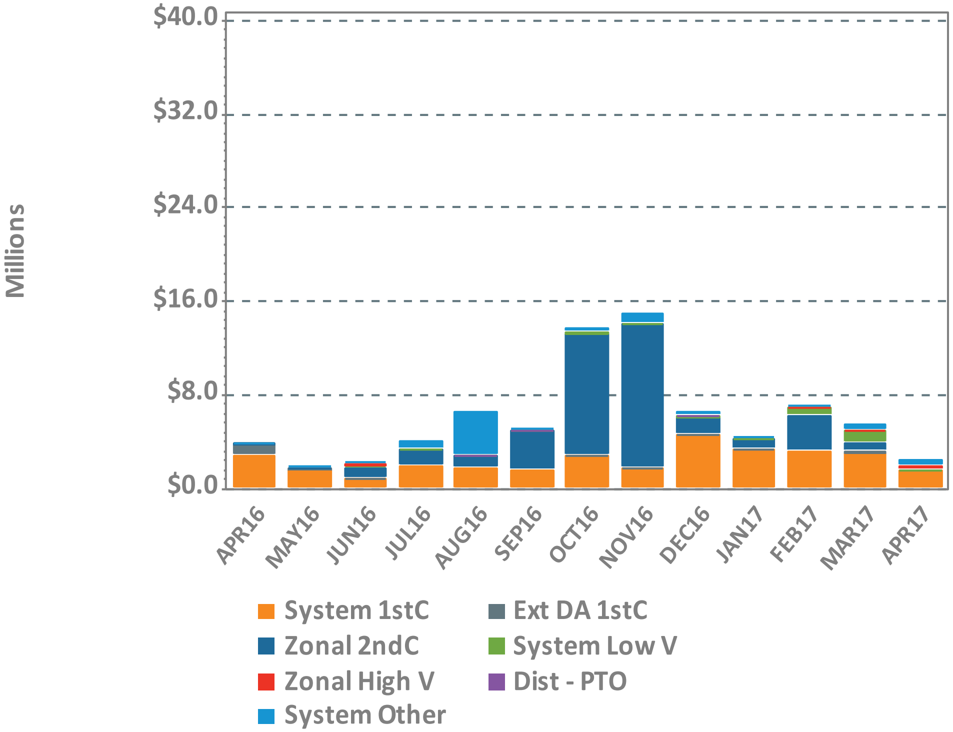


NCPC Charges by Allocation

APR-17 Total = $2.41 M

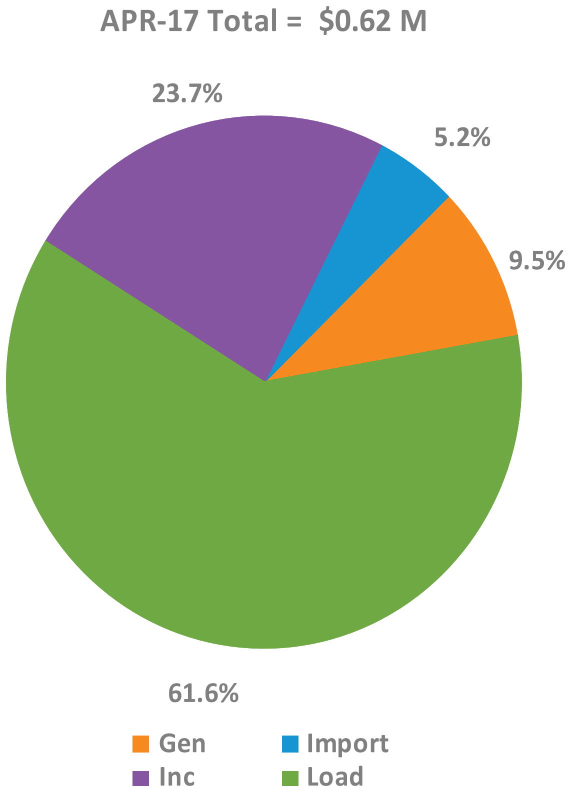


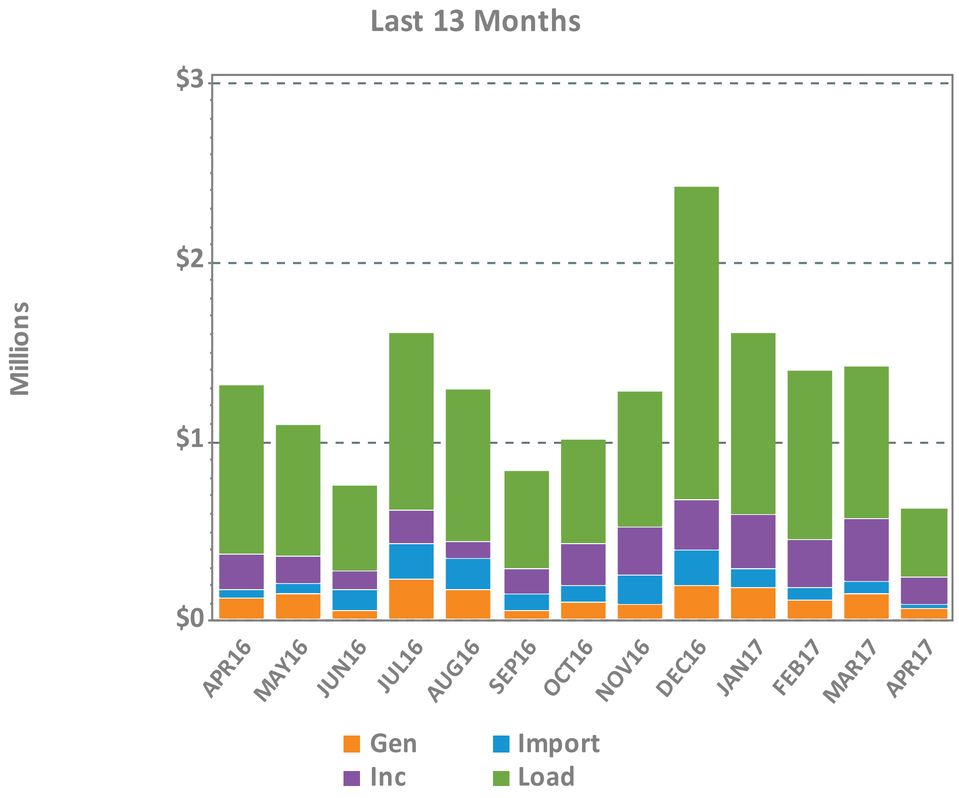
Last 13 Months



Note: ‘System Other’ includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

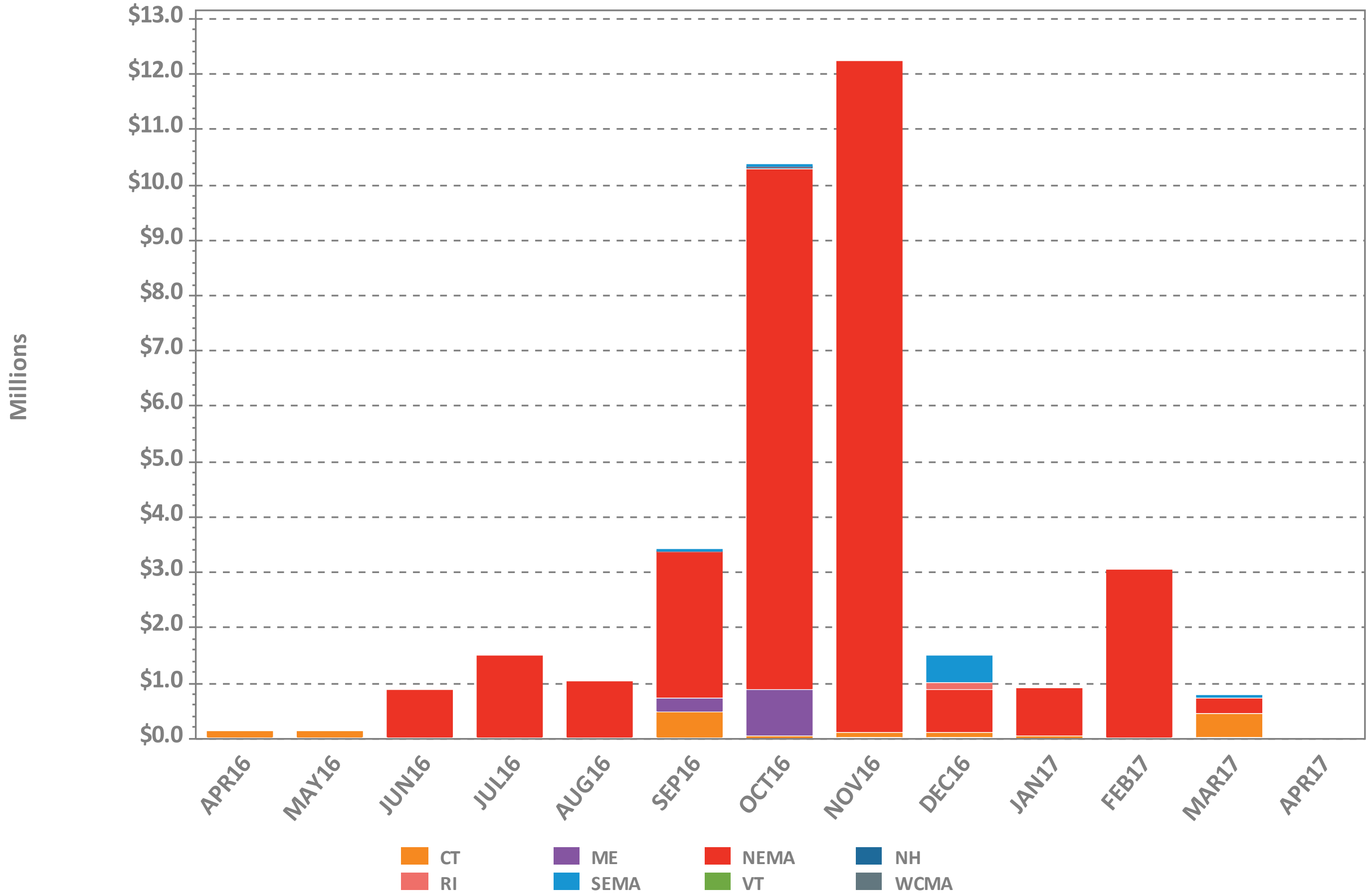
RT First Contingency Charges by Deviation Type





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

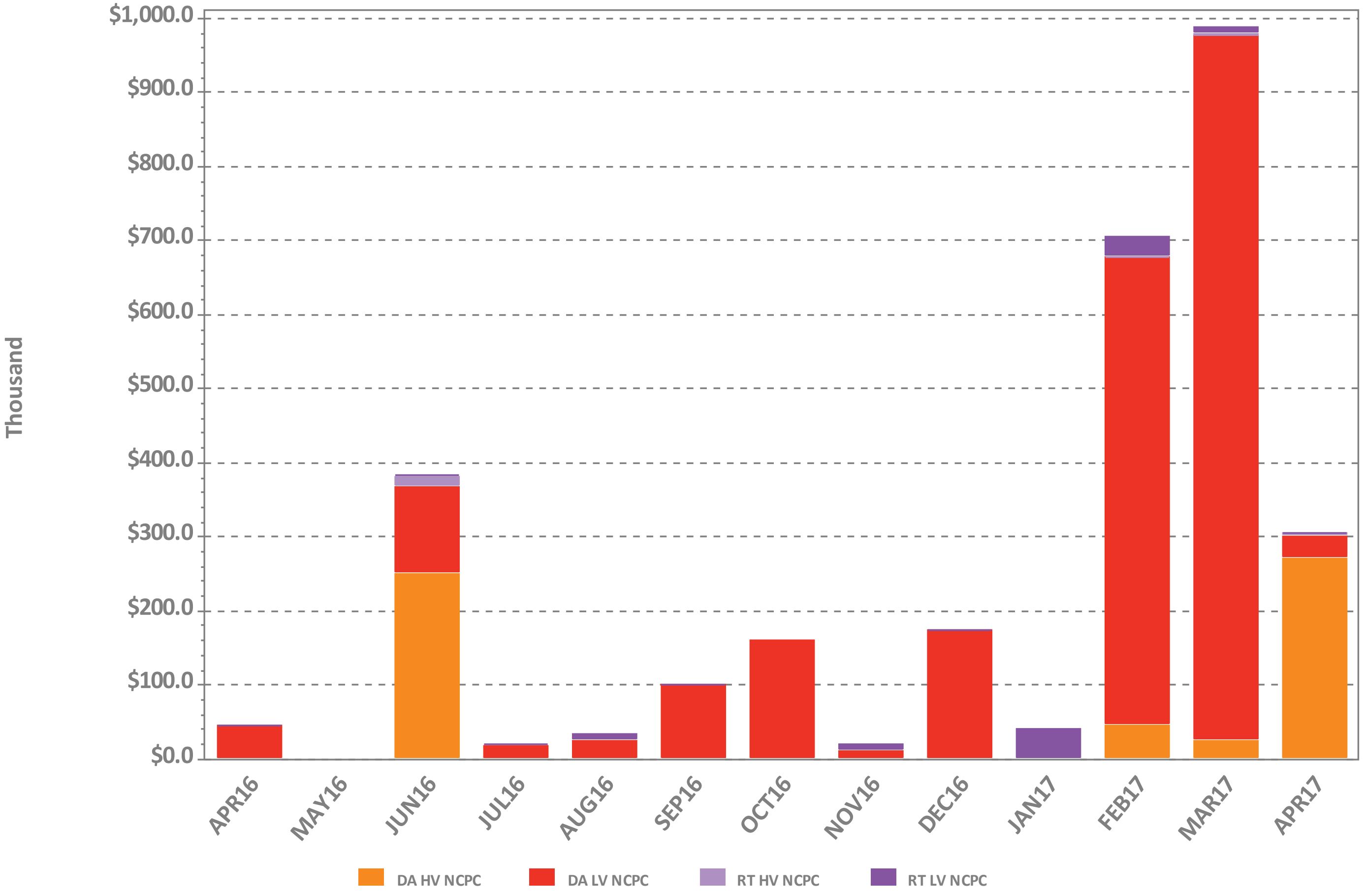
LSCPR Charges by Reliability Region



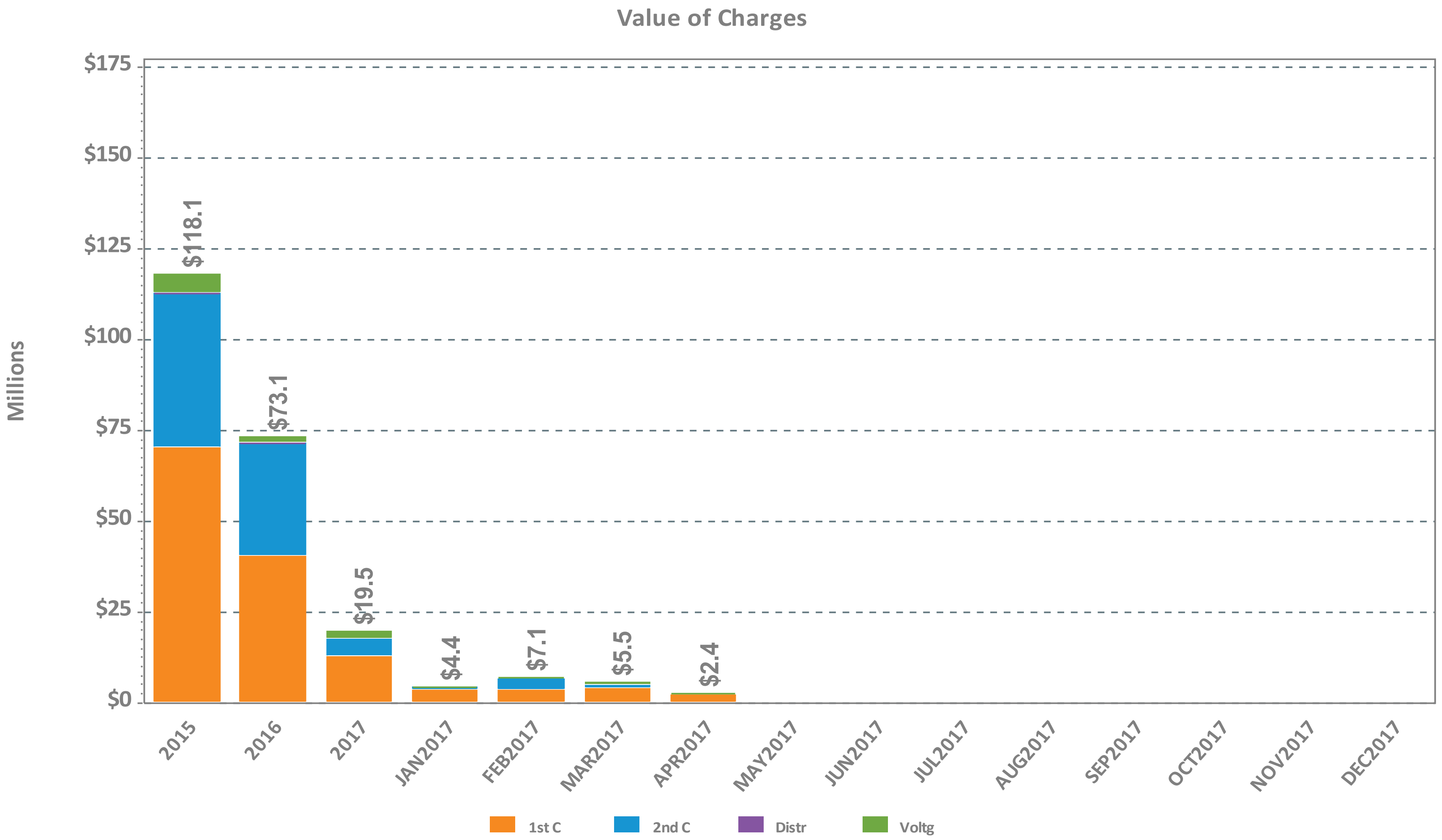
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

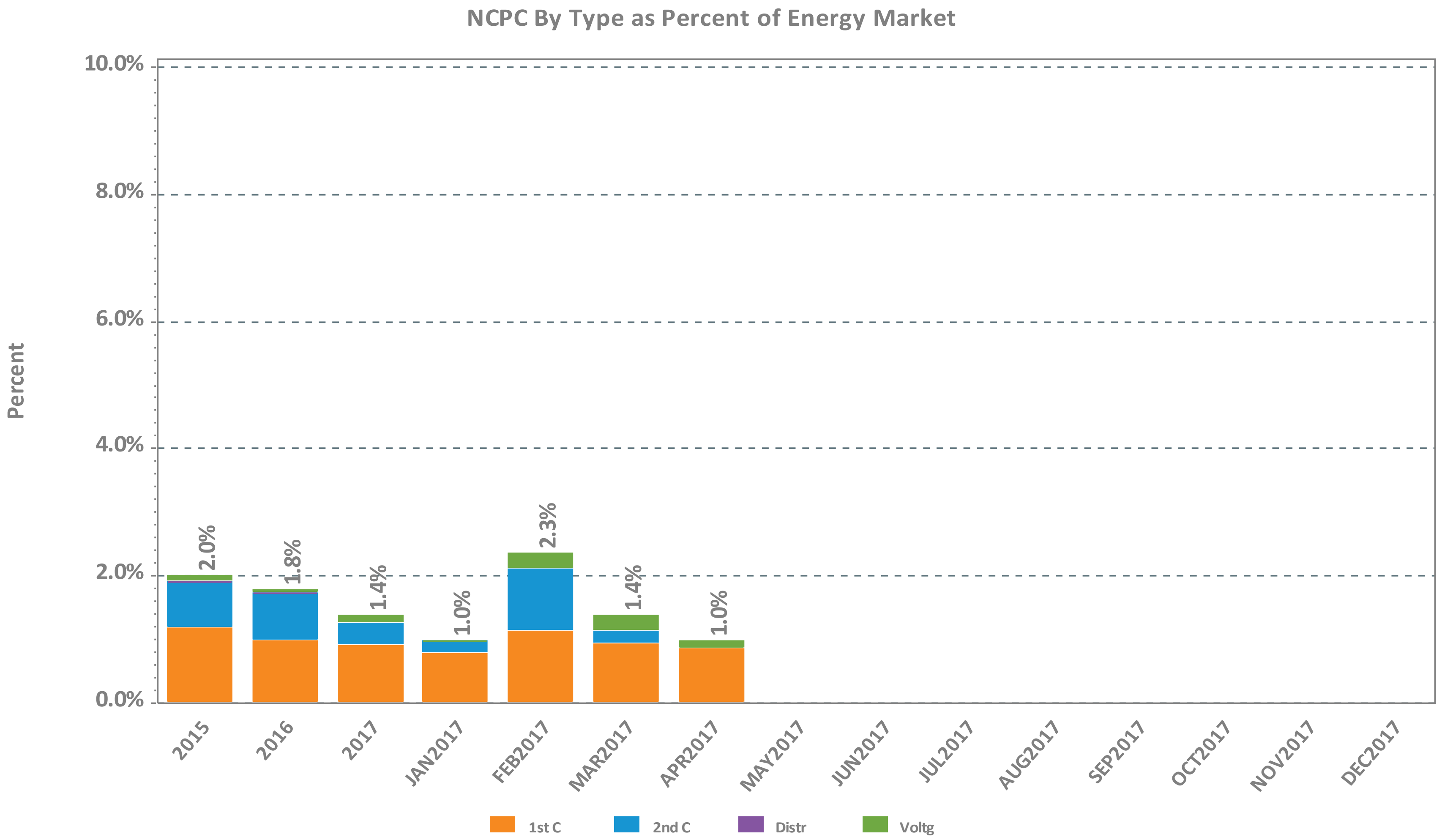
NCPC Charges for Voltage Support and High Voltage Control



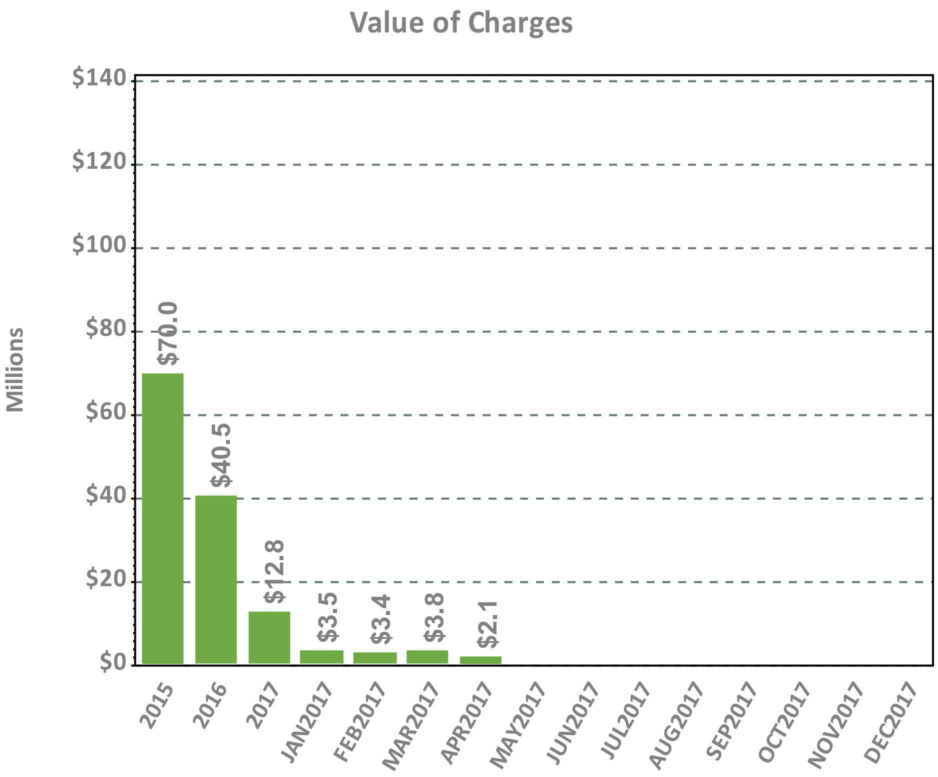
NCPC Charges by Type

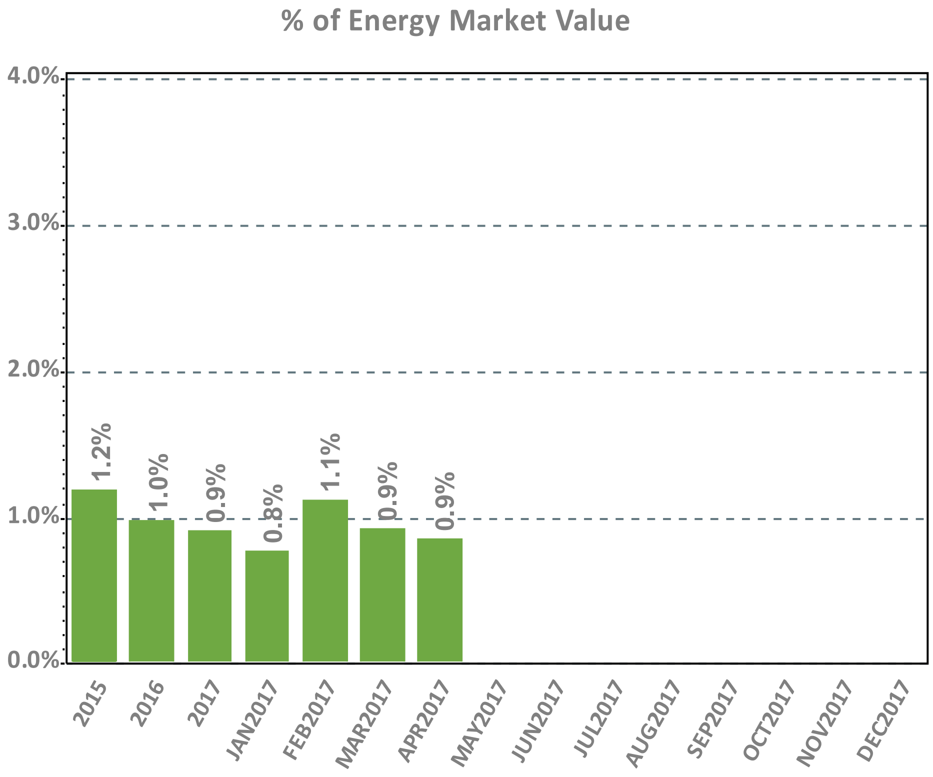


NCPC Charges as Percent of Energy Market



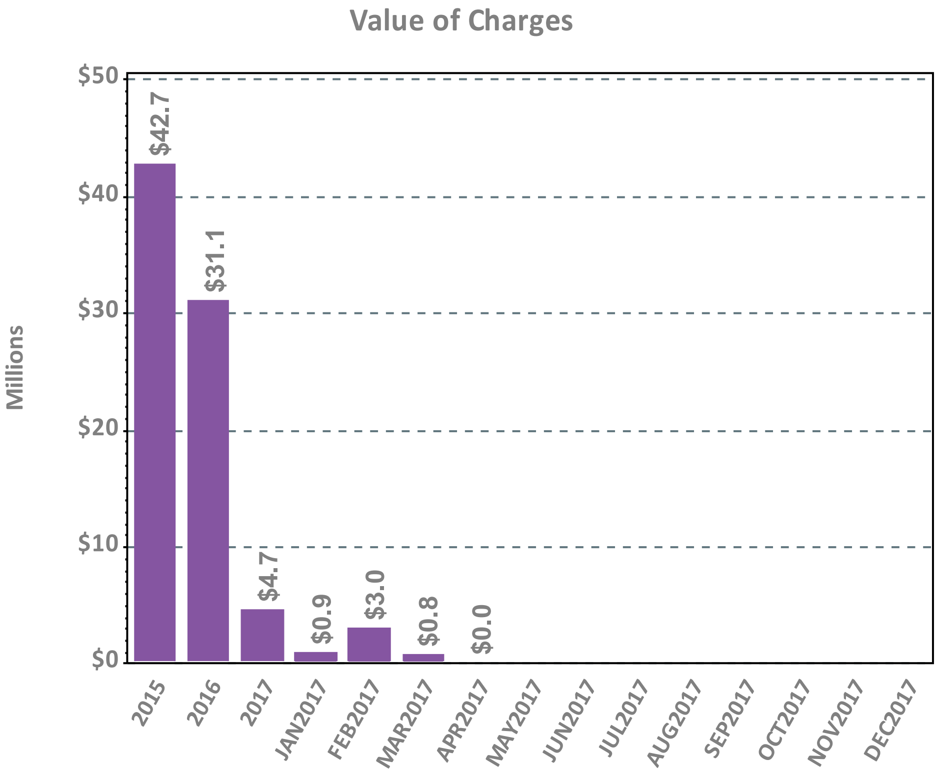
First Contingency NCPC Charges

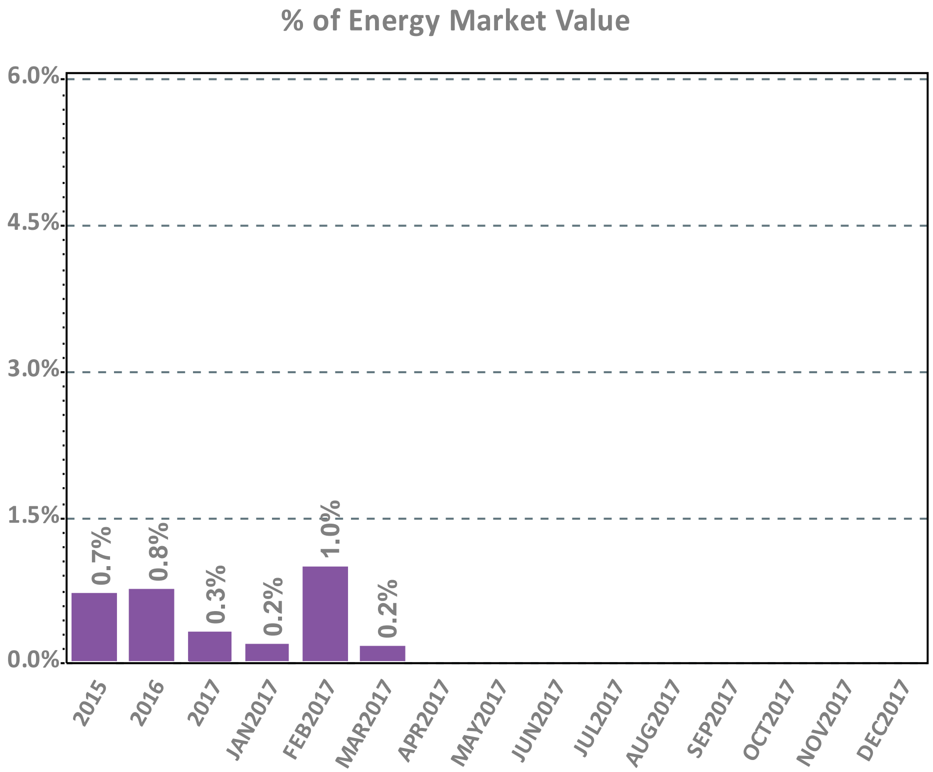




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

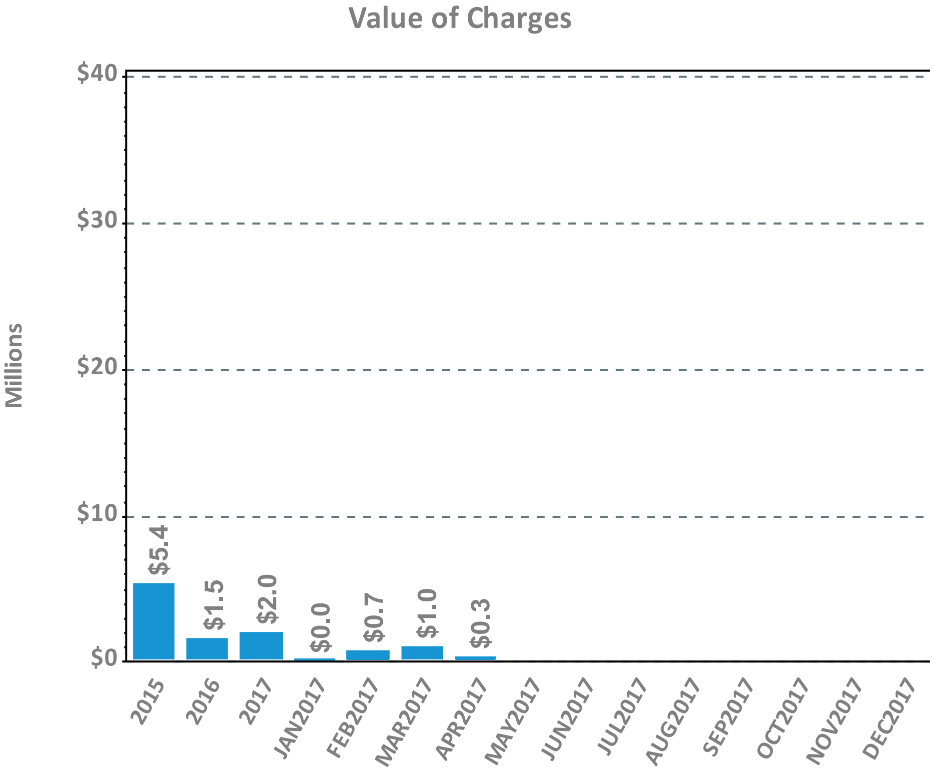
Second Contingency NCPC Charges

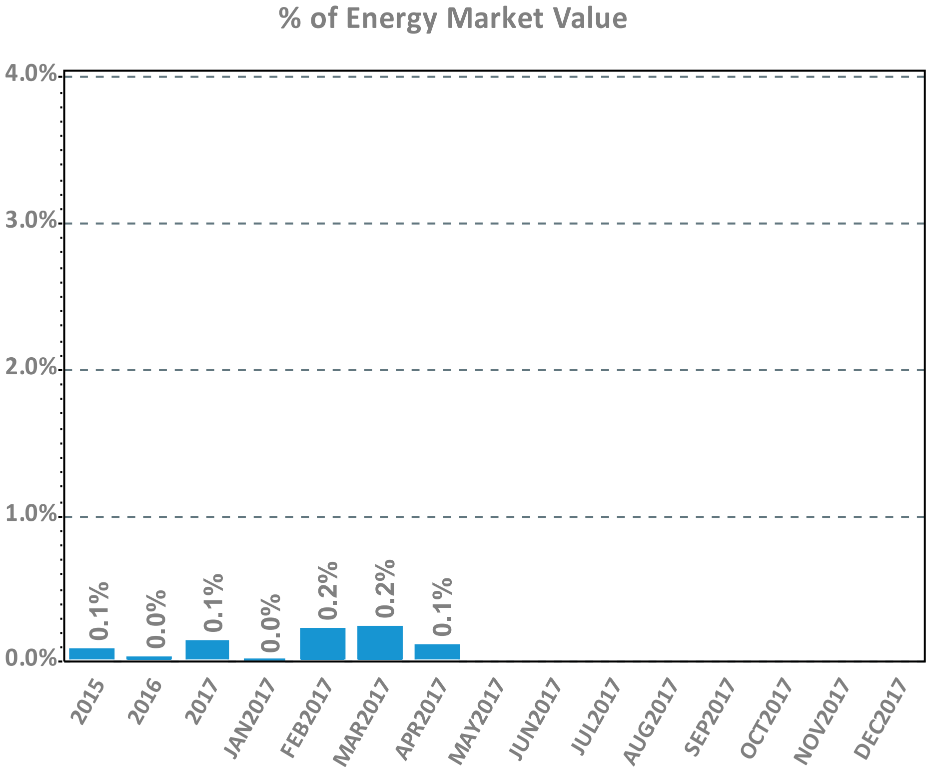




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

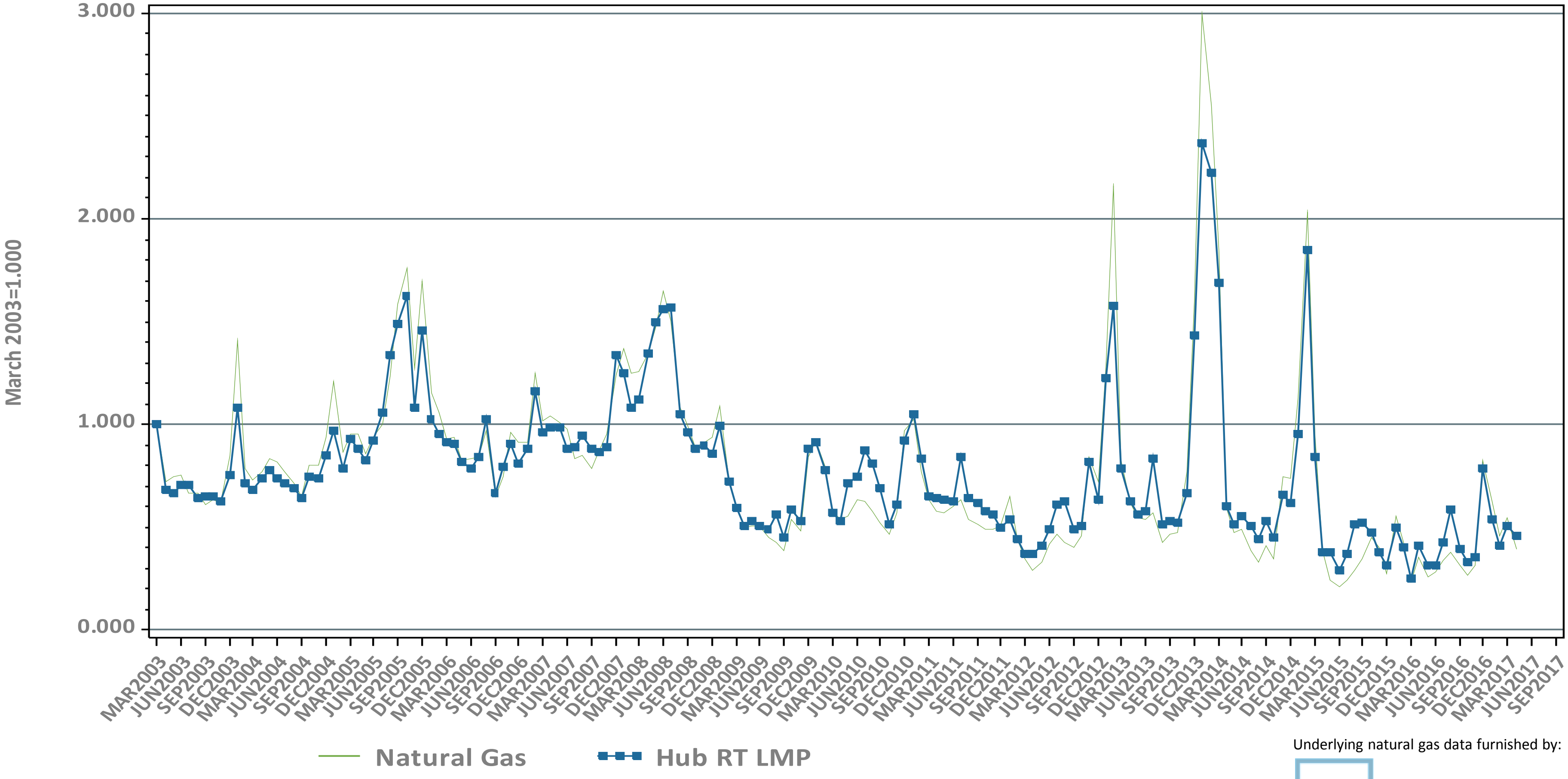
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2015	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$42.56	$41.23	$40.81	$42.11	$41.58	$42.20	$42.23	$41.93	$41.90
Real-Time	$41.58	$40.58	$39.23	$40.21	$40.22	$41.03	$41.21	$40.96	$41.00
RT Delta %	-2.3%	-1.6%	-3.9%	-4.5%	-3.3%	-2.8%	-2.4%	-2.3%	-2.2%
Year 2016	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$30.66	$29.77	$29.07	$29.64	$29.66	$29.66	$29.88	$29.85	$29.78
Real-Time	$29.74	$29.00	$27.81	$28.60	$28.49	$28.87	$29.01	$28.98	$28.94
RT Delta %	-3.0%	-2.6%	-4.3%	-3.5%	-3.9%	-2.7%	-2.9%	-2.9%	-2.8%

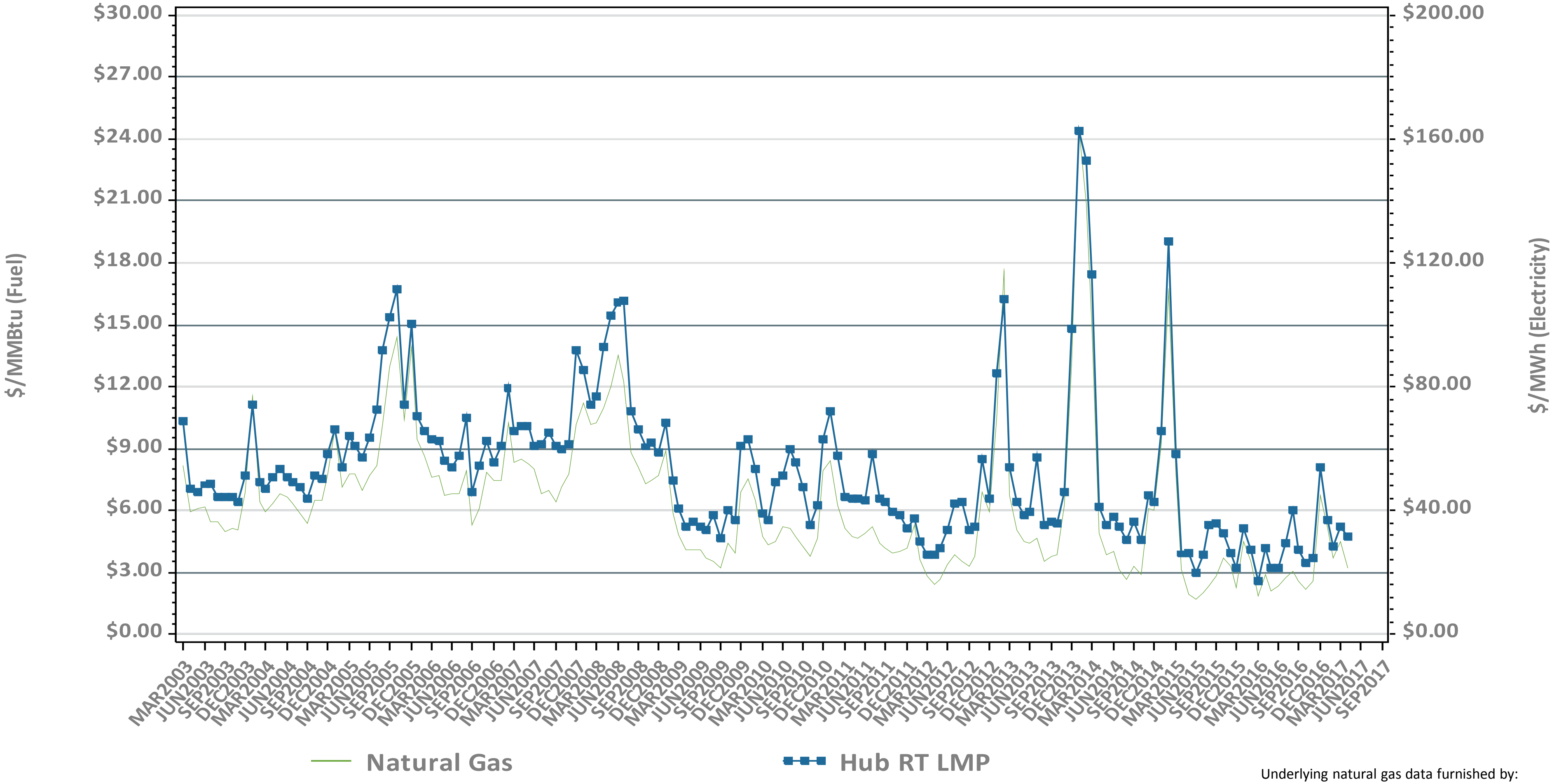
April-16	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$28.43	$28.11	$27.72	$28.18	$27.91	$28.30	$28.43	$28.33	$28.36
Real-Time	$28.11	$27.88	$27.03	$27.54	$27.16	$28.00	$28.06	$27.94	$28.00
RT Delta %	-1.1%	-0.8%	-2.5%	-2.3%	-2.7%	-1.1%	-1.3%	-1.4%	-1.3%
April-17	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$29.50	$30.00	$29.06	$29.53	$28.85	$29.12	$29.35	$29.59	$29.48
Real-Time	$31.52	$31.77	$29.58	$31.18	$30.35	$31.09	$31.32	$31.48	$31.42
RT Delta %	6.8%	5.9%	1.8%	5.6%	5.2%	6.8%	6.7%	6.4%	6.6%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	3.8%	6.7%	4.8%	4.8%	3.4%	2.9%	3.2%	4.4%	4.0%
Yr over Yr RT	12.1%	13.9%	9.4%	13.2%	11.8%	11.1%	11.6%	12.6%	12.2%

Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by: ice Global markets in clear view

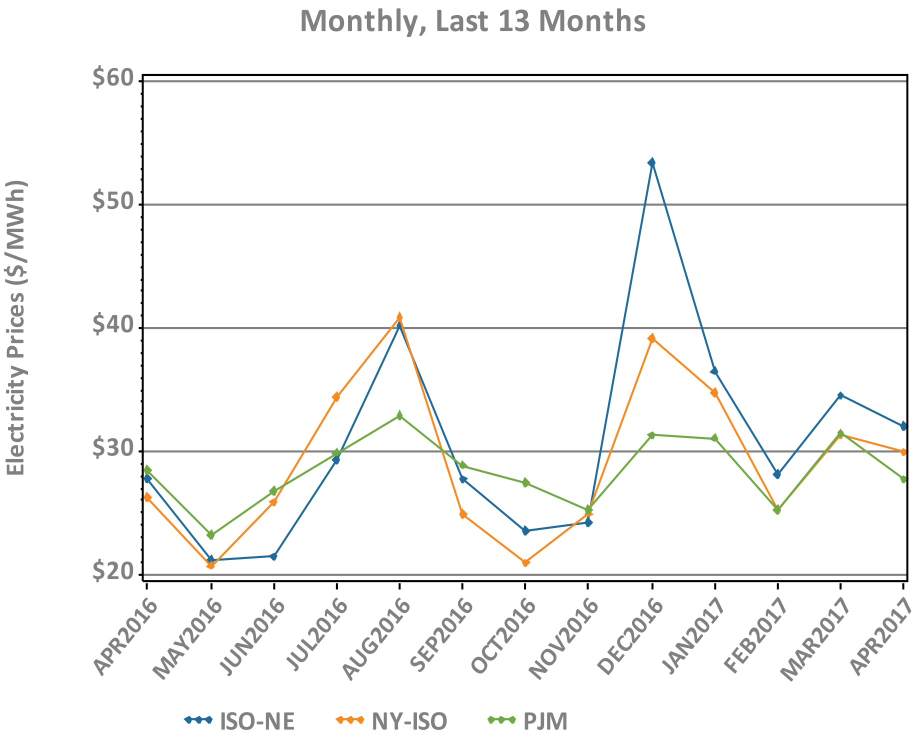
Monthly Average Fuel Price and RT Hub LMP



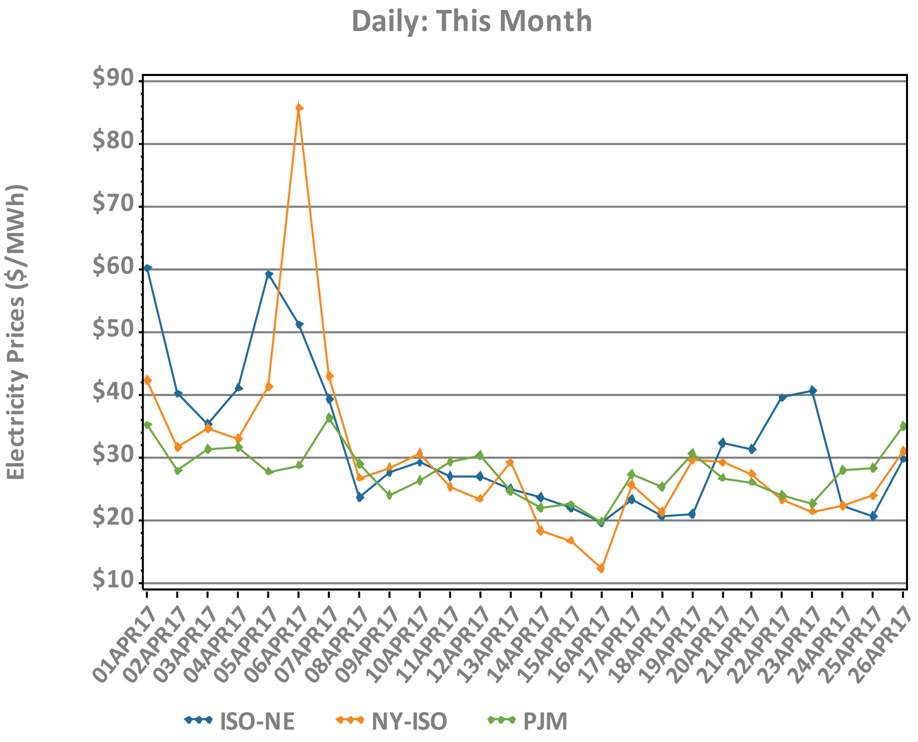
Underlying natural gas data furnished by:

ice Global markets in clear view

New England, NY, and PJM Hourly Average Real Time Prices by Month

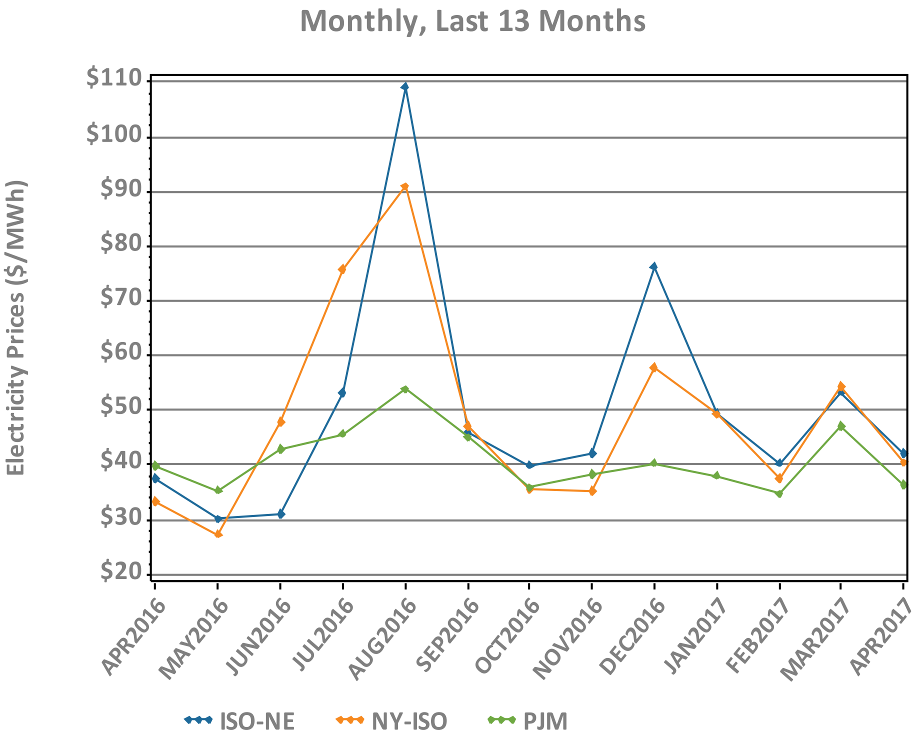


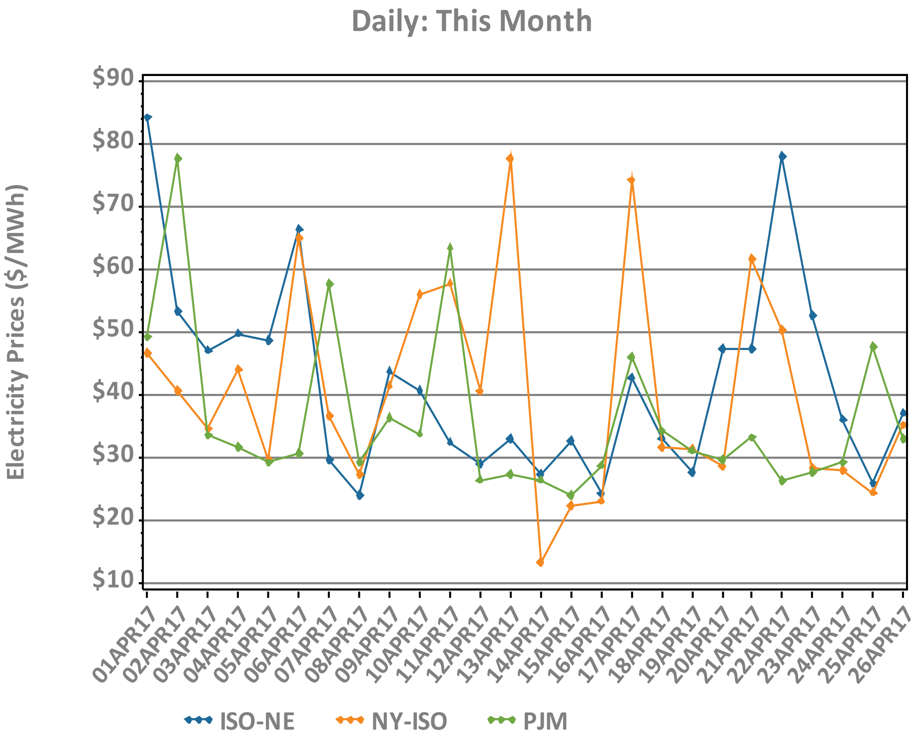
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

New England, NY, and PJM Average Peak Hour Real Time Prices





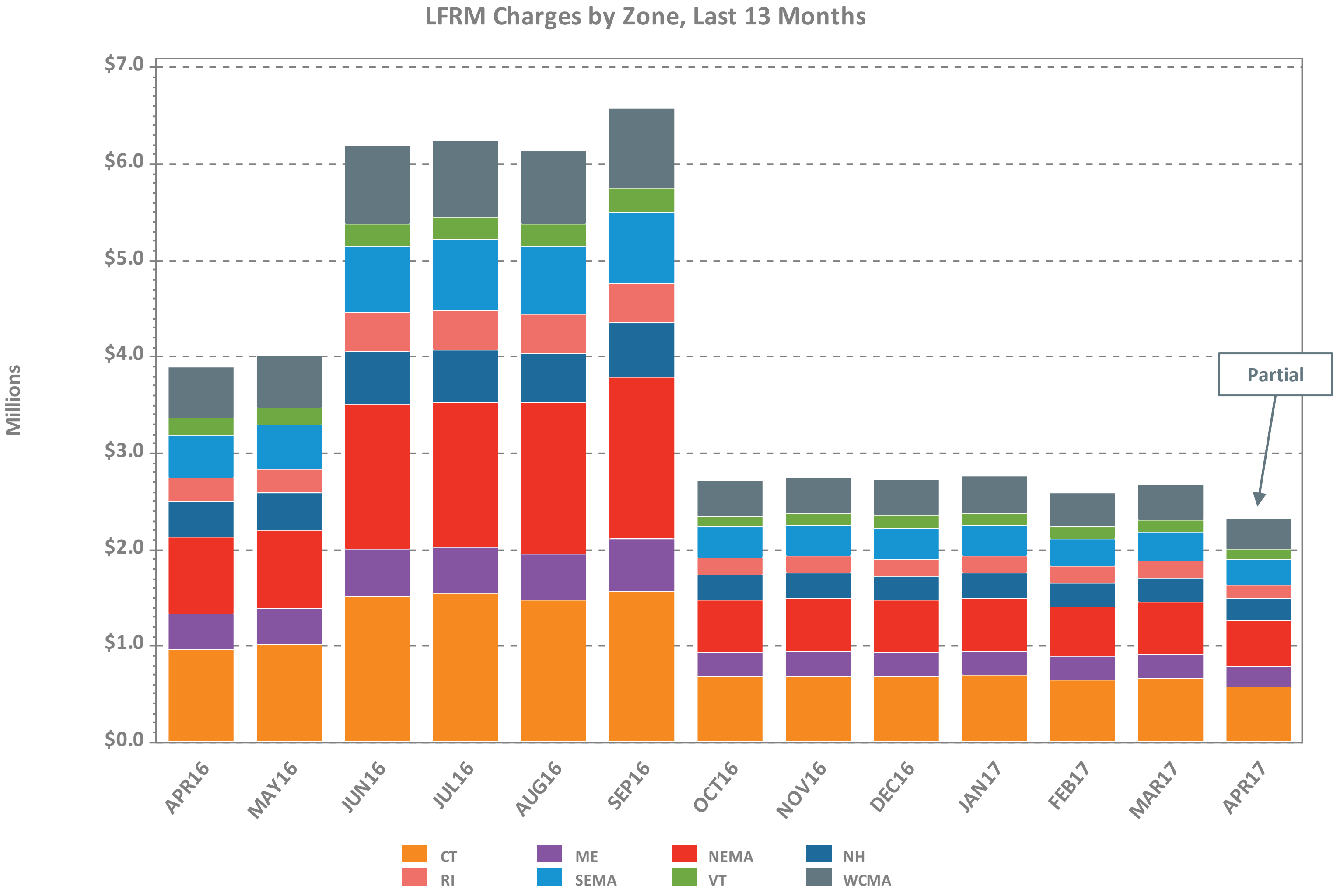
***Forecasted New England daily peak hours reflected**

Reserve Market Results – April 2017

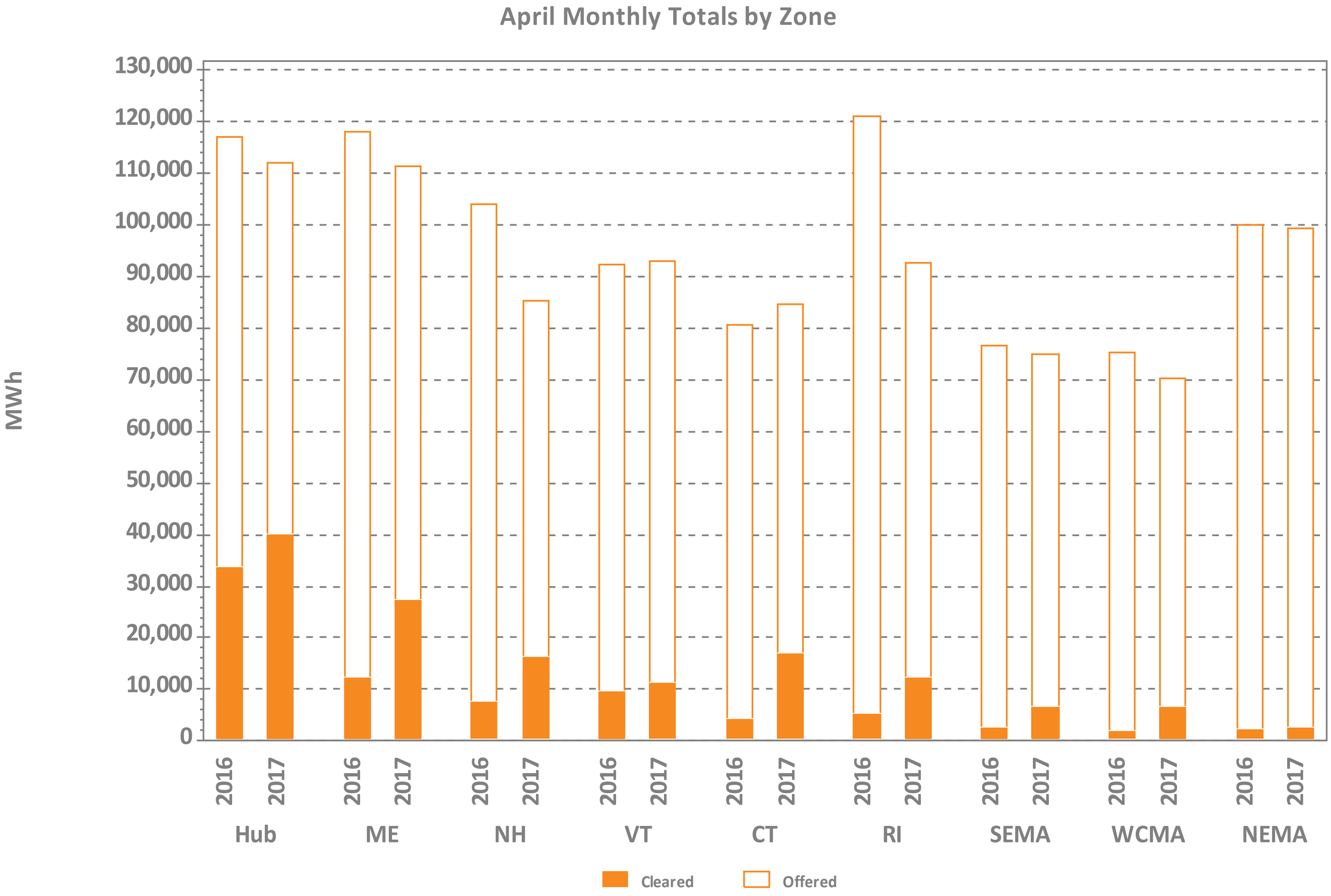
- Maximum potential Forward Reserve Market payments of \$2.5M were reduced by credit reductions of \$91K, failure-to-reserve penalties of \$137K and no failure-to-activate penalties, resulting in a net payout of \$2.3M or 91% of maximum
  - Rest of System: \$1.38M/1.48M (93)%
  - Southwest Connecticut: \$0.2M/0.25M (80)%
  - Connecticut: \$0.74M/0.81M (91)%
- \$628K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of \$628K in Real-Time Reserve payments
  - Rest of System: 200 hours, \$547K
  - Southwest Connecticut: 200 hours, \$18K
  - Connecticut: 200 hours, \$38K
  - NEMA: 200 hours, \$26K

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

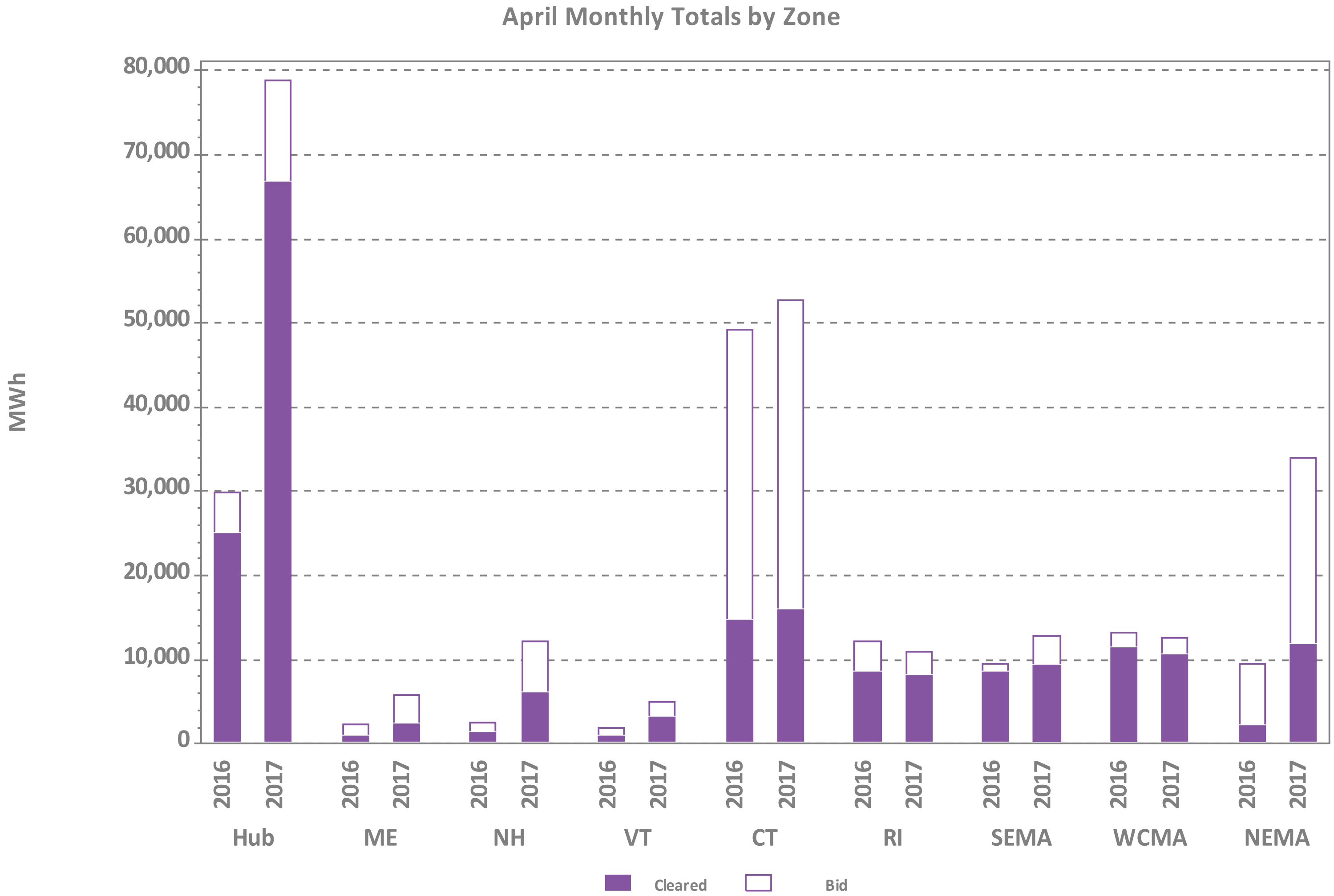
LFRM Charges to Load by Load Zone ($)



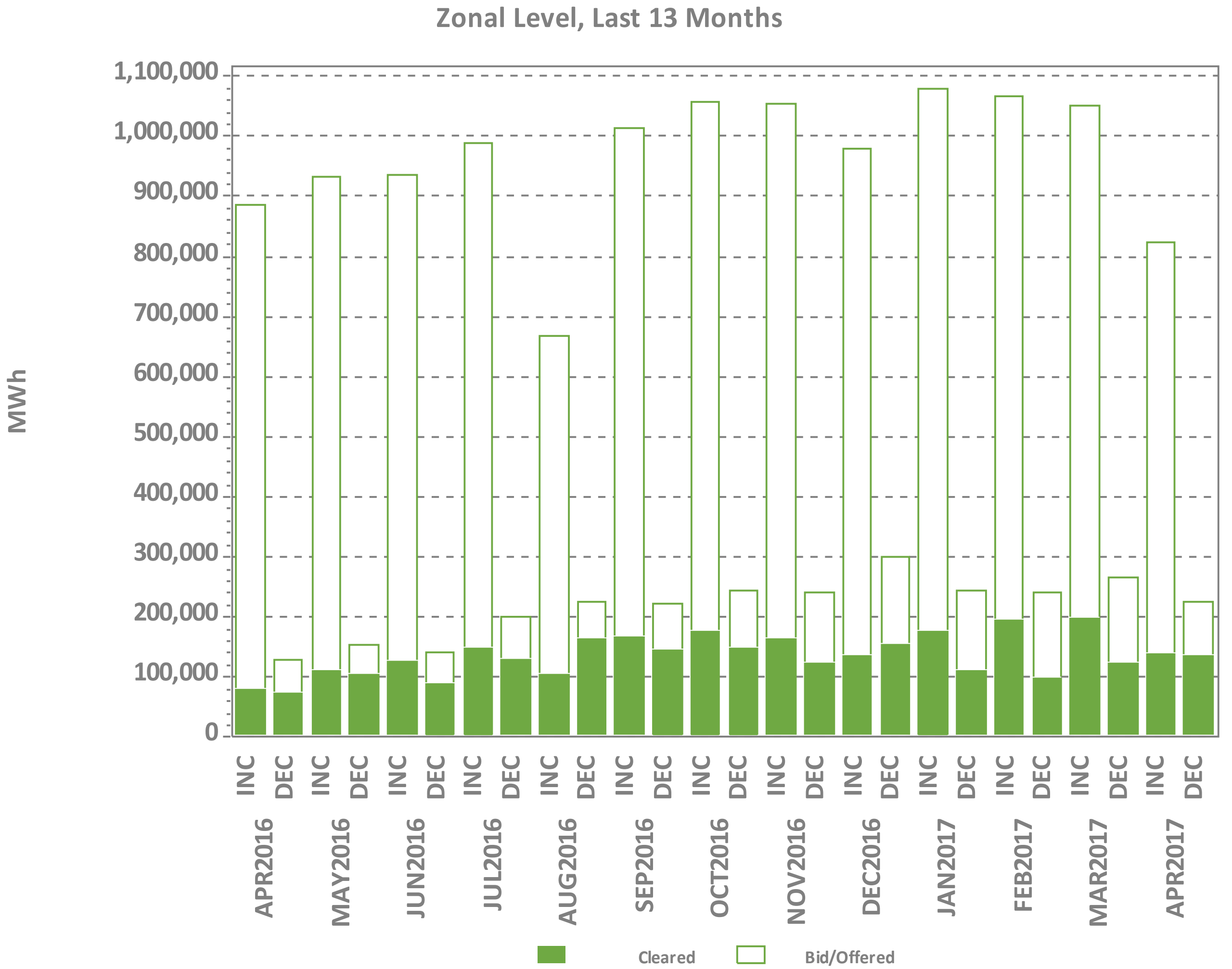
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

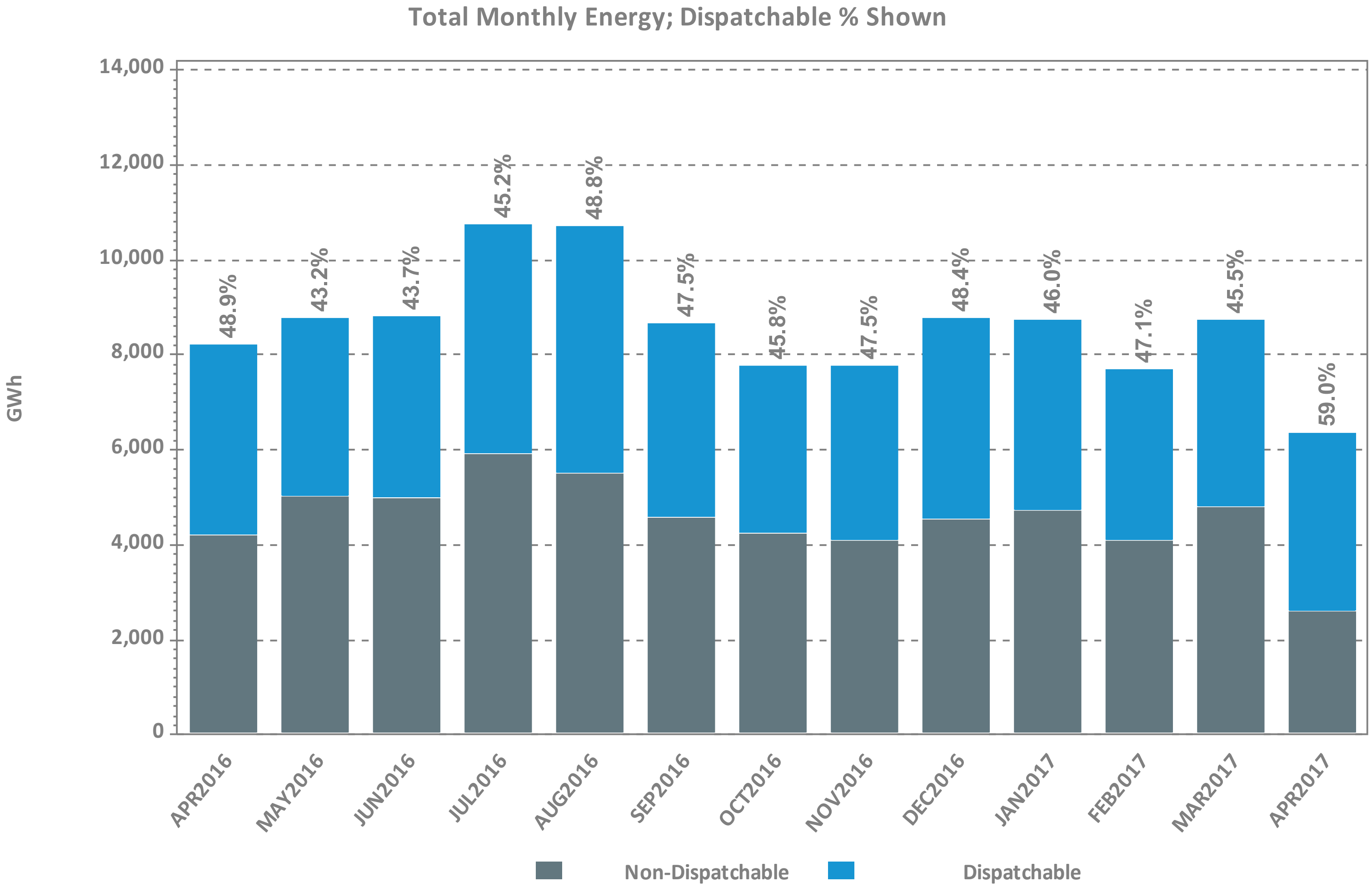


Total Increment Offers and Decrement Bids



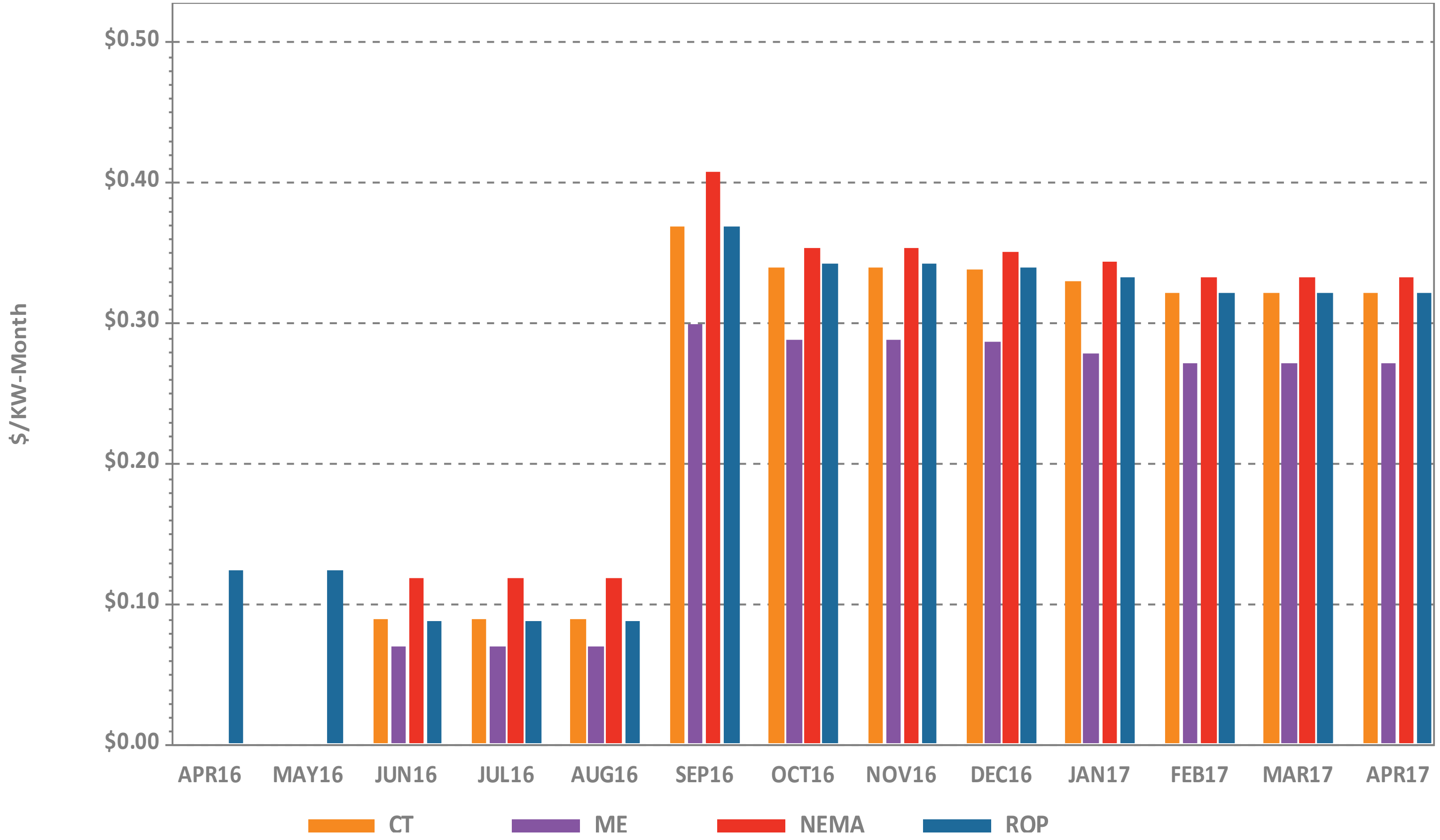
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



*** Dispatchable MWh here are defined to be generation output that is not self-scheduled (i.e, not self-committed or 'must run' by the customer).**

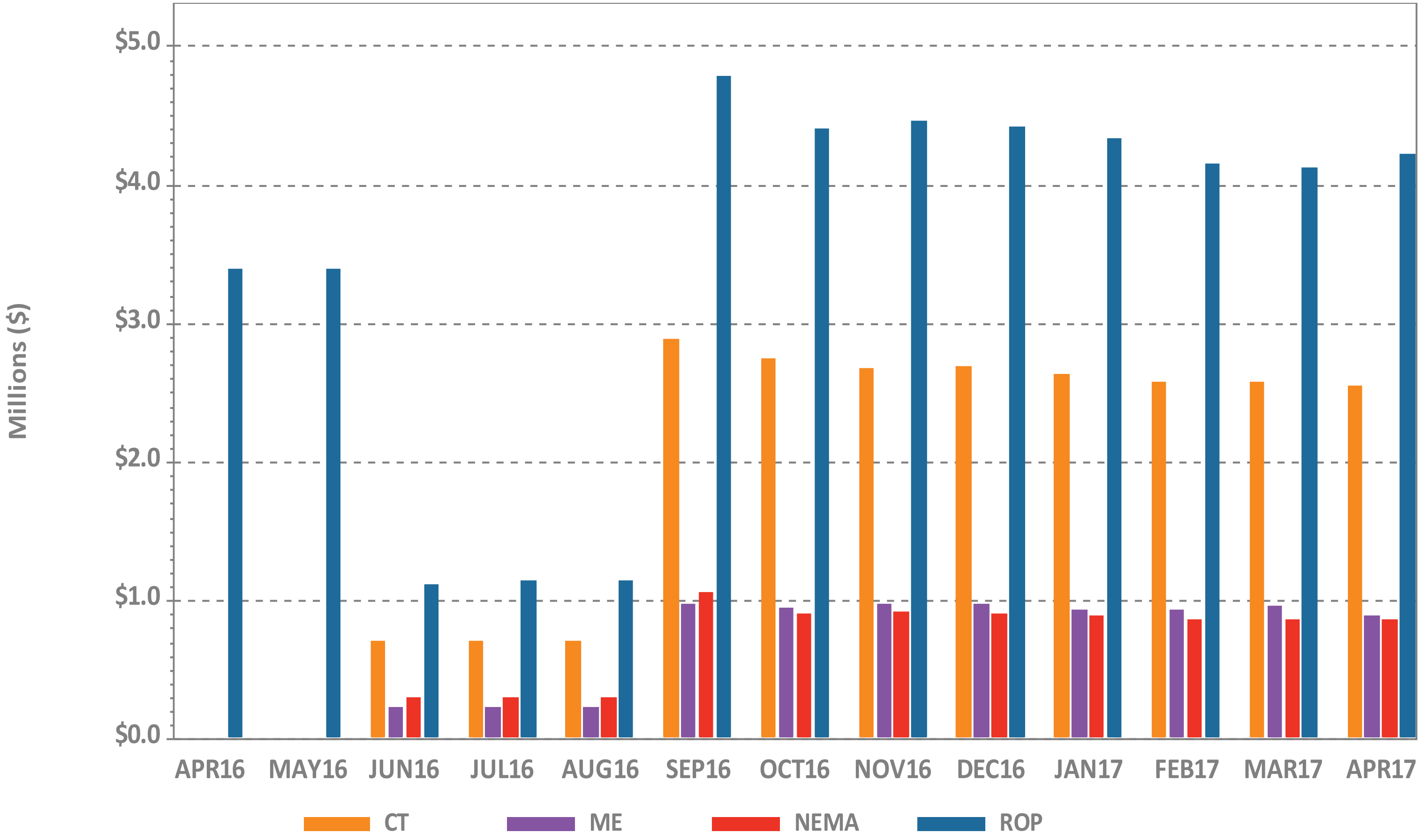
Rolling Average Peak Energy Rent (PER)



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

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

PER Adjustments



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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- RSP17 work is proceeding
- May 24 PAC Meeting Agenda*
  - Representative ICR and Associated Values
  - Representative Forward Reserve
  - Maine Resource Integration Study
  - Replace Failed Scobie Pond TB30 Transformer
  - 3419 Line Asset Condition and OPGW Project
  - Salem Harbor Substation 115 kV Asset Condition – Solutions
- May 25 PAC Meeting Agenda*
  - 2017 Economic Study Scope of Work
  - 2016 Economic Study Phase 2 - FCA Results
  - 2016 Economic Study Phase 2 - Scenario Analysis Natural Gas System Analysis Results

* Agenda items are subject to change. Visit https://www.iso-ne.com/committees/planning/planning-advisory for the latest PAC agendas.

Load, Energy Efficiency, and Photovoltaic Forecast

- Load Forecast
  - Final 2017 Gross and Net Load Forecasts are complete and results were published on May 1 as part of the 2017 CELT report
    - Compared to the 2016 CELT, the Gross Annual Energy Forecast is approximately 1% lower in 2025
      - Summer 50/50 is approximately 0.9% lower in 2025
      - Summer 90/10 is approximately 0.7% lower in 2025
    - Compared to the 2016 CELT, the Net Annual Energy Forecast is approximately 4.2% lower in 2025
      - Net summer 50/50 forecast is approximately 3.3% lower in 2025
      - Summer 90/10 forecast is approximately 2.9% lower in 2025
  - Next Load Forecast Committee will be in July 2017

- Energy-Efficiency (EE) Forecast
  - Final 2017 EE forecast is now complete and results were published on May 1 as part of the 2017 CELT report
    - Compared to the 2016 CELT, the EE forecast is approximately 11% higher in 2025

Load, Energy Efficiency, and Photovoltaic Forecast, cont.

- Photovoltaic (PV) Forecast
  - The PV forecast is complete and results were published on May 1 as part of the 2017 CELT report
    - As compared to the 2016 CELT forecast, the total 2017 nameplate PV forecast is approximately 40% higher in 2025, and estimated summer peak load reductions from the BTM PV portion of the forecast are approximately 24% higher in 2025

Environmental Matters

- The ISO continues tracking environmental regulatory developments
  - Environmental Advisory Group is scheduled to meet on June 6

Economic Studies

- 2016 Economic Study - NEPOOL Scenario Analysis Phase I draft report remains on schedule for the second quarter
  - Phase I observations and key messages and results for requests for additional metrics and sensitivities were discussed with the PAC for the six base scenarios
  - Work is proceeding on the Phase II scopes of work discussed at the December 14 PAC meeting and are scheduled for completion during 2017
    - Natural gas pipeline results
    - Scope of work for FCA auction results
    - Scope of work for regulation, ramping, and reserves
- 2017 Economic Study request was received from CLF and discussed with the PAC on April 19
  - The ISO will work with the requestor at the May 25 PAC meeting

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

Connecticut River Valley

Status as of 5/1/17

Project Benefit: Addresses system needs in the Connecticut River Corridor in Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild 115 kV line K31, Coolidge-Ascutney	Sep-17	3
Ascutney Substation - Add a +50/-25 MVAR dynamic reactive device	May-18	3
Hartford Substation - Split 25 MVAR capacitor bank into two 12.5 MVAR banks	Dec-16	4
Chelsea Station - Rebuild to a three-breaker ring bus	Feb-18	3

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 5/1/17

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	4
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Feb-17	4
New 115 kV overhead line, Scobie Pond-Huse Road	Dec-15	4
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-18	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

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

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 5/1/17

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Aug-16	4
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	4
Rebuild 115 kV line H137, Merrimack-Garvins	Jun-13	4
Rebuild 115 kV line D118, Deerfield-Pine Hill	Nov-14	4
Oak Hill Substation - Loop in 115 kV line V182, Garvins-Webster	Dec-14	4
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

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

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 5/1/17

Project Benefit: Addresses Needs in New Hampshire and Vermont

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

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

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 5/1/17

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Apr-17	4
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Feb-17	4
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add two 115 kV 25.2 MVAR capacitor banks	Dec-17	3
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-15	4
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Dec-17	4
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Jan-17	4
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 5/1/17

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

Upgrade	Expected/ Actual In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-18	2
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-18	2
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	Dec-17	3
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Dec-17	3
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-18	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 5/1/17

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	3
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	3
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-18	2
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-17	3
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Dec-17	3
Add a 345 kV breaker in series with breaker 5T at Southington	Dec-17	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 5/1/17

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-17	3
Add a new 115 kV line from Frost Bridge to Campville	Jun-18	3
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Dec-18	3
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-16	4
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-15	4
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-15	4
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Apr-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 5/1/17

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Mar-16	4
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Dec-18	2
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Sep-17	3
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-16	4
Loop the 1990 line in and out the Bunker Hill substation*	Dec-18	1
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Jul-18	2
Loop the 1570 line in and out the Pootatuck substation	Dec-18	2
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 5/1/17

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	2
Add a new 115 kV line from Plumtree to Brookfield Junction	Dec-18	1
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-18	2
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Dec-17	2
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	Dec-18	2
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	Dec-18	2
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Dec-18	2
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	Dec-18	2

Southwest Connecticut Projects, cont.

Status as of 5/1/17

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

Upgrade	Expected/ Actual In-Service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Apr-17	4
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	May-16	4
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	May-17	3
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-18	2
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-18	2

Southwest Connecticut Projects, cont.

Status as of 5/1/17

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

Upgrade	**Expected/ Actual In-Service**	**Present Stage**
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	4
Upgrade the 115 kV bus at the Baird substation	May-18	3
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-15	4
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Apr-19	3
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Dec-20	2

Southwest Connecticut Projects, cont.

Status as of 5/1/17

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

Upgrade	Expected/ Actual In-Service	Present Stage
Remove the Sackett phase shifter	Mar-17	4
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-16	4
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-16	4
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Jan-17	4
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Nov-16	4
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Greater Boston Projects

Status as of 5/1/17

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	3
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	3
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	3
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-18	2
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn	May-19	2
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jul-18	2

Greater Boston Projects, cont.

Status as of 5/1/17

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-17	2
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	3*
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-19	2
Install third 115 kV line from West Walpole to Holbrook	Sep-19	2
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	3
Install a new 115 kV line from Sudbury to Hudson	Dec-19	1

* Eversource portion of the project is complete

Greater Boston Projects, cont.

Status as of 5/1/17

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	May-19	3
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	3
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	3
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	3
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	Jun-18	3
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	May-19	2
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	May-19	2

Greater Boston Projects, cont.

Status as of 5/1/17

Plan Benefit: *Addresses long-term system needs in the Greater Boston area and improves system reliability*

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-18	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	Jun-18	3
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Jun-18	2
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 5/1/17

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Nov-17	3
Install a 200 MVAR STATCOM at Coopers Mills	Sep-18	2
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	3
Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-18	1
Install a 115 kV breaker in series with the 5 breaker at Framingham	Apr-17	4
Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

Pittsfield/Greenfield Projects

Status as of 5/1/17

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Separate and reconductor the Cabot Taps (A-127 and Y-177 115 kV lines)	Mar-17	4
Install a 115 kV tie breaker at the Harriman Station, with associated buswork, reconductor of buswork and new control house	Nov-17	3
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Jun-17	3
Build a new 115 kV three-breaker switching station (Erving) ring bus	Mar-17	4
Build a new 115 kV line from Northfield Mountain to the new Erving Switching Station	Jun-17	3
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 5/1/17

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild the Cumberland to Montague 1361 115 kV line and terminal work at Cumberland and Montague. At Montague Substation, reconnect Y177 115 kV line into 3T/4T position and perform other associated substation work	Dec-16	4
Remove the sag limitation on the 1512 115 kV line from Blandford Substation to Granville Junction and remove the limitation on the 1421 115 kV line from Pleasant to Blandford Substation	Dec-14	4
Loop the A127W line between Cabot Tap and French King into the new Erving Substation	Mar-17	4
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4

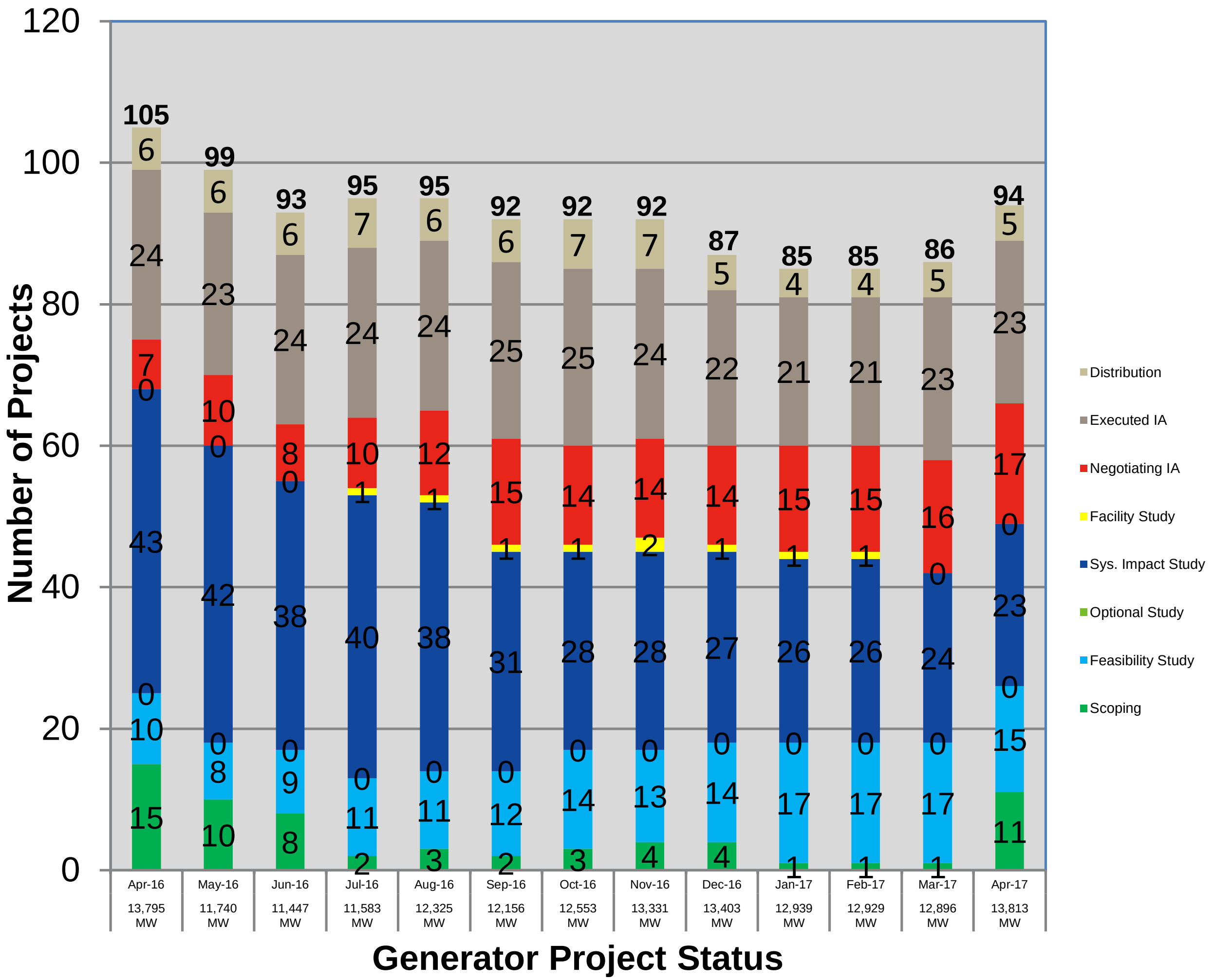
Pittsfield/Greenfield Projects, cont.

Status as of 5/1/17

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Install a 115 kV 20.6 MVAR capacitor at the Doreen substation and operate the 115 kV 13T breaker N.O.	Dec-17	2
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	2
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	2
Construct a 115 kV three-breaker ring bus at or adjacent to Pochassic 37R Substation, loop line 1512-1 into the new three-breaker ring bus, construct a new line connecting the new three-breaker ring bus to the Buck Pond 115 kV Substation on the vacant side of the double-circuit towers that carry line 1302-2, add a new breaker to the Buck Pond 115 kV straight bus and reconnect lines 1302-2, 1657-2 and transformer 2X into new positions	Dec-19	1

Status of Tariff Studies



Note: As of April 2017, there are 8 ETU's in SIS, 1 in OSIS, 3 in FS, 2 in Scoping, and 3 in Neg. IA

https://irtt.iso-ne.com/external.aspx

OPERABLE CAPACITY ANALYSIS

Spring 2017

Spring 2017 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2017 CSO	May - 2017 SCC
Operable Capacity MW [1]	30,241	32,828
OP CAP From OP-4 RTDR (+)	253	253
OP CAP From OP-4 RTEG (+)	13	13
Operable Capacity with OP-4 DR and RTEG	30,507	33,094
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	994	994
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	4,130	4,779
Gas Generator Outages/Reductions MW (-)	1,879	2,454
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	22,092	23,455
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,606	19,606
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,911	21,911
Operable Capacity Margin [3]	181	1,544

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **April 24, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 6, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Spring 2017 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	**May - 2017 CSO**	**May - 2017 SCC**
Operable Capacity MW [1]	30,241	32,828
OP CAP From OP-4 RTDR (+)	253	253
OP CAP From OP-4 RTEG (+)	13	13
Operable Capacity with OP-4 DR and RTEG	30,507	33,094
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	994	994
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	4,130	4,130
Gas Generator Outages/Reductions MW (-)	1,879	2,151
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	22,092	24,407
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,406	21,406
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,711	23,711
Operable Capacity Margin [3]	-1,619	696

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **April 24, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Load forecast that is based on the current CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 6, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Spring 2017 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

May 5, 2017 - 50/50 FORECAST using CSO values with RTDR and RTEG

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	EXTERNAL NODE AVAIL CAPACITY MW [2]	NON COMMERCIAL CAPACITY MW [3]	NON-GAS PLANNED OUTAGES CSO MW [4]	GAS GENERATOR OUTAGES CSO MW [5]	ALLOWANCE FOR UNPLANNED OUTAGES MW [6]	GAS AT RISK MW [7]	NET OPCAP SUPPLY MW [8]	PEAK LOAD FORECAST MW [9]	OPER RESERVE REQUIREMENT MW [10]	NET LOAD OBLIGATION MW [11]	OPCAP MARGIN MW [12]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [13]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [14]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [15]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [16]
5/6/2017	**30,241**	**994**	**0**	**4,130**	**1,879**	**3,400**	**0**	**21,826**	**19,606**	**2,305**	**21,911**	**(85)**	**253**	**168**	**13**	**181**
5/13/2017	30,241	994	0	3,439	1,100	3,400	0	23,296	20,629	2,305	22,934	362	253	615	13	628
5/20/2017	30,241	994	0	2,572	908	3,400	0	24,355	21,579	2,305	23,884	471	253	724	13	737
5/27/2017	29,420	1,304	0	1,509	339	3,400	0	25,476	22,622	2,305	24,927	549	380	929	2	931

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4.Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Preliminary net load forecast assumes Peak Load Exposrue (PLE) of 26,482 MW and does include credit of Passive Demand Response (PDR) http://www.iso-ne.com/system-planning/system-plans-studies/celt and behind-the-meter PV (BTM PV)
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of 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).

Spring 2017 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

May 5, 2017 - 90/10 FORECAST using CSO values with RTDR and RTEG

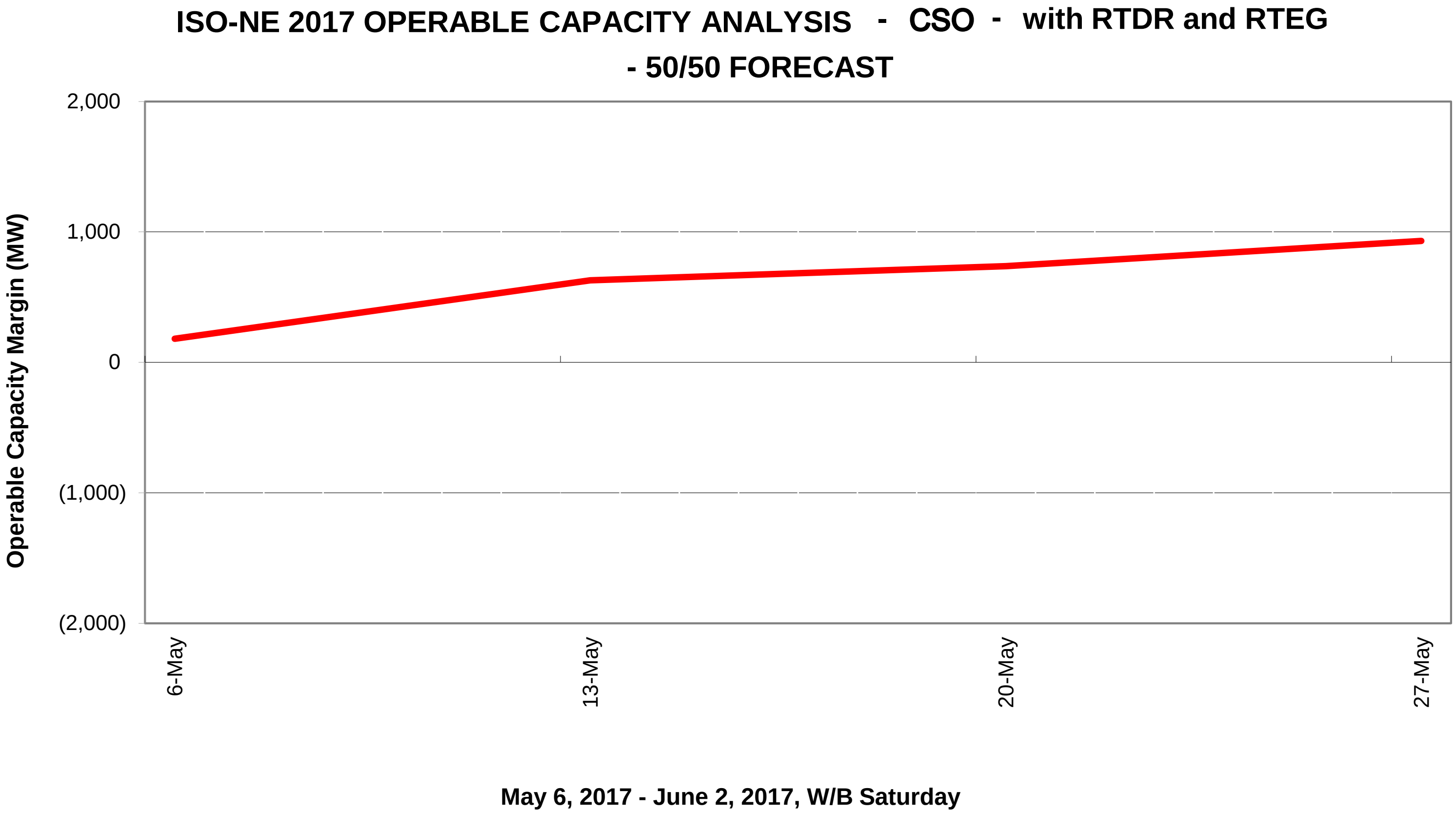
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
5/6/2017	**30,241**	**994**	**0**	**4,130**	**1,879**	**3,400**	**0**	**21,826**	**21,406**	**2,305**	**23,711**	**(1,885)**	**253**	**(1,632)**	**13**	**(1,619)**
5/13/2017	30,241	994	0	3,439	1,100	3,400	0	23,296	22,513	2,305	24,818	(1,522)	253	(1,269)	13	(1,256)
5/20/2017	30,241	994	0	2,572	908	3,400	0	24,355	23,541	2,305	25,846	(1,491)	253	(1,238)	13	(1,225)
5/27/2017	29,420	1,304	0	1,509	339	3,400	0	25,476	24,669	2,305	26,974	(1,498)	380	(1,118)	2	(1,116)

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Preliminary net load forecast assumes Peak Load Exposrue (PLE) of 26,482 MW and does include credit of Passive Demand Response (PDR) http://www.iso-ne.com/system-planning/system-plans-studies/celt
and behind-the-meter PV (BTM PV)
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of 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).

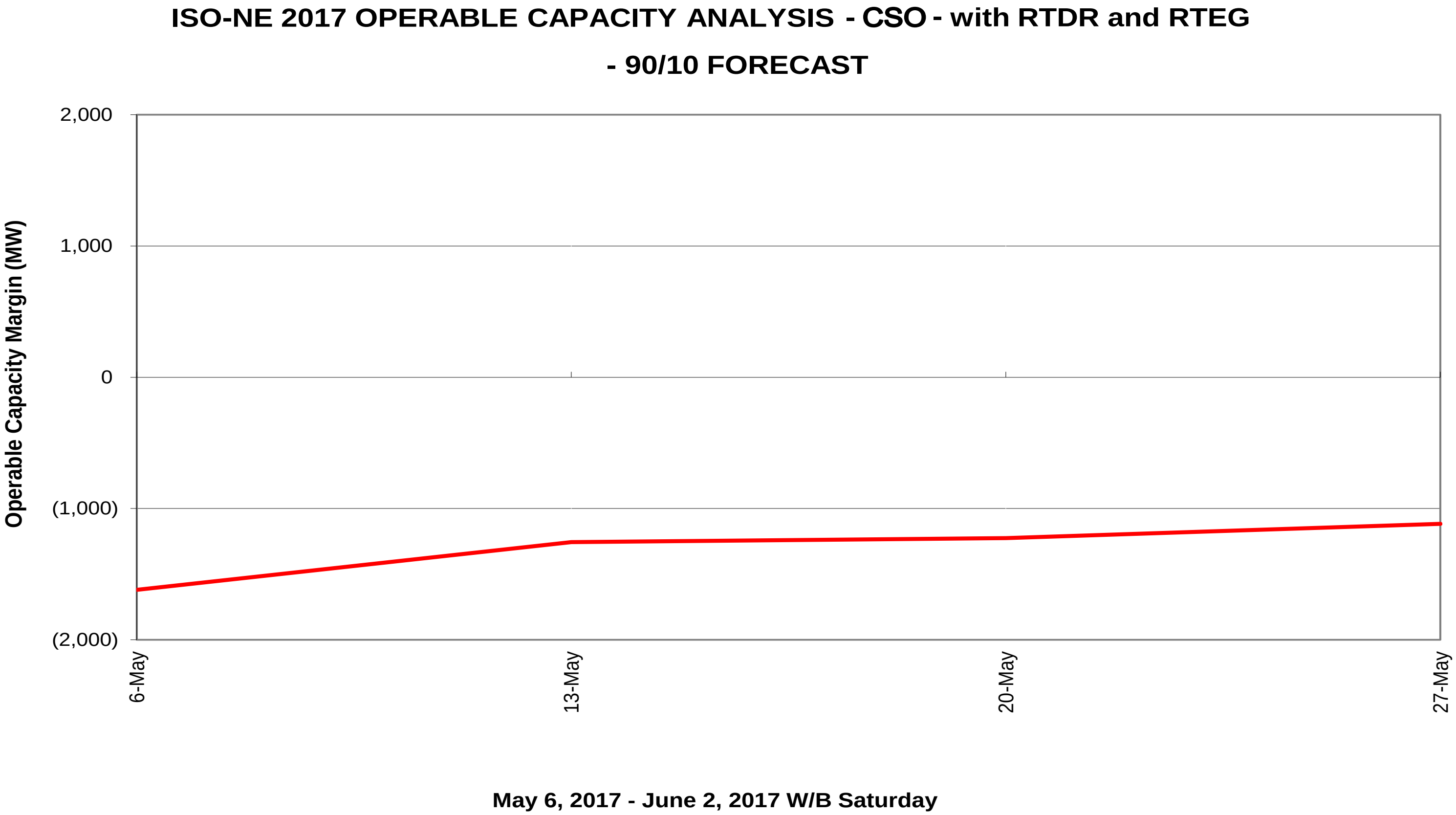
Spring 2017 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)



Spring 2017 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Summer 2017

Summer 2017 Operable Capacity Analysis

50/50 Load Forecast (Reference)	**July - 2017 CSO**	**July - 2017 SCC**
Operable Capacity MW [1]	29,491	29,412
OP CAP From OP-4 RTDR (+)	380	380
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	29,873	29,794
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,246	1,246
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	0	0
Gas Generator Outages/Reductions MW (-)	674	674
Allowance for Unplanned Outages (-) [5]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	28,345	28,266
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,482	26,482
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,787	28,787
Operable Capacity Margin [3]	-442	-521

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **April 24, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Net load forecast assumes Peak Load Exposure (PLE) of 26,482 MW and represents the peak demand of week beginning **July 15, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Summer 2017 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	**July - 2017 CSO**	**July - 2017 SCC**
Operable Capacity MW [1]	29,491	29,412
OP CAP From OP-4 RTDR (+)	380	380
OP CAP From OP-4 RTEG (+)	2	2
Operable Capacity with OP-4 DR and RTEG	29,873	29,794
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,246	1,246
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outages/Reductions MW (-)	0	0
Gas Generator Outages/Reductions MW (-)	674	674
Allowance for Unplanned Outages (-) [5]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	28,345	28,266
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	28,865	28,865
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	31,170	31,170
Operable Capacity Margin [3]	-2,825	-2,904

[1] Operable Capacity is based on the Capacity Supply Obligation (CSO) and Seasonal Claimed Capability (SCC) data as of **April 24, 2017**. This does not include Capacity associated with Settlement Only Generators (SOG).

[2] Net load forecast assumes Peak Load Exposure (PLE) of 26,482 MW and represents the peak demand of week beginning **July 15, 2017**.

[3] Includes OP4 actions associated with RTEG and RTDR

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

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Summer 2017 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

May 5, 2017 - 50/50 FORECAST using CSO values with RTDR and RTEG

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	EXTERNAL NODE AVAIL CAPACITY MW [2]	NON COMMERCIAL CAPACITY MW [3]	NON-GAS PLANNED OUTAGES CSO MW [4]	GAS GENERAT OR OUTAGES CSO MW [5]	ALLOWANCE FOR UNPLANNED OUTAGES MW [6]	GAS AT RISK MW [7]	NET OPCAP SUPPLY MW [8]	PEAK LOAD FORECAST MW [9]	OPER RESERVE REQUIREMENT MW [10]	NET LOAD OBLIGATION MW [11]	OPCAP MARGIN MW [12]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [13]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [14]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [15]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [16]
6/3/2017	29,420	1,304	0	0	963	2,800	0	26,961	26,482	2,305	28,787	(1,826)	380	(1,446)	2	(1,444)
6/10/2017	29,420	1,304	0	0	674	2,800	0	27,250	26,482	2,305	28,787	(1,537)	380	(1,157)	2	(1,155)
6/17/2017	29,420	1,304	0	14	674	2,800	0	27,236	26,482	2,305	28,787	(1,551)	380	(1,171)	2	(1,169)
6/24/2017	29,420	1,304	0	0	674	2,800	0	27,250	26,482	2,305	28,787	(1,537)	380	(1,157)	2	(1,155)
7/1/2017	29,491	1,246	0	14	674	2,100	0	27,949	26,482	2,305	28,787	(838)	380	(458)	2	(456)
7/8/2017	29,491	1,246	0	14	674	2,100	0	27,949	26,482	2,305	28,787	(838)	380	(458)	2	(456)
7/15/2017	**29,491**	**1,246**	**0**	**0**	**674**	**2,100**	**0**	**27,963**	**26,482**	**2,305**	**28,787**	**(824)**	**380**	**(444)**	**2**	**(442)**
7/22/2017	29,491	1,246	0	0	674	2,100	0	27,963	26,482	2,305	28,787	(824)	380	(444)	2	(442)
7/29/2017	29,491	1,246	0	14	674	2,100	0	27,949	26,482	2,305	28,787	(838)	380	(458)	2	(456)
8/5/2017	29,491	1,246	0	0	674	2,100	0	27,963	26,482	2,305	28,787	(824)	380	(444)	2	(442)
8/12/2017	29,491	1,246	0	90	674	2,100	0	27,873	26,482	2,305	28,787	(914)	380	(534)	2	(532)
8/19/2017	29,491	1,246	0	14	674	2,100	0	27,949	26,482	2,305	28,787	(838)	380	(458)	2	(456)
8/26/2017	29,491	1,246	0	0	674	2,100	0	27,963	26,482	2,305	28,787	(824)	380	(444)	2	(442)
9/2/2017	29,491	1,246	0	9	674	2,100	0	27,954	26,482	2,305	28,787	(833)	380	(453)	2	(451)
9/9/2017	29,491	1,246	0	9	674	2,100	0	27,954	26,482	2,305	28,787	(833)	380	(453)	2	(451)

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4.Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Preliminary net load forecast assumes Peak Load Exposrue (PLE) of 26,482 MW and does include credit of Passive Demand Response (PDR) http://www.iso-ne.com/system-planning/system-plans-studies/celt
and behind-the-meter PV (BTM PV)
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of 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).

Summer 2017 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2017 OPERABLE CAPACITY ANALYSIS

May 5, 2017 - 90/10 FORECAST using CSO values with RTDR and RTEG

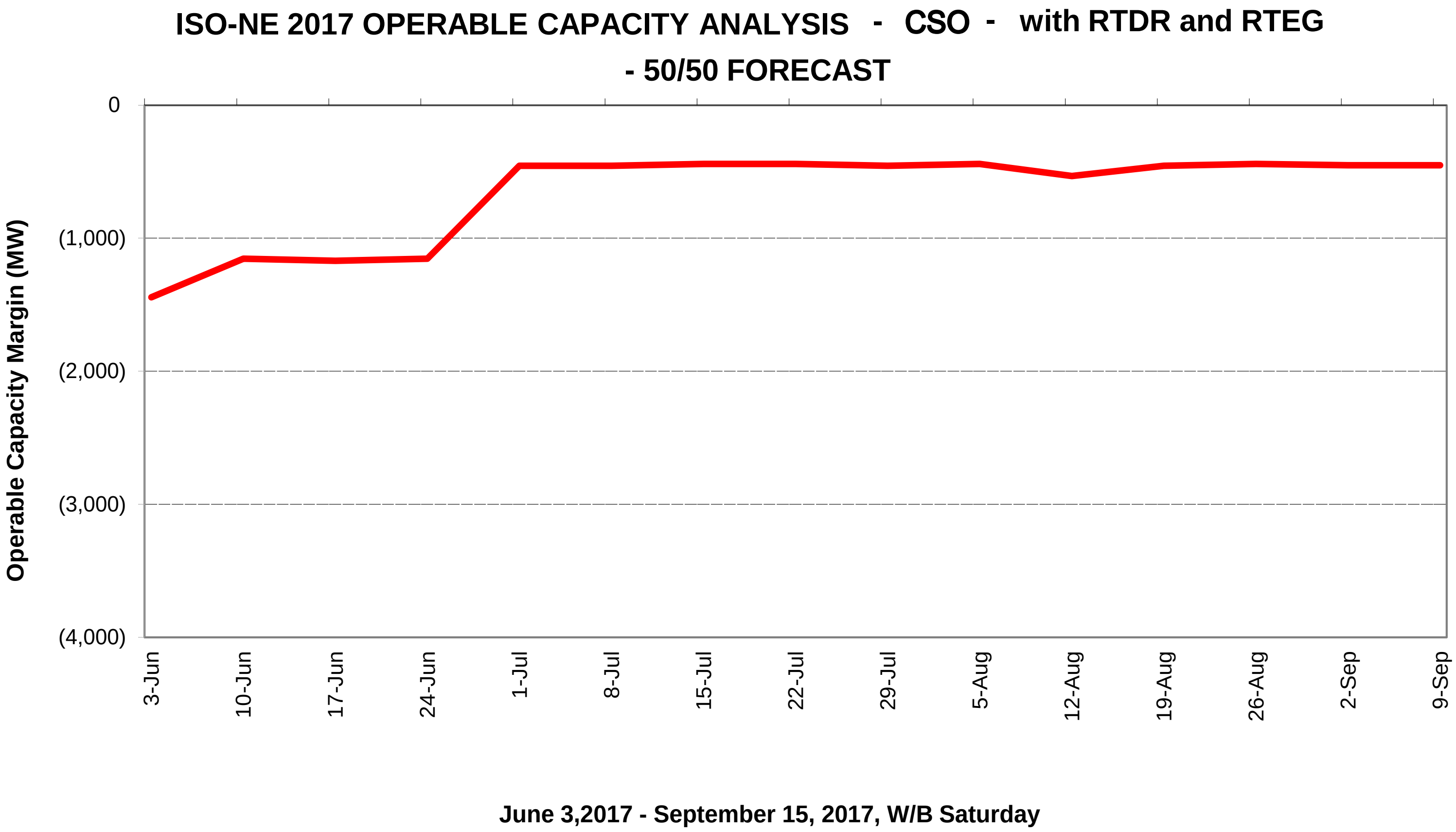
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	EXTERNAL NODE AVAIL CAPACITY MW [2]	NON COMMERCIAL CAPACITY MW [3]	NON-GAS PLANNED OUTAGES CSO MW [4]	GAS GENERATOR OUTAGES CSO MW [5]	ALLOWANCE FOR UNPLANNED OUTAGES MW [6]	GAS AT RISK MW [7]	NET OPCAP SUPPLY MW [8]	PEAK LOAD FORECAST MW [9]	OPER RESERVE REQUIREMENT MW [10]	NET LOAD OBLIGATION MW [11]	OPCAP MARGIN MW [12]	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW [13]	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW [14]	OPCAP FROM OP4 REAL-TIME EMER. GEN MW [15]	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW [16]
6/3/2017	29,420	1,304	0	0	963	2,800	0	26,961	28,865	2,305	31,170	(4,209)	380	(3,829)	2	(3,827)
6/10/2017	29,420	1,304	0	0	674	2,800	0	27,250	28,865	2,305	31,170	(3,920)	380	(3,540)	2	(3,538)
6/17/2017	29,420	1,304	0	14	674	2,800	0	27,236	28,865	2,305	31,170	(3,934)	380	(3,554)	2	(3,552)
6/24/2017	29,420	1,304	0	0	674	2,800	0	27,250	28,865	2,305	31,170	(3,920)	380	(3,540)	2	(3,538)
7/1/2017	29,491	1,346	0	14	674	2,100	0	28,049	28,865	2,305	31,170	(3,121)	380	(2,741)	2	(2,739)
7/8/2017	29,491	1,246	0	14	674	2,100	0	27,949	28,865	2,305	31,170	(3,221)	380	(2,841)	2	(2,839)
7/15/2017	**29,491**	**1,246**	**0**	**0**	**674**	**2,100**	**0**	**27,963**	**28,865**	**2,305**	**31,170**	**(3,207)**	**380**	**(2,827)**	**2**	**(2,825)**
7/22/2017	29,491	1,246	0	0	674	2,100	0	27,963	28,865	2,305	31,170	(3,207)	380	(2,827)	2	(2,825)
7/29/2017	29,491	1,246	0	14	674	2,100	0	27,949	28,865	2,305	31,170	(3,221)	380	(2,841)	2	(2,839)
8/5/2017	29,491	1,246	0	0	674	2,100	0	27,963	28,865	2,305	31,170	(3,207)	380	(2,827)	2	(2,825)
8/12/2017	29,491	1,246	0	90	674	2,100	0	27,873	28,865	2,305	31,170	(3,297)	380	(2,917)	2	(2,915)
8/19/2017	29,491	1,246	0	14	674	2,100	0	27,949	28,865	2,305	31,170	(3,221)	380	(2,841)	2	(2,839)
8/26/2017	29,491	1,246	0	0	674	2,100	0	27,963	28,865	2,305	31,170	(3,207)	380	(2,827)	2	(2,825)
9/2/2017	29,491	1,246	0	9	674	2,100	0	27,954	28,865	2,305	31,170	(3,216)	380	(2,836)	2	(2,834)
9/9/2017	29,491	1,246	0	9	674	2,100	0	27,954	28,865	2,305	31,170	(3,216)	380	(2,836)	2	(2,834)

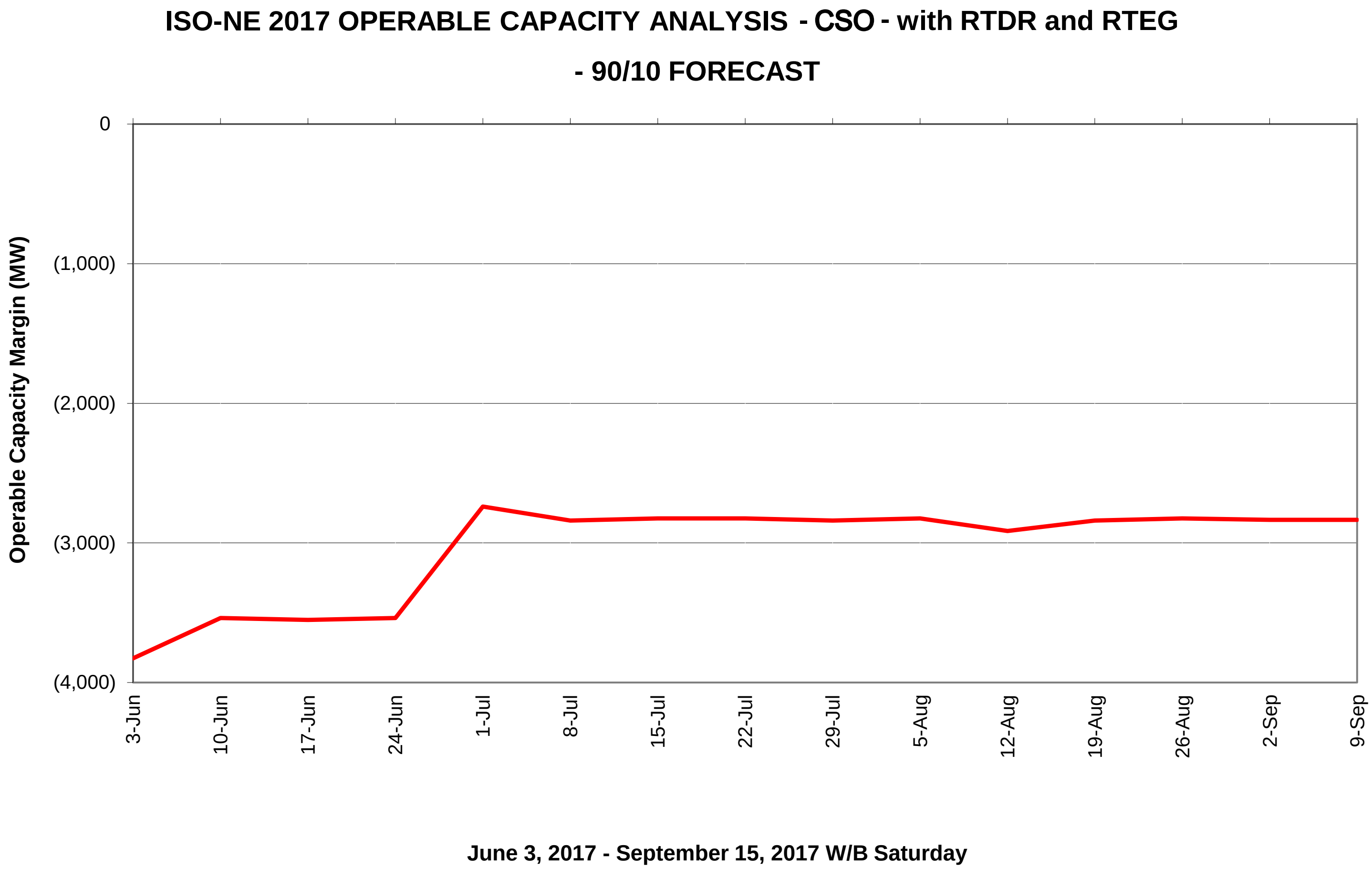
1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4. Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. Preliminary net load forecast assumes Peak Load Exposrue (PLE) of 26,482 MW and does include credit of Passive Demand Response (PDR) http://www.iso-ne.com/system-planning/system-plans-studies/celt and behind-the-meter PV (BTM PV)
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of 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).

Summer 2017 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)



Summer 2017 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.	0 [1] 600
2	Dispatch real time Demand Resources.	**May 253** [3] **June – September 380** [3]
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	134 [4] **May 13** [3] **June – September 2** [3]

NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of April 24, 2017.
4. The MW values are based on a 26,482 MW system load and the most recent voltage reduction test % achieved.

Possible Relief Under OP4: Appendix A, cont.

OP 4 Action Number	**Page 2 of 2** **Action Description**	**Amount Assumed Obtainable Under OP 4 (MW)**
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	267 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**May 2,812[3]** **June – September 2,928 [3]**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The RTDR and RTEG MW values are based on FCM results as of April 24, 2017.
4. The MW values are based on a 26,482 MW system load and the most recent voltage reduction test % achieved.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Counsel

DATE: May 3, 2017

RE: FERC Technical Conference on State Policies and Wholesale Markets
Docket No. AD17-11-000

This memo provides a brief report on the FERC's May 1-2, 2017, Technical Conference on State Policies and Wholesale Markets.[1]

The purpose of the Technical Conference was to explore the short- and long-term expectations regarding the relative roles of wholesale markets and state public policies in the Eastern RTOs/ISOs (ISO-NE, NYISO, and PJM) in shaping and/or reacting to the quantity and composition of resources needed to cost effectively meet future reliability and operational needs. The FERC Staff asked panelists to focus on the development of regional solutions in the Eastern RTOs/ISOs to reconcile the competitive wholesale market framework with the increasing interest by states to support particular resources or resource attributes outside of the organized markets. Both Acting Chairman LaFleur and Commissioner Honorable were present for the entirety of both days and repeatedly engaged with the panelists and Commission Staff. While there is no rulemaking proceeding at this stage, it was clear from the Conference that Commission Staff and the two Commissioners seek a better understanding of the various issues and perspectives at play and are considering how the FERC should proceed on these issues once there is a FERC quorum.

The two-day Technical Conference consisted of nine panels spread across five distinct sessions.[2] On Day 1, there were three, region-specific (New England, New York, and PJM, respectively) sessions, each with two panels – one comprised of state officials and representatives to talk about their state's policy perspectives and a second comprised of stakeholders in each respective region.

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[1] *See State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.* (Docket No. AD17-11).

[2] The final agenda for the May 1-2 Technical Conference, which provides more detail on the topics discussed and the questions asked by FERC Staff can be found here: https://www.ferc.gov/CalendarFiles/20170428154636-Final-Agenda.pdf. In addition, links to the pre-Technical Conference statements submitted by all of the panelists can be found at: https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8663&CalType=%20&CalendarID=116&Date=05/01/2017&View=Listview.

The two New England panels,[3] one of which included Tom Kaslow on behalf of NEPOOL, reflected the clear benefit that has resulted from the region's IMAPP efforts. There was general agreement among the New England panelists that they all wanted to retain robust markets to meet reliability needs and that the FERC should allow New England's stakeholder process to continue to work through issues and develop solutions. The states' panelists stressed the need for the FERC to accommodate state initiatives, rather than try to direct how the wholesale market might change to satisfy the states' objectives. For their part, the New England state officials/representatives made clear their requirement that they continue to be permitted to pursue their individual and/or collective procurement policies. Summarizing the perspectives shared, Acting Chairman LaFleur noted that the New England states see the value of centralized markets, but that states want to be allowed to pursue their own public policies and procurement goals. The New England market participants' panel also focused on the FERC's questions regarding markets accommodating and/or achieving state policies. Most of these panelists agreed that there is an urgent need to accommodate state policies, but that achieving state objectives through FERC-regulated markets is a more complex and a longer-term question/challenge. Overall, there was no information of particular note presented during the New England panels that had not already been touched upon in the IMAPP process.

The second and third session on Day 1, which addressed the NYISO and PJM markets, focused on similar themes. Panelists in those sessions addressed the respective, existing market structures and the effects of out-of-market subsidies. Again, both Commissioners focused on whether the FERC should seek to accommodate state policies, or if the FERC had a role to play in helping the states achieve their policy objectives through the organized markets. It was clear in these discussions that the issues in each region are sufficiently different that they may suggest different solutions.

As previously described to NEPOOL at its annual Participants Committee meeting in December 2016, Acting Chairman LaFleur took the opportunity on Day 1 of the Conference to reinforce three possible outcomes regarding the challenging issues before us. Under LaFleur's first and preferred scenario, negotiated solutions would be worked through a collaborative and consensus-driven process to reconcile tension(s) between state subsidies and wholesale price formation. The second possible outcome, according to LaFleur, involves the prospect of continued litigation over state subsidies for certain types of generation and iterative resolutions ordered by the FERC to address changing facts and circumstances as they materialize. Lastly, a third potential outcome would involve a complete redesign and re-rationalization of the markets, where the states take back resource adequacy (re-regulation).

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[3] The first New England panel, which focused on the perspectives of the New England states was composed of Jeff Bentz (NESCOE), Sarah Hofmann (Vermont PSB, speaking on behalf of the National Council on Electricity Policy), Robert Klee (CT DEEP), Angela O'Connor (MA DPU), and Bob Scott (NH PUC). The second New England panel, which was market participant-centric, featured Matt White (ISO-NE), David Patton (Potomac Economics), Brian Forshaw (for CMEEC, MMWEC, NHEC and VPPSA), Pete Fuller (NRG), Seth Kaplan (EDP Renewables and RENEW Northeast), Tom Kaslow (as NEPOOL Chairman), Aleks Mitreski (Brookfield), and Bill Murray (Dominion).

To begin Day 2 of the Technical Conference, Arnie Quinn, Director of FERC's Office of Energy Policy and Innovation, layered potential pathways on top of Acting Chairman LaFleur's three possible outcomes. Mr. Quinn identified the following five potential paths forward to address the issues raised during Day 1 of the Conference:

- Path #1: Grid operators would employ a very limited minimum offer price rule ("MOPR") or no MOPR at all.
- Path #2 (the "accommodation path"): State policies would be accommodated in the organized markets by allowing state-supported resources to secure capacity supply obligations while maintaining competitively-based capacity prices for non-subsidized resources.
- Path #3: This path would largely reflect the status quo, in which the MOPR is applied to some state actions but not to others.
- Path #4 (the "achieve path"): Attributes sought and identified by state policymakers would be achieved through the competitive wholesale market construct.
- Path #5: Stronger or expanded application of MOPR.

During the morning session on Day 2 of the Conference, discussions focused on potential wholesale market and resource adequacy implications of potential alternatives to reconcile state policy preferences with wholesale market design and there was fairly broad but not uniform urgency expressed to address the impact of out-of-market, state-sponsored activity. Prior to the afternoon session, Congressman Joseph Kennedy III (D-MA) visited and offered brief remarks to those in attendance, stressing the need to ensure that wholesale energy and capacity markets appropriately balance the needs of market participants and ratepayers. The afternoon of Day 2 focused on hearing from a panel of economists and consultants, dubbed the "Genius Bar" by Acting Chairman LaFleur, regarding their views on market design principles and potential solution spaces and ended with a group of ISO/RTO and state representatives who were given the opportunity to react and offer their perspectives on what had been discussed during the two-days.

Acting Chairman LaFleur concluded the Conference by stating that "when we [FERC] get back our quorum, I think there will be a lot to do."

For those who were unable to attend (in-person or via the web) and/or may be interested in further detail regarding the discussions that took place on May 1-2, a free webcast of the Technical Conference is available at: http://www.capitolconnection.net/capcon/ferc/ferc.htm. Additionally, a transcript of the Conference will be available from Ace Reporting Company and may be purchased online at: http://www.acefederal.com/.

NEPOOL counsel will continue to monitor this proceeding and keep you appraised of any developments. In the coming days, we expect that Commission Staff will invite submittal of post-Technical Conference comments and we will inform you once a notice has been issued. In the meantime, should you have any follow-up questions regarding the May 1-2 Technical Conference, please let us know.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of May 3, 2017

The following activity, as more fully described in the attached litigation report, has occurred since the report dated April 5, 2017 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

2	NEPGA PER Complaint (EL16-120)	Apr 18	Settlement Judge Young issues 2nd 60-day status report
		May 3	Settlement conf. held
3	Base ROE Complaint IV (2016) (EL16-64)	Apr 14	Complainant-Aligned Parties move to compel production of certain data requests
		Apr 21	FERC Trial Staff moves to extend procedural deadlines
		Apr 26	TOs' oppose FERC Trial Staff's Apr 21 request
		Apr 27	Chief Judge schedules May 18 oral argument on the question of why she should not recommend that this case be dismissed (in light of the DC Circuit's *Base ROE Complaint I Decision*)
		Apr 28	Trial Judge Glazer schedules May 16 oral argument regarding Apr 14 motion to compel; extends Trial Staff's deadline for submission of direct and answering testimony and exhibits
		May 3	Settlement Judge Long issues order cancelling May 3 settlement conf.
5	206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)	Apr 7	Judge Dring issues status report recommending that settlement judge procedures be continued and schedules settlement conf. for May 9

II. Rate, ICR, FCA, Cost Recovery Filings

6	FCA11 Results Filing (ER17-1073)	Apr 11	NEPOOL intervenes
		Apr 28	FERC accepts results filing, eff. Jun 14

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

8	Waiver Request: FCM Qualification for FCA8 MRAs (Emera ESS6) (ER17-1031)	Apr 7	FERC grants uncontested waiver request

IV. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

* 11	FTR Balance of Planning Period Financial Assurance Changes (ER17-1441)	Apr 20	NEPOOL and ISO-NE jointly file changes to the Financial Assurance Policy to account for upcoming changes in the FTR auction structure; comment date May11
		Apr 21-27	DC Energy, National Grid intervene
11	FAP FCM Capacity Charge Calculation Changes (ER17-1103)	Apr 7	FERC accepts changes, eff. Jun 1

VI. Schedule 20/21/22/23 Changes

11	Schedule 21-ES: Eversource Recovery of NU/NSTAR Merger-Related Costs (ER16-1023)	May 2	FERC accepts Mar 1 compliance filing, eff. Jun 1

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	13	LFTR Implementation: 34th Quarterly Status Report (ER07-476)	Apr 14	ISO files its 34th quarterly report
*	13	ISO-NE FERC Reporting Requirement 582 (not docketed)	Apr 24	ISO-NE submits 2016 annual report of total MWh of transmission service (approx. 1.33 million MWhs)

IX. Membership Filings

*	13	May 2017 Membership Filing (ER17-1506)	Apr 28	***New Members***: Block Island Power Co.; Georges River Energy; Ohmconnect; Rensselaer Generating; Roseton Generating; VECO Power Trading; ***Withdrawal***: Union Leader; ***Name Change***: Great River Hydro, LLC (f/k/a TransCanada Hydro Northeast, Inc.); comment date May 19
*	13	Suspension Notices (not docketed)	Apr 24	ISO files notice of suspension of First Wind Energy Marketing from New England Markets

X. Misc. - ERO Rules, Filings; Reliability Standards

	14	Revised Rel. Standards: IRO-002-5; TOP-001-4 (RD17-4)	Apr 17	FERC approves changes to IRO-002 and TOP-001, eff. Apr 17
	15	NOPR: Revised Rel. Standard: PRC-012-2 (RM16-20)	Apr 10	NERC, NESCOE, ISO-NE/IESO/NYISO , MISO, Bonneville, EEI, and ITC file comments
	15	*Frequency Control Changes NOPR*: Revised BAL-005-1 & FAC-001-3 (RM16-13)	Apr 6	NERC files response to data request

XI. Misc. - of Regional Interest

	16	203 Application: GMP/VT Transco (Highgate) (EC17-86)	Apr 11	Green Mountain Power and VT Transco supplement application
*	17	D&E Agreement: PSNH/Essential Power Newington (ER17-1495)	Apr 28	PSNH files Agreement; comment date May 19
*	17	Cost Reimbursement Agreement: NEP/Wynn MA (ER17-1495)	Apr 18	New England Power files Agreement; comment date May 8
	18	SGIA: ISO-NE/GMP (ER17-1296)	Apr 24	FERC accepts non-conforming SGIA, eff. Mar 14
	18	IA: Eversource/Covanta (Preston, CT) (ER17-1038)	Apr 13	FERC accepts IA, eff. Feb 18
	18	CL&P/Wallingford, CT Trans. Line Separation Agreement (ER17-967)	Apr 6	FERC accepts Agreement, eff. Feb 13

XII. Misc. - Administrative & Rulemaking Proceedings

	21	State Policies & Wholesale Markets Operated by ISO-NE, NYISO, PJM (AD17-11)	Apr 13 Apr 21-May 1 Apr 28 May 1-2	FERC issues supplemental notice of tech. conf. Parties file pre-conf. statements/comments FERC issues updated tech. conf. agenda FERC holds IMAPP tech. conf.

23	NOI: FERC's Policy for Recovery of Income Tax Costs & ROE Policies (PL17-1)	Apr 6-10	Reply comments received from 18 parties, including from AGA, Dominion, EEI, INGAA, and LSPower
23	NOPR: LGIA/LGIP Reforms (RM17-8)	Apr 10-28	Over 60 parties file comments, including: NEPOOL, ISO-NE, Avangrid, EDF, EDP, Eversource, Exelon, Invenergy, National Grid, NextEra, APPA/LPPC/NRECA, AWEA, EEI, ELCON, ESA, and Public Interest Organizations
25	NOPR: Uplift Cost Allocation and Transparency in RTO/ISO Markets (RM17-2)	Apr 10-25	Over 40 parties file comments, including: ISO-NE, Brookfield, Calpine, DC Energy, Direct, Exelon, Potomac Economics, Saracen, EEI, APPA/NRECA, AWEA, ELCON, EPSA, Financial Marketers Coalition, and the IRC
25	NOPR: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)	Apr 17	Harvard Environmental Policy Initiative files comments

XIII. Natural Gas Proceedings

29	New England Pipeline Proceedings Atlantic Bridge Project (CP16-9)	Apr 13	FERC grants authorization to proceed as requested on Apr 7/13

XIV. State Proceedings & Federal Legislative Proceedings

No Activity Reported

XV. Federal Courts

31	Demand Curve Changes (17-1110)	Apr 7 Apr 21-May 1	Clerk issues procedural order regarding initial submissions (first submissions due May 8) NEPOOL, NESCOE, CT PURA, CPV intervene
32	*Order 1000* Compliance Filings (15-11139)	Apr 18	DC Circuit denies petitions for review filed by NETOs and NESCOE et al.
32	Base ROE Complaint I (2011) (15-1118, 15-1119, 15-1121**) (consolidated)	Apr 14	DC Circuit grants the petitions for review of the FERC's orders in the Base ROE Complaint I proceedings, vacates the FERC's prior orders, and remands the case for further proceedings consistent with its order

MEMORANDUM

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: May 3, 2017

RE: Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures, and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"), state regulatory commissions, and the Federal Courts and legislatures through May 3, 2017. If you have questions, please contact us.[1]

I. Complaints/Section 206 Proceedings

- **NEPGA PER Complaint (EL16-120)**

As previously reported, the FERC, on January 19, (i) granted in part NEPGA's complaint[2] and (ii) set in part for hearing and settlement judge procedures the question of the appropriate method of calculating the PER Strike Price under Market Rule 1 section III.13.7.2.7.1.1.1.[3] In granting NEPGA's complaint in part, the FERC found that "for the period at issue in NEPGA's complaint (September 30, 2016 – May 31, 2018), the PER mechanism has become unjust and unreasonable as a result of the interaction between the PER mechanism and the higher Reserve Constraint Penalty Factors."[4] Accordingly, the FERC required the ISO to revise the method by which it calculates the PER Strike Price as set forth in Tariff section III.13.7.2.7.1.1.1. But, finding NEPGA's request that the PER Strike Price be increased by $250 per MWh "raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures", the FERC set the question of for hearing and settlement judge procedures under section 206 of the FPA.[5] The FERC established a refund effective date of September 30, 2016 (the date of the complaint). In establishing a September 30, 2016 effective date, the FERC clarified that "any changes to the calculation of the PER Strike Price under ISO-NE Tariff section III.13.7.2.7.1.1.1 would be prospective only from September 30, 2016, as required by FPA section 206, and would not impact the application of any PER Adjustment occurring before September 30, 2016."[6] On February 15, NEPGA requested clarification of the *PER Complaint Order* with respect to the PER Adjustment payments charged to NEPGA's members on capacity invoices issued after the refund effective date. Specifically, NEPGA asked for clarification that when the FERC "determines refunds, it will direct the ISO to refund to capacity suppliers the difference between: (i) the PER Adjustment payments charged to capacity suppliers after the September 30, 2016 refund effective date, and (ii) the PER Adjustment payments

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[1] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. ("ISO" or "ISO-NE") Transmission, Markets and Services Tariff (the "Tariff").

[2] NEPGA's complaint asked the FERC (i) to find the ISO Tariff's Peak Energy Rent ("PER") Adjustment provisions unjust & unreasonable; (ii) to direct the ISO to file revisions to the PER Adjustment sections of the Tariff that return the PER Adjustment to a just & reasonable level; (iii) to establish a refund effective date of September 30, 2016; and (iv) to issue an order granting the complaint by November 29, 2016.

[3] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 158 FERC ¶ 61,034 (Jan. 19, 2017).

[4] *Id.* at P 48.

[5] *Id.* at P 57.

[6] *Id.* at P 61.

that would have been charged to capacity suppliers if the PER Adjustment were calculated using a just and reasonable PER Strike Price." On March 3, NESCOE and RESA answered NEPGA's rehearing request. NEPGA answered those answers on March 17. The FERC issued a tolling order on March 16, 2017, affording it additional time to consider NEPGA's request for rehearing, which remains pending.

Settlement Judge Procedures. On January 25, Chief Cintron designated Judge H. Peter Young as the Settlement Judge in these proceedings. A first settlement conference was held on February 16. In his second status report, Judge Young reported that, in the interim since the first settlement conference, the ISO had conducted and circulated among all participants a revised PER Adjustment Strike Price analysis based on updated data, and had provided Real-Time pricing data for the PER Adjustment periods at issue in this proceeding. He stated that each recipient participant circulated a written response to the ISO's information on April 7, and those responses did not reflect any material deviations from the various participants' prior positions with respect to the appropriate PER Adjustments to be made under the ISO Tariff. A second settlement conference was held on May 3.

If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com), Jamie Blackburn (202-218-3905; jblackburn@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Base ROE Complaint IV (2016) (EL16-64)**

On September 20, 2016, the FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint.[7] As previously reported, EMCOS[8] filed the 4th ROE complaint on April 29, 2016. The Complaint asked the FERC to reduce the TOs' current 10.57% return on equity ("Base ROE") to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%. EMCOS identified three main considerations requiring submission of this Complaint: (1) the continuing decline of the market cost of equity capital, which makes NETOS' currently authorized ROE "excessive, unjust and unreasonable, and therefore ripe for adjustment under FPA Section 206"; (2) "divergent rulings concerning the persistence of the "anomalous" capital market conditions"; and (3) "the extent to which the Commission's anomalous conditions rationale in Opinion No. 531 is intended to reflect changes in its long-standing reliance on the DCF methodology, and particularly the DCF midpoint, for determining ROE remains unclear."

In setting the complaint for hearing and settlement judge procedures, the FERC found that the Complaint "raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures we order."[9] The FERC also found "unpersuasive the assertions of New England TOs and EEI that the Commission should dismiss the Complaint because the New England TOs' base ROE continues to fall within the zone of reasonableness. The Commission has repeatedly rejected the assertion that every ROE within the zone of reasonableness must be treated as an equally just and reasonable ROE."[10] Further, the FERC rejected arguments as to the propriety of allowing a fourth complaint against the TOs' ROE after three previous complaints have been filed since 2011. As it did when it allowed Complaints II and III to go forward, the FERC found that Complaint IV was properly set for hearing as it is based on newer, more current data than prior Complaints subsequent

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[7] *Belmont Mun. Light Dept. et al. v. Central Me. Power Co. et al.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("*Base ROE Complaint IV Order*").

[8] "EMCOS" are: Belmont Mun. Light Dept., Braintree Elec. Light Dept., Concord Mun. Light Plant, Georgetown Mun. Light Dept., Groveland Elec. Light Dept., Hingham Mun. Lighting Plant, Littleton Elec. Light & Water Dept., Middleborough Gas & Elec. Dept., Middleton Elec. Light Dept., Reading Mun. Light Dept. ("Reading"), Rowley Mun. Lighting Plant, Taunton Mun. Lighting Plant, and Wellesley Mun. Light Plant.

[9] *Base ROE Complaint IV Order* at P 37.

[10] *Id.* at P 38.

hearings.[11] The FERC is "initiating an entirely new proceeding, based on an entirely separate factual record, that may or may not reach the same conclusions as those reached in the earlier ROE proceeding."[12] The FERC estimated that, if this case does not settle and goes to hearing, the Commission's ultimate decision would be issued on or before June 30, 2018.[13] Both the TOs and EEI requested rehearing of the *Base ROE Complaint IV Order*. The FERC issued a tolling order on November 21, 2016, affording it additional time to consider the requests for rehearing, which remain pending.

Settlement Judge Procedures. On October 4, Chief Judge Cintron designated Judge Jennifer Long as the Settlement Judge. Settlement conferences have thus far been held on November 8 and December 20, 2016. Following requests of the parties (related to the *Emera Maine* proceeding (DC Cir. Case No. 15-1118), a third settlement conference was re-scheduled to May 3, 2017, and then subsequently cancelled. The TOs have indicated that settlement discussions will not be fruitful until the Commission addresses certain issues remanded to the Commission by the Court in the *Base ROE Complaint I Decision*. A further settlement conference has not been scheduled.

Concurrent Hearing Procedures. On December 21, 2016, in response to a request of the parties and supported by Settlement Judge Long, Chief Judge Cintron designated Steven A. Glazer as presiding judge for hearings in this matter, so that hearing procedures can proceed *concurrently* with settlement judge procedures still underway before Judge Long. Absent a settlement, these hearing procedures will be conducted under the FERC's "Track II" procedural time standards, which requires that an initial decision be issued within 47 weeks, or by November 15, 2017. Judge Glazer scheduled a preliminary conference for January 17, 2017, noting that hearing has been set for August 2, 2017 (with September 27, 2017 as the deadline for reply briefs). At the January 17 conference, Participants proposed the remaining procedural schedule, which was adopted by Judge Glazer in an order issued January 23. In addition, Judge Glazer has issued orders adopting rules for the conduct of the hearing (December 21, 2016) and the discovery plan (January 17). Direct and Answering Testimony and Exhibits have been filed. Hearings were scheduled for August 2-8, with an initial decision to be issued on or before November 15, 2017.

Additional Developments Since the Last Report. There are 3 additional developments to highlight since the last Report. First, and most significantly, in light of the DC Circuit's April 14, 2017 *Emera Maine* decision on the Base ROE Complaint I orders (*see* Section XV below), Chief Judge Cintron scheduled an oral argument for May 18, 2017, to be conducted *en banc* before her and Presiding Judge Glazer, in which participants are to address the question of why the Chief Judge should not recommend to the Commission that this case be dismissed. Second, in response to an April 14 motion by the Complainant-Aligned Parties[14]to compel the TO's production of certain data requests, subsequently contested by the TOs, Judge Glazer scheduled a May 16 oral argument to address the motion (any further answers to the motion to compel must be field by May 12). Third, in response to a Trial Staff request for a four-week extension for most of the remaining dates in the procedural schedule before the Hearing date and a five-week extension for the Hearing date and all deadlines subsequent to it, but in light of the May 18 oral argument scheduled by the Chief Judge calling into question the viability of the remaining procedural schedule, Judge Glazer extended, to May 25, 2017, the next procedural date for Trials Staff (for the submission of direct and answering testimony and exhibits).

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

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[11] Complaint IV was filed 21 months after the July 31, 2014 filing of Complaint III, nearly nine months after the July 2, 2015 close of the Complaint III evidentiary hearing record, and six months after the end of the Complaint III refund period.

[12] *Base ROE Complaint IV Order* at P 40.

[13] *Id.* at P 44.

[14] "Complainant-Aligned Parties" for these purposes are CT PURA, MMWEC and NHEC.

- **206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)**

Settlement discussions in this proceeding are on-going. As previously reported, the FERC instituted this Section 206 proceeding on December 28, 2015, finding that the ISO Tariff is unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS").[15] The FERC also found that the RNS and LNS rates themselves "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because (i) "the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates" and "could result in an over-recovery of costs" due to the "the timing and synchronization of the RNS and LNS rates".[16] Accordingly, the FERC established hearing and settlement judge procedures to develop just and reasonable formula rate protocols to be included in the ISO-NE Tariff and to examine the justness and reasonableness of the RNS and LNS rates. The FERC encouraged the parties to make every effort to settle this matter before hearing procedures are commenced.[17] Hearings are being held in abeyance pending the outcome of settlement judge procedures underway.[18] The FERC-established refund date is January 4, 2016.[19]

Settlement Judge Procedures. As previously reported, John P. Dring was designated the Settlement Judge in these proceedings. Five settlement conferences were held in 2016: January 19, March 24, April 28, August 30, and November 18 (telephonically). A 6th settlement conference was held on April 5, 2017. A 7th settlement conference is scheduled for May 9, 2017. Judge Dring's most recent status report was issued on April 7, indicating that the parties continue to circulate materials, participate in substantive settlement discussions, and make progress toward settlement. Accordingly, he recommended that the settlement procedures be continued. The Transmission Committee is being kept apprised, as appropriate, of settlement efforts. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Base ROE Complaints II & III (2012 & 2014) (EL13-33 and EL14-86) (consolidated)**

Judge Sterner's findings and Initial Decision, and pleadings in response thereto, remain pending before the FERC. As previously reported, the FERC, in response to second (EL13-33)[20] and third (EL14-86)[21] complaints regarding the TOs' 11.14% Base ROE, issued orders establishing trial-type, evidentiary hearings and separate refund periods. The first, in EL13-33, was issued on June 19, 2014 and established a 15-month refund period of December 27, 2012 through March 27, 2014;[22] the second, in EL14-86, was issued

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[15] *ISO New England Inc. Participating Transmission Owners Admin. Comm. et al.*, 153 FERC ¶ 61,343 (Dec. 28, 2015), *reh'g denied*, 154 FERC ¶ 61,230 (Mar. 22, 2016).

[16] *Id.* at P 8.

[17] *Id.* at P 11.

[18] *Id.*

[19] The notice of this proceeding was published in the *Fed. Reg.* on Jan. 4, 2016 (Vol. 81, No. 1) p. 89.

[20] The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), challenged the TOs' 11.14% return on equity, and seeks a reduction of the Base ROE to 8.7%.

[21] The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General ("MA AG"), together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the "2014 ROE Complainants"), seeks to reduce the current 11.14% Base ROE to 8.84% (but in any case no more than 9.44%) and to cap the Combined ROE for all rate base components at 12.54%. 2014 ROE Complainants state that they submitted this Complaint seeking refund protection against payments based on a pre-incentives Base ROE of 11.14%, and a reduction in the Combined ROE, relief as yet not afforded through the prior ROE proceedings.

[22] *Environment Northeast, et al. v. Bangor Hydro-Elec. Co.*, et al., 147 FERC ¶ 61,235 (June 19, 2014) ("*2012 Base ROE Initial Order*"), *reh'g denied*, 151 FERC ¶ 61,125 (May 14, 2015).

on November 24, 2014, established a 15-month refund period beginning July 31, 2014,[23] and, because of "common issues of law and fact", consolidated the two proceedings for purposes of hearing and decision, with the FERC finding it "appropriate for the parties to litigate a separate ROE for each refund period."[24] The TOs requested rehearing of both orders. On May 14, 2015, the FERC denied rehearing of both orders.[25] On July 13, 2015, the TOs appealed those orders to the DC Circuit Court of Appeals (*see* Section XIV below), and that appeal remains pending.

Hearings and Trial Judge Initial Decision. Initial hearings on these matters were completed on July 2, 2015. In mid-December 2015, Judge Sterner reopened the record for the limited purpose of having the discounted cash flow ("DCF") calculations re-run in accordance with the FERC's preferred approach and re-submitted. A limited hearing on that supplemental information was held on February 1, 2016. On March 22, 2016, Judge Sterner issued his 939-paragraph, 371-page Initial Decision, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[26] The Decision also lowered the ROE ceilings. Judge Sterner's decision, if upheld by the FERC, would result in refunds totaling as much as $100 million, largely concentrated in the EL13-33 refund period. Briefs on exceptions were filed by the TOs, Complainant-Aligned Parties ("CAPs"), EMCOS, and FERC Trial Staff on April 21, 2016; briefs opposing exceptions, on May 20, 2016. Judge Sterner's findings and Initial Decision, and pleadings in response thereto, remain pending, and will be subject to challenge, before the FERC. The *2012/14 ROE Initial Decision* and its findings can be approved or rejected, in whole or in part.

If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA11 Results Filing (ER17-1073)**

On April 28, the FERC accepted, without change or condition, the results of the February 6 eleventh FCA ("FCA11"). The results were accepted effective as of June 28, 2017, as requested. As previously reported, FCA11 highlights included:

- FCA11 Capacity Zones were the Southeastern New England ("SENE") Capacity Zone (the Northeastern Massachusetts ("NEMA")/Boston, Southeastern Massachusetts, and Rhode Island Load Zones), the Northern New England ("NNE") Capacity Zone (the Maine, New Hampshire and Vermont Load Zones) and the Rest-of-Pool Capacity Zone (the Connecticut and Western/Central Massachusetts Load Zones)
- FCA11 commenced with a starting price of $18.624/kW-mo. and concluded for the SENE, NNE and Rest-of-Pool after five rounds.
- Resources will be paid as follows:
    - $5.297/kW-mo. – all Capacity Zones
    - $5.297/kW-mo. – NY AC Ties imports (539.4 MW), HQ interfaces (441 MW) and Highgate (55 MW)
    - $3.381/kW-mo. – New Brunswick imports (200 MW)

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[23] *Mass. Att'y Gen. et al. -v- Bangor Hydro et al.*, 149 FERC ¶ 61,156 (Nov. 24, 2014), *reh'g denied*, 151 FERC ¶ 61,125 (May 14, 2015).

[24] *Id.* at P 27 (for the refund period covered by EL13-33 (i.e., Dec. 27, 2012 through Mar. 27, 2014), the ROE for that particular 15-month refund period should be based on the last six months of that period; the refund period in EL14-86 and for the prospective period, on the most recent financial data in the record).

[25] *Environment Northeast, et al. v. Bangor Hydro-Elec. Co., et al. and Mass. Att'y Gen. et al. -v- Bangor Hydro et al.*, 151 FERC ¶ 61,125 (May 14, 2015).

[26] *Environment Northeast, et al. v. Bangor Hydro-Elec. Co., et al. and Mass. Att'y Gen. et al. -v- Bangor Hydro et al.*, 154 FERC ¶ 63,024 (Mar. 22, 2016) ("*2012/14 ROE Initial Decision*").

- No resources cleared as Conditional Qualified New Generating Capacity Resources
- No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource
- No de-list bids were rejected for reliability reasons

Unless the April 28 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Exelon Request for Additional Cost Recovery (ER17-933)**

As previously reported, the Director of Office of Energy Market Regulation ("OEMR")-East, pursuant to the FERC's February 3 *Absence of a Quorum Delegation Order* (*see* Section XII, AD17-10 below), issued an order on March 30, 2017, accepting Exelon's Cost Recovery Filing for filing, suspended for a nominal period, to become effective March 30, 2017, subject to refund and further Commission order. As a practical matter, however, the letter order merely punted to a later date a final FERC decision on this matter. The letter order stated that "preliminary analysis indicates that Exelon's filing has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful … Protests and comments will be addressed in a further Commission order as appropriate."

Recall that, on February 3, pursuant to Section III.A.15 of Appendix A to Market Rule 1,[27] Exelon Generation Company ("Exelon") requested that the FERC authorize recovery of $1,495,171 of actual fuel costs for Mystic Generating Station Units 8 and 9 ("Mystic 8 and 9") that were not recovered due to market power mitigation applied during the months of October and November 2016, as well as associated regulatory costs (estimated by Exelon to be roughly $60,000). Comments on Exelon's request were due on or before February 24. The ISO answered the Exelon request on February 24, requesting that the FERC "reject [Exelon]'s request for additional cost recovery for October 1, 3 and 4, and, to the extent it accepts the remainder of [Exelon]'s Cost Recovery Request, affirm that the amount recovered is justified by the IMM's correct application of the ISO Tariff provisions for calculating cost-based Reference Levels." On March 13, Exelon and NEPGA (which also moved to intervene out-of-time) answered the ISO's February 24 answer. Exelon asked that the FERC strike the portions of the IMM's pleading related to issues Exelon is not seeking/ contesting -- Exelon's recovery of additional fuel costs incurred under a Shoulder Period Agreement with ENGIE and the IMM's request that the FERC "find that the IMM has properly applied the ISO Tariff in establishing the Reference Levels for the Mystic 8 and 9 units . . . ." NEPGA, which also moved to intervene out-of-time, also asked the FERC to deny the IMM's requested Reference Level finding. Additional parties to the proceeding include NEPOOL and Direct Energy Business. On March 29, the IMM responded to the March 13 Exelon and NEPGA answers.

This matter remains subject to further FERC proceedings and/or action. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ISO Securities: Authorization for Future Drawdowns (ES17-15)**

On March 31, the ISO requested the necessary continued FERC authorization for drawdowns under its previously authorized $20 million Revolving Credit Line and $4 million line of credit supporting the Payment Default Shortfall Fund.[28] (ISO authorization would otherwise terminate on June 30, 2017).[29]

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[27] Under Appendix A Section III.A.15, a Market Participant has the right to make a Section 205 filing seeking additional cost recovery if, as a result of mitigation applied under Appendix A or the Energy Offer Cap, it will not recover the fuel and variable operating and maintenance ("O&M") costs of a Resource for all or part of one or more Operating Days.

[28] *See ISO New England Inc.*, 139 FERC ¶ 62,248 (June 22, 2012) (initially authorizing borrowings through June 30, 2014); *ISO New England Inc.*, 147 FERC ¶ 62,091 (May 6, 2014) (continuing authorization through June 30, 2015); *ISO New England Inc.*, 151 FERC ¶ 62,185 (June 15, 2015) (continuing authorization through June 30, 2017).

Comments on this filing were due on or before April 21; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **Waiver Request: FCM Qualification for FCA8 MRAs (Emera ESS6) (ER17-1031)**

On April 7, the FERC granted Emera Energy Services Subsidiary No. 6's ("Emera ESS6") uncontested request for waiver of the FCM qualification rules to allow EES6 to qualify Bayside Station for participation in the summer 2017 Monthly Reconfiguration Auctions ("MRAs") associated with the FCA8 2017/18 Capacity Commitment Period.[30] Unless the April 7 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **CONE & ORTP Updates (ER17-795)**

The ISO's January 13 filing of updated FCM Cost of New Entry ("CONE"), Net CONE and Offer Review Trigger Price ("ORTP") values remains pending. With respect to CONE and Net CONE, the ISO will use a gas-fired simple cycle combustion-turbine ("CT") as the reference technology for the updated values, $11.35 and $8.04, respectively. The ISO will use a Capacity factor of 32%, resulting in a $11.02 ORTP for on-shore wind resources. The ISO requested a March 15, 2017 effective date for the new values to coincide with the beginning of the administrative cycle for FCA12. The CONE & ORTP Updates were not supported by the Participants Committee when considered at the January 6 meeting. Comments on this filing were due on or before February 3. Doc-less interventions were filed by Avangrid, Brookfield, Calpine, ConEd, Dominion, Eversource, Exelon, FirstLight, LSPower, National Grid, NextEra, NRG, PSEG, and Cogentrix[31] (out-of-time). Comments were filed by NEPOOL (identifying concerns and alternatives presented and reviewed in the course of the stakeholder process preceding the filing) and NESCOE (supporting the CONE/Net CONE values as overall reasonable updates reflecting changed market outcomes and market designs). NEPGA filed a protest (challenging the ISO's proposal to base Net CONE for FCA12 on a greenfield simple-cycle combustion turbine). The ISO answered the NEPGA protest on February 17. NEPGA answered the ISO's February 17 answer on March 6 and the ISO answered NEPGA's March 6 answer on March 21.

On March 6, the ISO submitted, in light of the contested nature of this proceeding and the lack of a FERC quorum, an amendment-type filing to extend indefinitely the date by which the FERC would otherwise have been required to act on the January 13 filing or have the filing become effective by operation of law. The ISO committed to submit a further amendment-type filing, triggering a new 60-day statutory action date, "at the appropriate time" (presumably once the FERC has a quorum). In the meantime, the ISO stated that the proposed March 15, 2017 effective date for the CONE and ORTP Updates remains unchanged and will be used for the administration of FCA12. Comments on the ISO's March 6 filing were due on or before March 27. NEPOOL filed limited comments seeking acknowledgement in any final order that the ISO's actions not be construed to have any precedential effect in future contested Section 205 proceedings where the FERC does have a quorum.

This matter will remain pending before the FERC until such time as the ISO makes its further filing re-starting the 60-day clock. Until then, if you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[29] *See ISO New England Inc.*, 151 FERC ¶ 62,185 (June 15, 2015).

[30] *Emera Energy Services Sub. No. 6*, 159 FERC ¶ 62,026 (Apr. 7, 2017).

[31] Cogentrix Energy Power Management, LLC ("Cogentrix") intervened on behalf of its Participant affiliates Rhode Island State Energy Center, LP, Essential Power Newington, LLC, and Essential Power Massachusetts.

- **FCM Enhancements (ER16-2451)**

The FERC's *FCM Enhancements Order*[32] remains subject to a request for rehearing by Indicated NYTOs.[33] As previously reported, the FERC accepted changes to the Tariff to increase liquidity in the FCM by increasing Market Participant opportunities to enter into reconfiguration auctions and bilateral contracts for the exchange of CSOs ("FCM Enhancements"). Specifically, the FCM Enhancements (i) modify certain FCM qualification rules to facilitate the ability of New Capacity Resources to supply capacity beginning four months after participating in their first FCA; (ii) provide Import Capacity Resources backed by one or more External Resources the opportunity (currently available to generators and demand response) to provide capacity beginning one or two years after participating in their first FCA; and (iii) establish a new form of bilateral contracting in which Market Participants can, as the Capacity Commitment Period approaches, trade CSOs for a seasonal strip of CSOs. The FCM Enhancements included several smaller improvements as well, including the elimination of a requirement that the ISO make a FERC filing in order to terminate the CSO of a resource that has voluntary withdrawn from the FCM resource development process. The FCM Enhancements were accepted, effective as of October 19, 2016, as requested.

In accepting the FCM Enhancements, the FERC noted that "protestors do not challenge the justness and reasonableness of the specific tariff revisions … the concerns raised by NYISO are not the result of ISO-NE's proposed tariff revisions, but result from NYISO's treatment of generators that export capacity from within a constrained locality under its current market rules."[34] Accordingly, the FERC was "not persuaded that the potential behavior of New York suppliers provides a sufficient basis to reject ISO-NE's filing in this case, and deferring the effective date of an otherwise just and reasonable proposal would be inconsistent with the notice provision in section 205 of the FPA."[35] The FERC did acknowledge NYISO's concerns about a potential flaw in its market rules, and encouraged NYISO stakeholders to timely complete discussions underway to address that flaw.

As noted above, on November 17, 2016, Indicated TOs' requested rehearing of the *FCM Enhancements Order*. On December 19, 2016, the FERC issued a tolling order affording it additional time to consider Indicated TOs' rehearing request, which remains pending before the FERC.

NYISO Tariff Revisions in Response to FCM Enhancements (ER17-446). Rehearing remains pending of the FERC's January 27, 2017 order conditionally accepting in part, and rejecting, in part, NYISO tariff revisions proposed in response to the acceptance of the FCM Enhancements, to correct a pricing inefficiency in NYISO's Installed Capacity ("ICAP") market design related to capacity exports from certain zones in the New York Control Area.[36] The order accepted NYISO's proposed locality exchange factor methodology to be implemented immediately but rejected NYISO's proposed one-year transitional mechanism.[37] In accepting the immediate implementation of NYISO's Locality Exchange Factor methodology, the FERC found the proposed methodology "just and reasonable because it corrects a pricing inefficiency in NYISO's ICAP market design. NYISO's proposed methodology will now recognize that an exporting generator continues to operate within its Locality, which would be reflected in the ICAP Spot Market Auction clearing prices by accounting for the portion of exported capacity that can be replaced by capacity located in Rest of State. Therefore, NYISO's proposal will ensure that prices within the Localities reflect actual market conditions and prices."[38] In rejecting the transition mechanism, the FERC found that

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[32] *ISO New England Inc. and New England Power Pool Participants Comm. and NY Indep. Sys. Op., Inc.*, 157 FERC ¶ 61,025 (Oct. 18, 2016) ("*FCM Enhancements Order*"), *reh'g requested*.

[33] "Indicated NYTOs" are Central Hudson Gas & Electric, Consolidated Edison Co. of New York, New York Power Authority, New York State Electric & Gas, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric.

[34] *Id.* at P 31.

[35] *Id.*

[36] *NY Indep. Sys. Op., Inc.*, 158 FERC ¶ 61,064 (Jan. 27, 2017), *reh'g requested*.

[37] *Id.* at P 20.

[38] *Id.* at P 35.

"that the mechanism lacks analytical basis and will delay efficient market signals … because it could overstate the extent to which the capacity export will unencumber NYISO's transmission capability into Southeast New York."[39] NYISO was directed to submit, and submitted on February 6 and corrected on February 10, a compliance filing removing the one-year transition mechanism provisions.[40] NRG requested rehearing of the January 27 order on February 24. The FERC issued a tolling order on March 27, 2017, affording it additional time to consider NRG's request for rehearing, which remains pending before the FERC.

If you have any questions concerning these proceedings, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **FCM Resource Retirement Reforms (ER16-551)**

The NEGPA, NextEra and Exelon request for rehearing of the FERC's *Resource Retirement Reforms Order*[41] remains pending. As previously reported, the FERC conditionally accepted, effective March 1, 2016, changes to the FCM rules for resource retirements proposed by the ISO and its Internal Market Monitor ("IMM") (the "ISO/IMM Proposal"). The FERC conditioned its acceptance of the ISO/IMM Proposal on the filing of Tariff revisions "establishing a materiality threshold for determining whether or not a particular proxy de-list bid will replace a Retirement Bid in an FCA,"[42] which were filed with and later accepted by the FERC.[43] NEPGA, Exelon and NextEra jointly requested rehearing of the *Resource Retirement Reforms Order*. On June 13, the FERC issued a tolling order affording it additional time to consider the joint rehearing request, which remains pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **2013/14 Winter Reliability Program Remand Proceeding (ER13-2266)**

Pending before the FERC is the ISO's compliance filing in response to the FERC's August 8, 2016 remand order.[44] In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed the ISO to request from Program participants the basis for their bids, including the process used to formulate the bids, and to file with the FERC a compilation of that information, an IMM analysis of that information, and the ISO's recommendation as to the reasonableness of the bids, so that the FERC can further consider the question of whether the Bid Results were just and reasonable.[45] The ISO submitted its compliance filing on January 23, reporting the IMM's conclusion that "the auction was not structurally competitive and a 'small

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[39] *Id.* at P 55.

[40] *Id.* at P 61.

[41] *ISO New England Inc.*, 155 FERC ¶ 61,029 (Apr. 12, 2016), *reh'g requested* ("*Resource Retirement Reforms Order*"). As previously reported, the ISO/IMM Proposal requires (i) that capacity suppliers with existing resources to submit a price for the retirement of a resource (to replace the existing Non-Price Retirement Request process), (ii) the use of a Proxy De-List Bid, and (iii) notice of the potential retirement and proposed retirement price to be submitted prior to the commencement of an FCA's qualification process for new resources. The ISO/IMM Proposal was considered but not supported by the Participants Committee at its Dec. 4, 2015 meeting.

[42] *Id.* at P 62.

[43] *ISO New England Inc.*, 15 FERC ¶ 61,067 (July 27, 2016) ("*Resource Retirement Reforms Compliance Order*").

[44] *ISO New England Inc.*, 156 FERC ¶ 61,097 (Aug. 8, 2016) ("*2013/14 Winter Reliability Program Remand Order*"). As previously reported, the DC Circuit remanded the FERC's decision in ER13-2266, agreeing with TransCanada that the record upon which the FERC relied is devoid of any evidence regarding how much of the 2013/14 Winter Reliability Program cost was attributable to profit and risk mark-up (without which the FERC could not properly assess whether the Program's rates were just and reasonable), and directing the FERC to either offer a reasoned justification for the order in ER13-2266 or revise its disposition to ensure that the Program rates are just and reasonable. *TransCanada Power Mktg. Ltd. v. FERC,* 2015 U.S. App. LEXIS 22304 (D.C. Cir. 2015).

[45] *2013/14 Winter Reliability Program Remand Order* at P 17.

proportion' of the total cost of the program may be the result of the exercise of market power" but that the "vast majority of supply was offered at prices that appear reasonable and that, for a number of reasons, it is difficult to assess the impact of market power on cost." Based on the IMM and additional analysis, the ISO recommended that "there is insufficient demonstration of market power to warrant modification of program." Comments on the ISO's report were due on or before February 13. Both TransCanada and the MA AG protested the ISO's conclusion and recommendation that modification of the program was unwarranted. TransCanada requested that FERC establish a settlement proceeding where market participants could "exchange confidential information to determine what the rates should be" and refunds and "such other relief as may be warranted" provided. On February 28, the ISO answered the TransCanada and MA AG protest. On March 10, TransCanada answered the ISO's February 28 answer. This matter is again pending before the FERC. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

- **FTR Balance of Planning Period Financial Assurance Changes (ER17-1441)**

On April 20, the ISO and NEPOOL jointly filed changes to the Financial Assurance Policy to account for upcoming changes in the FTR auction structure. These changes were supported unanimously by the Participants Committee at its December 2, 2016 annual meeting. Comments on this filing are due on or before May11. Thus far, interventions have been filed by DC Energy and National Grid. If you have any questions concerning this proceeding, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Financial Assurance Policy FCM Capacity Charge Calculation Changes (ER17-1103)**

On April 7, the FERC accepted changes that modify how FCM Capacity Charge Requirements are calculated. The changes were accepted effective as of June 1, 2017, as requested. Unless the April 7 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-ES: Eversource Recovery of NU/NSTAR Merger-Related Costs (ER16-1023)**

As previously reported, the FERC accepted Eversource's November 22 offer of settlement[46] to resolve the issues in this proceeding (principally, whether the $38.9 million in FERC-jurisdictional, merger-related transmission costs incurred as the result of the April 10, 2012 NU/NSTAR merger that Eversource sought to recover through changes to Schedule ES-21 were just and reasonable).[47] Eversource was directed to file revised tariff records in eTariff format to reflect the FERC's approval of the settlement. Eversource filed those tariff sheets on March 1, 2017, and those tariff sheets were accepted on May 2, 2017, effective June 1, 2017 as requested. Unless the May 2 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434 et al.)**

On June 2, 2016, the FERC accepted, but established hearing and settlement judge procedures for,[48] March 31 filings by Emera Maine in which Emera Maine sought authorization to recover certain merger-

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[46] *ISO New England Inc. et al.*, 158 FERC ¶ 61,096 (Jan. 31, 2017).

[47] *See ISO New England Inc. et al.*, 155 FERC ¶ 61,136 (May 3, 2016).

[48] *Emera Maine and BHE Holdings*, 155 FERC ¶ 61,230 (June 2, 2016) ("*June 2 Order*").

related costs viewed by the FERC's Office of Enforcement's Division of Audits and Accounting ("DAA") to be subject to the conditions of the orders authorizing Emera Maine's acquisition of, and ultimate merger with, Maine Public Service ("Merger Conditions"). As previously reported, the Merger Conditions imposed a hold harmless requirement, and required a compliance filing demonstrating fulfillment of that requirement, should Emera Maine seek to recover transaction-related costs through any transmission rate. Following its recent audit of Emera Maine, DAA found that Emera Maine "inappropriately included the costs of four merger-related capital initiatives in its formula rate recovery mechanisms" and "did not properly record certain merger-related expenses incurred to consummate the merger transaction to appropriate non-operating expense accounts as required by [FERC] regulations [and] inappropriately included costs of merger-related activities through its formula rate recovery mechanisms" without first making a compliance filing as required by the merger orders.

In the *June 2 Order*, the FERC found that the Compliance Filings raise issues of material fact that could not be resolved based on the record, and are more appropriately addressed in the hearing and settlement judge procedures.[49] The FERC reiterated several points with respect to transaction-related cost recovery explained in prior FERC orders and provided guidance on other transaction-related cost recovery points.[50] The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and will hold the hearing in abeyance pending the outcome of settlement judge procedures.[51] The separate compliance filing dockets were consolidated for the purposes of settlement, hearing and decision.[52]

Settlement Judge Procedures. ALJ John Dring is the settlement judge for these proceedings. A first settlement conference was held on June 29; a second settlement conference, October 25. A third settlement conference, scheduled for November 22, 2016, was cancelled and subsequently held on December 1. In a March 16 status report, Judge Dring indicated that the parties had reached a settlement in principal and were memorializing their agreement. He reported that the parties intend to file that agreement in late April or early May. He recommended that settlement procedures be continued. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- ***Opinion 531-A* Local Refund Report: FG&E (EL11-66)**

FG&E's June 29, 2015 refund report for its customers taking local service during *Opinion 531-A's* refund period remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Regional Refund Reports (EL11-66)**

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by the ISO in compliance with *Opinions No. 531-A*[53] *and 531-B*[54] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[49] *Id.* at P 24.

[50] *Id.* at PP 25-26.

[51] *Id.* at P 27.

[52] *Id.* at P 21; Ordering Paragraph (B).

[53] *Martha Coakley, Mass. Att'y Gen. et al.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

- ***Opinions 531-A/531-B* Local Refund Reports (EL11-66)**

The *Opinions 531-A and 531-B* refund reports filed by the following TOs for their customers taking local service during the refund period also remain pending before the FERC:

♦ Central Maine Power
♦ Emera Maine
♦ Eversource
♦ National Grid
♦ NHT
♦ NSTAR
♦ United Illuminating
♦ VT Transco

If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **LFTR Implementation: 34th Quarterly Status Report (ER07-476; RM06-08)**

The ISO filed the thirty-fourth of its quarterly status reports regarding LFTR implementation on April 14, 2017. The ISO again reported its plan to focus on implementation of the monthly reconfiguration auctions (accepted in ER12-2122). The ISO reported that it will file a Participants Committee-supported financial assurance design for monthly reconfiguration auctions (*see* ER17-1441 in Section V above) and will subsequently renew efforts to address LFTR financial assurance issues leveraging that design. As in previous reports, the ISO described the 18-month implementation process that will follow once the LFTR financial assurance issues are resolved. These status reports are not noticed for public comment and no comments have been filed.

- **ISO-NE FERC Reporting Requirement 582 (not docketed)**

On April 14, the ISO submitted a report of its total MWh of transmission service during 2016. The ISO reported that 132,813,111.824 MWh of transmission service in interstate commerce was provided during 2016 (roughly 1.25 million MWh less than 2015). These filings are not noticed for comment.

- **ISO-NE FERC Form 715 (not docketed)**

On April 1, the ISO submitted its 2017 Annual Transmission Planning and Evaluation Report. These filings are not noticed for filing.

IX. Membership Filings

- **May 2017 Membership Filing (ER17-1506)**

On April 28, NEPOOL requested that the FERC accept (i) the memberships of Block Island Power Company (Supplier Sector); Georges River Energy, LLC (Provisional Member Group Seat); Ohmconnect, Inc. (AR Sector, LR Sub-Sector); Rensselaer Generating, LLC and Roseton Generating, LLC [Related Persons to Castleton Commodities (Supplier Sector)]; and VECO Power Trading, LLC [Related Person to DC Energy (Supplier Sector)]; (ii) termination of the Participant status of Union Leader Corporation (MPEU, End User Sector), effective April 1, 2017; and (iii) Great River Hydro, LLC's name change (f/k/a TransCanada Hydro Northeast, Inc.). Comments on this filing are due on or before May 19.

- **April 2017 Membership Filing (ER17-1364)**

On March 31, as corrected on April 4, NEPOOL requested that the FERC accept (i) the membership of GridAmerica Holdings Inc. (National Grid Related Person); and (ii) the name changes of ENGIE Energy Marketing NA, Inc. (f/k/a GDF SUEZ Energy Marketing NA, Inc.) and Verso Energy Services LLC (f/k/a Verso Maine Energy LLC). This matter is pending before the FERC.

- **Suspension Notices (not docketed)**

Since the last Report, the ISO filed, pursuant to Section 2.3 of the Information Policy, a notice with the FERC noting that the following Participant was suspended from the New England Markets on the date indicated (at 8:30 a.m.) due to a Payment Default:

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[54] *Martha Coakley, Mass. Att'y Gen. et al.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

Date of Suspension/ FERC Notice	***Participant Name***
Apr 24/26	First Wind Energy Marketing LLC ("First Wind")

First Wind has since cured its Payment Default. However, First Wind has, for unrelated reasons, requested termination of its membership to be effective as of May 1, 2017. Stetson Holdings will now be the "lead" governance Participant for the SunEdison companies. Suspension notices are for the FERC's information only and are not docketed or noticed for public comment.

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).

- **Revised Reliability Standards: IRO-002-5; TOP-001-4 (RD17-4)**

On April 17, the FERC approved changes to Reliability Standards TOP-001-4 (Transmission Operations) and IRO-002-5 (Reliability Coordination - Monitoring and Analysis), as well as their associated Implementation Plans, Violation Risk Factors ("VRFs"), Violation Severity Levels ("VSLs"), and the retirement of the prior versions of the revised Standards. The changes were approved as of April 17, 2017. As previously reported, TOP-001-4 Requirement R10 was revised to require a Transmission Operator to monitor non-BES facilities for determining System Operating Limit ("SOL") exceedances within its Transmission Operator Area and TOP-001-4 was further revised to require that Real-Time data exchange capabilities needed for Real-Time monitoring and analysis have redundant and diversely routed data exchange infrastructure within the primary Control Center and that those capabilities are tested for redundant functionality on a regular basis. Similar revisions were reflected in IRO-002-5. The changes are intended to help ensure that all facilities that can adversely impact reliability are monitored and to prevent a single point of failure in primary Control Center data exchange infrastructure from halting the flow of Real-Time data used by operators to monitor and control the Bulk Electric System. Unless the April 17 order is challenged, this proceeding will be concluded.

- **Revised Reliability Standard: CIP-003-7 (RM17-11)**

On March 3, NERC filed for approval changes to Reliability Standard CIP-003 (Cyber Security - Security Management Controls), approval of the associated implementation plan, VRFs, VSLs, and revised NERC Glossary definitions of "Removable Media" and "Transient Cyber Asset", and the retirement of the currently-effective version of CIP-003 and the NERC Glossary definitions of "Low Impact External Routable Connectivity" and "Low Impact BES Cyber System Electronic Access Point". The CIP-003 Changes) (i) clarify the electronic access control requirements applicable to low impact BES Cyber Systems; (ii) add requirements related to the protection of transient electronic devices used for low impact BES Cyber Systems; and (iii) require Responsible Entities to have a documented cyber security policy related to declaring and responding to CIP Exceptional Circumstances for low impact BES Cyber Systems. The proposed implementation plan provides that the CIP-003-Changes become effective on the first day of the first calendar quarter that is 18 calendar months after the effective date of the FERC's order approving the CIP-003 Changes. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **New Reliability Standards: PRC-027-1 and PER-006-1 (RM16-22)**

On September 2, 2016, NERC filed for approval (i) two new Reliability Standards -- PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for Personnel), (ii) associated Glossary definitions, (iii) an implementation plan, (iv) VRFs and VSLs, and (v) the retirement of PRC-001-1.1(ii) (together, the "Protection System Changes"). NERC stated that the purpose of the Protection System Changes is to: (1) maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System ("BES") Elements, such that those Protection Systems operate in the intended sequence during Faults; and (2) require registered entities to provide training to their relevant personnel on Protection Systems and Remedial Action Schemes ("RAS") to help ensure that the BES is reliably operated. NERC requested that the new Standards and definitions become effective on the first day of the first calendar quarter that is 24 months following the effective date of the FERC's order approving the Standards. As of the date of this Report, the FERC still has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **NOPR: Revised Reliability Standard: PRC-012-2 (RM16-20)**

On January 19, 2017, the FERC issued a NOPR proposing to approve Reliability Standard PRC-012-2 (Remedial Action Schemes), its associated implementation plan, VRFs, VSLs, and effective date, and retirement of PRC-015-1 and PRC-016-1 (together, the "RAS Changes").[55] In addition, the FERC proposes to withdraw pending Standards PRC-012-1, PRC-013-1, and PRC-014-1. The RAS Changes are designed to ensure that remedial action schemes do not introduce unintentional or unacceptable reliability risks to the BES. NERC requested that the RAS Changes become effective on the first day of the first calendar quarter that is 36 months after the effective date of an order approving the Standard, pursuant to the Implementation Plans included with the Changes. Comments on the *RAS Changes NOPR* were due on or before April 10, 2017,[56] and were filed by NERC, NESCOE, ISO-NE/IESO/NYISO , MISO, Bonneville, EEI, and ITC. This matter is pending before the FERC.

- **NOPR: Revised Reliability Standards: BAL-005-1 & FAC-001-3 (RM16-13)**

On September 22, 2016, the FERC issued a NOPR proposing to approve Reliability Standards BAL-005-1 (Balancing Authority Control) and FAC-001-3 (Facility Interconnection Requirements), and associated Glossary definitions, implementation plan, VRFs and VSLs (together, the "Frequency Control Changes").[57] As previously reported, NERC stated that the Frequency Control Changes clarify and refine Requirements for accurate, consistent, and complete reporting of Area Control Error ("ACE") calculations. NERC indicated that the Frequency Control Changes will improve reliability by supporting efforts to maintain Interconnection frequency at 60 Hz in a manner consistent with FERC directives, technological developments, and NERC's current framework of integrated Reliability Standards. NERC requested that the Frequency Control Changes become effective on the first day of the first calendar quarter that is 12 months after the effective date of an order approving the Standard, pursuant to the Implementation Plans included with the Changes. Comments on the *Frequency Control Changes NOPR* were due on or before November 28, 2016,[58] and were filed by NERC, EEI, Bonneville, Idaho Power and J. Appelbaum.

On March 7, the FERC issued a data request seeking additional information about the current back-up power supply practices of a representative sample of entities potentially affected by the Frequency Control Changes. NERC filed its response to the FERC's data request on April 6. This matter is pending before the FERC.

- **NOPR: Revised Reliability Standard: MOD-001-2 (RM14-7)**

The *ATC NOPR* remains pending before the FERC. As previously reported, the FERC's June 19, 2014, NOPR[59] proposed to approve changes to MOD-001-2 (Modeling, Data, and Analysis - Available Transmission System Capability) to replace, consolidate and improve upon the Existing MOD Standards in addressing the reliability issues associated with determinations of Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC"). MOD-001-2 will replace the six Existing MOD Standards[60] to exclusively focus

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[55] *Remedial Action Schemes Rel. Standard*, 158 FERC ¶ 61,042 (Jan. 19, 2017) ("*RAS Changes NOPR*").

[56] The *RAS Changes NOPR* was published in the *Fed. Reg.* on Feb. 8, 2017 (Vol. 82, No. 25) pp. 9,702-9,706.

[57] *Balancing Authority Control, Inadvertent Interchange, and Facility Interconnection Rel. Standards*, 156 FERC ¶ 61,210 (Sep. 22, 2016) ("*Frequency Control Changes NOPR*").

[58] The *Frequency Control Changes NOPR* was published in the *Fed. Reg.* on Sep. 28, 2016 (Vol. 81, No. 188) pp. 66,555-66,562.

[59] *Modeling, Data, and Analysis Rel. Standards*, 147 FERC ¶ 61,208 (June 19, 2014) ("*ATC NOPR*").

[60] The 6 existing MOD Standards to be replaced by MOD-001-2 are: MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2.

on the reliability aspects of ATC and AFC determinations. NERC requested that the revised MOD Standard be approved, and the Existing MOD Standards be retired, effective on the first day of the first calendar quarter that is 18 months after the date that the proposed Reliability Standard is approved by the FERC. NERC explained that the implementation period is intended to provide NAESB sufficient time to include in its WEQ Standards, prior to MOD-001-2's effective date, those elements from the Existing MOD Standards, if any, that relate to commercial or business practices and are not included in proposed MOD-001-2. The FERC sought comment from NAESB and others whether 18 months would provide adequate time for NAESB to develop related business practices associated with ATC calculations or whether additional time may be appropriate to better assure synchronization of the effective dates for the proposed Reliability Standard and related NAESB practices. The FERC also sought further elaboration on specific actions NERC could take to assure synchronization of the effective dates. Comments on this NOPR were due August 25, 2014,[61] and were filed by NERC, Bonneville, Duke, MISO, and NAESB. On December 19, 2014, NAESB supplemented its comments with a report on its efforts to develop WEQ Business Practice Standards that will support and coordinate with the MOD Standards proposed in this proceeding. NASEB issued a report on September 25, 2015, informing the FERC that the NAESB standards development process has been completed and NAESB will file the new suite of business practice standards as part of Version 003.1 of the NAESB WEQ Business Practice Standards in October 2015. As noted above, the *ATC NOPR* remains pending before the FERC.

- **Annual NERC CMEP Filing (RR15-2)**

On February 22, NERC submitted a compliance filing reviewing the progress of its risk-based Compliance Monitoring and Enforcement Program ("CMEP") program. In this filing, NERC identified and proposed two enhancements to the risk-based CMEP: (1) providing minimal risk Compliance Exceptions ("CEs") identified through self-logging to FERC non-publicly; and (2) expanding the use of CEs to include certain moderate risk noncompliance currently processed through Find, Fix, Track and Report ("FFTs"). Comments on this filing were submitted by the ISO/RTO Council ("IRC"), AEP, EEI, PPL, and jointly by the American Public Power Association ("APPA"), the Electricity Consumers Resource Council ("ELCON"), the National Rural Electric Cooperative Association ("NRECA"), and the Transmission Access Policy Study Group ("TAPS"). This filing is pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Green Mountain Power/VT Transco (Highgate) (EC17-86)**

On March 1, Green Mountain Power ("GMP") and Vermont Transco ("VT Transco") filed an application requesting FERC authorization for GMP to sell its undivided ownership share in the Highgate Transmission Facility to VT Transco and for VTransco to acquire GMP's undivided ownership share, as well as certain undivided ownership shares of other joint owners of the Highgate Transmission Facility. Comments on the application were due on or before March 22, 2017; none were filed. On April 11, GMP and VT Transco supplemented their application at the request of FERC Staff to clarify the benefits to ratepayers of the proposed Transaction. No comments on the supplement were filed by the April 21 comment date. This matter is again pending before the FERC.

- **203 Application: Green Mountain Power/ENEL Hydros (EC17-76)**

On February 3, GMP filed an application requesting FERC authorization to acquire the following small hydroelectric generation facilities (each a QF, collectively 8.39 MW of total generating capacity) from subsidiaries of Enel Green Power North America, Inc.: Hoague-Sprague, Kelley's Falls, Lower Valley, Glen, Rollinsford, South Berwick, Somersworth, and Woodsville. Comments on the application were due on or before February 24, 2017; none were filed. This matter remains pending before the FERC.

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[61] The MOD-001-2 NOPR was published in the *Fed. Reg.* on June 26, 2014, (Vol. 79, No. 123) pp. 36,269-36,273.

- **203 Application: Helix Generation/TransCanada (EC17-38)**

On March 31, 2017, the FERC authorized a transaction whereby Helix Generation, LLC ("Helix"), an affiliate of LSPower, will indirectly acquire all of the interests in a number of TransCanada-owned projects, including TransCanada's non-hydro generating assets in New England (i.e. the Kibby wind project and Ocean State facility).[62] Among other conditions, the *Helix/TransCanada Order* required notice within 10 days of the consummation of the transaction. As of the date of this Report, that notice still has not been provided.

- **203 Application: NSTAR/WMECO Merger (EC17-62)**

On March 2, 2017, the FERC authorized Eversource's internal reorganization under which Western Massachusetts Electric Company ("WMECO") will merge with and into NSTAR Electric Company ("NSTAR"), with NSTAR as the surviving.[63] Applicants committed to hold harmless transmission and wholesale customers from transaction-related costs for five years to the extent that such costs exceed savings related to the merger. Among other conditions, the *NSTAR/WMECO Merger Order* required Eversource to notify the FERC within 10 days of the consummation of the merger, which was expected to occur on January 1, 2018.

- **MOPR-Related Proceedings (PJM, NYISO) (EL16-49; EL13-62)**

In two proceedings which, unless narrowly limited solely to the unique facts of the directly applicable markets (PJM in EL16-49; NYISO in EL13-62), could impact the New England market through FERC jurisdictional or other determinations, NEPOOL filed limited comments requesting that any Commission action or decision be limited narrowly to the facts and circumstances as presented in the applicable market. NEPOOL urged that any changes that may be ordered by the Commission in the proceedings not circumscribe the results of NEPOOL's stakeholder process or predetermine the outcome of that process through dicta or a ruling concerning different markets with different history and different rules. NEPOOL's comments were filed on January 24 in the NYISO proceeding; January 30 in the PJM proceeding, and are pending before the FERC. If you have any questions concerning these proceedings, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **D&E Agreement: PSNH/Essential Power Newington (ER17-1495)**

On April 28, Public Service Company of New Hampshire ("PSNH") filed an Agreement for Design, Engineering and Construction services between itself and Essential Power Newington (the "D&E Agreement"). The purpose of the D&E Agreement is to set forth the terms and conditions under which PSNH would undertake certain design, engineering and construction activities on the Interconnection Facilities that have been identified as required under the LGIA in connection with Essential Power's planned capacity increase (to 674 MW) at the facility. PSNH requested that the D&E Agreement be accepted for filing as of June 28, 2017. Comments on this filing are due on or before May 19. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Cost Reimbursement Agreement: NEP/Wynn, MA LLC (ER17-1431)**

On April 18, New England Power Company ("NEP") filed a Cost Reimbursement Agreement between itself and Wynn MA, LLC (the "Agreement"). The purpose of the Agreement is to reimburse NEP for the actual costs and expenses associated with Wynn's request that NEP relocate a portion of NEP's existing P-168 115 kV underground and overhead transmission line and related transition structure located in Everett, Massachusetts, in connection with Wynn's planned development and construction of a resort facility in that location. NEP requested that the Agreement be accepted for filing as of March 24, 2017. Comments on this filing are due on or before May 9. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[62] *Helix Generation, LLC et al.*, 158 FERC ¶ 62,268 (Mar. 31, 2017) ("*Helix/TransCanada Order*").

[63] *NSTAR Elec. Co. and W. Mass. Elec. Co.*, 158 FERC ¶ 62,155 (Mar. 2, 2017) ("*NSTAR/WMECO Merger Order*").

- **IAs: WMECO/Nautilus Hydros (ER17-1340 et al.)**

On March 28, Eversource, on behalf of WMECO ("Eversource"), filed five two-party Interconnection Agreement ("TGIAs") with Nautilus Hydro, LLC ("Nautilus") to govern the continuing interconnection of the following hydro facilities: Dwight Hydro (1.7 MW); Gardners Falls (3.7 MW); Indian Orchard (3.7 MW); Puss Bridge (4.1 MW); and Red Bridge (4.5 MW). Since the TGIAs continue the existing interconnection arrangements between Eversource and the hydro facilities, previously covered by an Interconnection and Operating Agreement ("IOA") with Essential Power Massachusetts ("Essential Power"), without modification to the any of facilities' capability or operating characteristics. Accordingly, new 3-party party Interconnection Agreements ("IAs") that would include the ISO were not required. A March 29, 2017 effective date was requested. Comments on these filings were due on or before April 19, 2017; none were filed. The TGIAs are pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA: WMECO/Essential Power (ER17-1322)**

On March 28, Eversource, on behalf of WMECO, filed an amended IA with Essential Power to remove the hydro facilities transferred to Nautilus (*see* ER17-1340 et al. immediately above) and to amend provisions that remain applicable to certain Essential Power fossil-fueled assets (West Springfield, Doreen Street and Woodland Road. A March 29, 2017 effective date was requested. Comments on this filing were due on or before April 19, 2017; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **SGIA: ISO-NE/GMP (ER17-1296)**

On April 24, 2017, the FERC accepted a non-conforming Small Generator Interconnection Agreement ("SGIA") between GMP and the ISO to allow the interconnection of GMP's Small Generating Facility to the Administered Transmission System at GMP's Huntington Falls Substation. The Small Generating Facility is an existing facility located in Weybridge, VT, constructed in 1910, that has been interconnected to GMP's system, and following modifications, will be rated at 6.58 MW. The SGIA is non-conforming in that GMP is both the Interconnection Customer and the Interconnecting Transmission Owner. The SGIA was accepted effective as of March 8, 2017, as requested. Unless the April 24 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA: Eversource/Covanta (Preston, CT) (ER17-1038)**

On April 13, the FERC accepted a non-conforming Interconnection Agreement ("IA") between Eversource and Covanta Southeastern Connecticut Company ("Covanta") governing the continuing interconnection of Covanta's 18.5 MW generating facility located in Preston, Connecticut. Since the IA continues the existing interconnection arrangements between Eversource and Covanta, without modification to the facility's capability or operating characteristics, a new three-party IA that would include the ISO was not required. The IA was accepted effective as of February 18, 2017, as requested. Unless the April 13 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LSA: CL&P/Wallingford, CT Transmission Line Separation Agreement (ER17-967)**

On April 6, the FERC accepted a Transmission Line Separation Agreement between CL&P and the Town of Wallingford, CT Department of Public Utilities Electric Division ("Wallingford"), which sets forth the terms and conditions under which CL&P will assist Wallingford in separating transmission lines 1630 and 1640 (a required upgrade following an ISO-NE post-FCA re-study). The Agreement was accepted effective as of February 13, 2017, as requested. Unless the April 6 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Emera MPD OATT Changes (ER15-1429; EL16-13, ER12-1650)**

As previously reported, the FERC conditionally accepted, on December 7, 2015, changes to the Maine Public District ("MPD") Open Access Transmission Tariff ("MPD OATT"), including to the rates, terms, and conditions set forth in MPD OATT Attachment J.[64] However, the FERC found, ultimately, that the changes to the MPD OATT had not been shown to be just and reasonable, may be unjust and unreasonable, instituted a Section 206 proceeding (in EL16-13) to examine the provisions, and set the matter for a trial-type evidentiary hearing, to be held in abeyance pending the outcome of settlement judge procedures (*see* below).

Background (ER15-1429). Emera Maine, as successor to Maine Public Service Company ("Maine Public"), provides open access to Emera Maine's transmission facilities in northern Maine (the "MPD Transmission System") pursuant to the MPD OATT. Emera Maine stated that the changes to the MPD OATT were needed to ensure that, in light of the filing by Emera of consolidated FERC Form 1 data (data comprising both the former Bangor Hydro and Maine Public systems), charges for service under the MPD OATT reflect only the costs of service over the MPD Transmission System. Emera Maine also proposed additional, limited changes to the MPD OATT. A June 1, 2015 effective date was requested. The "Maine Customer Group"[65] filed a motion to reject ("Motion to Reject") the April 1 Filing, asserting the April 1 Filing was deficient because, rather than actual rates, it included proxy rates that MPD said would be replaced with 2014 Form 1 numbers when MPD's 2014 Form 1 was available. On April 22, the Maine PUC and the Maine Customer Group protested the filing. The MPUC challenged three aspects of the filing: (i) the proposed increase of ROE from 9.75% to 10.20% based on anomalous economic conditions; (ii) the change from a measured loss factor calculation to a fixed loss factor; and (iii) the use of end-of-year account balances, rather than average 13-month account balances, for determination of facilities that are included in rate base. In addition to those aspects, the Maine Customer Group further challenged: (iv) inclusion of an out-of-period adjustment to rate base for forecasted transmission; (v) the proposed capital structure, which they assert is artificially distorted to accommodate a requirement resulting from the merger of Emera Maine's predecessor companies; and (vi) the proposed new cost allocation scheme. On April 24, Emera Maine answered the Maine Customer Group's Motion to Reject. On April 29, the Maine Customer Group answered Emera Maine's April 24 answer. On May 1, Emera Maine filed an amendment and errata to its April 1 filing, in part reflecting 2014 FERC Form 1 data rather than estimated data. On May 7, Emera Maine answered the April 22 Maine PUC and MCG protests and the MCG's April 29 answer. On May 8, MCG moved to compel revision to Emera's May 1 filing, asserting that it was not filed in accordance with Emera's OATT, and specifically the Protocols for Implementing and Reviewing Charges Established by the Attachment J Rate Formulas (the "Motion to Compel"). MCG also protested the May 1 filing on May 22. On May 26, Emera Maine answered MCG's May 8 Motion to Compel, which MCG answered the next day.

On June 2, 2016, the FERC granted Maine Customer Group's Motion to Compel, and set the remaining issues with respect to Emera Maine's 2014 and 2015 Annual Updates for hearing and settlement judge procedures.[66] The FERC also consolidated ER12-1650 with this proceeding. In addition, the FERC directed that Emera Maine to make a compliance filing, on or before July 5, that (1) revises its 2014-2015 formula rate charges to correct the errors the Maine Customer Group raised with respect to amortization of long-term debt costs and post-retirement benefits other than pensions, and (2) imputes the retired debt balance for the tax-free Maine Public bonds ($22.6 million) into the capital structure calculation for the 2014-2015 Rate Year. Emera Maine requested rehearing of the June 2 order on July 5. On January 6, 2017, the FERC denied rehearing and Emera Maine's alternative request for consolidation with the ongoing proceedings in Docket Nos. EC10-67-002, *et al*.[67]

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[64] *Emera Maine*, 153 FERC ¶ 61,283 (Dec. 7, 2015).

[65] The "Maine Customer Group ("MCG") is comprised of: the Maine Office of the Public Advocate ("MOPA"), Houlton Water Company ("Houlton"), Van Buren Light and Power District ("Van Buren"), and Eastern Maine Electric Cooperative, Inc. ("EMEC").

[66] *Emera Maine*, 155 FERC ¶ 61,233 (June 2, 2016), *reh'g denied*, 158 FERC ¶ 61,012 (Jan. 6, 2017).

[67] *Emera Maine*, 158 FERC ¶ 61,012 (Jan. 6, 2017) ("*January 6 Order*").

Compliance Filing (ER12-1650). The *January 6 Order* also conditionally accepted Emera Maine's July 5, 2016, pending compliance filing. submitted in response to the June 2 Order described above. The compliance filing was contested by the Maine Customer Group, which asserted that Emera's compliance filing was incorrect as to two of the three refund issues, and Emera should be ordered to pay immediate refunds in accordance with the corrected revised formula rate it proposed. While the FERC sided with Emera Maine on the refund issues, it agreed with the Maine Customer Group that immediate refunds were in order. Accordingly, the FERC directed Emera Maine to make adjustments during the 2014-2015 Rate Year and refund the nearly $400,000 of excess revenue requirement as shown in its compliance filing, demonstrating in a refund report 6 how the excess charges will be refunded.[68] Emera Maine submitted that report on February 9, indicating the amounts to be refunded by February 28, 2017 to each customer that took either point-to-point or network service under the MPD OATT. The FERC accepted the Report on March 15, 2017.

Hearing and Settlement Judge Procedures. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and is holding the hearing in abeyance pending the outcome of settlement judge procedures. As previously reported, Chief Judge Cintron substituted ALJ Dring in place of ALJ Johnson in mid-September as the settlement judge for these proceedings. Settlement conferences before Judge Johnson were held on January 5, March 3, and April 26, 2016 and on October 25 before Judge Dring. A fifth settlement conference, scheduled for November 22, was held on December 1. Since the last Report, Judge Dring issued on March 24 an eighth status report (i) indicating that the parties have reached a settlement in principal and are memorializing their agreement (which now is to be filed in late April or early May), and (ii) recommending that settlement judge procedures be continued. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **FERC Enforcement Action: Staff Notices of Alleged Violations (IN__-___)**

Westar Energy. On March 30, 2017, the FERC issued a notice that Staff of the Office of Enforcement ("OE") has preliminarily determined that Westar Energy, Inc. ("Westar Energy") violated various provisions of the Southwestern Power Pool ("SPP") Tariff. Specifically, Staff has preliminarily determined that Westar Energy included incorrect cost inputs in its mitigated energy offer curves and failed to timely update other cost inputs, as required by the Tariff.

Recall that Notices of Alleged Violations ("NoVs") are issued only after the subject of an enforcement investigation has either responded, or had the opportunity to respond, to a preliminary findings letter detailing Staff's conclusions regarding the subject's conduct.[69] NoVs are designed to increase the transparency of Staff's nonpublic investigations conducted under Part 1b of its regulations. A NoV does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

- **FERC Enforcement Action: Order of Non-Public, Formal Investigation (IN15-10)**

MISO Zone 4 Planning Resource Auction Offers. On October 1, 2015, the FERC issued an order authorizing Enforcement to conduct a non-public, formal investigation, with subpoena authority, regarding violations of FERC's regulations, including its prohibition against electric energy market manipulation, that may have occurred in connection with, or related to, MISO's April 2015 Planning Resource Auction for the 2015/16 power year.

Unlike a staff NOV, a FERC order converting an informal, non-public investigation to a formal, non-public investigation does not indicate that the FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation. It does, however, give OE's Director, and employees designated by the Director, the authority to administer oaths and affirmations, subpoena witnesses, compel their attendance and testimony, take evidence, compel the filing of special

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[68] *Id.* at PP 39-40.

[69] *See Enforcement of Statutes, Regulations, and Orders*, 129 FERC ¶ 61,247 (Dec. 17, 2009), *order on requests for reh'g and clarification*, 134 FERC ¶ 61,054 (Jan. 24, 2011).

reports and responses to interrogatories, gather information, and require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records.

- **FERC Audit of ISO-NE (PA16-6)**

The FERC's audit of ISO-NE docketed in this proceeding is on-going. As previously reported, the FERC informed ISO-NE on November 24, 2015 that it would evaluate ISO-NE's compliance with: (1) the transmission provider obligations described in the Tariff, (2) *Order 1000* as it relates to transmission planning and expansion, and interregional coordination, (3) accounting requirements of the Uniform System of Accounts under 18 C.F.R. Part 101, (4) financial reporting requirements under 18 C.F.R. Part 141; and (5) record retention requirements under 18 CFR Part 125. The FERC indicated that the audit will cover the July 10, 2013 period through the present.

XII. Misc. - Administrative & Rulemaking Proceedings

- **State Policies & Wholesale Markets Operated by ISO-NE, NYISO, PJM (AD17-11)**

On May 1-2, the FERC held a 2-day technical conference to foster further discussion regarding the development of regional solutions in the Eastern RTOs/ISOs that reconcile the competitive market framework with the increasing interest by states to support particular resources or resource attributes. FERC staff sought to "discuss long-term expectations regarding the relative roles of wholesale markets and state policies in the Eastern RTOs/ISOs in shaping the quantity and composition of resources needed to cost-effectively meet future reliability and operational needs". A more detailed summary of the technical conference is being circulated with this Report. Pre-conference comments from the conference's speakers, panelists and other interested parties are available in the FERC's eLibrary and through the tech conference's calendar entry. A notice requesting post-conference comments will be issued shortly.

- **Agency Operations in the Absence of a FERC Quorum (AD17-10)**

On February 3, the FERC issued an order delegating additional authority to agency staff to continue certain agency operations in the absence of a quorum of FERC Commissioners.[70] The *Absence of a Quorum Delegation Order* also affirmed that all pre-existing delegations of authority by the FERC to its staff continue to be effective. The *Absence of a Quorum Delegation Order* took effect February 4, 2017, and the additional authority granted to agency staff will last until the earlier of FERC action lifting the *Order* or 14 days following the date a quorum is re-established. The specific delegation of agency authority permits (i) the Director of OEMR to accept and suspend rate filings, and make them effective subject to refund and further order of the FERC, or accept and suspend them, make them effective subject to refund, and set them for hearing and settlement judge procedures (for initial rates or rate decreases submitted under section 205 of the FPA, for which suspension and refund protection are unavailable, FERC staff was granted authority under section 206 to institute proceedings in order to protect the interests of customers);[71] (ii) FERC staff to extend the time for action on matters where it is permitted by statute; and (iii) the Director of OEMR to take appropriate action on uncontested waiver and settlement filings. Although the *Delegation Order* was initially challenged by the Wyoming Pipeline Authority ("WPA"), the WPA withdrew its challenge and, with no other party challenging it, the *Delegation Order* is final, unappealable, and continues in effect.

- **BPS Reliability Technical Conference (AD17-8)**

On February 10, the FERC issued a notice that it will hold a June 22, 2017 technical conference to discuss policy issues related to the reliability of the Bulk-Power System ("BPS"). The FERC will issue an agenda at a later date.

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[70] Agency Operations in the Absence of a Quorum ,158 FERC ¶ 61,135 (Feb. 3, 2017) ("*Absence of a Quorum Delegation Order*").

[71] The acceptance for filing and suspension and making effective subject to refund and to further FERC order of these filings is without prejudice to any further action of the FERC with respect to these filings once the FERC again has a quorum.

- **Electric Storage Resource Utilization in RTO/ISO Markets (AD16-25)**

On November 9, 2016, the FERC held a technical conference to discuss the utilization of electric storage resources as transmission assets compensated through RTO/ISO transmission rates, for grid support services that are compensated in other ways, and for multiple services. On November 14, the FERC invited all those interested to file, on or before December 14, 2016, post-technical conference comments on the topics discussed in the November 1 Supplemental Notice of Technical Conference. Comments were filed by over 45 parties, including Avangrid, Brookfield, EEI, Energy Storage Association, Exelon, FirstLight, NEPGA, NextEra, PSEG, Solar City/Tesla, and UCS. This matter is pending before the FERC.

- **Competitive Transmission Development Rates (AD16-18)**

The FERC held a technical conference on a June 27-28, 2016 to discuss competitive transmission development process-related issues, including use of cost containment provisions, the relationship of competitive transmission development to transmission incentives, and other ratemaking issues. In addition, participants had the opportunity to discuss issues relating to interregional transmission coordination, regional transmission planning and other transmission development issues. Pre-technical conference comments were filed by over 20 parties, including by NESCOE, BHE US Transmission, LSPower, and NextEra Energy Transmission. Technical conference materials are available on the FERC's e-Library. On August 3, the FERC issued a notice inviting post-technical conference comments on questions listed in the attachment to the notice. Following requests by Utility Trade Associations[72] and the New Jersey BPU, the deadline for comments was extended to October 3, 2016 and comments were filed by over 60 parties, including: NEPOOL, ISO-NE, Avangrid, AWEA, BHE US Transmission, EDF Renewables, EEI, ELCON, Eversource, Exelon, LSP Transmission Holdings, MMWEC, National Grid, NESCOE, NextEra, and PSEG.

- **Reactive Supply Compensation in RTO/ISO Markets (AD16-17)**

A workshop to discuss compensation for Reactive Supply and Voltage Control (Reactive Supply) in RTO/ISO markets was held on June 30, 2016. The workshop explored the types of costs incurred by generators for providing Reactive Supply capability and service; whether those costs are being recovered solely as compensation for Reactive Supply or whether recovery is also through compensation for other services; and different methods by which generators receive compensation for Reactive Supply (e.g., FERC-approved revenue requirements, market-wide rates, etc.). The workshop also explored potential adjustments in compensation based on changes in Reactive Supply capability and potential mechanisms to prevent overcompensation for Reactive Supply. Technical conference materials are available on the FERC's e-Library. Written comments were due on or before July 28, 2016, and were filed by, among others, NYISO, PJM, the PJM IMM, AWEA, EEI, EPSA, EDF Renewables, Talen, Essential Power, and Exelon. EDF Renewables filed reply comments on August 19; the PJM IMM on August 21. This matter remains pending before the FERC.

- **PURPA Implementation (AD16-16)**

A workshop to discuss issues associated with the FERC's implementation of PURPA was held on June 29, 2016. The conference focused on two issues: the mandatory purchase obligation under PURPA and the determination of avoided costs for those purchases. Panelists' advanced written comments and materials from the technical conference are available on the FERC's e-Library. On September 6, the FERC issued a notice inviting post-technical conference comments addressing (1) the use of the "one-mile rule" to determine the size of an entity seeking certification as a small power production qualifying facility ("QF"); and (2) minimum standards for PURPA-purchase contracts. Comments were due on or before November 7, 2016 and were filed by over 40 parties, including AWEA, Covanta, CT PURA/MA AG, Duke, EDP, EEI, ELCON, NARUC, and NRECA.

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[72] The "Utility Trade Associations" are APPA, EEI, Large Public Power Council, NRECA, and TAPS.

- **Price Formation in RTO/ISO Energy and Ancillary Services Markets (AD14-14)**

As previously reported, the FERC directed each RTO/ISO to publicly provide, and the RTO/ISO's provided, information related to five price formation issues:[73] (1) pricing of fast-start resources; (2) commitments to manage multiple contingencies; (3) look-ahead modeling; (4) uplift allocation; and (5) transparency. The FERC indicated it would use the reports and comments filed in response thereto to determine what further action is appropriate. NOPRs addressing fast-start pricing and uplift allocation have already been issued.

- **NOI: FERC's Policy for Recovery of Income Tax Costs & ROE Policies (PL17-1)**

On December 15, 2016, the FERC issued a notice of inquiry ("NOI") seeking comments regarding how to address any double recovery resulting from the FERC's current income tax allowance and ROE policies.[74] The NOI follows the D.C. Circuit's *United Airlines*[75] holding that the FERC failed to demonstrate that there is no double recovery of taxes for a partnership pipeline as a result of the income tax allowance and ROE determined pursuant to the DCF methodology, and remanding the decisions to the FERC to develop a mechanism "for which the Commission can demonstrate that there is no double recovery" of partnership income tax costs".[76] In response to requests for an extension of the comment and reply comment deadlines, and objections to those requests, the FERC extended the comment and reply comment deadlines to March 8 and April 7, 2017, respectively. Comments were submitted by over 25 parties, including a particularly ebullient pleading by a former general counsel of FERC's predecessor, the Federal Power Commission. As noted immediately above, reply comments were due on or before April 7. 18 sets of reply comments were received, including reply comments from AGA, Dominion, EEI, INGAA, and LSPower. This matter is pending before the FERC.

- **NOPR: LGIA/LGIP Reforms (RM17-8)**

As previously reported, the FERC issued a NOPR[77] on December 15, 2016 proposing reforms designed to improve certainty,[78] promote more informed interconnection,[79] and enhance interconnection

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[73] *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221 (Nov. 20, 2015).

[74] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs*, 157 FERC ¶ 61,210 (Dec. 15, 2017).

[75] *United Airlines Inc., et al. v. FERC*, 827 F.3d 122, 134, 136 (D.C. Cir. 2016) ("*United Airlines*").

[76] *Id.* at 137.

[77] *Reform of Generator Interconnection Procedures and Agreements*, 157 FERC ¶ 61,212 (Dec. 15, 2016) ("*LGIP/LGIA Reforms NOPR*"). The *LGIP/LGIA Reforms NOPR* was published in the *Fed. Reg.* on Jan. 13, 2017 (Vol. 82, No. 9 pp. 4,464-4,501.

[78] To accomplish this goal, the FERC proposes to: (1) revise the *pro forma* LGIP to require transmission providers that conduct cluster studies to move toward a scheduled, periodic restudy process; (2) remove from the *pro forma* LGIA the limitation that interconnection customers may only exercise the option to build transmission provider's interconnection facilities and standalone network upgrades if the transmission owner cannot meet the dates proposed by the interconnection customer; (3) modify the *pro forma* LGIA to require mutual agreement between the transmission owner and interconnection customer for the transmission owner to opt to initially self-fund the costs of the construction of network upgrades; and (4) require that the RTO/ISO establish dispute resolution procedures for interconnection disputes. The Commission also seeks comment on the extent to which a cap on the network upgrade costs for which interconnection customers are responsible can mitigate the potential for serial restudies without inappropriately shifting cost responsibility. *Id.* at P 6.

[79] The FERC proposes to: (1) require transmission providers to outline and make public a method for determining contingent facilities in their LGIPs and LGIAs based upon guiding principles in the Proposed Rule; (2) require transmission providers to list in their LGIPs and on their OASIS sites the specific study processes and assumptions for forming the networking models used for interconnection studies; (3) require congestion and curtailment information to be posted in one location on each transmission provider's OASIS site; (4) revise the definition of "Generating Facility" in the pro forma LGIP and LGIA to explicitly include electric storage resources; and (5) create a system of reporting requirements for aggregate interconnection study performance. The FERC also seeks

processes.[80] Based, in part, on input received in response to AWEA's petition for changes to the *pro forma* LGIP/LGIA, and the FERC's May 13, 2016 technical conference to explore generator interconnection issues (as reported previously under Docket Nos. RM16-12; RM15-21), the FERC has identified proposed reforms which it states could remedy potential shortcomings in the existing interconnection processes. The FERC also seeks comment on whether any of its proposed reforms should be applied to the *pro forma* SGIP/SGIA.[81] Following a request from the IRC, supported by NEPOOL and a coalition of trade associations (APPA, LPPA, NRECA), for a 30-day extension of the comment deadline granted by the FERC on February 23, comments on the *LGIP/LGIA Reforms NOPR* were due April 13, 2017. 60 sets of comments and answers were submitted, including comments by: NEPOOL (approved at the April 7 Participants Committee meeting), ISO-NE, Avangrid, EDF Renewable, EDP Renewables, Eversource, Exelon, Invenergy, National Grid, NextEra, APPA/LPPC/NRECA, AWEA, EEI, ELCON, ESA, and Public Interest Organizations. This matter is pending before the FERC.

- **NOPR: Fast-Start Pricing in RTO/ISO Markets (RM17-3)**

On December 15, the FERC issued a NOPR proposing to require each RTO and ISO to incorporate market rules that meet certain requirements when pricing fast-start resources.[82] The FERC stated that these reforms should lead to prices that more transparently reflect the marginal cost of serving load, which will reduce uplift costs and thereby improve price signals to support efficient investments. Specifically, the FERC proposes to require that each RTO/ISO incorporate the following five requirements for its fast-start pricing:

1. an RTO/ISO must apply fast-start pricing to any resource committed by the RTO/ISO that is able to start up within 10 minutes or less, has a minimum run time of one hour or less, and that submits economic energy offers to the market;
2. when an RTO/ISO makes a decision to commit a fast-start resource, it should incorporate commitment costs, i.e., start-up and no-load costs, of fast-start resources in energy and operating reserve prices, but must do so only during the fast-start resource's minimum run time;
3. an RTO/ISO must modify its fast-start pricing to relax the economic minimum operating limit of fast-start resources and treat them as dispatchable from zero to the economic maximum operating limit for the purpose of calculating prices;
4. if an RTO/ISO allows offline fast-start resources to set prices for addressing certain system needs, the resource must be feasible and economic; and
5. an RTO/ISO must incorporate fast-start pricing in both the Day-Ahead and Real-Time markets.

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comment on proposals or additional steps that the Commission could take to improve the resolution of issues that arise when affected systems are impacted by a proposed interconnection. *Id.* at P 7.

[80] The FERC proposes to: (1) allow interconnection customers to limit their requested level of interconnection service below their generating facility capacity; (2) require transmission providers to allow for provisional agreements so that interconnection customers can operate on a limited basis prior to completion of the full interconnection process; (3) require transmission providers to create a process for interconnection customers to utilize surplus interconnection service at existing interconnection points; (4) require transmission providers to set forth a separate procedure to allow transmission providers to assess and, if necessary, study an interconnection customer's technology changes (e.g., incorporation of a newer turbine model) without a change to the interconnection customer's queue position; and (5) require transmission providers to evaluate their methods for modeling electric storage resources for interconnection studies and report to the Commission why and how their existing practices are or are not sufficient. *Id.* at P 8.

[81] *Id.* at P 11.

[82] *Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,213 (Dec. 15, 2016) ("*Fast-Start Pricing NOPR*").

Comments on the *Fast-Start Pricing NOPR* were due on or before February 28, 2017[83] and were filed by numerous parties, including NEPOOL, ISO-NE and EEI. Reply comments were filed by MISO and the PJM IMM. The *Fast-Start Pricing NOPR* is pending before the FERC.

- **NOPR: Uplift Cost Allocation and Transparency in RTO/ISO Markets (RM17-2)**

On January 19, the FERC issued a NOPR proposing to require each RTO and ISO that currently allocates the costs of Real-Time uplift due to deviations to do so only to those market participants whose transactions are reasonably expected to have caused the real-time uplift costs.[84] In addition, the FERC proposed to revise its regulations to enhance transparency by requiring that each RTO/ISO post uplift costs paid (dollars) and operator-initiated commitments (MWs) on its website; and define in its tariff its transmission constraint penalty factors, as well as the circumstances under which those penalty factors can set LMPs, and any procedure for changing those factors. Comments on the *Uplift/Transparency NOPR* were due on or before April 10, 2017[85] and were filed by over 40 parties, including: ISO-NE, Brookfield, Calpine, DC Energy, Direct, Exelon, Potomac Economics, Saracen, EEI, APPA/NRECA, AWEA, ELCON, EPSA, Financial Marketers Coalition, and the IRC. This matter is pending before the FERC.

- **NOPR: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)**

On November 23, the FERC issued a NOPR proposing to require each RTO and ISO to revise its tariff "to (1) establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets and (2) define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation."[86] Comments on the *Storage NOPR* were ultimately due on or before February 13, 2017, and were filed by over 100 parties, including: NEPOOL, ISO-NE, APPA/ NRECA, Avangrid, AWEA, Brookfield, CT DEEP, CT PURA, Dominion, DTE, EEI, ELCON, EPSA, EPRI, ESA, Exelon, FirstLight, Genbright, IPKeys, MA DPU, MIT, MMWEC, NARUC, NERC, NESCOE, NextEra, NRG, SEIA, UCS. Since the last Report, comments were filed by the Harvard Environmental Policy Initiative. This matter is pending before the FERC.

- **NOPR: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

The FERC's *Data Collection NOPR* remains pending. As previously reported, the FERC issued a July 21, 2016 NOPR, which superseded both its *Connected Entity NOPR* (RM15-23) and *Ownership NOPR* (RM16-3), proposing to collect certain data for analytics and surveillance purposes from market-based rate ("MBR") sellers and entities trading virtual products or holding FTRs and to change certain aspects of the substance and format of information submitted for MBR purposes.[87] The *Data Collection NOPR* presents substantial revisions from what the FERC proposed in the *Connected Entity NOPR*, and responds to the comments and concerns submitted by NEPOOL in that proceeding. Among other things, the changes proposed in the *Data NOPR* include: (i) a different set of filers; (ii) a reworked and substantially narrowed definition of Connected Entity; and (iii) a different submission process. With respect to the MBR program, the proposals include: (i) adopting certain changes to reduce and clarify the scope of ownership information

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[83] The *Fast-Start Pricing NOPR* was published in the *Fed. Reg.* on Dec. 30, 2016 (Vol. 81, No. 251 pp. 96,391-96,404.

[84] *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 158 FERC ¶ 61,047 (Jan. 19, 2017) ("*Uplift/Transparency NOPR*").

[85] The *Uplift/Transparency NOPR* was published in the *Fed. Reg.* on Feb. 7, 2017 (Vol. 82, No. 24 pp. 9,539-9,555.

[86] *Electric Storage Participation in Markets Operated by Regional Transmission Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

[87] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 156 FERC ¶ 61,045 (July 21, 2016) ("*Data Collection NOPR*").

that MBR sellers must provide; (ii) reducing the information required in asset appendices; and (iii) collecting currently-required MBR information and certain new information in a consolidated and streamlined manner. The FERC also proposes to eliminate MBR sellers' corporate organizational chart submission requirement adopted in *Order 816*. Comments on the *Data Collection NOPR* were due on or before September 19, 2016[88] and were filed by over 30 parties, including: APPA, Avangrid, Brookfield, EPSA, Macquarie/DC Energy/Emera Energy Services, NextEra, and NRG.

Technical Workshops. The FERC held two technical workshops. The first technical workshop was held on August 11 and focused on the *Data Collection NOPR's* draft data dictionary. The second technical workshop was held on December 7, 2016 and focused on the submittal process, with case studies serving as a platform for discussion of (i) the steps to submit data; (ii) data review and validation processes; and (iii) the notifications to be provided through the data validation and receipt process. Staff also provided a high-level update on proposed technical refinements to the data dictionary based on input received during the first workshop and additional outreach.

- ***Order 833*: Critical Energy/Electric Infrastructure Information (CEII) Procedures (RM16-15)**

The FERC issued *Order 833*[89] on November 16, 2016. *Order 833* amended FERC regulations to implement provisions of the Fixing America's Surface Transportation ("FAST") Act that pertain to the designation, protection and sharing of Critical Electric Infrastructure Information ("CEII") and amend other regulations that pertain to CEII. The amended procedures will be referred to as the Critical Energy/Electric Infrastructure Information (CEII) procedures. *Order 833* became effective February 21, 2017.[90] On December 19, 2016, EEI requested rehearing of *Order 833*. The FERC issued a tolling order on January 17, affording it additional time to consider the EEI request for rehearing, which remains pending.

- **NOPR: Primary Frequency Response - Essential Reliability Services and the Evolving Bulk-Power System (RM16-6)**

On November 17, 2016, the FERC issued a NOPR proposing to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of interconnection.[91] To implement these requirements, the Commission proposes to revise the *pro forma* LGIA and the *pro forma* SGIA. The *Primary Frequency Response NOPR* follows the FERC's *Frequency Response NOI*[92] from early 2016. Comments on the *Primary Frequency Response NOPR* were due on or before January 24, 2017[93] and were filed by over 30 parties, including AWEA, EEI, ELCON, EPSA, ESA, First Solar, the IRC, NRECA, and UCS. Supplemental comments were filed by ELCON. This matter is pending before the FERC.

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[88] The *Data Collection NOPR* was published in the *Fed. Reg.* on Aug. 4, 2016 (Vol. 81, No. 150 pp. 51,726-51,772.

[89] *Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information; Availability of Certain North American Electric Reliability Corporation Databases to the Commission,* Order No. 833, 157 FERC ¶ 61,123 (Nov. 17, 2016) ("*Order 833*").

[90] *Order 833* was published in the *Fed. Reg.* on Dec. 21, 2016 (Vol. 81, No. 245) pp. 93,732-93,753.

[91] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, 157 FERC ¶ 61,122 (Nov. 17, 2016) ("*Primary Frequency Response NOPR*").

[92] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, 154 FERC ¶ 61,117 (Feb. 18, 2016) ("*Frequency Response NOI*").

[93] The *Primary Frequency Response NOPR* was published in the *Fed. Reg.* on Nov. 25, 2016 (Vol. 81, No. 227) pp. 85,176-85,190.

- ***Order 831*: Price Caps in RTO/ISO Markets (RM16-5)**

On November 17, 2016, the FERC issued *Order 831*[94] requiring each RTO/ISO: (i) to cap each resource's incremental energy offer at the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer; and (ii) cap verified cost-based incremental energy offers at $2,000/MWh when calculating locational marginal prices ("LMP"). In addition, the FERC clarified that the verification process for cost-based incremental offers above $1,000/MWh should ensure that a resource's cost-based incremental energy offer reasonably reflects that resource's actual or expected costs. *Order 831* modified the FERC's *Offer Cap NOPR* by including a $2,000/MWh hard cap for the purposes of calculating LMPs. *Order 831* became effective February 21, 2017.[95] Market Rule changes implementing *Order 831* are required to be filed within 75 days of that effective date, or by May 8, 2017.[96] (Support for ISO-NE's proposed compliance changes is on the May 5 Consent Agenda, Item # 1.) On December 19, 2017, American Municipal Power Inc. ("AMP") and APPA, Exelon, NYISO, and TAPS requested rehearing and/or clarification of *Order 831*. The FERC issued a tolling order on January 17, affording it additional time to consider the requests for rehearing, which remain pending. On January 4, the PJM Market Monitor opposed Exelon's motion for clarification and/or rehearing. On January 13, MISO submitted comments supporting NYISO request for rehearing.

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 Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Algonquin EDC Capacity Release Bidding Requirements Exemption Request (RP16-618)**

On March 31, 2016, the FERC conditionally accepted Algonquin tariff modifications and request for waiver that provided an exemption from capacity release bidding requirements for certain types of firm transportation capacity releases by Electric Distribution Companies ("EDCs") that are participating in state-regulated electric reliability programs.[97] As previously reported, Algonquin stated that the modifications were consistent with the FERC's current policy of exempting releases pursuant to state-regulated retail access programs of natural gas local distribution companies ("LDCs") from bidding requirements. Algonquin added that its proposal (i) supports the efforts of EDCs to increase the reliability of supply for natural gas-fired electric generation facilities in New England and to address high electricity prices during peak periods in New England and therefore is in the public interest; and (ii) furthers the FERC's initiatives related to gas-electric coordination. On May 9, 2016, the FERC held a technical conference to examine "concerns raised regarding the basis and need for the waiver." Initial comments were due May 31. Almost two dozen sets of initial comments were filed, raising numerous issues both in support and in opposition to the Algonquin proposal. Reply comments were due June 10, 2016 and were filed by Algonquin Gas Transmission, Sequent Energy Management, L.P. and Tenaska Marketing Ventures, Indicated Shippers, National Grid, Eversource, Repsol, Calpine, Exelon/NextEra, New England LDCs, CT PURA and the MA AG.

On August 31, 2016, the FERC issued an order in which it rejected Algonquin's request for a waiver that would have exempted gas-fired generators from capacity release bidding requirements but accepted Algonquin's proposal to exempt from bidding an EDC's capacity release to an asset manager who is required to use the

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[94] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (Nov. 17, 2016) ("*Order 831*"), *reh'g requested*.

[95] *Order 831* was published in the *Fed. Reg.* on Dec. 5, 2016 (Vol. 81, No. 233) pp. 87,770-87,800.

[96] The 75-day period ends on Saturday, May 6. Pursuant to Rule 2007 of the FERC's Rules of Practice & Procedure, if the last day of a time period falls on a weekend, the time period does not end until the close of the next day on which the FERC remains open. See 18 CFR 385.2007(a)(2).

[97] *Algonquin Gas Transmission, LLC*, 154 FERC ¶ 61,269 (Mar. 31, 2016).

released capacity to carry out the EDC's obligations under the state-regulated electric reliability program.[98] The FERC explained that its capacity release regulations seek to balance the interests of the releasing shipper in releasing capacity to a replacement shipper of its choosing while still ensuring that allocative efficiency is enhanced by ensuring the capacity is used for its highest valued use.[99] Algonquin's proposal, whereby any gas-fired generator to whom EDCs release capacity would be a pre-arranged replacement shipper, failed to meet the standard of "improving the competitive structure of the natural gas industry" as formulated by the FERC in granting bidding exemptions for state-regulated retail access programs.[100] Furthermore, the FERC found that exemption proponents had not shown why such a broad exemption was necessary in order for EDCs to have a sufficient ability to direct their capacity releases to natural gas-fired generators in order to accomplish the goal of increasing electric reliability.[101] On September 30, 2016, ConEd and Orange & Rockland Utilities, Inc. ("O&R") requested clarification of the *Algonquin Order Following Technical Conference*, asking the FERC to clarify certain aspects of its approval exempting from bidding an EDC's capacity release to an asset manager. Algonquin Gas Transmission, National Grid Electric Distribution Companies, and Sequent Energy Management and Tenaska Marketing Ventures filed answers to the requests for clarification on October 17. Those requests are pending before the FERC.

On September 23, Algonquin submitted a compliance filing in response to the requirements of the *Algonquin Order Following Technical Conference*. Comments on that compliance were due on or before October 5; none were filed. The compliance filing is pending before the FERC.

- **Natural Gas-Related Enforcement Actions**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines:

BP (IN13-15). On July 11, 2016, the FERC issued *Opinion 549*[102] affirming Judge Cintron's August 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the Commission's regulations ("Anti-Manipulation Rule") and section 4A of the Natural Gas Act ("NGA").[103] Specifically, after extensive discovery and hearing procedures, Judge Cintron found that BP's Texas team engaged in market manipulation by changing their trading patterns, between September 18, 2008 through the end of November 2008, in order to suppress next-day natural gas prices at the Houston Ship Channel ("HSC") trading point in order to benefit correspondingly long position at the Henry Hub trading point. The FERC agreed, finding that the "record shows that BP's trading practices during the Investigative Period were fraudulent or deceptive, undertaken with the requisite scienter, and carried out in connection with Commission-jurisdictional transactions."[104] Accordingly, the FERC assessed a ***$20.16 million civil penalty*** and required BP to ***disgorge $207,169*** in "unjust profits it received as a result of its manipulation of the Houston Ship Channel Gas Daily index." The $20.16 million civil penalty was at the top of the FERC's Penalty Guidelines range, reflecting increases for having had a prior adjudication within 5 years of the violation, and for BP's violation of a FERC order within 5 years of the scheme. BP's penalty was mitigated because it cooperated during the investigation, but BP received no deduction for its compliance program, or for self-reporting. The *BP Penalties Order* also denied BP's request for rehearing of the

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[98] *Algonquin Gas Transmission, LLC*, 156 FERC ¶ 61,151 (Aug. 31, 2016) ("*Algonquin Order Following Technical Conference*")

[99] *Id.* at P 27.

[100] *Id.* at P 34.

[101] *Id.* at P 35

[102] *BP America Inc., et al.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*").

[103] *BP America Inc., et al.*, 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*").

[104] *BP Penalties Order* at P 3.

order establishing a hearing in this proceeding.[105] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, BP requested rehearing of the *BP Penalties Order*. On September 8, the FERC issued a tolling order, affording it additional time to consider BP's request for rehearing of the *BP Penalties Order*, which remains pending.

On September 7, BP submitted a motion for modification of the *BP Penalties Order's* disgorgement directive because it cannot comply with the disgorgement directive as ordered. BP explained that the entity to which disgorgement was to be directed, the Texas Low Income Home Energy Assistance Program ("LIHEAP"), is not set up to receive or disburse amounts received from any person other than the Texas Legislature. In response, on September 12, the FERC stayed the disgorgement directive (until an order on BP's pending request for rehearing is issued), but indicated that interest will continue to accrue on unpaid monies during the pendency of the stay.[106]

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[107] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[108]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA **-** ***$213.6 million***; Hall **-** ***$1 million*** (jointly and severally with TGPNA); and Tran **-** ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents field their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***Atlantic Bridge Project (CP16-9)***
    - Algonquin Gas Transmission filed for Section 7(b) and 7(c) certificate on Oct. 22, 2015.
    - 132,700 Dth/d of firm transportation to new and existing delivery points on the Algonquin system and 106,276 Dth/d of firm transportation service from Beverly, MA to various existing delivery points on the Maritimes & Northeast system.

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[105] *BP America Inc. et al.*, 147 FERC ¶ 61,130 (May 15, 2014) ("*BP Hearing Order*"), *reh'g denied,* 156 FERC ¶ 61,031 (July 11, 2016).

[106] *BP America Inc. et al.*, 156 FERC ¶ 61,174 (Sep. 12, 2016) ("*Order Staying BP Disgorgement*")

[107] *Total Gas & Power North America, Inc., et al.*, 155 FERC ¶ 61,105 (Apr. 28, 2016) ("*TGPNA Show Cause Order*").

[108] The allegations giving rise to the Total Show Cause Order were laid out in a September 21, 2015 FERC Staff Notice of Alleged Violations which summarized OE's case against the Respondents. Staff determined that the Respondents violated section 4A of the Natural Gas Act and the Commission's Anti-Manipulation Rule by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleged that the scheme involved making largely uneconomic trades for physical natural gas during bid-week designed to move indexed market prices in a way that benefited the company's related positions. Staff alleged that the West Desk implemented the bid-week scheme on at least 38 occasions during the period of interest, and that Tran and Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

  - 6.3 miles of replacement pipeline along Algonquin in NY and CT; new 7,700-horsepower compressor station in Weymouth, MA; more horsepower at existing compressor stations in CT and NY.
  - Seven firm shippers: Heritage Gas Limited, Maine Natural Gas Company, NSTAR Gas Company d/b/a Eversource Energy, Exelon Generation Company, LLC (as assignee and asset manager of Summit Natural Gas of Maine), Irving Oil Terminal Operations, Inc., New England NG Supply Limited, and Norwich Public Utilities.
  - Certificate of public convenience and necessity granted Jan. 25, 2017.[109]
  - Authorization to proceed with construction of certain Projects segments granted on Mar. 27 and Apr. 13, 2017.

- ***Connecticut Expansion Project (CP14-529)***
  - Tennessee Gas Pipeline filed for Section 7(c) certificate July 31, 2014.
  - 72,100 Dth/d of firm capacity.
  - 13.26 miles of three looping segments & facility upgrades/modifications in NY, MA & CT.
  - Three firm shippers: Conn. Natural Gas, Southern Conn. Gas, and Yankee Gas.
  - Environmental Assessment (EA) issued on Oct. 23, 2015.
  - Certificate of public convenience and necessity granted Mar. 11, 2016.[110]
  - Construction began 4th Quarter 2016.
  - In-service: Nov. 2017 (anticipated).

- ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
  - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
  - 650,000 Dth/d of firm capacity from Susquehanna County, PA (Marcellus Shale) through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
  - New 122-mile interstate pipeline.
  - Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
  - Final EIS completed on Oct 24, 2014.
  - Certificates of public convenience and necessity granted Dec 2, 2014.
  - On April 22, 2016, New York State Department of Environmental Conservation denied Constitution's application for a Section 401 permit under the Clean Water Act. The decision effectively guarantees that the Constitution Pipeline project will, at best, be delayed by several years.
  - On May 16, 2016, the New York Attorney General filed a complaint against Constitution at the FERC (CP13-499) seeking a stay of the December 2014 order granting the original certificates, as well as alleging violations of the order, the Natural Gas Act, and the Commission's own regulations due to acts and omissions associated with clear-cutting and other construction-related activities on the pipeline right of way in New York.
  - Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays.
    - On October 13, 2016, the FERC approved Constitution's request to proceed to remove the felled trees in Pennsylvania.

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[109] Order Issuing Certificate and Authorizing Abandonment, *Algonquin Gas Transmission LLC and Maritimes & Northeast Pipeline, LLC*, 158 FERC ¶ 61,061 (Jan. 25, 2017), *reh'g requested*.

[110] *Tennessee Gas Pipeline Co., LLC*, 154 FERC ¶ 61,191 (Mar. 11, 2016) (order issuing certificate); *reh'g requested*. *See also* 154 FERC ¶ 61,263 (Mar. 30, 2016) (order denying stay); 155 FERC ¶ 61,087 (Apr. 22, 2016) (order denying stay).

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report.

XV. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Demand Curve Changes (17-1110**)**
  Underlying FERC Proceedings: ER14-1639[111]
  Petitioners: NextEra, NRG, PSEG

On April 3, 2017, NextEra, NRG and PSEG ("Petitioners") again petitioned the DC Circuit Court of Appeals for review of the FERC's Demand Curve orders, which, as previously reported, had been remanded back to the FERC at the FERC's request following the first appeal by Petitioners. Petitioners' statement of issues and other initial procedural submissions, as well as the FERC's initial submissions are due May 8. Interventions were filed by NEPOOL, NESCOE, CT PURA, and CPV.

- **FCA10 Results (16-1408) and FCA9 Results (16-1068)**
  Underlying FERC Proceedings: ER16-1041[112] **ER15-1137**[113]
  Petitioners: UWUA Local 464 and Robert Clark

UWUA Local 464 and Robert Clark ("Petitioners") filed petitions for review of the FERC's orders on the FCA10 and FCA9 Results Filings, consolidated by the Court on January 31, 2017. On March 14, Petitions filed Petitioners' Brief . The briefing schedule calls for the following: Respondent's Brief to be filed by May 15, 2017; Intervenor for Respondent's Brief, May 22, 2017; Petitioners' Reply Brief, June 5, 2017; Deferred Appendix, June 12, 2017; and Final Briefs, June 26, 2017.

- **NEPGA PER Complaint and FCM Jump Ball and Compliance Proceedings (16-1023/1024)**
  Underlying FERC Proceeding: ER14-1050;[114] **EL14-52;115 EL15-25**[116]
  Petitioner: NEPGA

As previously reported, NEPGA filed, on January 19, 2016, a petition for review of the FERC's orders on NEPGA's first PER Complaint. On February 24, 2016, the Court granted NEPGA's motion to consolidate this proceeding with 16-1024. Briefing was completed on November 28, 2016 and this matter remains pending before the DC Circuit.

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[111] 147 FERC ¶ 61,173 (May 30, 2014) (*Demand Curve Order*); 150 FERC ¶ 61,065 (Jan. 30, 2015) (*Demand Curve Clarification Order)*; 155 FERC ¶ 61,023 (Apr. 8, 2016) (*Demand Curve Remand Order*); 158 FERC ¶ 61,138 (Feb. 3, 2017) (*Demand Curve Remand Rehearing Order*).

[112] 155 FERC ¶ 61,273 (June 16, 2016); 157 FERC ¶ 61,060 (Oct. 27, 2016).

[113] 153 FERC ¶ 61,378 (Dec. 30, 2015); 151 FERC ¶ 61,226 (June 18, 2015).

[114] 153 FERC ¶ 61,224 (Nov. 19, 2015); 153 FERC ¶ 61,223 (Nov. 19, 2015); 147 FERC ¶ 61,172 (May 30, 2014).

[115] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

[116] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

- **Base ROE Complaints II & III (2012 & 2014) (15-1212)**
  Underlying FERC Proceedings: EL13-33; EL14-86[117]
  Appellants: New England Transmission Owners

As previously reported, the TOs filed a petition for review of the FERC's orders in the 2012 and 2014 ROE complaint proceedings on July 13, 2015. On August 14, 2015, the TOs filed an unopposed motion to hold this case in abeyance pending final FERC action on the 2012 and 2014 ROE Complaints (*see* Section I above). On August 20, 2015, the Court granted the TOs' motion to hold the case in abeyance, subject to submission of status reports every 90 days. The most recent status report, the sixth such report filed, was filed on February 13, 2017. In that report, the parties again indicated, ultimately, that the proceedings upon which the TOs based their request for abeyance of this appeal remain ongoing. This case continues to be held in abeyance.

- **Order 1000 Compliance Filings (15-1139, 15-1141**) (consolidated)**
  Underlying FERC Proceedings: ER13-193; ER13-196[118]
  Appellants: New England Transmission Owners (NETOs); NESCOE/CT DEEP/CT PURA, *et al*.

On April 18, the DC Circuit denied the petitions for review filed by NETOs[119] and NESCOE *et al*.[120] As previously reported, NETOs sought review of the FERC's *Order 1000* compliance filing orders largely on the grounds that FERC's determination that the right of first refusal must be removed from the TOA contravened the *Mobile-Sierra* Doctrine) and NESCOE (asserting the FERC went beyond *Order 1000* and impermissibly altered the balance of responsibility and power as between state governments and the ISO). Following briefing and oral argument before a Judges Brown, Wilkins and Edwards, the Court denied those petitions, finding that (i) the FERC's orders contain the requisite "particularized" analysis to overcome the *Mobile-Sierra* presumption that the filed rate established from a freely negotiated contract is just and reasonable, and (ii) there was no inconsistency or expansion of *Order 1000* and "the division of roles between ISO-NE and the states poses no jurisdictional problem" (recalling the Court's previous rejection of the argument that "the regional planning 'mandate infringes on the States' traditional regulation of transmission planning, siting, and construction'").[121] Issuance of the mandate is being withheld until seven days after disposition of any timely petition for rehearing/ rehearing *en banc*. As of the issuance of this Report, no petition for rehearing has been filed.

- **Base ROE Complaint I (2011) (15-1118, 15-1119, 15-1121**) (consolidated)**
  Underlying FERC Proceeding: EL11-66[122]
  Appellants: NETOs

On April 14, 2017, the DC Circuit granted the petitions for review of the FERC's orders in the Base ROE Complaint I proceedings, vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order.[123] The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers" (that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness). As was noted earlier in this Report, the *Base ROE Complaint I*

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[117] 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).

[118] 150 FERC ¶ 61,209 (Mar. 19, 2015); 143 FERC ¶ 61,150 (May 17, 2013).

[119] "NETOs" are Emera Maine; Central Maine Power Co., National Grid; New Hampshire Transmission ("NHT"), Eversource (on behalf of its electric utility company affiliates CL&P, WMECO, PSNH, and NSTAR), UI, and Vermont Transco.

[120] *Emera Maine et al. v. FERC,* Case No. 15-1139 (decided Apr. 18, 2017).

[121] Slip op. at p. 21, citing *S.C. Pub. Serv. Auth. v. FERC* ("*South Carolina*"), 762 F.3d 41, 72 (D.C. Cir. 2014) (*per curiam*).

[122] 150 FERC ¶ 61,165 (Mar. 3, 2015); 149 FERC ¶ 61,032 (Oct. 16, 2014); 147 FERC ¶ 61,234 (June 19, 2014).

[123] *Emera Maine et al. v. FERC*, 2017 U.S. App. LEXIS 6406 (D.C. Cir. April 14, 2017) ("*Base ROE Complaint I Decision*").

Decision has implications for the subsequent ROE proceedings. A more detailed memo that summarizes comprehensively the status of each of the ROE proceedings will be provided later in May under separate cover.

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[124] EL15-23[125]
  Petitioners: NEPGA, Exelon

On March 31, 2015, NEPGA filed a petition for review of the FERC's orders on NEPGA's FCM Administrative Pricing Rules Complaint. On May 22, the Court granted NEPGA's motion to hold the case in abeyance pending a decision in EL15-23 and, following the FERC's decision in EL15-23 and Exelon's appeal of that case (16-1042), Exelon's motion to consolidate this proceeding with 16-1042. All briefing in the consolidated proceeding has now been completed and this matter is now before the Court.

- **Allco Finance Limited v. Klee et al. (Commissioners, CT DEEP and CT PURA) (2d Cir. 16-2946)**

In this proceeding, an appeal from an unsuccessful challenge of Connecticut's actions under the 2015 multi-state clean energy RFP ("Clean Energy RFP") in Connecticut District Court, Allco continues its challenges to Connecticut's actions under the Clean Energy RFP. Allco asserts that Connecticut's actions are inconsistent with PURPA and constitutional principles recently addressed by the Supreme Court in *Hughes v Talen Energy Marketing* and summarized in prior Reports. As reported at the November Participants Committee meeting, the Second Circuit Court of Appeals on November 2 granted Allco's motion for an emergency injunction. The emergency injunction enjoined Connecticut (but not Massachusetts or Rhode Island) from "awarding, entering into, executing, or approving any wholesale electricity contracts in connection with the [Clean Energy RFP] during the pendency of this appeal." The injunction did "not apply retroactively to any wholesale electricity contract that has been entered into, executed, and approved" as of November 2, 2016. Briefs and Amicus Briefs were filed. Oral argument was held on December 9, 2016. On December 12, 2016 the Court vacated the November 2 injunction, indicating that an opinion would follow in due course. That opinion has not yet been issued.

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[124] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[125] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

INDEX
Status Report of Current Regulatory and Legal Proceedings
as of May 3, 2017

I. Complaints/Section 206 Proceedings

II. Rate, ICR, FCA, Cost Recovery Filings

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

IV. OATT Amendments/Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

VI. Schedule 20/21/22/23 Updates

VII. NEPOOL Agreement/ Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

IX. Membership Filings

X. Misc. - ERO Rules, Filings; Reliability Standards

XI. Misc. Regional Interest

XII. Misc: Administrative & Rulemaking Proceedings

XIII. Natural Gas Proceedings

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: David Cavanaugh, Chair, NEPOOL GIS Agreement Working Group
Paul Belval and John Shriver, NEPOOL Counsel

DATE: May 3, 2017

RE: Proposed Modified GIS Fee Structure of GIS Development and Administration Agreement with APX, Inc.

We have scheduled a teleconference for Thursday, May 11 at 10 a.m. to further discuss the proposed modified fee structure of the Generation Information System ("GIS") Development and Administration Agreement (the "GIS Agreement") between APX, Inc. ("APX") and NEPOOL. The call-in information for that teleconference is as follows:

800-993-4149
Access Code: 860 275 0403

This call follows up on the teleconference on April 27, 2017 (the "April 27 Conference"), to discuss proposed modifications of the fee structure of the GIS Agreement. This memorandum summarizes key discussion points from the April 27 Conference, and supplements the regular reports on the GIS Agreement discussions previously provided at monthly Participant Committee meetings. For reference, a copy of the April 21, 2017 memorandum regarding the extension of the GIS Agreement and proposed modified GIS fee structure is attached hereto as Exhibit A.

During the April 27 Conference, members of the Participants Committee raised the following issues, concerns and suggestions related to the allocation of costs for the GIS that were described in that April 21 memorandum, which will be further discussed during the May 11 teleconference referenced above:

Billing for Multiple Accounts: If an entity holds GIS account subscriptions as both a Trader and as a Large or Medium generator, will such entity be billed as both a Trader and as a generator? If it will only be billed in one capacity, will such an entity be billed as a Trader or as a generator?

Fee for Medium Generators: Would the $1,000 annual subscription fee for Medium generators (1MW up to 10MW in aggregate nameplate capacity registered) under the proposed modified GIS fee structure unduly affect the profitability of Medium generators on the low end of the 1MW to 10MW range? Should the MW range of the Medium generator category be revised or should that category be further differentiated?

Ceiling on APX's Fee: Under the proposed modified GIS fee structure, APX's total fee would vary positively and negatively with the number of account subscriptions. In light of the rapid rise in the number of account subscriptions, should NEPOOL request a ceiling on the total annual fee that APX may receive for developing and administering the GIS? If so, which fees would be discounted when the cap is reached? Would there also be a floor, consistent with the fee structure under the current GIS Agreement? If so, which fees would be increased to bring the total amount collected to the floor?

Third Party Meter Readers: A member of the Participants Committee requested confirmation that third party meter readers would not be charged any fees under the proposed modified GIS fee structure.

Secondary Transfer Fees: A member of the Participants Committee requested confirmation that the purchase of certificates by a load serving entity directly from a generator is not subject to a secondary transfer fee. In addition, another member asked whether transfers between affiliates would be subject to a secondary transfer fee.

Transaction Fee: A member of the Participants Committee suggested that NEPOOL request APX to implement a transaction fee structure, in which GIS account holders would incur a fee when a Certificate is created, traded or retired. If that approach is taken, would there be a fee exclusion for the creation of low volumes of Certificates?

Delay in Implementation of Revised Fee Structure: A member of the Participants Committee suggested that the implementation of any modified GIS Agreement fee structure, and APX's responsibility to collect certain fees directly from GIS account holders, be delayed by a year in order to give NEPOOL more time evaluate various fee structures. If implemented, this approach would maintain the current GIS fee structure through December 31, 2018.

cc: NEPOOL GIS Agreement Working Group

EXHIBIT A:

April 21, 2017 Memorandum to NPC Regarding Extension of GIS Development and Administration Agreement and Proposed Modified GIS Fee Structure

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: David Cavanaugh, Chair, NEPOOL GIS Agreement Working Group
Paul Belval and John Shriver, NEPOOL Counsel

DATE: April 21, 2017

RE: Extension of GIS Development and Administration Agreement with APX, Inc.
Proposed Modified GIS Fee Structure

As mentioned in an email sent last week, we have scheduled a teleconference for ***Thursday, April 27 at 10 a.m.*** to discuss the proposed modified fee structure for the extension of the Generation Information System ("GIS") Development and Administration Agreement (the "GIS Agreement") between APX, Inc. ("APX") and NEPOOL. The call-in information for that teleconference is as follows:

800-993-4149
Access Code: 860 275 0403

This memorandum describes the proposed fee structure and provides background on the discussions regarding that fee structure to date. This memorandum supplements the regular reports on the GIS Agreement discussions previously provided at monthly Participant Committee meetings.

Under the current version of the GIS Agreement, 100% of the cost of the GIS is charged to NEPOOL as an organization. Pursuant to a protocol approved by the Participants Committee in 2002, those costs are allocated to NEPOOL Participants that serve load assets subject to a renewable portfolio standard, alternative energy portfolio standard or bill disclosure law (so-called "GIS Load"). The ISO bills those costs to the NEPOOL Participants under the ISO Billing Policy, and payment of those charges to APX has priority over the payments to Market Participants under the Billing Policy.

Last year, the NEPOOL GIS Agreement Working Group (the "Working Group") proposed numerous changes for the existing GIS Agreement, including the following business level goal:

> Amend fee structure for the GIS so that (1) the GIS Administrator imposes and collects charges on generators, traders and verifiers utilizing the GIS, even if those entities are not NEPOOL Participants or ISO-NE Market Participants, which fees would be triggered by a certain minimum level of system utilization, and would have a fee floor and cap and (2) a portion of the GIS Administrator's fee is performance-based, depending upon the satisfaction of the service level agreements described below.

In response to the Working Group's request, APX submitted a fee structure, which the Working Group commented on and APX revised. The revised APX proposal is included in Appendix 1 to this memorandum. As requested, that fee structure spreads the cost of the GIS to more than just NEPOOL Participants with GIS Load, and would assess charges to both NEPOOL Participants and non-NEPOOL Participants who use the GIS. Thus, some non-Participants who are not currently charged will be charged a portion of the GIS costs, as will some Participants that use the GIS but do not currently pay any costs for such use. It is worth noting that the Appendix shows that there would be a material decrease in the aggregate costs of the GIS to be paid to APX. As shown, if the new fee structure had been in place for 2015 and 2016, total payments to APX would have been reduced from about $1,100,000 in each of those years to about $800,000 and $850,000, respectively.

In reviewing the APX proposal, the following qualifications should be kept in mind:

- This is a preliminary proposal that has been subject to only minimal levels of review and discussion by the Working Group and to no substantive discussion between NEPOOL and APX;
- There has been no discussion of how any of the fees will be collected (i.e., by APX or by the ISO) or how often those fees will be collected;
- While we believe there is agreement in principle to the fee proposal, APX's entire proposal, including the fee proposal, is subject to negotiations between NEPOOL and APX; and
- APX's entire proposal should be viewed as a package, and changes to any portion of the proposal could result in other changes to the proposal as well.

Several Participant representatives have asked why the Working Group has proposed to address a reallocation of GIS costs in the extension of the GIS Agreement. The answer is that the ISO has indicated that it could not collect charges from entities that are neither NEPOOL Participants nor Market Participants. Since the Working Group is seeking to assess GIS costs on entities that hold accounts in the GIS (and therefore trade GIS Certificates) that are neither NEPOOL Participants nor Market Participants, only APX would have the data required to assess those charges. Our only documented arrangement with APX is the GIS Agreement, so the proposal is to expand that Agreement to reflect how APX charges will be assessed for users of the GIS.

cc: NEPOOL GIS Agreement Working Group

Appendix 1

NEPOOL COST REDUCTION

APX can offer an additional reduction to the Load Fee so it would go from today's level of $0.007 per MWh to $0.0025 (our original proposal reduced the fee to $0.003) per MWh. This amounts to a projected savings of $600,000+ annually compared to today for load serving entities (and an additional savings of $66,000 compared to our original proposal). This is an average of 67% reduction for each LSE. As well, this would represent a reduction from the current 2017 projected overall annual revenue figure from approximately $1,000,000+ today, to $783,500 for this proposal.

In the Supplemental Information submitted to NEPOOL in January of 2016, APX provided additional detail on the estimated revenue associated with NEPOOL GIS operating under a new fee structure as submitted in our original proposal. Below is that same table re-published with the new discount applied to the Load Fee:

		2015		***2016***		***2017***	
	Rate	***Volume***	***Total Annual Fee***	***Volume***	***Total Annual Fee***	***Volume***	***Total Annual Fee***
Load Fee	**$0.0025**	138,645,873	$346,614	137,368,725	$343,421	132,000,000	$330,000
Secondary Transfer Fee	$0.005	12,390,166	$61,951	13,000,000	$65,000	13,000,000	$65,000
Unit Import Claims	$0.01	3,004,381	$30,044	3,000,000	$30,000	2,600,000	$26,000
Account Subscription: Large	$1,500	80	$120,000	88	$132,000	100	$150,000
Account Subscription: Medium	$1,000	152	$152,000	168	$168,000	175	$175,000
Account Subscription: Trader	$500	192	$96,000	213	$106,500	75	$37,500
Total			***$806,609***		***$844,921***		***$783,500***