NEW ENGLAND POWER POOL

David T. Doot
Secretary

March 6, 2019

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of March 13, 2019 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the NEPOOL Participants Committee will be held on **Wednesday, March 13, 2019 at 10:00 a.m. at the Colonnade Hotel, 120 Huntington Avenue, Boston, MA.** The Participants Committee meeting will be held in the Huntington Ballroom for the purposes set forth on the attached agenda and posted with the meeting materials.

For your information, this meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating, either in person or by phone, are required to identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

Rooms at the Colonnade Hotel for the March 13 meeting are available at the rate of $259.00 per night, on a first-come, first-served basis **UNTIL March 8, 2019.** To take advantage of these arrangements, you can make your reservation using the following link: New England Power Pool Online Booking Link for March or contact the hotel directly (617-424-7000) and reference the "NEPOOL Participants Committee" block of rooms.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the preliminary minutes of the Participants Committee meeting held on February 1, 2019. The preliminary minutes of the February 1 meeting marked to show changes from the draft circulated with the initial notice are included with this supplemental notice 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 supplemental notice and posted with the meeting materials.

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To consider and take action, as appropriate, on Participant-sponsored proposals concerning the treatment of energy efficiency resources under the Forward Capacity Market (FCM) Pay-for-Performance (PFP) rules. Background materials and draft resolutions are included and posted with this supplemental notice.

6. To consider and take action, as appropriate, on the ISO's interim proposal to provide compensation for inventoried energy during Capacity Commitment Periods #14 and #15 (June 1, 2023 – May 31, 2015)(referred to as Chapter 2B). Background materials and a draft resolution are included and posted with this supplemental notice.

7. To consider and take action, as appropriate, on the application of Michael Kuser for membership in NEPOOL as an End User Participant. Background materials and a draft resolution are included and posted with this supplemental notice.

8. 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.

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

    - Markets Committee
    - Reliability Committee
    - Transmission Committee
    - Budget & Finance Subcommittee
    - Others

10. Administrative matters.

11. 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, February 1, 2019, at the Colonnade Hotel, Boston, Massachusetts, pursuant to notice duly given. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates attending the meeting.

Ms. Nancy Chafetz, Chair, presided and Mr. David Doot, Secretary, recorded. Ms. Chafetz welcomed the members, alternates and guests who were present.

Ms. Chafetz acknowledged and expressed appreciation, on behalf of NEPOOL and the Participants Committee, to Ms. Angie O'Connor, Chair of the Massachusetts Department of Public Utilities (MA DPU), on the completion on February 15, 2019 of her term as Chair of the MA DPU and for her longstanding collaboration with NEPOOL.

APPROVAL OF JANUARY 4, 2019 MEETING MINUTES

Ms. Chafetz referred the Committee to the preliminary minutes of the January 4, 2019 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the January 4 meeting were unanimously approved without change.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the January 4 meeting, which had been circulated and posted in advance of the meeting. He confirmed in response to questions that the Board Markets Committee had discussed ~~last~~the previous summer's operational issues with both Market Monitors and had also been updated on both Chapter 2B and Chapter 3 of the efforts to address fuel security in the region.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the February COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. He noted that the monthly report reflected data through January 23, 2019. He summarized the following: (i) Energy Market value was $480 million, down $50 million from December 2018 and $860 million from January 2018; (ii) average natural gas prices in January were 16% higher than in December; (iii) average Real-Time Hub LMPs ($53.24/MWh) were 27% higher than December LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 98.6% in January, up from 98.2% in December (minimum value for the month was 94.4% on January 22); and (v) daily Net Commitment Period Compensation (NCPC) for January (based on data through January 22, 2019) totaled $1.7 million, down $1.5 million from December 2018 and $18.6 million from January 2018. January 2019 NCPC was 0.3% of the total Energy Market value and was comprised of (a) $1.6 million in first contingency payments, down $0.6 million from December, and (b) $49,000 in second contingency payments, down $876,000 from December. In follow up to a request at the January meeting, he referred to information concerning the level of participation by Price Responsive Demand (PRD).

Looking forward, Dr. Chadalavada reminded the Committee that FCA13 would begin on February 4 and would include the first substitution auction under the new CASPR (Competitive Auctions with Sponsored Policy Resources) design. He reported that there was heavy participation in the mock auction on January 28, with minor connectivity issues identified and corrected.

He reported that the scope of work for the 2019 Regional System Plan (RSP) would be discussed at the February 13 Planning Advisory Committee (PAC) meeting. He noted that there

were over 20,000 MW of new project proposals in the ISO's interconnection queue, approximately 10,000 MW of which were for offshore wind. Referring to the Vineyard Wind request for waiver of Tariff provisions necessary to participate in FCA13 as a Renewable Technology Resource (RTR), Dr. Chadalavada noted that, unless the ISO received a FERC order granting the requested waiver that day, the ISO would not treat Vineyard Wind as an RTR in FCA13. He committed to have a ~~report~~notice issued by the ISO by the end of the day confirming whether or not Vineyard Wind would be subject to RTR treatment in the auction.

He then reviewed an exhibit posted in advance of the meeting of the load curve on January 16, where there had been a sudden deviation of approximately 1,000 MW between the forecast and the actual load. He explained the deviation was caused by mid-day clouds which reduced photovoltaic (PV) outputs. He reported that the ISO expected to have updated PV forecasting tools in its Control Room at the end of March, which it would use both prospectively and with backcasting to better understand the performance of the system. A member noted the importance of ramping capability in those instances and urged the ISO to consider accelerating development of market tools to encourage ramping on the system. Dr. Chadalavada agreed to take that feedback back to the ISO. He also agreed to report back to the Committee on whether the ISO planned to publish its PV forecasts when the new tools were implemented.

Dr. Chadalavada then reviewed cold weather operations ~~on~~for January 20-22, 2019. He reported that temperatures in portions of New England set new record lows, with temperatures more than 20°F below normal. Those low temperatures resulted in a peak load of roughly 20,741 MW, the highest peak for Winter 2018-19. He reviewed a chart showing the natural gas schedules for the system. High liquefied natural gas (LNG) injections were noted, with some members attributing that LNG performance to improved pricing, in part because of less price

suppression from earlier winter reliability programs and the ISO's commitment before the start of the season to minimize posturing.

Dr. Chadalavada encouraged ~~all~~everyone to note these new data points in discussing design change to address fuel security concerns. He explained that a two-day cold snap separated by two weeks produced a very different outcome on the system than one two-week cold snap. He noted that the market experiences during cold weather in Winter 2017-18 were impacted by the Winter Reliability Program, and in Winter 2018-19 the market responded well to very cold weather on January 21-22, 2019 and again on January 31, 2019, with moderate weather in between. He referred to a chart showing that approximately 50,000 barrels of oil had been consumed to that point in the winter, compared to 400,000 barrels of oil consumed the prior year. Reviewing the record high LNG injections, he questioned whether continued injections at that level could have been sustained if the cold weather continued unabated for five consecutive days. He summarized that market performance was positive, but the consistency and longevity of that performance was uncertain. He committed to discuss at a future meeting how the market performed during the cold weather on January 31 and February 1.

REPORT ON JULY 12, 2018 NETWORK OUTAGE

Ms. Chafetz referred the Committee to the ISO's earlier report on the July 12, 2018 network outage, as circulated and posted with the meeting materials. She reminded the Committee that the outage had been referenced earlier, at both the December Markets Committee and January Participants Committee meetings, with members seeking more detailed information.

Dr. Chadalavada reviewed the presentation that summarized the July 12, 2018 network outage event, as well as post-outage improvements, emphasizing the rarity of such an event (experienced just twice in the ~~past~~prior 15 years). He explained in response to questions that the hardware/firmware that failed was in use across the manufacturer's entire equipment portfolio ~~so~~

~~it~~and would have impacted ~~the~~ Back-up Control Center (BCC) operations as well. Continuing to respond to questions and observations, he stated that it was not feasible to build a completely fail-safe system. Mr. van Welie noted that the ISO had considered at the time switching over to the BCC but decided not to do that before it could determine the cause of the problem. ~~The~~A switch from and ~~potentially~~ back to the Master Control Center (MCC) would have been both time consuming and resource and data intensive. He reinforced that at no time was the power system at risk. Mr. van Welie summarized that the New England control systems had a very sophisticated level of redundancy and seeking more redundancy or protections would be very expensive.

Continuing with discussion and reaction, members expressed concern with the ISO's delay in communicating the failure. Dr. Chadalavada responded by acknowledging communications could have been better and reporting that the ISO had modified its processes to do the following, in order of priority: (1) notify ~~the~~ Designated Entities as soon as possible; (2) declare an ~~MCC/LCC~~Master/Local Control Center Procedure No. 2 Abnormal Conditions Alert and the reason; and (3) report promptly at a subsequent Committee meeting on any future events of this magnitude.

Members also sought to assure that the ISO understood the substantial market implications to some of such an event. It was noted that, during this event, renewable resources, wind in particular, were uneconomically held to the pre-event production levels (10 MWh~~ of production~~) even though studies showed the wind during this time had picked up to the point that the system ~~could~~might well have produced over 600 MWh ~~production~~ during the event. ~~The result was very~~By holding those resources to pre-event levels, wind resources experienced substantial revenue losses ~~to wind resources and~~and consumers paid higher prices~~ for consumers~~. Members urged the ISO to explore post-outage improvements to mitigate this type of market outcome. Dr.

Chadalavada responded that, while the ISO appreciated the market impacts of these conditions, ~~but~~the ISO would maintain its priority on reliable operations. He acknowledged that manual dispatch was less than ideal and operators would benefit from more information in deciding how to operate the system reliably when in manual dispatch mode. ~~They~~Operators cannot, ~~though~~however, respond to marked, unpredictable swings in production during those circumstances. He further acknowledged that the ISO, in retrospect, should have alerted the market earlier of the problems, as soon as they understood what the operators were facing.

REVISIONS TO OP-24, OP-3, OP-5, AND OP-19

Ms. Chafetz referred the Committee to the materials circulated and posted in advance of the meeting related to a new Operating Procedure No. 24 (including Appendices A, B and D) (OP-24) and related revisions to OP-3, OP-5, and OP-19 (together, the OP-24 Related Revisions). She reminded the Committee that this matter had first been presented to the Committee at its December meeting and the ISO had agreed to take it back through the Reliability Committee to explore changes to address concerns raised at that meeting.

Ms. Mariah Winkler, Reliability Committee Chair, then reviewed the OP-24 Related Revisions circulated in advance of the meeting. She summarized that the ISO had agreed to retain a consultant at the outset to develop protective relay models for generators commercial on or before June 1, 2019. Generators entering commercial operation after June 1, 2019 would be required at their expense to develop appropriate protective relay models. In all circumstances, the generators were required to provide data on their facilities and to certify the results of the model. She then reported that the Reliability Committee at its January 17 meeting recommended Participants Committee support for the conforming OP-24 Related Revisions, with no opposition and three abstentions noted.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the OP-24 Related Revisions, as recommended by the Reliability Committee, and as reflected in the materials distributed to the Participants Committee for its February 1, 2019 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

Ahead of voting, numerous Participants expressed appreciation to the ISO for working with NEPOOL to address concerns that had been raised. The Committee then voted and unanimously approved the motion, with an abstention noted by Jericho.

PP-10 CASPR REVISIONS

Ms. Chafetz referred the Committee to the materials circulated and posted in advance of the meeting on Planning Procedure No. 10 (PP-10) revisions addressing primarily changes relating to the implementation of CASPR (PP-10 CASPR Revisions). She noted that the Committee would be asked to consider and vote on two Participant-sponsored amendments to the PP-10 CASPR Revisions, which she referred to as substantive amendments, and then would be asked to consider a motion to move certain sections of those changes into the Tariff, which she referred to as a process motion.

Ms. Winkler reported that the Reliability Committee discussed the PP-10 CASPR Revisions over the course of five meetings. At its January 17, 2019 meeting the Reliability Committee voted and failed to support the ISO-proposed PP-10 CASPR Revisions with a 55.34% Vote in favor. The Reliability Committee also voted and failed to support the two Participant-sponsored amendments to the PP-10 CASPR Revisions that were to be proposed to this Committee, with both amendments receiving a 44.22% Vote in favor.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the PP-10 CASPR Revisions, as recommended by the ISO, and as reflected in the materials distributed to the Participants Committee for its February 1, 2019 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

The PSEG representative then reviewed the two substantive amendments that had been included in materials circulated in advance of the meeting. He explained that the first amendment to be offered would change how the PP-10 CASPR Revisions treat all partial Retirement De-List Bids, Permanent De-List Bids and Substitution Auction (SA) Demand Bids and the second amendment would only address how the PP-10 CASPR Revisions treat SA Demand Bids. He further explained at highest level that the amendments were intended to ensure that the Capacity Network Resource Capability (CNRC) rating for a resource that successfully retires a portion of its capacity in the substitution auction would be reduced only by the amount of capacity released in the substitution action. He said the ISO proposal would result in the CNRC rating, which was used in planning to calculate available interconnection service on the grid, being further reduced to the remaining qualified capacity rating of the resource, with the capability difference between those two values freed up in planning for use by other resources.

A motion to amend the main motion as follows was then duly made and seconded:

> To modify the provisions for the Interconnection Service Reduction following clearing in the Forward Capacity Auction/Substitution Auction in the way identified in the materials circulated in advance of the meeting. (PSEG Amendment No. 1).

In response to clarifying questions, the proponent of PSEG Amendment No. 1 clarified that the proposal was only to address interconnection service capability changes resulting from cleared Retirement De-List Bids, Permanent De-List Bids and SA Demand Bids and would not extend to other kinds of De-List Bids. He further clarified that, under the ISO's proposal, interconnection service above the qualified capacity rating of a resource would be made available for other customers. He argued that, under the PSEG proposal, the current holder of such surplus interconnection service would have the opportunity to monetize that surplus service. He explained that, if surrendering some capacity to the substitution auction deprived a resource owner

of additional interconnection service, that owner would be less likely to surrender its capacity unless ~~it~~the owner was able to monetize its rights through higher payment in the substitution auction.

Some members, arguing in favor of the amendment, noted that the ISO's proposal would provide some financial disincentive for existing resources to partially retire their capacity in the substitution auction, which could reduce the effectiveness of CASPR. Others, opposing the amendment, argued that the transmission system properly should be considered a common carrier system that does not assign property rights to customers on the system. Such a change might better be considered as the Committee reviewed proposed revisions in response to Order 845 (the FERC's rule on generator interconnection reform) but not at that time. The NESCOE representative stated NESCOE did not support PSEG Amendment No. 1, and agreed that available interconnection headroom on the system should be available to all customers. Focusing on process, one member expressed concern that this topic was not discussed at the Markets Committee, with a chance for any lost opportunity costs to be includable in FCM bids. Another member noted that this matter related to a Planning Procedure and any concerns about lost opportunity cost should be addressed separately from the consideration of the Planning Procedure change.

The ISO directed the Committee to the ISO memorandum circulated and posted with the meeting materials outlining its reasons why it opposed PSEG Amendment No. 1.

The PSEG representative concluded the arguments in support by discussing why a resource might want to retire part of its resource but retain additional interconnection service. He identified the possibility of ~~that~~a resource wanting to add energy storage to its facility that could use the interconnection service applying for new service. He argued that ~~the~~ PSEG Amendment No. 1 adhere~~s~~d to the most basic fundamental market principle that a ~~m~~Market ~~p~~Participant

should be able to decide what it ~~is~~was selling and not have rights taken away without compensation. He noted that PSEG's issue ~~is~~was with how the PP-10 CASPR Revisions affect interconnection rights and that PSEG's focus ~~in~~was not on how PP-10 already applies to Retirement De-List Bids and Permanent De-List Bids. He further argued that ~~the~~ PSEG Amendment No. 1 would advance public policy goals of integrating public policy resources.

Following further discussion and comment, the Committee voted the motion to amend the main motion (PSEG Amendment No. 1), which failed to pass with a 41.97% Vote in favor (Generation Sector – 11.19%; Transmission Sector – 0%; Supplier Sector – 14.39%; AR Sector – 0%; Publicly Owned Entity Sector – 14.85%; and End User Sector – 1.53%). (~~PSEG Amendment No. 1). (~~See Vote 1 on Attachment 2).

A second motion to amend the main motion as follows was then duly made and seconded:

> To address, as identified in the PSEG materials circulated in advance of the meeting, treatment of Interconnection Service Reduction only for Demand Bids that clear in the Substitution Auction. (PSEG Amendment No. 2).

The proponent explained that PSEG Amendment No. 2 would apply only to how interconnection service related to SA Demand Bids were treated and would make no change to how PP-10 treated Retirement De-List Bids and Permanent De-List Bids. There was no separate discussion on this motion and the Committee determined that the second motion to amend the main motion failed to pass with the same votes for all members on PSEG Amendment No. 2 as they cast on PSEG Amendment No. 1.

The Committee then returned to discussion of the unamended main motion. The PSEG representative stated that PSEG would oppose the motion because the ISO's formula for calculating winter rating was not accurate and should be improved to ~~make it~~be more accurate. Other members expressed opposition to the main motion arguing that surplus interconnection service had value that the ISO should not be able to take without compensation. The ISO

responded that its proposal for treating substitutions in CASPR was consistent with how Retirement De-List Bids and Permanent De-List Bids were then being treated under the Tariff.

The Committee voted the main motion. The main motion required a 66.67% Vote to pass, but failed to pass with a 58.69%[1] Vote in favor (Generation Sector – 9.6%; Transmission Sector – 16.79%; Supplier Sector – 5.04%; AR Sector – 13.57%; Publicly Owned Entity Sector – 1.94%; and End User Sector – 11.75%[1]). (See Vote 2 on Attachment 2).

The Chair then reminded the Committee that it needed to consider the procedural motion, and the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee directs NEPOOL Counsel, in consultation with the Chair and Vice-Chairs of this Committee, to work with the ISO to include the elements of Sections 7.7 and 7.8 of the PP-10 CASPR Provisions in the Tariff.

The PSEG representative, who had advanced this proposal, argued in support of the motion by stating that PP-10 was an unfiled procedure that changes interconnection service and affects participation in the markets. He argued that the provisions of Section 7.7 and 7.8 were properly treated as rates, terms or conditions of service that should be filed with the FERC.

In response, Ms. Monica Gonzalez, ISO Counsel, confirmed that the ISO considered the PP-10 Revisions as merely clarifying what was already set forth in the Tariff, but did not oppose including the requested provisions in the Tariff, although their inclusion could not happen in advance of the upcoming capacity auction. She said the ISO would undertake to make that change whether or not NEPOOL acted on the motion and committed the ISO to work with the Chair and Vice-Chair of the appropriate Technical Committee to bring the Tariff change through the NEPOOL stakeholder process.

[1] The NEPOOL Vote tally has been corrected to reflect the fact that at the meeting the vote of one End User Participant (Utility Services Inc.) was cast as an abstention (rather than in favor as initially recorded), lowering the total vote tally and End User Sector vote tally as announced at the meeting.

The Committee then voted and unanimously approved the procedural motion, with abstentions noted by AVANGRID, CPV, Emera Maine, Entergy, and NRDC. NEPOOL Counsel committed to work with ISO Counsel to facilitate stakeholder review before the additional provisions were filed with the FERC.

SUPPORT FOR THE ISO'S MOTION TO EXTEND THE FILING DATE FOR THE "CHAPTER 3" FUEL SECURITY FILING

Ms. Chafetz referred the Committee to the materials circulated and posted in advance of the meeting related to the ISO's January 18 request of the FERC for an extension of time (Extension Request) to submit the filing of a longer-term market solution(s) to address regional fuel security concerns (the Chapter 3 Filing). She noted earlier discussions at the Participants Committee and Markets Committee and summarized the ISO request. She noted that comments on that request were due on or before February 4, 2019.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee (i) supports the ISO's request to the FERC to extend the "Chapter 3" filing deadline set forth in the FERC's July 2, 2018 order from July 1, 2019 to November 15, 2019 and (ii) authorizes and directs NEPOOL Counsel to work with the Chair and Vice-Chairs of this Committee to reflect the substance of NEPOOL's support and feedback in a pleading to be filed with the FERC.

In discussion, one member expressed his intent to abstain on the motion because of concern that a deferral would delay the implementation date, notwithstanding ISO assurances otherwise. He agreed that more time would help to address the first two elements of the ISO's conceptual proposal and urged that time during the extension be dedicated to define the forward element of Chapter 3. Other representatives spoke in favor of the extension, urging diligence throughout the period before the filing, including diligence in defining the forward element. One representative urged that the forward element be included in the filing when it is made, even if details had not yet been fully defined, in order to emphasize the interrelated nature of the changes.

Following further comment, the Committee voted and unanimously approved the motion, with abstentions noted by CLF, CSC and NRG.

LITIGATION REPORT

Mr. Doot referred the Committee to the January 30 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted and summarized the following:

1) The FERC's January 29 order rejecting the 132nd Agreement to the NEPOOL Agreement. Following his summary, he explained that the Membership Subcommittee was scheduled to meet later that month to discuss the pending application from Mr. Kuser, the RTO Insider press reporter. The results of the Membership Subcommittee deliberations would be presented to the Participants Committee for its discussion and action.
2) The FERC's January 29 order on remand from the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) concerning the treatment of Retirement De-List Bids.
3) The FERC's January 29 order regarding the permissible CASPR bids and test price formation.

Ms. Maria Gulluni, ISO General Counsel, concurred with the summaries and noted that the D.C. Circuit was expected to issue a further order relating to the Retirement De-List Bids matter. She noted that the IMM must determine how it would address the ~~Commission's~~FERC's direction in its annual filings. She said that the FERC did not address the question of whether generator bids are properly considered rates, terms or conditions of service. In her view, the last paragraph of the CASPR order was probably the best direction for the region, where FERC effectively said the IMM would submit its proposed test price together with the Market Participant's bid, along with the IMM's views on that bid, and the ~~Commission~~FERC would make a determination as to what is controlling.

Mr. Bruce Anderson, NEPGA Counsel, agreed that the FERC left some issues undecided, including whether a Market Participant has a Section 205 Filing right over its bids and whether a Retirement De-List Bid is a rate, term or condition of wholesale power service. He opined that it

followed from the order that a Market Participant's Retirement De-List Bids would effectively be treated as a filing under Section 205, even though filings of those bids would be submitted by the ISO and would include both the Retirement De-List Bids and the test prices.

Mr. Doot concluded the Litigation Report by noting that the FERC had not yet ruled on the Vineyard Wind request and members would need to await ISO direction on how the auction would be administered in the absence of a FERC order on that request. He encouraged anyone with questions on the Report to contact NEPOOL Counsel.

COMMITTEE REPORTS

Mr. Alex Kuznecow, Markets Committee Chair, reported that Committee was scheduled to meet on February 5-6 in Westborough. The Committee would discuss interim compensation treatment and winter energy security improvements with stakeholder input on their thoughts on Chapter 3.

Mr. José Rotger, Transmission Committee Vice-Chair, reported that Committee was scheduled to meet on February 20 in Westborough. The primary topics would be a new Tariff schedule to cover compensation for interconnection reliability operating limits, proposed changes to the pro forma interconnection agreement in Schedules 22 and 23 regarding requirements for solar forecast data, and discussion of the Reactive Compensative Schedule 2 of the Tariff, with revisions related to electric storage facilities and the audit of those facilities.

Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that Subcommittee was scheduled to meet by teleconference on February 11 at 2:30 p.m. to discuss general membership issues and then to begin discussion of the membership application of Mr. Kuser at 3:00 p.m. She reported the Subcommittee materials for that meeting were available on the NEPOOL website.

Mr. Patrick Gerity, NEPOOL Counsel, reported that the Budget & Finance Subcommittee was scheduled to meet on February 14. He said the main agenda item would be continued

discussion of a Participant proposal to expand permissible forms of financial assurance beyond cash and letters of credit, which discussion began in November. He encouraged participation by all interested members.

OTHER BUSINESS

Mr. Doot reported that the March 13 Participants Committee meeting would be at the Colonnade Hotel in Boston. Looking ahead, he noted there were no Technical Committee meetings scheduled to take place between March 13 and the planned April 5 Participants Committee meeting. Accordingly, he urged members to pay attention to notices to determine whether that April 5 meeting would still be held and, if so, whether it would be in-person or by teleconference. He reported that FERC Commissioner Cheryl LaFleur's term with the Commission would end on June 30, 2019, though she had indicated an intention to continue to serve as a Commissioner until her position was filled. With the expiration of her term, the administration had two FERC vacancies to fill.

There being no further business, the meeting adjourned at 12:43 p.m.

Respectfully submitted,

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David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
FEBRUARY 1, 2019 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
AR Small Load Response (LR) Group Member	AR-LR	Doug Hurley (tel)	Brad Swalwell (tel)	
AR Small Renewable Generation (RG) Group Member	AR-RG	Erik Abend (tel)		
American PowerNet Management	Supplier			Mary Smith Michael Macrae
Ashburnham Municipal Light Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Associated Industries of Massachusetts	End User			Roger Borghesani
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Block Island Power Company	Supplier	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
BP Energy Company	Supplier			Nancy Chafetz
Braintree Electric Light Department	Publicly Owned			Dave Cavanaugh
Brookfield Energy Marketing	Supplier	Aleks Mitreski		
Chester Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
CPV Towantic, LLC	Generation	Daniel Pierpont		
Competitive Energy Services, LLC	Supplier			Glenn Poole (tel)
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User			Dave Thompson (tel)
Conservation Law Foundation (CLF)	End User	David Ismay		
Consolidated Edison Energy, Inc. (ConEd)	Supplier	Jeff Dannels		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned		Dave Cavanaugh	
Direct Energy Business, LLC	Supplier	Ron Carrier		Nancy Chafetz
Dominion Energy Generation Marketing, Inc.	Generation	Michael Purdie		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Emera Energy Services Subsidiaries (Emera Energy)	Transmission	Sandi Hennequin (tel)		
Emera Maine	Transmission			Cal Bowie
Enel X North America, Inc.	AR-LR		Herb Healy (tel)	
Entergy Nuclear Power Marketing, LLC	Generation			Daniel Pierpont
Environmental Defense Fund	End User	Liz Delaney		
Eversource Energy	Transmission	James Daly	Cal Bowie	
Exelon Generation Company	Supplier	Steve Kirk		
FirstLight Power Resources Management	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation		Abby Krich	Bob Stein
Georgetown Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Groton Electric Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault (tel)	Bob Stein	Abby Krich
Harvard Dedicated Energy Limited	End User	Mary Smith	Michael Macrae	Roger Borghesani
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Holyoke Gas & Electric Department	Publicly Owned		Brian Thomson	Brian Forshaw
Hull Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Industrial Energy Consumer Group (IECG)	End User		Todd Griset (tel)	
Ipswich Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer		

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ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
FEBRUARY 1, 2019 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Littleton (MA) Electric Light and Waster Department	Publicly Owned		Dave Cavanaugh	
Long Island Lighting Company (LIPA)	Supplier		William Killgoar (tel)	
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate Office	End User			Paul Peterson (tel)
Maine Skiing, Inc.	End User		Todd Griset (tel)	
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	Brian Forshaw
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Marble River, LLC	Supplier		John Brodbeck (tel)	
Mass. Attorney General's Office	End User	Christina Belew	Sarah Bresolin Silver	
Mass. Bay Transportation Authority	Publicly Owned		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned	Brian Thomson		Brian Forshaw
Merrimac Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned		Dave Cavanaugh	Brian Forshaw
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
National Grid	Transmission		Tim Martin	
Natural Resources Defense Council	End User			Liz Delaney
New Hampshire Electric Cooperative	Publicly Owned			Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson (tel)		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller (tel)	
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Peabody Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
PowerOptions, Inc.	End User	Cindy Arcate (tel)		
Princeton Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned			
Repsol Energy North America Company	Gas Industry Part.		Nancy Chafetz	
Rowley Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned		Brian Thomson	Brian Forshaw
Salem (Footprint Power Salem Harbor Development LP	Generation			Nancy Chafetz
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson	Brian Forshaw
South Hadley Electric Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Sterling Municipal Electric Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Stowe Electric Department	Publicly Owned		Dave Cavanaugh	
Taunton Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
The Energy Consortium	End User	Roger Borghesani	Mary Smith	Paul Peterson (tel)
Utility Services Inc.	End User			Paul Peterson (tel)
Vermont Electric Cooperative	Publicly Owned		Katie Orost (tel)	
Vermont Electric Power Company	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley (tel)	
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw
Verso Energy Services LLC	Generation	Glenn Poole (tel)		
Village of Hyde Park (VT) Electric Department	Publicly Owned	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Wallingford DPU Electric Division	Publicly Owned		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Westfield Gas & Electric Department	Publicly Owned		Dave Cavanaugh	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
FEBRUARY 1, 2019 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Wheelabrator/Calpine	AR-RG	Brett Kruse		

VOTES TAKEN AT
FEBRUARY 1, 2019 PARTICIPANTS COMMITTEE MEETING

TOTAL

Sector/Group	Vote 1	Vote 2
GENERATION	11.19	9.60
TRANSMISSION	0.00	16.79
SUPPLIER	14.39	5.04
ALTERNATIVE RESOURCES	0.00	13.57
PUBLICLY OWNED ENTITY	14.86	1.94
END USER	1.53	11.75
% IN FAVOR	**41.97**	**58.69**

GENERATION SECTOR

Participant Name	Vote 1	Vote 2
CPV Towantic, LLC	F	O
Dominion Energy Marketing	A	O
Entergy Nuclear Power Marketing	O	F
FirstLight Power Resources	O	F
Generation Group Member	F	A
NextEra Energy Resources, LLC	F	F
NRG Power Marketing, LLC	A	A
Salem (Footprint Power Salem)	A	F
Verso Energy Services LLC	F	O
IN FAVOR (F)	4	4
OPPOSED (O)	2	3
TOTAL VOTES	6	7
ABSTENTIONS (A)	3	2

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2
AVANGRID (CMP/UI)	O	F
Emera Maine	S[2]	S[2]
Emera Maine	O	F
Emera Energy Services Subsidiaries	O	F
Eversource Energy	O	F
National Grid	A	F
Vermont Electric Power Co.	A	A
IN FAVOR (F)	0	4
OPPOSED	3	0
TOTAL VOTES	3	4
ABSTENTIONS (A)	2	1

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2
Renewable Generation Sub-Sector		
Jericho Power	A	--
Small RG Group Member	A	A
Wheelabrator North Andover Inc.	O	F
Distributed Generation Sub-Sector		
CLEAResult Consulting, Inc.	A	A
Load Response Sub-Sector		
Enel X North America, Inc.	A	A
VT Energy Investment Corp.	A	A
Small LR Group Member	O	F
IN FAVOR (F)	0	2
OPPOSED	2	0
TOTAL VOTES	2	2
ABSTENTIONS (A)	5	4

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2
American PowerNet Management	O	A
BP Energy Company	A	A
Block Island Power Company	A	A
Brookfield Energy Marketing Inc.	A	A
Competitive Energy Services	F	O
Consolidated Edison Energy, Inc.	F	O
Cross-Sound Cable Company	A	A
Direct Energy Business, LLC	F	O
DTE Energy Trading, Inc.	A	A
Exelon Generation Company	A	O
Galt Power, Inc.	A	F
H.Q. Energy Services (U.S.) Inc.	A	F
Long Island Power Authority (LIPA)	F	O
Maine Power, LLC	A	F
Marble River, LLC	F	O
PSEG Energy Resources & Trade	F	O
IN FAVOR (F)	6	3
OPPOSED	1	7
TOTAL VOTES	7	10
ABSTENTIONS (A)	9	6

[2] 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.
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VOTES TAKEN AT
FEBRUARY 1, 2019 PARTICIPANTS COMMITTEE MEETING

END USER SECTOR

Participant Name	Vote 1	Vote 2
Associated Industries of Mass.	O	A
Conn. Office of Consumer Counsel	O	F
Conservation Law Foundation	A	A
Environmental Defense Fund	A	A
Harvard Dedicated Energy Limited	O	A
High Liner Foods (USA) Inc.	F	O
Maine Public Advocate Office	O	F
Mass. Attorney General's Office	O	F
Natural Resources Defense Council	O	F
NH Office of Consumer Advocate	O	F
PowerOptions, Inc.	O	F
The Energy Consortium	O	F
Utility Services Inc.	O	A
IN FAVOR (F)	1	7
OPPOSED	10	3
TOTAL VOTES	11	10
ABSTENTIONS (A)	2	5

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2
Ashburnham Municipal Light Plant	F	O
Belmont Municipal Light Dep't	A	A
Boylston Municipal Light Dep't	F	O
Braintree Electric Light Dept.	F	O
Chester Municipal Light Dep't	A	A
Chicopee Municipal Lighting Plant	F	O
Concord Municipal Light Plant	A	A
Conn. Mun. Electric Energy Coop.	O	F
Danvers Electric Division	A	A
Georgetown Municipal Light Dep't	A	A
Groton Electric Light Department	F	O
Groveland Electric Light Dep't	A	A
Hingham Municipal Lighting Plant	A	A
Holden Municipal Light Dep't	F	O
Holyoke Gas & Electric Dep't	F	O
Hull Municipal Lighting Plant	F	O
Ipswich Municipal Light Dep't	F	O

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1	Vote 2
Littleton (MA) Electric Light Dep't	A	A
Mansfield Municipal Electric Dep't	F	O
Marblehead Municipal Light Dep't	F	O
Mass. Bay Transportation Authority	A	A
Mass. Mun. Wholesale. Elec. Co.	F	O
Merrimac Municipal Light Dep't	A	A
Middleborough Gas & Elec. Dep't	A	A
Middleton Municipal Electric Dep't	A	A
New Hampshire Electric Coop.	O	F
North Attleborough Electric Dept.	A	A
Norwood Municipal Light Dept.	A	A
Pascoag Utility District	A	A
Paxton Municipal Light Dep't	F	O
Peabody Municipal Light Plant	F	O
Princeton Municipal Light Dep't	F	O
Rowley Municipal Lighting Plant	A	A
Russell Municipal Light Dep't	F	O
Shrewsbury's Elec. & Cable Ops.	F	O
South Hadley Electric Light Dep't	F	O
Sterling Mun. Elec. Light Dep't	F	O
Stowe (VT) Electric Department	A	A
Taunton Municipal Lighting Plant	F	O
Templeton Mun. Lighting Plant	F	O
Vermont Electric Cooperative	A	A
VT Public Power Supply Authority	O	F
Village of Hyde Park Electric Dep't	A	A
Wakefield Mun. Gas & Light Dep't	F	O
Wallingford, Town of	A	A
Wellesley Municipal Light Plant	A	A
West Boylston Mun. Lighting Plant	F	O
Westfield Gas & Elec. Light Dep't	A	A
IN FAVOR (F)	23	3
OPPOSED	3	23
TOTAL VOTES	26	26
ABSTENTIONS (A)	22	22

CONSENT AGENDA

Markets Committee

From the notice of actions of the Markets Committee's ***February 5-6, 2019*** meeting,[1] dated February 7, 2019, which has been previously circulated:

1. **MR1 Revisions (Technical Error Correction to FCA Qualification Significant Decrease Calculations)**

   Support revisions to Market Rule 1 to address a technical error related to the significant decrease calculations used for Forward Capacity Auction (FCA) qualification, as recommended by the Markets Committee at its February 5-6, 2019 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.

Reliability Committee

From the notice of actions of the Reliability Committee's ***February 12, 2019*** meeting,[2] dated February 13, 2019, which has been previously circulated:

2. **OP-11 , OP-11 Appendix G Revisions; Retirement of OP-11 Appendix C (Schedule 16 Conforming Changes; additional clean-up/clarifications)**

   Support revisions to ISO New England Operating Procedure (OP) No. 11 (Blackstart Resource Administration) (OP-11) and OP-11 Appendix G, and the retirement of OP-11 Appendix C (Designated Blackstart Resources CIP Costs Compensation form) to (i) conform OP-11 to the Schedule 16 changes accepted by the FERC in ER19-251 (by deleting reference to Category A and Category B Designated Blackstart Resource types, deleting references to NERC Critical Infrastructure Protection compensation requirements, and retiring Appendix G); and (ii) make additional clean-up and clarifying changes, as recommended by the Reliability Committee at its February 12, 2019 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, with one abstention in the Supplier Sector.

3. **OP-14 Revisions (Continuous Storage Facility Participation; SOG § II.A.2 Compliance Deadline; DG Registration Options; PRD Clean-Up Changes)**

   Support revisions to OP-14 (Technical Requirements for Generators, Demand Response Resources, Asset Related Demands, and Alternative Technology Regulation Resources) to (i) incorporate the participation by Continuous Storage

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

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

CONSENT AGENDA (cont.)

Facilities (CSF),[3] (ii) establish June 1, 2020 as the date by which all Settlement-Only Generators (SOGs) must be compliant with Section II.A.2 criteria, (iii) provide registration options for generators meeting the definition of Distributed Generation (DG), and (iv) incorporate Price-Responsive Demand (PRD) clean-up revisions, all as recommended by the Reliability Committee at its February 12, 2019 meeting, together 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, with three abstentions in the Publicly Owned Entity Sector.

4. <u>New OP-14 Appendix I (Establishing Operating and Reporting Requirements for CSF Participation in the New England Markets)</u>

Support the institution of new Appendix I to OP-14 (OP-14I) (CSF Plant Operator Guide), establishing the Real-Time operational, telemetry and additional data reporting requirements for CSF participation in the wholesale markets, as recommended by the Reliability Committee at its February 12, 2019 meeting,[3] 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, with three abstentions in the Publicly Owned Entity Sector.

5. <u>OP-18 Appendix A Revisions (Incorporating New Data Points to Support Meteorological Data; Revisions from Biennial Review and Changes Conforming to Current Practices)</u>

Support revisions to Appendix A (ICCP [inter-control center communications protocol] CNP [communications network processor] Node Requirement) to OP-18 (Metering and Telemarketing Criteria) that incorporate new data points to support meteorological data, revisions from the biennial review, and editorial changes to conform to current practices, as recommended by the Reliability Committee at its February 12, 2019 meeting, together 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, with three abstentions in the Publicly Owned Entity Sector.

[3] Both Consent Agenda items recommending Participants Committee support for CSF-related changes to OP-14 (item nos. 3(i) and 4) were recommended subject to the outcome in FERC Docket No. ER19-84 (where enhanced storage participation Tariff changes were pending at the time). On February 25, 2019, the FERC accepted the Tariff changes effective as of April 1, 2019, as requested. Accordingly, with that certainty, all of the changes to OP-14, both CSF-related and non-CSF-related, will become effective on April 1, 2019.

Summary of ISO New England Board and Committee Meetings

March 13, 2019 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee met by teleconference on February 12. On February 21, the Audit and Finance Committee, the Markets Committee, the Compensation and Human Resources Committee, and the Board of Directors each met in Holyoke.

The Compensation and Human Resources Committee reviewed updated survey data regarding employers' proposed 2019 executive compensation at the February 12th meeting, and the appropriateness of the benchmarks utilized. During the executive session, the Committee discussed corporate performance for 2018 and officer compensation for 2019. The Committee also discussed succession and transition plans to manage upcoming retirements. At the February 21st meeting, the Committee continued its discussion on executive compensation and benefits plans.

The Audit and Finance Committee met with the investment advisors for the Company's benefits plan assets and 401(k) plan and received an analysis of investment options and details regarding the mix, cost, and performance of offerings. The investment performance costs continue to be reasonable with a competitive weighted average expense ratio, and funds are currently scoring "in good standing" based on investment advisors' scoring methodology. The Committee then reviewed significant accounting estimates used in the Company's budgeting and financial statements, including earnings and discount rates, health care trends, and depreciation. After considering the impact of these accounting estimates, the Committee approved the rates. Next, the Committee discussed the Code of Conduct and rules related to prohibited investments. Finally, the Committee met in executive session to review Internal Audit Department results for 2018 and considered the performance and 2019 compensation for the Director of Internal Audit.

The Markets Committee was provided with an update on the results of the Annual Forward Capacity Auction, including the clearing of new generation, the participation of energy efficiency, the results of the first CASPR auction, and the impact of resources retained for reliability on the market. The Committee then discussed the proposed interim compensation treatment to address winter energy security, including the design elements and stakeholder feedback.

The Board of Directors received reports from the standing committees and the Chief Executive Officer. The Board was provided with an update on the results of the Annual Forward Capacity Auction. The Board then outlined elements for consideration at its next meeting with regard to strategic planning and review of the Company's five-year business plan. Mr. Mike Curran reported on the structural differences between ISO-NE and MISO, at which he was previously a director. During executive session, the Board approved corporate performance results for 2018 and officer compensation for 2019.

NEPOOL Participants Committee Report

March 2019

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 $366M, down $305M from January 2019 and down $35M from February 2018
    - February natural gas prices were 40% lower than January average values
    - Average RT Hub Locational Marginal Prices ($36.92/MWh) were 28% lower than January averages
      - DA Hub LMP averaged $35.62/MWh
    - Average February 2019 natural gas prices and RT Hub LMPs over the period were down 5.4% and unchanged, respectively, from February 2018 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98% during February, down from 99% during January*
    - The minimum value for the month was 93.4% on February 25

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

Underlying natural gas data furnished by:

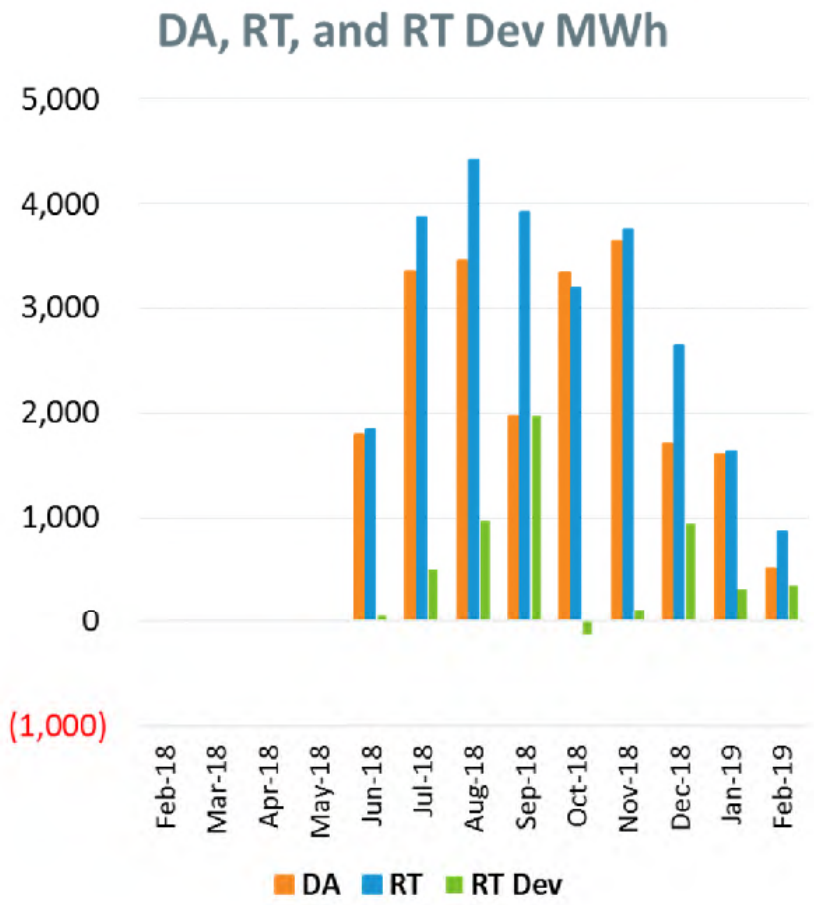
ICE Global markets in clear view

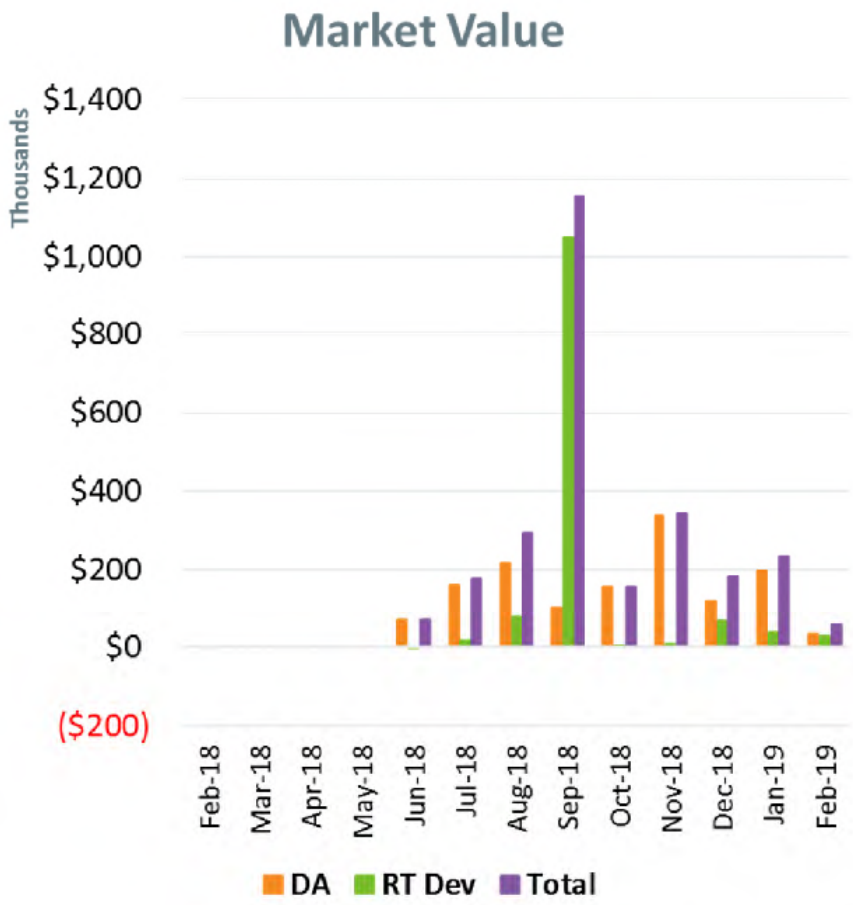
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - February NCPC payments totaled $1.9M over the period, down $370K from January and down $103K from February 2018
    - First Contingency* payments totaled $1.8M, down $421K from January
      - $1.7M paid to internal resources, down $405K from January
        - » $521K charged to DALO, $553K to RT Deviations, $678K to RTLO
      - $10K paid to resources at external locations, down $16K from January
        - » $2K charged to DALO at external locations, $8K to RT Deviations
    - Second Contingency payments totaled $52K, up $3K from January
    - Voltage payments totaled $13K, up $13K from January
    - Distribution payments totaled $46K, up $35K from January
  - NCPC payments over the period as percent of Energy Market value were 0.5%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $237K; Rapid Response Pricing (RRP) Opportunity Cost - $267K; Posturing - $61K; Generator Performance Auditing (GPA) - $113K;**

Price Responsive Demand (PRD) Energy Market Activity by Month





Note: DA and RT (deviation) MWh are settlement obligations and reflect appropriate gross-ups for distribution losses.

Highlights

- Results of the thirteenth Forward Capacity Auction (FCA 13) were filed with FERC on February 28
  - In total, 34,839 MW of new and existing resources cleared the auction
  - The FCA 13 payment rate is $3.80/kW-month, with the exception of capacity imports from New Brunswick which cleared at a price of $2.68/kW-month
- The March 21 PAC meeting will include a presentation of the updated load, solar PV, and energy-efficiency forecasts and FCA 14 zonal boundaries
- PAC "Grid Transformation Day" is scheduled for May 23

Forward Capacity Market (FCM) Highlights

- CCP 9 (2018-2019)
  - Late, new resources are being monitored closely
- CCP 10 (2019-2020)
  - ARA ICR & related values were filed with FERC on November 30 and accepted on January 28
  - Third reconfiguration auction will be March 1-5 and results will be posted no later than March 19

ARA – Annual Reconfiguration Auction
CCP – Capacity Commitment Period
ICR – Installed Capacity Requirement

FCM Highlights, cont.

- CCP 11 (2020-2021)
  - ARA ICR & related values were filed with FERC on November 30 and accepted on January 28
  - Second reconfiguration auction will be August 1-5, and results to be posted by September 3
- CCP 12 (2021-2022)
  - ARA ICR & related values were filed with FERC on November 30 and accepted on January 28
  - First reconfiguration auction will be June 3-5

FCM Highlights, cont.

- CCP 13 (2022-2023)
  - The auction was held from February 4-6, and results were filed with FERC on February 28; approximately 34,839 MW of new and existing resources cleared the auction
    - Payment rate will be $3.80/kW-month
      - Capacity imports from New Brunswick cleared at lower prices of $2.68/kW-month due to excess supply of imports at the pool-wide price
      - Auction starting price was $13.050/kW-month
    - Overall, 174 MW of new and existing wind, and 223 MW of new and existing solar resources cleared
    - One large combined-cycle generator, Killingly Energy Center (632 MW), cleared the auction
    - Approximately 25 MW of projects consisting of energy storage cleared in FCA 13, as compared to 7.56 MW of energy storage in FCA 12
    - In total, approximately 1,521 MW of delist bids cleared the auction

FCM Highlights, cont.

- CCP 14 (2023-2024)
  - Qualification is ongoing
    - Existing resource qualification will be issued on March 8
    - Retirement and permanent delist bids are due by March 15
      - Note: this date was revised with FERC approval of the CASPR Conforming Changes
    - Substitution Auction demand bids are due by March 15
    - Show of Interest window is April 12 – April 26
  - ICR & Related Values development to commence in the April timeframe with the PSPC

CASPR – Competitive Auctions with Sponsored Policy Resources

FERC Order 1000

- Intraregional Planning
  - 20 companies have achieved Qualified Transmission Project Sponsor (QTPS) status
  - 2019 Annual QTPS Certification
    - All 20 QTPSs submitted completed Annual QTPS Certification forms to ISO prior to the close of the Certification Window on January 31
      - ISO expects to issue notifications of completion of 2019 Annual QTPS certification by March 8

Highlights

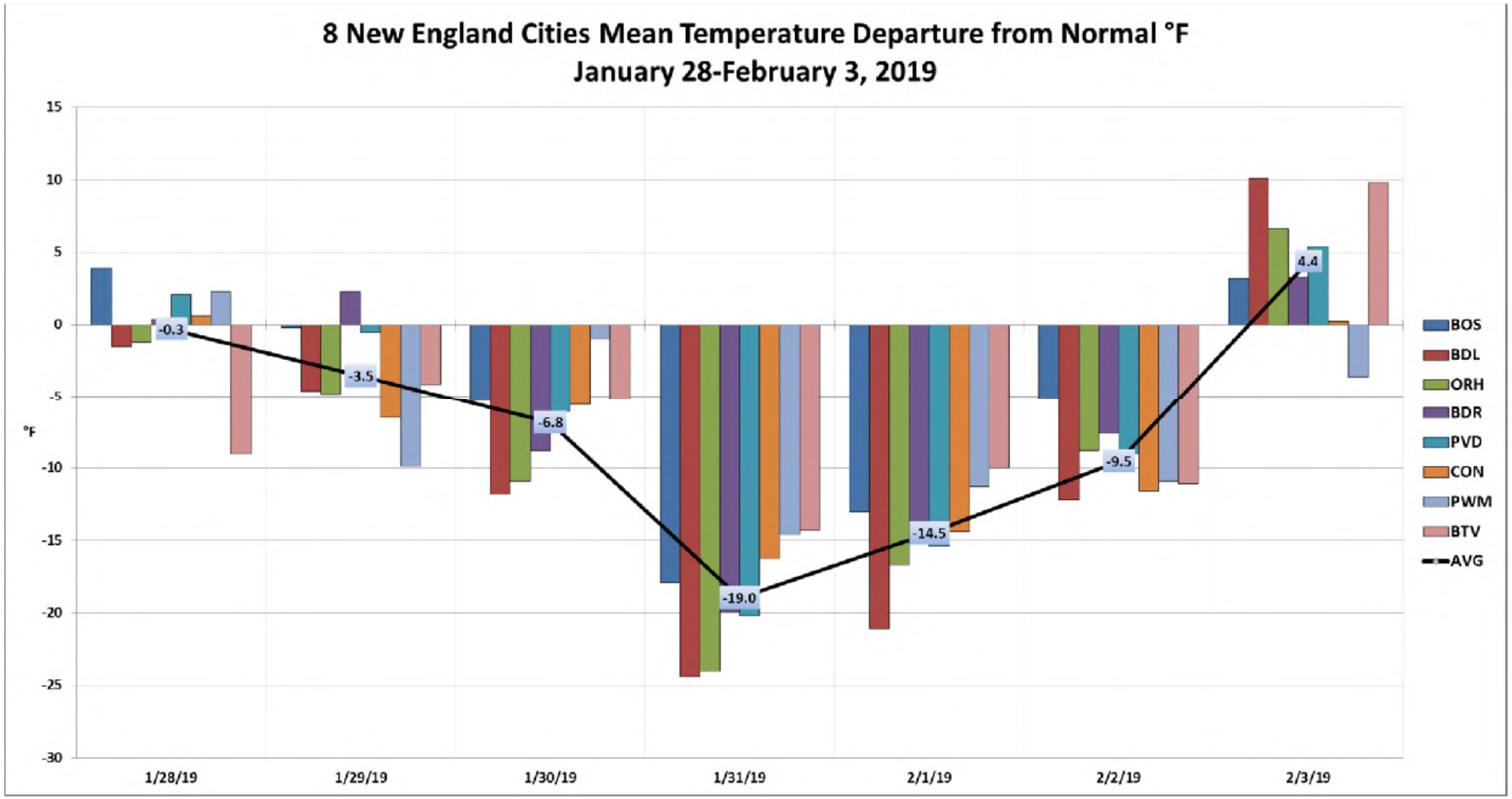
- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning March 2, 2019.
- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 11, 2019.

JAN 31 – FEB 2 BRIEF COLD SNAP

Cold Snap January 31-February 2, 2019

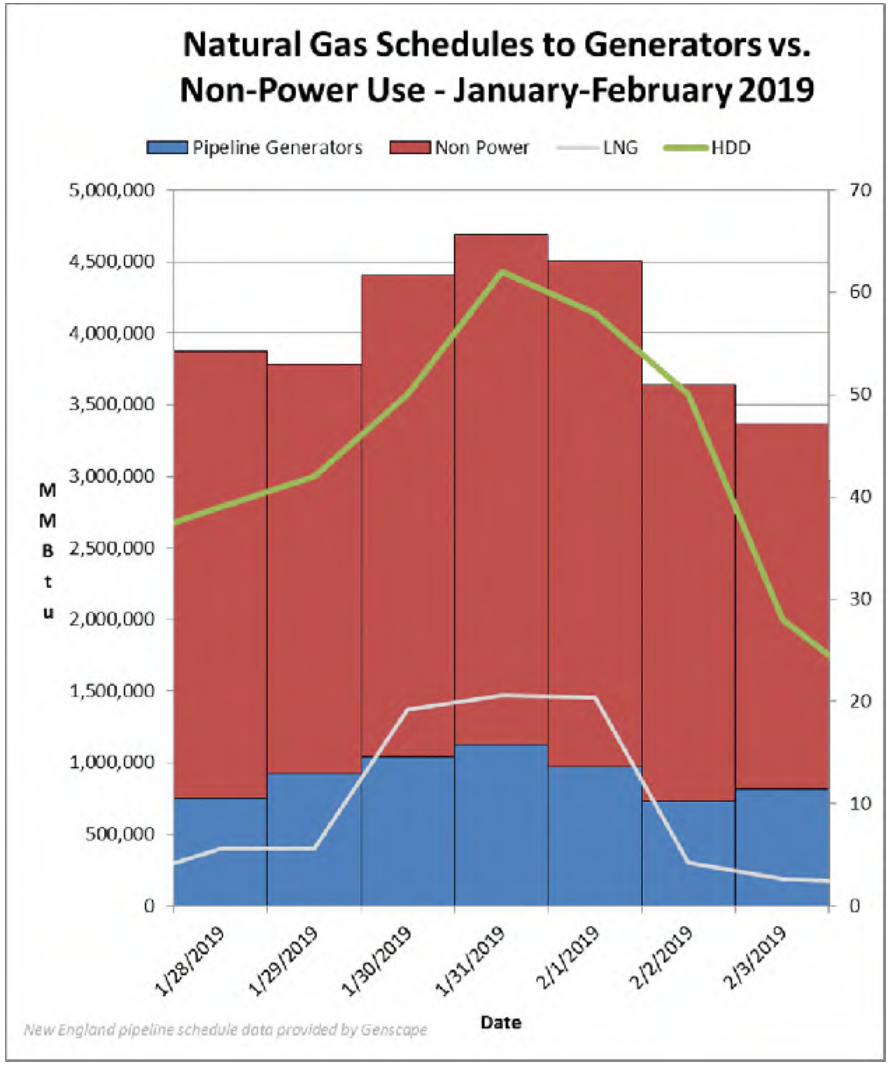
- New England was affected by a second brief cold snap January 31st through February 2nd
- The 8 city New England mean temperature on January 31st was 6.5°F, **19.0°F** below the normal of 25.5°F
- On February 1st the New England mean temperature was 11.1°F, **14.5°F** below the normal of 25.6°F
- On February 2nd the New England mean temperature was 16.2°F, **9.5°F** below the normal of 25.7°F

New England Mean Temperatures Compared To Normal January 28-February 3, 2019

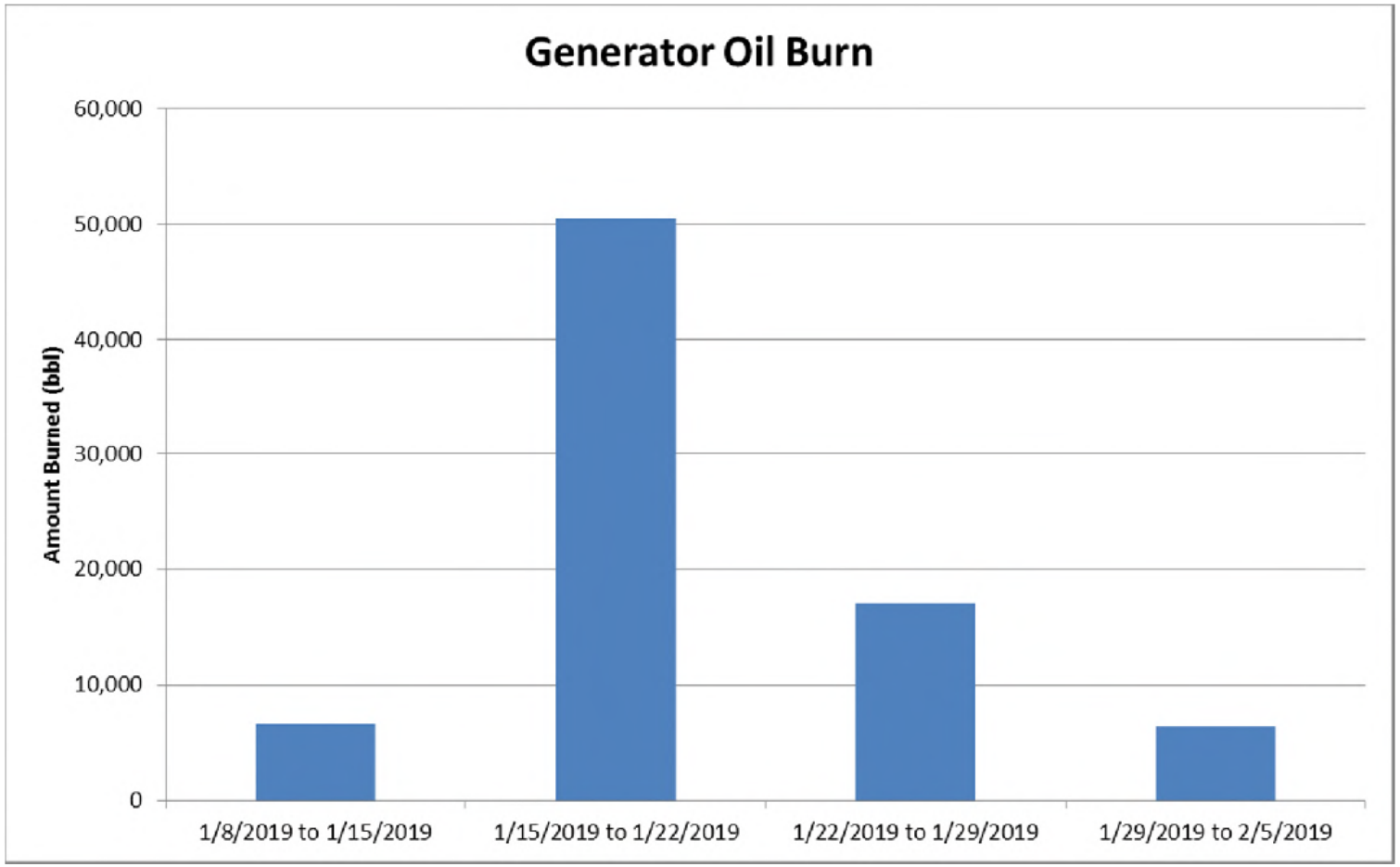


Gas Demand and LNG Supply

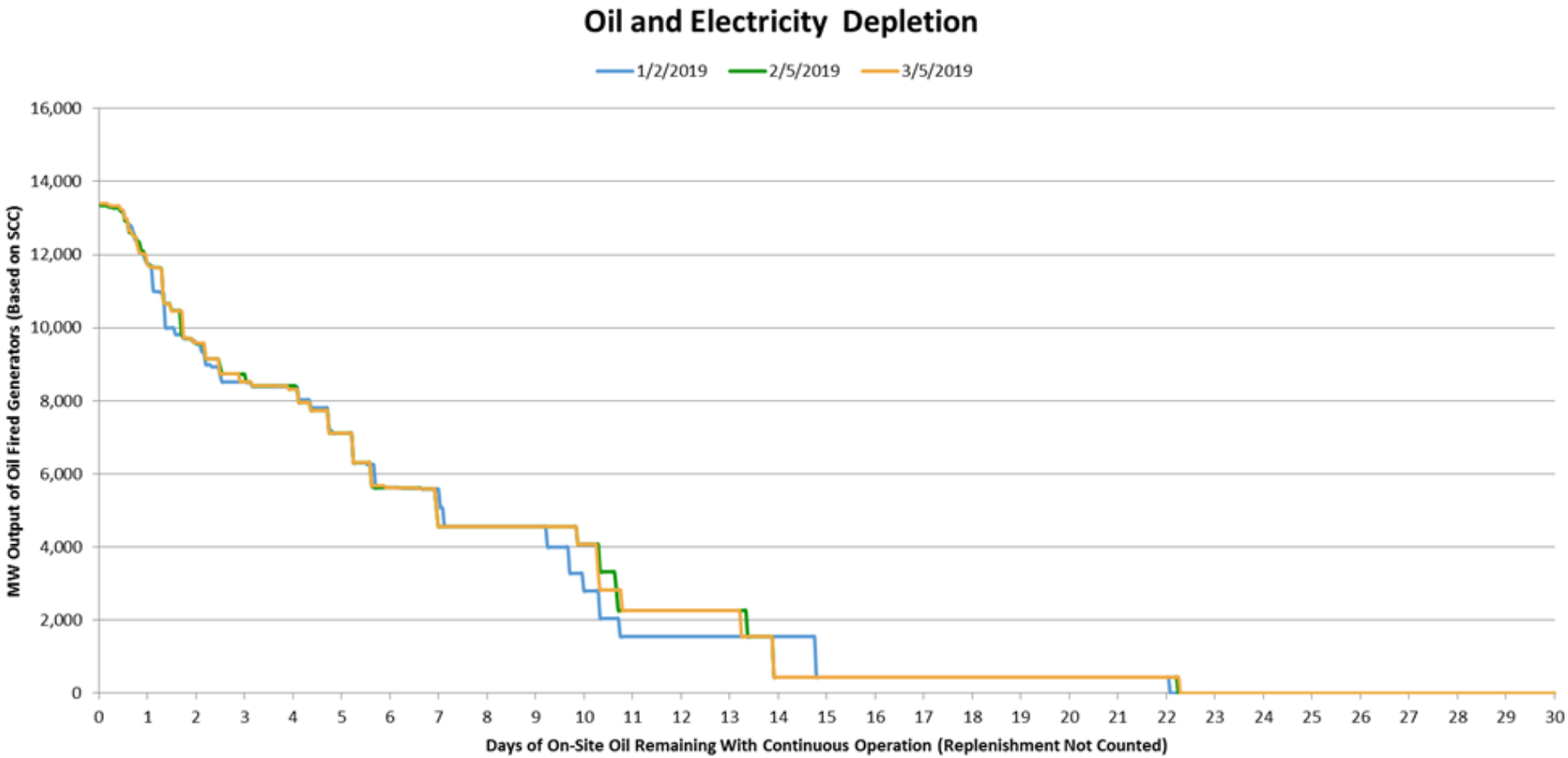
- High gas demand on three days
- Scheduled gas delivery days for 1/30, 1/31, 2/1
  - 1/30: 4,407,825
  - 1/31: 4,686,378
  - 2/1: 4,502,994
- Includes both LDC consumption and Power Generation scheduled gas



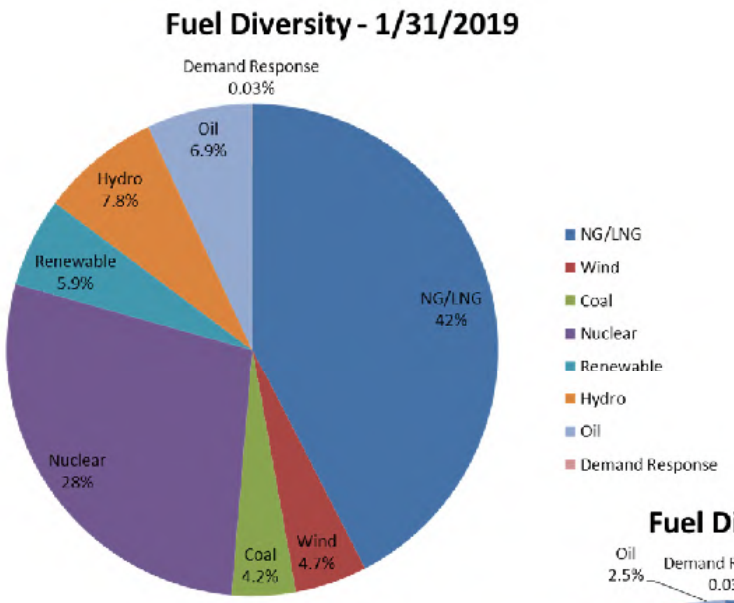
Generator Oil Burn

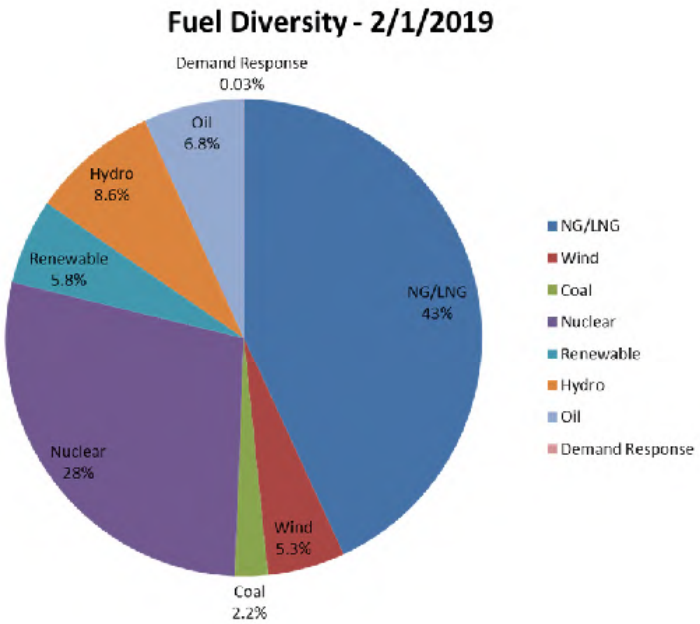


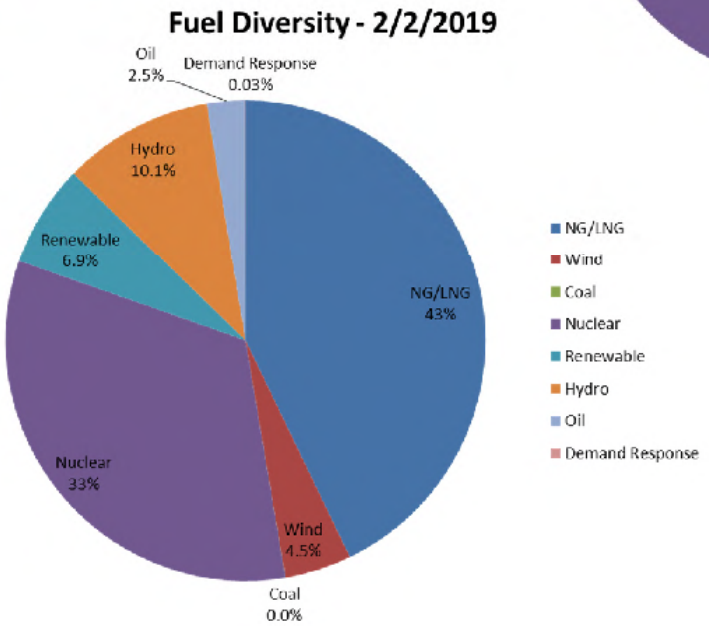
Oil Depletion Chart



Fuel Diversity Pie Chart Summary







SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (+1.8°F) Max: 65°F, Min: 10°F Precipitation: 3.45” – Above Normal Normal: 3.25” Snow: 11.6”	Hartford	Temperature: Above Normal (1.0°F) Max: 64°F, Min: (-7)°F Precipitation: 3.27” - Below Normal Normal: 2.89” Snow: 9.2”

Peak Load:	18,480 MW	Feb 1, 2019	19:00 (ending)

Emergency Procedure Events (OP-4, M/LCC 2, Minimum Generation Emergency)

Procedure	Declared	Cancelled	Note
No Events in February, 2019			

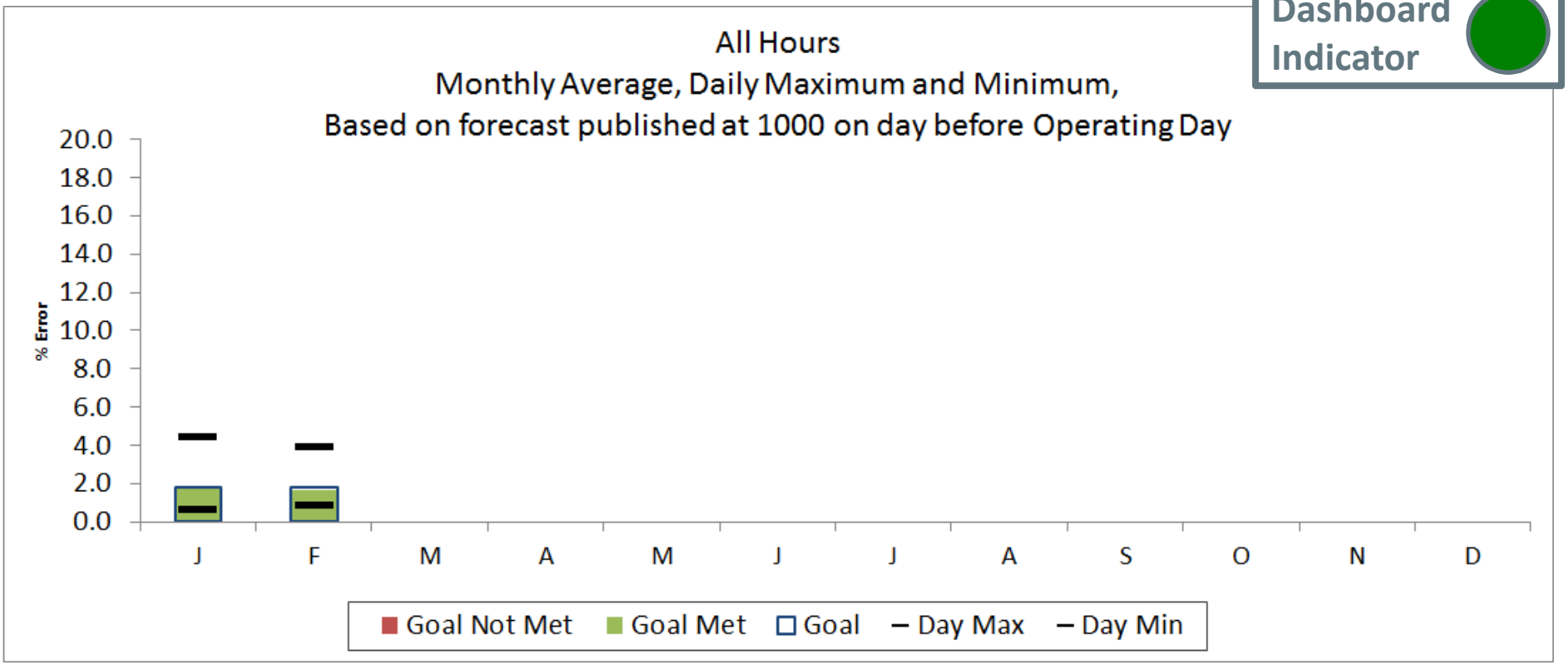
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
2/21/2019	NYISO	630

2019 System Operations - Load Forecast Accuracy

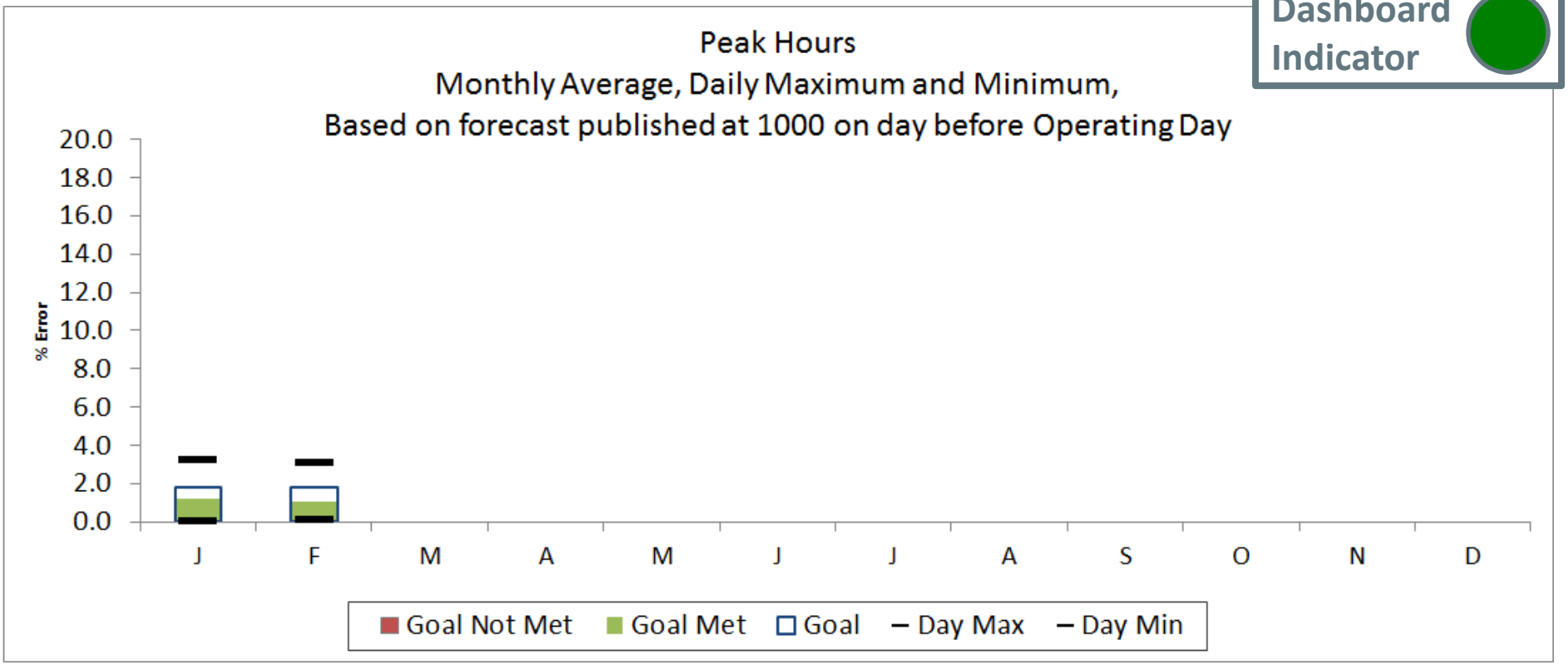
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.36	3.87											4.36
Day Min	0.60	0.77											0.60
MAPE	1.76	1.68											1.72
Goal	1.80	1.80											

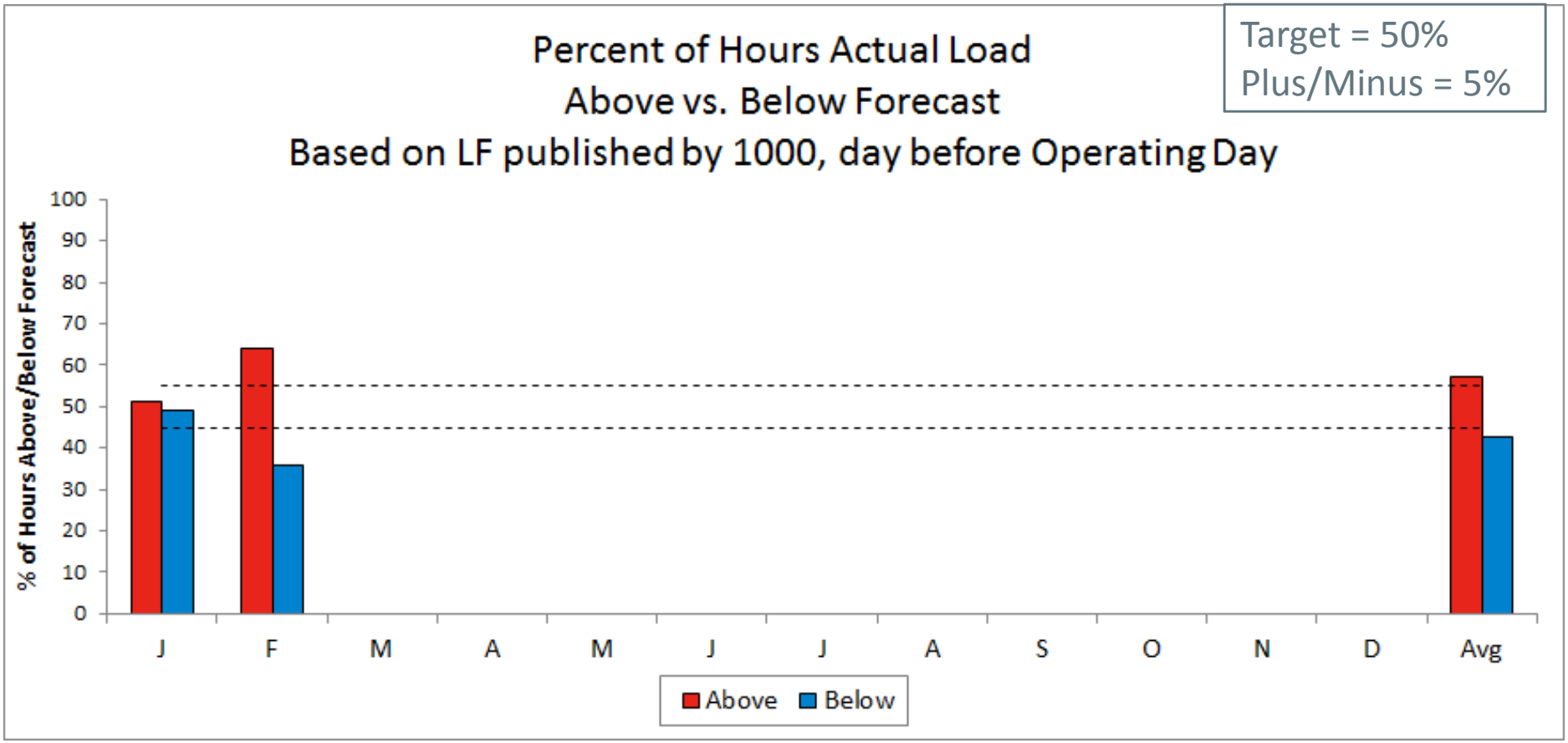
2019 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



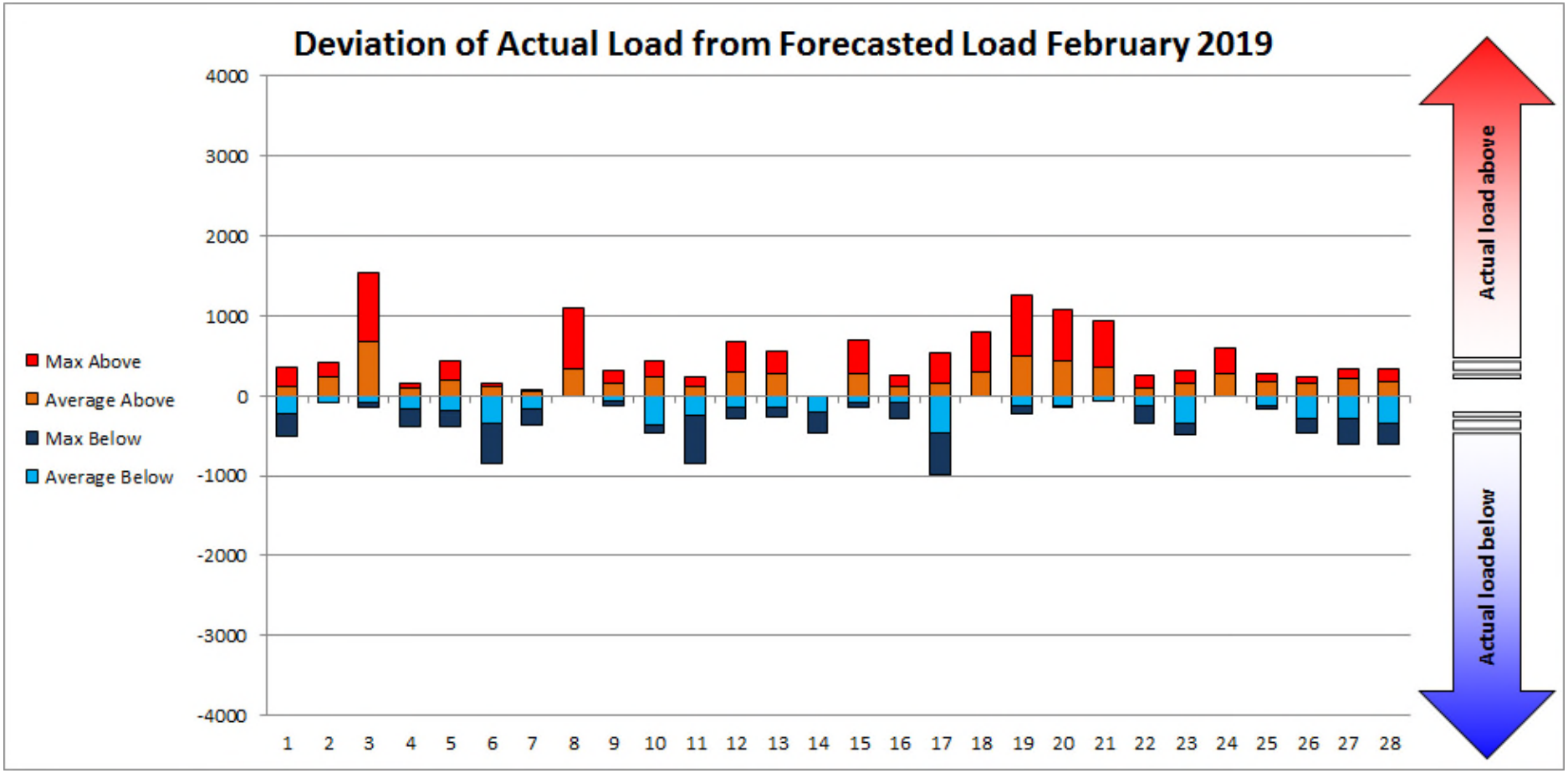
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.17	3.03											3.17
Day Min	0.02	0.06											0.02
MAPE	1.22	1.04											1.13
Goal	1.80	1.80											

2019 System Operations - Load Forecast Accuracy cont.

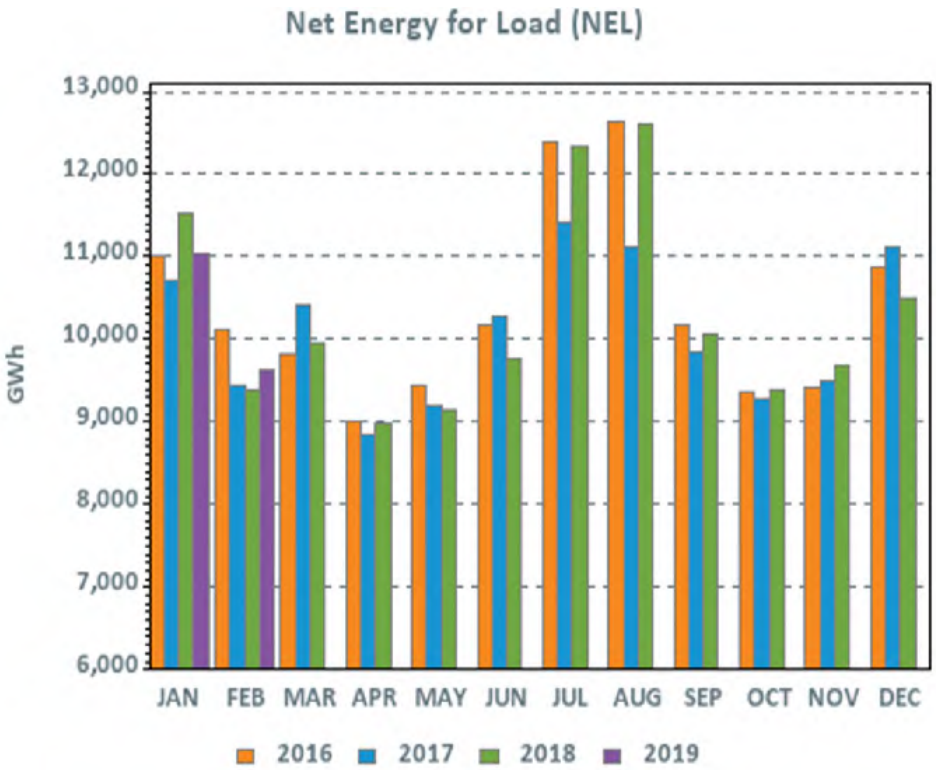


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	51.1	64											57
Below %	48.9	36											43
Avg Above	211.7	224.2											224
Avg Below	-183.0	-174.3											-183
Avg All	30	88											58

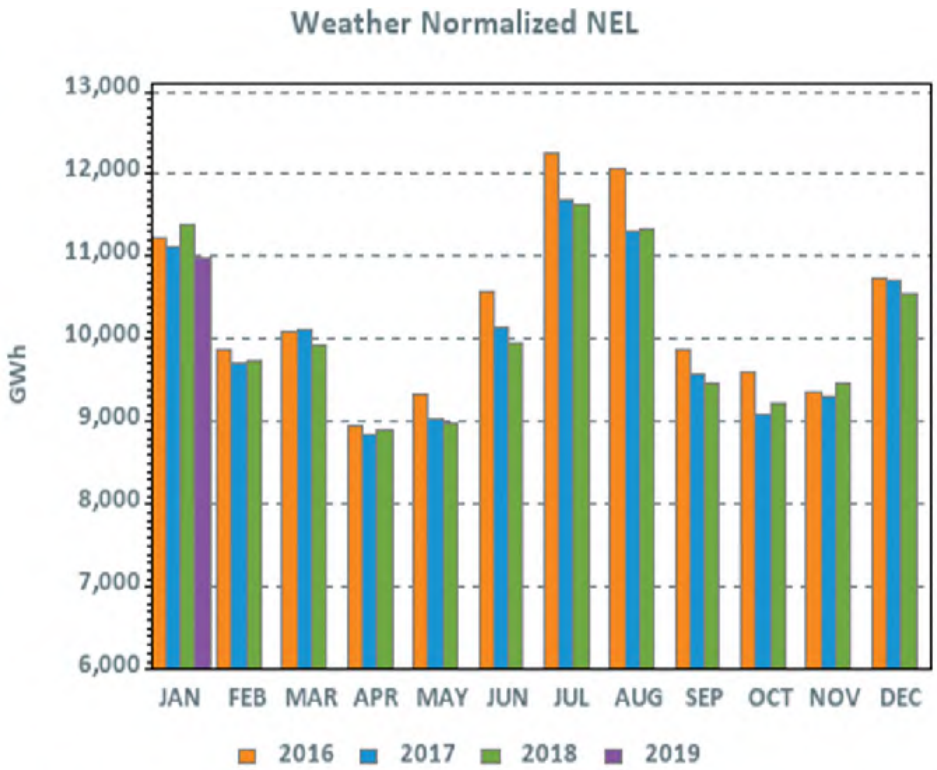
2019 System Operations - Load Forecast Accuracy cont.



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



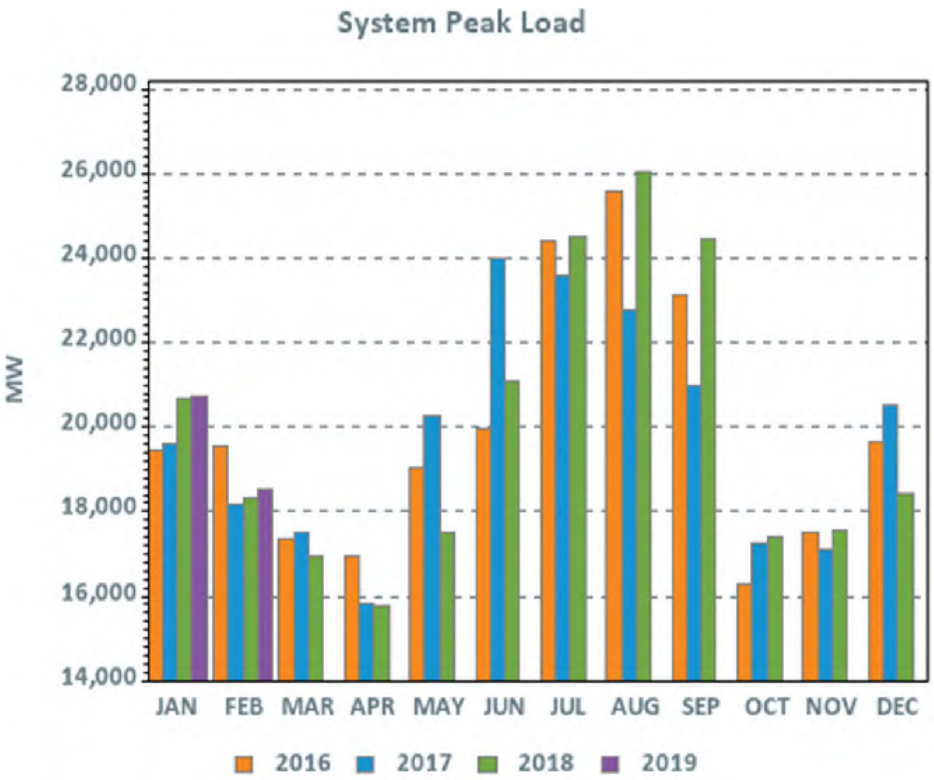
Ann Tot (TWh): 124.4 121.2 123.3 20.7



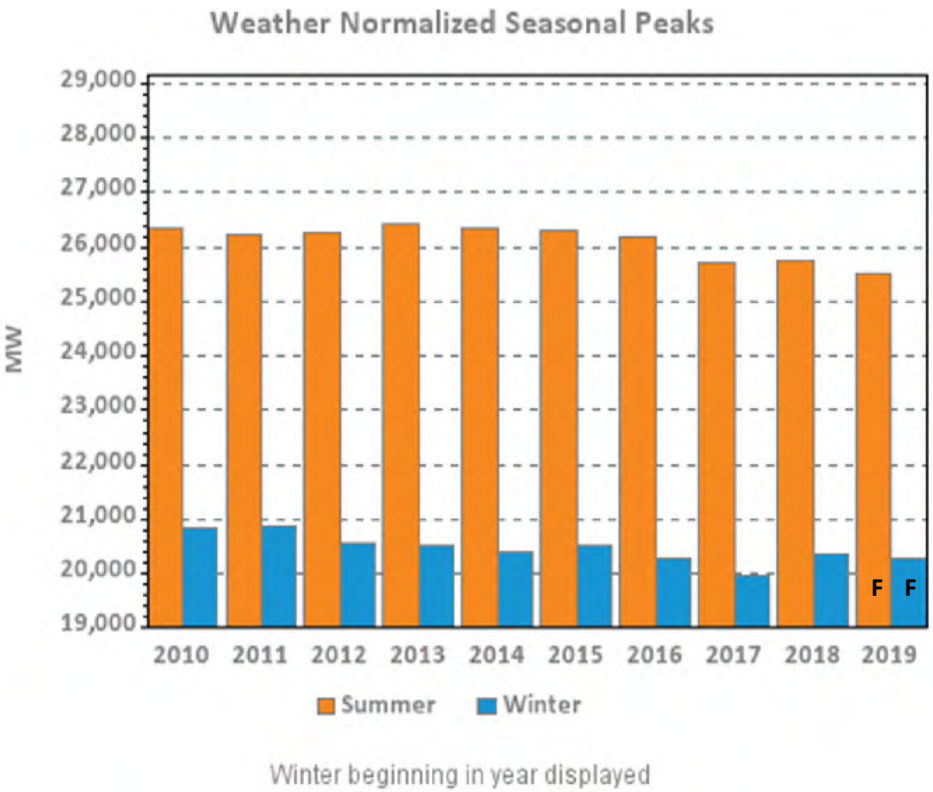
Ann Tot (TWh): 124.0 120.7 120.6 11.0

NEPOOL NEL is the total net revenue quality metered 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



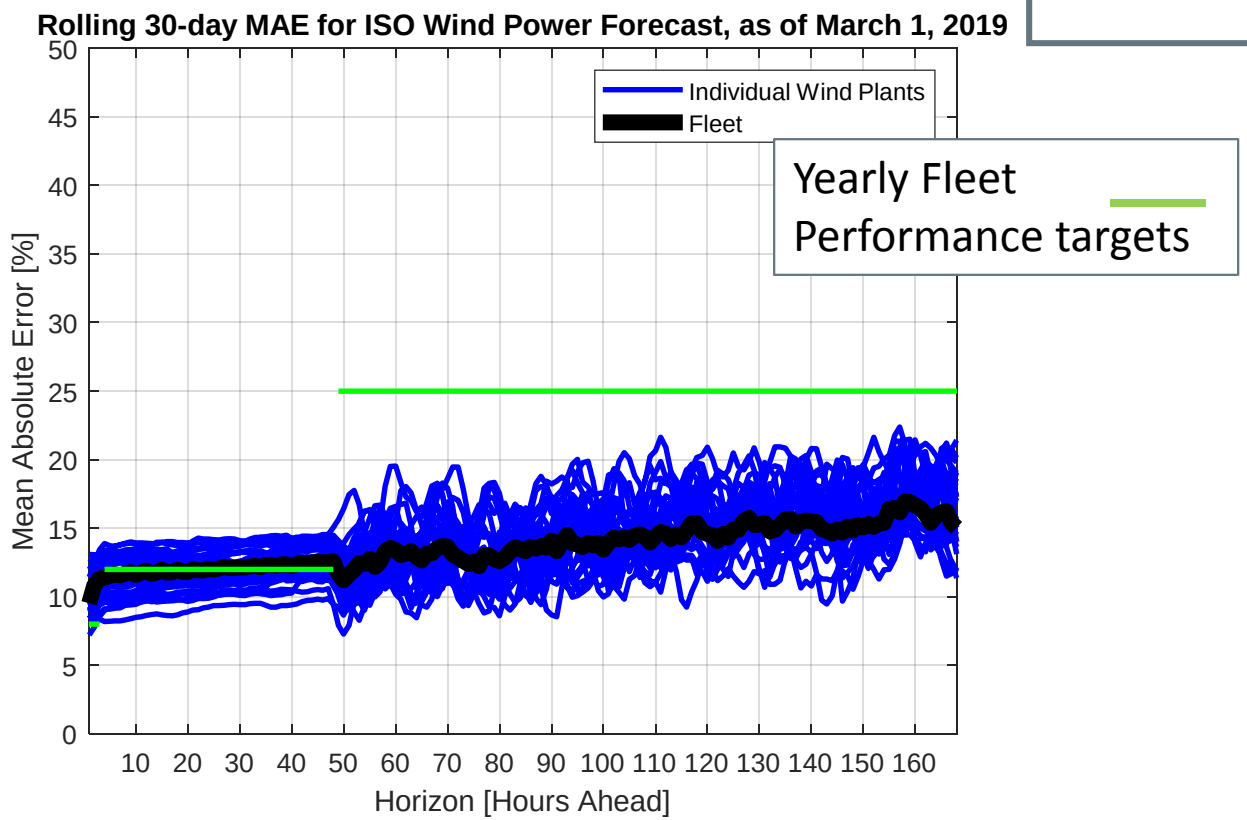
*Revenue quality metered value



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

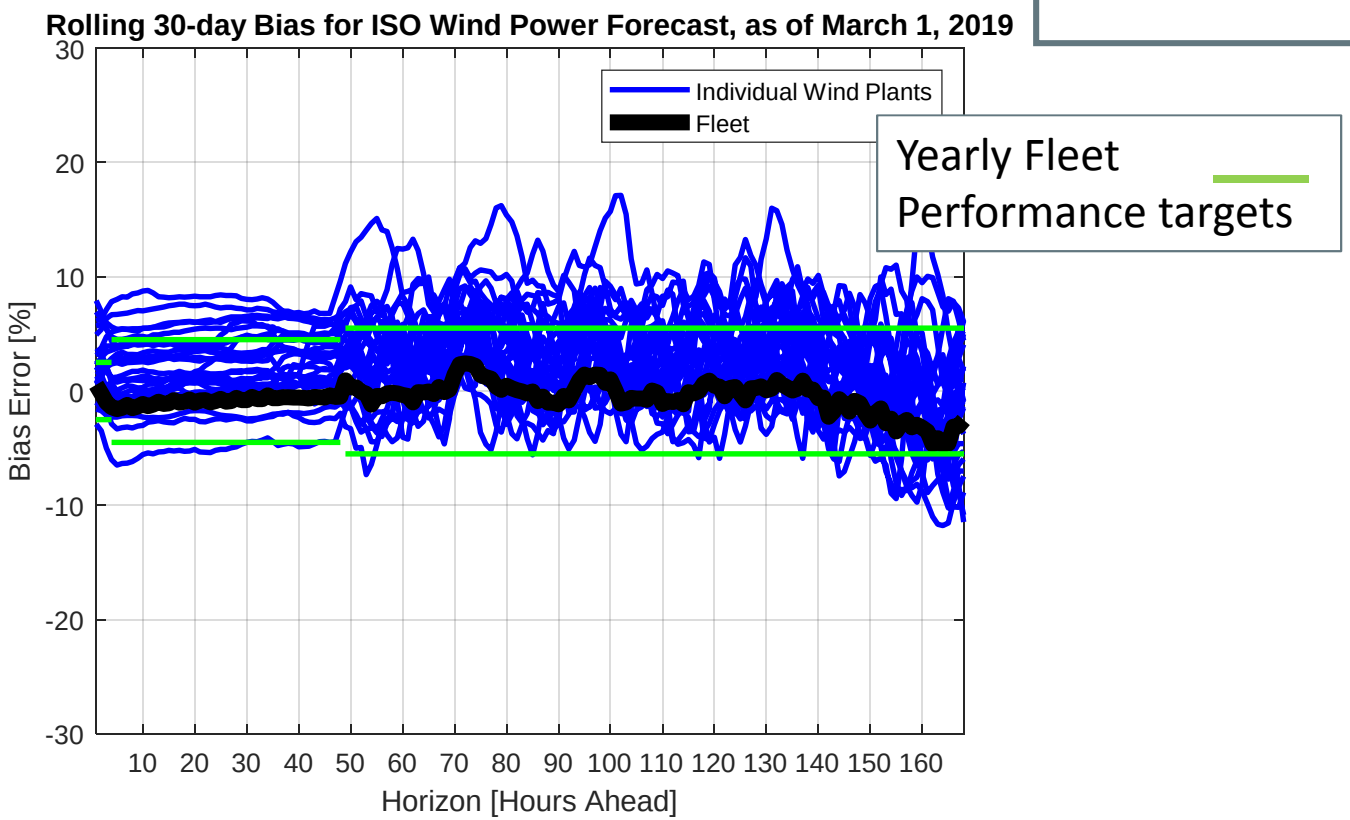
Dashboard Indicator



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 for almost all hours.

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

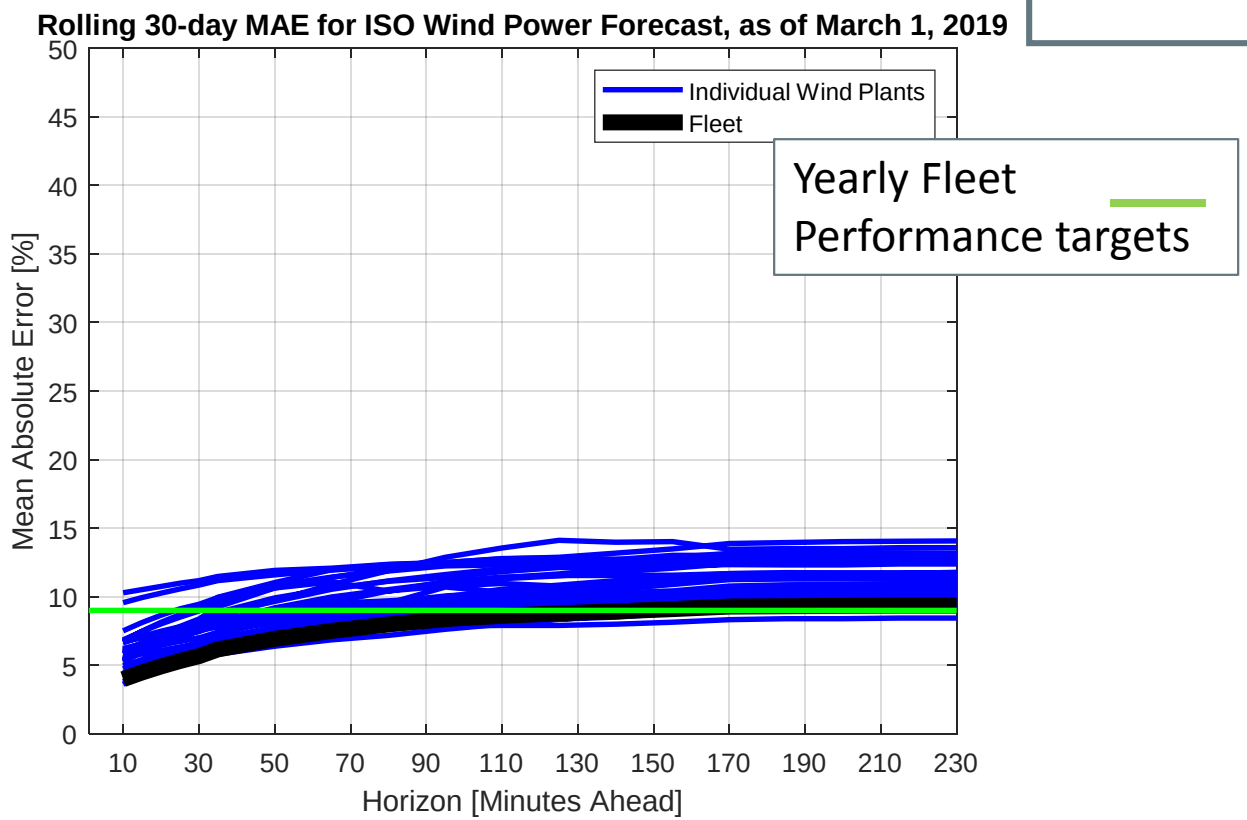
Dashboard Indicator



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

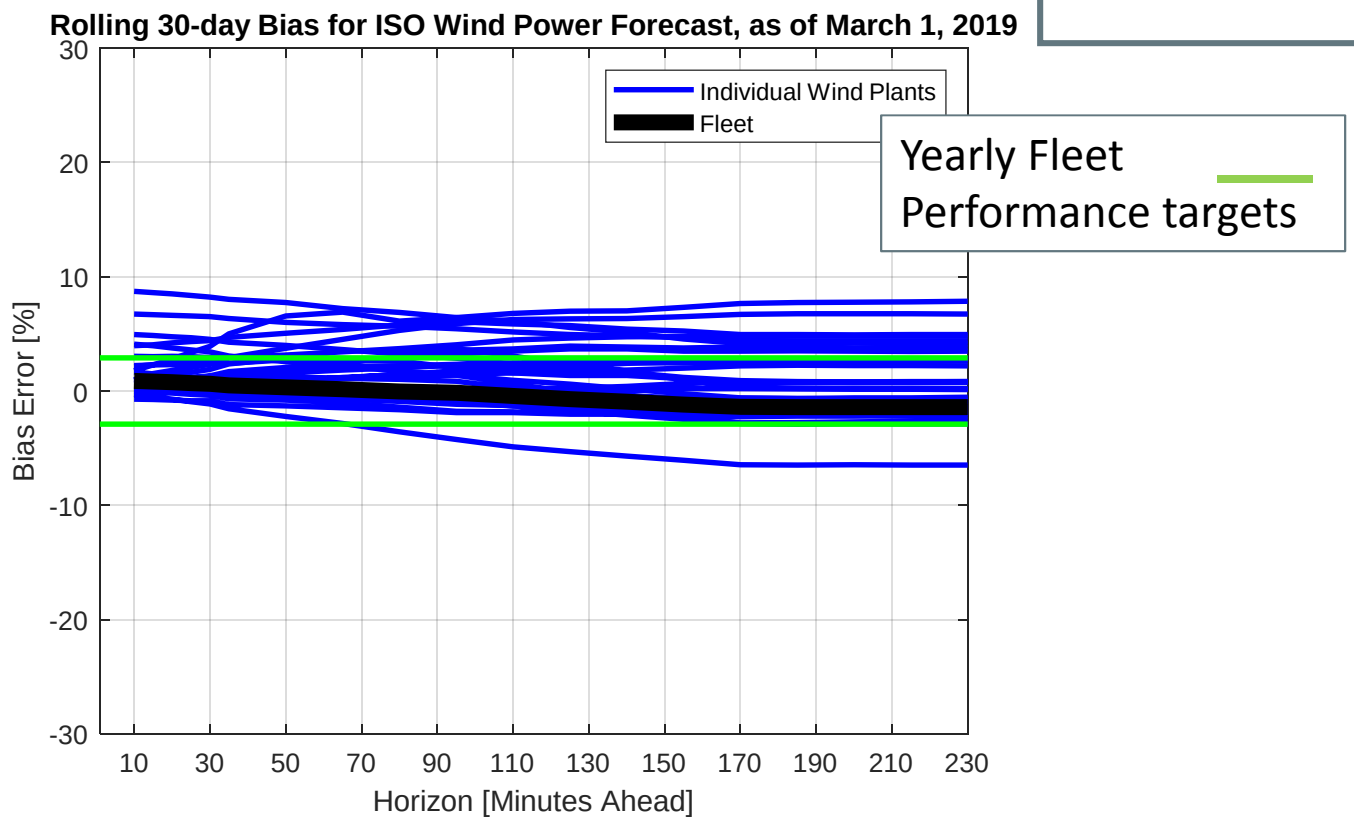
Dashboard Indicator



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: Short Term Forecast Bias

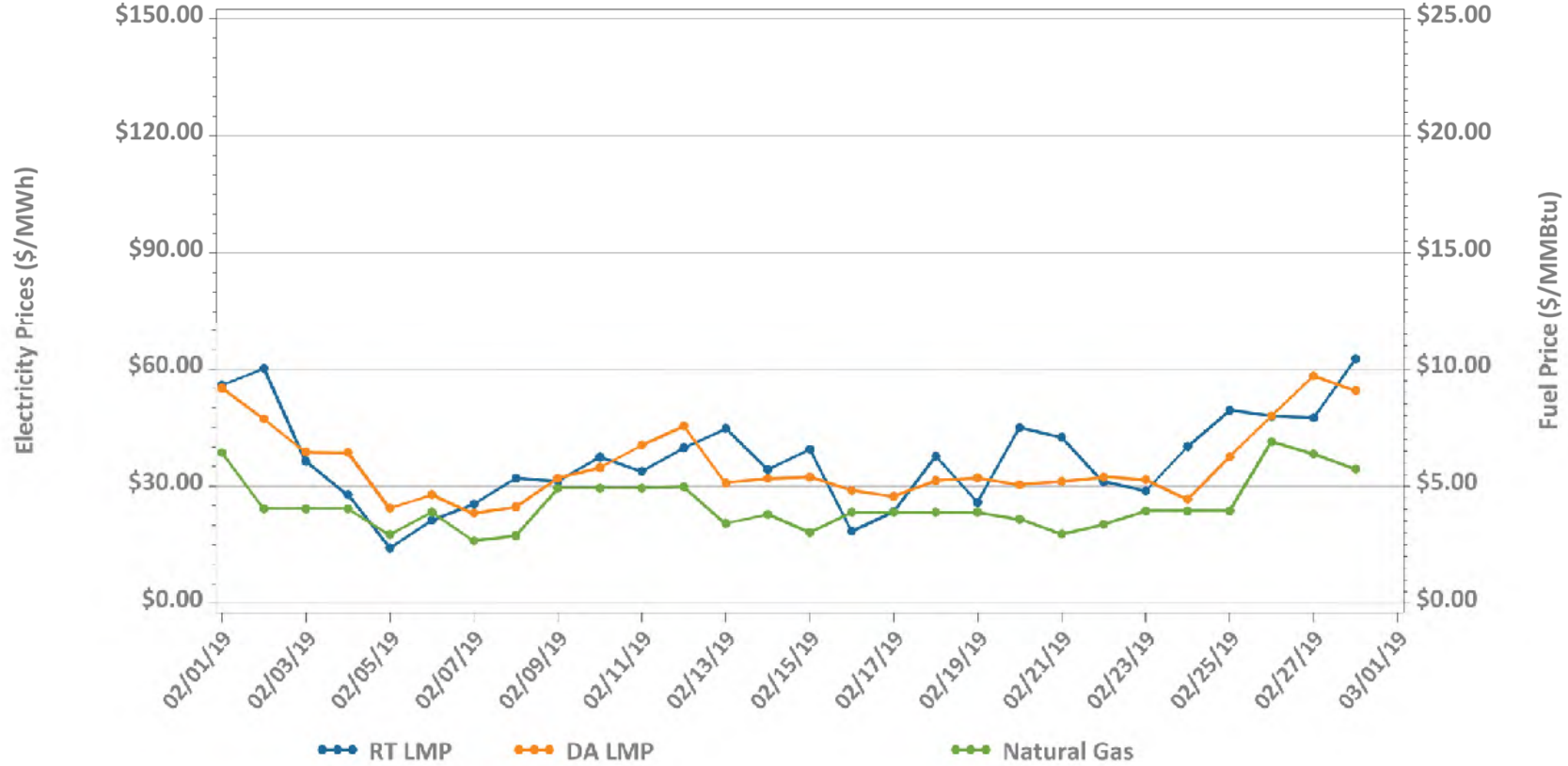
Dashboard Indicator



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: February 1-28, 2019

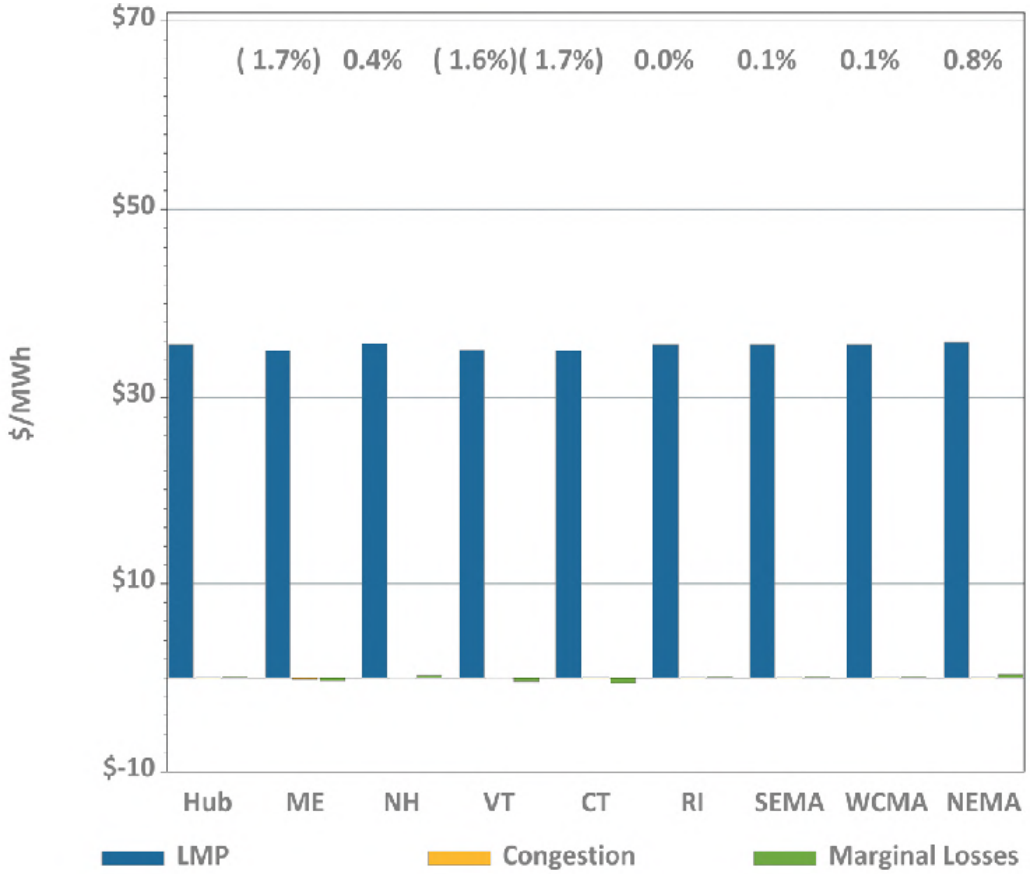


Underlying natural gas data furnished by:

ICE Global markets in clear view

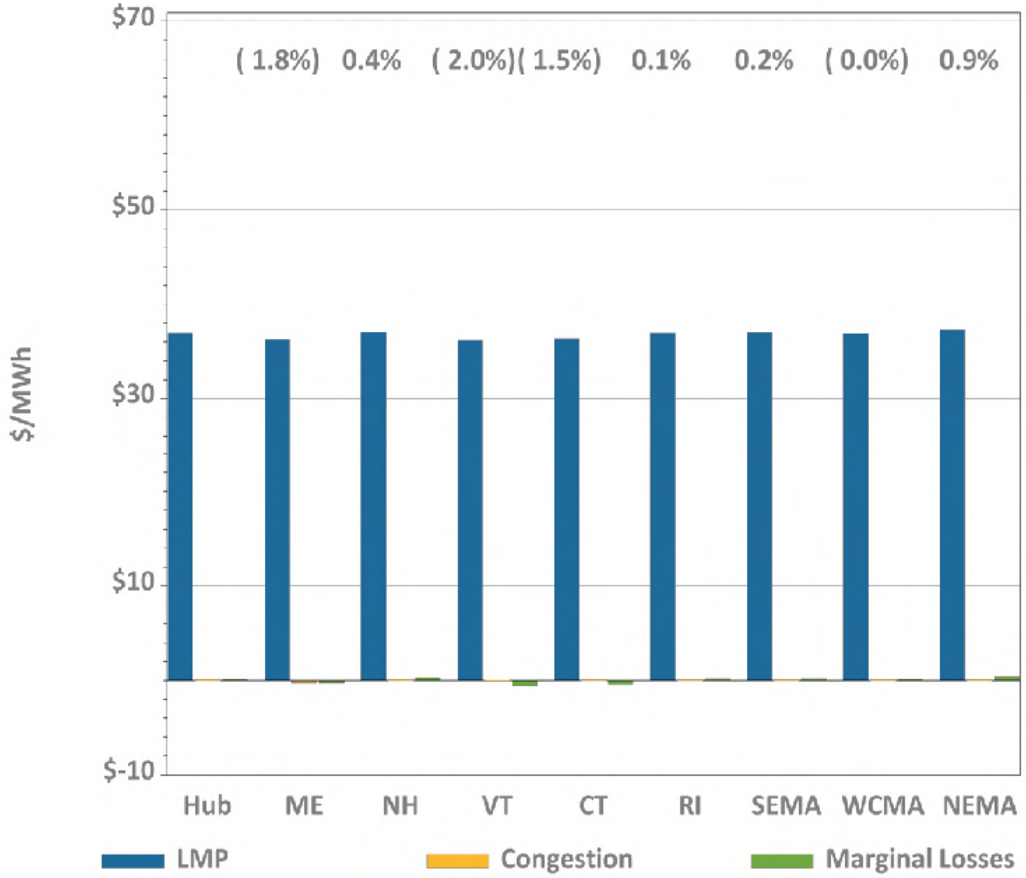
Average price difference over this period (DA-RT): $-1.30
Average price difference over this period ABS(DA-RT): $6.90
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 19%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, February 2019



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

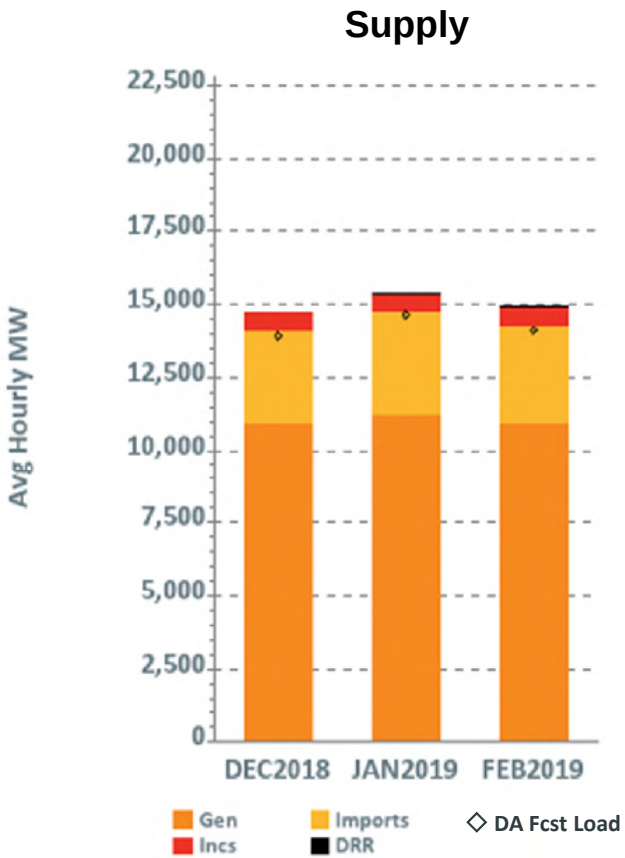
RT LMPs Average by Zone & Hub, February 2019

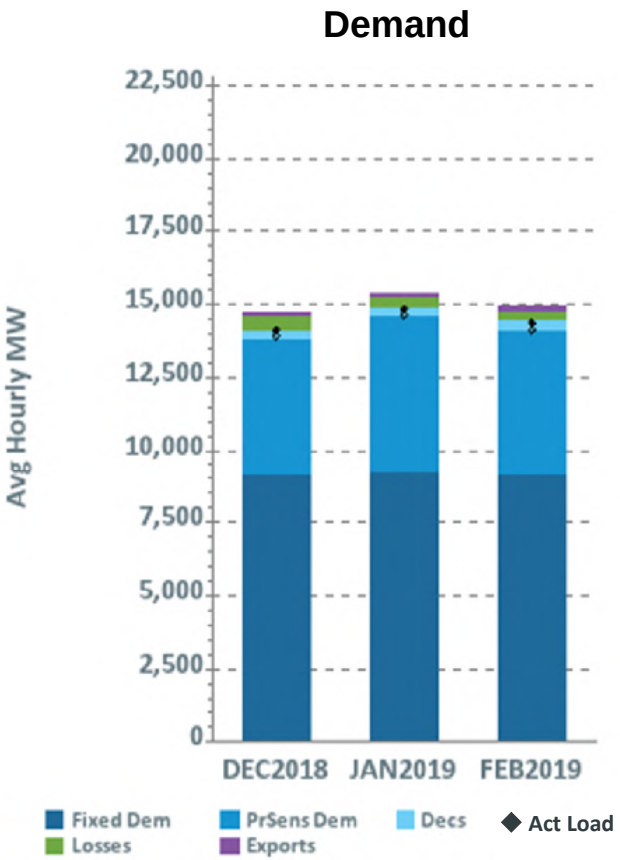


Definitions

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

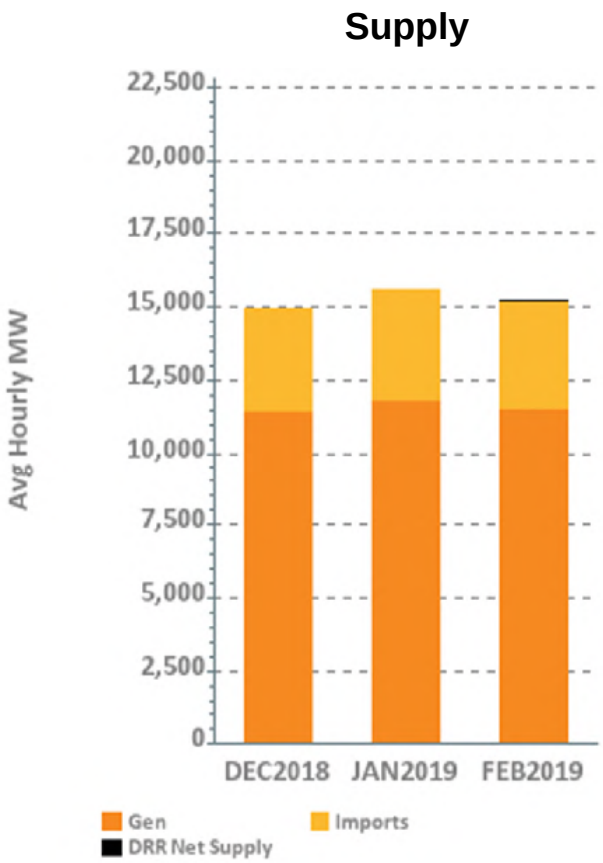


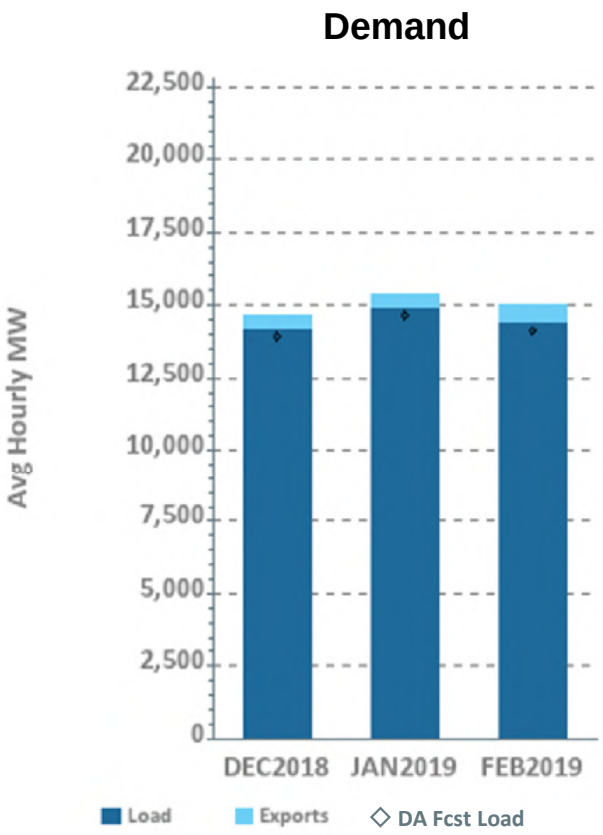


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

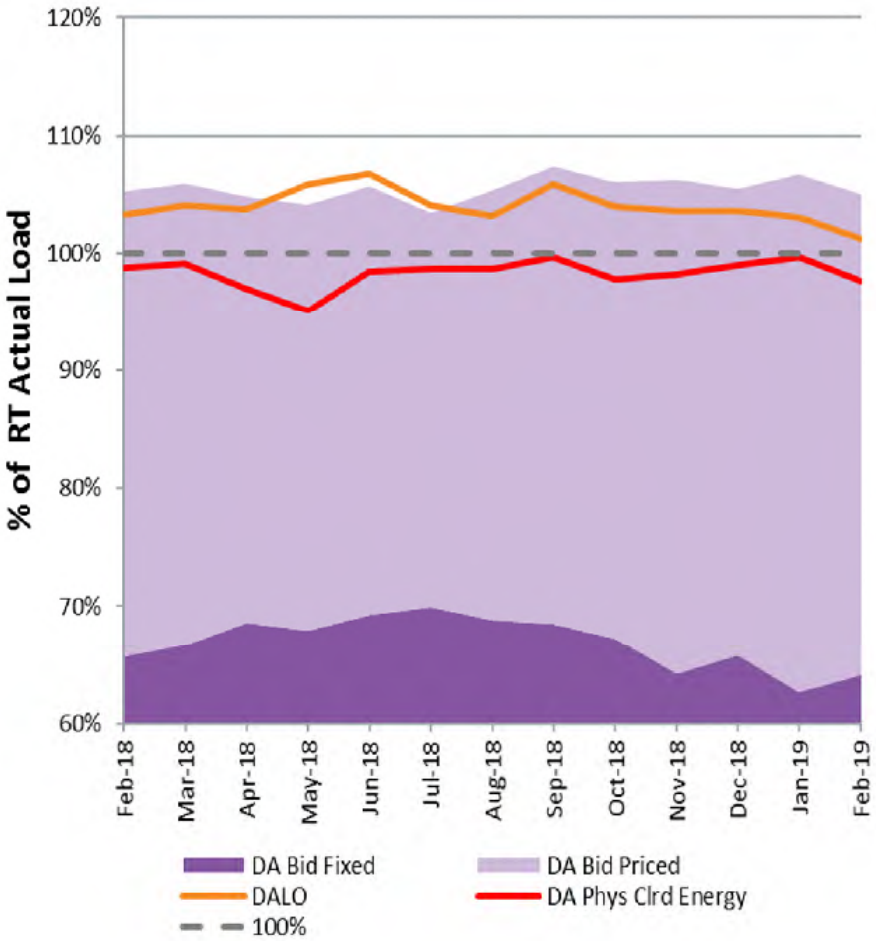
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

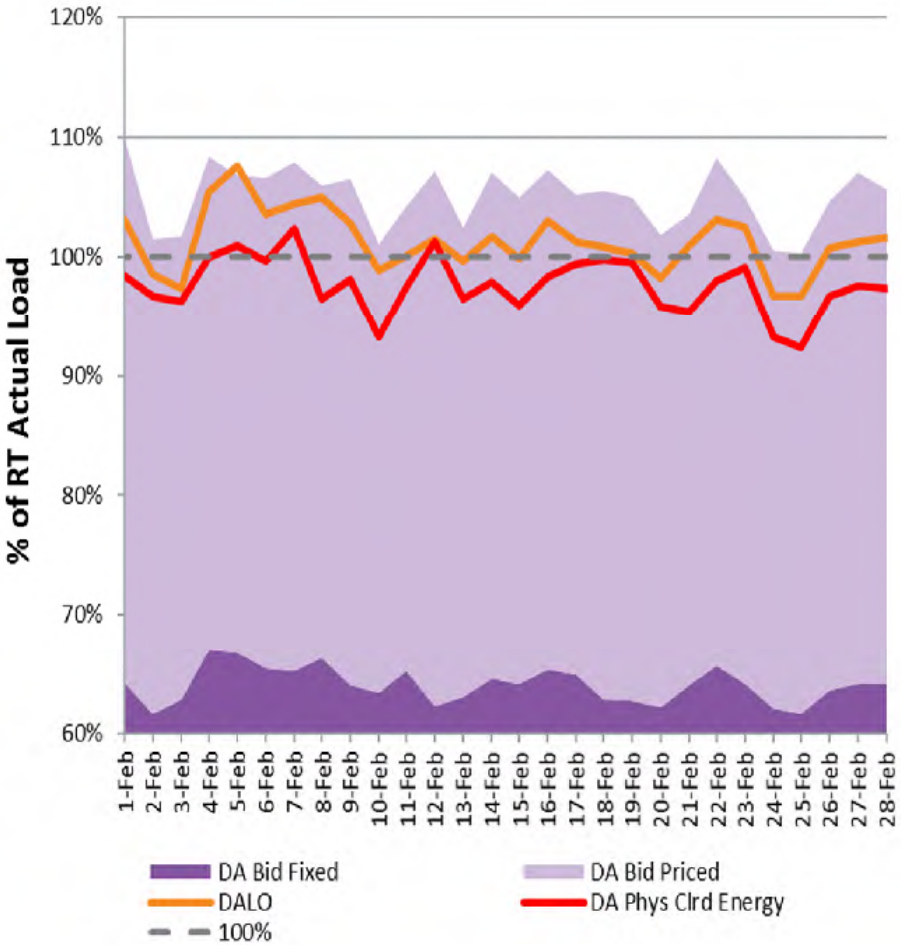
Components of RT Supply and Demand – Last Three Months





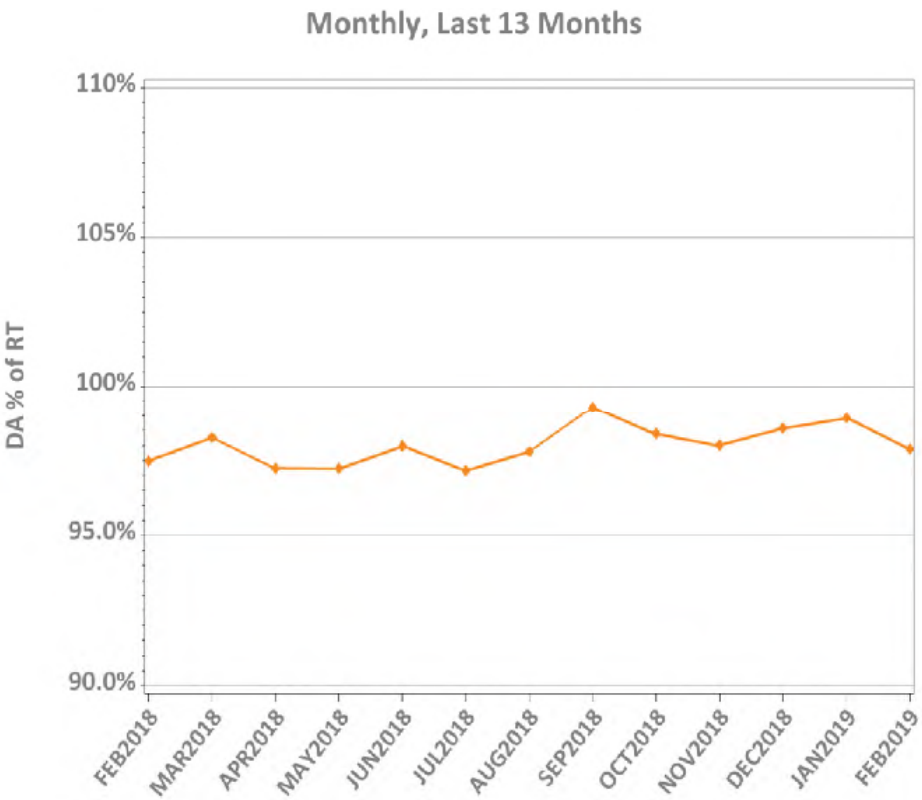
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

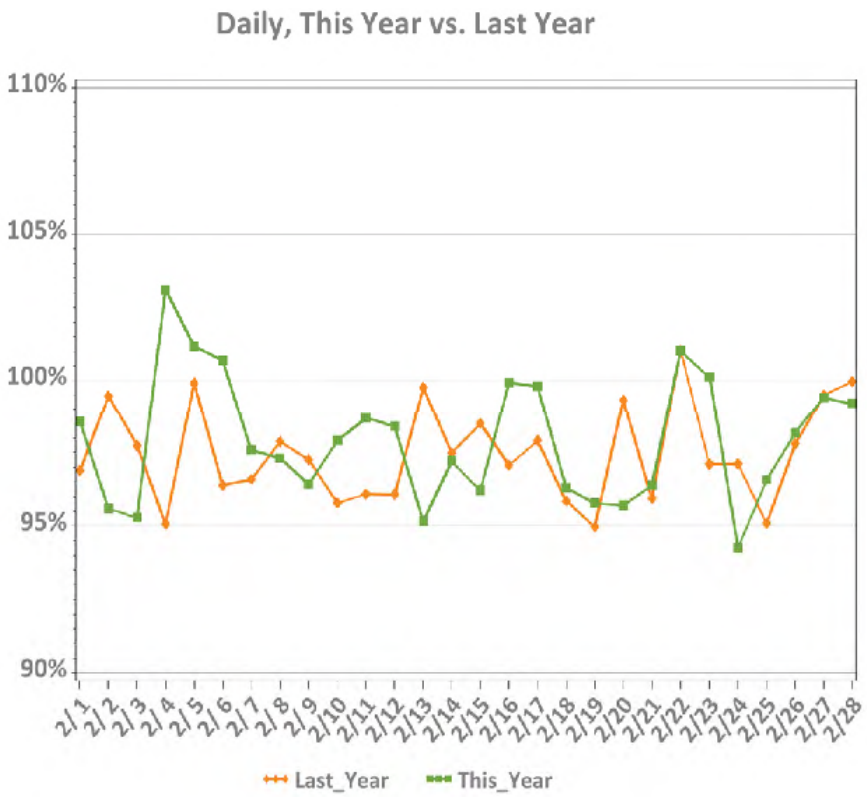




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

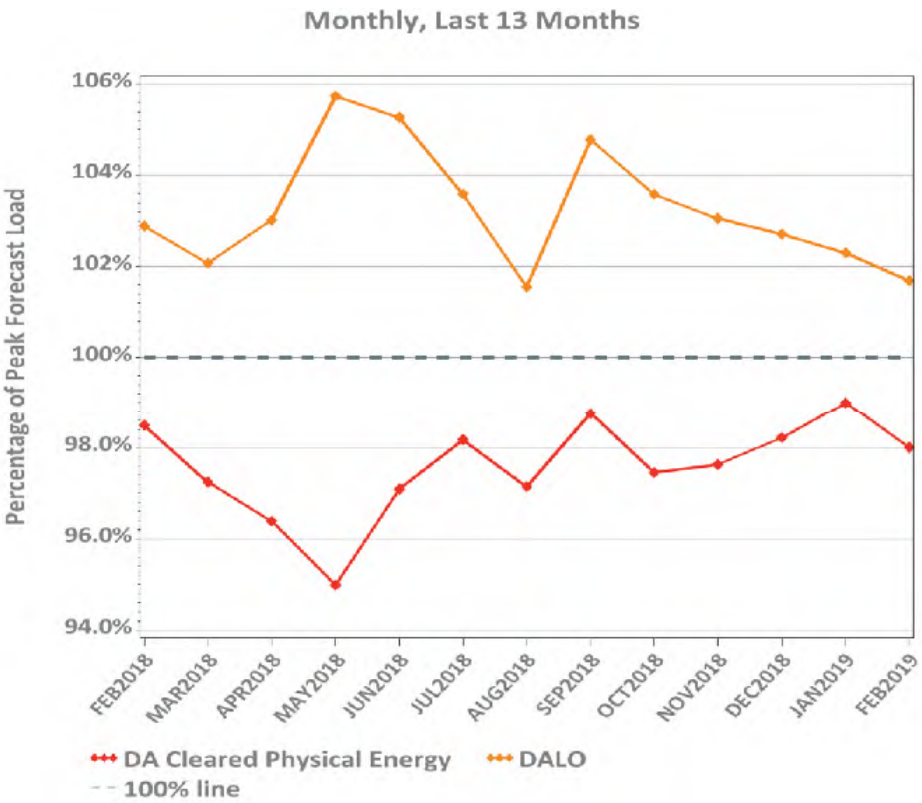
DA vs. RT Load Obligation: February, This Year vs. Last Year

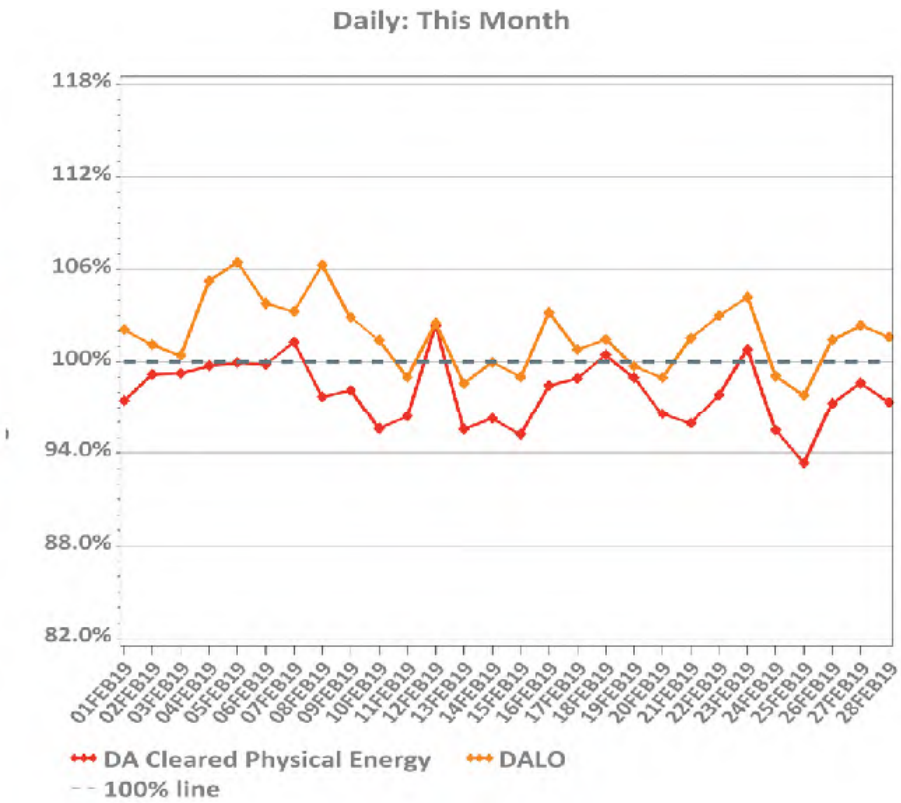




*Hourly average values

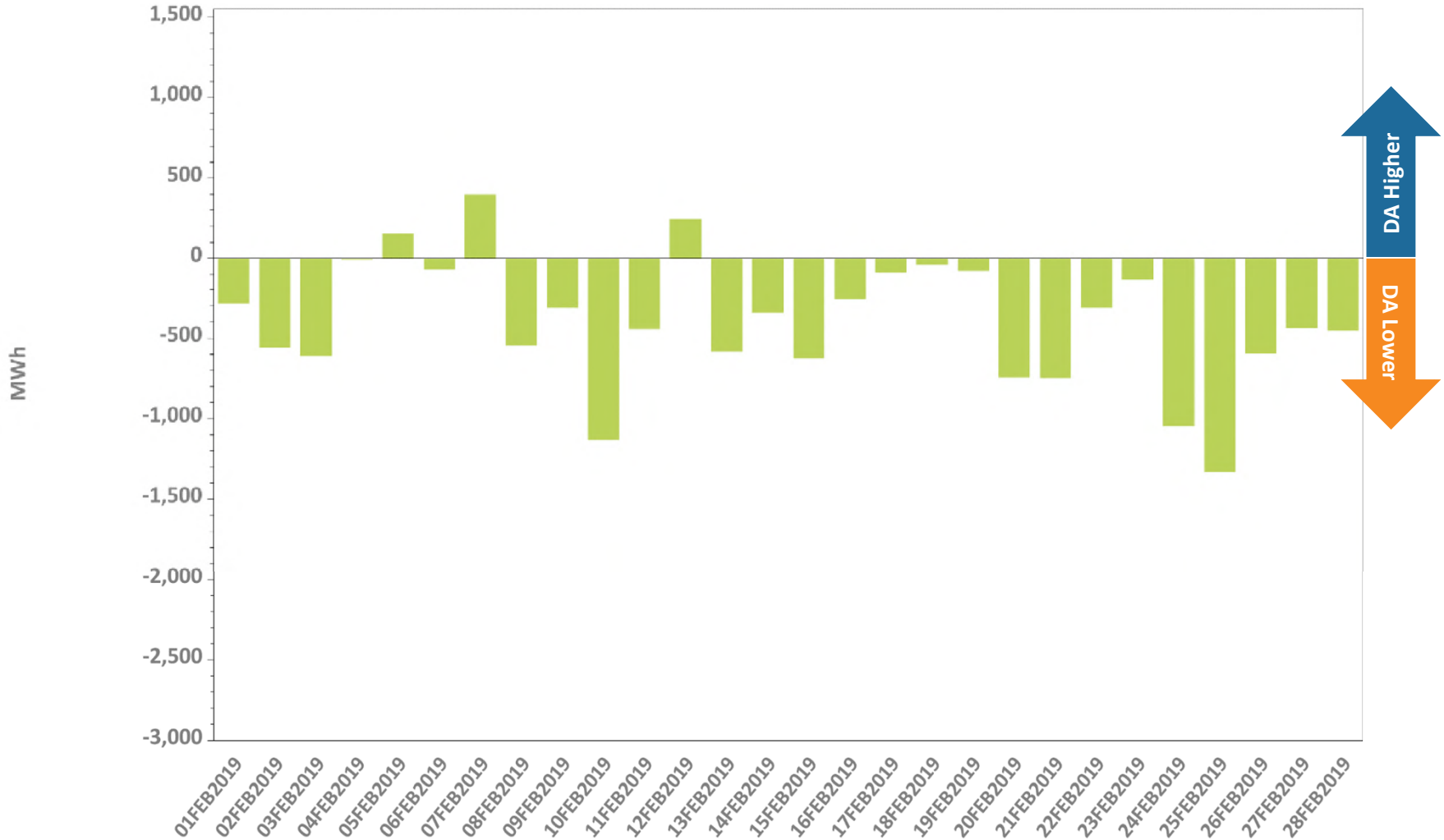
DA Volumes as % of Forecast in Peak Hour





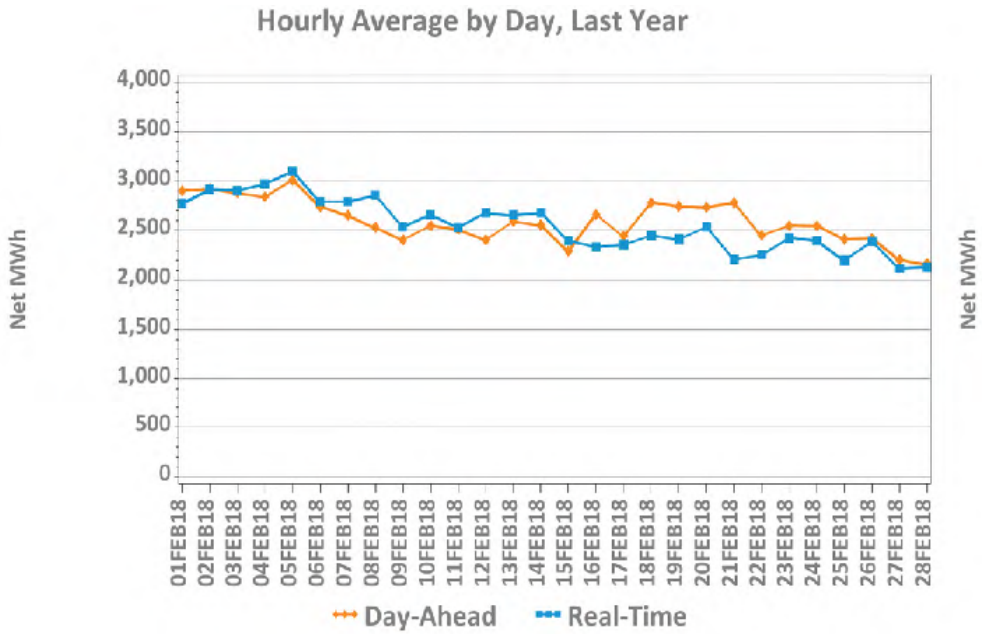
***There were no supplemental commitments required for capacity during the Reserve Adequacy Assessment (RAA) during February.**

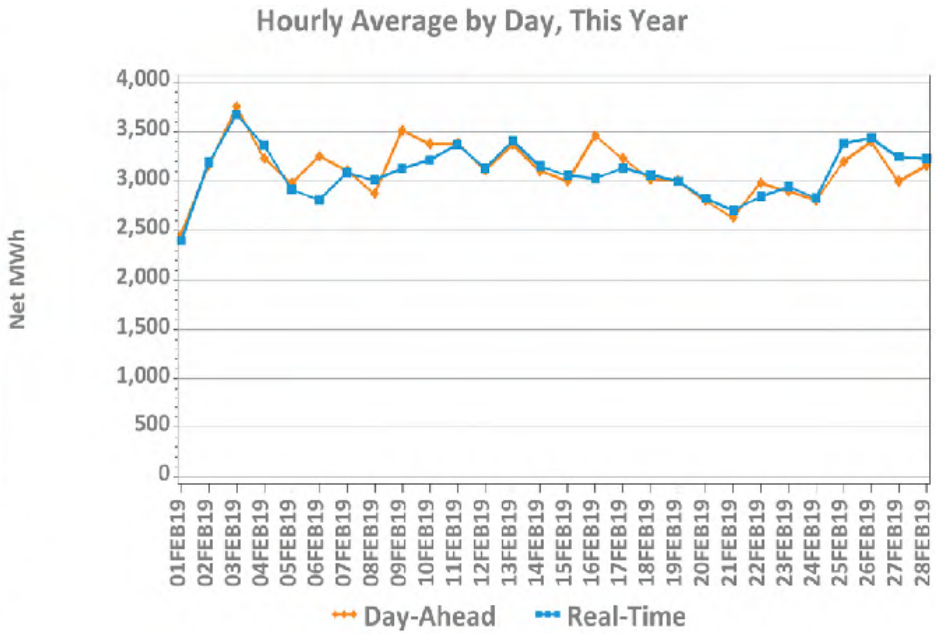
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

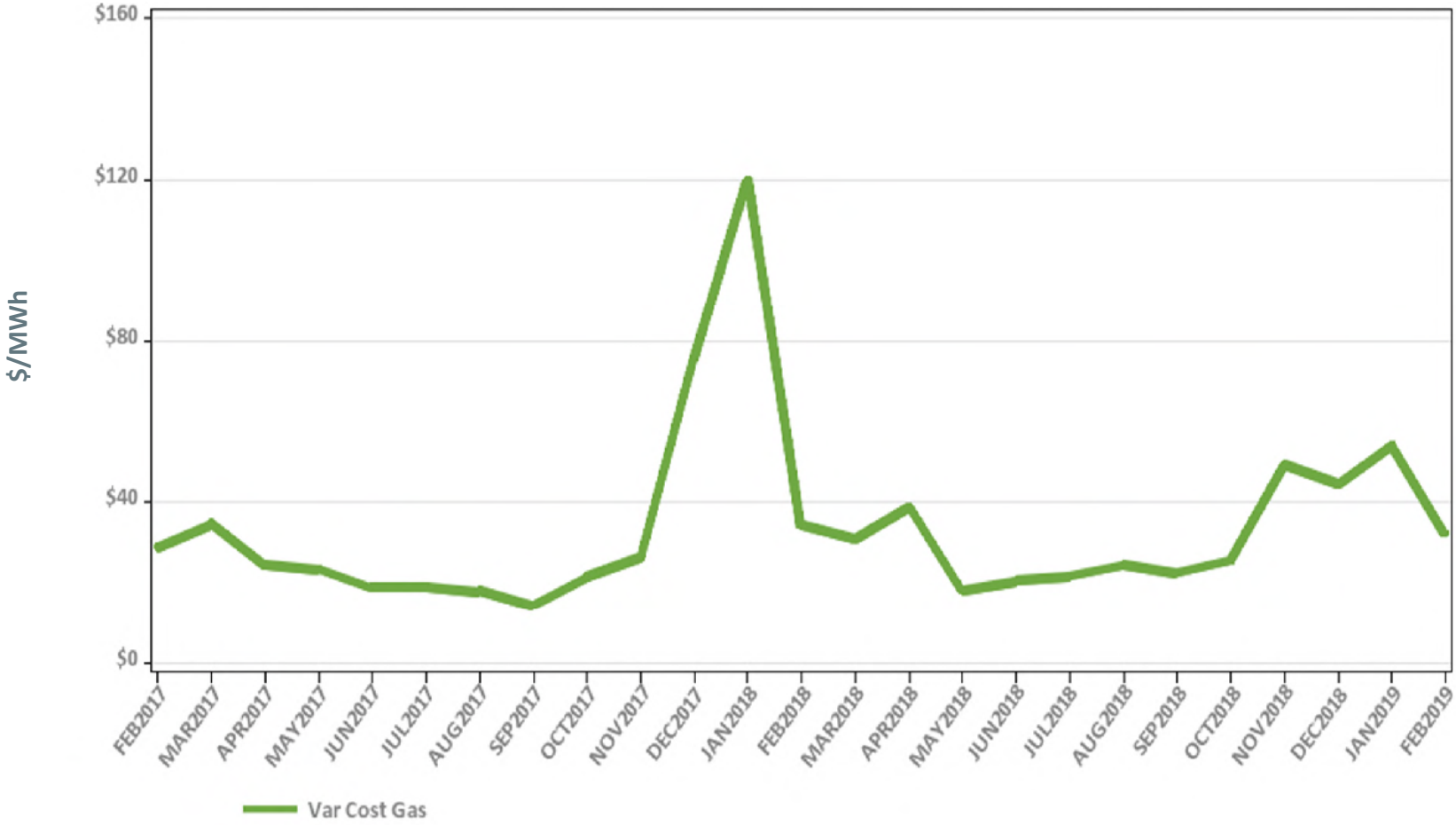
DA vs. RT Net Interchange February 2019 vs. February 2018





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

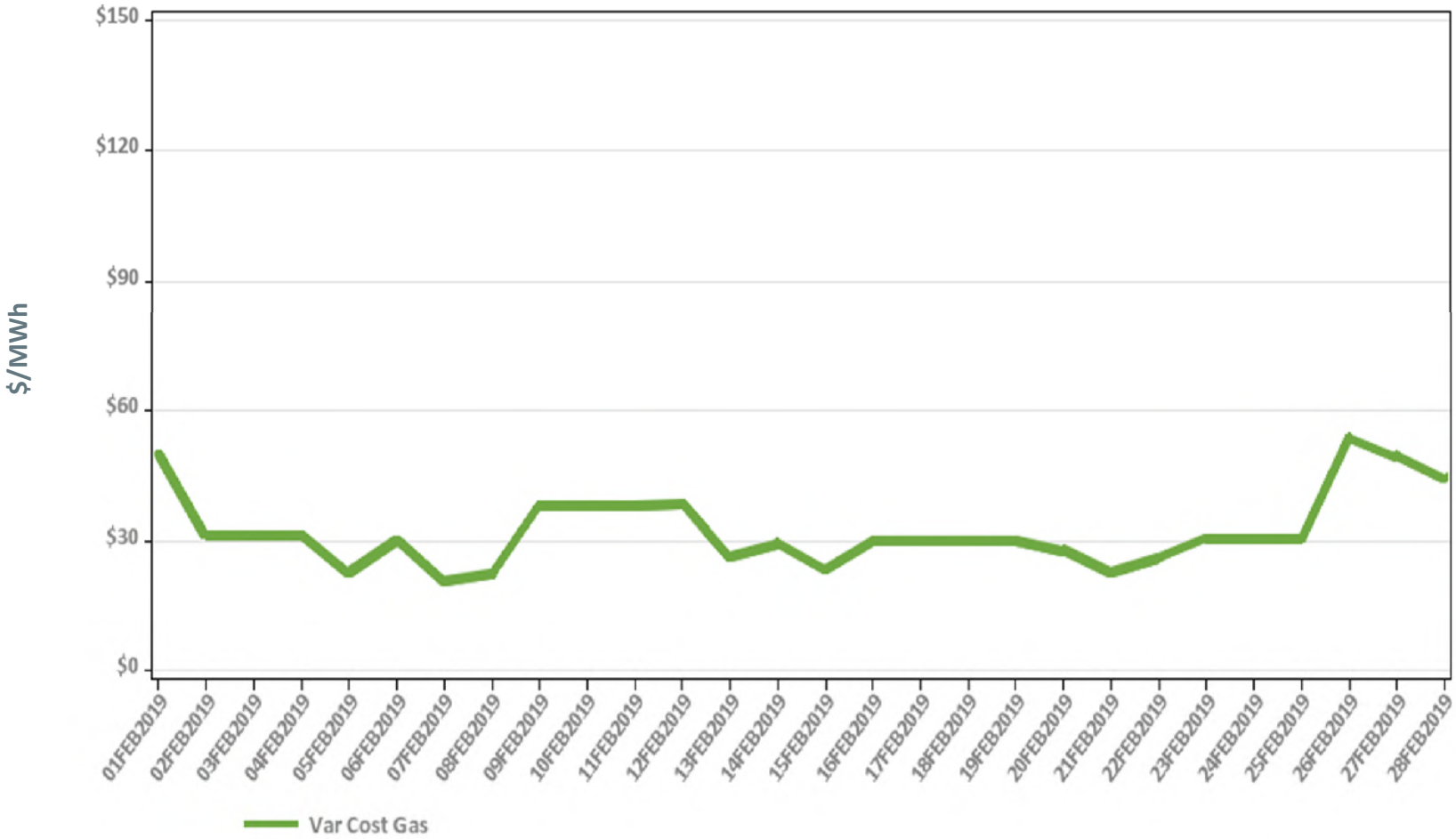


Underlying natural gas data furnished by:

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

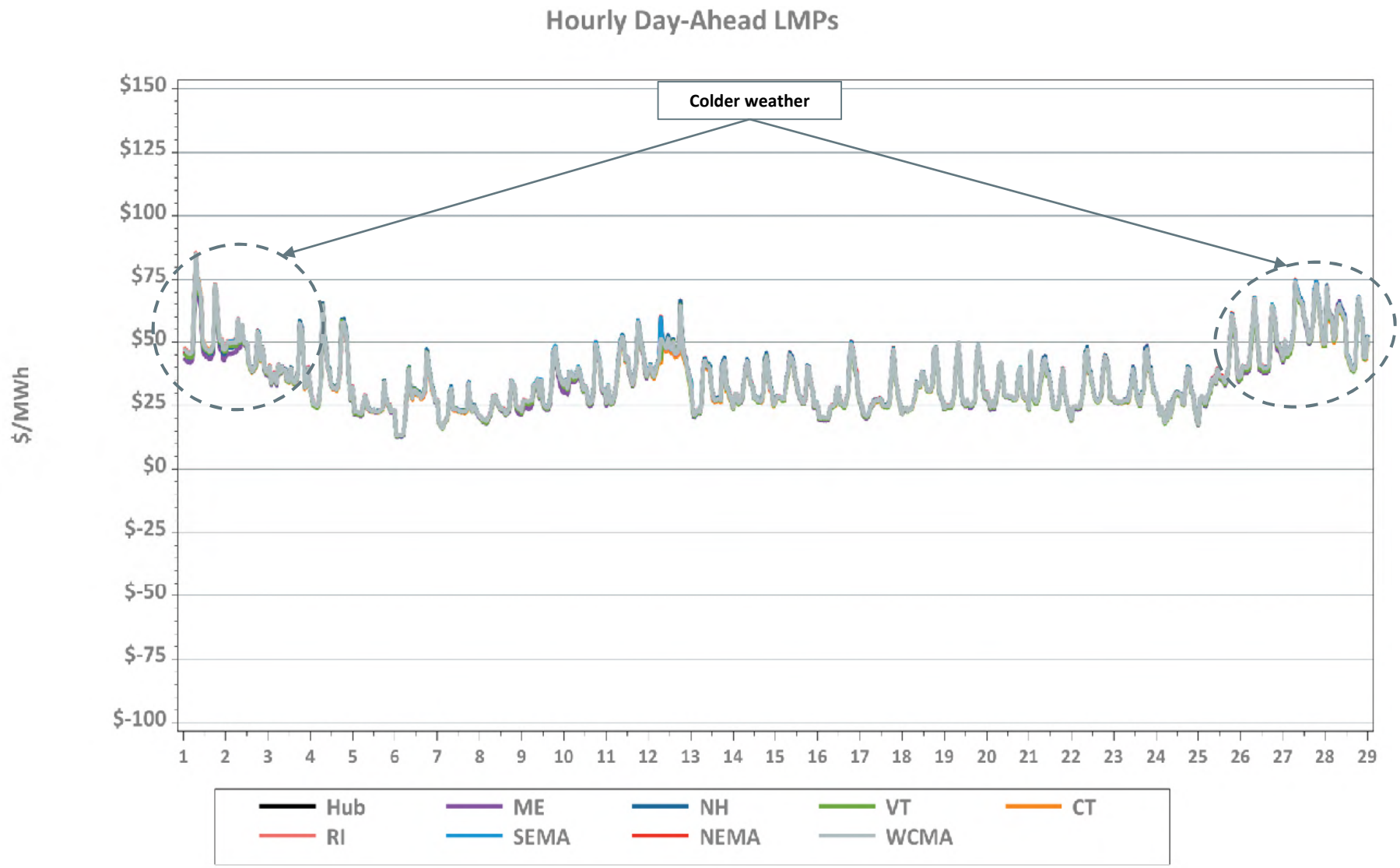


Underlying natural gas data furnished by:

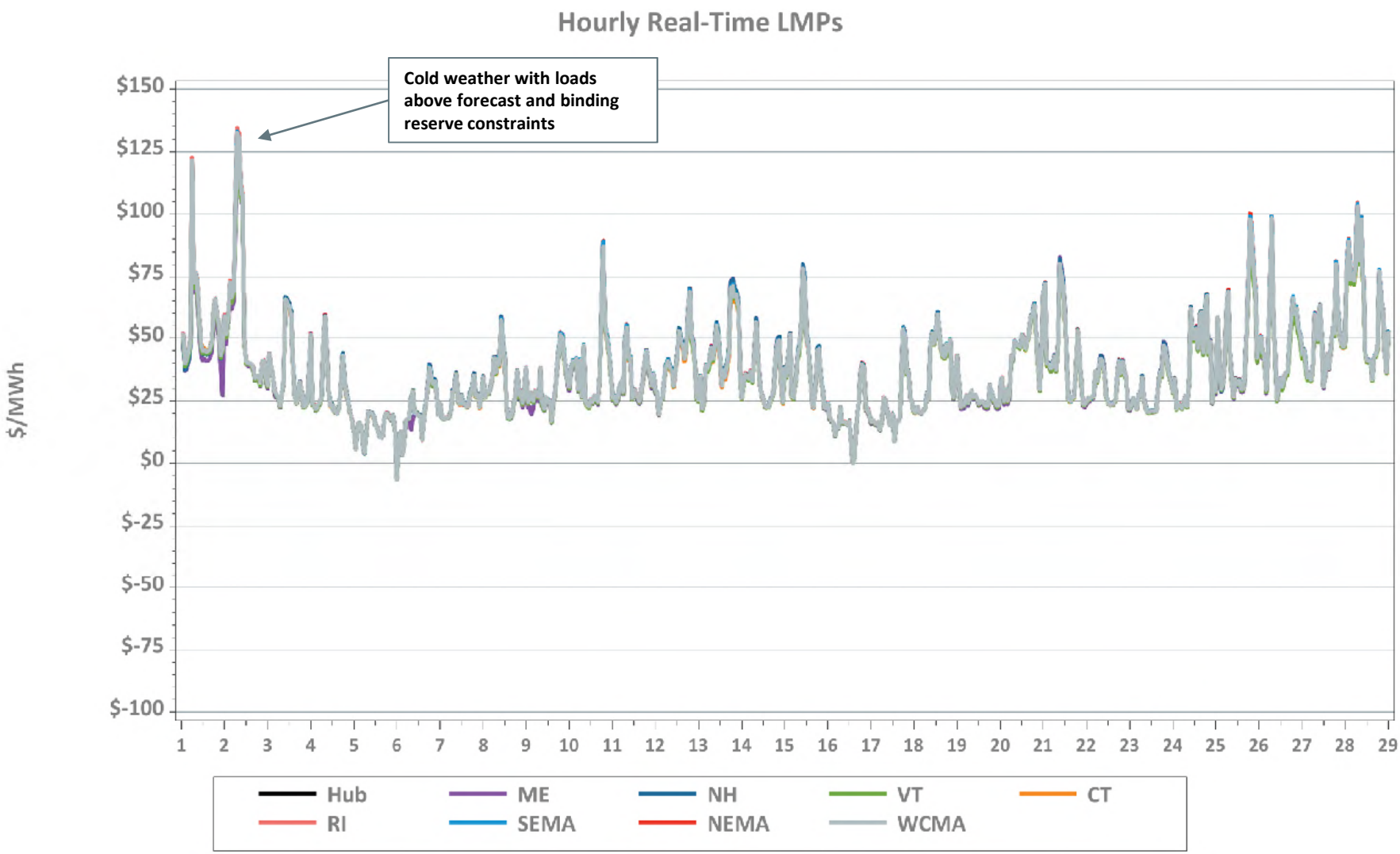
ICE Global markets in clear view

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

Hourly DA LMPs, February 1-28, 2019

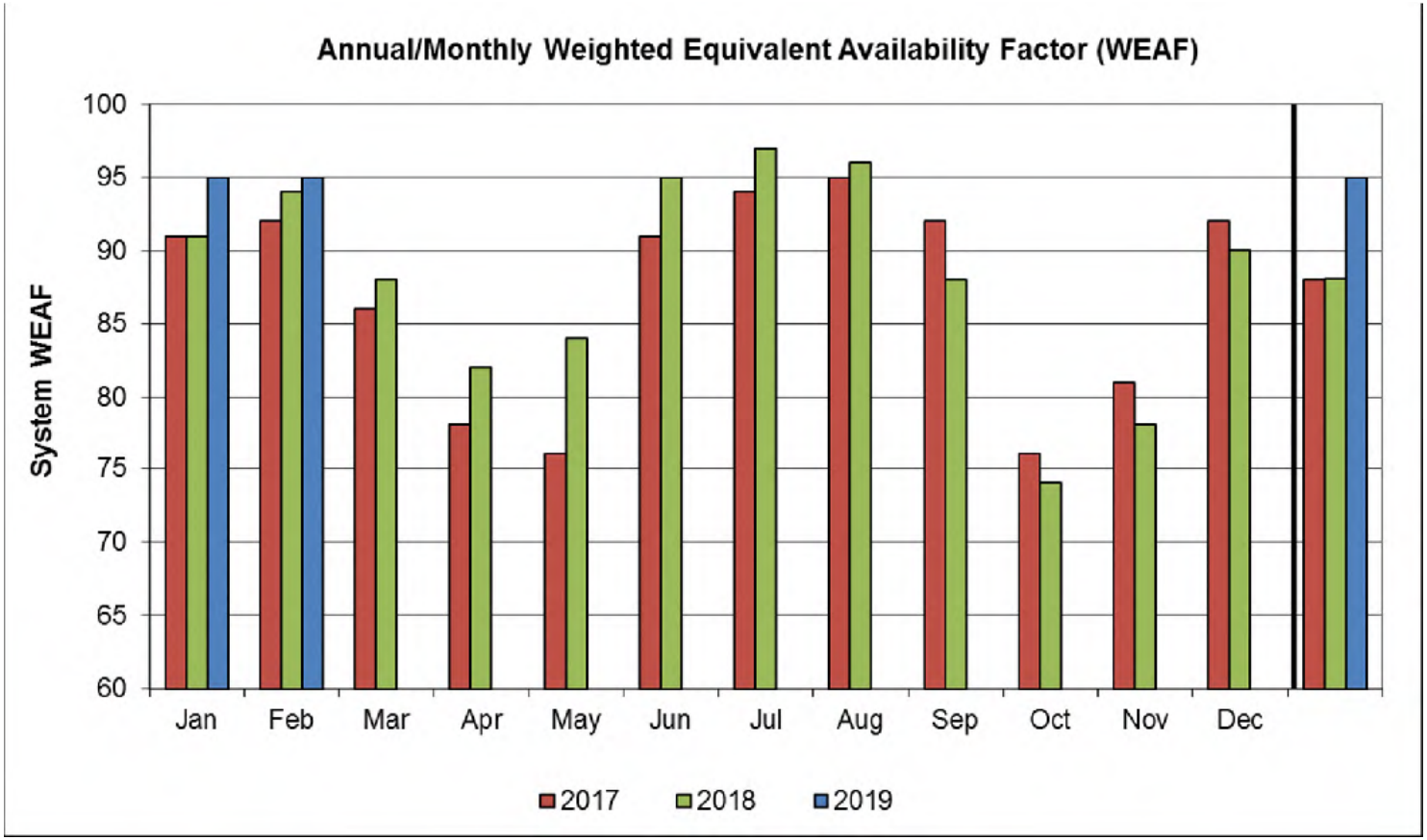


Hourly RT LMPs, February 1-28, 2019



- No Minimum Generation Emergencies were declared in February.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2019	95	95											95
2018	91	94	88	82	84	95	97	96	88	74	78	90	88
2017	91	92	86	78	76	91	94	95	92	76	81	92	88

Data as of 3/1/19

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for March 2019

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	107.1	174.7	0.0	281.7
NH	16.2	91.1	0.0	107.3
VT	25.1	141.9	0.0	166.9
CT	85.5	70.5	434.1	590.1
RI	16.5	239.8	0.0	256.3
SEMA	20.8	391.0	0.0	411.7
WCMA	33.8	367.7	40.9	442.5
NEMA	31.7	685.0	0.0	716.7
Total	**336.7**	**2,161.6**	**475.0**	**2,973.3**

*** Active Demand Capacity Resources**
NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

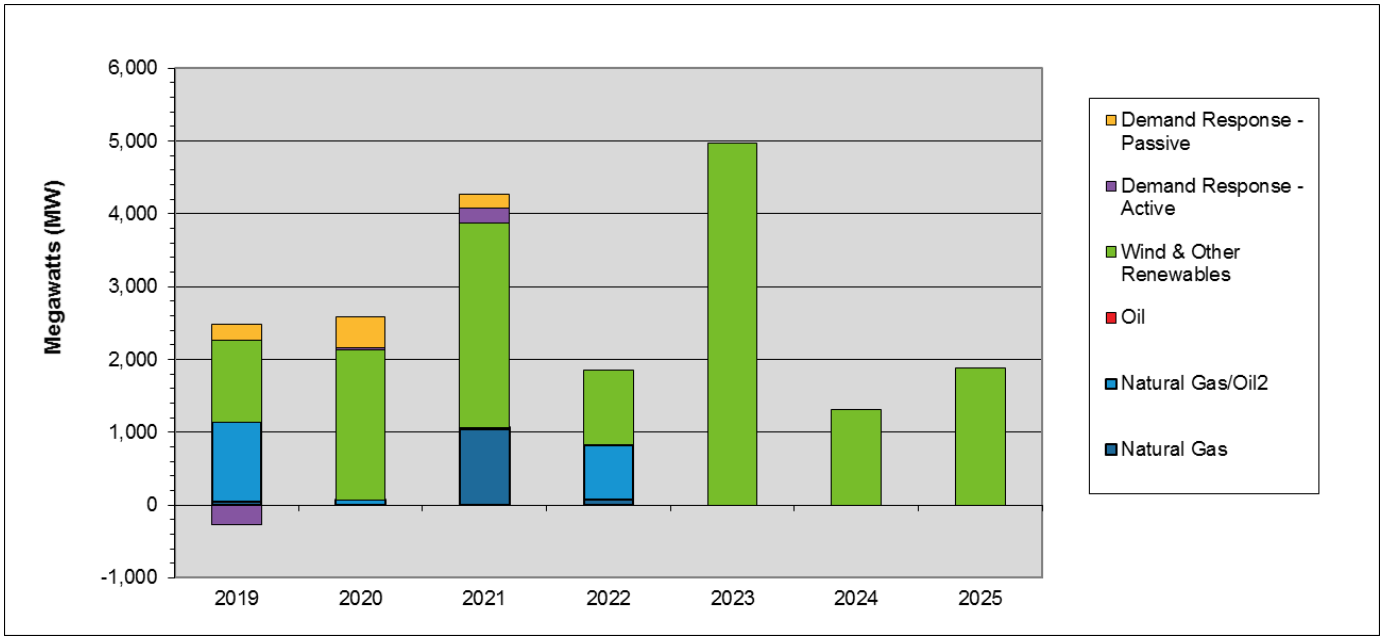
New Generation Update

Based on Queue as of 3/5/19

- 3 Solar projects totaling 36 MW applied for interconnection study since the last update, with in-service dates in 2019
- 11 projects withdrew and none went commercial resulting in a net decrease in new generation projects of 2,283 MW
- In total, 152 generation projects are currently being tracked by the ISO, totaling approximately 18,300 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2019	2020	2021	2022	2023	2024	2025	Total MW	% of Total[1]
Demand Response - Passive	212	422	184	0	0	0	0	819	4.3
Demand Response - Active	-270	42	204	0	0	0	0	-23	-0.1
Wind & Other Renewables	1,130	2,057	2,807	1,027	4,972	1,312	1,884	15,189	79.6
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	1,097	62	23	755	0	0	0	1,937	10.1
Natural Gas	43	6	1,045	73	0	0	0	1,167	6.1
Totals	**2,213**	**2,590**	**4,263**	**1,855**	**4,972**	**1,312**	**1,884**	**19,089**	**100.0**

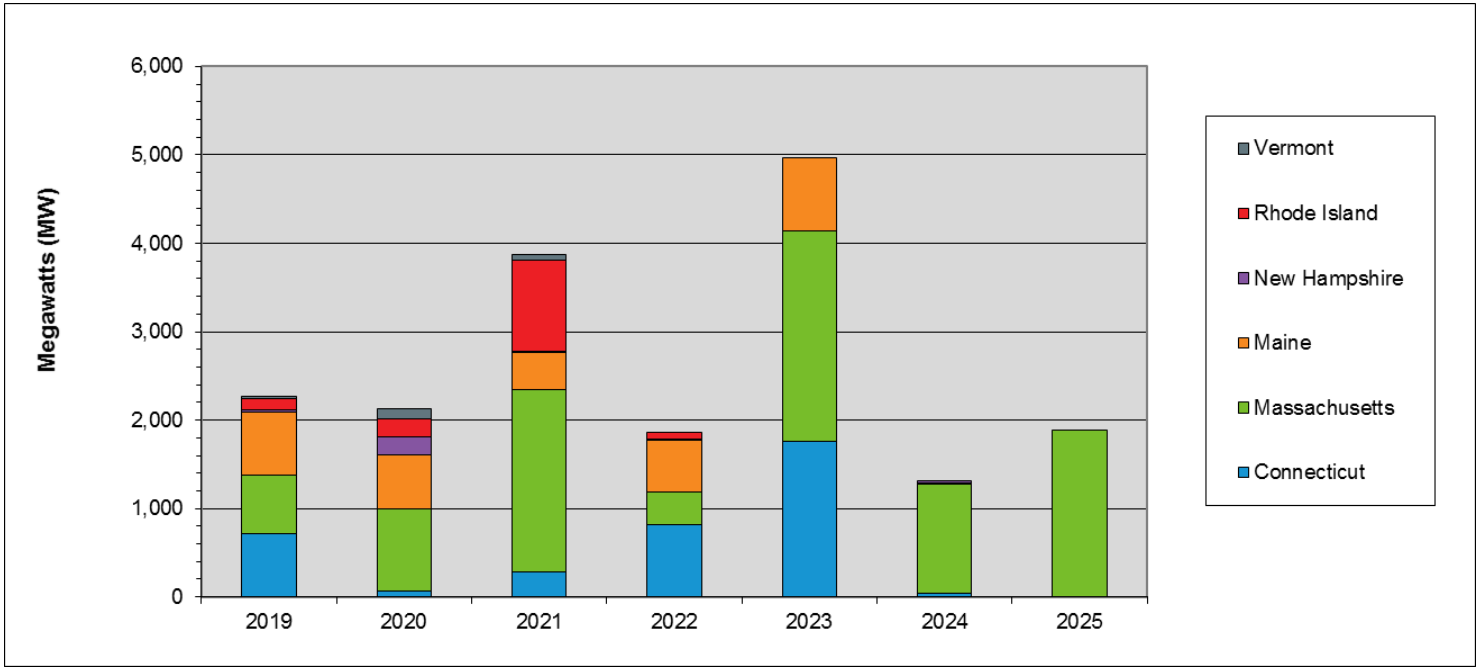
[1] Sum may not equal 100% due to rounding

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

- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2019	2020	2021	2022	2023	2024	2025	Total MW	% of Total[1]
Vermont	33	115	70	0	0	0	0	218	1.2
Rhode Island	123	197	1,030	73	0	0	0	1,423	7.8
New Hampshire	28	210	10	5	0	20	0	273	1.5
Maine	710	612	415	595	828	20	0	3,180	17.4
Massachusetts	662	931	2,063	364	2,384	1,232	1,884	9,520	52.0
Connecticut	714	60	287	818	1,760	40	0	3,679	20.1
Totals	**2,270**	**2,125**	**3,875**	**1,855**	**4,972**	**1,312**	**1,884**	**18,293**	**100.0**

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

New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/wood waste	2	39	0	0	2	39
Hydro	3	74	0	0	3	74
Landfill Gas	0	0	0	0	0	0
Natural Gas	7	1,230	0	0	7	1,230
Natural Gas/Oil	8	1,937	3	1,051	5	886
Oil	0	0	0	0	0	0
Solar	95	2,785	0	0	95	2,785
Wind	25	11,115	1	30	24	11,085
Battery storage	12	1,113	0	0	12	1,113
Total	152	18,293	4	1,081	148	17,212

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	5	123	0	0	5	123
Intermediate	5	1,657	1	510	4	1,147
Peaker	117	5,398	2	541	115	4,857
Wind Turbine	25	11,115	1	30	24	11,085
Total	152	18,293	4	1,081	148	17,212

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

New Generation Projection

By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/wood waste	2	39	1	37	0	0	1	2	0	0
Hydro	3	74	2	8	0	0	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	7	1,230	2	78	3	1,146	2	6	0	0
Natural Gas/Oil	8	1,937	0	0	2	511	6	1,426	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	95	2,785	0	0	0	0	95	2,785	0	0
Wind	25	11,115	0	0	0	0	0	0	25	11,115
Battery storage	12	1,113	0	0	0	0	12	1,113	0	0
Total	152	18,293	5	123	5	1,657	117	5,398	25	11,115

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

FORWARD CAPACITY MARKET

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	525.843	-28.014	484.972	-40.871	438.282	**-46.690**	407.62	-30.662
	Passive Demand	2,156.151	2,153.94	-2.211	2,150.196	-3.744	2,150.196	0	2,389.958	239.762	2,394.341	**4.380**	2,548.346	154.005
Demand Total		**2,803.411**	**2,750.641**	**-52.77**	**2,704.053**	**-46.588**	**2,676.039**	**-28.014**	**2,874.93**	**198.891**	**2,832.623**	**-42.310**	**2,955.966**	**123.343**
Generator	*Non-Intermittent*	29,550.564	29,558.181	7.617	29,783.831	225.65	29,803.997	20.166	29,833.445	29.448	29,720.393	**-113.060**	29,700.519	-19.874
	Intermittent	891.616	864.924	-26.692	872.425	7.501	853.414	-19.011	870.558	17.144	855.947	**-14.611**	788.037	-67.91
Generator Total		**30,442.18**	**30,423.105**	**-19.075**	**30,656.256**	**233.151**	**30,657.41**	**1.155**	**30,704.003**	**46.593**	**30,576.34**	**-127.660**	**30,488.556**	**-87.784**
Import Total		**1,449**	**1,449**	**0**	**1,449**	**0**	**1,449**	**0**	**1,449**	**0**	**1,599**	**150.000**	**1,568**	**-31.000**
****Grand Total**		**34,694.591**	**34,622.746**	**-71.845**	**34,809.309**	**186.563**	**34,782.45**	**-26.859**	**35,027.933**	**245.483**	**35,007.963**	**-19.970**	**35,012.522**	**4.559**
Net ICR (NICR)		**34,189**	**33,883**	**-306**	**33,883**	**0**	**33,421**	**-462**	**33,421**	**0**	**33,247**	**-174**	**33,247**	**0**

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

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	367.227	-10.298	464.715	97.488	460.55	-4.165	459.928	-0.622	457.966	-1.962		
	Passive Demand	2,368.631	2,366.783	-1.848	2,363.949	-2.834	2,363.789	-0.16	2,527.244	163.46	2,529.014	1.77		
Demand Total		**2,746.156**	**2,734.01**	**-12.146**	**2,828.664**	**94.654**	**2,824.339**	**-4.325**	**2,987.172**	**162.83**	**2986.98**	**-0.192**		
Generator	*Non-Intermittent*	30,520.433	30,462.67	-57.763	30,048.398	-414.272	30,103.684	55.286	30,093.142	-10.54	30,081.64	-11.502		
	Intermittent	850.143	893.189	43.046	904.311	11.122	831.251	-73.06	798.958	-32.293	800.387	1.429		
Generator Total		**31,370.576**	**31,355.86**	**-14.716**	**30,952.709**	**-403.151**	**30,934.935**	**-17.774**	**30,892.1**	**-42.84**	**30,882.027**	**-10.073**		
Import Total		**1,449.8**	**1,449.8**	**0**	**1,451**	**1.2**	**1,451**	**0**	**1,451**	**0**	**1,459**	**8**		
****Grand Total**		**35,566.532**	**35,539.668**	**-26.864**	**35,232.373**	**-307.295**	**35,210.274**	**-22.099**	**35,330.272**	**120.00**	**35,328.007**	**-2.265**		
Net ICR (NICR)		**34,151**	**33,755**	**-396**	**33,755**	**0**	**33,407**	**-348**	**33,407**	**0**	**33,390**	**-17**		

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 11

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	419.928	441.221	21.293				
	Passive Demand	2,791.02	2,835.354	44.334				
Demand Total		**3,210.95**	**3,276.575**	**65.625**				
Generator	*Non-Intermittent*	30,494.80	30,064.23	-430.569				
	Intermittent	894.217	823.796	-70.421				
Generator Total		**31,389.02**	**30,888.03**	**-500.993**				
Import Total		**1,235.40**	**1,622.037**	**386.637**				
****Grand Total**		**35,835.37**	**35,786.64**	**-48.731**				
Net ICR (NICR)		**34,075**	**33,660**	**-415**				

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 12

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	624.445						
	Passive Demand	2,975.36						
Demand Total		**3,599.81**						
Generator	*Non-Intermittent*	29,130.75						
	Intermittent	880.317						
Generator Total		**30,011.07**						
Import Total		**1217**						
****Grand Total**		**34,827.88**						
Net ICR (NICR)		**33,725**						

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

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
2021-22	Active	480.941	143.504	624.445
	Passive	2604.793	370.568	2975.361
	Grand Total	3085.734	514.072	3599.806

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

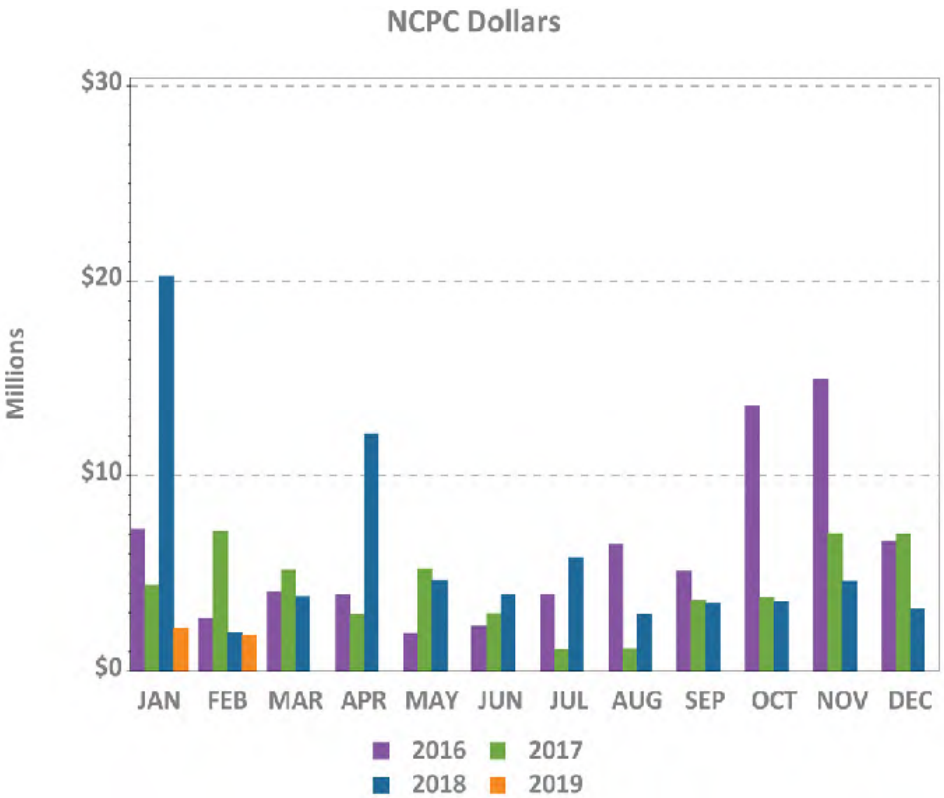
Definitions

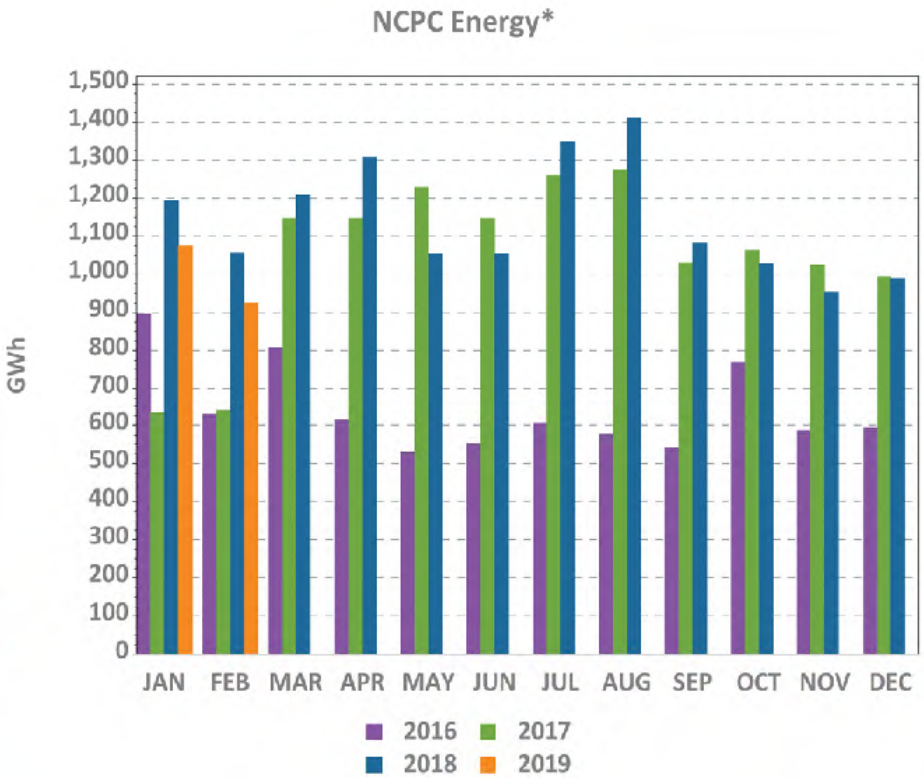
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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).

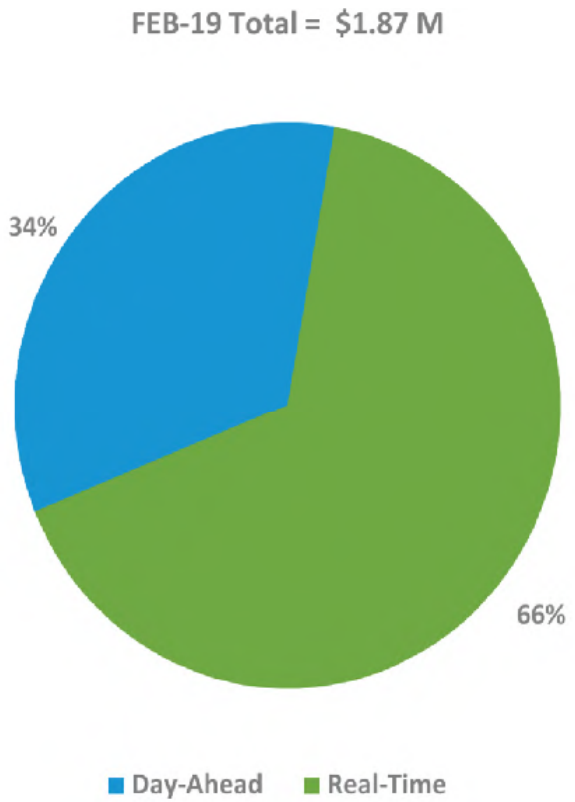
Year-Over-Year Total NCPC Dollars and Energy



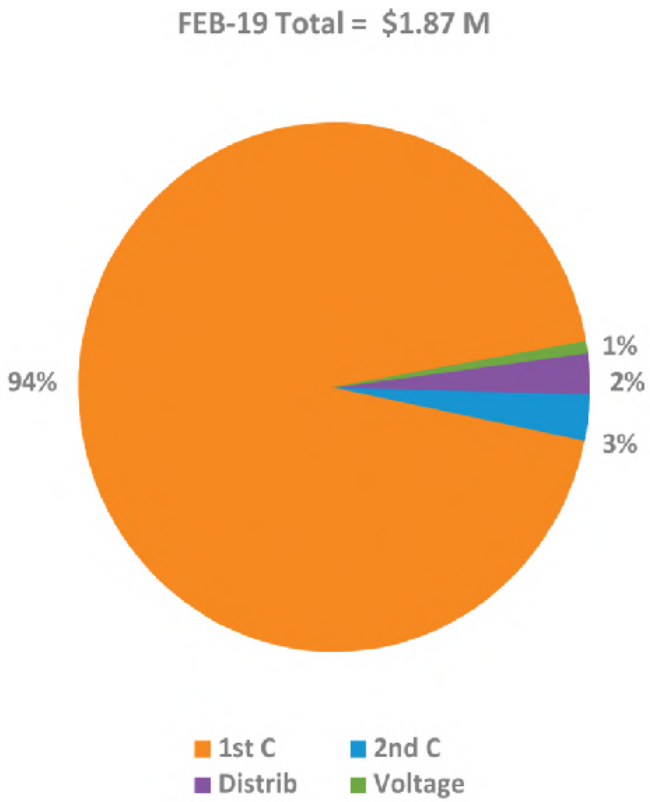


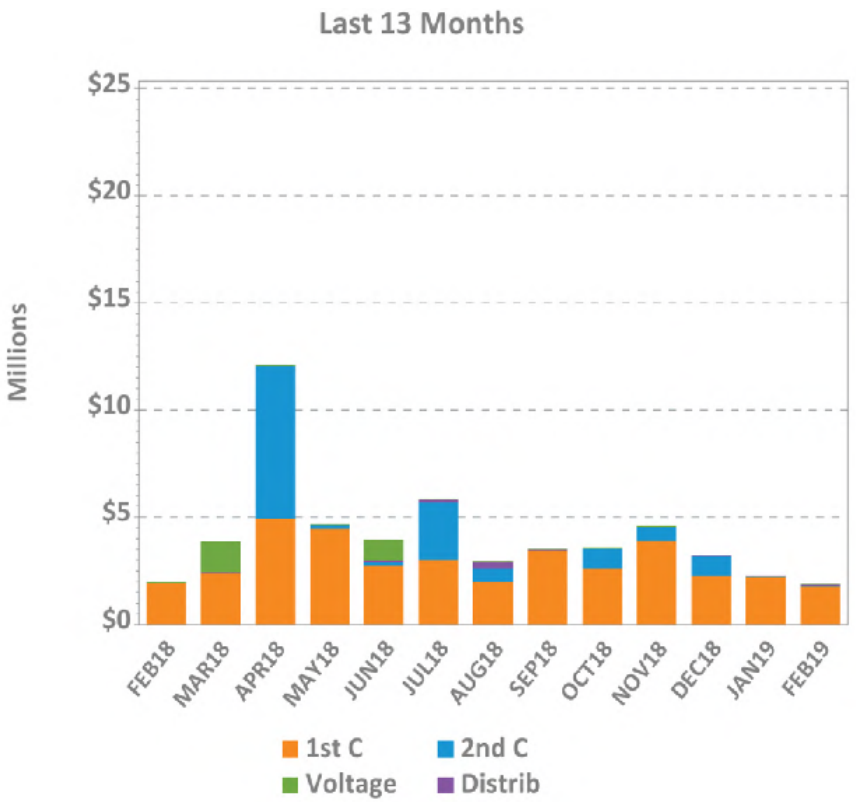
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



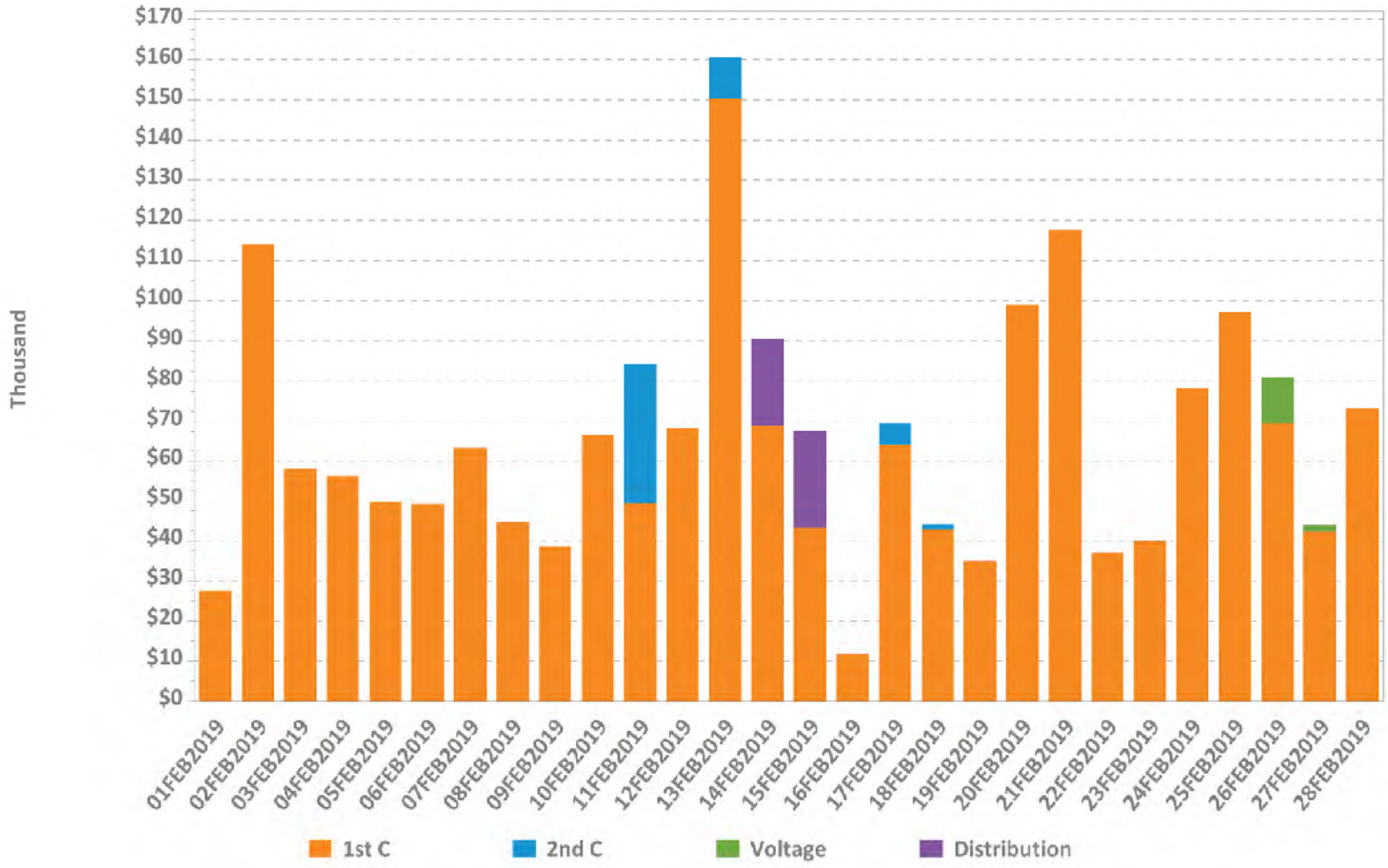
NCPC Charges by Type



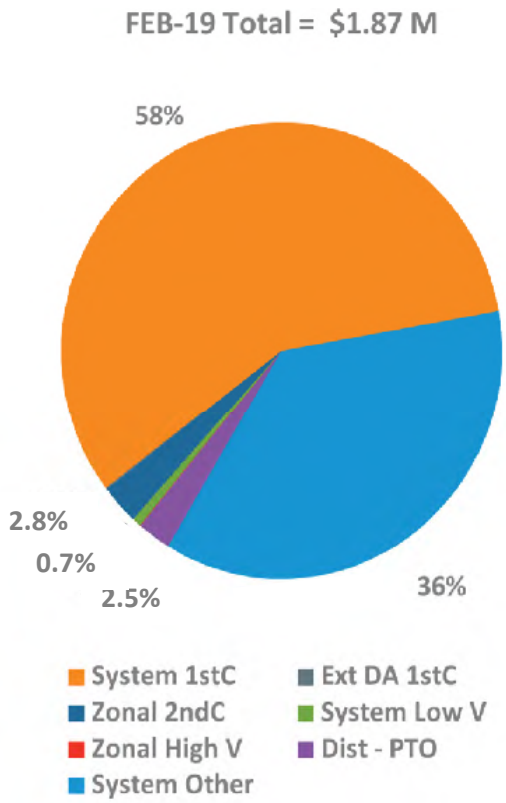


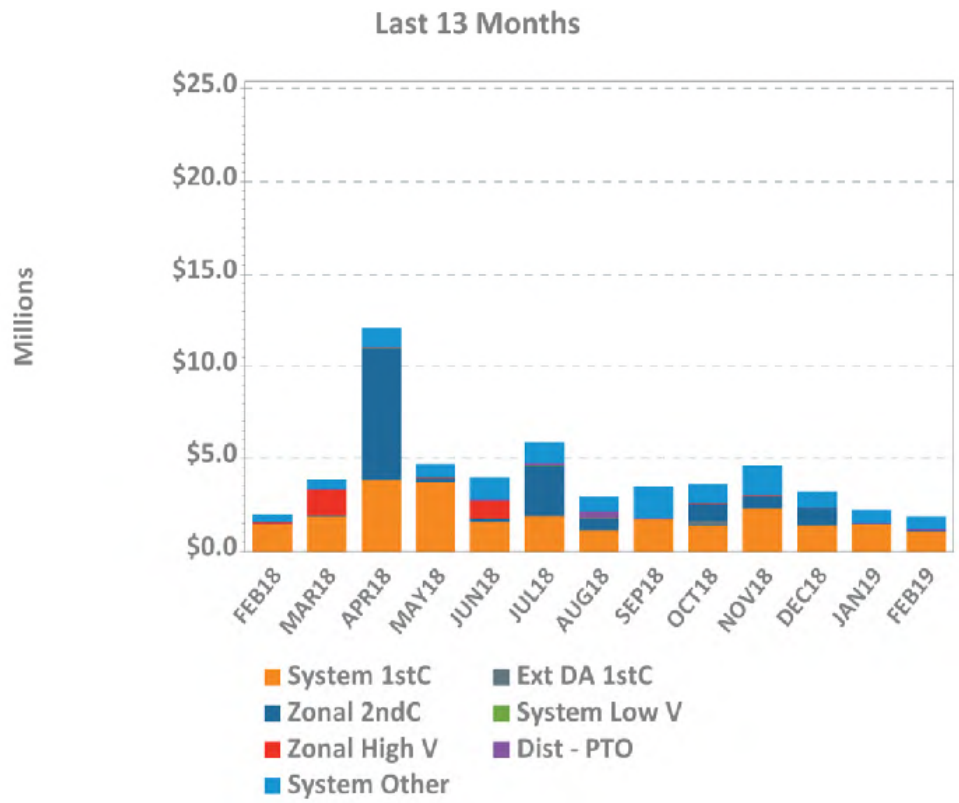
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



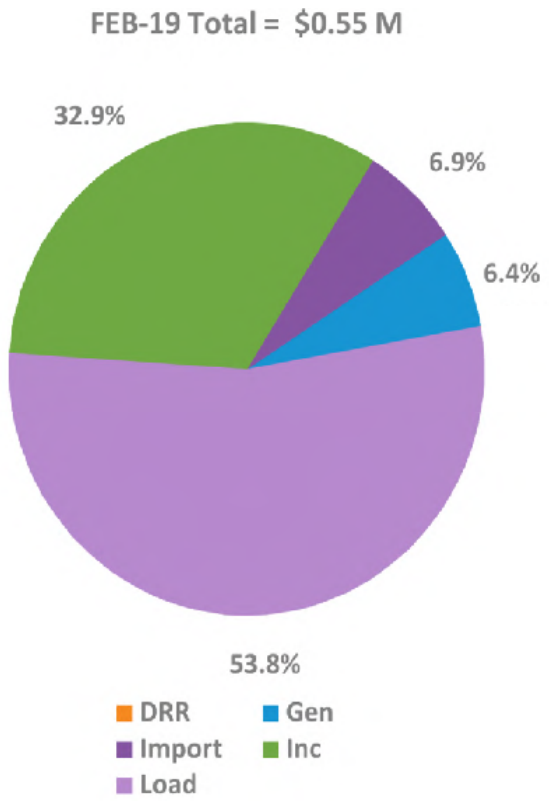
NCPC Charges by Allocation

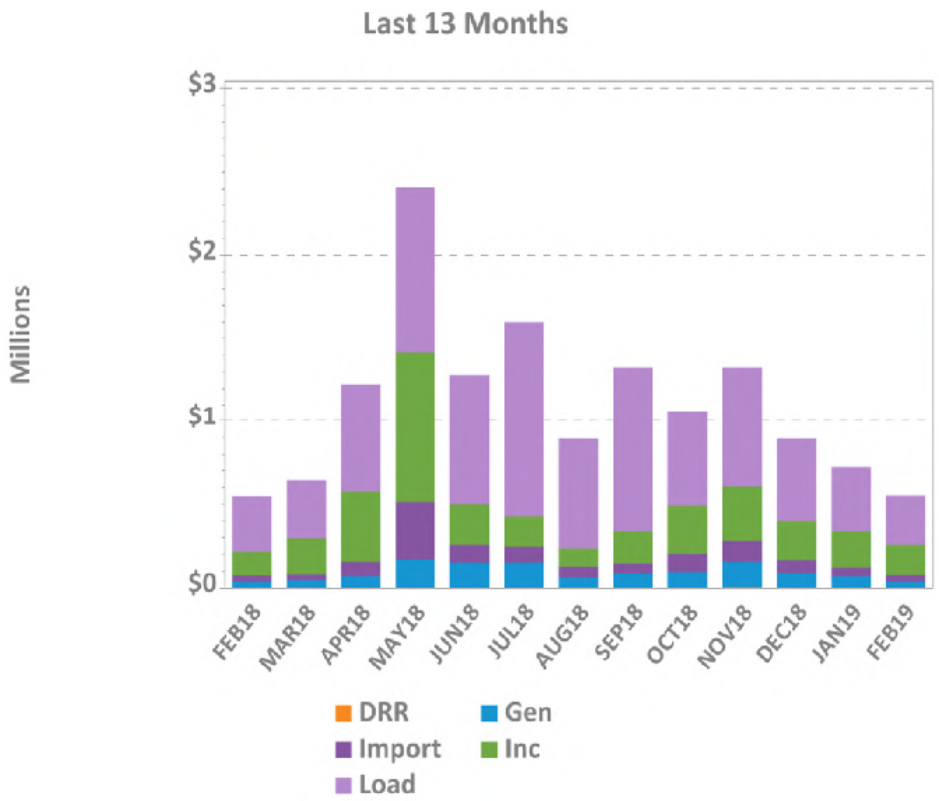




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

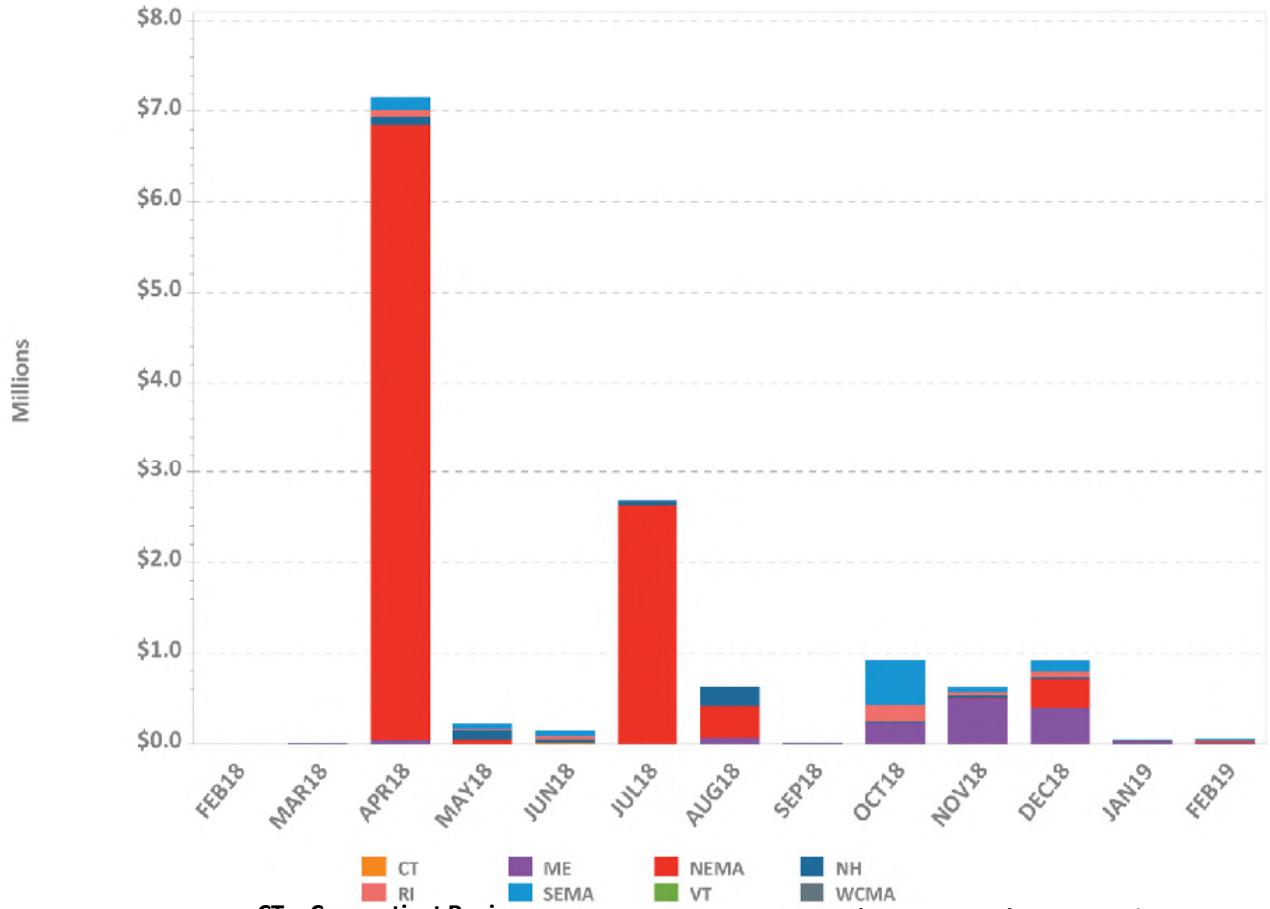
RT First Contingency Charges by Deviation Type





DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

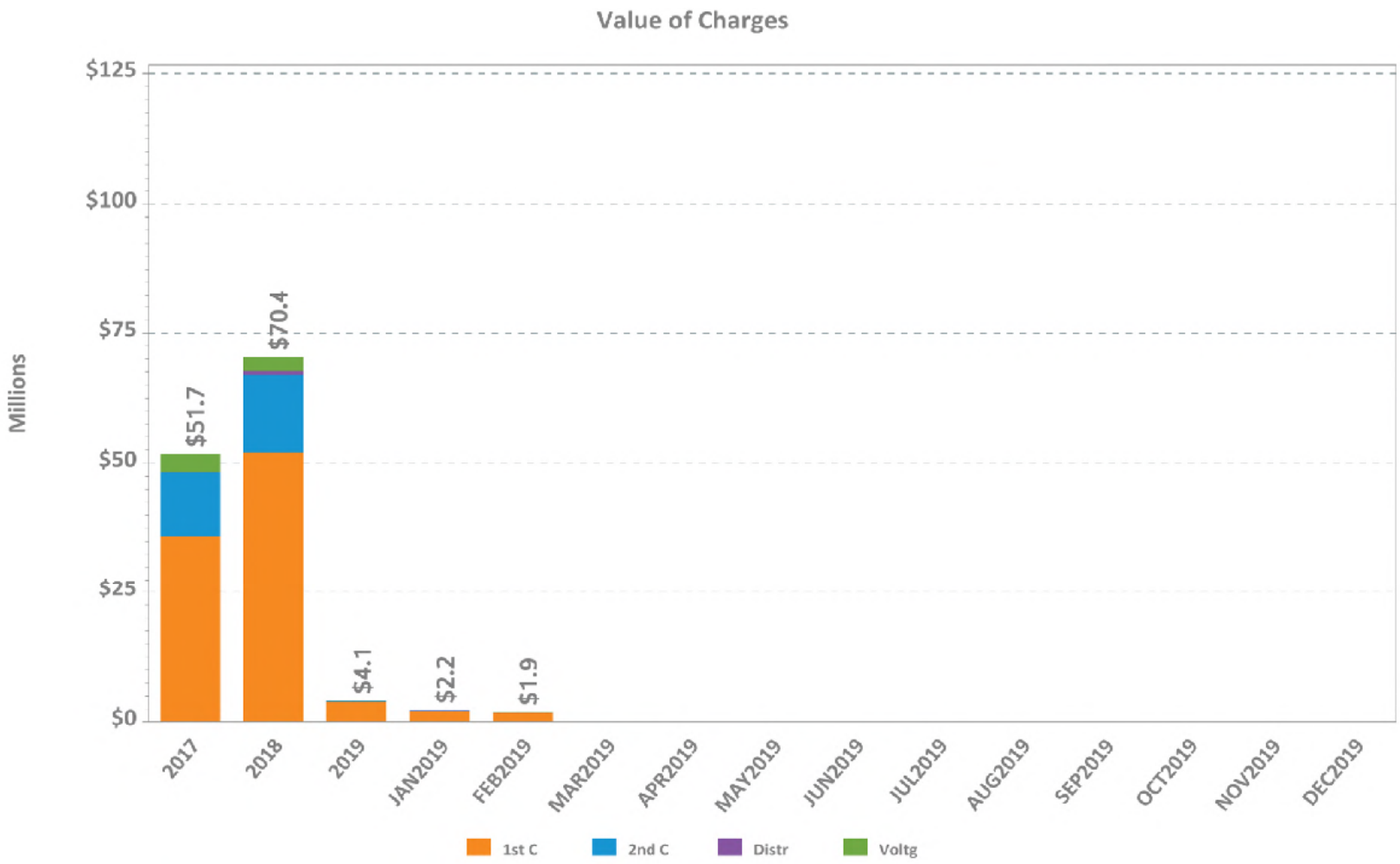
LSCPR Charges by Reliability Region



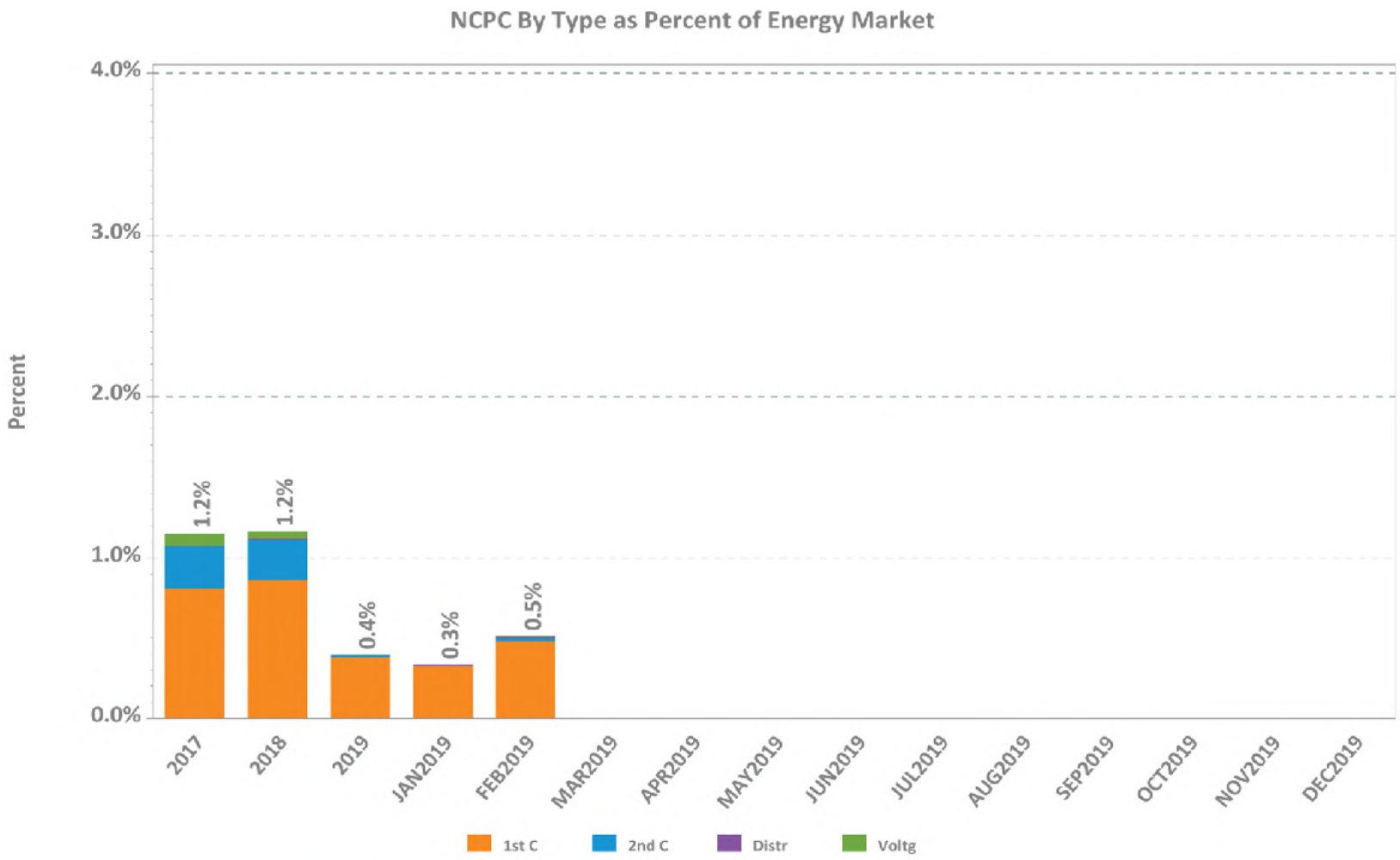
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

NCPC Charges for Voltage Support and High Voltage Control

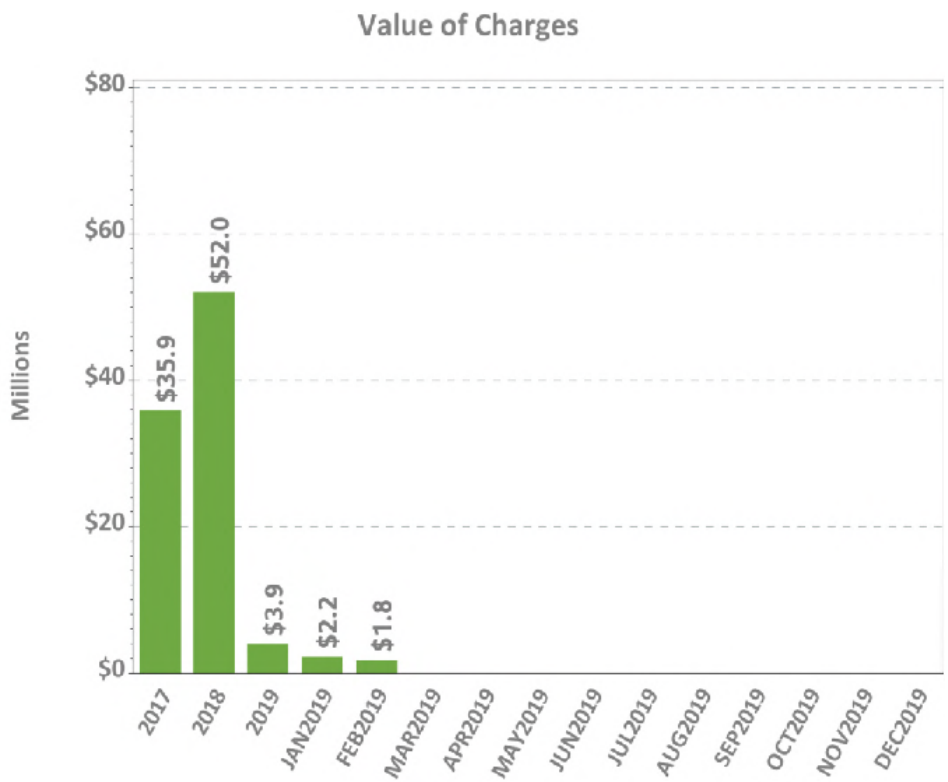
NCPC Charges by Type

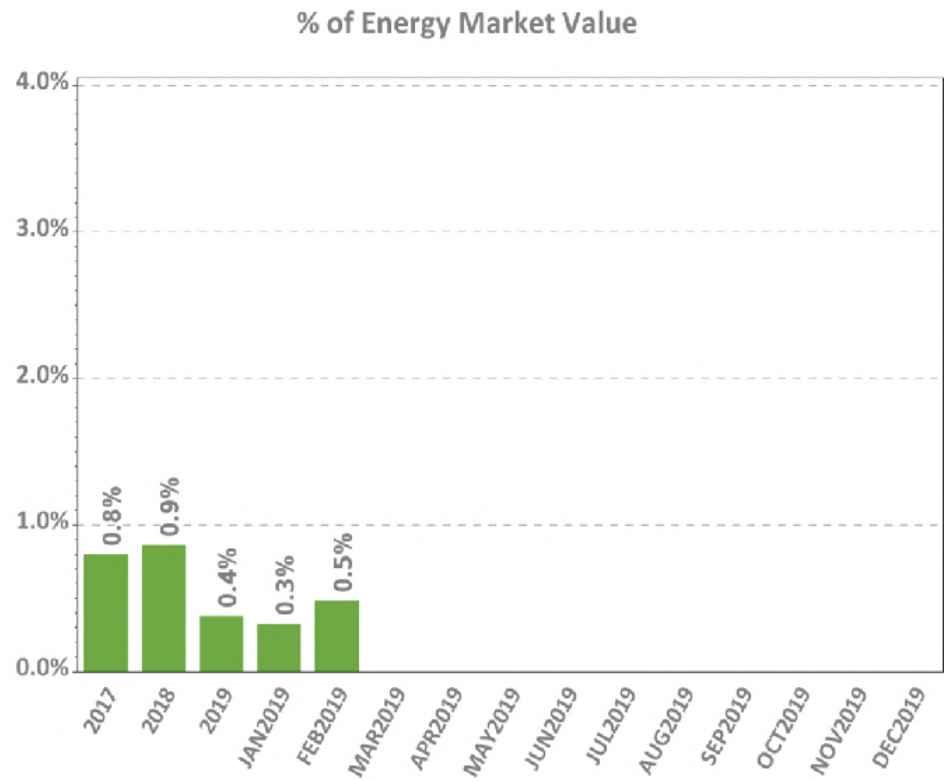


NCPC Charges as Percent of Energy Market



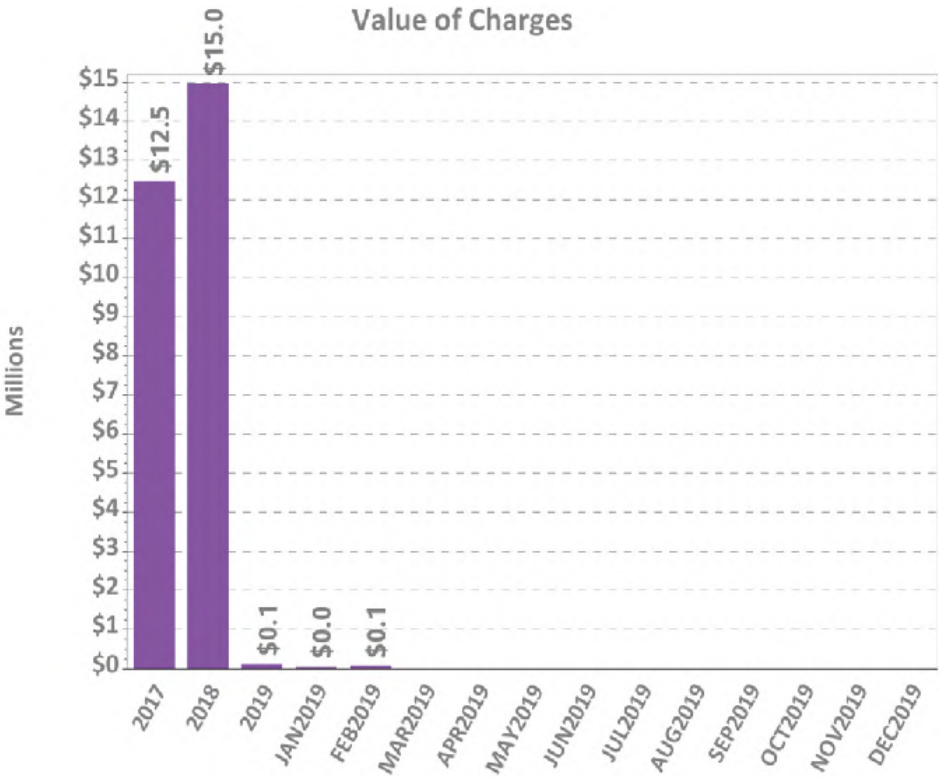
First Contingency NCPC Charges

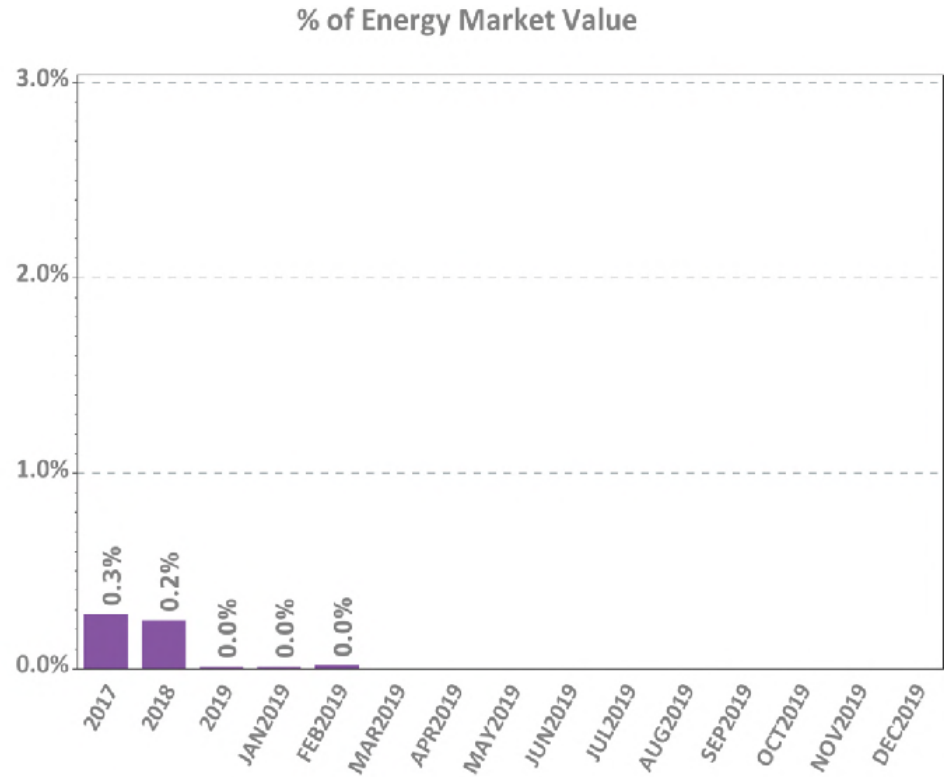




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

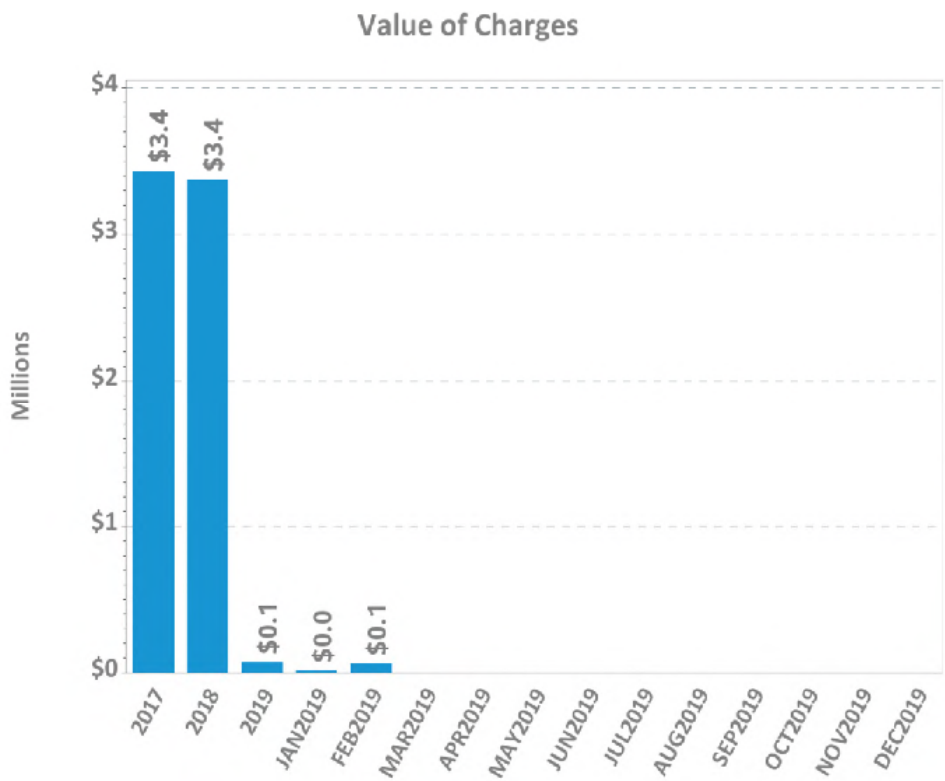
Second Contingency NCPC Charges

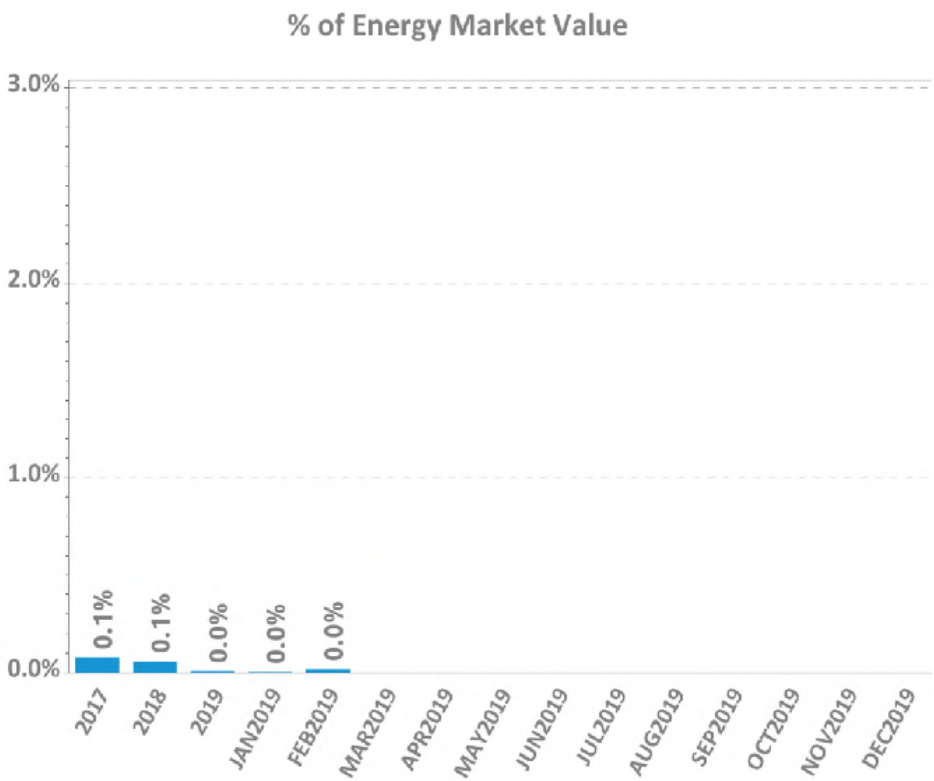




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

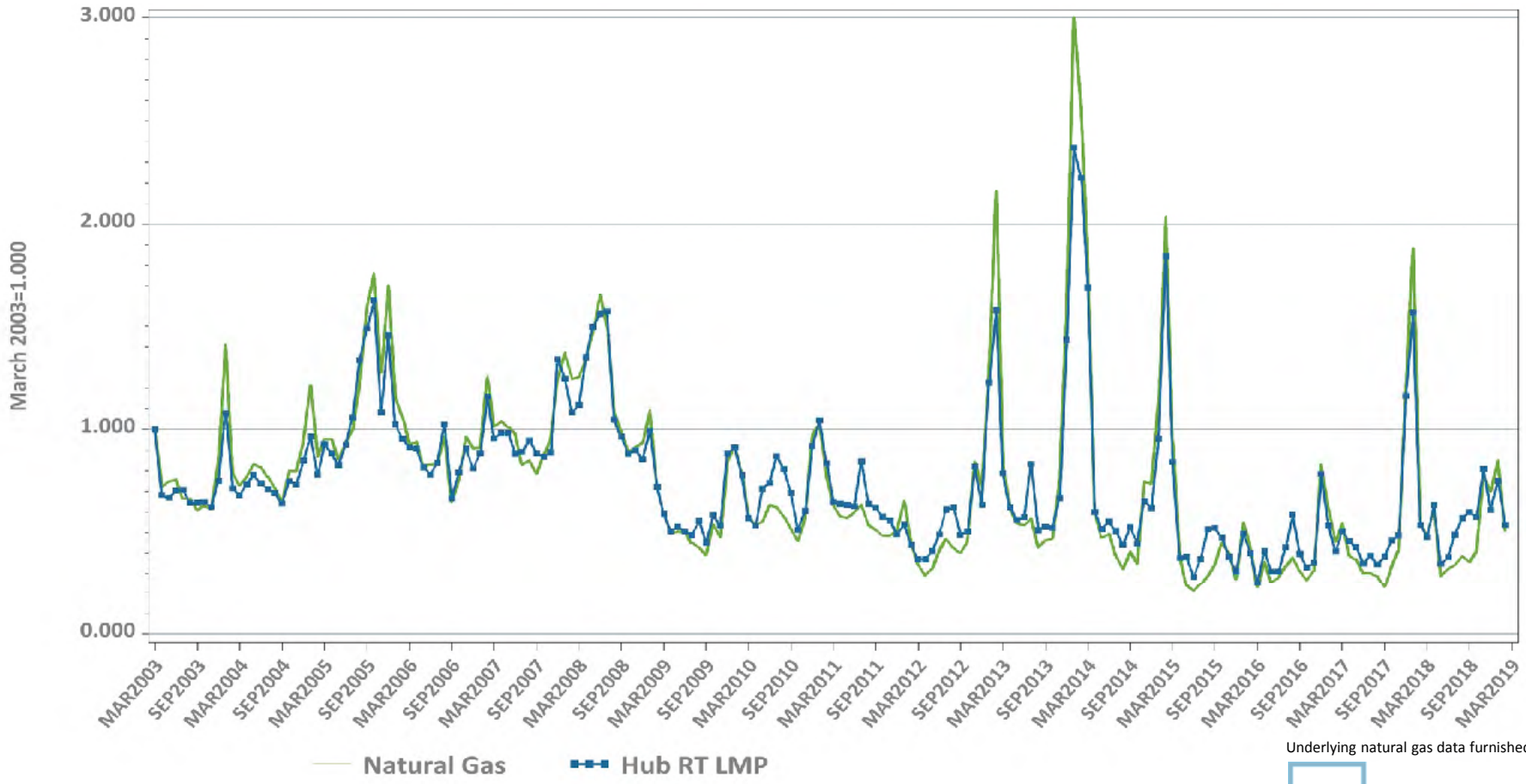
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2017	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$33.46	$33.35	$32.50	$33.13	$33.05	$33.13	$33.27	$33.43	$33.35
Real-Time	$34.76	$33.93	$31.39	$32.78	$33.02	$33.78	$33.98	$33.97	$33.94
RT Delta %	3.9%	1.7%	-3.4%	-1.0%	-0.1%	2.0%	2.1%	1.6%	1.7%
Year 2018	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$44.45	$43.60	$42.63	$44.04	$43.71	$44.11	$44.62	$44.19	$44.13
Real-Time	$43.87	$43.13	$41.03	$43.17	$42.83	$43.37	$43.68	$43.58	$43.54
RT Delta %	-1.3%	-1.1%	-3.8%	-2.0%	-2.0%	-1.7%	-2.1%	-1.4%	-1.3%

February-18	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$39.49	$39.34	$38.45	$39.34	$39.35	$39.52	$39.53	$39.66	$39.58
Real-Time	$36.88	$36.74	$35.52	$36.61	$36.35	$36.87	$36.86	$36.97	$36.91
RT Delta %	-6.6%	-6.6%	-7.6%	-6.9%	-7.6%	-6.7%	-6.7%	-6.8%	-6.7%
February-19	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$35.90	$35.01	$35.01	$35.76	$35.06	$35.64	$35.66	$35.64	$35.62
Real-Time	$37.26	$36.37	$36.25	$37.08	$36.17	$36.97	$36.99	$36.91	$36.92
RT Delta %	3.8%	3.9%	3.6%	3.7%	3.2%	3.7%	3.8%	3.6%	3.7%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	-9.1%	-11.0%	-9.0%	-9.1%	-10.9%	-9.8%	-9.8%	-10.1%	-10.0%
Yr over Yr RT	1.0%	-1.0%	2.1%	1.3%	-0.5%	0.3%	0.4%	-0.2%	0.0%

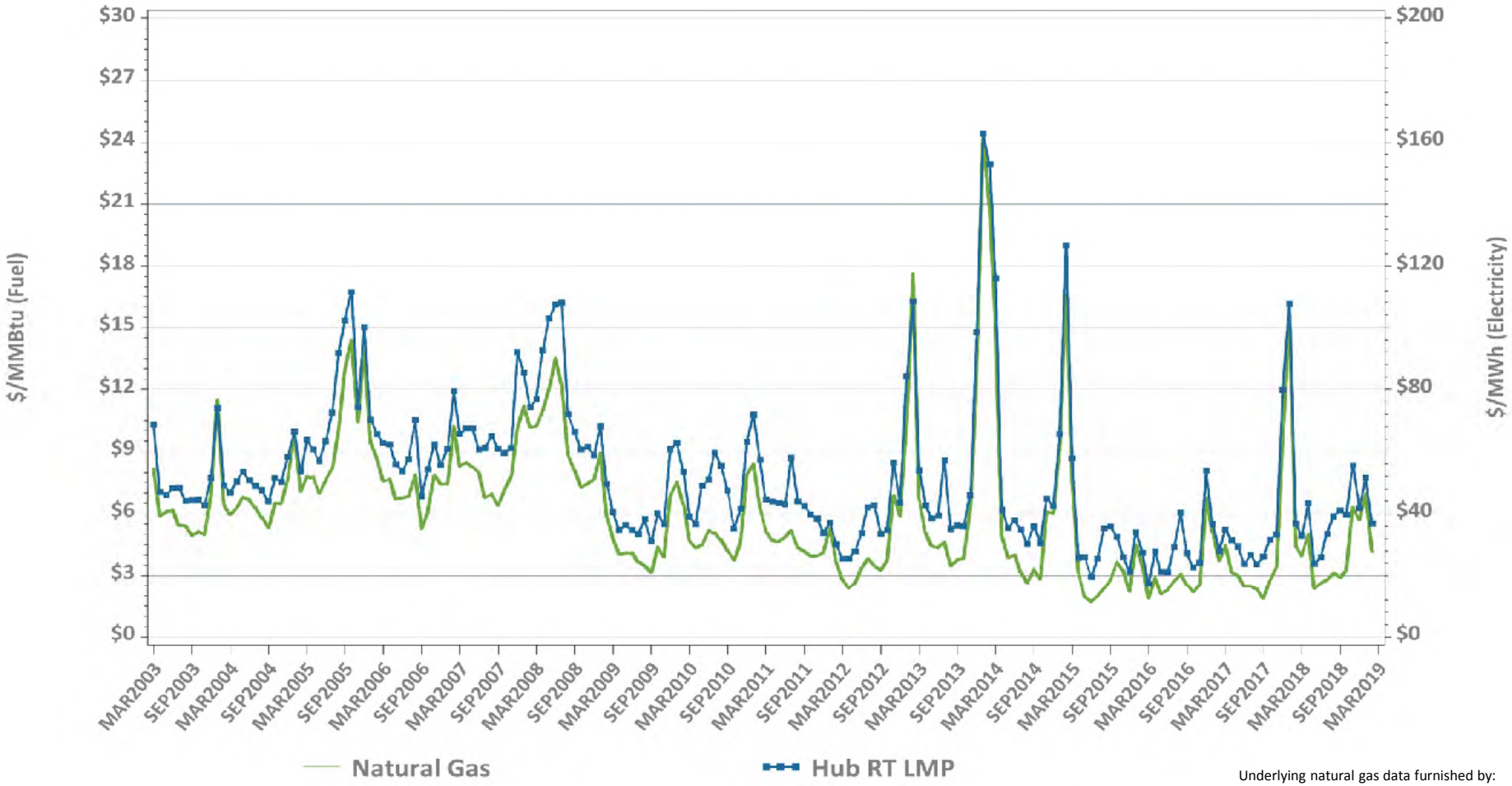
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

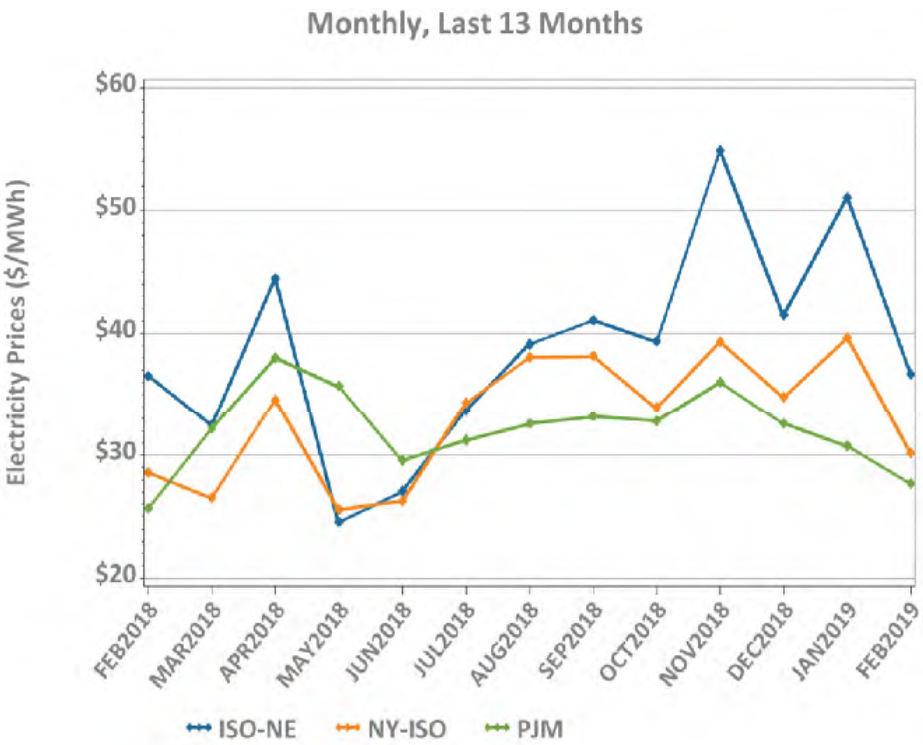
Monthly Average Fuel Price and RT Hub LMP



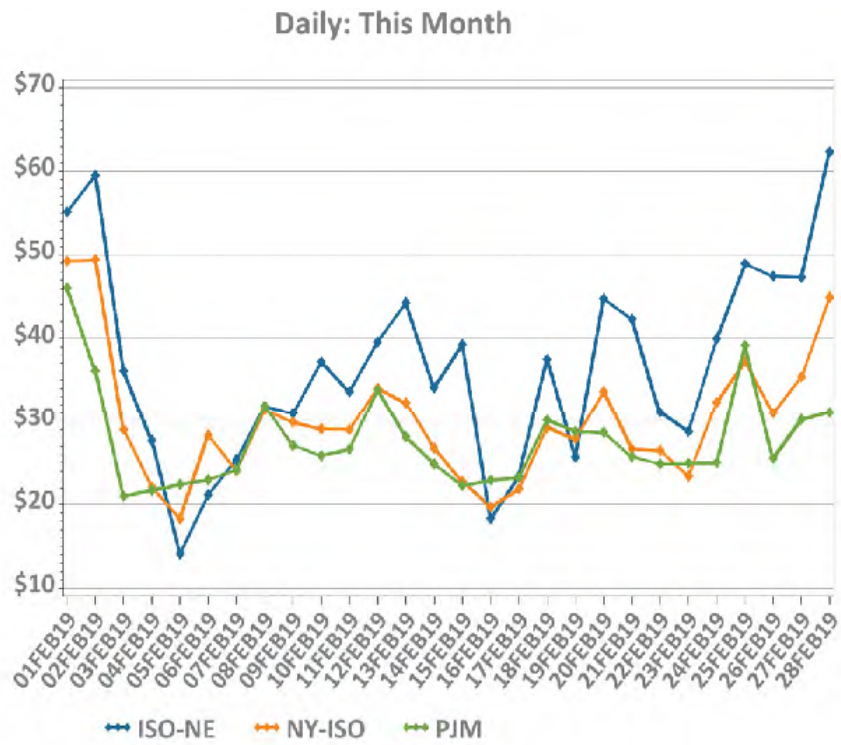
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

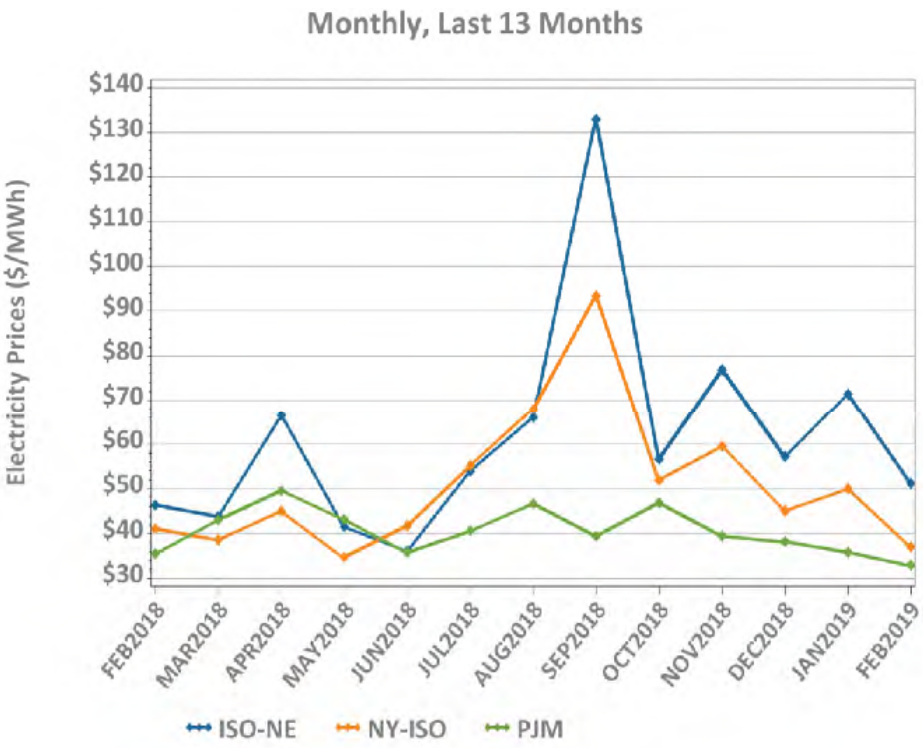


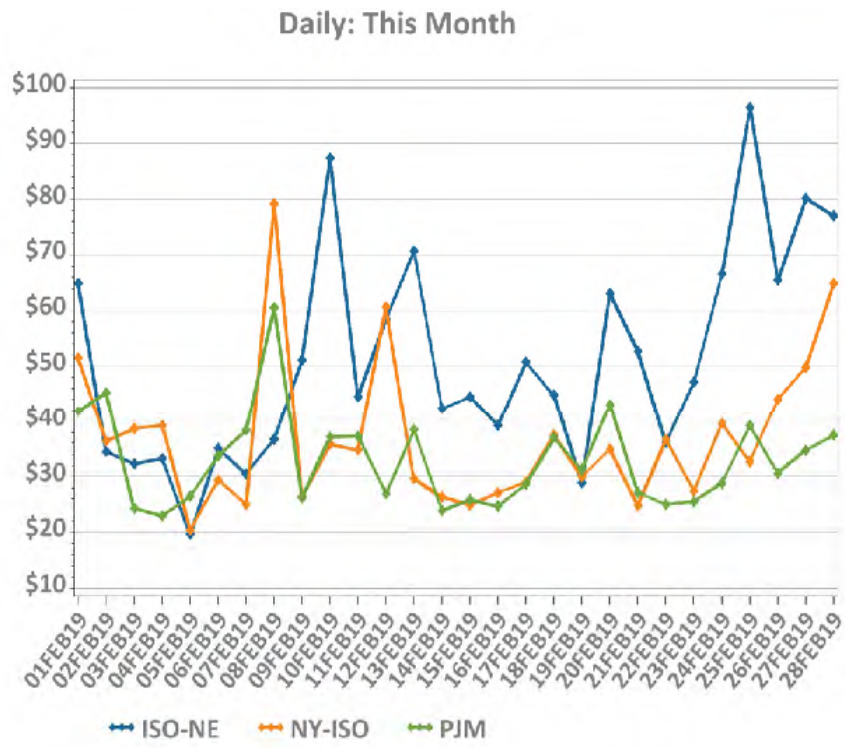
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





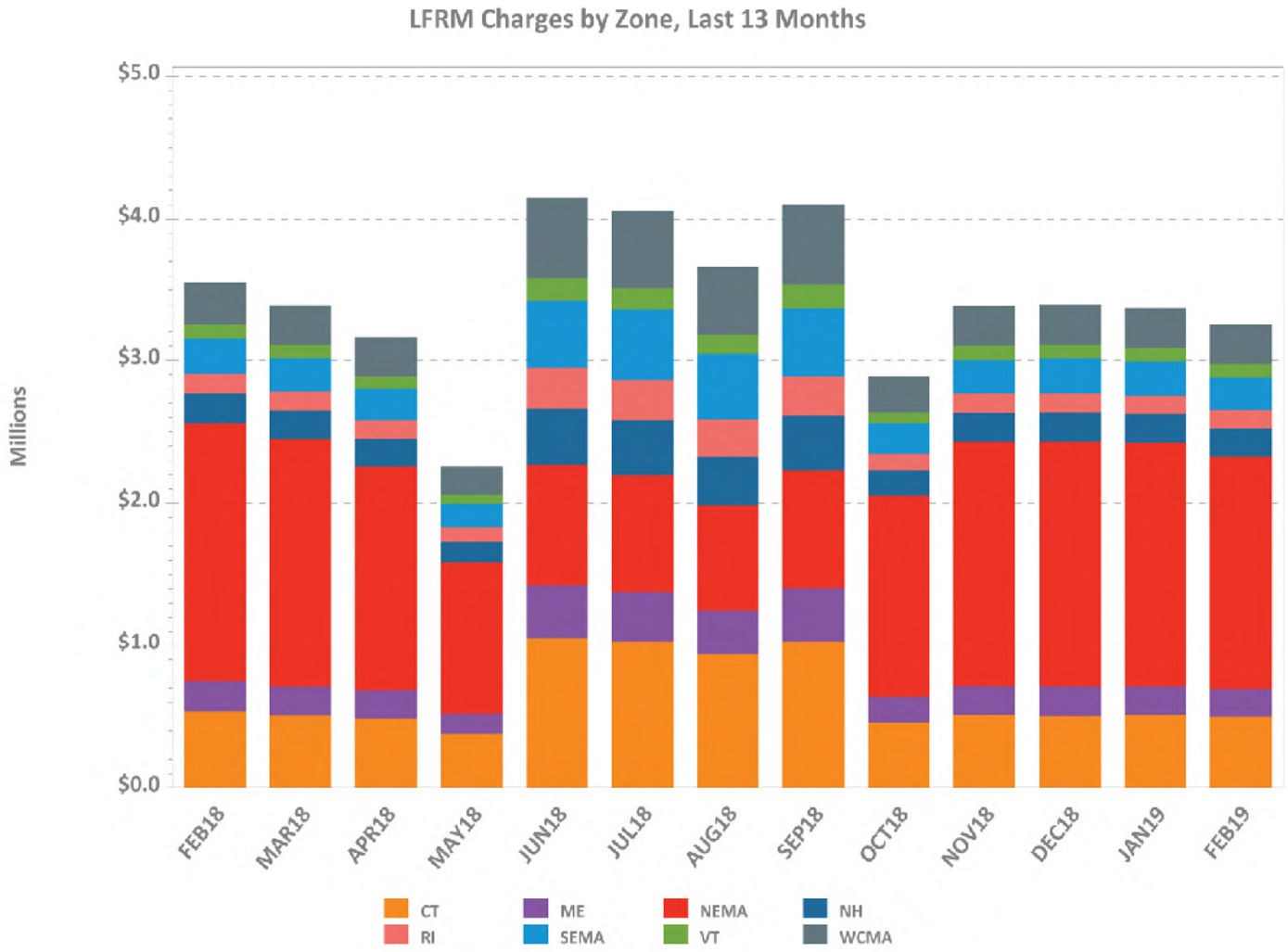
***Forecasted New England daily peak hours reflected**

Reserve Market Results – February 2019

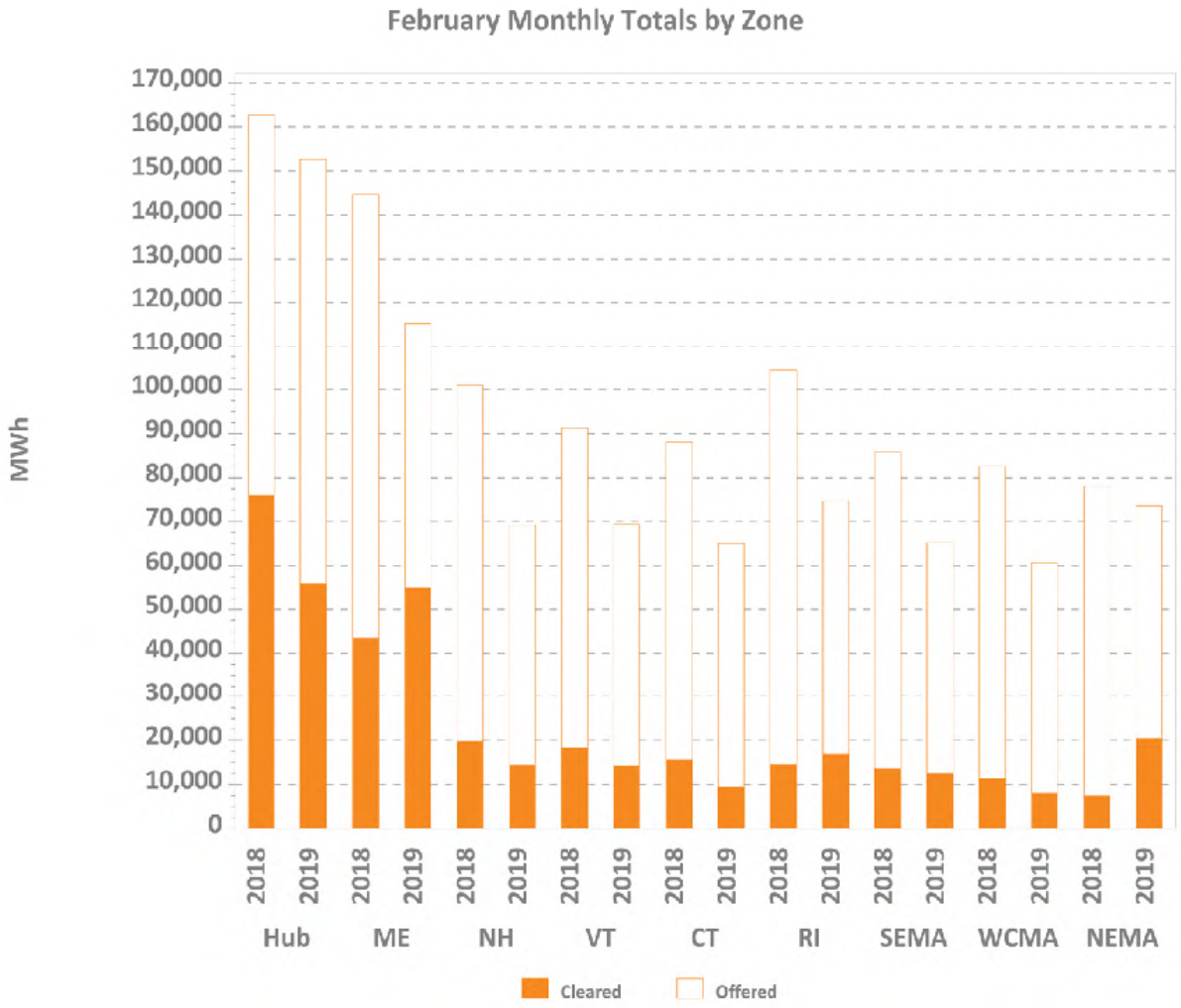
- Maximum potential Forward Reserve Market payments of $3.5M were reduced by credit reductions of $85K, failure-to-reserve penalties of $128K and no failure-to-activate penalties, resulting in a net payout of $3.3M or 94% of maximum
  - Rest of System: $1.11M/1.13M (98%)
  - Southwest Connecticut: $0.12M/0.15M (81%)
  - Connecticut: $0.3M/0.31M (98%)
  - NEMA: $1.7M/1.9M (92%)
- $1.3M total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $1.3M in Real-Time Reserve payments
  - Rest of System: 269 hours, $866K
  - Southwest Connecticut: 269 hours, $244K
  - Connecticut: 269 hours, $111K
  - NEMA: 269 hours, $52K

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

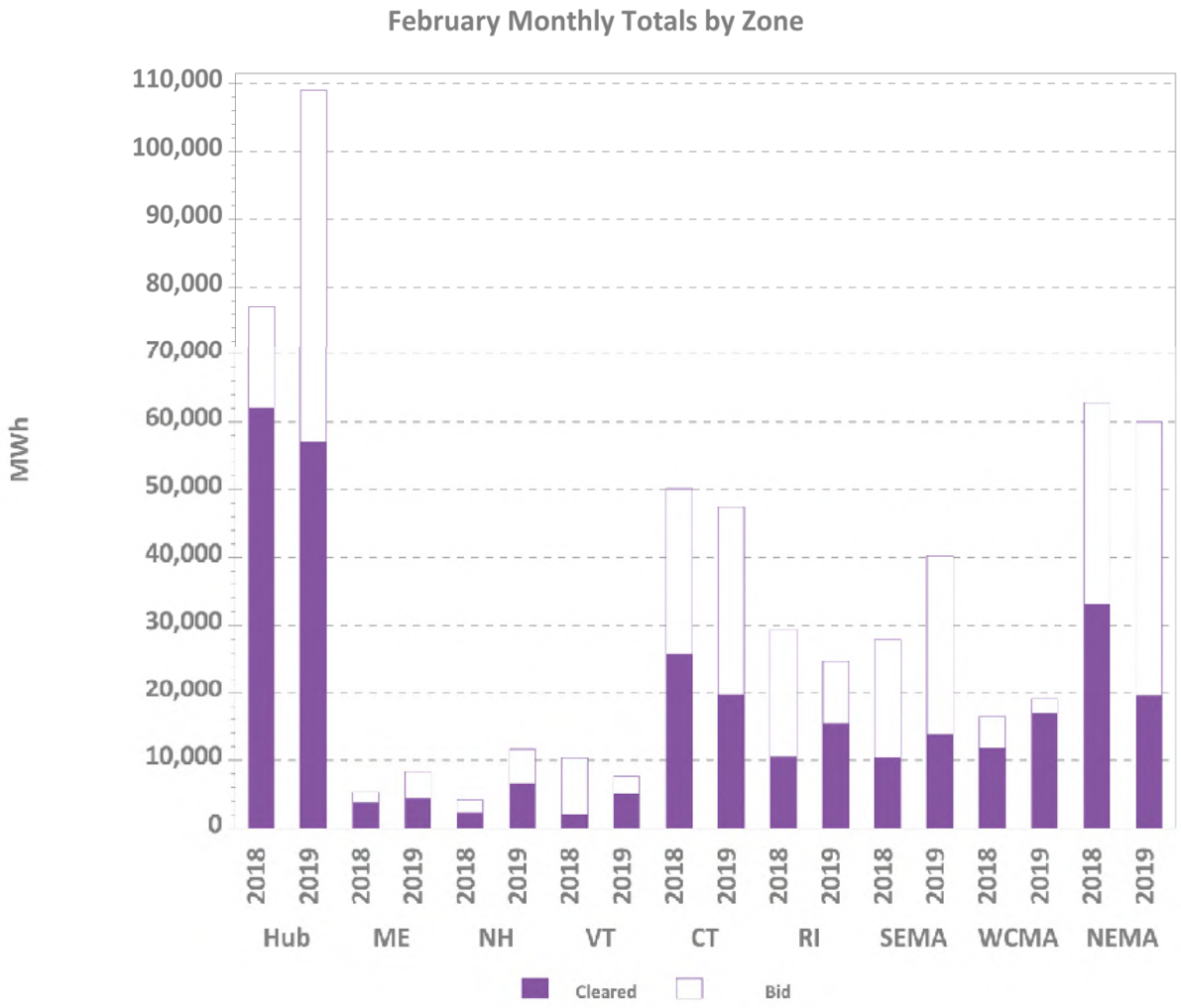
LFRM Charges to Load by Load Zone ($)



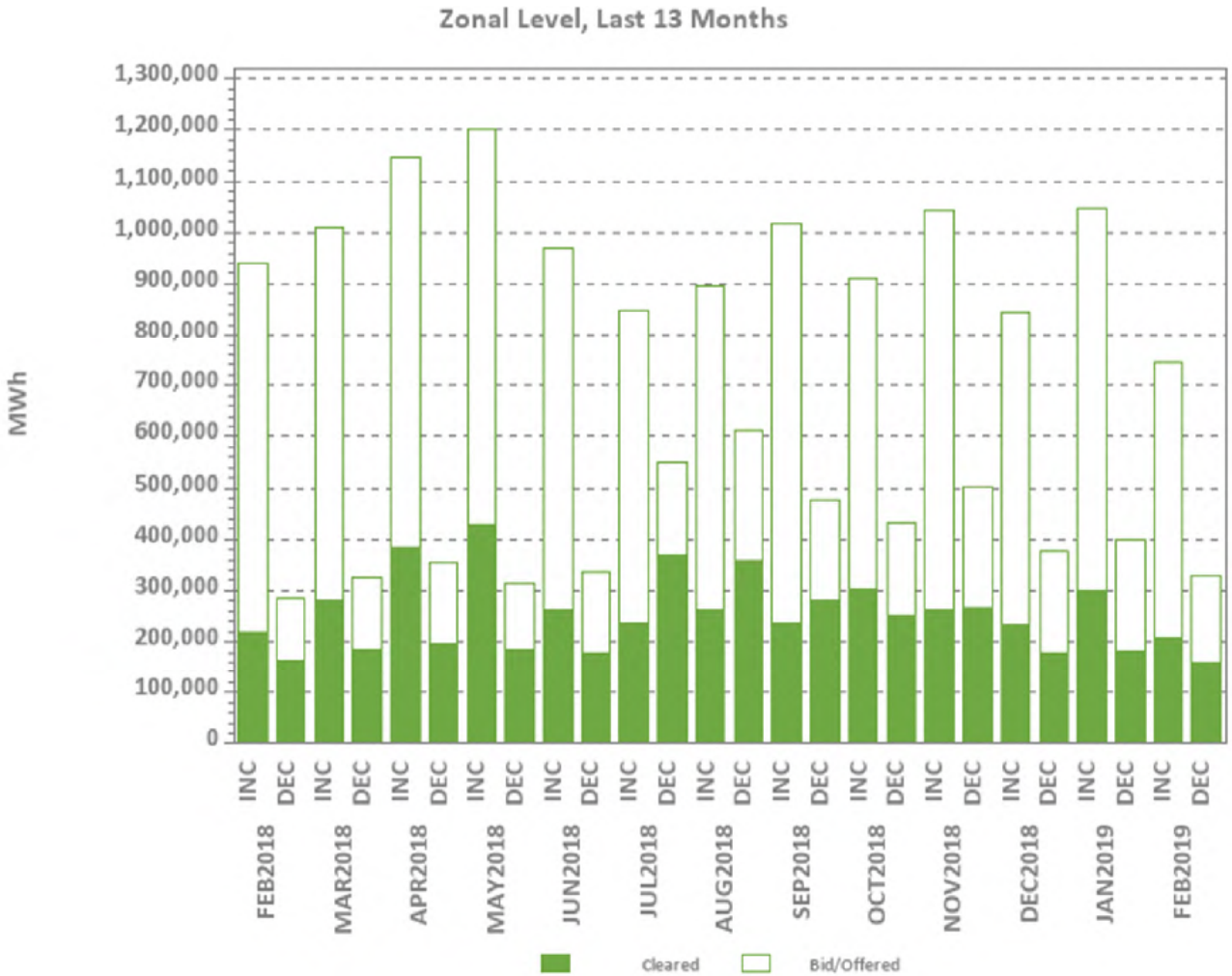
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

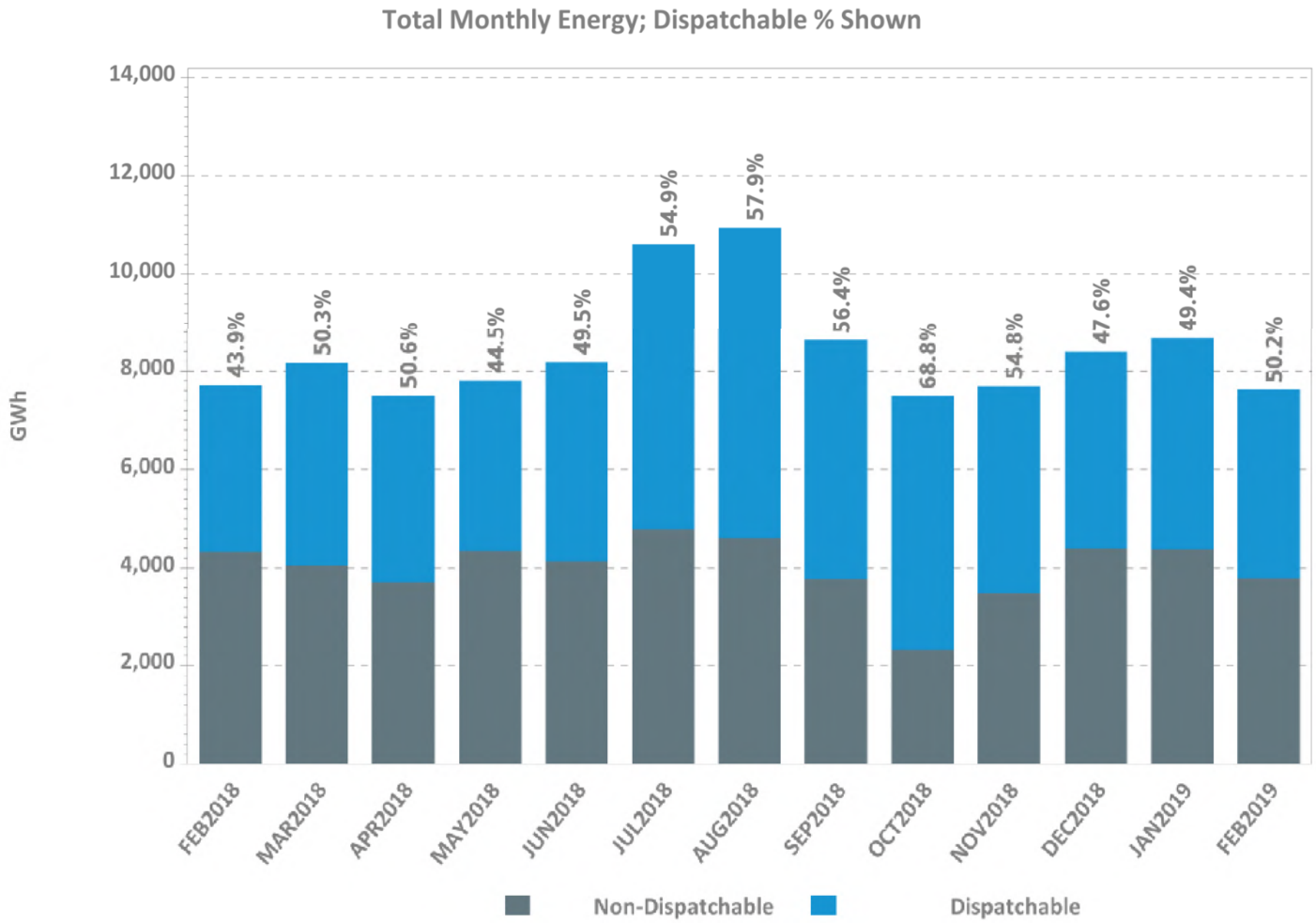


Total Increment Offers and Decrement Bids



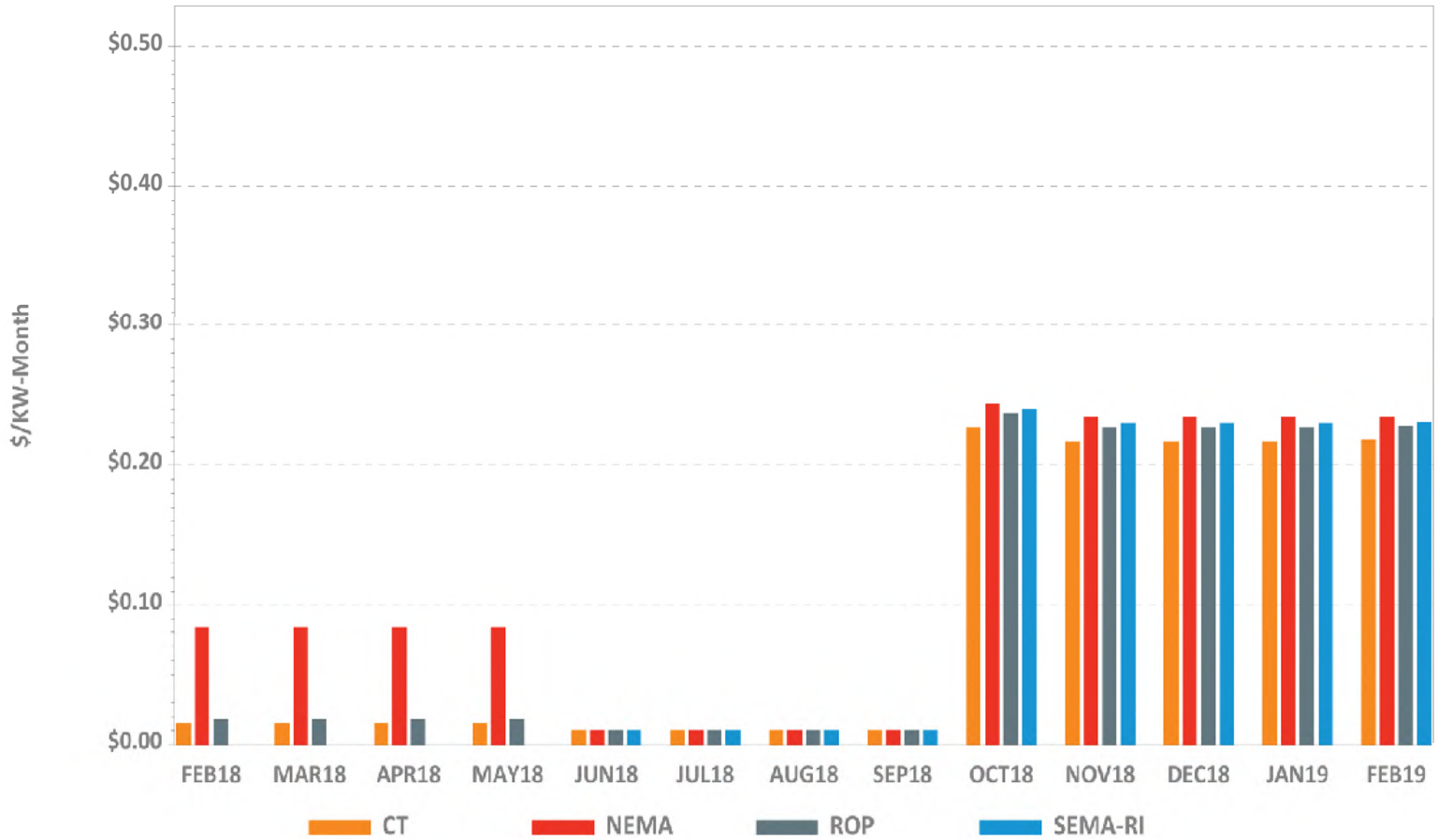
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



*** Dispatchable MWh here are defined to be all generation output that is not self-committed (a.k.a, offered as 'must run') by the customer.**

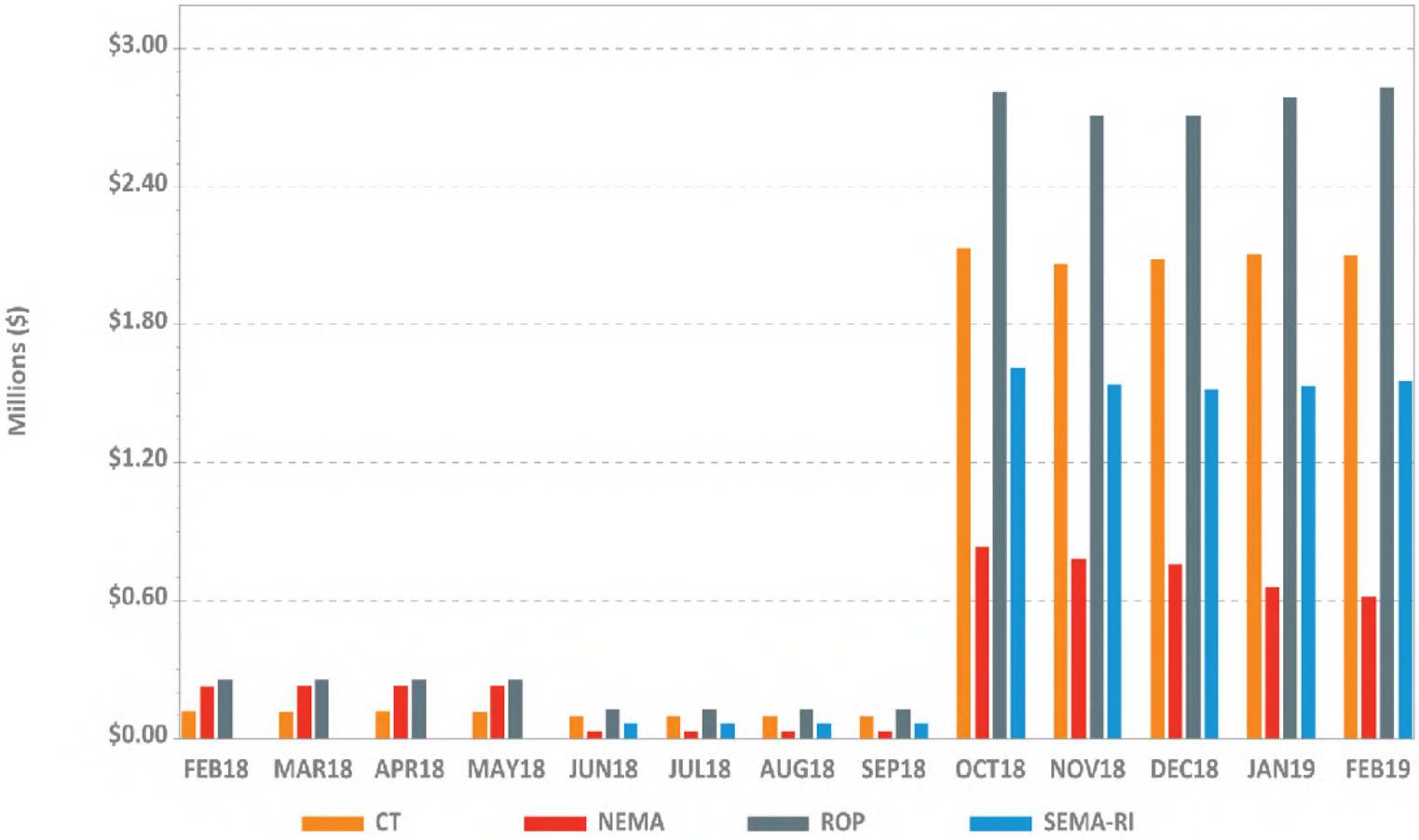
Rolling Average Peak Energy Rent (PER) by Capacity Zone



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)

- March 21 PAC Meeting Agenda Topics*
  - Update on New England Natural Gas Developments
  - Regional System Plan Transmission Projects and Asset Condition March 2019 Update
  - FCA 14 Zonal Boundary Determinations
  - EIPC Frequency Response Update
  - Draft New England EE, PV, and Load Forecast Update (New England region, not states)
  - Updating Needs Assessments to Reflect Latest Assumptions
  - Minimum, Light, and Shoulder Loads - Update to the Transmission Planning Technical Guide

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

PAC "Grid Transformation Day" – May 23

- The large-scale development of wind generation facilities, distributed energy resources (especially PV), storage (batteries and other types), demand response, and HVDC/FACTS are transforming the electric power system
- Discussions will include physical and technical challenges, potential solutions, implementation experience in New England, and regulatory and business models

Load, Energy Efficiency, and Photovoltaic Forecast

- The 2019 ten-year load forecast development process is underway
  - Enhancements will be implemented, such as including cooling degree days in the demand models and the development of monthly energy models
  - Staff is investigating ways to better capture expiring measures in the energy-efficiency forecast
  - Draft forecast to be discussed with the PAC in March and April
  - Forecast to be finalized and posted as part of the CELT report by May 1
- Discussions with industry and counterparts at other ISOs/utilities continue regarding potential impacts of future emerging technologies/trends and methods of incorporating these into the forecast
- Upcoming forecast stakeholder meetings:
  - Energy Efficiency Working Group – March 8
  - Distributed Generation Forecast Working Group – March 19
  - Load Forecasting Committee – March 29

Interregional Planning

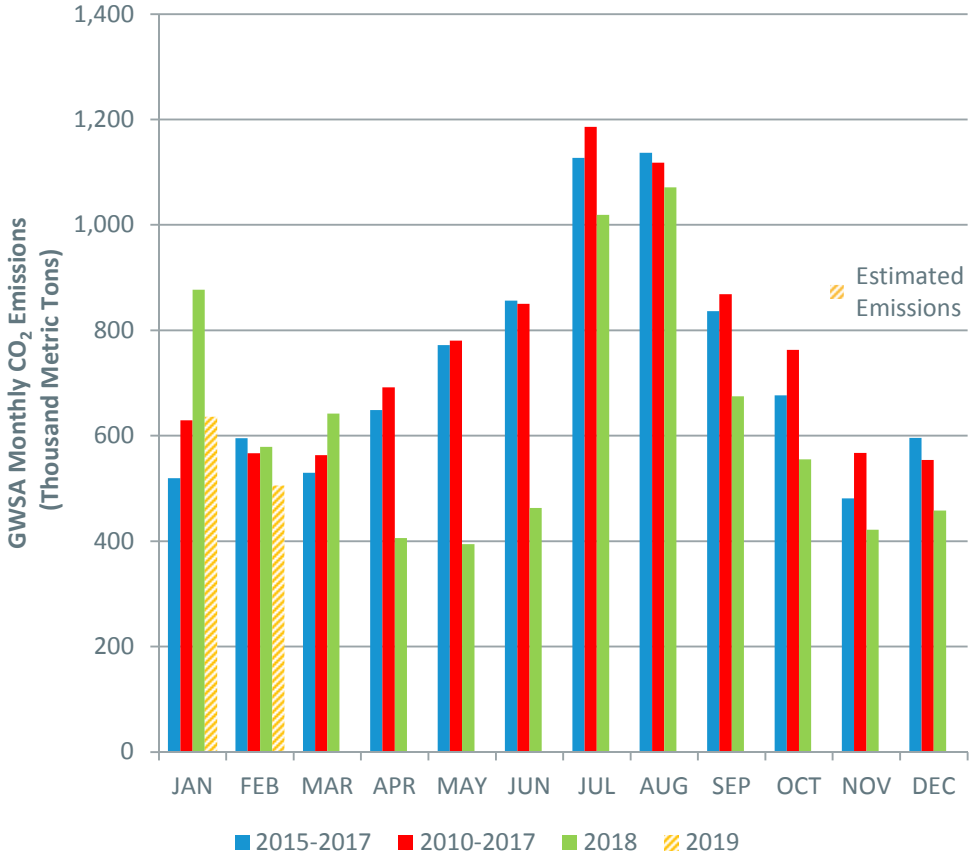
- The next Inter-Area Planning Stakeholder Advisory Committee (IPSAC) meeting is tentatively scheduled for May 13 from 2:00pm - 4:30pm
  - Draft agenda items include:
    - Regional Planning Needs and Solutions
      - PJM
      - ISO-NE
      - NYISO
    - Interconnection Coordination - Interconnection Queue and Long-Term Firm Transmission Requests
      - NYISO
      - ISO-NE
      - PJM
    - Receive Stakeholder Input and Outline Next Steps

Environmental Matters – MA CO_2 Generator Emissions Cap Update (310 CMR 7.74)

GWSA Estimated CO_2 Emissions Below 2018 Cap

- 2018 CO_2 emissions - 7.5 million metric tons, well below 9.15 million metric ton 2018 cap
- 2019 cap to 8.73 million metric tons. Estimated 2019 emissions:
  - January 2019: 635,949
  - February 2019: 505,696
- Affected generators previously emitted between 8.77 and 9.13 million metric tons of CO_2 per year

GWSA Monthly CO_2 Emissions (Thousand Metric Tons)



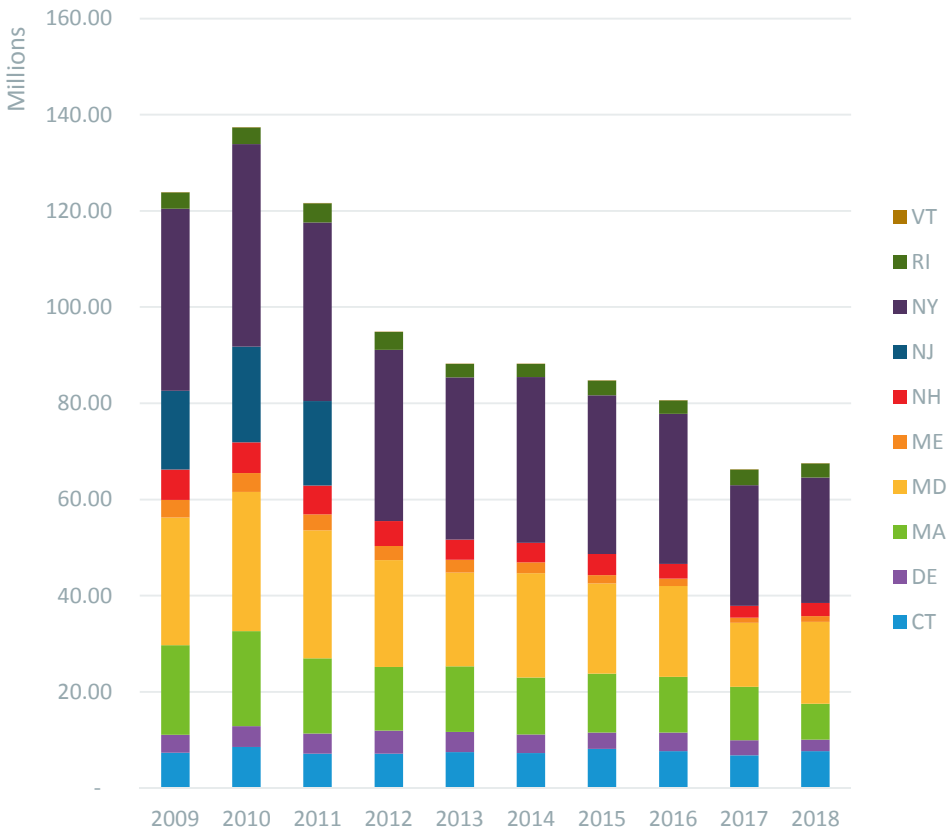
CMR – Code of Massachusetts Regulations
GWSA – Global Warming Solutions Act

Environmental Matters – Regional Greenhouse Gas Initiative Update

First Year-to-Year Increase Ever in RGGI Emissions

- RGGI emissions (73.3 million short tons (MT) in 2018) increased for only the 2nd time in the 9-year history of the program compared to 2017 emissions (66.1), a 7.18 MT increase:
  - ↑ CT 1.91 million
  - ↓ DE 0.486 million
  - ↓ MA 2.81 million
  - ↑ MD 5.16 million
  - ↑ ME 0.113 million
  - ↑ NH 0.267 million
  - ↑ NY 1.0 million
  - ↓ RI 0.325 million
  - ↓ VT 0.002 million
- New England RGGI emissions overall declined by 194,497 short tons between 2017 (24.7 MT) and 2018 (24.5 MT)

RGGI Annual CO_2 Emissions (Million Short Tons)



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

Note: The listings in this section focus on major transmission line construction and rebuilding.

New Hampshire/Vermont 10-Year Upgrades

Status as of 2/20/19

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-19	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 2/20/19

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

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 2/20/19

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

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 2/20/19

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	Jun-18	4
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	Mar-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 2/20/19

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 3.7 mile 115 kV hybrid overhead/underground line from Newington to Southwest Hartford and associated terminal equipment including a 1.4% series reactor	Dec-19	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Jun-18	4
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	May-17	4
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Nov-17	4
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-19	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 2/20/19

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	4
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	4
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-19	3
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-18	4
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-19	3
Add a 345 kV breaker in series with breaker 5T at Southington	May-17	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 2/20/19

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-18	4
Add a new 115 kV line from Frost Bridge to Campville	Dec-17	4
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	Jun-18	4
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 2/20/19

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	Oct-18	4
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Sep-17	4
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-16	4
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Jul-18	4
Loop the 1570 line in and out the Pootatuck substation	Jul-18	4
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 2/20/19

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	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-19	2
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Apr-17	4
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	May-18	4
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	4
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Jun-18	4
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	4

Southwest Connecticut Projects, cont.

Status as of 2/20/19

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	Jun-17	4
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Nov-19	2
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Nov-19	2

Southwest Connecticut Projects, cont.

Status as of 2/20/19

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	Mar-18	4
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)	Dec-18	4
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Sep-20	2

Southwest Connecticut Projects, cont.

Status as of 2/20/19

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 2/20/19

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	4
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	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
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-19	3
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-21	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	Jun-19	3

* Substation portion of the project is a Present Stage status 3

Greater Boston Projects, cont.

Status as of 2/20/19

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-18	4
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	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Dec-19	3
Install third 115 kV line from West Walpole to Holbrook	Dec-19	3
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	4
Install a new 115 kV line from Sudbury to Hudson	Dec-20	2

Greater Boston Projects, cont.

Status as of 2/20/19

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	Dec-19	3
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
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	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	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	Nov-20	3
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	Dec-19	3

Greater Boston Projects, cont.

Status as of 2/20/19

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-20	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	3
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	3
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 2/20/19

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	Dec-17	4
Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
Install a 345 kV 160 MVAR shunt reactor at K Street	Nov-19	2
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 2/20/19

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	4
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Jun-17	4
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	4
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 2/20/19

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 2/20/19

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.	Oct-17	4
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	4
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	4
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	Jun-20	1

SEMA/RI Reliability Projects

Status as of 2/20/19

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Nov-20	3
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Nov-20	3
1715	Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Jun-20	2
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	2
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	3

SEMA/RI Reliability Projects

Status as of 2/20/19

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Nov-20	2
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Dec-20	2
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Nov-21	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-21	2
1722	Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation	Dec-21	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Sep-21	2

SEMA/RI Reliability Projects

Status as of 2/20/19

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-21	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Nov-20	1
1727	Retire the Barnstable SPS	Dec-21	1
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-21	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-21	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-21	1

SEMA/RI Reliability Projects

Status as of 2/20/19

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	1
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Dec-21	1
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Dec-21	1
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Dec-21	3

* Does not include the reconductoring work over the Cape Cod canal

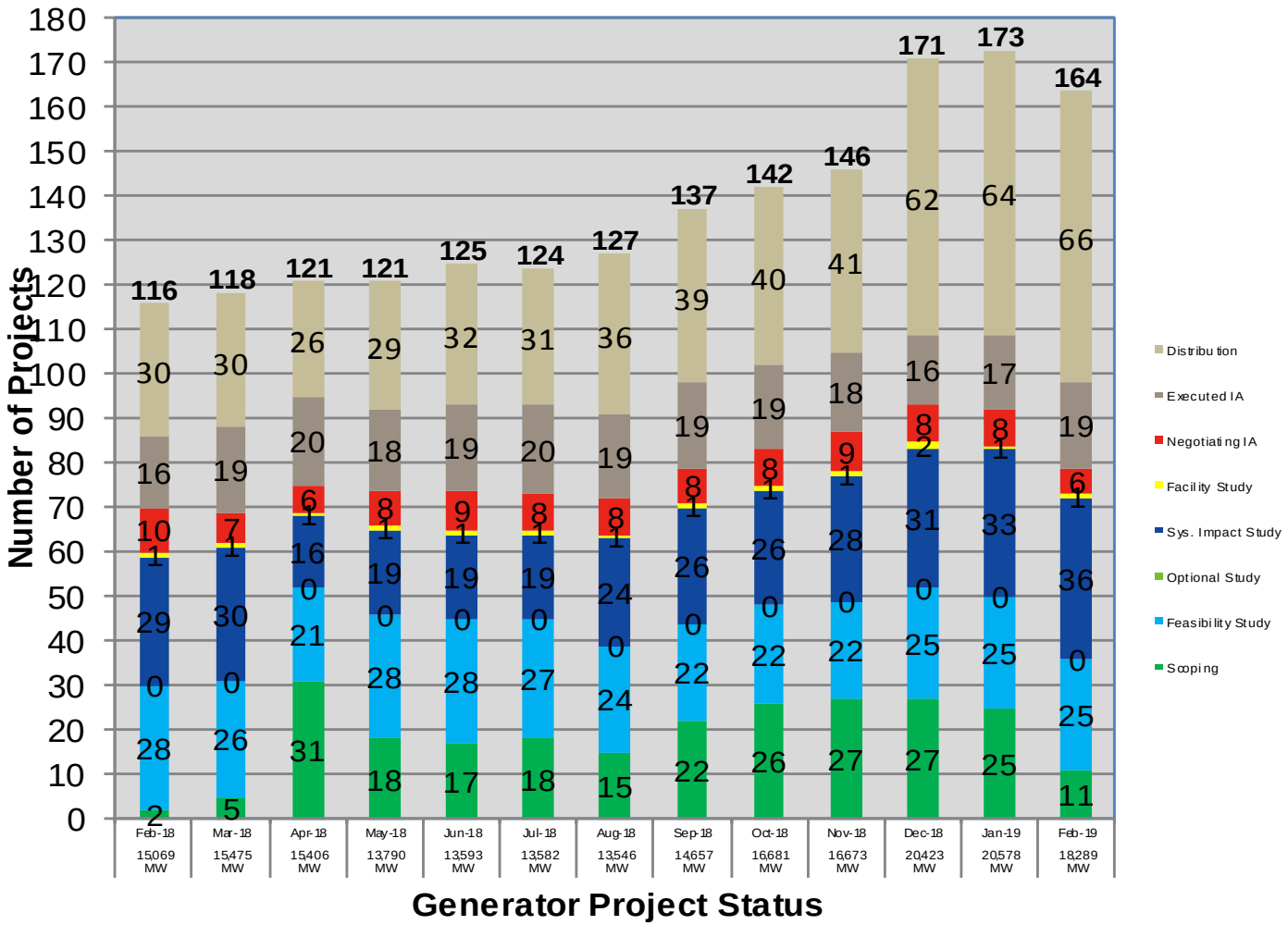
SEMA/RI Reliability Projects

Status as of 2/20/19

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	3
1782	Reconductor the J16S line	Dec-20	2
1724	Replace the Kent County 345/115 kV transformer	Nov-20	2
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	2
1790	Medway 115 kV circuit breaker replacements	Dec-21	2

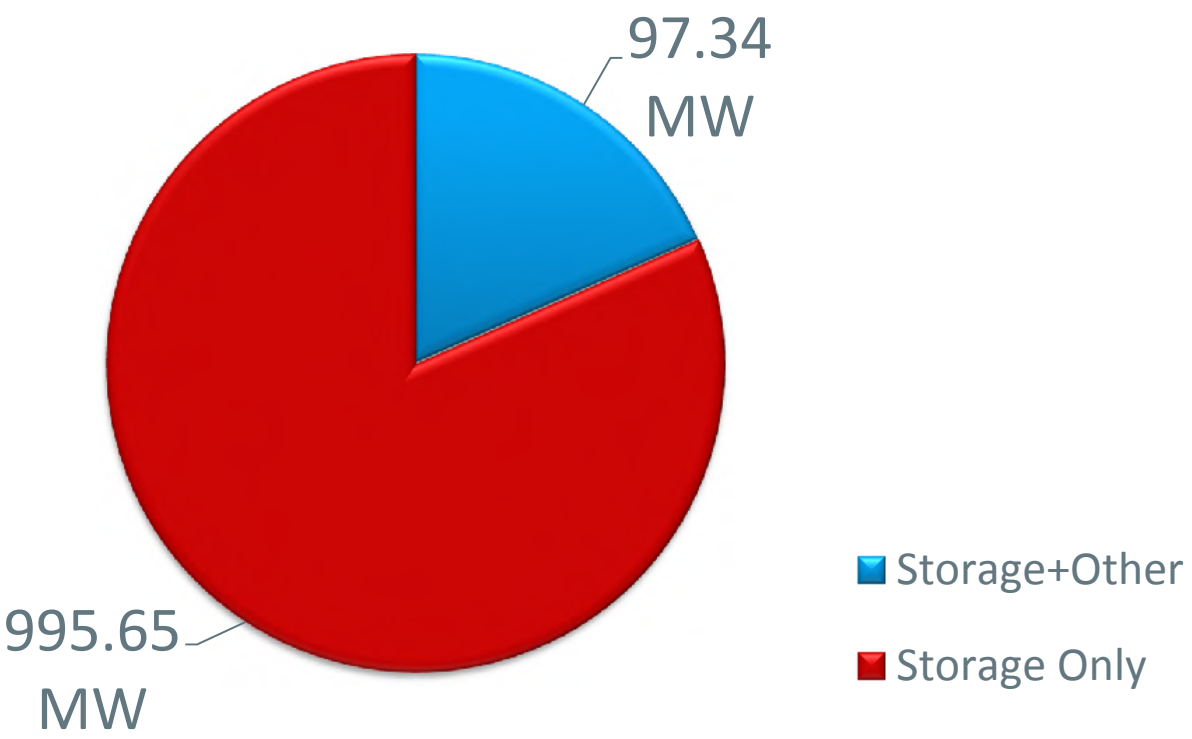
Status of Tariff Studies



As of February 2019, there are 5 ETU's in SIS, 3 in FS, 5 in Scoping, 1 Negotiating IA, and 2 with Executed IA
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of March 1, 2019)

Storage Projects are proposed as stand-alone storage or as co-located with wind or solar projects



OPERABLE CAPACITY ANALYSIS

Winter 2019 Analysis

Winter 2019 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Mar. - 2019[2] CSO (MW)	Mar. - 2019[2] SCC (MW)
Operable Capacity MW [1]	30,890	33,315
Active Demand Capacity Resource (+) [5]	312	322
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	802	802
Non Commercial Capacity (+)	156	156
Non Gas-fired Planned Outage MW (-)	1,520	1,741
Gas Generator Outages MW (-)	681	760
Allowance for Unplanned Outages (-) [4]	2,200	2,200
Generation at Risk Due to Gas Supply (-) [3]	1,395	1,534
Net Capacity (NET OPCAP SUPPLY MW)	26,364	28,360
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,165	18,165
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,470	20,470
Operable Capacity Margin	5,894	7,890

[1]Operable Capacity is based on data as of **February 19, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **February 19, 2019.**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 2, 2019.**

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

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

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2019 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	Mar. - 2019[2] CSO (MW)	Mar. - 2019[2] SCC (MW)
Operable Capacity MW [1]	30,890	33,315
Active Demand Capacity Resource (+) [5]	312	322
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	802	802
Non Commercial Capacity (+)	156	156
Non Gas-fired Planned Outage MW (-)	1,520	1,741
Gas Generator Outages MW (-)	681	760
Allowance for Unplanned Outages (-) [4]	2,200	2,200
Generation at Risk Due to Gas Supply (-) [3]	1,626	1,789
Net Capacity (NET OPCAP SUPPLY MW)	26,133	28,105
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,798	18,798
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,103	21,103
Operable Capacity Margin	5,030	7,002

[1]Operable Capacity is based on data as of **February 19, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **February 19, 2019.**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 2, 2019.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW)**.**

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

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Winter 2019 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 1, 2019 - 50/50 FORECAST using CSO

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	Active Capacity Demand 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
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
3/2/2019	**30890**	**312**	**802**	**156**	**1520**	**681**	**2200**	**1395**	**26364**	**18165**	**2305**	**20470**	**5894**
3/9/2019	30890	312	802	156	1787	496	2200	1442	26235	17962	2305	20267	5968
3/16/2019	30890	312	802	156	782	438	2200	946	27794	17585	2305	19890	7904
3/23/2019	30890	312	802	156	960	171	2200	798	28031	17000	2305	19305	8726

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. 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.
8. 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.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2018 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Winter 2019 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

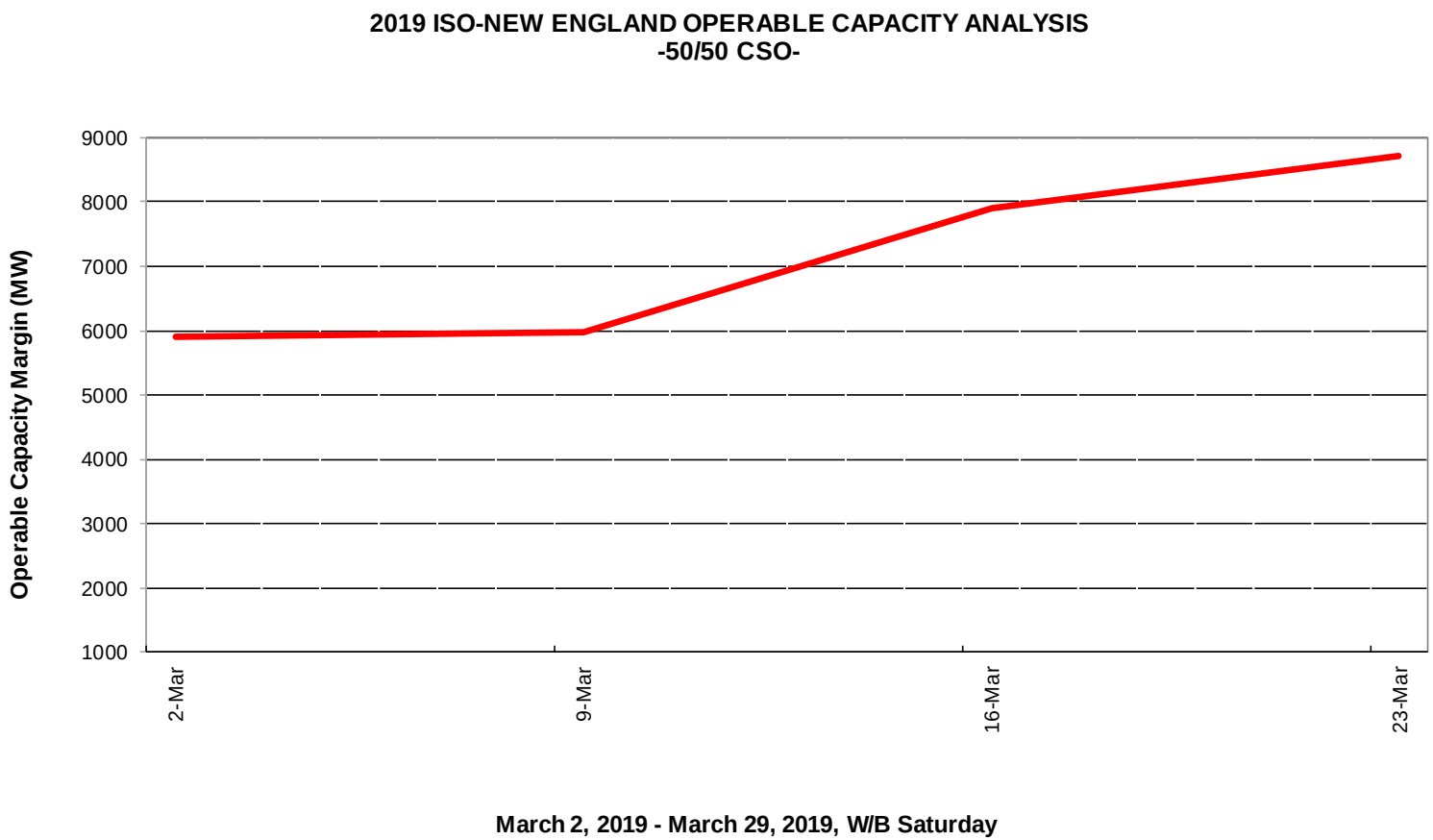
March 1, 2019 - 90/10 FORECAST using CSO

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

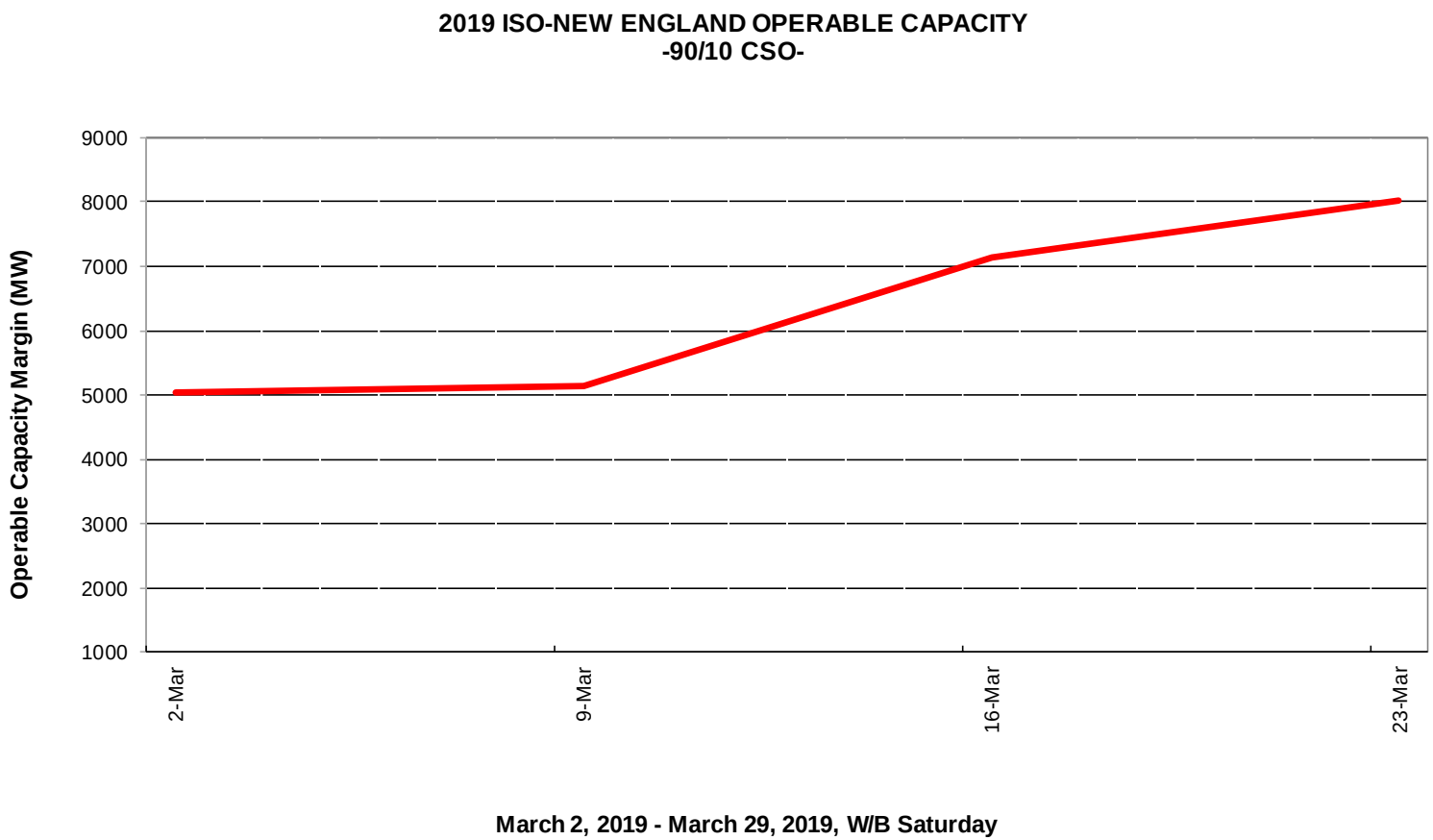
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
3/2/2019	**30890**	**312**	**802**	**156**	**1520**	**681**	**2200**	**1626**	**26133**	**18798**	**2305**	**21103**	**5030**
3/9/2019	30890	312	802	156	1787	496	2200	1657	26020	18589	2305	20894	5126
3/16/2019	30890	312	802	156	782	438	2200	1100	27640	18200	2305	20505	7135
3/23/2019	30890	312	802	156	960	171	2200	906	27923	17597	2305	19902	8021

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. 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.
8. 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.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2018 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Winter 2019 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2019 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Spring 2019 Analysis

Spring 2019 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2019[2] CSO (MW)	May - 2019[2] SCC (MW)
Operable Capacity MW [1]	31,013	33,315
Active Demand Capacity Resource (+) [5]	377	342
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	802	802
Non Commercial Capacity (+)	156	156
Non Gas-fired Planned Outage MW (-)	4,065	4,002
Gas Generator Outages MW (-)	642	740
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	24,241	26,473
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,743	19,743
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,048	22,048
Operable Capacity Margin	2,193	4,425

[1]Operable Capacity is based on data as of **February 19, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **February 19, 2019.**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 11, 2019.**

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

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

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Spring 2019 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May - 2019[2] CSO (MW)	May - 2019[2] SCC (MW)
Operable Capacity MW [1]	31,013	33,315
Active Demand Capacity Resource (+) [5]	377	342
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	802	802
Non Commercial Capacity (+)	156	156
Non Gas-fired Planned Outage MW (-)	4,065	4,002
Gas Generator Outages MW (-)	642	740
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	24,241	26,473
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,656	21,656
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,961	23,961
Operable Capacity Margin	280	2,512

[1]Operable Capacity is based on data as of **February 19, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Operable Capacity (CSO) and SCC values are based on data as of **February 19, 2019.**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 11, 2019.**

[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW)**.**

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

[5] Active Demand Capacity Resources (ADCRs) can participate in the Forward Capacity Market (FCM), have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.

Spring 2019 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

March 1, 2019 - 50/50 FORECAST using CSO

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	Active Capacity Demand 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
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
3/30/2019	31013	377	802	156	2309	1165	2700	0	26174	16459	2305	18764	7410
4/6/2019	31013	377	802	156	3506	2368	2700	0	23774	16199	2305	18504	5270
4/13/2019	31013	377	802	156	4161	2312	2700	0	23175	15671	2305	17976	5199
4/20/2019	31013	377	802	156	3922	900	2700	0	24826	15397	2305	17702	7124
4/27/2019	31013	377	802	156	3781	244	3400	0	24923	14649	2305	16954	7969
5/4/2019	31013	377	902	156	4782	577	3400	0	23689	18715	2305	21020	2669
5/11/2019	**31013**	**377**	**802**	**156**	**4065**	**642**	**3400**	**0**	**24241**	**19743**	**2305**	**22048**	**2193**
5/18/2019	31013	377	856	156	1881	910	3400	0	26211	20699	2305	23004	3207
5/25/2019	31013	377	856	156	507	267	3400	0	28228	21747	2305	24052	4176

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. 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.
8. 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.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2018 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Spring 2019 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

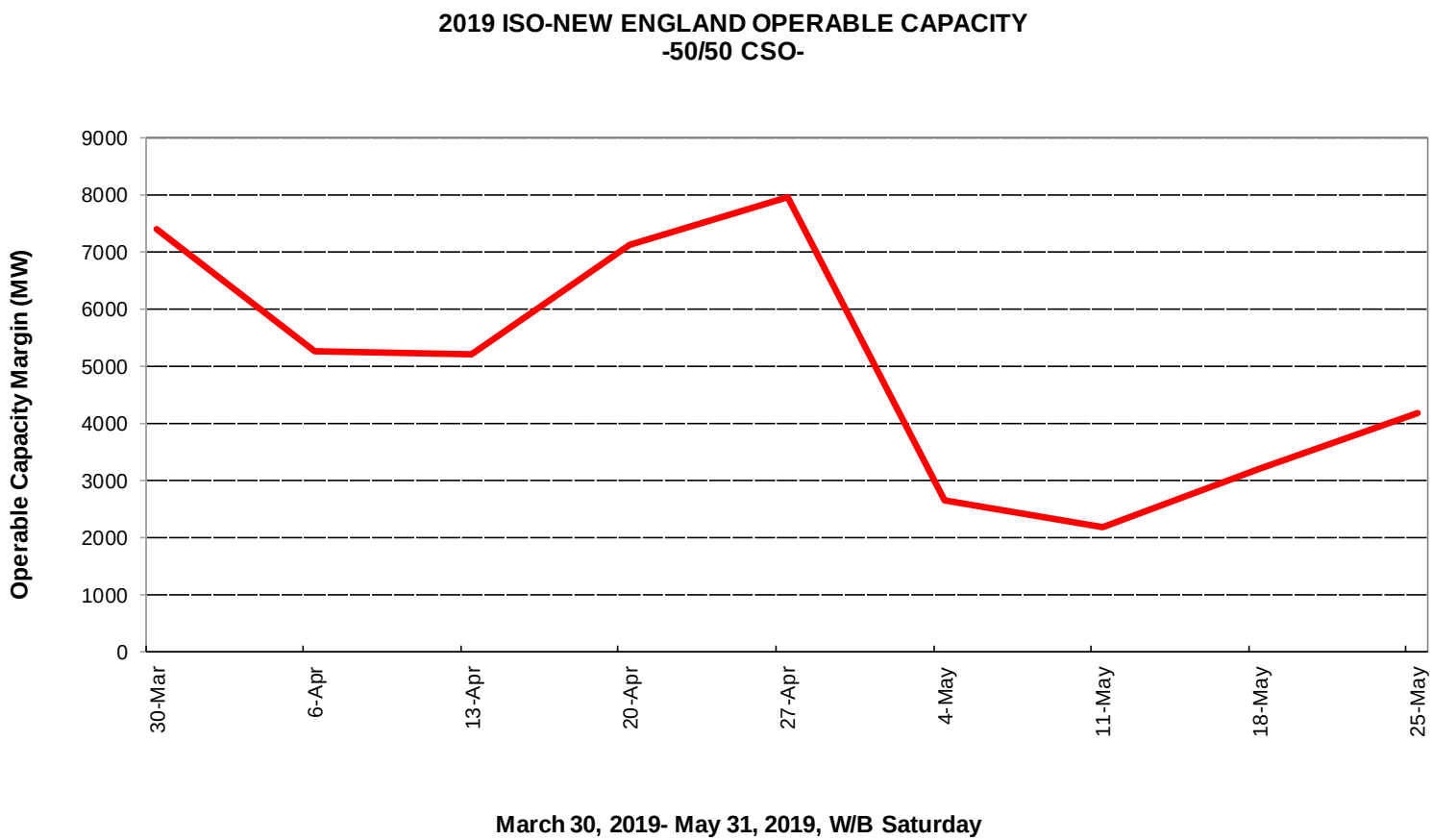
March 1, 2019 - 90/10 FORECAST using CSO

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

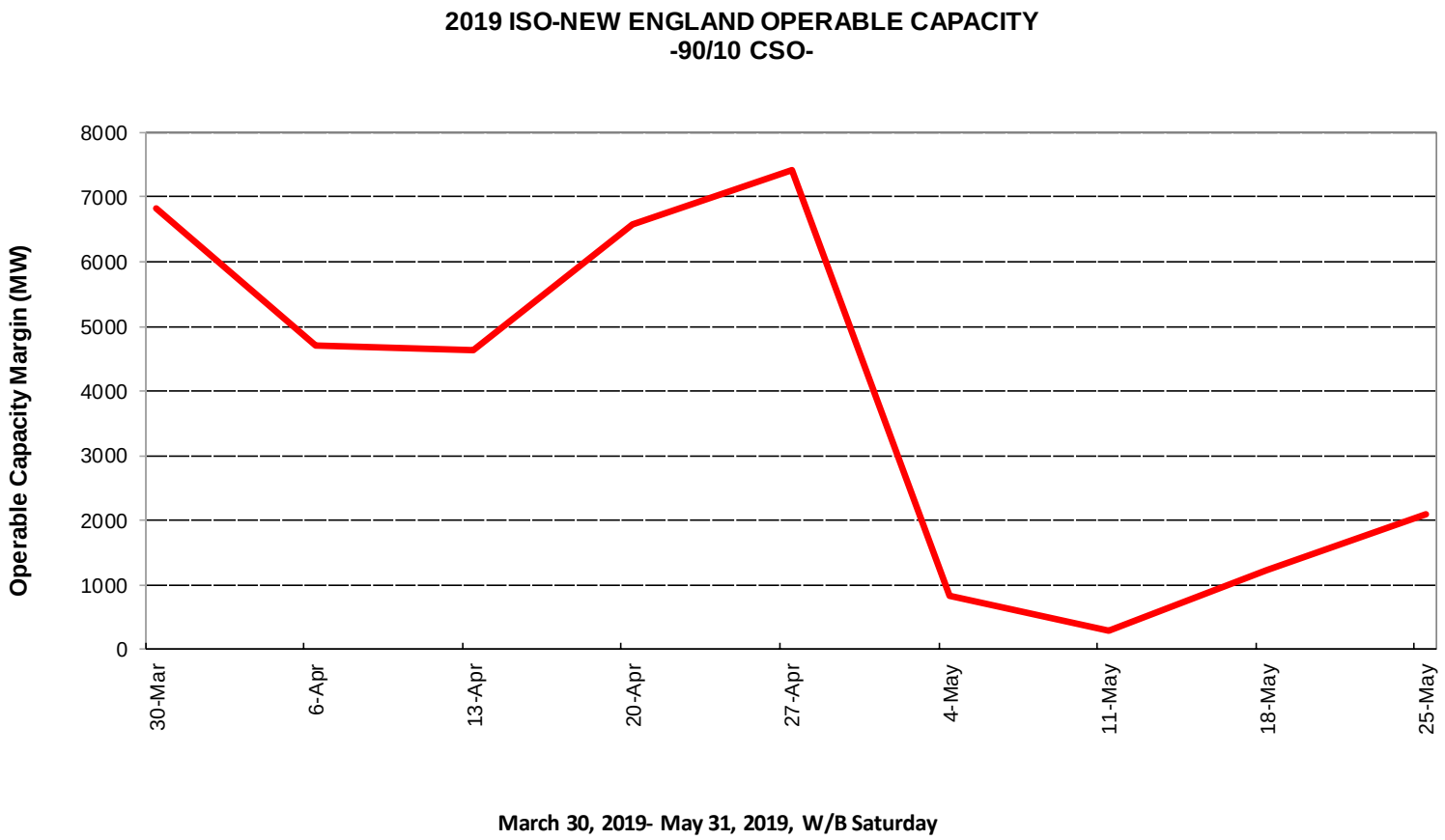
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
3/30/2019	31013	377	802	156	2309	1165	2700	0	26174	17041	2305	19346	6828
4/6/2019	31013	377	802	156	3506	2368	2700	0	23774	16773	2305	19078	4696
4/13/2019	31013	377	802	156	4161	2312	2700	0	23175	16229	2305	18534	4641
4/20/2019	31013	377	802	156	3922	900	2700	0	24826	15947	2305	18252	6574
4/27/2019	31013	377	802	156	3781	244	3400	0	24923	15198	2305	17503	7420
5/4/2019	31013	377	902	156	4782	577	3400	0	23689	20542	2305	22847	842
5/11/2019	**31013**	**377**	**802**	**156**	**4065**	**642**	**3400**	**0**	**24241**	**21656**	**2305**	**23961**	**280**
5/18/2019	31013	377	856	156	1881	910	3400	0	26211	22690	2305	24995	1216
5/25/2019	31013	377	856	156	507	267	3400	0	28228	23825	2305	26130	2098

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity Market (FCM). These resources will have the ability to obtain a CSO and also participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. 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.
8. 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.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2018 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,729 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Spring 2019 Operable Capacity Analysis
50/50 Forecast (Reference)



Spring 2019 Operable Capacity Analysis
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 the depletion of 30-minute reserve.	0 [1] 600
2	Declare Energy Emergency Alert (EEA) Level 1[4]	0
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	132 [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 MW values are based on a 26,458 MW system load based on the 2017 CELT Gross 50/50 Forecast minus PV and PDR and verified by the most recent voltage reduction test..
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

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	5% Voltage Reduction requiring 10 minutes or less	265 [3]
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		**2,542**

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 26,458 MW system load based on the 2017 CELT Gross 50/50 Forecast minus PV and PDR and verified by the most recent voltage reduction test..
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Jamie Blackburn, NEPOOL Counsel

DATE: March 6, 2019

RE: Participant-Sponsored Proposal(s): Treatment of Energy Efficiency Resources Under the FCM Pay-for-Performance Rules

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At its March 13, 2019 meeting, the Participants Committee may be asked to consider Tariff revisions to effectuate one or more Participant-sponsored proposal concerning the treatment of energy efficiency resources under the Forward Capacity Market ("FCM") Pay-for Performance ("PFP") rules. Two separate, but related Participant-sponsored proposals on this subject were considered by the Markets Committee, both of which failed to garner the requisite 60% support needed for a Markets Committee recommendation to the Participants Committee. This memorandum provides information on these two differing market rule proposals, including detail on the vote outcome at the Markets Committee.

BACKGROUND & OVERVIEW

In 2014, the FERC approved ISO-NE's PFP market rules, including the mechanism whereby resources are charged/credited during "Capacity Scarcity Conditions" based on their ability to cover their share of the system's total energy and reserve requirements during those periods.[1] Pursuant to direction from the FERC, the PFP construct does not assess energy efficiency resources performance penalties during Capacity Scarcity Conditions occurring in off-peak hours.[2] In the absence of applying the charges/credits to energy efficiency resources during those hours, the ISO adjusts the settlement of the Capacity Performance Payments to exclude energy efficiency resources and assesses a pro rata charge on all other capacity suppliers.

Due to Capacity Scarcity Conditions occurring on an off-peak day on September 3, 2019 (referred to here as the "Labor Day Event"), capacity suppliers incurred an additional $9.7 million in PFP charges due to the method by which the current tariff rules implement the exclusion of energy efficiency resources from the calculation of Capacity Performance Payments. Following that Labor Day Event, the New England Power Generators Association ("NEPGA") developed a proposal (the "NEPGA Proposal") to address generator concerns with the current treatment of energy efficiency under the FCM PFP rules. Conversely, the Vermont Energy Investment Corp. ("VEIC") developed an alternative approach to NEPGA (the "VEIC

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[1] *See ISO New England Inc.*, 149 FERC ¶ 61,009 (2014) (Order on Compliance). *See also ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (2014).

[2] *Id*. at P 89. During Capacity Scarcity Conditions occurring in off-peak hours, the Capacity Performance Score for energy efficiency resources is set to zero.

Proposal"). Further information on both Participant-sponsored proposals is included below, with additional detail provided in materials included with this memorandum.

A. *NEPGA/Dynegy Proposal*

The NEPGA Proposal, as sponsored by NEPOOL member, Dynegy, would allocate the PFP settlement imbalance caused by the current treatment of energy efficiency resources on a pro rata basis by State, based on the percentage of energy efficiency Capacity Supply Obligation (CSO) MWs located within each state. More specifically, the difference between PFP collections and amounts due resulting from the energy efficiency exemption during off-peak hours would be allocated to Regional Network Load based on the percentage of energy efficiency CSOs in each State.[3] Additional information on the NEPGA Proposal is included as Attachment A.

B. *VEIC Proposal*

The VEIC Proposal, put forth in response – and as an alternative – to the NEPGA Proposal would adjust the formula for how PFP charges are calculated in off-peak days by changing the calculation of the Balancing Ratio, which is used to calculate Capacity Performance Scores. Under the VEIC Proposal, there would be one formula for the Balancing Ratio for on-peak or seasonal peak hours (the current formula in use today), but another new and different formula for the Balancing Ratio in all other hours (i.e., off-peak hours). The CSOs associated with energy efficiency resources would be included in the calculation for on-peak and seasonal peak hours (as they are now) but would be entirely excluded from the calculation in other hours. Further detail on the VEIC Proposal is included as Attachment B.

NEPOOL MARKETS COMMITTEE CONSIDERATION

The NEPOOL Markets Committee discussed, debated and considered both the NEPGA Proposal and VEIC Proposal over the course of five meetings.

During the Markets Committee review process, the ISO explained that while it was sympathetic to the proponents' discomfort with the status quo regarding how the costs associated with the exclusion of energy efficiency resources during off-peak hours are allocated, the ISO made clear that, at this time, it does not support either the NEPGA Proposal or the VEIC Proposal. The ISO provided further explanation of its position in a memorandum presented to the Markets Committee (dated January 3, 2019), which is included with this memo as Attachment C.

[3] During the Markets Committee review process, NEPGA initially put forth an additional proposal that would require energy efficiency resources to be subject to performance charges and payments during all Capacity Scarcity Conditions, including on off-peak days. The Markets Committee did not vote on that proposal, but did instruct the Demand Resources Working Group ("DRWG") to consider how energy efficiency resources' performance in all hours for existing and new measures could be established and, what, if any, additional methodological standards and reporting mechanisms are required to accommodate such a change. The DRWG will report potential options back to the Markets Committee, which may include time and cost estimates associated with implementing each option.

The Markets Committee voted on both proposals at its March 5-6, 2019 meeting. First, with the intent of replacing NEPGA's proposed solution with an alternative approach, VEIC offered its proposal as a motion to amend the NEPGA Proposal. The Markets Committee voted, but failed to support that VEIC motion to amend, with a 58.38% Vote in favor.[4] The NEPGA Proposal was then voted, but also failed to achieve Markets Committee support, with a 34.95% Vote in favor.[5]

Since neither proposal achieved Markets Committee support, if either proposal is not put forth for a vote at the Participants Committee on March 13, neither NEPOOL nor the ISO will argue in response to advocates seeking FERC approval of those proposals that the advocates failed to complete or follow the NEPOOL Participant Processes. If, instead, one or both proponents seek Participants Committee consideration of its Proposal, the following form of resolution may be used for Participants Committee action:

> RESOLVED, that the Participants Committee support revisions to Market Rule 1, as proposed by [Dynegy Marketing and Trade, LLC] [Vermont Energy Investment Corp.] and as circulated to this Committee with the March 6, 2019 supplemental notice, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Were either Proposal to be voted and passed by the Participants Committee, the Committee also needs to consider how best to achieve the outcome sought by that Proposal. The Participants Committee could use the following additional form of resolution for that purpose:

> RESOLVED, that the Participants Committee authorizes and directs NEPOOL Counsel to work with the proponents of the NEPOOL-supported Tariff revisions to file, if necessary, a complaint with the FERC under Section 206 of the Federal Power Act to show that, without the NEPOOL-supported Tariff revisions, the current FCM rules are not just and reasonable or are unduly discriminatory or preferential.

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[4] The individual Sector votes were Generation (1.87% in favor, 14.93% opposed), Transmission (14.93% in favor, 1.87% opposed), Supplier (3.05% in favor, 13.74% opposed, 6 abstentions), Alternative Resources (4.95% in favor, 11.09% opposed, 3 abstentions), Publicly Owned Entity (16.79% in favor), End User (16.79% in favor, 2 abstentions).

[5] The individual Sector votes were Generation (11.99% in favor, 4.80% opposed, 1 abstention), Transmission (1.87% in favor, 14.93% opposed), Supplier (11.19% in favor, 5.60% opposed, 5 abstentions), Alternative Resources (9.90% in favor, 6.15% opposed, 3 abstentions), Publicly Owned Entity (0% in favor, 16.79% opposed), End User (0% in favor, 16.79% opposed).

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.13.7.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales. (b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures~~, prior to June 1, 2023,~~ if the Capacity Scarcity Condition occurs during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided shall be equal to the applicable reported monthly performance value; if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided shall be zero.

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(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

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(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource's Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource's Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the

higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval minus the product of the resource's Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that ~~prior to June 1, 2023,~~ for an On-Peak Demand Resource or a Seasonal Peak Demand Resource, (i) if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided and Capacity Supply Obligation associated with any Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score; and (ii) for any Energy Efficiency, Load Management, or Distributed Generation measures reflected as a reduction in the load forecast as described in Section III.12.8 the Actual Capacity Provided and Capacity Supply Obligation shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

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III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5455/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (FCAcp – FCAsp) – (12 months x FCAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.

For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then

the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month; provided, however, that for the amount of positive sum caused by the xxxxx due to the exclusion of Energy Efficiency asset Actual Capacity Provided and Capacity Supply Obligation from the calculation of an On-Peak Demand Resource or a Seasonal Peak Demand Resource Capacity Performance Score under Section III.13.7.2.4 and Section III.13.7.2.2(c)(i), such amount shall instead be charged to Regional Network Load *pro rata* by New England state according to the percentage of total Energy Efficiency asset CSO MWs located within that state, where each state's percentage is equal the EE CSO MWs physically located in the state divided by total system-wide EE CSO MWs at the time of the Capacity Scarcity Condition. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).

(b) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b)

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), less PER adjustments for resources in the zone as defined in Section III.13.7.1.2, and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied.

III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. A Market Participant with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to the following charges and adjustments:

III.13.7.5.1.1.1 Forward Capacity Auction Charge.

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total FCA Costs are the sum of, for all Capacity Zones, Capacity Supply Obligations in each zone (the total obligation awarded to resources in the Forward Capacity Auction for the Obligation Month in the zone, excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction and excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4(c)) multiplied by the applicable Capacity Clearing Price.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.2 Annual Reconfiguration Auction Charge.

The total annual reconfiguration auction charge, for each Capacity Zone and each associated annual reconfiguration auction, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone Annual Reconfiguration Auction Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone Annual Reconfiguration Auction Costs, for each Capacity Zone, are the Total Annual Reconfiguration Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total Annual Reconfiguration Auction Costs are the sum, for all Capacity Zones and each associated annual reconfiguration auction, of the product of the Capacity Supply Obligations acquired through the annual reconfiguration auction in each zone (adjusted for any obligations procured in the annual reconfiguration auction that are subsequently terminated pursuant to Section III.13.3.4(c)) and the zonal annual reconfiguration auction clearing price, minus the sum, for all Capacity Zones, of the product of the amount of any Capacity Supply Obligation shed through the annual reconfiguration auction in each zone and the applicable annual reconfiguration auction clearing price.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

SETTLEMENT SHORTFALL CAUSED BY THE ENERGY EFFICIENCY RESOURCE EXEMPTION FROM SCARCITY CONDITION CHARGES IN OFF-PEAK HOURS: STAGE 1

REVISION 1

NEPOOL Markets Committee Meeting
March 5, 2019

Bruce Anderson
New England Power Generators Association, Inc.

The Avoidance and Reallocation of Charges

- **Energy efficiency (EE) resources are exempt from Capacity Scarcity Condition charges/credits during off-peak hours, causing a settlement imbalance. ISO-NE adjusts the settlement of charges and credits by assessing a *pro rata* charge on all capacity suppliers to balance the equation (e.g., Capacity Scarcity Conditions on September 3, 2018, caused capacity suppliers to incur $9.7 million in settlement imbalance charges).**

- **RESULT: net performers are paid less and net under-performers are charged more than they would otherwise but for the avoidance and reallocation of EE performance obligation.**
- **This was not part of the original design – it came as a result of the Commission ordering the EE exemption.**

- **ISO-NE complied by filing Tariff changes that set the Capacity Performance Score for an Energy Efficiency Demand Response Asset to zero.**
- **This treatment is necessary because an On-Peak Demand Resource or Seasonal Peak Demand Resource may include both energy efficiency and non-energy efficiency assets (e.g., Distributed Generation). Thus, ISO-NE cannot simply "not count" these Demand Resource types in assessing PfP charges and credits. *See* Order on Compliance Filing, 149 FERC 61,009, at 33 (2014).**

The Current Treatment Undermines the FCM Design and Violates Basic Legal Principles

- **The arbitrary assignment of the settlement imbalance caused by the EE exemption to capacity suppliers: (1) dilutes the FCM price signals; (2) is unduly discriminatory; and (3) violates the cost causation/beneficiary pays principle.**

- **The Commission did not dictate any cost allocation methodology for the EE exemption. NEPGA proposes an allocation methodology that: (1) avoids the dilution of price signals; and (2) assigns the costs to those entities that have legally caused the settlement imbalance and who benefit from the EE exemption.**

Stage 1 Solution

- **NEPGA's overall proposal is a two-stage solution that seeks to allocate the settlement imbalance on a cost-causation/beneficiary pays basis in the short-term, and to hold EE resources that have assumed a Capacity Supply Obligation to a standard consistent with that of all other capacity resources.**

- **NEPGA asks for a vote here only on the shorter-term, or "Stage 1" proposal.**

- **Stage 1 Proposal : For effect upon acceptance by the Commission, the assumption of EE asset-avoided PfP charges *pro rata* by state based on the percentage of EE asset CSO MW located within the state, though transmission rates. A state may avoid the re-allocation if the EE resources located in their state produce off-peak hour measurements (thus avoiding the settlement imbalance caused by the exemption of that state's EE resources from off-peak hour charges).**

Stage 1: Assumption of EE Exemption Costs

- **The distribution of EE resources in New England is largely a function of the respective state policies, with the majority of EE resources located in Massachusetts and Connecticut and paid for through charges to local distribution company customers in those states.**

- **The New England states appropriately benefit from EE resources holding CSOs, yet inappropriately also receive exemption from their performance obligations under a CSO in off-peak hours.**

- **The cost of EE resources participating in the FCM – that is, the cost of the exempted performance obligation in off-peak hours - should therefore be allocated to New England states *pro rata* based on the amount of EE capacity MWs in each state through Regional Network Load rates.**

Necessary Tariff Changes

- **Stage 1**

  - **Section III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments: providing that any difference between PfP collections and amounts due to the paid as a result of the EE exemption are allocation to Regional Network Load to each pro rata based on the percentage off EE CSO in each state.**

Questions?

Bruce Anderson -- banderson@nepga.org -- 617-902-2347

III.13.7.2.3 Capacity Balancing Ratio.
For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation =

(i) For each interval that occurs during Demand Resource On Peak or Demand Resource Seasonal Peak Hours, the total amount of Capacity Supply Obligations in the New England Control Area during the interval.
(ii) For each interval that occurs outside of Demand Resource On Peak or Demand Resource Seasonal Peak Hours, the total amount of Capacity Supply Obligations in the New England Control Area during the interval excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation =

(i) For each interval that occurs during Demand Resource On Peak or Demand Resource Seasonal Peak Hours, the total amount of Capacity Supply Obligations in the New England Control Area during the interval.
(ii) For each interval that occurs outside of Demand Resource On Peak or Demand Resource Seasonal Peak Hours, the total amount of Capacity Supply Obligations in the New England Control Area during the interval excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy

imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation =

(i) For each interval that occurs during Demand Resource On Peak or Demand Resource Seasonal Peak Hours, the total amount of Capacity Supply Obligations in the Capacity Zone during the interval.

(ii) For each interval that occurs outside of Demand Resource On Peak or Demand Resource Seasonal Peak Hours, the total amount of Capacity Supply Obligations in the Capacity Zone during the interval excluding the Capacity Supply Obligations associated with Energy Efficiency measures in the Capacity Zone.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

Synapse
Energy Economics, Inc.

Energy Efficiency in Capacity Scarcity Condition Events

NEPOOL Markets Committee

March 5, 2019

Doug Hurley
On behalf of Vermont Energy Investment Corp.

Summary of Proposed Change

During DR On Peak or Seasonal Peak hours

$$\text{BR} = \frac{(Load + Reserves\ Req't)}{Total\ CSO}$$

In all other hours

$$\text{BR} = \frac{(Load + Reserves\ Req't)}{(Total\ CSO - CSO\ for\ EE)}$$

Reminder: Load = Total ACP excluding RT Reserves, where ACP for EE is set to 0 during DR On Peak or Seasonal Peak hours

EE Resources remain in the "mutual insurance pool" for all scarcity events.

Approach only exists as long as DR On Peak and Seasonal Peak hours exist. If and when EE resources are subject in all hours, this change is revoked.

Reminder from Nov - Feb

- Current calculation of BR when Capacity Scarcity Conditions occur during DR On Peak or DR Seasonal Peak hours seems to work as expected
- Current calculation of BR when these events occur outside of EE performance hours (e.g., Labor Day 2018) had unexpected results. EE resources are treated as if they had hit the stop-loss limits, and all resources suffer the consequence.
- Original proposal had three components:
  - Primary component: Adjustment to Balancing Ratio
  - Associated changes to:
    - Actual Capacity Provided from EE
    - Share of charges or credits from over/under-collection (the “mutual insurance pool”)
- Discussion with NEPOOL and ISO-NE has already led to numerous compromises and adjustments in the proposal. Proposal now has just one component: Adjustment to Balancing Ratio

Framing the Issue

- Not correct to refer to this as a "Settlement Shortfall caused by Energy Efficiency" that must be recovered from all resources
- The issue is more correctly identified as "An Adjustment to the Balancing Ratio." Current calculation deflates the Balancing Ratio in some hours by removing EE from the numerator but not from the denominator
- Our proposal rectifies the current situation and the mutual insurance pool reverts to its original intent, to cover resources that reach stop-loss limits.
- Without this change the mutual insurance pool triggers charges to all resources with a CSO during any scarcity condition that occurs outside of DR On Peak or Seasonal Peak hours, introducing uncertainty for all participants.

Response to Feedback

- Thank you to those participants who have offered thoughtful, considered feedback.
- I understand that some participants are frustrated that EE resources are subject to PfP only during DR On Peak and Seasonal Peak hours.
  - This treatment is in direct compliance with the FERC order.
  - Cannot be changed until at least CP-15, and will be addressed later today in this meeting.
  - Our proposal is separate from addressing that issue. It would apply only if and as long as the FERC-ordered treatment exists.
  - As such, for the sake of the Committee and our Chairman, please refrain from comments on the Stage 2 proposal until that issue is raised later today.
- This approach will not materially change total payment or penalty during an event. Examples provided.

Proposed Change to Balancing Ratio

- Current formula for Balancing Ratio during any interval is:
  - BR = (Load + Reserve Requirement) / Total CSO, where
  - Load = "the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval."
- Because the ACP for EE is set to zero in any interval outside of DR On Peak or Seasonal Peak hours, EE is excluded from the numerator, but not excluded from the denominator.
  - This approach artificially deflates the balancing ratio
- Our proposal is to change "Total CSO" to "(Total CSO – EE CSO)" in the denominator for all intervals outside of DR On Peak or Seasonal Peak hours
- Under our proposal, the BR for any interval would be calculated based upon those resources that are subject to payments or penalties in that interval, as the FERC order intended.

Mutual Insurance Pool

- Intent of this component of the PfP design was to issue a small credit to all resources with a CSO during any month with Capacity Scarcity Conditions wherein no resource has a significant stop-loss amount.
- If a resource hits a stop-loss limit an under-collection would result. If large enough, a charge is applied pro-rata to all resources with CSO.
- Proposed change to BR would result in under-collection only if a resource hits stop-loss limits, reverting the Mutual Insurance Pool to it's original intent.
- Proposal: EE included in the insurance pool. No change to the existing tariff language. All resources receive a credit during all "normal" events, and risk suffering a charge if a resource hits the stop-loss limit.

Examples, p.1

Several participants requested examples that show only how their resources might be affected. The examples show total event payments to a hypothetical 100 MW resource on Labor Day under various approaches.

	Current Rules		VEIC Proposal	
Event ACP:	100 MW	10 MW	100 MW	10 MW
Capacity Performance Pay	$148k	$(332k)	$119k	$(361k)
Pool Credit / (Charge)	$(22k)	$(22k)	$5k	$5k
Total Event Pay	**$126k**	**$(354k)**	**$124k**	**$(356k)**

Examples, p.2

Total event payments to a hypothetical 100 MW resource if EE is required to report in all hours, as NEPGA suggests for Stage 2. Various assumptions for EE performance to show potential variation.

	NEPGA EE at Full CSO		NEPGA EE at 75% CSO		NEPGA EE at 0 MW	
Event ACP:	100 MW	10 MW	100 MW	10 MW	100 MW	10 MW
Capacity Performance Pay	$111k	$(369k)	$120k	$(360k)	$148k	$(332k)
Pool Credit / (Charge)	$5k	$5k	$5k	$5k	$5k	$5k
Total Event Pay	**$115k**	**$(365k)**	**$125k**	**$(355k)**	**$153k**	**$(327k)**

Examples demonstrate that the long-term solution sought by NEPGA does not enact a material difference from either current rules or our proposal. As expected, if we assume EE at 75% (roughly the BR on Labor Day), the total event payment is nearly identical to current rules.

Tariff Language

Parallel changes in subsections (b) and (c)

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

i. If the interval Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval.

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total CSO =

i. For each interval that occurs during Demand Resource On Peak or Demand Resource Seasonal Peak Hours, the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

ii. For each interval that occurs outside of Demand Resource On Peak or Demand Resource Seasonal Peak Hours, the total amount of Capacity Supply Obligations in the New England Control Area during the interval excluding the Capacity Supply Obligations associated with Energy Efficiency measures.

Comments on NEPGA Approach

- NEPGA proposes a combination of two approaches. The second part requires that EE resources provide load reduction values in every hour of the year beginning with CP-14.
- This issue is being referred to the DRWG to be resolved.
- Our proposed approach would be enacted immediately, and would be effective only if and until EE resources are subject to penalties or payments in all hours.
- NEPGA continues to repeat false justification that has already been debunked and dismissed. Resources consisting of both EE and non-EE assets are *de minimus* and no longer an impact. (NEPGA Stage 1 at Slide 2)
- We agree that the current treatment violates cost causation principles, but the NEPGA approach only prolongs this error. Our approach rectifies it by correctly calculating the BR rather than creating a false "settlement imbalance" akin to a stop-loss that has not occurred, which is then distributed to all capacity resources.

Comments on ISO-NE Memo

- ISO-NE released a memo dated January 3, 2019. We agree that the status quo is inconsistent with cost-causation principles.
- We disagree with the assessment that our proposal shifts the cost of a "shortfall" to non-EE resources. Instead, our proposal correctly applies the Balancing Ratio to all resources subject to PfP payments in each interval, whenever that interval occurs.
- Status quo is contrary to the intent of the FERC order, and narrowly singles out one resource for guaranteed penalties.
- The current implementation of the tariff guarantees that EE resources will always receive a charge during any event outside of EE performance hours. There is no opportunity to avoid this charge, and no opportunity to earn offsetting payments, regardless of actual EE performance.
- Our proposal is simple and straightforward, and we hope it can be adopted quickly.

Summary of Proposed Change

During DR On Peak or Seasonal Peak hours

$$\text{BR} = \frac{(Load + Reserves\ Req't)}{Total\ CSO}$$

In all other hours

$$\text{BR} = \frac{(Load + Reserves\ Req't)}{(Total\ CSO - CSO\ for\ EE)}$$

Reminder: Load = Total ACP excluding RT Reserves, where ACP for EE is set to 0 during DR On Peak or Seasonal Peak hours

EE Resources remain in the "mutual insurance pool" for all scarcity events.

Approach only exists as long as DR On Peak and Seasonal Peak hours exist. If and when EE resources are subject in all hours, this change is revoked.

Process

- This amendment would replace the NEPGA motion in its entirety.
- A vote in favor of the amendment would remove NEPGA's proposed tariff changes, and replace them with the one change to the calculation of the Balancing Ratio.
- Thank you for your support for this simple, effective change.

Any confusion?

Guide dog in training Horace. February 2019.
Photo Credit: Kerry Lemerise. Puppy Program Manager. Guiding Eyes for the Blind.

ISO new england

memo

To: NEPOOL Markets Committee

From: ISO New England

Date: January 3, 2019

Subject: Stakeholder Proposals on PFP Settlement and Energy Efficiency

The ISO has been asked to provide its views on two stakeholder-led proposals concerning the treatment of energy efficiency (EE) resources under the Forward Capacity Market (FCM) Pay-for-Performance (PFP) rules. This memorandum provides the ISO's perspective.

Context and Background

In its May 30, 2014 order on the ISO's PFP filing, the Commission ordered changes to the ISO's proposed treatment of EE resources.[1] Specifically, the Commission directed (using defined Tariff terms) that "energy efficiency resources' Capacity Performance Payments [be] calculated only for Capacity Scarcity Conditions during hours in which demand reduction values are calculated under the Tariff for that particular type of resource."[2] The ISO complied by excluding EE resources from the calculation of Capacity Performance Payments for all but those hours, as directed, and its July 24, 2014 compliance filing explained the revised Tariff provisions to that effect.[3] The Commission accepted the ISO's Tariff revisions on October 2, 2014.[4]

As discussed at the Markets Committee recently, this treatment of EE resources produces a settlement shortfall in pool-wide Capacity Performance Payments. In simple terms, to settle all Capacity Performance

[1] *ISO New England Inc. and New England Power Pool*, Order on Tariff Filing and Instituting Section 206 Proceeding, 147 FERC ¶ 61,172 (2014) (at https://www.iso-ne.com/static-assets/documents/regulatory/ferc/orders/2014/may/er14_1050_000_5_30_14_pay_for_performance_order.pdf).

[2] *Id.,* at P 89. For simplicity, the hours for which EE demand reduction values are not calculated are referred to as "off-peak hours."

[3] *See ISO New England Inc. and New England Power Pool*, Compliance Filing of Two-Settlement Forward Capacity Market Design, Docket No. EL14-52-000 (filed July 14, 2014) at pp. 7-8 (at https://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14_2419_000_pfp_comp_7_14_2014.pdf). Note that the ISO's Tariff language on compliance was structured to also accommodate "mixed measure types" (that is, EE and non-EE) comprising the same passive demand response capacity resource, a situation that complicates the relevant Tariff language but is peripheral to this memorandum.

[4] *See ISO New England Inc.*, Order on Compliance Filing, 149 FERC ¶ 61,009 (2014) at P 33 ("We therefore find that ISO-NE's proposed treatment of energy efficiency resources complies with the Commission's directive in the May 30, 2014 Order.") (At https://www.iso-ne.com/static-assets/documents/2014/10/er14-2419-000_-001_10-2-14_pay_for_performance_compliance_order.pdf.)

Payments (both credits and charges) to market participants for a Capacity Scarcity Condition (CSC), the credits or charges from which EE resources are excluded must be allocated to someone else.

This settlement shortfall was brought into sharp focus following the September 3, 2018 Capacity Scarcity Condition; the Appendix to this memorandum summarizes the relevant data for that event.

The Commission's orders in the PFP proceedings did not direct changes to the ISO's initially filed PFP rules governing the disposition of any Capacity Performance Payment imbalances. Those rules stipulate that any settlement shortfall (or surplus) be tabulated monthly and allocated to all resources with Capacity Supply Obligations (CSOs), on a CSO pro-rata basis.[5] Since over 90 percent of all CSO MW are presently non-EE resources, over 90 percent of the credits or charges from which EE resources are excluded are allocated to non-EE CSO resource owners.

At the last Markets Committee meeting, several stakeholders noted they interpreted the Commission's orders as intending to create an exemption for EE resources from *any* PFP-related charges (when associated with Capacity Scarcity Conditions during excluded hours) – including an exemption from the CSO pro-rata share of any PFP settlement shortfall. However, the Commission's orders did not direct the latter; rather, they directed only that EE resources be excluded from Capacity Performance Payments during hours for which EE demand reduction values are not calculated.[6]

With regard to the broader issue of who should bear the costs of the settlement shortfall arising from EE resources' treatment, a review of the record in these proceedings is not dispositive of the Commission's intent. Indeed, on that issue, the Commission is silent.

Some stakeholders also inquired whether the underlying problem lies in the implementing Tariff rules, rather than the Commission's directive. In brief, no. The settlement shortfall is a symptom of a larger issue the Commission's directive created but did not dispose with: If any capacity resources are excluded from Capacity Performance Payments, who should cover the charges that the excluded resources do not remit? Those costs must be borne by someone, in some form, to complete the market's settlement.

As a case in point, the Tariff's current rules deem EE resources' performance to be zero during off-peak CSC events.[7] As an alternative, if the Tariff deemed EE resources to be performing perfectly, but their

[5] We simplify here; those allocation rules, which were developed as part of the stop-loss mechanism under PFP, have additional provisions not at issue here. The allocation rules for imbalances of pool-wide Capacity Performance Payments are found at Market Rule 1, Section III.13.7.4, "Allocation of Deficient or Excess Capacity Performance Payments."

[6] On an annual basis, EE resources are excluded from Capacity Performance Payments approximately 96% or more of the hours each year. The demand reduction value of an On-Peak Demand Resource comprising EE measures is determined only for Demand Resource On-Peak Hours, which account for about 4% of the hours each year. The demand reduction value of a Seasonal Peak Demand Resource comprising EE measures is determined only for Demand Resource Seasonal Peak Hours, the number of which change each year but are fewer than Demand Resource On-Peak Hours.

[7] Market Rule 1, Section III.13.7.2.2(c)(i). As noted previously, EE resources do not submit demand reduction value data for off-peak hours (more on that below).

actual performance fell short of that, then the costs of their actual underperformance (which they do not remit due to their exclusion) would no longer manifest in the form of a pool-wide settlement shortfall at the end of the Obligation Month. Instead, that same settlement shortfall dollar amount would reappear in a different place: It would produce lower (or more negative) Capacity Performance Payments to all non-EE CSO holders.[8] In other words, the settlement shortfall dollar amount would take a different form, but would still be borne by non-EE CSO resource owners.

In summary, the fundamental issue of who should bear the costs of EE resources' treatment under the Commission's orders cannot be resolved with simple tweaks to the PFP settlement rules or with an arbitrary assumption of EE resources' performance during off-peak CSCs. Absent an alignment of EE resources' settlements with their actual performance, the costs of EE resources' exclusion from Capacity Performance Payments must be allocated to someone.

Stakeholders' Proposals

Two stakeholder proposals on this subject were discussed at the November and December Markets Committee meetings:[9]

- The New England Power Generators Association (NEPGA) presented two proposed changes to the Tariff, one to apply prior to Capacity Commitment Period 14 (2023/24), and another to apply to that period and beyond. The December presentation describing this proposal is at https://www.iso-ne.com/static-assets/documents/2018/12/a3_nepga_presentation_settlement_shortfall_energy_efficiency.pdf

- Vermont Energy Investment Corporation (VEIC)/Synapse Energy Economics Consultants (Synapse) proposed several interrelated changes to the Tariff, effective concurrently. The December presentation describing this proposal is at https://www.iso-ne.com/static-assets/documents/2018/12/a3a_veic_presentation_energy_efficiency_in_capacity_scarcity_condition_events.pdf

ISO Perspective

As a preliminary matter, the ISO views the near-term issue here as one of cost allocation. The Commission's order directing EE resources' exclusion from Capacity Performance Payments during certain hours created a (new) settlement shortfall, but the Commission did not direct how the shortfall created by its ruling should be addressed.

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[8] This occurs because assuming artificially high performance (relative to actual performance) for a resource results in an artificially high CSC Balancing Ratio. An artificially high Balancing Ratio, in turn, results in lower performance credits to all over-performing capacity resources, and higher performance charges to all under-performing capacity resources.

[9] We caveat that this memorandum is based on the ISO's understanding of the proposals presented at the December Markets Committee meeting. Any updates provided by the proposals' proponents will be posted to the Markets Committee page of the ISO's website at https://www.iso-ne.com/committees/markets/markets-committee.

The Status Quo. We are sympathetic to stakeholders' discomfort with the status quo cost allocation of the EE-related settlement shortfall. In general, there are two established principles governing appropriate cost-allocation rules: cost-causation and beneficiary-pays. It appears that the current allocation of the settlement shortfall that occurs due to EE resources' exclusion from Capacity Performance Payments during certain hours is not consistent with either of these two principles. As noted, approximately 90 percent of the settlement shortfall associated with the EE exclusion from Capacity Performance Payments during certain hours is borne by non-EE CSO resource owners, who neither caused this settlement shortfall nor benefited from the Commission-directed exclusion.

Near Term. For the near term approaches (prior to CCP 14), the ISO is not comfortable with either of the current stakeholder proposals. Although the details are involved, a central feature of the VEIC/Synapse proposal is to shift the settlement shortfall dollars into other, performance-related credits or charges levied on non-EE CSO resource owners. This is achieved by modifications to the Balancing Ratio that, relative to current rules, would reduce Capacity Performance Payments to all non-EE CSO resource owners.

That change would, in effect, exacerbate the present outcome that non-EE CSO resource owners bear the costs of EE resources' exclusion from Capacity Performance Payments. Like the status quo, the VEIC/Synapse proposal is inconsistent with the cost-causation and beneficiary pays principles.

NEPGA's near term proposal seeks to allocate the settlement shortfall to consumers (via transmission rates) in a manner reflecting each states' level of EE resources. This proposal would break one of the main tenets of the PFP design, which is that consumers are insulated from all performance-related settlements.[10] The ISO articulated this tenet to the Commission as one of the core concepts of the PFP design; nothing presently persuades us to abandon that tenet.

Moreover, the beneficiary-pays rationale for NEPGA's proposed cost allocation is indirect: while EE resources' exclusion from Capacity Performance Payments may lower their costs of FCM participation, and those lower costs may ultimately accrue to consumers' benefit, there is no clear nexus between existing transmission rate allocators and utilities' EE participation in the FCM.

We realize that absent some 'third way,' the foregoing observations may result in maintaining the status quo for the near term. While the status quo appears not to be consistent with established cost-allocation principles, the Commission (intentionally or otherwise) created that inconsistency with its directive to exclude EE resources from Capacity Performance Payments (during certain hours). There is no obviously 'correct' way for the Tariff to re-allocate the charges that EE resources do not remit – any mechanism that maintains the exclusion of EE resources from Capacity Performance Payments will result in winners and losers.

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[10] *See ISO New England Inc. and New England Power Pool*, Filings of Performance Incentive Market Rule Changes, Docket Nos. ER14-1050 and ER14-1050-001 (filed January 17, 2014) joint cover letter at pp. 25-26 (explaining that the costs to consumers are hedged once the capacity auctions are complete) (at https://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jan/er14_1050_000_1_17_14_pay_for_performace_part_1.pdf).

Longer Term. For the longer term (CCP 14 and beyond), the ISO supports pursuing an effort to collect measurement and verification (M&V) data to calculate demand reduction values for EE resources in all hours. That would cleanly remedy the cost allocation problem the Commission's order precipitated, and produce outcomes consistent with both cost-causation and beneficiary-pays principles. In this way, EE resources' sponsors would receive the costs and benefits of both their under- and over-performance (respectively) during off-peak CSC events; those costs and benefits would no longer be shifted onto other, non-EE CSO resource owners.

In support of that long-term direction, we note the following:

a. The language in the Commission's May 30, 2014 order requires that EE resources be excluded from Capacity Performance Payments only for hours in which demand reduction values are not calculated.[11] Read closely, this directive would appear not to preclude the region from expanding the set of hours for which demand reduction values are calculated; that, in turn, would reduce (and eliminate, if performed for all hours) this EE-related cost allocation problem.

b. Prior to PFP's implementation, participants with On-Peak or Seasonal Peak Demand Resources composed of Load Management (LM) or Distributed Generation (DG) were not required to submit performance data (*i.e.,* demand reduction data and/or meter data, as applicable) for all hours. Because LM and DG are not EE and are not excluded from Capacity Performance Payments, the ISO worked with impacted participants to memorialize a process to collect performance data and establish appropriate Actual Capacity Provided values for LM and DG for all hours.[12] This provides a useful precedent for EE capacity resources to follow, particularly with several years ahead to compile the relevant data.

c. In the Commission's May 30th order, it noted that EE resources may "incur significant costs to measure and verify their load reductions around-the-clock, rather than only in certain peak hours of the year."[13] However, factual evidence in the record on such costs is scant. Thus it remains an open question whether such costs are significant relative to the costs that EE resources' PFP treatment imposes on other capacity suppliers (in contrast to cost-causation principles). As a related observation, the M&V plans upon which demand reduction values for EE resources are based are typically updated about every three years, based upon a schedule set out by each state's energy efficiency planning process. The incremental cost to obtain M&V information for all hours, when obtained as part of a new M&V study that program administrators must undertake in any event (at their expense), may well be lower than the cost such resources would incur to re-conduct M&V studies for the CCPs associated with FCAs that have already been conducted.

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[11] *Cf.* note 2, *supra.*

[12] *See ISO New England Inc. and New England Power Pool,* Pay For Performance Enhancements, Docket No. ER18-1223-000 (filed March 29, 2018) joint cover letter at pp. 8-9 (at https://www.iso-ne.com/static-assets/documents/2018/03/pay_for_performance_enchancements.pdf).

[13] *See* note 2, *supra*.

d. The rapid change in technology – namely, New England's growth in solar PV and potential battery storage – is fundamentally changing the system's daily load shape, the timing of peak and off-peak periods, and therefore the time value of EE. The magnitude of these changes could not have been foreseen at the time the Commission issued its 2014 orders. These changes will likely require future changes to the on-peak and seasonal-peak hours, which will require EE resources to collect M&V data and calculate demand reduction values for additional hours in any event.

e. Currently neither the ISO, nor market participants, know how EE resources would perform during hours when demand reduction values are not (presently) calculated. However, since PFP was originally proposed, the ISO has observed that many EE resources are composed of measures with (loss-adjusted) demand reduction values in excess of their CSO MW. In other words, like other resources that can provide energy (or reduce demand) in excess of their CSOs, many EE resources may systematically *over-perform* (even during their putative off-peak hours). This highlights the importance of determining demand reduction values for EE resources for all hours, so that their contributions during off-peak CSCs can be appropriately compensated.

In closing, we are sympathetic to the concerns surrounding the Tariff's existing rules on this issue, and the ISO remains open to further ideas that may be able to garner broad stakeholder support. We anticipate that further stakeholder discussion of these issues may be productive, and hope the information provided in this memorandum may facilitate that discussion.

Appendix: EE-related Settlement Implications for the September 3rd, 2018 Event

This Appendix summarizes the impact of the current Tariff treatment of EE resources on PFP settlements for the Capacity Scarcity Condition (CSC) on September 3, 2018. A CSC corresponds to a deficiency in real-time operating reserves; by definition, during a CSC the system has more under-performing than over-performing resources (on a MW basis). Here, the terms under- and over- refer to a resource's performance (its Actual Capacity Provided) relative to its balancing-ratio-adjusted CSO MW. See Tariff §III.13.7.2.4 (Capacity Performance Score).

In the absence of the Commission-directed treatment of EE resources, PFP settlement would result in a net over-collection of Capacity Performance Payments during this CSC. That over-collection would be equal to the real-time reserve deficiency MW multiplied by the interval Performance Payment Rate ($166.67 per MW-5min, which is the current Capacity Performance Payment Rate of $2000/MWh divided by 12). The ISO explained this "net surplus" calculation in detail, and its purpose in relation to the stop-loss mechanism, in the May 30, 2014 filing.[14]

For the September 3, 2018 CSC event, the average (per interval) reserve deficiency MW during the 32 CSC intervals was 302 MW. No resources reached the stop-loss limit during this CSC. Thus, for this CSC, the net surplus in PFP settlement, in the absence of EE resources' Commission-directed treatment, would have been an over-collection of $1.61 million (302 MW × $166.67/MW-5min interval × 32 5-min intervals).

EE-Related Calculations. September 3 was an off-peak period for which EE resources' demand reduction values are not (presently) calculated. Per the Tariff (§III.13.7.2.2(c)), the Actual Capacity Provided of EE resources is zero.

There were approximately 2458 CSO MW of EE resources during this CSC. Their balancing-ratio adjusted CSO for this CSC event was 1774 MW (0.722 BR × 2458 CSO MW). As a result, in PFP settlements, total collections (credits less charges) results in an EE-related settlement shortfall of approximately:

–1774 MW score × 32 5-min intervals × $166.67 / MW-5min interval = –$9.46 million

This $9.46 million value was not charged to EE resources in the form of Capacity Performance Payments, because EE resources are excluded from Capacity Performance Payments during this CSC (Tariff §III.13.7.2.4(i)), pursuant to the Commission's order.

Combined with the partially-offsetting over-collection of $1.61 million from other under-performers (on net, as discussed above), the final result is a settlement shortfall for this CSC of approximately:

– $9.46 million + $1.61 million = – $7.85 million settlement shortfall

The allocation to all CSO MW of this deficiency in total Capacity Performance Payments (pursuant to §III.13.7.4), as actually settled in the FCM billing statements issued on October 15th, 2018 (for the month of September 2018) was $7.85 million.

[14] *Id.,* pp. 44-45, 49-51, and references therein.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Jamie Blackburn, NEPOOL Counsel

DATE: March 6, 2019

RE: ISO-NE's Interim Winter Energy Security Proposal

At its March 13, 2019 meeting, the Participants Committee will be asked to consider supporting Tariff revisions proposed by ISO-NE to implement its interim proposal to provide compensation for inventoried energy during certain winter months in Capacity Commitment Periods #14 and #15 (June 1, 2023 – May 31, 2015) ("ISO Proposal," also referred to as "Chapter 2B"). This memorandum provides further detail on the ISO Proposal and the Participant-sponsored amendments to that proposal that were presented to the Markets Committee, and describes potential resolutions based on the history of this matter before the Markets Committee. If any Participant wishes to offer amendment(s) to the ISO's proposed set of changes that are not included with this memorandum, please provide those amendments to NEPOOL Counsel (slombardi@daypitney.com or jblackburn@daypitney.com) as soon as possible so that we can circulate them in time for stakeholder review and consideration before the meeting.

There were three Participant-sponsored amendments presented for a vote at the Markets Committee, none of which received sufficient support to be recommended by that Committee. Nor was the ISO's unamended proposal supported by the Markets Committee. Thus, consistent with past practice, the Participants Committee will begin its consideration of this matter with a motion to approve the ISO Proposal, and then consider those amendments that Market Participants seek to place before the Committee. If those amendments that did not achieve Markets Committee support are not advanced for vote at the Participants Committee, neither NEPOOL nor the ISO will argue in response to advocates seeking FERC approval of those amendments that the advocates failed to complete or follow the Participant Processes.

BACKGROUND

Last year, in response to the FERC's July 2, 2018 order rejecting the ISO's waiver request in Docket No. ER18-1509, the ISO submitted Tariff revisions that expanded its authority– on an interim basis – to retain units needed for fuel security subject to a reliability review, a trigger for such retentions and appropriate cost-of-service arrangements (otherwise known as "Chapter 2").[1] The ISO's Chapter 2 proposal was approved by the FERC in December 2018, and those relevant Tariff provisions of general applicability are now in effect for FCAs 13, 14, and 15, which correspond to Capacity Commitment Periods 2022/23, 2023/24, and 2024/25, respectively.

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[1] *ISO New England, Inc.*, 165 FERC ¶ 61,202 (Dec. 3, 2018).

The ISO has concluded that more needs to be done in the interim period prior to the implementation of the longer-term market-based tariff revisions intended to address regional energy security issues ("Chapter 3"). As such, the ISO developed an interim compensation proposal for certain winter months during Capacity Commitment Periods ("CCPs") 2023/24, and 2024/25.

THE ISO'S INTERIM WINTER ENERGY SECURITY PROPOSAL

The ISO has explained that its proposal is intended to serve as bridge to the longer-term, market-based approach. The ISO identified the following four design objectives for its Proposal: (a) provide similar compensation for similar service; (b) reduce the likelihood that an otherwise economic resource seeks to retire because it is not fully compensated for its winter energy security attributes in the wholesale markets; (c) simple, transparent, and can be implemented in time for CCP 14 (by June 1, 2023); and (d) satisfies standard market design principles.

The design of the ISO's Proposal consists of five core components:

(1) trigger condition criteria, which can be satisfied on (i) days in December, January, or February on which (ii) the average of the daily high and low temperatures at Bradley Airport (Windsor Locks/Hartford) is less than or equal to 17 degrees Fahrenheit;

(2) maximum duration, which caps the total amount of inventoried energy that is compensated, limited to 72 hours;

(3) a forward settlement rate, which would be a per MWh payment rate for inventoried energy sold forward for entire winter season;

(4) a spot settlement rate, which would be a per MWh payment rate for inventoried energy maintained during each trigger condition; and

(5) a two settlement structure, which would pay/charge participants for deviations between their forward and spot positions at the spot settlement rate.

Those eligible to participate in the ISO Proposal would include electric storage resources, biomass/refuse resources, coal resources, certain demand response resources, hydro resources with on-site or upstream reservoir/pondage controlled by a participant, natural gas resources with a supply contract for firm delivery, nuclear resources and oil resources. To be eligible to participate and receive compensation under the ISO Proposal, a resource's inventoried energy would need to be able to be converted to electric energy at the ISO's direction, the conversion of this inventoried energy to electric energy would need to reduce the amount of electric energy the resource could produce in the future (before replenishment), and the inventoried energy would need to be measured in MWh and reported for each trigger condition day. Inventoried energy may be stored on site (such as oil in a tank) or off site (such as a contract for natural gas). The ISO now estimates direct costs under its Proposal would be in the range of $102 million to $148 million per year (depending on the amount of inventoried energy sold via contracts for LNG-based gas supply). Further information on the ISO's Interim Winter Energy Security Proposal can be found in Attachment A.

The ISO's Internal Market Monitor (IMM) has explained to the Markets Committee how it would view the interaction between the ISO Proposal and the market power mitigation rules. In particular, the IMM explained that it would account for expected revenues to resource's under the Proposal in mitigating bids or offers from existing capacity resources in the FCM. Further information on the IMM's view regarding the ISO Proposal can be found in Attachment B.

STAKEHOLDER PROCESS TO DATE

The NEPOOL Markets Committee, following several months of discussions, took a series of votes at its March 5-6, 2019 meeting on the ISO's Proposal and multiple Participant-sponsored amendments to that Proposal.

There were three amendments proposed to the ISO Proposal, none of which achieved the requisite 60% Vote to become a Markets Committee supported amendment to the ISO Proposal. The unamended main motion was voted and did not receive sufficient support for a Markets Committee recommendation, with a 36.89% Vote in favor. A copy of the Notice of Actions of the Markets Committee detailing these votes, including amendments proposed at the Markets Committee, is also included with this memorandum as Attachment C.

Potential Motions to Amend the ISO's Proposal

The Participants Committee may be asked to consider one or more of the amendments that were considered previously by the Markets Committee, which are summarized as follows:

1. Union of Concerned Scientists (UCS) Amendment

The UCS Amendment would modify certain components of the ISO Proposal. First, the UCS Amendment would expand the resources eligible for payment in both the forward and spot settlements to include resources that provide energy without inventory (such as wind resources or gas resources without an LNG contract). Second, this Amendment would change the ISO's proposed compensation structure so that the same forward and spot settlement rates are applicable, but for each trigger condition day, a resource is credited with delivering the greater of its actual energy produced on the trigger condition day or the inventoried energy maintained for the trigger condition day. *See* Attachment D.

The UCS Amendment failed based on a show of hands. We have been advised that UCS does not anticipate asking for a Participants Committee vote on its Amendment, with the understandings described above.

2. Energy New England (ENE) Amendment

Rather than expand resources that could receive payment under the ISO Proposal, the ENE Amendment would modify the ISO Proposal to limit interim compensation only to oil, natural gas (with an LNG contract), certain demand response and certain electric storage resources. This proposed amendment would therefore prohibit any payments under the ISO Proposal to coal, nuclear, hydro, or biomass resources. *See* Attachment E.

The ENE Amendment failed with a 48.46% Vote in favor.

3. PSEG Energy Resources & Trade (PSEG) Amendment

The PSEG Amendment would adjust how and when the forward and spot payment rates are established. Rather than fixing the rates in the Tariff (approximately 4 ¾ years prior to the beginning of the first delivery period), under PSEG Amendment, the rates would be determined consistent with a methodology presented by the Analysis Group, "Calculation of Rate for Interim Compensation Program" dated January 30, 2019, which uses contracted call options for LNG over the three winter months period along with updated price inputs. This methodology would be applied on the April 30 prior to the relevant delivery period so that recent market-based inputs to the model can be incorporated into formulation of the rate. *See* Attachment F.

The PSEG Amendment failed based on a show of hands.

FORM OF MAIN MOTION FOR PARTICIPANTS COMMITTEE ACTION

The following form of resolution may be used for Participants Committee action on Chapter 2B:

> RESOLVED, that the Participants Committee supports the revisions to Tariff Section I.2.2. and Appendix K of Section III of Market Rule 1 to effect the Interim Winter Energy Security Proposal, as proposed by ISO New England in the package of materials circulated to this Committee with the March 6, 2019 supplemental notice, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

ISO new england

memo

To: NEPOOL Markets Committee

From: Christopher Geissler

Date: March 5, 2019

Subject: Interim Compensation Treatment Proposal

The ISO is requesting a vote on the Interim Compensation Treatment proposal (the 'proposal') which would be in place for Capacity Commitment Periods 14 and 15 and serve as a bridge to the ISO's longer-term, market based approach. This proposal seeks to provide compensation to resources that provide winter energy security to the region. To accomplish this, the ISO developed the design[1] around the following objectives: (a) provide similar compensation for similar service; (b) reduce the likelihood that an (otherwise economic) resource seeks to retire because it is not fully compensated for its winter energy security attributes in the wholesale markets; (c) simple, transparent, and can be implemented in time for CCP 14 and; (d) satisfies standard market design principles.

The proposal for the committee's consideration today has been presented in the meeting dates outlined below.

- November 7-8, 2019, agenda item #5 https://www.iso-ne.com/event-details?eventId=134567
- December 11-12, 2019 agenda item #5 https://www.iso-ne.com/event-details?eventId=134569
- January 8-9, 2019 agenda item #2 https://www.iso-ne.com/event-details?eventId=137567
- February 5-6, 2019, agenda item #2 https://www.iso-ne.com/event-details?eventId=137569

[1] The design consists of five core components: (1) trigger conditions; (2) maximum duration; (3) forward settlement rate; (4) spot settlement rate and; (5) two settlement structure.

other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

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

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Deleted:

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

APPENDIX K

INVENTORIED ENERGY PROGRAM~~WINTER RELIABILITY SOLUTIONS~~

III.K Inventoried Energy Program

For the winters of 2023-2024 and 2024-2025, the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. To participate in both the forward and spot components of the program, the information listed in this Section III.K.1 must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter (a separate election submission must be made for each winter) and must reflect an ability to provide the submitted inventoried energy throughout the relevant winter period. To participate in the spot component of the program only, the information listed in this Section III.K.1 may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

(a) A list of the Market Participant's assets that will participate in the inventoried energy program, with a description for each such asset of: the Market Participant's Ownership Share in the asset; the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site (and in upstream ponds) or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets: Settlement Only Resources; assets not located in the New England Control Area; assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

(ii) A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must specify the parties to the contract, the volume of gas to be delivered, the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed

asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas.

(b) A detailed description of how the Market Participant's energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than the default approach described in Section III.K.3.2.1.1(d)(i), this description should explain and support that alternate allocation.

(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the "Forward Energy Inventory Election"). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site (and in upstream ponds) for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election"). (For Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. For election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter, and participation will

begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); or

(ii) requires (except in the case of an asset that is supplied from a liquefied natural gas facility adjacent and directly connected to the asset) the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory Election shall be adjusted accordingly.

III.K.1.2 Posting of Forward Energy Inventory Election Amount

As soon as practicable after the November 1 immediately preceding the start of the relevant winter, the ISO will post to its website the total amount of Forward Energy Inventory Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by $82.49 per MWh and divided by the total number of days in those three months.

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried Energy Spot Payment

A Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory Election, with the difference multiplied by $8.25 per MWh.

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2); provided, however, that where more than one Market Participant has an Ownership Share in an asset, the asset's Real-Time Energy Inventory will be apportioned based on each Market Participant's Ownership Share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory

Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Market Participant must measure and report to the ISO the Real-Time Energy Inventory for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of dedicated barrels of oil stored in ~~a dedicated~~ an~~d~~ in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.

(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.

(iv) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Market Participant must specify what portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.

(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in on-site and upstream ponds controlled by the Market Participant with a transit time to the asset of no more than 12 hours, excluding any amount that is unobtainable or unusable for any reason.

(vii) Biomass/Refuse. The Real-Time Energy Inventory of an asset that runs on biomass or refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.

(viii) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh.

(b) If the Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as water flow or emissions limitations).

(d) The reported amounts are subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program.

(e) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(d);

(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and

(iii) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

~~**WINTER RELIABILITY SOLUTIONS**~~

~~**III.K.1. General.**~~

~~(a) **Term.** This Appendix K is intended to mitigate potential fuel-related system reliability issues within New England during the 2015-16, 2016-17 and 2017-18 winter seasons. This Appendix K expires on March 15, 2018, provided that all rights and obligations, including those pertaining to payments, charges and default, shall survive expiration to the extent necessary or made explicit herein.~~

~~(b) **Eligibility.** Only Market Participants may provide the services described in this Appendix K. A participating Generator Asset must: be located in New England; modeled in the EMS; and either (i) dispatchable as described in Operating Procedure #14, or (ii) Self-Scheduled for the entire winter period. Market Participants may provide only one of the services described in Sections III.K.2 through III.K.4 herein.~~

~~(c) **Offer Obligation.** Regardless of whether they have a Capacity Supply Obligation, Market Participants obligated hereunder must submit Supply Offers for participating Generator Assets into the Day-Ahead Energy Market and Real-Time Energy Market at the Generator Assets' Economic Maximum Limit for each hour of the Operating Day during the relevant winter.~~

~~(d) **Fuel Retention Obligation.** Market Participants may not sell the fuel (or fuel rights) described herein during the winter(s) in which they are obligated, or take any other action that is inconsistent with ensuring the availability of the fuel for Energy production and use in New England in accordance with this Appendix K.~~

~~(e) **October 1 Notice.** To participate in one of the services set out in Sections III.K.2 through III.K.4, a Market Participant must notify the ISO by the October 1 immediately preceding the relevant winter and provide the detail specified below. This notice shall be the Market~~

~~Participant's binding commitment to meet the relevant minimum requirements set forth in this Appendix K for that winter. The ISO reserves the right to reject any notice of proposed participation on any grounds, including the ISO's concerns about the deliverability of the fuel or the past performance of the relevant Asset. No later than October 15, the ISO will calculate the maximum potential cost of the program based on the submitted inventory levels and provide a summary to stakeholders.~~

~~(f) **Shared Fuel Supply.** Generator Assets that share a fuel supply may participate in Sections III.K.2 and III.K.3 only if all Generator Assets sharing the fuel supply participate, in which case the fuel levels described below will be calculated in the aggregate. Notwithstanding the foregoing, the ISO may exempt one or more Generator Assets from the participation requirement if the ISO determines at the beginning of the relevant winter period that the Generator Asset(s) are reasonably expected to be out of service for the relevant winter period.~~

~~(g) **Determination of Compensation Rate.** As set forth below, compensation is determined with reference to a "Set Rate." The Set Rate establishes partial compensation for the per-barrel carrying costs of stored fuel oil.~~

~~i. For each of the 2015-16, 2016-17 and 2017-18 winters, the ISO shall establish the Set Rate ($/bbl) and post it on its website no later than the preceding July 15, using the following formula:~~

~~*Set Rate = CC + OC + LC*~~

~~CC = P_f x r_{rf}~~

~~*Where:*~~
~~P_f: Next October fuel price (Diesel, DFO) (Source: NYMEX Futures)~~
~~r_{rf}: Risk-free return set at 0.73%~~

~~OC = October 12-month put option premium calculated using K, S, σ~~

~~*Where:*~~
~~K: Strike Price = P_f~~
~~S: Price at expiry (*i.e.*, price 12-months from P_f) (Source: NYMEX Futures)~~
~~σ: Implied volatility on fuel put options on futures contracts (Source: Bloomberg)~~

~~LC = P_f x R~~

~~*Where:*~~
~~R: the implied risk premium on the after-tax weighted average cost of capital (*i.e.*, WACC – r_{rf}) (Source: ISO-NE Sloped Demand Curve filing)~~

ii. Through conversion based on a fuel oil heat content of 6.0 MMBTU per barrel, the ISO shall calculate an equivalent rate for liquefied natural gas.

iii. The Set Rate for the demand response service in Section III.K.4 shall be calculated as follows:

$$DR\ Set\ Rate = R_o \times [(1/H_{avg}) \times HR_g \times 100MW \times 180_h]/(100{,}000\ kW \times 3\ months)$$

Where:

R_o: Oil program Set Rate in $/bbl
H_{avg}: MW-Weighted average heat content of oil-fired units in New England = 6.0 MMBtu/bbl
HR_g: Generic heat rate = 10 MMBtu/MWh
180_h: 180 hours, which is the maximum number of hours a demand response asset could be dispatched during the winter

(h) **Conflict.** Unless expressly stated otherwise, this Appendix K does not vary any other terms or conditions contained in the Tariff and other governing documents.

III.K.2. Oil Fuel.

Pursuant to this service, Market Participants with oil-fired Generator Assets will secure fuel supply as of December 1 of the relevant winter and will be eligible for compensation to allay some of the costs related to unused fuel at the end of the winter.

Where used in this Appendix K, "usable" shall mean, with reference to oil inventory, the total inventory minus inventory unobtainable due to priming requirements, sediment and volume below the suction line. Where used with reference to storage capacity, "usable" shall mean the total shell capacity of a dedicated tank (including a dedicated tank at an adjacent location with direct pipeline transfer capability to the Generator Asset), minus the capacity of (i) unusable inventory, and (ii) vapor space at the top of the tank due to safety fill and structural limitations. Tanks removed from service due to structural damage or for long-term repairs are not included in storage capacity calculations. Tanks removed from service for economic considerations are included in storage capacity calculations. Market Participants are responsible for determining and reporting usable storage capacity and usable oil inventory to the ISO.

(a) **Eligibility.** To be eligible, Generator Assets must be capable of operating on oil. Dual fuel Generator Assets are eligible to the extent that the ISO determines that they have demonstrated, or before January 1 of the relevant winter will demonstrate, their ability to run on oil.

~~(b) **December 1 Oil Inventory.** In the notice specified in Section III.K.1(e), the Market Participant must set forth the Generator Asset's expected level of oil inventory on December 1 of the upcoming winter. The ISO will evaluate the Generator Asset's inventory on December 1 and shall deem eligible for compensation the amount of a Generator Asset's usable oil inventory that meets or exceeds the lesser of: (i) 85% of the usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability; provided that a Generator Asset that needs additional time to achieve these minimum inventory levels shall have until January 1 to do so, although the inventory level on December 1 will be used for the purpose of calculating compensation pursuant to Section III.K.2(c). The December 1 inventory level will be deemed to include: oil that the ISO determines was burned to produce electricity on and after November 15 of that year, including during an audit of dual fuel capability, provided that oil used in an audit must be replenished by the later of the upcoming January 1 or 15 days after the audit. Failure to replenish the oil will result in ineligibility for any compensation pursuant to this Section III.K.2.~~

~~(c) **Compensation.** Participating Generator Assets will be compensated after March 15 of the relevant winter based on the formula below:~~

~~*(Eligible Inventory x Set Rate) x Performance Adjustment*~~

~~Eligible Inventory is the lesser of the December 1 Inventory, Maximum December 1 Inventory, and March 15 Inventory. December 1 Inventory is calculated as set out in the second and third sentences of Section III.K. 2(b). Maximum December 1 Inventory is the lesser of (i) 95% of usable fuel storage capability and (ii) supply sufficient to operate the Generator Asset for 10 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. March 15 Inventory is the usable oil inventory on March 15, excluding any oil that (i) the Market Participant identifies as intended for use other than in the production of electricity by the Generator Asset, or (ii) is added to inventory after March 1. Performance Adjustment shall mean:~~

~~*(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)*~~
~~*(Total number of winter hours)*~~

~~The March 15 Inventory shall be adjusted for any Market Participant that added oil inventory after February 1 that is subsequently sold. To make this determination, the ISO shall monitor through November 30 of the same year the oil inventory levels of those Generator Assets that~~

~~added oil inventory after February 1. If the ISO determines that any oil is sold, the compensation will be recalculated and the Market Participant will be charged the difference between the original and recalculated amounts of compensation.~~

~~III.K.3. Liquefied Natural Gas.~~

~~Pursuant to this service, Market Participants with gas-fired Generator Assets that may be supplied by a liquefied natural gas provider will secure fuel supply as of December 1 and will be eligible for compensation to allay some of the costs related to unused fuel at the end of that winter.~~

~~(a) **Eligibility.** To be eligible, gas-fired Generator Assets, including dual fuel Generator Assets, must be capable of receiving pipeline gas or supplies of liquefied natural gas.~~

~~(b) **Proposed Contracts.** In the notice specified in Section III.K.1(e), the Market Participant must describe the contract for liquefied natural gas for which it proposes to receive compensation pursuant to this Section III.K.3. The notice must specify the contract parties, and include the proposed contract volume and a commitment to ensure that the contract will meet the requirements outlined in Section III.K.3(c). The ISO will review the notices and inform Market Participants of provisional acceptance (pending the certification specified in Section III.K.3(c) below) of contracts that meet the criteria in the preceding sentence and that, in the aggregate for each winter, do not exceed 6 BCF and the daily output of the providers of liquefied natural gas. The ISO shall provisionally accept proposed contracts on a "first come/first served" basis and shall inform Generator Assets of their provisional acceptance by each October 15.~~

~~(c) **Contract Review.** By December 1, Market Participants receiving provisional acceptance must present their executed contracts to the ISO along with a completed, executed certificate in the form of Attachment 1 on which the Market Participant avers that its contract includes: a "take-or-pay" construct; the volume specified by the Market Participant pursuant to Section III.K.3(b) above; a term that spans, at a minimum, December 1 through the end of February (provided that the Generator Asset must be entitled to call the entire volume eligible for compensation within the winter period); the pipeline delivery point name and gas meter number of the submitting Generator Asset; and pipeline transportation to the meter of the Generator Asset (with indication of whether the gas supplier or another entity is providing the transportation). Contracts that do not include one or more of these terms will be rejected, and the ISO's provisional acceptance will be withdrawn.~~

~~(d) **Compensation.** Participating Generator Assets will be compensated after March 1 of the relevant winter based on the formula below:~~

~~*(Unused Quantity x Set Rate) x Performance Adjustment*~~

~~Unused Quantity is the lesser of the December 1 and March 1 contract volumes, and may not exceed the amount of fuel necessary to permit the Generator Asset to operate for 4 days at full load based on the Generator Asset's winter Seasonal Claimed Capability. Performance Adjustment shall mean:~~

~~*(Winter hours in which the Generator Asset was fully or partially available or in which the Generator Asset was fully unavailable as a result of an outage on the New England Transmission System)*~~
~~*(Total number of winter hours)*~~

~~**III.K.4. Demand Response Service.**~~

~~All defined terms used in this Section III.K.4 shall have the same meanings as if the asset were a Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.~~

~~Market Participants with an asset located within the New England Control Area with a positive Demand Response Baseline (showing energy consumption at the Retail Delivery Point), including an asset with behind-the-meter generation capable of reducing demand from the electric system and delivering any net supply, are eligible to participate pursuant to this Appendix K. Assets mapped to a Real-Time Demand Response Resource are eligible to participate, subject to the additional requirements specified below, and provided that the capacity supplied by these assets is in addition to the Capacity Supply Obligation, as of December 1 of the relevant Capacity Commitment Period, of the Real-Time Demand Response Resource to which the asset is mapped, and provided further that the prohibitions in Section III.E1.1.2 are not triggered.~~

~~Except for assets mapped to a Real-Time Demand Response Resource, an asset may consist of an aggregation of individual end-use facilities so long as those facilities are located within the same Dispatch Zone, and provided further that such aggregation does not result in a quantity of demand reduction and net supply of 5 MW or greater at a single Node.~~

~~The following asset types are not eligible to provide services under this Section III.K.4: (i) Real-Time Emergency Generation Assets; (ii) any asset that is dependent upon a non-firm or an additional supply of natural gas to produce demand reductions or net supply; and (iii) any asset that participates in the energy market pursuant to Section III.1 of the Tariff.~~

~~Each Market Participant that has an asset accepted by the ISO for this service is subject to the following additional requirements from the relevant December 1 through March 1:~~

~~(a) **In service.** By December 1, participating assets must, in accordance with the existing requirements for Real-Time Demand Response Assets and Real-Time Emergency Generation Assets: (i) be registered with the ISO; (ii) have meters installed and operational; (iii) have a valid Demand Response Baseline; (iv) have a Demand Designated Entity to which Dispatch Instructions are communicated; and (v) otherwise be fully ready to respond.~~

~~(b) **Size of Program and Assets.** Each participating asset shall provide at least 100 kW of capability. No more than 100 assets at a level not to exceed 100 MW shall be accepted by the ISO pursuant to this Appendix K.~~

~~(c) **Metering.**~~

~~i. Market Participants must meet the metering requirements specified in Appendix III.E and the ISO New England manuals, with the exception that 5-minute meter data does not have to be reported to the ISO in real time for assets not mapped to a Real-Time Demand Response Resource.~~

~~ii. To the extent that an asset consists of an aggregation of individual end-use facilities, Market Participants must submit a single set of interval meter data, as measured from each facility's Retail Delivery Point, representing the sum of the metered demand of the end-use facilities comprising the asset.~~

~~iii. Market Participants shall report meter data and may submit meter data corrections to the ISO using the Demand Response Market User Interface within 2.5 business days after the Operating Day.~~

~~iv. Meter data corrections may be submitted during the 70-day period beginning with the first of the month following the operating month. To the extent meter data affecting an asset's performance measurement and passing all quality checks has not been submitted by the initial settlement deadline (i.e., within 2.5 business days after the Operating Day), payments related to that asset shall be deferred to the resettlement process.~~

~~v. In the event that valid meter data affecting an asset's monthly performance measurement that passes all quality checks is not submitted by the end of the 70-day data correction~~

~~limit, that asset's performance shall be deemed to be zero for the intervals for which the meter data did not pass all quality checks.~~

~~(d) **Dispatch.**~~

~~i. Assets must be available for dispatch in real time between hours ending 0600 and 2300 on all days.~~

~~ii. Each dispatch shall be for no more than six hours.~~

~~iii. There will be no more than two dispatches per asset per day.~~

~~iv. There shall be at least four hours between the end of one dispatch and the start time of another dispatch.~~

~~v. Assets will be dispatched by the ISO at its discretion prior to, or concurrent with, ISO New England Operating Procedure No. 4, Action 2. The ISO may aggregate assets into blocks and dispatch only those assets comprising the blocks.~~

~~vi. Each asset shall be required to respond to Dispatch Instructions no more than thirty times.~~

~~vii. The ISO will communicate Dispatch Instructions to the Demand Designated Entity specified by the Market Participant for each participating asset.~~

~~viii. Assets will be dispatched for their entire, committed MW quantity except in cases where such dispatch may cause or worsen a local reliability problem. The ISO may, upon notification to the Demand Designated Entity, exclude from dispatch assets located in a particular Dispatch Zone, and/or individual assets where the committed MW quantity is 5 MW or more.~~

~~ix. Except as outlined in viii. above, assets must produce the MW quantity accepted pursuant to this Appendix K within thirty minutes of the issuance of a Dispatch Instruction.~~

~~x. If assets mapped to a Real-Time Demand Response Resource are dispatched pursuant to this Appendix K concurrently with the dispatch of the Real-Time Demand Response Resource, and the amount of demand reduction plus any net supply produced in that interval is less than the Real-Time Demand Response Resource's Capacity Supply Obligation plus the sum of the asset's committed MW quantity pursuant to Appendix K,~~

~~the amount of demand reduction plus any net supply produced shall be credited first to the Real-Time Demand Response Resource's Capacity Supply Obligation and the remainder shall be credited pro-rata to each asset with an obligation pursuant to Appendix K based on asset performance.~~

~~(e) **Acceptance Criteria.** Market Participants must indicate their commitment to provide this demand response service by providing the notice indicated in Section III.K.1(e). That notice must include: the name and other pertinent identifiers of the asset that the Market Participant is seeking to enroll, the asset's electrical location, the MW quantity of demand reduction and any net supply, as measured from the asset's Retail Delivery Point, that the asset is willing and able to produce in response to Dispatch Instructions, and the method(s) by which the demand reduction or any net supply would be produced. If the Market Participant has not yet identified all of the assets that will be recruited to meet the service requirements, the Market Participant shall provide a description of how it will meet the requirements, and provide the Dispatch Zone within which these assets will be located. If an asset specified in the notice consists of an aggregation of individual end-use facilities, the information shall be provided for each facility that is part of the aggregation. The ISO shall accept up to 100 qualified assets at a level not to exceed 100 MW from those Market Participants providing notice, based on:~~

~~i. The asset's proposed capacity;~~
~~ii. The asset's location relative to known constrained areas; and/or~~
~~iii. Any historic performance from the asset.~~

~~The ISO may accept or reject any and all assets proposed for participation.~~

~~(f) **Compensation.**~~

~~i. **Monthly Payment for Assets Not Mapped to a Real-Time Demand Response Resource.** For each winter, Market Participants providing the demand response services described herein shall be compensated under this Appendix K through a monthly payment of the Set Rate multiplied by the average MW performance achieved by the asset in the month, provided that such MW performance shall not exceed 150% of the committed MW quantity. The computation of average MW performance shall be the simple average of an asset's performance in each five-minute interval during the month when dispatched pursuant to this Appendix K excluding the thirty-minute notification time. If the asset was not dispatched or audited in the month of December, the payment for that asset for that month will be based on its average MW performance in response to~~

~~dispatch (including a dispatch for an audit) in the following month. If an asset was not dispatched in January or February, but was dispatched or audited in a previous month, the asset's payment for the month in which it was not dispatched will be based on its average MW performance in the most recent month in which the asset was dispatched or audited.~~

~~ii. **Monthly Payment for Assets Mapped to a Real-Time Demand Response Resource.** For each winter, the monthly payment for assets that are mapped to a Real-Time Demand Response Resource will be the Set Rate multiplied by the average MW performance achieved by the asset in the month not to exceed 100% of the committed MW quantity, and further multiplied by the Performance Factor. The computation of average MW performance shall be the simple average of an asset's performance in each five-minute interval during the month when dispatched pursuant to this Appendix K excluding the thirty-minute notification time. If an asset is dispatched in a month pursuant to Appendix K concurrently with the dispatch of the Real-Time Demand Response Resource to which it is mapped, a Performance Factor will be calculated as follows:~~

$$\textit{Performance Factor} = \frac{\textit{(Average Hourly FCM Performance} - \textit{Average Hourly Dispatch MW)}}{\textit{Winter Obligation MW}}$$

~~Average Hourly FCM Performance is the average hourly MW reduction amount (inclusive of any net supply) achieved during the month by the Real-Time Demand Response Resource to which the asset is mapped during dispatch or audit pursuant to Section III.13. Average Hourly Dispatch MW is the average hourly MW reduction amount (inclusive of any net supply) in the Dispatch Instructions issued during the month pursuant to Section III.13 to the Real-Time Demand Response Resource to which the asset is mapped, which would not exceed the resource's Capacity Supply Obligation. Winter Obligation MW is the committed quantity of the asset pursuant to Appendix K in MW. The Performance Factor shall not exceed 1.0. The Performance Factor for a month will apply to monthly payments in subsequent months during the term if, in those subsequent months, the Real-Time Demand Response Resource to which the participating asset is mapped is not dispatched or audited pursuant to Section III.13. If the Real-Time Demand Response Resource to which the participating asset is mapped is not dispatched or audited pursuant to Section III.13 in the month of December, an audit of the resource will be conducted in the month of January. The audit shall assess the resource's ability to meet its Capacity Supply Obligation plus the sum of the committed~~

~~quantity pursuant to Appendix K for assets mapped to the resource. The Performance Factor calculated during this audit will be applied to the month of December.~~

~~iii. **Energy Payment for Assets Not Mapped to a Real-Time Demand Response Resource.** For each winter, Market Participants providing the demand response services described herein shall also receive a monthly energy payment, as follows:~~

~~*Winter DR Program Energy Payment =*~~

~~*(MAX ($250/MWh, Zonal LMP) x MWh Delivered x 1.065) – E Payment*~~

~~Zonal LMP is the hourly Real-Time LMP for the Load Zone in which the asset is located. MWh Delivered is the performance of the asset in MWh calculated pursuant to this Section III.K.6 during the hours of dispatch excluding any performance during the thirty-minute notification time and where the 1.065 factor applies only to the demand reduction portion of MWh Delivered and not to the net supply portion. E Payment is any energy payment otherwise made for Net Supply to a generation asset pursuant to III.1 located at the same Retail Delivery Point that is coincident with the dispatch of the demand response asset. In the event that there are multiple assets participating in the Program located behind a single Retail Delivery Point, the reduction for any E Payments based on energy delivered from that Retail Delivery Point will be allocated on a pro-rata basis.~~

~~iv. **Energy Payment for Assets Mapped to a Real-Time Demand Response Resource.** For each winter during hours in which an asset is dispatched concurrently with the hours in which it receives a demand curtailment schedule or initiates a Real-Time demand reduction pursuant to Section III.E or with the dispatch of the Real-Time Demand Response Resource to which the asset is mapped, the Energy payment received by the asset pursuant to Section III.E or Section III.13.7.2.5.3 will be subtracted from the energy payment hereunder. The energy payment for these assets will be computed as follows:~~

~~*Winter DR Program Energy Payment =*~~

~~*MAX [(MAX ($250/MWh, Zonal LMP) x MWh Delivered) x 1.065 – TDR Payment - E Payment, 0]*~~

~~Zonal LMP is the hourly Real-Time LMP for the Load Zone in which the asset is located. MWh Delivered is the performance of the asset in MWh calculated pursuant to this Section III.K.4 during the hours of dispatch excluding any performance during the thirty-~~

~~minute notification time. TDR Payment is the Energy payment received by the asset pursuant to Section III.13.7.2.5.3 or Section III.E. The 1.065 factor applies only to the demand reduction portion of MWh Delivered and not to the net supply portion. E Payment is any energy payment otherwise made for Net Supply to a generation asset pursuant to III.1 located at the same Retail Delivery Point that is coincident with the dispatch of the demand response asset. In the event that there are multiple assets participating in the Program located behind a single Retail Delivery Point, the reduction for any E Payments based on energy delivered from that Retail Delivery Point will be allocated on a pro-rata basis.~~

~~v. **Voluntary Performance.** If the ISO dispatches an asset more than thirty times, the asset's response to those dispatches is voluntary, and any performance by the asset in response to those dispatches would not be used to calculate the monthly payment for services under this Appendix K or to assess non-performance. However, any Energy provided by the asset in response to these dispatches would be compensated as described in the preceding paragraphs.~~

~~vi. **Non-Performance Charges.** The non-performance charges for assets providing the demand response services described in this Section III.K.4 shall be:~~

~~A. For failure to reach 75% performance: If the asset fails to achieve an average MW performance of at least 75% of the committed MW quantity in a month, the asset shall forfeit its monthly payment for that month and for any other month during the term for which such performance is utilized for settlement.~~

~~B. For failure to submit valid meter data: the provisions of Section III.K.4(c)(v) shall apply with regard to meter data deemed to be zero because of quality problems.~~

~~**III.K.5 Dual Fuel Commissioning Service.**~~

~~As set out in this Section III.K.5, Market Participants with gas-fired Generator Assets will receive compensation to allay some of the auditing costs incurred in commissioning oil-fired dual fuel capability.~~

~~(a) **Eligibility.** Gas-fired Generator Assets that have not demonstrated the ability to operate on oil on or after December 1, 2011 are eligible for compensation as set out in this Section III.K.5.~~

~~(b) **Plan.** By December 1, 2014, the Market Participant must submit to the ISO, for the ISO's review, a plan to render the Generator Asset capable of operating on oil as an additional fuel. The plan must specify the target date for commissioning. The ISO will then determine a cap on the compensation for which the Market Participant is eligible if it achieves dual fuel capability. The cap on compensation will be established based upon the following assumptions, and with reference to the information used by the Internal Market Monitor to calculate the Generator Asset's cost-based reference level pursuant to Section III.A.7.5: (a) 20 hours of Energy cost at full load operation if the target commissioning date is on or before December 1, 2015; (b) 10 hours of Energy cost at full load operation if the target commissioning date is after December 1, 2015 and on or before December 1, 2016; (c) three start-ups from a cold state on the secondary fuel; and (d) an estimate of Energy revenues that would be paid while the Generator Asset is auditing.~~

~~(c) **Successful Commissioning.** A Generator Asset will have been successfully commissioned to operate on oil if the ISO determines that, on or before December 1, 2016, the Generator Asset: (i) has an oil tank able to hold sufficient fuel to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time; (ii) from an online state, demonstrates the ability to switch fuels within 8 hours and, if the Generator Asset must shut down to perform the switch, returns to operation at its Economic Minimum Limit within eight hours; and (iii) demonstrates its ability to run on oil at its Economic Maximum Limit for 1 hour.~~

~~(d) **Compensation.** The ISO shall compensate the Generator Asset for its auditing costs, up to the amount of the cap established in III.K.5(b), through Section III.F, the terms of which shall apply. If the Generator Asset has a target commissioning date on or before December 1, 2015 and is not commissioned by December 1, 2015 but is successfully commissioned on or before December 1, 2016, its compensation cap shall be recalculated consistent with the rules in III.K.5(b) for a Generator Asset with a scheduled commissioning date after December 1, 2015, and the Generator Asset shall refund any payments made in excess of that recalculated cap. If the Generator Asset is not successfully commissioned as described in Section III.K.5(c) on or before December 1, 2016, the Market Participant shall be required to repay the amount of auditing compensation that it received pursuant to this Section III.K.5.~~

~~(e) **Ongoing Fuel Inventory Obligations.** Every Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 must, as of each December 1 through and including December 1, 2017, have oil in its tank sufficient to start the Generator Asset from a~~

~~cold state and to support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time, provided that the tank will be deemed to include: (i) oil that the ISO determines was burned to produce electricity on and after November 15; and (ii) a credit for oil that was burned in an audit of dual fuel capability for purposes of commissioning, provided that the oil used in the audit must be replenished by the later of January 1 or 15 days after the audit. In addition, a Generator Asset that has successfully commissioned its ability to operate on oil pursuant to this Section III.K.5 between December 1, 2014 and February 1, 2015, must, within 15 days of that demonstration, have oil in its tank sufficient to start the Generator Asset from a cold state and support its operation at its Economic Minimum Limit for the greater of four hours or the Generator Asset's minimum run time. Generator Assets may be eligible for compensation for their fuel inventories pursuant to other sections of this Appendix K to the extent they meet the terms thereof.~~

~~(f) **Ongoing Auditing Obligations.** Each year after the year in which the Generator Asset is commissioned to operate on oil, and continuing through 2018, the ISO shall schedule an audit pursuant to Section III.I.5.2(f) to confirm the Generator Asset's capability to operate on oil and switch fuels within eight hours. The provisions of Section III.1.5.2(f) shall apply, provided that the Market Participant shall not receive compensation for more than one audit per year, even if the Market Participant undergoes multiple audits because one or more initial audits are unsuccessful. Notwithstanding the foregoing, if the Generator Asset is unable to undergo an audit in a given year due to an outage, the Generator Asset must undertake the audit within 30 days of its return to service, provided that, if the Generator Asset remains unavailable on May 31, 2018 as a result of an outage, and the ISO determines that the Generator Asset has had a protracted outage that threatens its future dual fuel capability, the Generator Asset shall be subject to the charge outlined in Section III.K.5(g).~~

~~(g) **Failure to Meet Obligations.** Failure of a Generator Asset that has been successfully commissioned pursuant to this Section III.K.5 to meet any of the obligations outlined above shall result in a charge, calculated as follows:~~

~~*Monthly Compensation x the number of months between date of the breach and May 31, 2018*~~

~~Monthly Compensation shall mean the total payment made to the Generator Asset pursuant to Section III.K.5(d) divided by the number of months between the commission date and May 31, 2018. In no event may total charges exceed the amount of the NCPC paid to the Generator Asset pursuant to Section III.K.5(d). If a Generator Asset subsequently cures its breach, the ISO will~~

~~issue a refund in the amount of the Monthly Compensation multiplied by the number of months remaining until May 31, 2018. Where used herein, "number of months" shall mean the number of months beginning on the first of the next month.~~

~~III.K.6. Resource Auditing and Performance Monitoring.~~

~~Participating Generator Assets must report their usable oil inventory levels and remaining contracted liquefied natural gas volumes to the ISO on the first of the month during the winter(s) in which they are providing services (or, in the case of Section III.K.5, are obligated to maintain fuel inventory) and as otherwise requested by the ISO. These Market Participants must also maintain detailed fuel logs indicating the amount of fuel utilized during the Generator Asset's operation until all payments and charges made pursuant to this Appendix K are final. Market Participants shall provide the logs, fuel inventory levels, and other relevant documentation, including fuel inventory receipts/documents, to the ISO upon request, and shall allow ISO staff or designees on-site to verify reported fuel levels, with reasonable prior notice.~~

~~In each winter, Market Participants providing the demand response service described in Section III.K.4 shall be audited by the ISO in the month of January if the asset was not dispatched or audited prior to the scheduled audit. During the audit, the ISO shall dispatch the asset without prior notice and assess its performance during the sixty minutes immediately following the end of the thirty-minute notification time. The results of an audit will be treated and settled as though it were a dispatch to maintain thirty-minute Operating Reserve. Audits of assets mapped to Real-Time Demand Response Resources will be concurrent with audits of those resources. If a Real-Time Demand Response Resource with a Capacity Supply Obligation is dispatched or audited, the performance of any assets providing demand response service pursuant to this Appendix K that are mapped to that resource shall be excluded from the performance of the resource if the audit is used as a Demand Resource Commercial Operation Audit. The performance of assets dispatched or audited pursuant to this Appendix K shall be equal to the difference between the asset's adjusted Demand Response Baseline, determined pursuant to Section III.8A, and the asset's meter reading during the period of dispatch (after consideration of the thirty-minute notification time). For purposes of establishing, computing, and adjusting an asset's Demand Response Baseline, assets dispatched or audited pursuant to this Appendix K shall be treated like a dispatch or audit pursuant to Section III.13.~~

~~**III.K.7. Settlements, Cost Allocation and Financial Assurance.**~~

~~(a) **Cost Allocation and Settlement**.~~

~~i. Compensation to Market Participants for services described in Sections III.K.2 and III.K.3 shall be estimated monthly for December, January and February and collected from Market Participants in proportion to the monthly sum of their Real-Time Load Obligation for that month, excluding (1) Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only) and (2) Real-Time Load Obligation associated with Coordinated External Transactions. All charges shall be included on invoices as miscellaneous Non-Hourly Charges that are separately identifiable as associated with this Appendix K. Actual costs for the three months will be calculated in March and the difference between the actual and estimated costs will be charged and/or refunded to Real-Time Load Obligation for the relevant month, excluding Real-Time Load Obligation associated with (1) Dispatchable Asset Related Demand Resources (pumps only) and (2) Real-Time Load Obligation associated with Coordinated External Transactions. Payments shall be made to the Market Participants providing the services through the ISO's settlements system one month after the refunds and charges are paid and collected.~~

~~ii. The monthly compensation described in Section III.K.4(f)(i)-(ii) for the demand response services described in Section III.K.4 shall be allocated to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month in which the compensation is earned, excluding (1) Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only) and (2) Real-Time Load Obligation associated with Coordinated External Transactions. The hourly compensation described in Section III.K.4(f)(iii)-(iv) shall be allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligation for the hour in which the service was provided, excluding (1) Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only) and (2) Real-Time Load Obligation associated with Coordinated External Transactions. All charges shall be included on invoices as miscellaneous Non-Hourly Charges that are separately identifiable as associated with this Appendix K. Payments shall be made to the Market Participants providing the services through the ISO's settlements system in the month after the ISO makes the collections referenced in the first two sentences of this paragraph.~~

~~iii. Compensation to Market Participants for the dual fuel commissioning services in Section III.K.5 shall be allocated and settled consistent with other payments made through Section III.1.5.2.~~

~~(b) **Allocation and Settlement of Non-Performance Charges.** All repayments required herein, other than Section III.K.5(g), shall be refunded to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month in which the related compensation was earned, excluding (1) Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only) and (2) Real-Time Load Obligation contributions from Coordinated External Transactions. Repayments required pursuant to III.K.5(g) will be allocated to Market Participants in proportion to the monthly sum of their Real-Time Load Obligation in the month of the repayment charge, excluding (1) Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (pumps only) and (2) Real-Time Load Obligation associated with Coordinated External Transactions.~~

~~(c) **Financial Assurance and Payment Default.** No charges related to this Appendix K, other than those pursuant to Section III.K.5, shall create additional Financial Assurance Obligations pursuant to the ISO New England Financial Assurance Policy, and the relevant sections of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy shall not apply, including without limitation Section III.A of the Financial Assurance Policy and Sections 3.3(c), 3.10 and 3.11 of the ISO New England Billing Policy. Failure to pay any amounts due under this Appendix K will result in set-off in accordance with Sections 3.3(b) and 3.6 of the ISO New England Billing Policy and suspension in accordance with Section 3.7 of the ISO New England Billing Policy. Sections 3.3(e) through (j) of the ISO New England Billing Policy, which are related to the collection and socialization of defaults on the payment of ISO Charges, shall not apply. Rather, a payment default by Real-Time Load Obligation on charges pursuant to this Appendix K shall be allocated pro-rata to Market Participants receiving payments for services rendered under this Appendix K. Failure to make required repayments pursuant to this Appendix K. shall result in a reduced refund pursuant to Section III.K.7(b) to Real-Time Load Obligation.~~

~~APPENDIX K, ATTACHMENT 1~~

~~CONTRACT CERTIFICATION~~

~~The undersigned, duly authorized representative of [Market Participant], hereby certifies that [Market Participant] has entered into a contract for Liquefied Natural Gas on the following terms and conditions:~~

1. ~~Contracting parties:~~ _____
2. ~~Date of contract:~~ _____
3. ~~Pipeline delivery point and name gas meter number of the Generator Asset entitled to supply under the contract:~~ _____
4. ~~Maximum total volume available under the contract:~~ _____
5. ~~Contract term (date and years) (must span, at a minimum, December 1 through the end of February):~~ _____
6. ~~Confirmation that the Generator Asset is entitled to call the entire volume eligible for compensation within the winter period: [Confirmed]~~
7. ~~Any contract terms that restrict when the supply may be taken by the Generator Asset:~~ _____
8. ~~Confirmation that the contract includes pipeline transportation to the meter of the Generator Asset: [Confirmed]~~
9. ~~Entity providing pipeline transportation:~~ _____
10. ~~Confirmation that contract has a "take or pay" construct: [Confirmed]~~

~~[MARKET PARTICIPANT]~~

~~By:~~ _____
~~Name:~~
~~Title:~~
~~Date:~~

ISO new england

memo

To: NEPOOL Markets Committee

From: Internal Market Monitor, ISO New England

Date: February 1, 2019

Subject: Interim Compensation Treatment and Market Power Mitigation

The purpose of this memo is to explain the interaction between ISO New England's proposed Interim Compensation Treatment (ICT) and the market power mitigation rules. In particular, we provide guidance on Retirement and Permanent De-List bid, and CASPR Test Price submissions in the upcoming Forward Capacity Market (FCM) process for the fourteenth Forward Capacity Auction (FCA #14).

1. Background

ISO New England's proposed interim solution to address winter energy security will impact competitive offers and bids in both the Forward Capacity Market (FCM) and the energy market. The Internal Market Monitor (IMM) will account for expectations of ICT revenue and costs in its administration of the FCM and energy market mitigation rules.

The impact on FCM bids is more immediate than energy market impacts. The FCM submission windows and IMM review process for FCA #14 will commence in the coming weeks. By contrast, changes to reference level calculations used in energy market mitigation will need to be completed by December 2023.

Finally, we are conscious of the fact that the ISO proposal can evolve during the stakeholder process and in the FERC process. The IMM will consider how any changes to the proposal may impact market power mitigation and provide updates to stakeholders as appropriate.

2. Relevant Timeline for FCA #14 Bid Submission and IMM Review Process

We understand that the proposed ICT rules will likely be filed with FERC shortly after the conclusion of the stakeholder process in March 2019. Therefore, the FERC process will overlap with the FCM qualification timeline for FCA #14, and participants will not have certainty on the effective rules that will be in place. There will be an overlap with the window for submitting certain bids and the IMM review of those bids,

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specifically Retirement and Permanent De-list bids and the CASPR Test Price.[1] It is possible that a FERC decision will be issued prior to the submission of Static De-List bids and New Supply Offers.

Table 1 below shows the key dates in the FCA #14 process over the coming months.[2]

Table 1: FCM Bid Submission and IMM Review Process 2019

	Start	End
Filing of proposed ITC rule changes (expected)	After March 13 PC meeting	
Retirement and Permanent De-List Bids Submission Window	March 8	March 15
Existing Resource SA Demand Election & CASPR Test Price Window	March 8	March 15
Static and Export De-List Bid Submission Window	May 23	June 13
New Capacity Submission Window	June 7	June 21
IMM Notifies Existing Capacity of Retirement/Permanent De-List Request Determination	June 6	June 6
IMM FERC Info Filing (Retirement and Permanent De-List Bids)	July 5	July 5
ISO Qualification Package (QP) Review Window	April 26	September 27

3. The ICT Proposal and FCM Market Power Mitigation

In formulating bids and offers in the FCA, participants will take account of the expected impact of the ICT proposal (to the extent that it affects their resources). The IMM will account for ICT revenue and costs in its application of the mitigation rules as they apply to Retirement and De-list bids, the CASPR Test Price and to New Supply Offers.

As discussed above, by the time of the Retirement, Permanent De-list Bid and CASPR Test Price deadlines (March 15) FERC will not have issued its decision on the proposed rule changes. Therefore, the IMM will review any submitted bids under two scenarios; one with ICT in place, and one without ICT (the status quo).

This will be accomplished by participants submitting two bids with accompanying cost workbooks and supporting documentation and analysis. The IMM is currently working on designing a template that participants can use to calculate net revenues from ICT that would be used to adjust the FCA bid. In their submissions, participants will need to include details of estimated ICT revenues and the associated

[1] The CASPR Test Price applies to resources electing to submit a demand bid in the substitution auction.
[2] The detailed FCA#14 schedule is available on the ISO-NE website at https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/

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incremental costs for the proposed two-year duration of the program. The following is a summary of inputs to the calculation of ICT revenues and costs that should be included in submissions:

- ***Revenue*** from ICT for the capacity commitment period 2023/24 (FCA #14) and 2024/25 (FCA #15), based on[3]:
  - expected level of participation in megawatt hours in the forward and spot ICT markets
  - forward and spot rates
  - expected number of trigger conditions
- ***Costs*** are the incremental costs of participating in ICT. This does not include costs of fuel inventory that would otherwise be incurred as a result of participating in the energy, ancillary services and capacity markets. Items may include, but are not limited, to:
  - carrying costs
  - liquidation cost
  - price risk and/or associated hedging costs
  - transportation
  - LNG and oil fixed contract costs for firm delivery (variable market-based costs should be included in energy market offers and reference levels)
- ***Indirect revenue due to the impact on energy market prices.*** Participants should consider, and factor in as appropriate, additional energy market revenues as a result of the inclusion of energy market opportunity costs in supply offers (this issue is covered in more detail in the next section) and any increased energy revenue due to having more inventory. Participants should consider their expectation of:
  - generation volumes based on higher supply offers (when opportunity cost is included)
  - inframarginal rents based on expected generation and the corresponding energy prices (given the inclusion of opportunity costs) during the periods of generation

4. The ICT Proposal and Market Power Mitigation in the Energy Market

Under the ICT proposal, eligible resources will be compensated for unused stock as measured on the morning following a defined trigger condition. To the extent that a resource has limited fuel, this creates

[3] The IMM recognizes the challenge participants will have in estimating revenue from an "energy security" market solution beyond the FCA#15 period, and that they may reasonably choose not to make an allowance for such revenue beyond two years in their FCM bids for FCA 14.

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an opportunity cost of using that inventory for energy (as opposed to not using it for fuel security) up to the time of inventory measurement.

The IMM believes it would be rational to include the opportunity costs of estimated foregone ICT revenues in energy market *supply offers*. The IMM will therefore need to also account for this new opportunity cost in *reference levels* for the duration of the program. Details regarding the methodology and process for computing the opportunity costs will need to be developed and put in place prior to December 2023. To date, discussions and examples on this new opportunity cost have been at a conceptual level, and have highlighted some of the key inputs that will be required, including the expected number and timing of trigger conditions, current inventory, timing and volume of replenishment, and the ICT spot rate.

The IMM will be working with ISO staff to expand on the current process for calculating opportunity costs to include ICT opportunity costs. This is likely to be a significant undertaking that will take some time to develop. It will be discussed further at future stakeholder meetings.

5. Next Steps

The IMM is currently working on a template for participants to use to submit inputs and their calculation of expected net revenues from ICT. The template may be built into the existing cost workbook and used to adjust FCA Retirement and Permanent De-list bids, and the CASPR Test Price based on the ISO's ICT proposal. We plan to have the template available for the March 5-6, 2019 Markets Committee meeting. The IMM is also open to providing training to participant staff on completing the template.

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ISO new england

memo

To: Participants Committee

From: Erin Wasik-Gutierrez, Secretary, Markets Committee

Date: March 6, 2019

Subject: Actions of the Markets Committee

This memo is notification to the Participants Committee of the following actions taken by the Markets Committee (MC) at its March 5-6, 2019 meeting. All sectors had a quorum.

1. **(Agenda Item 2B) Interim Compensation Treatment**

ACTION: MOTION FAILED

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

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Tariff Section I.2.2 and Market Rule 1 to support the Interim Compensation Treatment, as proposed by ISO New England Inc. (the "ISO") and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

(**Vote 1 – Failed**) (Union of Concerned Scientists (UCS) Amendment) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend Tariff Section I.2.2 and Appendix K of Market Rule 1 as proposed by UCS.

The motion to amend the main motion was then voted. Based on a show of hands, the motion to amend failed.

(Vote 2 – Failed) (Energy New England (ENE) Amendment) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend Appendix K of Market Rule 1 as proposed by ENE.

The motion to amend the main motion was then voted. The motion to amend failed with a vote of ~~48.46~~36.89% in favor. The individual Sector votes were Generation (2.10% in favor, 14.69% opposed, 2 abstentions), Transmission (4.80% in favor, 11.99% opposed, 1 abstention), Supplier (7.75% in favor, 9.04% opposed, 7 abstentions), Alternative Resources (0% in favor, 16.04% opposed, 2 abstentions), Publicly Owned Entity (9.45% in favor, 7.35% opposed), End User (12.79% in favor, 4.00% opposed).

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(Vote 3 – Failed) (PSEG Amendment #1) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend Appendix K of Market Rule 1 as proposed by PSEG's Amendment #1, setting the Inventoried Energy Base Payment rate on April 30 prior to the delivery period, and as modified at the meeting.

The motion to amend the main motion was then voted. Based on a show of hands, the motion to amend failed.

The main motion was then voted. The main motion failed with a vote of 42.29% in favor. The individual Sector votes were Generation (10.79% in favor, 6.00% opposed, 3 abstentions), Transmission (7.20% in favor, 9.60% opposed, 1 abstention), Supplier (4.80% in favor, 11.99% opposed, 6 abstentions), Alternative Resources (10.69% in favor, 5.35% opposed, 3 abstentions), Publicly Owned Entity (7.35% in favor, 9.45% opposed), End User (1.46% in favor, 15.33% opposed, 2 abstentions).

2. **(Agenda Item 4A) Settlement Shortfall Caused by the Energy Efficiency Resource Exemption from Pay-for-Performance Penalties in Off-Peak Hours**

ACTION: MOTION FAILED

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

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Market Rule 1 to support the proposal to address the settlement shortfall caused by the treatment of Energy Efficiency Resources during Capacity Scarcity Conditions that occur during off-peak hours (previously identified as the "stage 1" proposal), as proposed by Dynegy Marketing and Trade, LLC ("Dynegy") and as circulated for this meeting with those further changes recommended by this Committee and supported by ~~the ISO~~Dynegy and such further non-substantive changes as the Chair and Vice-Chair approve.

(**Vote 1 – Failed**) (Vermont Energy Investment Corp. (VEIC) Amendment)) Before the main motion could be voted, it was moved and seconded by the Markets Committee to amend Market Rule 1 as proposed by VEIC.

The motion to amend the main motion was then voted. The motion to amend failed with a vote of 58.38% in favor. The individual Sector votes were Generation (1.87% in favor, 14.93% opposed), Transmission (14.93% in favor, 1.87% opposed), Supplier (3.05% in favor, 13.74% opposed, 6 abstentions), Alternative Resources (4.95% in favor, 11.09% opposed, 3 abstentions), Publicly Owned Entity (16.79% in favor), End User (16.79% in favor, 2 abstentions).

(**Vote 2 – Failed**) (Dynegy)

The main motion was then voted. The main motion failed with a vote of 34.95% in favor. The individual Sector votes were Generation (11.99% in favor, 4.80% opposed, 1 abstention), Transmission (1.87% in favor, 14.93% opposed), Supplier (11.19% in favor, 5.60% opposed, 5 abstentions),

Alternative Resources (9.90% in favor, 6.15% opposed, 3 abstentions), Publicly Owned Entity (0% in favor, 16.79% opposed), End User (0% in favor, 16.79% opposed).

3. (Agenda Item 5) Markets Committee Ad Hoc Group Report & Referral to the Demand Resources Working Group

ACTION: REFERRED

The following request was referred to the Demand Resources Working Group by the Markets Committee:

The Markets Committee instructs the Demand Resources Working Group ("DRWG") to consider how energy efficiency resources' performance in all hours for existing and new measures could be established and, what, if any, additional methodological standards and reporting mechanisms are required to accommodate such a change. The DRWG will report potential options back to the Markets Committee, which may include time and cost estimates associated with implementing each option.

RENEW Northeast

Amendment to ISO Interim Compensation Treatment Proposal

March 5, 2019
Markets Committee Meeting

Abby Krich, Boreas Renewables

RENEW Northeast

About RENEW

An association of the renewable energy industry and environmental advocates united to promote renewable energy in the Northeast.

AWEA American Wind Energy Association
Anbaric Transmission
Apex Clean Energy
AvanGrid Renewables
BNE Energy Inc. Producer of green clean energy
Brookfield
Calpine NYSE CPN
Cianbro
clf conservation law foundation
ConnectGEN
Cypress Creek Renewables
EDF renewables
edp renewables powered by nature
EnBW
enel Green Power
Eversource
GE Renewable Energy
innogy
Key Capture Energy
National Wildlife Federation
NextEra Energy
NovatusEnergy
Ørsted
Patriot Renewables
Record Hill Wind
Siemens Gamesa Renewable Energy
Reed & Reed Est. 1928
Sierra Club
SunEast Development
S.W.E.B
TerraForm Power
Terra-Gen
Union of Concerned Scientists Science for a healthy planet and safer world
Vestas
Vineyard Wind

Design Objective A Not Being Met: No Compensation for Actual Energy Provided

- ISO's Design Objective A: "Provide similar compensation for similar service"
- Chapter 3 proposal recognizes and appears to satisfy this objective.
  - "Levels the competitive playing field for the reliable delivery of **energy** through cold-weather conditions" – ISO's Design Principles presented to MC 9/13/18
- ISO's Interim Compensation proposal compensates only for inventoried energy
  - It does not compensate for energy actually provided during cold weather conditions
  - It therefor fails to meet Design Objective A because it does not recognize that providing energy during cold weather conditions is just as important, and a similar service, as providing inventoried energy during these conditions.

Energy and Inventory Are Both Needed to Ensure Winter Reliability

- Resources that provide energy during cold weather conditions are necessary to maintaining reliability.
- Resources that, due to their technology type, do this without relying on "inventoried energy" receive no direct compensation for this service under ISO's proposal.
- Every MWh these resources provide means another MWh of inventory is able to be maintained. The two are interrelated.

RENEW Northeast

Proposed Amendment:

Energy Actually Provided Should Receive Same Compensation as Inventory

- RENEW proposes that the spot rate be paid for either:
  - Inventory available at the end of the trigger day (as proposed by ISO), or
  - Actual MWh provided during the trigger day
  - (whichever is greater)

→ Resources that:

- provide energy without inventory (e.g., wind, gas without LNG contract)
  - paid LMP plus spot rate for what they actually provide
- have inventory but provide no energy (e.g., oil)
  - paid exactly as ISO has proposed
- provide energy and have inventory (e.g., nuclear)
  - are not double paid for both
  - are paid for inventory (exactly as proposed by ISO) unless they have less inventory than the MWh they actually produced during trigger day in which case paid for energy.

- Truly technology neutral
- More properly values winter <u>energy</u> security

Proposed Amendment:

Allow Forward Sale of Energy

- RENEW also proposes that resources that expect to provide energy during trigger conditions can sell forward seasonally for actual MWh to be provided in each event.
- Would settle at spot rate if they produce more MWh or fewer MWh during trigger period than committed.

Benefits of RENEW Amendment

- Modifies ISO proposal to achieve the design objective to "Provide similar compensation for similar service."
- Does so at modest, if any, additional cost
- Does not double-pay for energy provided
- Provides incentive for better utilization of available energy/ inventory supply

Questions

Abby Krich
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(Consultant to RENEW)
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other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

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

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory or Actual Energy Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried and/or actual energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

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Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Real-Time Energy Delivery is a component of the spot payment that a Market Participant may receive through the inventoried and/or actual energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried and/or actual energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of

APPENDIX K

INVENTORIED ENERGY PROGRAM

Deleted: WINTER RELIABILITY SOLUTIONS

III.K Inventoried Energy Program

For the winters of 2023-2024 and 2024-2025, the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. To participate in both the forward and spot components of the program, the information listed in this Section III.K.1 must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter (a separate election submission must be made for each winter) and must reflect an ability to provide the submitted inventoried and/or actual energy throughout the relevant winter period. To participate in the spot component of the program only, the information listed in this Section III.K.1 may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

(a) A list of the Market Participant's assets that will participate in the inventoried and/or actual energy program, with a description for each such asset of: the Market Participant's Ownership Share in the asset; the types of fuel it can use; the maximum amount of each fuel type that can be stored on site (and in upstream ponds) or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets providing inventoried energy: Settlement Only Resources; assets not located in the New England Control Area; assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction. The following asset types may not be included in a Market Participant's list of assets providing actual energy: assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period.

(ii) A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed

contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must specify the parties to the contract, the volume of gas to be delivered, the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas.

(b) For assets providing inventoried energy, a detailed description of how the Market Participant's energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than the default approach described in Section III.K.3.2.1.1(d)(i), this description should explain and support that alternate allocation.

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(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried and/or actual energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the "Forward Energy Inventory or Actual Energy Election"). For a forward inventory election, this MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site (and in upstream ponds) for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). For a forward actual energy election, this MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 24 hours, If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory or Actual Energy Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election"). A Market Participant may make either a forward inventory election or forward actual energy election for each of its assets, but may not elect both for any individual asset. (For Market Participants electing to participate in only the spot component of the program, the

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Deleted: Forward Energy Inventory Election

Forward Energy Inventory or Actual Energy Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. For election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter, and participation will begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); or

(ii) requires (except in the case of an asset that is supplied from a liquefied natural gas facility adjacent and directly connected to the asset) the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory or Actual Energy Election shall be adjusted accordingly.

Deleted: Forward Energy Inventory Election

III.K.1.2 Posting of Forward Energy Inventory or Actual Energy Election Amount

Deleted: Forward Energy Inventory Election

As soon as practicable after the November 1 immediately preceding the start of the relevant winter, the ISO will post to its website the total amount of Forward Energy Inventory or Actual

Deleted: Forward Energy Inventory Election

Energy Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried and/or actual energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory or Actual Energy Election (adjusted as described in Section III.K.1.1) multiplied by $82.49 per MWh and divided by the total number of days in those three months.

Deleted: Forward Energy Inventory Election

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried and/or actual energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried or Actual Energy Spot Payment

In the case of assets for which a forward inventory election was made, a Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory or Actual Energy Election, with the difference multiplied by $8.25 per MWh.

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Deleted: Forward Energy Inventory Election

In the case of assets for which a forward actual energy election was made, a Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Delivery minus its Forward Energy Inventory or Actual Energy Election, with the difference multiplied by $8.25 per MWh.

In the case of assets for which no forward election was made, a Market Participant's spot payment for an Inventoried Energy Day, which may only be positive, shall equal the Market Participant's Real-Time Energy Inventory or Real-Time Energy Delivery, whichever value is greater for each of the assets, multiplied by $8.25 per MWh.

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2) and a Market Participant's Real-Time Energy Delivery for an Inventoried Energy Day shall be the sum of the Real-Time Energy Deliveries for each of the Market Participant's assets participating in the program; provided, however, that where more than one Market Participant has an Ownership Share in an asset, the asset's Real-Time Energy Inventory or Real-Time Energy Delivery will be apportioned based on each Market Participant's Ownership Share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory or Real-Time Energy Delivery

Each asset's Real-Time Energy Delivery will equal its actual, metered MWh delivery during the Energy Inventory Day, subject to meter data corrections. Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Market Participant must measure and report to the ISO the Real-Time Energy Inventory for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of barrels of oil stored in a dedicated and in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.

(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.

(iv) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Market Participant must specify what

portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.

(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in on-site and upstream ponds controlled by the Market Participant with a transit time to the asset of no more than 12 hours, excluding any amount that is unobtainable or unusable for any reason.

(vii) Biomass/Refuse. The Real-Time Energy Inventory of an asset that runs on biomass or refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.

(viii) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh.

(b) If the Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as water flow or emissions limitations).

(d) The reported amounts are subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program.

(e) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(d);

(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and

(iii) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

Deleted: WINTER RELIABILITY SOLUTIONS¶
¶
III.K.1. . General.¶
<#>**Term.** This Appendix K is intended to mitigate potential fuel-related system reliability issues within New England during the 2015-16, 2016-17 and 2017-18 winter seasons. This Appendix K expires on March 15, 2018, provided that all rights and obligations, including those pertaining to payments, charges and default, shall survive expiration to the extent necessary or made explicit herein.¶
<#>**Eligibility.** Only Market Participants may provide the services described in this Appendix K. A participating Generator Asset must: be located in New England; modeled in the EMS; and either (i) dispatchable as described in Operating Procedure #14, or (ii) Self-Scheduled for the entire winter period. Market Participants may provide only one of the services described in Sections III.K.2 through III.K.4 herein.¶
<#>**Offer Obligation.** Regardless of whether they have a Capacity Supply Obligation, Market Participants obligated hereunder must submit Supply Offers for participating Generator Assets into the Day-Ahead Energy Market and Real-Time Energy Market at the Generator Assets' Economic Maximum Limit for each hour of the Operating Day during the relevant winter.¶
<#>**Fuel Retention Obligation.** Market Participants may not sell the fuel (or fuel rights) described herein during the winter(s) in which they are obligated, or take any other action that is inconsistent with ensuring the availability of the fuel for Energy production and use in New England in accordance with this Appendix K.¶
<#>**October 1 Notice.** To participate in one of the services set out in Sections III.K.2 through III.K.4, a Market Participant must notify the ISO by the October 1 immediately preceding the relevant winter and provide the detail specified below. This notice shall be the Market Participant's binding commitment to meet the relevant minimum requirements set forth in this Appendix K for that winter. The ISO reserves the right to reject any notice of proposed participation on any grounds, including the ISO's concerns about the deliverability of the fuel or the past performance of the relevant Asset. No later than October 15, the ISO will calculate the maximum potential cost of the program based on the submitted inventory levels and provide a summary to stakeholders.¶
<#>**Shared Fuel Supply.** Generator Assets that share a fuel supply may participate in Sections III.K.2 and III.K.3 only if all Generator Assets sharing the fuel supply participate, in which case the fuel levels described below will be calculated in the aggregate. Notwithstanding the foregoing, the ISO may exempt one or more Generator Assets from the participation requirement if the ISO determines at the beginning of the relevant winter period that the Generator Asset(s) are reasonably expected to be out of service for the relevant winter period.¶
<#>**Determination of Compensation Rate.** As set forth below, compensation is determined with reference to a "Set Rate." The Set Rate establishes partial compensation for the per-barrel carrying costs of stored fuel oil. ¶ ... [1]

Winter Energy Security:
Interim Compensation Treatment Amendment

NEPOOL Participants Committee
March 13, 2019
David Cavanaugh

ISO Comments for ICT Design

- Development program to address energy security as part of FERC's July 2nd Order
  - Slide #2, 2nd bullet, ISO Markets Committee presentation on November 8, 2018
- Develop program to address retaining a resource for fuel security reliability and to prevent uneconomic retirement bids from resource "critical to winter energy security"
  - Slide #2, 3nd bullet, ISO Markets Committee presentation on November 8, 2018
  - Similar supporting language page 4 ISO August 31,2018 Fuel Security Compliance filing
- ENE Positon
  - ISO proposal far exceeds the statements above. Resource eligibility is to broad and extends beyond target resources.

ICT Resource Eligibility

- **Modify ISO-NE's proposal to limit compensation to oil, natural gas, demand response and electric storage resources.**

- **Tariff language redline change to III.K.1(a)(i):**

(i) The following asset types may not be included in a Market Participant's list of assets: Settlement Only Resources; assets not located in the New England Control Area; assets listed with coal, nuclear, biomass or hydro as a fuel type; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

ICT Resource Eligibility

- **Conforming change to III.K.1(d):**

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the "Forward Energy Inventory Election"). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for ownership share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site ~~(and in upstream ponds)~~ for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election"). (For Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

ICT Resource Eligibility

- **Conforming changes in III.K.1.1**

(c) In performing this review, the ISO shall accept the full demand reduction value for a Demand Response Resource in MWh as measured pursuant to the tariff

(d) In performing this review, the ISO shall accept the full amount of an Electric Storage Resource capability in MWh measured pursuant to the tariff.

Differing Objectives - ISO Proposal and ENE Amendment

- ENE: The fundamental objective is similar to past winter reliability programs - improve the region's overall energy security by targeting payments to resources like oil and LNG that provide incremental winter reliability benefits.

- The ISO's interim program includes these same targeted payments for oil and LNG resources, but also expands payments to other resources like nuclear, coal, biomass, and hydro that are not expected to provide any measureable increase in winter reliability benefits. The additional payments are justified on the ground that they help maintain energy security by deterring such resources from retiring during the interim period.

Program Objectives in Summary

- ISO Interim Program
  - Improve winter energy security by providing an incentive to resources that can maintain or increase available inventoried energy[1]

- ENE Amendment
  - Improve winter energy security by providing an incentive only to resources that can increase available inventoried energy

Supporting Rational For ENE Amendment

- The interim program is a stopgap, out-of-market solution designed to improve energy security until a long-term market solution can be implemented, just like past winter reliability programs. For this reason, and because additional compensation is unlikely to deter retirements, the FERC's 2015 decision on the last winter reliability program is relevant here.
- **Consistent with that decision, compensation should be limited to resources capable of improving winter energy security by providing incremental reliability benefits.**
  - "While ISO-NE expanded the types of resources eligible to participate in the [winter reliability] program, the record does not reflect that including the additional resource types under the same general program principles will incent any additional fuel procurement." ISO-NE and NEPOOL (152 FERC ¶ 61,190 (2015))
  - "Coal, nuclear, and hydro resources are not similarly situated to the resources included in the NEPOOL Proposal as the record reflects that including such resources in the Program would not provide any additional winter reliability benefit to the region." Reh'r Order (154 FERC ¶ 61,133)
- Further, no energy security needs assessment has been conducted to justify compensating *all* energy secure resources.
- Conclusion:- increasing consumer costs without any relationship to improved energy security or the region's need for additional reliability services would be unjust and unreasonable.

Retirement Considerations

- No evidence has been provided to support the claim that nuclear, coal, biomass or hydro resources are at significant risk of retirement during the interim period. Indeed, it seems doubtful such resources would retire prior to knowing the financial opportunities available them under a Chapter 3 market design.
- Regardless, the ISO has not shown that the proposed additional compensation would meaningfully reduce risk.
- Even if such other resources did retire, the ISO would be well positioned to maintain energy security – without recourse to RMRs- by utilizing the increase in energy inventory that results from payments to oil and LNG resources.

Chapter 2B
"Interim Compensation Treatment"

Technology Type	ISO Proposed Program Eligibility	ENE Amendment Proposed Program Eligibility
Batteries	Yes	Same as ISO-NE except only for new electric storage assets or those that have added capacity
Biomass	Yes	No – Unlikely to change current behavior
Coal	Yes	No – Unlikely to change current behavior
Demand response	If distributed generation with eligible technology type	Same as ISO-NE except only for new demand response assets or those that have added capacity
Hydro	If has reservoir/pondage controlled by participant	No – Unlikely to change current behavior
Natural gas	If has LNG contract (to NE)	Same as ISO-NE.
Nuclear	Yes	No – Unlikely to change current behavior
Oil	Yes	Same as ISO-NE.
Passive DR	No	Same as ISO-NE.
Solar	No	Same as ISO-NE.
Wind	No	Same as ISO-NE.

Consumer Cost Are Relevant

- New England consumers already pay some of the highest rates in the nation and even higher rates are projected when the above-market costs of the Mystic contract are collected.
- ISO estimates consumer cost for its interim program to be over one hundred million dollars more than the cost of last winter reliability program.
  - The interim program and the WRP are out-of-market, stopgap measures that share the same goal: To improve energy security while the region addresses long-term risks associated with (1) increased dependence on natural gas and (2) resource performance during periods of stressed system conditions
  - As a stopgap measure, the interim program should be focused on achieving its goal at least cost and not on rectifying a flaw in the current market design.
  - Not compensating resources for a service they currently provide is a problem best addressed in Ch. 3, after the product has been defined and its demand determined.
- A more targeted interim program—similar to past winter reliability programs—can achieve the same short-term energy security goal at substantially less cost.

Amendments Impact ICT Cost

- Amendment reduces total direct cost of interim program by **~$45M** annually
- Despite this change, oil/dual fuel units receive more than under last Winter Reliability Program
  - 2017/2018 WRP costs for oil/dual fuel **$24.5M**
  - Payments to oil/dual fuel units under amendment **$60.84M**
- Gas units also receive more than under last WRP
  - 2017/2018 WRP costs for LNG-backed gas **$0.0M**
  - Payments to LNG-backed gas units under amendment **$46.19M**

Tariff Language

Tariff language to support the amendment is provided in attachment for committee review

Questions

APPENDIX K

INVENTORIED ENERGY PROGRAM

III.K Inventoried Energy Program

For the winters of 2023-2024 and 2024-2025, the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. Any Market Participant may elect to participate by submitting the following information to the ISO no later than the October 1 immediately preceding the start of the relevant winter (a separate election submission must be made for each winter):

(a) A list of the Market Participant's assets that will participate in the inventoried energy program, with a description for each such asset of: the Market Participant's ownership share in the asset; the types of fuel it can use; the maximum amount of each fuel type that can be stored on site (or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii)), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets: Settlement Only Resources; assets not located in the New England Control Area; assets listed with coal, nuclear, biomass or hydro as a fuel type; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

a. (ii) Market Participants with a Demand Response Resource comprised of Demand Response Assets located within the New England Control Area with a positive Demand Response Baseline (showing energy consumption at the Retail Delivery Point), including a Demand Response Asset with behind-the-meter generation capable of reducing demand from the electric system and delivering any Net Supply, are eligible to participate pursuant to this Appendix K provided that ~~A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.~~

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must specify the parties to the contract, the volume of gas to be delivered, the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the

transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas.

(b) A detailed description of how the Market Participant's energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than the default approach described in Section III.K.3.2.1.1(d)(i), this description should explain and support that alternate allocation.

(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the "Forward Energy Inventory Election"). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for ownership share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site ~~(and in upstream ponds)~~ for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election"). (For Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. The ISO will report the final Forward Energy Inventory Election and other participation values to each Market Participant by the November 1 immediately preceding the start of the relevant winter.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); or

(ii) requires the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the first Business Day in September prior to that winter period.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory Election shall be adjusted accordingly.

(c) In performing this review, the ISO shall accept the full demand reduction value for a Demand Response Resource in MWh as measured pursuant to the tariff

(d) In performing this review, the ISO shall accept the full amount of an Electric Storage Resource capability in MWh measured pursuant to the tariff.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by $82.49 per MWh and divided by the total number of days in those three months.

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried Energy Spot Payment

A Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory Election, with the difference multiplied by $8.25 per MWh.

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2); provided, however, that where more than one Market Participant has an ownership share in an asset, the asset's Real-Time Energy Inventory will be apportioned based on each Market Participant's ownership share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory

Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Market Participant must measure and report to the ISO the amount of each type of fuel for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. These amounts must be reported to the ISO both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of barrels of oil stored in a dedicated and in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

~~(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.~~

~~(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.~~

(~~iv~~ii) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Market Participant must specify what portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

~~(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the number of gallons of water in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.~~

~~(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the number of gallons of water in on-site and upstream ponds controlled by the Market Participant and available for generation within 12 hours, excluding any amount that is unobtainable or unusable for any reason.~~

~~(vii) Biomass/Refuse. The Real-Time Energy Inventory of an asset that runs on biomass or refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.~~

(~~viii~~iii) Demand Repsonse. The Real-Time Energy Inventory of a Demand Response Reource shall be its available demand reduction plus the any net supply in MWh ~~capped by the eligibility requirements defiend in III.K.1.1(c).~~as measured pursuant to the the ISO tariff.

(iv) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh ~~capped by the Electric Storage eligibility requirements as defined in III.K.1.1(d)~~as measured pursuant to the ISO tariff.

(b) If the Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as water flow or emissions limitations).

(d) The reported amounts are subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program.

(e) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(d);

(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and

(iii) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

TO: NEPOOL Markets Committee Membership DATE: February 26, 2019

FROM: Joel Gordon, PSEG Energy Resources & Trade LLC

RE: Proposed Amendments to ISO-NE Proposal Interim Winter Energy Security Program – Chapter 2B

Overview:
PSEG will offer two amendments to the ISO-NE proposal on Chapter 2B – the Interim Compensation Treatment of the Winter Energy Security Proposal as presented to the MC over the last several committee meetings. Specifically, the amendments will address one direct component of the program – the timing of when the actual payment rate is set. The second will address how the program is incorporated into the Internal Market Monitor's treatment of revenues associated with the program when the IMM conducts its Static Delist Bids reviews during the qualification process under the Forward Capacity Auction.

Together, the amendments will act to create greater efficiency in the implementation of the proposed design by using market-based information in a timelier manner enhancing the success of the interim program and resulting in greater levels of contracting of LNG-based supply contracts. These amendments will improve fuel security across the pool during the FCM delivery period. In addition, it will also improve the competitiveness of the FCA itself, by better reflecting the expected market conditions faced by suppliers in the auction over that same delivery period.

Amendment I: Set the Inventoried Energy Base Payment rate on April 30, prior to the Delivery Period.

Argument:
It is widely recognized that setting the Energy Base Payment rate for the Winter delivery period over four years prior to when the contracts are expected to be obtained increases the likelihood that the rate will be inconsistent with market conditions when resources are expected to go to market to obtain those contracts. If the rate is too low, the program will fail to procure the additional fuel security needs of the system. Conversely, if the rate is too high, the overall cost of the program will be greater than otherwise required to achieve its objectives. Thus, setting the rate closer to the contract period will better align the program with the market conditions – a valuable condition necessary to ensure its success at the most efficient cost.

Failure to better align market conditions with the program rate would undermine LNG contracting and would result in a violation of two of the four objectives of the program:

- Objective A: Not all fuel secure capable resources would be compensated for the fuel security service currently being paid to the Mystic Units.
- Objective B: Resources unable to procure an LNG contract due to insufficient rates would be subjected to lower net capacity revenues resulting in a higher likelihood of early retirements.

While it has been suggested that setting the rate four years in advance provides a level of certainty regarding the program costs to wholesale suppliers (those who are allocated the cost of the program) and revenue streams to resources, that is not the entire picture.. One could just as easily claim that setting the rate so far in advance increases the level of uncertainty as relates to resources ability to participate in the program (rate is too low) and thus adds uncertainty as to net market revenues to resources. In addition, it raises the uncertainty as to the impact on the capacity auction outcomes

depending upon the type of resource that is the marginal unit in the auction and its projected contribution to revenues. This uncertainty impacts both load as well as suppliers. PSEG contends that the uncertainties created by such forward rate setting of a volatile commodity product significantly outweigh any benefits obtained from the forward rate setting.

Proposed Tariff Language Redlines:

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by ~~$82.49~~ the rate set on April 30 prior to the delivery period as calculated under Section III.K.2.A below delineated on a per MWh and divided by the total number of days in those three months.

III.K.2.A. The Inventoried Energy Base Payment will be determined consistent with the methodology presented by the Analysis Group "Calculation of Rate for Interim Compensation Program" dated January 30, 2019 which uses the ten contracted call options for LNG over the three winter period months methodology. This methodology will be applied in April prior to the delivery period so that the most up-to-date market based inputs to the model can be incorporated into the rate. This updated rate will be filed with the FERC in April prior to the delivery period.

Amendment II: Revise the language of how the IMM evaluates Static Delist Bids to incorporate forward looking revenue streams, consistent with existing language for Retirement Delist Bids, Permanent Delist Bids, CASPR Test Price Submissions, and New Supply Offer MOPR reviews.

Argument:

With the addition of this new program, the IMM has indicated that it will incorporate projected net revenues resulting from this program (both program net revenues and energy market impacts) into all Retirement and Permanent Delist Bids, CASPR Test Price Submissions, New Supply Offers, and Static Delist Bids participating in the FCA during the interim period: "The Internal Market Monitor (IMM) will account for expectations of ICT revenue and costs in its administration of the FCM and energy market mitigation rules." Ref: Page 1 IMM Memo to MC February 1, 2019.

Under existing capacity market mitigation rules, resource owners provide to the IMM their own projected revenues and costs of participating in the market for all but Static Delist Bids. The language from the existing tariff is for those resource types are shown below. The relevant excerpts are italicized for emphasis.

> **III.13.1.2.3.2.1.2.B Permanent De-List Bid and Retirement De-List Bid Net Present Value of Expected Cash Flows**.
> The net present value of the *Existing Capacity Resource's expected cash flows* is equal to (i) the net present value of *the Existing Capacity Resource's net annual expected cash flows over the resource's remaining economic life*.

Expected net operating profit, in dollars, *is the Lead Market Participant's expected annual profit* that might otherwise be avoided or not accrued if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period.

> **Retirement or Permanent Delist Bid Model User Guide – Line 50:** *The Market Participant shall provide the source of the energy revenue forecast and explain any adjustments to expected revenues over the forecast period in the Project Assumptions tab.*

Expected capacity revenues, in dollars, *are the forecasted annual expected capacity revenues based on the Lead Market Participant's forecasted expected capacity prices* for each of the subsequent Capacity Commitment Periods of the resource's remaining economic life.

(NOTE: The methodology is the same for CASPR Test Price Submissions and New Supply Offers:

> CASPR Test Price Submission: Under Section III.13.2.8.3.1A(b), the IMM will review the participant-submitted test price *using the same cost-review framework that is utilized for Retirement De-List Bids*.
>
> New Supply Offers: "Line 57 – Energy Revenue ($/MWh)) *The Project Sponsor shall provide the source of the energy revenue forecast and explain any adjustments to expected revenues over the forecast period in the Project Assumptions tab.*"

However, the methodology for evaluating the forecasted revenue streams for Static Delist bids was not updated during recent rule revisions and continues to reflects backward looking revenue forecast – effectively using historic revenues and gross margins looking backwards up to three years as the revenue forecast applied over three years forward for the future capacity delivery period. It is widely acknowledged that such a rear view forecasting methodology is inappropriate in a market in which there is a large shift in the generating technologies being employed and with changes to the overall fuel mix in the supply stack.

Existing Tariff Provisions and IMM User Guides (emphasis added in italics):

> **III.13.1.2.3.2.1.2.A. Static De-List Bid and Export Bid Net Going Forward Costs**.
> The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs in a manner and format specified by the Internal Market Monitor …
>
> As soon as practicable*, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO* and available to the Lead Market Participant upon request.
>
> > **Static Delist Bid Model – User Guide Section 2.0: Infra-marginal Revenue** – calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the total ISO market revenues as provided by ISO-NE. I
> >
> > **Cells C33-H33 – ISO Revenues ($)** Enter the ISO revenues, in dollars, in Cells C33-H33 for each individual unit that is the subject of this De-list Bid submission. *This information is provided by ISO-NE.*

4.0 Import ISO Table

The *Import ISO Table* worksheet is designed for Market Participants to import a table of relevant values *that are provided by ISO-NE* for use in populating certain sections of the *General Inputs* worksheet. *These values include* the following: EFORd; *ISO Revenues*; and Peak Energy Rent.

Proposed Tariff Changes:

The changes shown in redline below comport the Static Delist Bid net revenue determination with how Retirement and Permanent Delist net revenues are evaluated by the IMM. The majority of the proposed changes are simply copied from the existing language from the Retirement/Permanent Delist bid methodology of the tariff and inserted into the Static Delist Bid section. The entirety of the section is included for completeness.

III.13.1.2.3.2.1.2.A. Static De-List Bid and Export Bid Net Going Forward Costs.

The Lead Market Participant for an Existing Capacity Resource that submits a Static De-List Bid or an Export Bid at or above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report all expected costs, revenues, prices, discount rates and capital expenditures~~net going forward costs~~ in a manner and format specified by the Internal Market Monitor, and may supplement this information with other evidence. The Internal Market Monitor will review the Lead Market Participant's submitted data to ensure that it is consistent with overall market conditions and reflects expected values. The Internal Market Monitor will adjust any data that are inconsistent with overall market conditions or do not reflect expected values . A Static De-List Bid or Export Bid at or above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Capacity Resource's net going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Capacity Resource from the most recent full Capacity Commitment Period available.

$$[GFC - \cancel{(}IMR \cancel{- PER)}] \text{ x } InfIndex$$
$$(CQ_{Summer,}\, kw) \text{ x } (12, months)$$

Where:
GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market

Monitor shall also consider adjustments submitted, provided the costs are based upon expectatons of the Lead Market Participant ~~on known and measurable conditions~~ and supported by appropriate documentation to reflect those costs.

> $CQ_{Summer}kW$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's annual expected ~~total ISO~~ market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00. ~~As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.~~

~~PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.~~ NOTE: PER is no longer part of the market design
~~At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected~~

$$\text{InfIndex} = \text{inflation index. infIndex} = (1 + i)_4$$

Where: "*i*" is the most recent reported 4- Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

M E M O R A N D U M

TO: Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: March 6, 2019

RE: Membership Subcommittee Recommendation to Approve End User Application

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The Participants Committee (NPC) will be asked at the March 13 meeting to approve the application for membership as an End User Participant (Application) by Michael Kuser (Applicant), subject to Applicant's acceptance of the Standard Membership Conditions, Waivers and Reminders (Standard Conditions). The Membership Subcommittee (Subcommittee) by consensus recommended that the Participants Committee take this action in light of (1) the history and circumstances surrounding the Application, (2) the understandings, Principal Committee Bylaws and Standard Conditions applicable to all members, and (3) the FERC's January 29, 2019 order in Docket No. ER18-2208. We have summarized below the relevant information concerning the history and circumstances of the Application, have included a form of resolution for NPC action, and have included with this memorandum copies of the Application, Standard Conditions, NPC Bylaws, and the Subcommittee's February 12 Notice of Actions.

A. Background

NEPOOL received Applicant's Application for membership as a Governance Only End User Participant late last March. Applicant, who is a press reporter for *RTO Insider*, has a residence and consumes electricity in Vermont, part of the New England Control Area, as required in order to be eligible for membership in the End User Sector. In presenting the Application for NEPOOL consideration, Applicant and his editor explained to the Subcommittee that the Application was intended specifically to enable Applicant and his representatives to attend in the role of press reporter and report on NEPOOL meetings. Because that activity ran would violate the existing understandings among NEPOOL members that discussions and statements made during consideration of proposals and issues in NEPOOL meetings are not to be published publicly with attribution and association to members or the Participant(s) they represent, the Subcommittee sought and received guidance from the NPC, deferring further consideration of the application pending further direction.

With further input from the Membership Subcommittee, the NPC considered the matter and approved at the June 26-28, 2018 NPC Summer Meeting a proposal that included amendments to the Second Restated NEPOOL Agreement ("RNA") defining "Press" and prohibiting Press from becoming a Participant, or to be or become a representative (member, alternate, temporary alternate) of a

Participant.[1] The NPC approved the balloting of the amendments to the RNA (the 132nd Agreement).[2] The 132nd Agreement was subsequently approved in balloting.

The approved 132nd Agreement was filed with the FERC and was challenged by a number of parties, including by *RTO Insider*, and by members of NEPOOL that had voted against the 132nd Agreement. In addition to challenging the 132nd Agreement, RTO Insider also filed a complaint against NEPOOL challenging NEPOOL's press attendance policy.[3]

On January 29, 2019, the FERC rejected the 132nd Agreement ("*January 29 Order*"),[4] concluding that NEPOOL had not supported that "barring members of the press from exercising the privileges unique to NEPOOL membership—i.e. attending, speaking, and voting at NEPOOL meetings—will meaningfully advance its aim for candid deliberation in light of" NEPOOL's Bylaws and Standard Conditions "currently in place—which this order does not affect—[that] already prohibit reporting on deliberations or attributing statements to other NEPOOL members."[5] In the *January 29 Order*, the FERC further indicated that the *Order* only addressed NEPOOL's proposed changes to the RNA, and not the pending RTO Insider Complaint (*see* Litigation Report, EL18-196), which it explained it would address in a separate order. NEPOOL requested clarification, or in the alternative, rehearing, of the *January 29 Order* on February 28, 2019. In that request, NEPOOL asked the FERC, particularly in light of issues that remain pending in EL18-196, to clarify the extent to which the FERC seeks to assert jurisdiction over the RNA, or

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[1] The NPC also considered, but did not support, an alternative approach proposed by a group of members that would have permitted Press membership and attendance, subject to defined limitations and parameters that would have been set forth in the Standard Conditions and Bylaws.

[2] In conjunction with approving the balloting of these changes to the RNA , the NPC also approved (i) the addition to the Bylaws of the understanding that statements in NEPOOL meetings are not to be disclosed publicly, and that the NPC is the entity to approve Press attendance as a guest at a NEPOOL meeting; and (ii) the inclusion in the Standard Conditions that each new member must accept of the understanding that

> Applicant and each of its representatives will have an ongoing obligation … not to publicly quote or to cause to have published publicly (i) any statement made in, or (ii) any information distributed or shared confidentially in connection with, a NEPOOL meeting. If Applicant or any representative of Applicant violates this understanding (d), Applicant's right to attend NEPOOL meetings will be suspended by the Participants Committee and will not be restored until or unless the Participants Committee affirmatively acts to allow Applicant to attend future NEPOOL meetings.

[3] The RTO Insider Complaint against NEPOOL, filed on Aug. 31, 2018, requests that the FERC either (i) find NEPOOL's press policy "unlawful, unjust and unreasonable, unduly discriminatory and contrary to the public interest, and direct NEPOOL to cease and desist" from implementing its policy; or (ii) "if the [FERC] finds that NEPOOL can sustain such a ban as a "private" entity, [] direct that NEPOOL's special powers, privileges and subsidies be terminated and that an open stakeholder process be used by [ISO-NE]." The RTO Insider Complaint remains pending before the FERC.

[4] *New England Power Pool Participants Comm.*, 166 FERC ¶61,062 (Jan. 29, 2019), *clarif., or in the alt. reh'g, requested*.

[5] *Id.* at P 50.

in the alternative, grant rehearing of the *January 29 Order* on the grounds that it reflects an impermissible exercise of the FERC's jurisdiction.

B. February 12, 2019 Membership Subcommittee Consideration of Application

Following notice to NPC, the Subcommittee considered the pending Application at its February 12, 2019 meeting. While there remained lingering concerns that had been explored throughout the application process, given the *January 29 Order* and continued assurances regarding members' obligation not to publicly quote or to cause to have published publicly any statement made in, or any information distributed or shared confidentially in connection with, a NEPOOL meeting, the Subcommittee members did not want to impose any further conditions to Applicant's membership. The Subcommittee agreed based on the history and circumstances that final action on the Application should be taken by the NPC and recommended NPC approval of Applicant's Application as an End User, subject to Applicant's acceptance of the Standard Conditions. (*see* item #2 on the Subcommittee's February 13, 2019 notice of actions included herewith.)

C. Resolution

The following form of resolution could be used for Participants Committee action at the March 13 meeting:

> RESOLVED that the Participants Committee approves the application for membership in NEPOOL as an End User Participant by Michael Kuser (Applicant) on the condition that Applicant accept and complies with the Standard Membership Conditions, Waivers and Reminders, and each of NEPOOL's governing documents, including the Bylaws governing conduct at Principal Committee meeting, with such membership to become effective, subject to FERC acceptance of the membership filing that adds Applicant to the list of NEPOOL members, as of date requested for such membership in that filing.[6]

If you have questions in advance of the meeting, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[6] The effective date for Applicant's membership, should he accept the Standard Conditions, will be the first of the month that is 60 days from date of such acceptance (allowing for FERC filing and acceptance), or the next first of a month should he also execute the standard form of Indemnification Agreement (which permits him to be treated as a Participant during the time his Application is pending before the FERC).

MEMBERSHIP APPLICANT QUESTIONNAIRE
New England Market / New England Power Pool

Please note: *All Applicants are required to provide detailed information to the New England Membership Coordinator regarding any changes to the information supplied herein after the application has been submitted. Capitalized terms used but not defined in this Questionnaire are intended to have the same meaning given to such terms in the Second Restated New England Power Pool Agreement (the "2d RNA"), the Participants Agreement ("PA"), or the ISO New England Inc. ("ISO") Transmission, Markets and Services Tariff ("ISO Tariff"). Applications expire 12 months from the date the application is reviewed by the Membership Subcommittee. All materials may be subject to update if 6 months or older.* ***Application fees paid are non-refundable.***

I. Applicant Name (Full Corporate Name or Full Name if Applicant is an individual):
Michael Kuser

A. Corporate Form. Applicant is *(please check appropriate category):*

☐ Corporation created under the laws of _____

☐ LLC (limited liability company) created under the laws of _____

☐ Political subdivision (US or US State, Canada or Canadian Province, or an agency thereof)

☐ Partnership ☒ Natural Person ☐ Electric cooperative

☐ Other (please describe): _____

B. Date of incorporation/formation/organization (MM-DD-YYYY): _____

C. Registered & Principal Place of Business: _____

_____

D. Description of Applicant's business operations: _____

E. Prior New England Registration. Has Applicant previously registered with the ISO or NEPOOL?
☒ No. Proceed to Section II.
☐ Yes. Provide Customer Name and ID number: _____

II. Web Page Address: _____

III. Applicant Dun & Bradstreet Number: _____
All Applicants must have a D&B number. If applied for but not yet received, please so indicate.

IV. Related Persons that are Participants. Does Applicant have a Related Person/Affiliate that is currently a NEPOOL Member or Market Participant?
☒ No Proceed to Section V.
☐ Yes. Please provide the name of the Related Person(s): _____

V. Requested Effective Date of Membership: 3-1-18
(Please note: Requested Effective Date should reflect the first day of a month and allow for the 60-day notice period required by the FERC following the approval of the application. Applicants which wish to be treated as if they were Participants during the interim period before the FERC has acted in a favorable manner on their application may request an earlier Effective Date with the understanding that requests for such treatment will generally be granted subject to execution of an Indemnification Agreement with the ISO and NEPOOL.)

Applicant Name Michael Kuser

VI. Activities. Please identify all activities that Applicant will or plans to conduct in New England *(pending appropriate approvals)* as a New England Market and/or NEPOOL Participant *(select all that apply)*:

- ☐ **Alternative Resource Provider** ("substantial business interest" in Alternative Resources located within the New England Control Area)
- ☐ **Broker** (arranges power transactions without taking title)
- ☐ **Cooperative**
- ☒ **End User:** ☒ **Governance Only Member** ☐ **Market Participant End User ("MPEU")**
  - ☐ Large End User (a single end user with a peak monthly demand for load in New England, including load served by End User Behind-the-Meter Generation, of at least one 1 MW, or a group of 2 or more corporate entities each with a peak monthly demand (non-coincident) for load in New England, including load served by End User Behind-the-Meter Generation, of at least 0.35 MWs that together totals at least 1 MW). Please indicate peak monthly demand (non-coincident) for load in New England, including load served by End User Behind-the-Meter Generation: _____MW.
  - ☐ End User Organization
    - ☐ Non-profit organization (____ 501(c)(3); _____ (other)) with an organized board of directors and a membership of:
      - ☐ at least 100 Entities that buy electricity at wholesale or retail in the New England states; or
      - ☐ Entities with an aggregate peak monthly demand (non-coincident) for load in New England, including load served by End User Behind-the-Meter Generation, of at least 10 MW.
  - ☐ Municipality or other governmental agency located in New England which does not meet the definition of Publicly Owned Entity
  - ☒ Small End User (an End User which does not otherwise meet the definition of Large End User or End User Organization.)
- ☐ **Exempt Wholesale Generator ("EWG")**
- ☐ **Financial Marketer/Trader** (submits Increment Offers and/or Decrement Bids in the Day-Ahead Market)
- ☐ **FTR-Only Customer**
- ☐ **Gas Industry Participant**
- ☐ **GIS-Only Participant**
- ☐ **Independent Power Producer** (exclusive business is owning or owning and operating all or a part of one or more generating facilities and selling electric energy at wholesale or retail, but not an EWG or QF)
- ☐ **Load Aggregator** (purchases at wholesale to sell at retail)
- ☐ **Publicly Owned Entity** (as defined in the 2d RNA)
- ☐ **Power Marketer** (purchases and sells at wholesale): *Please provide the docket number in which FERC accepted* Applicant's *filed materials for engaging in power marketing activities and the exact name of the entity for which such activities were approved by FERC:* ER _____
- ☐ **Provisional Member** (see 2d RNA for qualifications)
- ☐ **Qualifying Facility**
- ☐ **Related Person Supplier** (see 2d RNA for qualifications)
- ☐ **Transmission and/or Distribution Company**
- ☐ **Other** (please describe) _____

Applicant Name_Michael Kuser_____

VII. Generation (All Applicants):

A. Applicant's Generation

☒ No Generation. (proceed to VII.B)

☐ Developing Generation.*

☐ (i) Owns, or (ii) leases with rights equivalent to ownership, facilities for the generation of electric energy that are located in the New England Control Area.*

* *Please indicate on a separate sheet of paper attached to this Questionnaire the following information for each such facility: (1) Total Generation (Name-Plate Capacity); (2) Net Generation; and (3) Ancillary services to be provided.*

B. Affiliate's Generation

☒ No Generation.

☐ Affiliate(s) (i) Own, or (ii) lease with rights equivalent to ownership, facilities for the generation of electric energy that are located in the New England Control Area. *Please indicate on a separate sheet of paper attached to this Questionnaire a list of Generation assets in the New England Control Area owned by your Affiliates identified pursuant to Section XII.*

VIII. OATT Information (All Applicants):

A. Business Across the External Interfaces. Does the Applicant anticipate conducting business across the external interfaces under the ISO's Open Access Transmission Tariff ("OATT")?

☒ **No.** Proceed to VIII.B below.

☐ **Yes.**

1. **NERC Purchasing Selling Entity (PSE) code:** _____
2. Applicant must (i) complete the OASIS registration process for external transaction customers which is described in detail on the ISO's website: https://www.iso-ne.com/participate/applications-status-changes/access-software-systems.

PLEASE NOTE: OASIS access will only be approved for a Market Participant as defined by its associated DUNs number. OASIS certificates will not be approved for member company branches with a different number than the member.

B. Regional Network Load. Does the Applicant anticipate that it will be responsible for Regional Network Load under Section II.B. of the OATT?

☒ **No.** Proceed to Section IX or X if applicable; Section XI if not.

☐ **Yes.** Applicant may need to complete and submit an Application for Regional Network Service ("RNS Application"). Prior to submitting a completed RNS Application, it is recommended that the Applicant Contact ISO-NE Customer Services (custserv@iso-ne.com) and request guidance from the ISO-NE Operations Tariff & Agreement Manager with regard to the need to submit an application at this time. The RNS Application can be found at: http://www.iso-ne.com/static-assets/documents/trans/services/types_apps/rns_tout_srvc_agrmnt_app.docx .

Applicant Name Michael Kuser

IX. Market Participant End User Information (if applicable):

A. Current LDC (Local Distribution Company): Green Mountain Power

B. MPEU Accounts to be Served. List ALL Account Number(s) and/or meter number(s) for loads to be served by Applicant as an MPEU (attach separate sheet if necessary):

Account Number(s) and/or ***Meter Number(s)***

C. Peak Load. Highest aggregated hourly load in any month in the preceding year ("Peak Load") for all accounts listed in Section IX.B above:_____

D. Authorization: By submission of this questionnaire, Applicant expressly authorizes the LDC identified in IX.A above to release to ISO and NEPOOL representatives the information necessary to determine and/or verify Applicant's coincident Peak Load, subject to the terms and conditions of the ISO New England Information Policy.

X. Alternative Resources Provider Data (if applicable):

A. Aggregate Governance Rating.[1] For all Alternative Resources ("AR") owned or controlled by Applicant **or** its Related Persons in the New England Control Area:

Renewable Generation:_____MW Distributed Generation:_____MW Load Response:_____MW

B. Substantial Business Interest in Alternative Resources (*check and complete all that apply*):

☐ at least 75% of the Energy resources owned or controlled by the Undersigned within the New England Control Area are Alternative Resources. Alternative Resources are _____% of the Energy resources owned or controlled by the Undersigned within the New England Control Area.

☐ Applicant owns or controls at least 50 MW of AR within the New England Control Area.

☐ has an independently verifiable capital investment in its Alternative Resources in the New England Control Area of at least $30 million.

AND

☐ the quantity of Alternative Resources (in megawatts) and other generation resources in the New England Control Area owned or controlled by it (_____MW) exceeds the highest quantity of hourly Governance Load responsibility held by the Participant in the prior twelve (12) months (_____MW).

☐ the quantity of generation (in megawatt hours) in the past twelve months from Alternative Resources and other generation resources in the New England Control Area that the Participant owns or controls (_____MWh) exceeds the total quantity of Governance Load responsibility held by the Participant in the prior twelve (12) months (_____MWh).

☐ the Participant has not held any Governance Load responsibility in the prior twelve (12) months.

OR

☐ Applicant is unable to check a box in each part of Section X.B. above and requests a determination by the AR Sector and Participants Committee that it has "a Substantial Business Interest" in AR.

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[2] Governance Rating is (a) for electric generating units or combination of units (other than a Distributed Generation Resource), (i) the Winter Capability of such unit or combination of units determined by the ISO, or (ii) the aggregate name plate rating of such unit or combination of units; (b) for Demand Response Resources, the highest adjusted capability value (determined in accordance with the Load Response Program) for those Demand Response Resources in the prior twelve (12) months; (c) for Distributed Generation Resources not participating in the New England Markets or the Load Response Program, the name plate rating of the Distributed Generation Resource; or (d) for Energy Efficiency Resources, the highest verified co-incident peak savings provided during the hours of the Load Response Program during the prior twelve (12) months.

Applicant Name Michael Kuser

XI. Sector or Provisional Member Selection. Please indicate the Sector you will join as a Participant of the New England Power Pool *(check only one)*:

☐ **Generation Sector.** Aggregate Winter Capability (in megawatts) for your generation facilities in the New England Control Area: _____. (2d RNA Section 6.2(a))

- ☐ **Individual Voting Member.** (if > 15 MW and not electing the Group Seat immediately below)
- ☐ **Group Seat.** ** (mandatory under 15 MW; optional 15 MW and above)

☐ **Transmission Sector.** Amount of original capital investment in PTF owned or leased with rights equivalent to ownership in PTF: _____. (2d RNA Section 6.2(b))

☐ **Supplier Sector.** (2d RNA Section 6.2(c))

☐ **Alternative Resources Sector.** (check one Sub-Sector and one certification). *Note: a Participant eligible to join the End User Sector shall not join the AR Sector. (2d RNA Section 6.2(d))*

- ☐ **Renewable Generation** Sub-Sector (2d RNA Section 6.2(d)(i)(1))
- ☐ **Distributed Generation** Sub-Sector (2d RNA Section 6.2(d)(i)(2))
- ☐ **Load Response** Sub-Sector (2d RNA Section 6.2(d)(i)(3))

Applicant certifies that it, together with all of its Related Persons (*check only one*):

- ☐ meets the minimum requirements necessary to designate an individual voting member, and an alternate to the member, of each Principal Committee in the AR Sub-Sector selected above. The names of each Principal Committee member and alternate to that member are listed in Section **XIII.**
- ☐ elects together with the AR Providers identified herein (together, the "Self-Defined Group") to be represented by a "self-defined" group voting member and an alternate to that member for each Principal Committee. The Self-Defined Group meets the minimum requirements of the AR Sub-Sector selected above for the designation of a "self-defined" group voting member. The names of each Principal Committee voting member and alternate to that member for the Self-Defined Group are listed in Section **XIII.**

  The Self-Defined Group will be composed of the following AR Providers:
  _____
  _____
  _____
- ☐ is not entitled, and has not elected with another member(s) of the AR Sub-Sector to designate a self-defined group member for each Principal Committee.

☐ **Publicly Owned Entity Sector.** (2d RNA Section 6.2(e))

☒ **End User Sector.** (2d RNA Section 6.2(f))

- ☒ **Governance Only Member**
- ☐ **Market Participant End User (MPEU)**

OR

☐ **Provisional Member Group Seat.** (Provisional Members that do not have a Participant Related Person in a Sector will be assigned to this group seat). Applicant intends to join the following Sector when eligible: _____.

Applicant Name_____

XII. Affiliate Information:

The governance provisions of the 2d RNA require that Related Persons[2] vote together on NEPOOL matters. The Related Person definition is one that was required by the FERC and agreed to among the Participants. In addition, the ISO has an obligation to ensure that members of its board of directors and staff are not affiliated with any of the NEPOOL Participants and their Affiliates.[3] The Participants and the FERC required that policies related to affiliation be implemented to enhance the perceived and actual independence of the ISO. There are additional Tariff provisions that require Affiliate evaluation. To ensure compliance with these obligations, each Governance Participant is required to identify its Affiliates. Accordingly, please provide a ***flow chart*** illustrating the corporate structure of which applicant is a part, including ***all parent and subsidiary relationships***; and *every* other Affiliate that is a:

- ***Market Participant Affiliate*** (any Affiliate that is an ISO customer and/or NEPOOL member, or a market participant in another wholesale electricity market);
- ***Code of Conduct Affiliate*** (any Affiliate whose securities[4] trade or are available publicly); or
- ***LOC Affiliate*** *(any Affiliate that is included on the ISO's list of "Acceptable Letter of Credit Banks" posted at: http://www.iso-ne.com/static-assets/documents/stlmnts/assur_crdt/approved_letter_of_credit_banks.pdf.*

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[2] Section 1 of the 2d RNA provides that, "A Related Person of a Participant is (a) for all Participants, either (i) a corporation, partnership, business trust or other business organization 10% or more of the stock or equity interest in which is owned directly or indirectly by, or is under common control with, the Participant, or (ii) a corporation, partnership, business trust or other business organization which owns directly or indirectly 10% or more of the stock or other equity interest in the Participant, or (iii) a corporation, partnership, business trust or other business organization 10% or more of the stock or other equity interest in which is owned directly or indirectly by a corporation, partnership, business trust or other business organization which also owns 10% or more of the stock or other equity interest in the Participant , or (iv) a natural person, or a member of such natural person's immediate family, who is, or within the last 6 months has been, an officer, director, partner, employee, or representative in NEPOOL activities of, or natural person having a material ongoing business or professional relationship directly related to NEPOOL activities with, the Participant or any corporation, partnership, business trust or other business organization related to the Participant pursuant to clauses (i), (ii) or (iii) of this Section (a); and (b) for all End User Participants which are also natural persons, a Related Person is (i) a member of such End User's immediate family, or (ii) a Participant and any corporation, partnership, business trust, or other business organization related to the Participant pursuant to clauses (i), (ii) or (iii) of Section (a), of which such End User Participant, or a member of such End User Participant's immediate family, is, or within the last six (6) months has been, an officer, director, partner, or employee of, or with which an individual End User Participant has, or within the last twelve (12) months had, a material ongoing business or professional relationship directly related to NEPOOL activities, or (iii) another Participant which, within the last twelve (12) months, has paid a portion of the End User Participant's expenses under Section 14 of [the NEPOOL] Agreement, or (iv) a corporation, partnership, business trust or other business organization in which the End User Participant owns stock and/or equity with a fair market value in excess of $50,000. (c) Notwithstanding the foregoing, for the purposes of this definition, an individual shall not be deemed to have or had a material on-going business relationship directly related to NEPOOL activities with any corporation, partnership, business trust, other business organization or Publicly Owned Entity solely as a result of being served, as a customer, with electricity or gas."

[3] Pursuant to the ISO's Code of Conduct, Affiliate "with respect to an entity, means any individual, corporation, partnership, firm, joint venture, association, joint-stock company, trust or unincorporated organization, or other form of entity, directly or indirectly Controlling, Controlled by, or under common Control with, such entity. The term "Control" means the possession, directly or indirectly, of the power to direct the management or policies of an entity. A voting interest of ten percent or more creates a rebuttable presumption of control."

[4] "Securities" means stocks, stock options, bonds and any other instruments of debt or equity, and includes all interests in debt or equity instruments, including, without limitation, secured and unsecured bonds, debentures, notes, securitized assets, commercial paper, preferred and common stock, any beneficial or legal interest derived from a trust, and any right to acquire any long or short position in such securities, including, without limitation, interests convertible into the aforementioned securities, options, rights, warrants, puts, calls and straddles with respect to such securities.

Applicant Name_____

XIII. Application Contact Information *(leave no box empty)*:

A. Application Contacts (for further information regarding this application):

Application Primary Contact	Application Alternate Contact
Name: Michael Kuser	Name:
Title:	Title:
Address: 228 Washington Ave. Bennington, VT 05201-2311	Address:
Phone: (802) 681-5581	Phone:
Fax:	Fax:
E-mail: Michael.kuser@rtoinsider.com	E-mail:

B. Financial Assurance ("FA") Contacts *(2 contacts required)*:

Primary FA Contact	Alternate FA Contact
Name:	Name:
Title:	Title:
Address:	Address:
Phone:	Phone:
Fax:	Fax:
E-mail:	E-mail:

Applicant Name_____

XIV. Principal NEPOOL Committee Designations *(only if Applicant (i) is not a Related Person to a current NEPOOL Participant or (ii) will not be represented by a group voting member)*:

A. PARTICIPANTS COMMITTEE

NPC Member	NPC Alternate
Name: Michael Kuser	Name:
Title:	Title:
Address: 228 Washington Ave.	Address:
Bennington, VT 05201-2311	
Phone: (802) 681-5581	Phone:
Fax:	Fax:
E-mail: Michael.kuser@rtoinsider.com	E-mail:

B. MARKETS COMMITTEE

Markets Committee Member	Markets Committee Alternate
Name: Michael Kuser	Name:
Title:	Title:
Address: 228 Washington Ave.	Address:
Bennington, VT 05201-2311	Phone:
Phone: (802) 681-5581	Fax:
E-mail: Michael.kuser@rtoinsider.com	E-mail:

Applicant Name_____

C. RELIABILITY COMMITTEE

Reliability Committee Member	Reliability Committee Alternate
Name: Michael Kuser	Name:
Title:	Title:
Address: 228 Washington Ave.	Address:
Bennington, VT 05201-2311	
Phone: (802) 681-5581	Phone:
Fax:	Fax:
E-mail: Michael.kuser@rtoinsider.com	E-mail:

D. TRANSMISSION COMMITTEE

Transmission Committee Member	Transmission Committee Alternate
Name: Michael Kuser	Name:
Title:	Title:
Address: 228 Washington Ave.	Address:
Bennington, VT 05201-2311	
Phone: (802) 681-5581	Phone:
Fax:	Fax:
E-mail: Michael.kuser@rtoinsider.com	E-mail:

COUNTERPART SIGNATURE PAGE
NEW ENGLAND POWER POOL AGREEMENT

IN WITNESS WHEREOF, the undersigned has caused this counterpart signature page to the New England Power Pool Agreement, being dated as of September 1, 1971, as amended, to be executed by its duly authorized representative as of 20 March 2018.
(please insert date)

Michael Kuser
(Applicant Name)

By: _____

Name: Michael Kuser

Title:Correspondent

Company:RTO Insider

Address: 228 Washington Ave.
Bennington, VT 05201

STATE OF VERMONT
COUNTY OF BENNINGTON, SS

At BENNINGTON, this 20TH day of MARCH, 2018, personally appeared **MICHAEL KUSER** and he acknowledged this instrument, by him sealed and subscribed, to be his free act and deed.

VTDL 3299487
exp. 7/3/19

_____ Kelli H Burns
Notary Public
My Commission Expires: 2/9/10

GREEN MOUNTAIN POWER

Previous Account Balance	[redacted]
Payments Received	[redacted]
Balance Forward	[redacted]
New Charges/Adjustments due by **04/11/18**	[redacted]

Your Account

Bill Date 03/15/18

Account Number	[redacted]52
Account Name	MICHAEL M KUSER
Service Address	228 WASHINGTON AVE BENNINGTON VT 05201

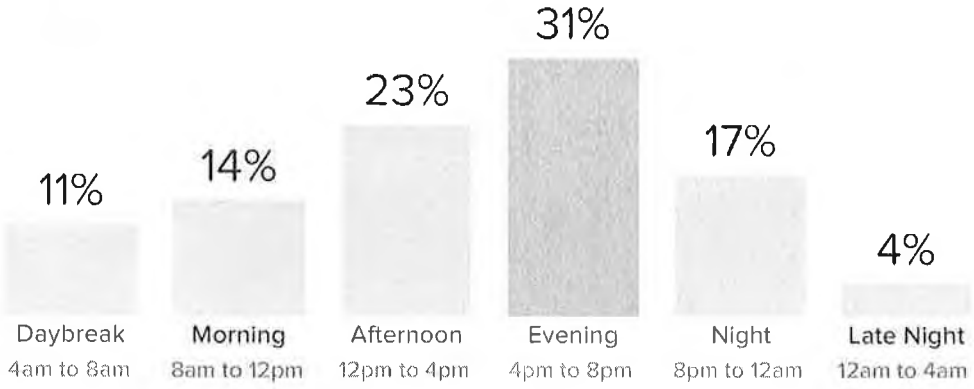
Your Bill

Total Amount Due

$ [redacted]

My Energy Use Snap Shot

Learn how you used electricity over the past service period and how that breaks down time of day. For more details visit your account at greenmountainpower.com



This Bill
366
kWh

Last Month
460
kWh

Continued on back

1/1

GREEN MOUNTAIN POWER

163 Acorn Lane
Colchester, VT 05446

Contact Us: 1.888.835.4672

Bill Date	03/15/18
Account Number	[redacted]52
Balance Forward	[redacted]
New Charges/Adjustments due by **04/11/18**	[redacted]
Total Amount Due	$ [redacted]

10000000

Amount Enclosed $ _____

SEND REMITTANCE TO:

GREEN MOUNTAIN POWER CORPORATION
PO BOX 1611
BRATTLEBORO VT 05302-1611

0089691-GMPS93797-ST.NOPRIN-000825
MICHAEL M KUSER
MICHAEL.KUSER@GMAIL.COM

00336512329502500000007565

Meter Number:	Usage Period:	Usage:	Previous Read:	Current Read:
[redacted]79	02/15/18 - 03/15/18	366	19784	20150

Next reading approx 04/13/18

Message Center

Beginning with April bills, there are several minor changes we want you to know about:

•Base rates will increase by 0.20% for two years to cover costs of a major storm in 2016.

•There will be an additional Power Cost Adjustor of $0.00108/kWh for two years as a result of higher power costs.

•Starting at the end of February, you will also see a monthly credit of 1.18% through the end of 2018 due to savings from federal tax changes that GMP is passing 100% on to customers through a lower bill.

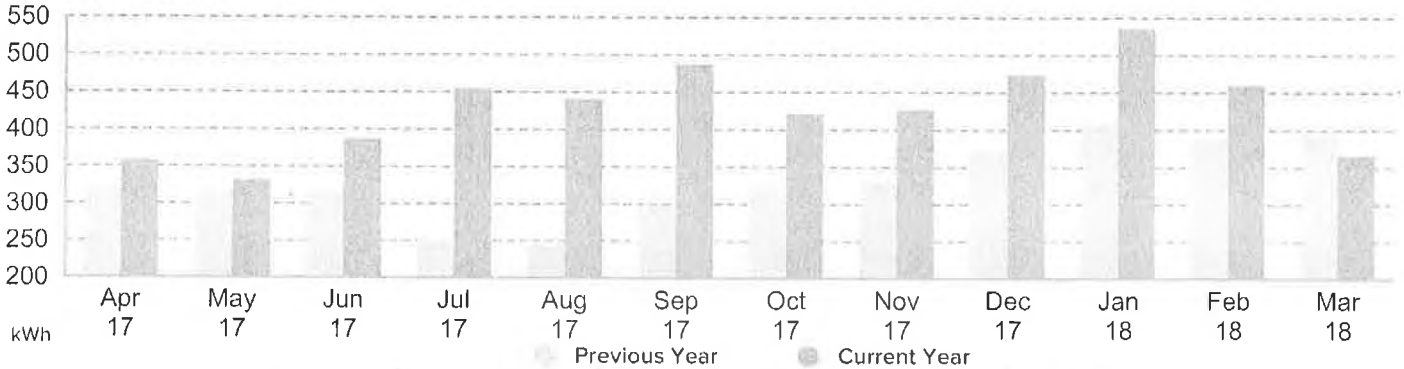
Bill Details

Rate: E01 Residential

New Charges/Adjustments

Customer Charge: 28 Days @ $0.456	[redacted]
366 Total KWH @ $0.15637	
Energy Efficiency Charge 366 x $0.01413	
Power Adjustment	
Federal Tax Reform Credit	
Electric Assistance Program Fee	
New Charges/Adjustments due by 04/11/18	$[redacted]

Usage History



Date:	kWh:	Number of Days:	Usage Per Day:	Temperature:
March-2018	366	28	13	33°
March-2017	394	30	13	29°

Did you know we accept ACH and Debit payments along with some major credit cards?

You can also sign up for other convenient services like paperless billing and automatic payment options. Please visit our website at greenmountainpower.com for more information.

To pay by phone please call 1-844-551-4550.

When making a payment, it is important to either provide your bill remittance or the full 11-digit account number and name on the account. If you do not have this on hand when making a payment, you can contact us at 1-888-835-4672.

For your convenience, you may pay your electric bill at any of the businesses listed below:

Peoples United Bank:	All branches
Jock Oil:	Wells River

STANDARD MEMBERSHIP CONDITIONS, WAIVERS AND REMINDERS

WHEREAS, an applicant ("Applicant") for membership in the New England Power Pool ("NEPOOL") may be one or more of the following types of entities: a **"load aggregator,"** which is considered for this purpose to be an entity that purchases at wholesale electric energy and capacity for resale to retail customers and resells such energy and capacity to retail customers in New England; a **"power marketer,"** which is considered for this purpose to be an entity that purchases as a principal or as a principal and a broker at wholesale electric energy and capacity for resale to wholesale customers and resells such energy and capacity to wholesale customers in New England; a "**financial marketer/trader,**" which is considered for this purpose to be an entity that submits Increment Offers and/or Decrement Bids in the Day-Ahead Energy Market; an **"exempt wholesale generator"** or **"EWG,"** which is considered for this purpose to be an entity granted such status by the Federal Energy Regulatory Commission under the Public Utility Holding Company Act of 2005, as amended ("PUHCA 2005"), pursuant to which it is required to be engaged "exclusively in the business of owning or operating, or both owning and operating, all or part of one or more eligible facilities and selling electric energy at wholesale"; an entity which owns a **"qualifying facility"** or **"QF,"** which is considered for this purpose to be an entity within the meaning of the Public Utility Regulatory Policies Act of 1978 ("PURPA") or an **"eligible facility"** within the meaning of the PUHCA 2005; an **"independent power producer"** or **"IPP,"** which is considered for this purpose to be an entity other than an EWG or QF whose exclusive business is owning or owning and operating all or a part of one or more generating facilities and selling electric energy at wholesale or retail; a **"broker,"** which is considered for this purpose to be an entity that acts from time to time for purchasers or sellers in New England in arranging the purchase or sale at wholesale of electric energy and/or capacity; an "**AR Provider,**" which is considered for this purpose to be an entity with a "Substantial Business Interest" in Alternative Resources located within the New England Control Area; or an **"end user,"** which is considered for this purpose to be (a) a consumer of electricity in the New England Control Area that generates or purchases electricity primarily for its own consumption, (b) a non-profit group representing such consumers, or (c) a Related Person of an End User Participant and which (i) is licensed as a competitive supplier under the statutes and regulations of the state in which the End User Participant which is its Related Person is located and (ii) participates in the New England Market solely to serve the load of the End User which is its Related Person.

WHEREAS, effective February 1, 2005 the NEPOOL Agreement was amended by the One Hundred Seventh Agreement Amending New England Power Pool Agreement and restated as the "Second Restated NEPOOL Agreement"; and

WHEREAS, ISO New England Inc. (the "ISO"), has been approved by the Federal Energy Regulatory Commission ("FERC") as the regional transmission organization ("RTO") for the New England region consisting of the states of Connecticut, Massachusetts, New Hampshire, Rhode Island, Vermont and substantial portions of Maine;

WHEREAS, the ISO will be responsible for maintaining the reliability of the System by, among other things, exercising operational authority over the Transmission Facilities of the System, administering and seeking to enhance sustainable, competitive and efficient energy markets in New England and providing non-discriminatory, open-access transmission service over the Transmission Facilities in accordance with the Participants Agreement, the ISO's Transmission, Markets and Services Tariff (the "Tariff"), and the System Rules;

WHEREAS, an Applicant that proposes to act as a load aggregator must represent that, if it is permitted to become a Market Participant, it would qualify under existing law and regulation in the one or more New England states where it proposes to act as a load aggregator;

WHEREAS, an Applicant that is qualified to become an End User Participant may elect to be a "Governance Only Member";

WHEREAS, a duly authorized NEPOOL subcommittee has recommended that certain conditions and waivers be applied to an Applicant in connection with its becoming a Participant in NEPOOL; and

WHEREAS, each Applicant acknowledges that it has reviewed the Second Restated NEPOOL Agreement and the Tariff, including the billing policy and financial assurance policies set forth as Exhibits to Section I of the Tariff, and fully understands its financial obligations that could arise under the Second Restated NEPOOL Agreement and the Tariff from participation in NEPOOL and the New England Markets.

WHEREAS, each Applicant acknowledges that (i) NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, representatives of the ISO, consumer advocates, federal and state officials and guests whose attendance has been cleared with the Committee Chair (or in the case of a Technical Committee, with the Committee Chair or Vice-Chair), and when in attendance at, or participating in, a meeting, either in person or by phone, will be required to identify themselves and their affiliation; (ii) Press may not attend any meeting of a NEPOOL Committee, subcommittee, working group or task force unless separately and specifically authorized by action of the Participants Committee; (iii) official records and minutes of NEPOOL meetings are posted publicly; and (iv) no statements made in NEPOOL meetings are to be quoted or published publicly.

NOW, THEREFORE, an Applicant to become a Participant in NEPOOL shall be required to agree in writing to the following understandings:

Any capitalized terms used in the following understandings (a) through (m) that are not defined in such understandings shall have the same meaning ascribed to them in the Second Restated NEPOOL Agreement, the Participants Agreement or the Tariff, as appropriate. The following understandings (a) through (e) apply to all Applicants:

(a) Applicant will have an ongoing obligation to meet the definition of an "Entity" within the meaning of the Second Restated NEPOOL Agreement as it is in effect on the date of the approval by the NEPOOL Participants Committee or its designee of Applicant's application to become a Participant in NEPOOL.

(b) Applicant shall notify NEPOOL of any proposed change in affiliate status or any proposed change in the electric business Applicant conducts within the New England Control Area to include business other than that originally applied for in its membership application. NEPOOL shall have the right to delete any conditions imposed or waivers granted at this time and to impose additional reasonable conditions on Applicant's participation in NEPOOL that shall apply to such change in Applicant's business or circumstances, if such deletions or conditions are necessary or appropriate in view of such changes (see additional provisions regarding this understanding (b) in understanding (f) below for load aggregators and understanding (g) below for EWGs and QF owners and understanding (h) below for end users electing Governance Only Membership). Applicant shall be advised of any deletion of conditions or waivers and shall be provided a draft of any additional conditions before such deletions or additional conditions become effective. In accordance with the Second Restated NEPOOL Agreement, comments on such

deletions or additions may be presented by Applicant to the NEPOOL Participants Committee or its designee for consideration.

(c) In lieu of a certified copy of its Board of Directors duly authorizing the execution and performance of the Second Restated NEPOOL Agreement, Applicant may provide, each in a form reasonably acceptable to NEPOOL Counsel, (i) an opinion of competent outside counsel that the officer or other representative executing a counterpart of the Second Restated NEPOOL Agreement on behalf of the Applicant is duly authorized to do so and to cause the Applicant to perform its obligations under the Agreement upon the effectiveness of its membership; and (ii) an affidavit by Applicant's duly-authorized officer or other representative that he/she has reviewed the Second Restated NEPOOL Agreement and the Tariff, including the billing policy and financial assurance policies set forth as Exhibits to Section I of the Tariff, and fully understands Applicant's financial obligations that could arise under the Second Restated NEPOOL Agreement and the Tariff from participation in NEPOOL and the New England Markets.

(d) Applicant and each of its representatives will have an ongoing obligation, consistent with the recital above, not to publicly quote or to cause to have published publicly (i) any statement made in, or (ii) any information distributed or shared confidentially in connection with, a NEPOOL meeting. If Applicant or any representative of Applicant violates this understanding (d), Applicant's right to attend NEPOOL meetings will be suspended by the Participants Committee and will not be restored until or unless the Participants Committee affirmatively acts to allow Applicant to attend future NEPOOL meetings.

(e) In the event it is determined in an appeal, or by a court or regulatory agency, that any of these conditions is invalid for any reason, NEPOOL shall have the right to impose one or more valid reasonable conditions in place of the invalidated condition. Applicant shall be advised of any invalidated condition and shall be provided a draft of any replacement conditions before such conditions become effective. In accordance with the Second Restated NEPOOL Agreement, comments on such replacement conditions may be presented by Applicant to the NEPOOL Participants Committee or its designee for consideration.

The following additional understanding (f) applies only to Applicants while acting, now or in the future, as load aggregators in the New England Control Area:

(f) Consistent with understanding (b) above, NEPOOL shall have the right to delete any conditions initially imposed or waivers initially granted and to impose additional reasonable conditions on Applicant's participation in NEPOOL which shall apply to any of the following changes in Applicant's circumstances, if such deletions or conditions are necessary or appropriate in view of such changes:

(i) it is determined that Applicant has failed to qualify as a load aggregator in the one or more New England states where it proposes to act as a load aggregator in accordance with its representation; or

(ii) the state laws or regulations under which Applicant does qualify to act as a load aggregator are changed in ways that could impact NEPOOL or ISO operations.

The following additional understanding (g) applies only to Applicants while acting, now or in the future, as EWGs and/or QF owners:

(g) Consistent with understanding (b) above, NEPOOL shall have the right to delete any conditions initially imposed or waivers initially granted and to impose additional reasonable conditions on Applicant's participation in NEPOOL which shall apply to any of the following changes in Applicant's circumstances, if such deletions or conditions are necessary or appropriate in view of such changes:

(i) Applicant has represented that its facility is a "qualifying facility" within the meaning of PURPA and the facility is determined at any time not to be such a facility or PURPA is amended to permit Applicant to own facilities or engage in activities not permitted to it as the owner of a qualifying facility under the present provisions of PURPA; or

(ii) Applicant has represented that it is an "exempt wholesale generator" within the meaning of PUHCA 2005 and Applicant is determined at any time not to be such a generator or PUHCA 2005 is amended to permit Applicant to own facilities or engage in activities not permitted to it as an exempt wholesale generator under the present provisions of PUHCA 2005.

The following additional understanding (h) applies only to Applicants while acting, now or in the future, as end users in NEPOOL:

(h) Consistent with understanding (b) above, NEPOOL shall have the right to delete any conditions initially imposed or waivers initially granted and to impose additional reasonable conditions on Applicant's participation in NEPOOL which shall apply if it is determined that Applicant has failed to qualify as an End User Participant, as defined in Section 1 of the Second Restated NEPOOL Agreement, if such deletions or conditions are necessary or appropriate in view of such changes.

The following additional understandings (i), (j), and (k) apply only to Applicants that would qualify as End User Participants and elect before their application is approved by NEPOOL to be a Governance Only Member (as described more fully below):

(i) Applicant's participation in NEPOOL shall be for governance purposes only ("Governance Only Member"). As a Governance Only Member, Applicant shall be:

(i) entitled to participate in all NEPOOL governance matters, including voting membership in all Principal Committees;

(ii) required to pay all application and annual fees applicable to End User Participants pursuant to Section 14 of the Second Restated NEPOOL Agreement;

(iii) required to forego participation in the New England Market, other than as permitted or required pursuant to the Load Response Program; and

(iv) required to deliver written notice of such election to the Secretary of the Participants Committee. Other than for an election made prior to the approval of its application by NEPOOL, the election to be a Governance Only Member shall become effective beginning on the first annual meeting of the Participants Committee following notice of such election

(j) The acceptance in NEPOOL of such Applicant as a Governance Only Member does not require nor prescribe any different treatment from the treatment then accorded to any other End User Participant for the determination of its transmission or distribution charges.

(k) The Governance Only Member Applicant with generation shall certify in a form reasonably acceptable to NEPOOL as to the following conditions, and shall become a End User Participant without Governance Only Member status if and when such conditions are no longer satisfied:

(i) For any hour in which the End User Behind-the-Meter Generation owned by the Governance Only Member does not fully meet its associated Electrical Load which is behind the meter, another Participant which is not a Governance Only Member is obligated under tariff or contract to include as part of its load asset in such hour the difference between (x) the Electrical Load of the Governance Only Member and (y) the kilowatthours of that Electrical Load which are produced by the End User Behind-the-Meter Generation; and

(ii) For any hour in which the output of the End User Behind-the-Meter Generation owned by the Governance Only Member exceeds its Electrical Load, the Governance Only Member is obligated to ensure that another Participant which is not a Governance Only Member is obligated under tariff or contract to report such excess to the ISO pursuant to applicable Market Rules.

The following additional understanding (l) applies only to Applicants that would qualify as End User Participants entitled to join the End User Sector, and which are Small End Users:

(l) Applicant may not appoint to a NEPOOL committee a voting member or alternate to that member, or have its vote cast by another person pursuant to a written, standing designation or proxy, except in accordance with this understanding (l):

(i) An Applicant shall be entitled to appoint as its voting member, and alternate to that member, of each NEPOOL committee, and have as its designated representative or proxy, any individual; provided, however, that such individual shall not be a Related Person of another Participant in a Sector other than the End User Sector.

The following additional understanding (m) applies only to Applicants that are end users without generation, that do not elect to be Governance Only Members, and that participate directly in the New England Market ("Market Participant End Users"):

(m) The Applicant shall certify in a form reasonably acceptable to NEPOOL as to the following conditions, and shall be permitted to participate in the New England Market only if, and for so long as, the following conditions are satisfied:

(i) Applicant shall have no ability to be reflected in the ISO's settlement system as either a purchaser or a seller of any Market Products so long as such participation causes NEPOOL and/or the ISO to be subject to regulation as the electrical supplier for Applicant's Electrical Load ("Retail Supplier") by the state regulatory agency of the state(s) in which the Applicant consumes electricity;

(ii) The obligation to serve the electrical load of the Applicant shall at all times be assigned to a Market Participant (whether such Market Participant is Applicant or another Participant) which is duly authorized or required under the applicable state statutes and regulations of the Applicant's state(s) to be a licensed Retail Supplier or is otherwise authorized to serve its electrical load without a license; and

(iii) Applicant shall have in place arrangements with its default service provider, either contractual or statutory, to provide for the automatic assignment of the obligation to serve its electrical load and the load associated with any of its Load Assets to such default service provider should the Retail Supplier be suspended from the New England Markets in accordance with the provisions of the Tariff, including the Financial Assurance Policy for Market Participants (Exhibit IA to Section I of the Tariff).

In notifying an Applicant that its application has been accepted subject to the stated understandings and requesting Applicant's written acceptance of the understandings, the Membership Subcommittee Chair, or appropriate NEPOOL Participants Committee designee, shall include in a letter to Applicant the following reminders (1) through (8), applicable to all Applicants, unless otherwise specified in the following provisions:

(1) each Participant is obligated to provide NEPOOL or the ISO the information that NEPOOL or the ISO determines is required in order to administer and implement the Second Restated NEPOOL Agreement, the Participants Agreement, the Tariff, and these conditions and waivers;

(2) each Participant is obligated to conform to any future changes in NEPOOL requirements;

(3) each Participant is obligated to comply with all governmental, regulatory or other legal requirements which must be satisfied as a condition to its participation in NEPOOL or the New England Markets, or which may be otherwise applicable to such participation;

(4) each Participant is obligated to pay an allocated portion of certain NEPOOL and ISO costs in accordance with the Second Restated NEPOOL Agreement, the Participants Agreement, and the Tariff;

(5) each Participant is obligated to pay its monthly share of Participant Expenses by the payment date as specified in the Billing Policy (or any successor rule or procedure), which is currently the third Business Day after the issuance of the first weekly statement issued after the tenth of a calendar month (the Monthly Statement due date) but may be subject to change. If a Participant is delinquent two or more times within any period of 12 months in paying on time its share of Participant Expenses or other Hourly or Non-Hourly Charges, such Participant shall pay, in addition to interest on each late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a "Late Payment Charge") in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $1,000.

(6) each Participant is obligated to meet the requirements specified in the Billing Policy on file with the FERC as it may be amended from time to time (Participants are encouraged to regularly review the Billing Policy for any changes to the billing and payment dates or procedures; the far-reaching consequences of the failure to pay all or any part of an amount due when and as due are set forth in the Billing Policy);

(7) each Participant is obligated to meet the requirements specified in the Financial Assurance Policies on file with the FERC as they may be amended from time to time; and

(8) each Participant is required to submit information to the ISO from time to time, as is necessary to enable the ISO to meet its obligations, concerning any entity owned 10% or more by the Participant or any entity which owns 10% or more of the Participant, including upon a change in ownership or control of the Participant or any such entity.

The Membership Subcommittee Chair, or appropriate Participants Committee designee, shall further include in a letter to Applicant the following reminders (9) and (10), applicable to Applicants, other than Governance Only Members:

(9) each Participant, except a Governance Only Member, has the obligation to assure for each transaction that it has identified transmission facilities required to accomplish such transaction and has made appropriate arrangements with the ISO or the owners of such transmission facilities, as appropriate, for use of such facilities; and

(10) each Participant is obligated to provide NEPOOL or the ISO the information that NEPOOL or the ISO determines is required in order to administer and implement the Second Restated NEPOOL Agreement, the Participants Agreement, the Tariff and any other agreement that NEPOOL or the ISO administers and, except a Governance Only Member, to verify that satisfactory transmission arrangements have been made for each transaction.

The Membership Subcommittee Chair, or appropriate Participants Committee designee, shall further include in a letter to Applicant the following reminder (11), applicable to load aggregators, power marketers and brokers:

(11) for brokered transactions, a Participant while acting, now or in the future, as a broker would not be considered either the purchaser or the seller.

The Membership Subcommittee Chair, or appropriate Participants Committee designee, shall further include in a letter to Applicant the following reminders (12) and (13), applicable while the Applicant is acting, now or in the future, as a load aggregator, IPP, or end user:

(12) each Participant is obligated to conform to standards established by the ISO or any duly authorized NEPOOL committee to assure reliable operation of the New England Control Area, including, without limitation, the obligation to have the ability to subject its load to load shedding as required by the ISO; and

(13) no Participant may use its rights under the Second Restated NEPOOL Agreement, Tariff or the System Rules to avoid the application of any stranded cost policy, or to avoid or reduce the payment of any applicable stranded costs or access charges related to such stranded cost policy that has been approved by Federal regulators or regulators in any New England state in which that Participant is purchasing or selling electric energy and/or capacity for resale at wholesale or to retail customers.

The Membership Subcommittee Chair, or appropriate Participants Committee designee, shall further include in a letter to Applicant the following reminder (14), applicable to EWGs, QF owners and IPPs:

(14) membership in NEPOOL and participation in the New England Markets could affect Applicant's operations in many ways, including without limitation its status as the owner of a qualifying facility under PURPA, an exempt wholesale generator under PUHCA, or an entity exempt under PUHCA because of its predominantly intrastate activities. Applicant should assess all such effects before becoming a Participant or participating in the New England Markets. Pursuant to the understandings under which it does become a Participant, Applicant should notify NEPOOL if, as a result of or following its joining of NEPOOL or as a result of its participation in the New England Market, the facility loses its status as a qualifying facility or the Market Participant loses its status as an exempt wholesale generator.

The Membership Subcommittee Chair, or appropriate Participants Committee designee, shall further include in a letter to Applicant the following reminders (15) and (16), applicable to all end users:

(15) membership in NEPOOL and participation in the New England Markets could affect Applicant in many ways, including without limitation subjecting Applicant to the jurisdiction of federal and/or state regulatory agencies to which Applicant may not already be subject. Applicant should assess all such effects before becoming a Participant or participating in the New England Markets. Pursuant to the understandings under which it does become a Participant, Applicant should notify NEPOOL if, as a result of or following its joining of NEPOOL or as a result of its participation in the New England Market, it becomes subject to regulation by any federal and/or state regulatory agencies; and

(16) without limiting the generality of reminder (2), each End User Participant is obligated to provide NEPOOL and the ISO, within fifteen (15) days of the annual meeting of the Participants Committee, with a report of its highest Energy use during any hour in the preceding year (net of any use of End User Behind-the-Meter Generation) and any other information that NEPOOL or the ISO determines is required in order to administer and implement the provisions of Section 14 of the Second Restated NEPOOL Agreement or Section 14 of the Participants Agreement, as appropriate.

The Membership Subcommittee Chair, or appropriate Participants Committee designee, shall further include in a letter to Applicant the following reminder (17), applicable to all Provisional Members:

(17) A Provisional Member that becomes eligible to designate an individual voting member of a Sector other than the End User Sector or is eligible to be represented by a group voting member (other than a Provisional Member Group Member) is obligated to promptly designate in a notice to the Secretary of the Participants Committee either (i) the voting member appointed by it for each Principal Committee and alternate of each such member; or (ii) the group voting member by which it shall be represented. Such change in representation and/or Sector shall become effective beginning on the first day of the calendar month following the notice of such change.

NEW ENGLAND POWER POOL

PARTICIPANTS COMMITTEE

BYLAWS

REVISION 3

Dated June 26, 2018

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NEPOOL PARTICIPANTS COMMITTEE

BYLAWS

Section 1. Scope and Purpose, Effective Date.

These Bylaws have been adopted by the Participants Committee provided for in the New England Power Pool Agreement dated as of September 1, 1971, as amended and restated, and are effective upon adoption. (Said Agreement as now amended and twice restated, and as it may be amended from time to time hereafter is referred to herein as the "NEPOOL Agreement"). These Bylaws provide details to implement the provisions of the NEPOOL Agreement. In the event of any inconsistency between these Bylaws and the NEPOOL Agreement, the provisions of the NEPOOL Agreement shall control.

Section 2. Definition of Terms.

Unless otherwise required by the context, all terms defined in the NEPOOL Agreement, the Participants Agreement, and the ISO New England Inc. Transmission, Markets and Services Tariff ("ISO Tariff") shall have the same meaning in these Bylaws. Section references in these Bylaws unless otherwise attributed are to sections of these Bylaws.

Section 3. Participants Committee Members.

3.1 Composition. The Participants Committee shall be composed of the following Sectors: a Generation Sector, Transmission Sector, Supplier Sector, Alternative Resources Sector, Publicly Owned Entity Sector and End User Sector. Separate Sectors may be created and the membership of existing Sectors modified by amendment of the NEPOOL Agreement and the Participants Agreement.

3.2 Sector Selection. Each Participant, together with all of its Related Persons, shall be obligated to designate in a notice to the Secretary of the Participants Committee the Sector that it or its Related Persons is eligible to join and that it elects to join for purposes of the Participants Committee; provided, however, that a Participant and the Participants which are its Related Persons or Individual RTO Participants shall not be eligible to join the End User Sector if any one of them is not eligible to join the End User Sector. A Participant may change the Sector which it joins by notice to the Secretary. Other than for Sector changes required by Section 6.4(c) of the NEPOOL Agreement, a change in the Sector to which a Participant belongs shall become effective beginning on the first annual meeting of the Participants Committee following such notice of change.

3.3 Members and Alternates.

(a) A Participant which meets the minimum requirements, if any, of the Sector or Sub-Sector it has elected to join shall designate an individual voting member to the Participants Committee and an alternate to that member. Such designation shall be in a written notice executed, or an electronic notice delivered, by a duly authorized representative of the Participant to the Secretary of the Participants Committee. In addition, the ISO shall designate an individual non-voting member to the Participants Committee and an alternate to that member.

(b) A Participant that has elected to join a Sector or Sub-Sector for which it is not entitled to designate an individual voting member to the Participants Committee, together with the other Participants electing such Sector which also do not meet the threshold requirements to designate an individual voting member, and, in the case of the Generation or Alternative Resources Sectors, those Participants entitled and electing to be represented by a group voting member, shall appoint by a majority vote a group voting member ("Group Member") and an alternate to that Group Member to represent such a group. The appointment (or reappointment) of a Group Member shall be made (i) when a Participant which does not meet the threshold requirements to designate an individual voting member joins the Sector or Sub-Sector, and (ii) when a Participant in the Sector or Sub-Sector, which previously designated an individual voting member, no longer meets the threshold requirements to designate an individual voting member, and (iii) to replace a Group Member whose term has expired, who has resigned as the Group Member, or who has been voted out as the Group Member by a majority of the Participants entitled to appoint that Group Member. Any change in such appointment shall be identified in a written notice delivered to the Secretary of the Participants Committee.

(c) Each member shall have the right to (i) request a special meeting in accordance with Section 5.3, (ii) express views on any matter to be acted upon at any meeting of the Committee (subject to the established meeting rules and procedures), (iii) make or second motions, and (iv) if a voting member, vote on any action properly brought before the Participants Committee.

(d) Any alternate to a member of the Participants Committee designated or appointed in accordance with this Section 1.1 shall have all the powers of the member, including, when a voting member is absent, the power to vote.

3.4 Term of Members and Alternates. Each Participants Committee member and alternate shall serve until either (a) such member or alternate is replaced by the Participant or group of Participants, or entity authorized to appoint such member or alternate, or (b) the appointing Participant ceases to be a Participant, or (c) the appointing Participant (or its Related Person) is no longer eligible to designate an individual voting member in the Sector to which it belongs but is eligible to designate an

individual voting member in a different Sector, except that if a Participant ceases to be eligible to designate an individual voting member of the Sector for which it previously designated an individual voting member, other than as a result of failing to meet the threshold requirements to designate an individual voting member, and is not eligible to designate an individual voting member for another Sector other than the End User Sector, the Participant shall have the right to have its member remain and vote in the Sector in which the Participant is currently a member for up to one (1) year.

3.5 **Appointment of Replacement.** Appointment or replacement of a member or alternate shall be effected by delivery of written notice executed, or electronic notice of such appointment or replacement delivered by the duly authorized representative of the Participant, group of Participants, or entity authorized to appoint or replace such member to the Secretary of the Participants Committee at or prior to the initial meeting at which the new member or alternate is to participate.

3.6 **E-Mail Address.** Each Participants Committee member and alternate shall designate and maintain a current e-mail address to which notices sent pursuant to Section 5.5 may be delivered. Such designation shall be in a written or electronic notice delivered to the Secretary of the Participants Committee which sets forth the name of the member or alternate and the current e-mail address.

3.7 **Subgroups.** The Participants Committee shall have the authority to establish subcommittees, working groups, task forces and ad hoc committees (collectively, "Subgroups") for particular studies and functions. The Chair of the Participants Committee shall appoint a Chair for each Subgroup from the Vice-Chairs of the Participants Committee or such other person as the Chair deems appropriate in light of the function of the Subgroup, and the experience, expertise, and availability of the persons eligible to serve as Chair.

Section 4. **Officers.**

4.1 **Officers.** The officers of the Participants Committee may include, in addition to a Chair, one or more Vice-Chairs and a Secretary, such other officers as the Participants Committee may deem appropriate.

4.2 **Chair.** The Chair shall be elected by the Participants Committee from its voting members. The Chair shall preside at meetings of the Participants Committee and shall have the power and duties specified in the NEPOOL Agreement and such other powers and duties as are usually incident to such office.

4.3 **Vice-Chairs.** Vice-Chairs shall be selected in accordance with Section 4.6. Each Vice-Chair shall have such power and perform such duties as the Chair or the Participants Committee may

from time to time prescribe and shall perform such other duties as may be prescribed by these Bylaws. The Vice-Chairs shall have the powers and duties of the Chair during periods when the Chair is unavailable; provided that only one Vice-Chair may exercise the powers and duties of the Chair at one time. The acting Chair shall be determined by the Chair in consultation with the Vice-Chairs or, if not determined by the Chair, by consensus of the Vice-Chairs.

4.4 **Secretary and Assistant Secretary.** The Secretary and an Assistant Secretary shall be elected by the Participants Committee. The Secretary shall not be a member of the Participants Committee. The Secretary shall have the powers and duties specified in the NEPOOL Agreement and such other powers and duties as are usually incident to such office. In the absence of the Secretary, an Assistant Secretary, who shall have the powers and duties of the Secretary during periods when the Secretary is unavailable, shall serve as Secretary. In the absence of a Secretary or Assistant Secretary, the Chair may appoint any person to act as Secretary of the meeting.

4.5 **Nominating Committee.** One (1) member from each active Sector of the Participants Committee shall be appointed annually by a majority of all the voting members in its Sector to represent the Sector on a Nominating Committee. The Nominating Committee shall oversee the nominations and elections pursuant to Sections 4.6(a) through 4.6(c) and report to the Participants Committee at, or prior to, the annual meeting of the Participants Committee the results of said elections. The Nominating Committee shall also report to the Participants Committee at, or prior to, the annual meeting of the Participants Committee its recommendation for any officer that is not elected pursuant to Sections 4.6(a)-(c).

4.6 **Election of Officers.**

(a) Nominations. One (1) voting member from each active Sector of the Participants Committee shall be selected by a majority of all the voting members in its Sector either (i) to serve as a nominee for Chair or (ii) if not elected Chair in accordance with Section 4.6(b), to serve as a Vice-Chair. That selection shall be accomplished on the later of thirty days before the annual meeting of the Participants Committee or the day of the Participants Committee meeting immediately preceding the annual meeting of the Participants Committee.

(b) Chair. Election of the Chair shall be accomplished as follows:

(i) The election of the Chair shall be conducted by secret written ballot. The Secretary shall circulate a form of ballot that lists as nominees the Vice-Chair-elects, which were nominated in accordance with Section 4.6(a) above. That circulation shall be accomplished on the later of thirty days before the annual meeting of the Participants Committee or the day of the Participants

Committee meeting immediately preceding the annual meeting of the Participants Committee.

(ii) No Participant may cast a ballot in favor of a nominee from its Sector.

(iii) In order to be counted, ballots must be properly executed by a Participant's voting member or alternate on the Participants Committee or such Participant's duly authorized officer and returned to the Secretary in accordance with the following schedule:

(1) If the ballots are delivered to each Participant by regular mail, properly executed ballots must be returned to and received by the Secretary within ten (10) Business Days after deposit of such ballots in the mail by the Secretary, and

(2) If the ballots are delivered to each Participant by overnight delivery, facsimile, electronic mail or hand delivery at a Participants Committee meeting, then properly executed ballots must be returned to and received by the Secretary within five (5) Business Days after (A) deposit of such ballots with an overnight delivery courier if delivered by overnight delivery, or (B) transmission of such ballots by the Secretary if delivered by facsimile or electronic mail, or (C) receipt by the Participant if delivered by hand delivery.

(3) If the Minimum Response Requirement has not been received by the Secretary within the schedule identified in subsection (1) or (2) above, the Secretary shall send notice by overnight delivery, facsimile, electronic mail or hand delivery to all non-responding Participants and shall count any additional properly executed ballots which it receives within five (5) Business Days after such notice. The date by which properly executed ballots must be returned and received by the Secretary shall be specified by the Secretary in the notice accompanying such ballots.

(iv) In order for a nominee to be elected Chair, the following criteria must be satisfied:

(1) The Minimum Response Requirement must be satisfied with respect to the election of the Chair.

(2) The Chair shall be elected by greater than one-half of the aggregate Sector voting shares from Participants returning their ballots to the Secretary within the prescribed time period.

(v) If a nominee is not elected Chair pursuant to subsection (iv), then one or more new ballots shall be circulated by the Secretary in accordance with this Section 4.6 until a nominee is duly elected Chair. Each new ballot circulated by the Secretary shall list as nominees all of the previous nominees listed in the previous ballot, omitting (1) the nominee (or nominees in the case of a tie)

receiving the fewest votes in the previous ballot and (2) any other nominee receiving ten percent (10%) or less of the aggregate Sector voting shares in the previous ballot.

(c) Vice-Chairs. The Vice-Chair-elects who are not elected Chair pursuant to Section 4.6(b) shall serve as Vice-Chairs for the ensuing year.

(d) Other Officers. The Secretary, Assistant Secretary and any other officers as the Participants Committee deems appropriate who are not selected pursuant to Sections 4.6(a), (b) or (c) shall be elected by the Participants Committee at its Annual Meeting.

4.7 **Term of Officers.** Each officer shall hold office until such officer either (a) is required to be a member of the Participants Committee and ceases to be a member during the officer's term, (b) resigns the position, (c) is replaced pursuant to election under Section 4.6, or (d) is replaced by the Participants Committee. Any officer, other than a Vice-Chair, may be replaced by the Participants Committee at any time, with or without cause, including, but not limited to replacement of an officer because such officer has changed Participant affiliation, by a NEPOOL Vote equal to or greater than two-thirds of the aggregate Sector Voting Shares. A Vice-Chair may be replaced at any time, with or without cause, including, but not limited to replacement because such Vice-Chair has changed Participant affiliation, by a majority of all the voting members of the Sector the Vice-Chair represents.

Section 5. Meetings.

5.1 **Annual Meeting.** The annual meeting of the Participants Committee shall be held in the month of December or January, on such date, at such time and at such place as shall be designated by the Chair. Reasonable efforts will be made to provide notice of the proposed date and location of the annual meeting well in advance of such date to permit members to make the requisite arrangements to be present.

5.2 **Regular Meetings**. Regular meetings of the Participants Committee shall be held at such place as the Chair may designate in accordance with a schedule adopted by the Participants Committee or at the call of the Chair.

5.3 **Special Meetings**. Special meetings of the Participants Committee may be called by the Chair or by any five (5) or more voting members of the Participants Committee in the event that the Chair shall fail to schedule such a meeting within three (3) Business Days following the Chair's receipt from such members of a request specifying the subject matters to be acted upon at the meeting. A special meeting shall be held at such time and at such place in New England as shall be designated by the person or persons calling the meeting in accordance with the notice provisions of Section 5.5.

5.4 **Meetings by Conference Call**. Members of the Participants Committee may participate in a meeting of the Participants Committee in person, by telephone, or by means of conference telephone, electronic video screen communication, or other communications equipment by means of which all persons participating in the meeting can communicate in real time with each other, and such participation in a meeting shall constitute presence in person at the meeting. To the extent that meetings are to be held in person, upon request, provisions shall be made for a member or alternate to listen to the in person meeting by telephone and if otherwise authorized to vote at such meeting, but telephonic participation by such member or alternate may be limited by the Chair in the Chair's discretion.

5.5 **Notice of Meeting**. The Participants Committee intends to ensure to the maximum extent possible that all interested Participants have an opportunity to prepare for and participate fully in Participant Committee meetings. In furtherance of this intent, written or electronic notice of the time and place of each meeting of the Participants Committee shall be given to each member and alternate no later than the tenth (10th) Business Day prior to the date of the meeting, to the extent practicable, but in no event no later than the fifth (5th) Business Day prior to the date of the meeting, except as noted in Section 5.6 below. No later than the fifth (5th) Business Day prior to the date of the meeting, the Secretary shall supplement such notice with a proposed agenda specifying the principal subject matters expected to be acted upon. In addition, such supplemental notice shall include, or specify the internet location of, a draft of all resolutions to be voted at the meeting, and all background materials available and deemed by the Chair or Secretary to be necessary to the Committee to have an informed opinion on such matters. Notice shall be deemed to have been given as follows: (1) if personally delivered, notice shall be deemed given upon delivery to the member or his or her designee; (2) if mailed, postage prepaid, to the member at his or her designated mail address, notice shall be deemed given when received, (3) if sent by facsimile to the member at his or her designated fax number, notice shall be deemed given when sent; and (4) if sent electronically to the member at his or her designated electronic mail address, notice shall be deemed given when transmitted electronically. To the extent practicable, notices, agendas and supporting materials shall be circulated electronically. The notice requirements of this Section 5.5 and Section 6.6 of the NEPOOL Agreement may be waived by unanimous consent of the Participants Committee.

5.6 **Attendance: Principles, Protocols, Privileges Revoked.** The NEPOOL Participant Processes play a unique role in considering, evaluating, identifying, resolving disputes regarding, and acting on all matters affecting the New England region's wholesale electric power and transmission arrangements. The intent of NEPOOL meetings is to permit Participants to understand proposals presented for NEPOOL action, to improve those proposals through input, and to negotiate, discuss and work out any disputes, questions, and counterproposals that Participants may have and as they may evolve in advance of those issues being litigated at FERC or discussed publicly. Transparency among those participating in the process, and to the maximum extent possible, the process itself, is paramount. Accordingly,

(a) Protocols. Meeting attendance and participation is conditioned on adherence to the rules, practices and procedures of NEPOOL meetings, including the following additional understandings:

(i) Posting/Provision of Meeting Materials. Except for matters identified for discussion in executive session, and unless expressly marked as confidential, agendas and supporting materials for discussion at NEPOOL meetings shall be circulated and posted publicly. Unless expressly marked to the contrary, materials distributed and posted are to be considered and treated as works in progress and not as final or complete documents nor the final positions nor views of any author or sponsor of such materials;

(ii) Meeting Discussions. Attendees may use the information received in discussion, and may share the information received within their respective organizations or with those they represent, provided those who receive such communications are not Press and also are aware of and agree to respect the non-public nature of the information. In no event may attendees reveal publicly the identity or the affiliation (other than Sector affiliation) of those participating in meeting discussions;

(iii) Recordings/Transcriptions. Except as expressly authorized by the Chair, no audio or visual recording or transcription of the meeting may be made; and

(iv) Public Record. The only official public record of the meeting will be the final minutes of the meeting, as approved by the Committee.

(b) Attendance Privileges Revoked. The right or privilege to attend a NEPOOL meeting will be revoked by the Participants Committee upon violation of any of the conditions set forth in subsection (a) and will not be restored until or unless the

Participants Committee affirmatively acts to allow that person to attend future NEPOOL meetings.

5.7 **Press Attendance.** Press may only attend a meeting of the Participants Committee or portions thereof to which they have been separately and specifically authorized by action of the Participants Committee taken pursuant to the provisions of Section 6.9 of the Agreement at a meeting at which all related notice requirements of Section 6.6 of the Agreement have been satisfied. Any such attendance would be as a guest.

5.8 **Adjournments and Reconvening**. Any Participants Committee meeting may be adjourned from time to time to reconvene at the same or some other place, and notice need not be given of any such adjourned meeting if the time and place thereof are announced at the meeting at which the adjournment is taken. If not so announced, notice of a reconvened meeting shall be given, to the extent practicable, no later than the tenth (10th) Business Day prior to the reconvened meeting via personal delivery, facsimile, electronic mail or U.S. Mail. In exigent circumstances, the Chair shall have the ability to reconvene the meeting with less notice, provided that members and alternates receive at least twenty-four (24) hours' notice of the reconvening of the meeting. At the reconvened meeting, the Participants Committee may transact any business which might have been transacted at the original meeting.

5.9 **Quorum**. A quorum of the Participants Committee must be present for any action to be taken by the Committee other than adjournment of the meeting. A majority of the activated Sectors must be present for there to be a quorum. For a Sector to be considered present at a Participants Committee meeting, it must have voting members in attendance at the meeting in a number equal to the lesser of (a) fifty percent (50%) or more (rounded to the next higher whole number) of the voting members of the Sector or (b) five (5) or more voting members from the Sector. The requirements for amendments to the NEPOOL Agreement and the Participants Agreement are as set forth in Sections 6.8 and 6.10 of the NEPOOL Agreement, and Section 17.2 of the Participants Agreement.

5.10 **Voting**. For all matters other than amendments to the NEPOOL Agreement or the Participants Agreement, each voting member of the Participants Committee shall have the same percentage of the Sector votes as each of the other voting members designated by other Participants in the Sector which meet the minimum threshold for the Sector except for voting members of an AR Sub-Sector that has a Sub-Sector Voting Share that is less than the Fully Activated Sub-Sector Voting Share, and the Transmission Group Member representing Participants whose aggregate capital investment in PTF equals or exceeds twice the $30,000,000 threshold amount. The Voting member(s) representing AR Providers shall each have the Member Adjusted Voting Share or Member Fixed Voting Share, as appropriate, determined in accordance with the NEPOOL Agreement. The Transmission Group Member representing Participants whose aggregate capital investment in PTF equals or exceeds twice the $30,000,000 threshold amount shall have a percentage of the Sector votes equal to the number of full multiples of the $30,000,000 threshold, provided that the Transmission Group Member shall in no event be entitled to more than twenty-five percent (25%) of the Sector vote. Any voting member shall be

entitled to split his or her vote; provided, however, that a member must provide notice of the intention to split his or her vote to the Secretary of the Participants Committee not less than three (3) Business Days prior to the first meeting at which such member's vote is split. A vote may be cast in person by the member or the member's alternate or by another person pursuant to a written designation or proxy dated not more than one year previous to the meeting and delivered by the member or alternate to the Secretary of the Participants Committee at or prior to the meeting at which the vote is cast; provided, however, that (i) the vote of a member or alternate to that member representing a Small End User may not be cast by a Participant or a Related Person of a Participant in a Sector other than the End User Sector and (ii) the vote of a member or alternate to that member representing an AR Provider which pays less than the lowest amount of Participant Expenses paid by an individual voting Participant in the Generation, Transmission, or Supplier Sectors may not be cast by a Participant or a Related Person of a Participant in a Sector other than the AR Sector. A member or alternate may revoke a designation or a proxy by delivering written notice of the revocation of the designation or proxy to the Secretary of the Participants Committee.

5.11 **Limits on Member Fixed Voting Share**. In the End User Sector, no one person may vote on behalf of more than five (5) Small End Users. Limits on the voting power any one individual may have in any of the other Sectors may be imposed by unanimous written agreement of the Participants in that Sector delivered to the Secretary of the Participants Committee prior to the meeting at which such limitation is to be imposed. Notice of any limits on voting power must be posted on the ISO web site and be capable of being accessed by all Participants.

5.12 **Controlling Vote**. A NEPOOL Vote equal to or greater than two-thirds of the aggregate Sector Voting Shares shall be the act of the Participants Committee, except as provided (i) in Section 11.1.3 of the Participants Agreement with respect to action related to Market Rules, and (ii) in Section 4.6 with respect to the election of a Chair and Vice-Chairs for the Participants Committee. A NEPOOL Vote with respect to a proposed action is the sum of (i) the Member Adjusted Voting Shares of the voting members of the Participants Committee which cast an affirmative vote on the proposed action and which have been appointed by a Participant or group of Participants which are members of a Sector or AR Sub-Sector satisfying its Sector Quorum or AR Sub-Sector Quorum Requirements and (ii) the Member Fixed Voting Shares of the voting members of the Participants Committee which cast an affirmative vote on the proposed action and which have been appointed by a Participant or group of Participants which are members of a Sector or AR Sub-Sector which fails to satisfy its Sector Quorum or AR Sub-Sector Quorum Requirements.

5.13 **Participation by Non-Members**. In accordance with Section 6.13 of the NEPOOL Agreement, each Participant which does not have the right to designate an individual voting member of the Participants Committee shall be entitled to attend any meeting of the Participants Committee, and shall have a reasonable opportunity to express views on any matter to be acted upon at the meeting. For the purposes of this Section 5.13, "Participant" shall be deemed to include, in addition to those individuals who are a member or alternate to that member, individuals employed by, retained by, or

otherwise affiliated with the Participant. Non-Participants may attend a meeting of the Participants Committee or speak at the meeting only if and to the extent invited to do so by the Chair. All Non-Participants attending a meeting of the Participants Committee shall be identified at the meeting to the members and alternates present.

5.14 **Review of Proposals Pursuant to Participant Processes**. A proposal by the ISO or a Governance Participant (the "Proponent") to change a Market Rule, Operating Procedure, Manual, Reliability Standard, Installed Capacity Requirement, General Tariff Provision, or Non-TO OATT Provision (a "Proposal") which has undergone the procedures outlined in Section 11.1.2 of the Participants Agreement shall be considered by the Participants Committee no later than the first regularly scheduled meeting following the submission of the Proposal to the Participants Committee (which meeting shall be held within thirty-five (35) days of the submission of the Proposal unless a later date is acceptable to the Proponent), provided that the Proposal is submitted with sufficient time to permit proper notice in accordance with Section 5.5. The Participants Committee shall: (i) by motion and vote defer action on any Proposal if it reasonably determines that the Proposal presented is materially different from the Proposal presented to the appropriate Technical Committee(s) and was not voted on by the Technical Committee(s), or (ii) vote on (A) the merits of the Proposal as it may be amended by the Proponent or by a vote of at least 60% for any Market Rule Proposal and 66-2/3% for any other Proposal, and (B) if any ISO Proposal is modified in a way that ISO does not support, the ISO's Proposal and any changes thereto ISO finds acceptable. Notwithstanding the foregoing, the Participants Committee may, in its discretion, consider and vote upon any Proposal submitted to it and such a vote shall have the same effect as if the Proposal had first been voted upon by a Technical Committee. The Participants Committee may not defer a vote on any Proposal that has been voted on by a Technical Committee and presented to the Participants Committee for a vote unless the Proponent consents to such deferral.

5.15 **Action on Motions Raised**. The Participants Committee shall not act at a meeting on any motion or other proposal (a "Motion") raised for which the notice requirements of Section 5.5 have not been satisfied. On motions for which the notice requirements of Section 5.5 have been satisfied, the Participants may either (i) act on a Motion, or (ii) act to table or defer consideration of a pending Motion, or (iii) act on a proposed amendment to a Motion that addresses the subject matter of the draft resolution circulated in advance of the meeting. Motions raised for which the notice requirements of Section 5.5 have not been satisfied, upon request by a voting member, shall be deferred to a subsequent meeting which is properly noticed.

5.16 **Conduct of Meetings.**

(a) The Chair shall confirm through the Secretary that a Quorum as defined in Section 5.7 is present and that notice of the meeting has been served in accordance with Section 5.5.

(b) All matters to be acted upon by the Participants Committee shall be stated in the form of a motion by a voting member, which must be seconded. Only one motion and any one amendment to that motion may be pending at one time.

(c) Except to the extent inconsistent with the NEPOOL Agreement or these Bylaws, the Chair shall have the right and authority to prescribe other such rules, protocols and procedures and to do all such acts as, in the judgment of the Chair, are appropriate for the proper conduct of the meeting. Such rules, regulations or procedures shall include, without limitation, the following:

(i) Except in the case of a meeting called by five (5) or more voting members of the Participants Committee in accordance with Section 5.3, the agenda for each meeting of the Participants Committee shall be established by the Chair.

(ii) In the conduct of each meeting, the Chair shall have the authority normally vested in a presiding officer and shall have, in particular, the authority to limit the aggregate amount of time allowed for discussion of a particular matter and the amount of time allowed to each member or other person to speak on a matter.

5.17 Consent Agenda.

(a) All actions which have been recommended to the Participants Committee by the Markets Committee, the Reliability Committee, and the Transmission Committee (herein referred to as the "Technical Committees") as set forth in notices provided pursuant to Section 8.2, Section 9.2, or Section 10.2 of the NEPOOL Agreement, whichever is applicable, or any other Subgroup established by the Participants Committee, no later than the tenth (10th) Business Day prior to the date of the Participants Committee meeting shall be voted on as a group (the "Consent Agenda"), except to the extent that any recommendation has been removed from the Consent Agenda pursuant to Subsection (b) or (c) of this Section 5.17.

(b) A voting member of the Participants Committee may request that a recommended action be removed from the Consent Agenda by providing a written or electronic notice of objection to the Secretary of the Participants Committee no later than the fifth (5th) Business Day prior to the Participants Committee meeting. Such recommendation shall be removed from the Consent Agenda and shall be separately discussed and voted at the Participants Committee meeting. The voting member providing a notice of objection resulting in the removal of a recommended action from the Consent Agenda shall be required at the direction of the Chair to speak before the Participants Committee and explain the reasons for such removal and any alternative action proposed by such member.

(c) A voting member of the Participants Committee who requests that a specific recommended action be removed from the Consent Agenda may provide an alternative draft resolution(s) regarding such action to the Secretary of the Participants Committee and may also provide to the Secretary such background materials the voting member reasonably determines to be necessary for the Committee to have an informed opinion on such matters. The Secretary shall include such materials and draft resolution(s) in the materials for the meeting circulated to each member of the Participants Committee, provided that such request, draft resolution(s) and supporting materials are provided to the Secretary no later than the fifth (5th) Business Day prior to the Participants Committee meeting.

5.18 Draft Resolutions.

(a) In accordance with Section 5.5 and Section 6.6 of the NEPOOL Agreement, the following draft resolution may be considered in connection with the Consent Agenda action items:

RESOLVED, that the Participants Committee individually [supports/ and/or approves] each action set forth in the _____ [insert date] notice of actions by the _____ [identify name of Technical Committee/Subgroup] as recommended by such Committee.

(b) Absent an alternative form of resolution provided in accordance with Section 5.15(c), a recommended action, properly removed as an item from the Consent Agenda in accordance with Section 5.15, shall be deemed to have been noticed in accordance with Section 5.5 of these Bylaws and Section 6.6 of the NEPOOL Agreement and shall be voted on in the following form:

RESOLVED, the following recommendation of the _____ [identify name of Technical Committee/Subgroup] as specified in a notice dated _____ [insert date] and which reads as follows: _____ [insert recommended action] is hereby [supported/ approved] by the Participants Committee.

Section 6. Amendment, Suspension and Repeal of Bylaws.

These Bylaws may be amended, suspended or repealed by action of the Participants Committee taken pursuant to the provisions of Section 6.9 of the NEPOOL Agreement at a meeting held pursuant to the notice requirements of Section 6.6 of the NEPOOL Agreement.

NEW ENGLAND POWER POOL

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Membership Subcommittee

DATE: February 12, 2019

SUBJECT: **ACTIONS OF THE NEPOOL MEMBERSHIP SUBCOMMITTEE**

This memorandum is notification that the NEPOOL Membership Subcommittee took the following actions at its February 11 meeting:

1. **New Member Application Approved.** Approved the Applications for membership in NEPOOL of the following Entity, subject to the following routine conditions: (i) that the applicant sign and return the Standard Membership Conditions, Waivers and Reminders acceptance letter; (ii) that the ISO and NEPOOL Counsel find the Application complete; and (iii) the applicant execute an Indemnification Agreement (requested effective date in parentheses):

   - NDC Partners LLC (Mar 1, 2019) Supplier Sector

2. **Application Recommended for NPC Approval.** Recommended that, in light of (1) the history and circumstances surrounding this application, (2) the understandings, Bylaws and Standard Membership Conditions, Waivers and Reminders (SCWRs) applicable to all members, and (3) the FERC's January 29, 2019 order in Docket No. ER18-2208, the Participants Committee consider and approve the following application for membership in NEPOOL as an End User Participant, subject to the applicant satisfying the following two routine conditions after the Participants Committee approval: (i) that the applicant sign and return the SCWRs acceptance letter; and (ii) the applicant execute an Indemnification Agreement (potential effective date in parentheses).[1]

   - Michael Kuser (Apr 1, 2019)[1] End User Sector

   Participants Committee consideration of this application and the Subcommittee's recommendation will be scheduled for the next Participants Committee meeting (Mar 13, 2019).

Next ***regularly***-scheduled Subcommittee meeting: Mon, Mar 11, 2019 ***10:00 a.m***.

Subcommittee Activity since Jan 1, 2019

Number of Meetings	New Member Applications	Terminations	Other Actions
3	4	7	

2019 NEPOOL Membership Totals (as of Feb 1, 2019)

# of Members	New Members	Terminations
501	4	8

[1] Subject to approval by the Participants Committee and signature and return of the SCWRs acceptance letter, applicant will have satisfied the requirements of Section 3.1(a) of the NEPOOL Agreement. Pursuant to Section 3.1(b) of the Agreement, the applicant will become a Participant, following filing with and acceptance of the membership by the FERC. The membership will become effective, on the first day of the second calendar month following satisfaction of those requirements (*e.g.* June 1, 2019), or earlier if an Indemnification Agreement is executed (*e.g.* April 1, 2019)).

Comments of Liz Delaney, End User Sector Vice-Chair
3.13.2019 NEPOOL Participants Committee Meeting
RE: Press

As the End User Sector Vice-Chair, I'd like to say a few words about this issue and would welcome additional comments from my Sector. Last year, when we were first considering this application, most members of my Sector expressed two preferences:

1. Many felt that press should be accommodated at NEPOOL
2. And most felt that categorizing press as End Users, including providing them with voting rights, was not the appropriate way to accommodate them.

To rectify this, several members proposed an amendment to create a press membership category that better defined the role that press could play. This amendment was not supported by NEPOOL. We recognize that this is not what we are voting on today, but would like the minutes to reflect that we remain deeply dissatisfied with the current circumstances and are eager to re-open this conversation as soon as possible.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings as of March 8, 2019

The following activity, as more fully described in the attached litigation report, has occurred since the report dated January 30, 2019 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

*	1	EE M&V Declaratory Order Petition (EL19-43)	Feb 13	Advanced Energy Economy and Sustainable FERC Project file a request for a declaratory order that (i) new M&V standards cannot be retroactively applied to approved FCA 13 Qualification Packages and (ii) the implementation of a new practice for determining the capacity value of EE Resources cannot implemented prior to filing with and acceptance by the FERC
			Feb 15-Mar 7	Acadia Center, Calpine, CLF, Dominion, National Grid, NRDC, NRG, AMP, Earthjustice, E. KY Power Coop, EPSA, MA DPU, Modern Energy intervene
			Feb 22	NESCOE files comments
			Mar 5-6	NEPOOL, Eversource, NH OCA file comments
			Mar 7	ISO-NE answers Petition; Cape Light Compact /Efficiency Maine Trust, EDF, MA AG, PIOs, AEMA file comments supporting Petition
	2	Winter Fuel Security (Chapter 3) (EL18-182)	Feb 1	FERC issues tolling order affording it additional time to consider requests for reh'g of Dec 3 *Fuel Security Retention Proposal Order;* National Grid supports ISO-NE's Chapter 3 extension request
			Feb 4	NEPOOL, NEPGA, MA DPU support ISO-NE's Chapter 3 extension req.
			Feb 6	NEPOOL submits 2018 Annual Report for the record in this proceeding
	4	Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)	Feb 12	Louisiana PSC replies to TOs Jan 24 motion to oppose
			Mar 6, 7	Complainant-Aligned Parties, FERC Trial Staff file errata to Jan 11 submissions
			Mar 8	TOs, Complainant-Aligned Parties, EMCOS, FERC Trial Staff file reply briefs

II. Rate, ICR, FCA, Cost Recovery Filings

*	7	FCA13 Results Filing (ER19-1166)	Mar 1	ISO-NE files FCA13 results; comment date Apr 12
			Mar 1-6	Eversource, Exelon, Public Citizen intervene
	8	Dighton Request for Additional Cost Recovery (ER19-853)	Feb 1	National Grid intervenes
	8	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Feb 6	Constellation answers requests for rehearing of Dec 20 *Mystic Order*
			Feb 8	Constellation requests 10-day extension, to Mar 1, 2019, of compliance filing deadline established in *Mystic Order*
			Feb 8	CT Parties answer Constellation's request for rehearing
			Feb 14	FERC extends compliance filing deadline to Mar 1, 2019; NESCOE answers Constellation Feb 6 answer
			Feb 15	FERC issues tolling order affording it additional time to consider requests for rehearing of *Mystic Order*
			Mar 1	Mystic submits compliance filing in response to the *Mystic Order*; comment date Mar 22
	9	VTransco Recovery of Highgate Ownership Share Acquisition Costs (ER18-1259)	Feb 21	FERC grants clarification and denies rehearing of *Highgate Acquisition Cost Recovery Order*

10	MPD OATT Annual Informational Filing (ER15-1429)	Feb 1 Feb 19	Emera Maine answers Maine Customer Group's Dec 31 Challenge MPUC and Maine Customer Group respond to Emera Maine's Feb 1 answer

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

11	Post-PRD Implementation Conforming and Clean-Up Changes (ER19-614)	Feb 13	FERC accepts changes, eff. Feb 19, 2019
11	Waiver Request: Vineyard Wind FCA13 Participation (ER19-570)	Jan 31 Feb 1 Feb 4 Feb 5-6 Feb 13 Feb 15 Feb 19	Vineyard Wind requests immediate issuance of order on Request Mass. Gov Baker requests FERC grant waiver request on Feb 1 Vineyard Wind submits emergency motion for stay of FCA13 or requirement that FCA13 be re-run following FERC action; Commissioners LaFleur and Glick issue statement ISO-NE and NEPGA protest emergency motion MA AG submits letter regarding FERC's failure to act ISO-NE submits letter clarifying two concerns raised in Commissioner Glick's dissent to the *CASPR Conforming Changes Order* Vineyard Wind answers NEPGA's and ISO-NE's Feb 5-6 protests
12	*Order 841* Compliance Filing (ER19-470)	Feb 7 Feb 7-8 Mar 1	Calpine, EDF, RENEW, Advanced Energy Economy, ESA, Tesla file protests APPA, NRECA, GlidePath Development, Voith Hydro intervene Voith Hydro submits comments on advance pumped storage hydro
12	Enhanced Storage Participation Changes (ER19-84)	Feb 25	FERC accepts changes, eff. Apr 1, 2019
13	Fuel Security Retention Proposal (ER18-2364; EL18-182)	Feb 1	FERC issues tolling order affording it additional time to consider requests for reh'g of Dec 3 *Fuel Security Retention Proposal Order*

IV. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

18	Schedule 21-NEP: BIPCO LSA Amendments (ER19-707)	Feb 22	FERC conditionally accepts Amendments, eff. Jan 1, 2019; compliance filing (correcting Agreement's eTariff title) due on or before Mar 25
19	Schedule 21-EM: Stored Solar J&WE LSA Extension (ER19-706)	Feb 22	FERC accepts amended LSA, eff. Jan 1, 2019

VII. NEPOOL Agreement/Participants Agreement Amendments

19	132nd Agreement (Press Membership Provisions) (ER18-2208)	Feb 6 Feb 28 Mar 4	NEPOOL submits 2018 Annual Report for the record in this proceeding NEPOOL requests clarification, or in the alternative rehearing, of the *Press Provisions Order* Public Citizen submits comments on NEPOOL's Feb 28 Request

VIII. Regional Reports

*	20	Capital Projects Report - 2018 Q4 (ER19-1052)	Feb 14 Feb 19 Feb 27	ISO-NE files Q4 Report NEPOOL intervenes and files comments supporting Q4 Report National Grid intervenes

*	21	Transmission Projects Annual Info Filing (ER13-193)	Jan 30	ISO-NE files annual informational filing of projects on the RSP project list that had a year of need 3 years or less from the completion of the Needs Assessment as required under OATT § 4.1(j)(iii)

IX. Membership Filings

*	21	March 2019 Membership Filing (ER19-1146)	Feb 28	Memberships: MidAmerican Energy Services; NDC Partners; Terminations: BlueRock Energy, OhmConnect, Lotus Danbury Two; comment date Mar 21
	21	February 2019 Membership Filing (ER19-936)	Jan 31	Memberships: Manchester Street; McCallum Enterprises 1 LP; Terminations: Clear Choice Energy; Covanta Projects of Wallingford; Fairchild Energy and Fairchild Semiconductor; Noble Environmental Power; StateWise Energy Mass.; Swift River Trading Co.; and Name Change: Tomorrow Energy Corp (f/k/a Sperian Energy Corp.)
			Feb 8	NEPOOL files to correct Fairchild Companies termination effective date
*	21	Suspension Notice – Great Eastern Energy (not docketed)	Feb 13	ISO-NE files notice of Feb 12 suspension of BBPC LLC d/b/a Great Eastern Energy from the New England Markets
*	21	Suspension Notice – OhmConnect (not docketed)	Feb 15	ISO-NE files notice of Feb 13 suspension of OhmConnect, Inc. from the New England Markets

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

No Activity to Report

XI. Misc. - of Regional Interest

	23	203 App.: ECP/ Fawkes Holdings (Wheelabrator) (EC19-14)	Feb 15	Fawkes Holdings files notice of Feb 12 consummation of transaction; Wheelabrator and Macqarie to vote together in the AR Sector
*	27	Mystic COS Agreement Amendment No. 1 (ER19-1164)	Mar 1	Mystic files amendment to its COS Agreement (reciprocal right of termination following OFA updates); comment date Mar 22
			Mar 4-8	MA AG, Verso, New England LDCs intervene
			Mar 5	Constellation moves for expedited entry of a protective order
*	27	SGIA Termination: CMP/Sparhawk (ER19-1019)	Feb 8	CMP submits notice of cancellation of SGIA
*	27	EPCOM Agreement Cancellation: CL&P/ Cricket Valley (ER19-980)	Feb 4	CL&P submits notice of cancellation of EPCOM Agreement
*	27	D&E Agreement: CL&P/NRG Middletown Repowering (ER19-978)	Feb 4	CL&P files D&E Agreement
	27	D&E Agreement Cancellation: PSNH/ Essential Power Newington (ER19-817)	Feb 28	FERC accepts notice of cancellation of D&E Agreement, eff. Jan 15, 2019
	28	Related Facilities Agreement: NSTAR / Clear River Energy (ER19-693)	Feb 22	FERC accepts Agreement, eff. Feb 26, 2019
	28	Related Facilities Agreement: CL&P / Clear River Energy (ER19-689)	Feb 22	FERC accepts Agreement, eff. Feb 26, 2019
	28	Related Facilities Agreement: CL&P / Cricket Valley (ER19-590)	Feb 1	FERC accepts RFA, eff. Feb 17, 2019

28	TSAs: First Amendments to EDC New England Clean Energy Connect TSAs (ER19-324 et al.)	Feb 8	FERC accepts amendments to agreements, eff. Jan 9, 2019
29	FERC Enforcement Action: Show Cause Order – Footprint Power (IN18-7)	Feb 25	FERC terminated the proceeding initiated by the *Show Cause Order*

XII. Misc. - Administrative & Rulemaking Proceedings

31	*Order 853*: Civil Monetary Penalty Inflation Adjustments (RM19-9)	Feb 1	Order 853 published in *Federal Register* and thus becomes eff. Feb 1, 2019
32	*Order 855*: Amended FPA Section 203(a)(1)(B) (RM19-4)	Feb 21	FERC issues *Order 855,* which revises its regulations relating to mergers or consolidations by a public utility (requiring prior authorization under FPA section 203(a)(1)(B) only for facilities having a value in excess of $10 million, and a post-transaction 30-day notice requirement for mergers or consolidations with facilities exceeding $1 million); eff. 30 days after publication in the *Federal Register*
32	NOPR: Refinements to Horizontal Market Power Analysis Requirements (RM19-2)	Feb 1 Feb 11-	NOPR published in the *Federal Register*; comment date Mar 18, 2019 Powerex submits comments
33	DER Participation in RTO/ISOs (RM18-9)	Feb 11	A group of 18 US Senators submits a letter urging the FERC to adopt a final rule and requesting an update no later than Mar 1, 2019
33	*Orders 845/845-A*: LGIA/LGIP Reforms (RM17-8)	Feb 21	FERC grants in part and denies in part the requests for rehearing and clarification of *Order 845*, eff. May 20, 2019; *Order 845* compliance filings due May 22, 2019

XIII. Natural Gas Proceedings

38	New England Pipeline Proceedings		
	• Atlantic Bridge Project (CP16-9)	Feb 25	FERC issues tolling order affording it additional time to consider pending requests for reh'g of FERC order granting 2-year extension of time for completion of Project construction and availability for service
		Feb 20	Parties request Case No. 18-1045 continue to be held in abeyance

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

No Activity to Report

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: March 11, 2019

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"),[1] state regulatory commissions, and the Federal Courts and legislatures through March 8, 2019. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **EE M&V Declaratory Order Petition (EL19-43)**

On February 13, 2019, Advanced Energy Economy ("AEE") and Sustainable FERC Project (together, "Petitioners") filed a request for a declaratory order that ISO-NE's (i) new Measurement and Verification (M&V) standards cannot be retroactively applied to approved FCA 13 Qualification Packages and (ii) ISO-NE's implementation of a new practice for determining the capacity value of Energy Efficiency ("EE") Resources (i.e., valuation on net rather than adjusted gross savings) cannot implemented prior to filing with and acceptance by the FERC. Petitioners stated that ISO-NE, in a series of phone calls to FCM Participants with EE Resources, had indicated its intention to change how it measures the demand reduction value of EE Resources for FCM purposes (using a valuation on net rather than adjusted gross savings basis). Petitioners assert that the new conversion factors (i) were never previously required of, nor imposed on, Market Participants; (ii) are not defined or described in the Tariff or Manuals; and (iii) are not included in most Market Participants' ISO-NE-approved M&V Documents. Petitioners explained that EE Resources have been defined and valued on their total reduction to energy consumption from the baseline federal standards (i.e. adjusted gross reduction to load) and in appearing to move towards a valuation based only on net energy savings achieved by EE resources, ISO-NE has created uncertainty about the methodology it will use to calculate demand resource values going forward, and is thereby harming the FCM. Comments on the Petition were due on or before March 7, 2019.

On March 7, ISO-NE answered the Petition. In its answer, notably, ISO-NE stated that it "has made no proposal to change its [M&V] standards. Furthermore, should the ISO propose any such changes, it will not implement them without first vetting the changes through the stakeholder process and making any necessary filings at the Commission. Thus, interested parties will have ample opportunity to address any concerns, including retroactivity, if and when the ISO presents a definite proposal to the stakeholders and, if necessary, to the Commission."[2] Commenters included NEPOOL, which filed limited comments, and Cape Light

[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] Answer of ISO New England Inc., Docket No. EL19-43 (filed Mar. 7, 2019). ISO-NE also asserted that Petitioners "misconstrue energy efficiency's participation in the forward capacity market and misunderstand the ISO's purpose in reaching out to energy efficiency providers."

Compact/Efficiency Maine Trust, EDF, Eversource, MA AG, NESCOE, NH OCA, PIOs,[3] and Advanced Energy Management Alliance ("AEMA"), each of whom supported the Petition. Doc-less interventions were filed by Acadia Center, Calpine, CLF, Dominion, National Grid, NRDC, NRG, AMP, Earthjustice, E. KY Power Coop, EPSA, MA DPU, and Modern Energy.

This matter is now pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **RTO Insider Press Policy Complaint (EL18-196)**

RTO Insider's August 31 Complaint against NEPOOL, requesting that the FERC either (i) find that NEPOOL's press policy "unlawful, unjust and unreasonable, unduly discriminatory and contrary to the public interest, and direct NEPOOL to cease and desist" from implementing its policy; or (ii) "if the [FERC] finds that NEPOOL can sustain such a ban as a "private" entity, [] direct that NEPOOL's special powers, privileges and subsidies be terminated and that an open stakeholder process be used by [ISO-NE]" ("Press Policy Complaint"), remains pending. The Press Policy Complaint, which was also filed as a "protest" to NEPOOL's filing of the 132nd Agreement (dismissed on January 30, 2019 -- *see* ER18-2208 in Section VIII below), broadens RTO Insider's efforts to "be in the room" and on terms it prefers.

NEPOOL answered the Complaint on September 20. NEPOOL cited numerous jurisdictional and procedural reasons why RTO Insider's claims fail and should be summarily rejected. NEPOOL also answered RTO Insider's arguments on the merits, should the FERC decide not to reject the Complaint summarily. Comments supporting the Complaint were submitted by the New Hampshire Office of Consumer Advocate ("NH OCA"), the Reporters Committee for Freedom of Press ("RCFP"), Bill Short, Public Interest Organizations ("PIOs"),[4] and Public Citizen. Doc-less interventions only were submitted by Conservation Law Foundation ("CLF"), National Grid, NESCOE, New York Transmission Owners ("NYTOs"), the Sustainable FERC Project and Natural Resources Defense Council ("NRDC").

On October 5, NEPOOL answered elements of the NH OCA and PIOs' September 20 pleadings. Also on October 5, RTO Insider and PIOs answered NEPOOL's September 20 answer. On October 15, NEPOOL filed a limited response to the October 5 pleadings of RTO Insider and PIOs. The Complaint remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Winter Fuel Security (Chapter 3) (EL18-182)**

As previously reported, the July 2, 2018 *Mystic Waiver Order*[5] (reported on in more detail in ER18-1509 in Section III below) in part instituted this Section 206 proceeding in light of the FERC's preliminarily finding that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record in ER18-1509 that could result in reliability violations as soon as 2022. Accordingly, the *Mystic Waiver Order* directed ISO-NE, in part, to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns (the "Chapter 3 Proposal").

ISO-NE Extension Request. On January 18, 2019, ISO-NE requested an extension of time, to November 15, 2019, to file its Chapter 3 Proposal. Both NESCOE and the MA AG filed motions supporting ISO-NE's Extension Request. On January 25, the FERC extended the date for comments on the Extension Request to February 4, 2019, in order to permit NEPOOL an opportunity to report on its consideration of the Extension Request. Additional

[3] "PIOs" are for this proceeding are Acadia Center, Conservation Law Foundation ("CLF"), Earthjustice, Natural Resources Defense Council ("NRDC"), and Union of Concerned Scientists ("UCS").

[4] "PIOs" are for this proceeding are CLF, Earthjustice and NRDC.

[5] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

comments supporting ISO-NE's extension request were filed by NEPOOL, National Grid, NEPGA, and the MA DPU. ISO-NE's request is pending before the FERC.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19; ER18-2235)**

As previously reported, the Settling Parties[6] filed on August 17, 2018, in ER18-2235, a Joint Offer of Settlement (the "Settlement") to resolve all issues in the Section 206 proceeding instituted by the FERC on December 28, 2015.[7] The Settlement proposes changes to Section II.25, Schedules 8 and 9, Attachment F (including the addition of Interim Formula Rate Protocols ("Interim Protocols")), and the Schedule 21s to the ISO-NE OATT. If approved, the changes to Attachment F are to be effective mid-June, 2019, with the remaining changes to be effective January 1, 2020. The Interim Protocols, as well as the changes to Section II.25 and Schedules 8 and 9 were supported by the Participants Committee at its July 24, 2018 meeting.

NESCOE filed comments supporting the Settlement. Comments opposing the Settlement were filed by Municipal PTF Owners[8] and FERC Trial Staff. The ***Municipal PTF Owners*** ("Munis") assert that the Settlement worsens, rather than improves, the issues of "lack of transparency, clarity and specificity that led the Commission [to] find the existing Attachment F formula unjust and unreasonable", discriminates against load directly connected to PTF and exempted by Section II.12(c) of the ISO-NE Tariff from paying costs associated with service across non-PTF facilities, contravenes numerous settled rate principles without explanation or justification,[9] and imposes an unacceptable moratorium and burden on parties inclined to challenge Attachment F. ***FERC Trial Staff*** asserted that the Settlement, as filed, is not fair and reasonable nor is it in the public interest "because it would result in unreasonable rates and contains fundamental defects",[10] and opposed the Settlement terms which would bind non-settling parties to the terms of the Settlement and establish a standard of review for changes to the Settlement. FERC Trial Staff suggested that these defects could be corrected in a comprehensive compliance filing,

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[6] "Settling Parties" are identified as: CMP; CMEEC/CTMEEC; CT OCC; CT PURA; Emera Maine; Eversource (CL&P, PSNH, NSTAR); Fitchburg and Unitil; Green Mountain Power; Maine Electric Power Co.; ME OPA; MPUC, MA AG, MA AG, MA DPU, MMWEC, National Grid; NESCOE; NHEC; NH PUC; New Hampshire Transmission; RI DPUC; UI; VT DPS; VEC; VELCO; and Vermont Transco, LLC ("VTransco").

[7] *ISO New England Inc. Participating Transmission Owners Admin. Comm.*, 153 FERC ¶ 61,343 (Dec. 28, 2015), *reh'g denied,* 154 FERC ¶ 61,230 (Mar. 22, 2016) ("*RNS/LNS Rates and Rate Protocols Order*"). The *RNS/LNS Rates and Rate Protocols Order* found the ISO-NE Tariff 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"). 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". The FERC encouraged the parties to make every effort to settle this matter before hearing procedures are commenced. The FERC-established refund date is January 4, 2016.

[8] "Municipal PTF Owners" are: Braintree, Chicopee, Middleborough, Norwood, Reading, Taunton, and Wallingford.

[9] The elements of the Settlement that Municipal PTF Owners assert contravene settled rate principles include: provision for a fixed accrual for Post-Employment Benefits Other than Pension ("PBOPs"); continued TO use of net proceeds of debt, rather than gross proceeds of debt, in establishing capital structures under their proposed revenue requirement formula; inappropriate allocation of rental revenues from secondary uses of transmission facilities; the addition of miscellaneous intangible plant (Account 303), and depreciation and amortization of intangibles, to rate base; and the creation of a Regulatory Asset for an unspecified Massachusetts state tax rate change (without explanation).

[10] Included in the "fundamental defects" of the Settlement identified by FERC Trial Staff are that it: (1) enables the TOs to conduct extra-formulaic, ad hoc ratemaking for all externally-sourced inputs every year; (2) enables certain PTOs to over-recover certain plant costs; (3) enables certain PTOs to recover greater than 50% of Construction Work in Progress ("CWIP") in rate base (4) violates prior FERC orders about which customer groups can be made to pay incentive returns; (5) fails to appropriately calculate federal and state income taxes and, in particular, fails to account for excess Accumulated Deferred Income Taxes ("ADIT") created by the Tax Cuts and Jobs Act; (6) does not contain a fixed and stated ROE; and (7) does not contain a fixed and stated PBOPs expense.

and requested that the FERC either (i) conditionally approve the Settlement subject to the submission of such a corrective compliance filing, or (ii) reject the Settlement in its entirety and set the entire matter for hearing.

Reply comments were submitted by NEPOOL, NESCOE and the MA AG. In its limited comments, ***NEPOOL*** noted that it supported the Interim Protocols and that it had no objection to the Settlement. ***NESCOE*** reiterated its support for the Settlement in its reply comments, urging the FERC to reject any arguments that consumer-interested parties "were not familiar with the issues relating to the Settlement or that they reached a settlement for any reason other than their view that it is in the best interests of consumers."[11] ***MA AG*** urged the FERC to approve the Settlement as submitted, despite the objections of FERC Trial Staff and Municipal PTF Owners, because it complies with the *RNS/LNS Rates and Rate Protocols Order* and represents a carefully negotiated resolution to numerous complex ratemaking and transparency issues.[12]

Settlement Judge Report. Settlement Judge Dring submitted the contested settlement to the Commission on November 5, 2018. In his report, Judge Dring noted his "complete agreement with the statements that were filed in support of this settlement." He referred the Commission to the TOs' reply comments for the reasons why Trial Staff's and Municipal PTF Owners opposition are in error. On November 14, the Munis moved that the Commission expunge from the record in this proceeding the Settlement Judge's views on the merits of the settlement, arguing that the inclusion of those views exceeds the regulatory limits of the settlement judge's role. On November 29, FERC Trial Staff supported the Munis' motion, providing additional arguments as to how the settlement report exceeded the judge's authority and was otherwise deficient.

The Settlement continues to be pending before the Commission. Given this proceeding's procedural posture, Chief Judge Cintron terminated settlement judge procedures on November 15, subject to final action by the Commission. 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).

- **Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)**

There are four proceedings pending before the FERC in which consumer representatives seek to reduce the TOs' return on equity ("Base ROE") for regional transmission service.

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[13] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[14] However, the FERC's orders were challenged, and in *Emera Maine,*[15] the DC Circuit Court vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the

[11] Reply Comments of NESCOE, Docket Nos. ER18-2235 and EL16-19, at p. 2 (filed Sep. 28, 2018).

[12] Reply Comments of the Mass. Att'y General in Support of Settlement, Docket Nos. EL16-19 and ER18-2235 (filed Sep. 28, 2018).

[13] The TOs' 11.14% pre-existing Base ROE was established in *Opinion 489*. *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarific.*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom.*, Conn. Dep't of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010) ("*Opinion 489*")).

[14] *Coakley Mass. Att'y Gen. v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,234 (2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014) ("*Opinion 531-A*"), *order on reh'g*, 150 FERC ¶ 61,165 (2015) ("*Opinion 531-B*").

[15] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. 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).

FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[16] and third (EL14-86)[17] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 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.[18] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[19] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[20] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under section 206 of the FPA.[21] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[22] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings. The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[23]

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[16] 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%.

[17] 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.

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

[19] The 4th ROE 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%. The FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint on September 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11-15, 2017. The September 26, 2016 order was challenged on rehearing, but rehearing of that order was denied on January 16, 2018. *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("*Base ROE Complaint IV Order*"), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) (together, the "*Base ROE Complaint IV Orders"*). *The Base ROE Complaint IV Orders*, as described in Section XV below, have been appealed to, and are pending before, the DC Circuit.

[20] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 162 FERC ¶ 63,026 (Mar. 27, 2018) ("*Base ROE Complaint IV Initial Decision*").

[21] *Id.* at P 2.; Finding of Fact (B).

[22] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (Oct. 18, 2018) ("*Order Directing Briefs"* or "*Coakley*").

[23] *Id.* at 19.

At highest level, the new methodology will determine whether (1) an existing ROE is unjust and unreasonable under the first prong of FPA section 206 and (2) if so, what the replacement ROE should be under the second prong of FPA section 206. In determining whether an existing ROE is unjust and under the first prong of Section 206, the FERC stated that it will determine a "composite" zone of reasonableness based on the results of three models: the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and Expected Earnings models. Within that composite zone, a smaller, "presumptively reasonable" zone will be established. Absent additional evidence to the contrary, if the utility's existing ROE falls within the presumptively reasonable zone, it is not unjust and unreasonable. Changes in capital market conditions since the existing ROE was established may be considered in assessing whether the ROE is unjust and unreasonable.

If the FERC finds an existing ROE unjust and unreasonable, it will then determine the new just and reasonable ROE using an averaging process. For a diverse group of average risk utilities, FERC will average four values: the midpoints of the DCF, CAPM and Expected Earnings models, and the results of the Risk Premium model. For a single utility of average risk, the FERC will average the medians rather than the midpoints. The FERC said that it would continue to use the same proxy group criteria it established in *Opinion 531* to run the ROE models, but it made a significant change to the manner in which it will apply the high-end outlier test.

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[24] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[25] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, EEI, Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24. The Louisiana PSC answered the TO's January 24 motion on February 12. Reply briefs were due March 8, 2019. Reply briefs were submitted by the TOs, Complainant-Aligned Parties, EMCOS, FERC Trial Staff.

Disclosure Order. On January 7, 2019, the FERC granted a November 16, 2018 request by CT PURA, EMCOS, MMWEC, and NHEC ("Customers") that it identify and, where not already in the record in these four proceedings, release, the sources, data sets, and analyses underlying Figure 2 and Figure 3 in the *Order Directing Briefs* (at least one figure appeared to be based on proprietary information not available or included in the record).[26] The FERC attached to the *Disclosure Order* an Appendix A that identified the record exhibits that the FERC relied upon to develop the ROE data points for the test period for Base ROE Complaints II-IV,

[24] *Id.* at P 59.

[25] For purposes of the motion seeking clarification, "Customers" are CT PURA, MA AG, and EMCOS.

[26] *Coakley et al.*, 166 FERC ¶ 61,013 (Jan. 7, 2019) ("*Disclosure Order*").

together with an explanation of adjustments made. The data underlying the Base ROE Complaint I test period was discussed in the *Order Directing Briefs*.[27] With respect to Figure 3, the FERC stated that Evercore ISI produced the chart and the information requested cannot be provided.[28] However, the FERC went on to state that the *Order Directing Briefs* "relied on Figure 3 only for the limited purpose of showing that there had been a substantial increase in utilities' price to earnings ratio during the period October 2012 to December 2017" and that the FERC "did not rely on Figure 3 for any final determination on the use of the DCF model to determine utility ROEs."[29] The FERC emphasized that it "did not reach any final conclusions or make any final determinations with respect to the proposed new ROE methodology in the [*Order Directing Briefs*]", "did not reach any final conclusions or make any final determinations … with respect to the use of the DCF in determining the ROE or whether the DCF alone has ceased to be sufficient to estimate investors' expectations for a [ROE]", and "did not rely on Figure 2 and Figure 3 to make any final determinations."[30] The FERC noted that "participants may present evidence either in support of, or opposing, the [*Order Directing Briefs*], including whether stock prices during the periods at issue in these proceedings have performed in a manner inconsistent with the theory underlying the DCF methodology, as illustrated by Figure 3 …, and whether various financial models may move in different directions over time, as illustrated by Figure 2."

These matters are now pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA13 Results Filing (ER19-1166)**

On March 1, ISO-NE filed the results of the thirteenth FCA ("FCA13") held February 4, 2019. ISO-NE reported the following highlights:

- FCA13 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).
- FCA13 commenced with a starting price of $13.050/kW-mo. and concluded for the SENE, NNE and Rest-of-Pool after four rounds.
- Resources will be paid as follows:
  - $3.800/kW-mo. – all Capacity Zones
  - $3.800/kW-mo. – NY AC Ties imports (522 MW) and Highgate (57 MW)
  - $3.800/kW-mo. – Phase I/II HQ Excess external interface (431 MW)
  - $2.681/kW-mo. – New Brunswick imports (184 MW).
- The substitution auction resulted in a single clearing price of $0.000 for all Capacity Zones. No demand bids cleared that were priced below the substitution auction clearing price.
- 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.

[27] *Disclosure Order* at P 8.

[28] *Id.* at P 9.

[29] *Id.* at P 10.

[30] *Id.*

ISO-NE asked the FERC to accept the FCA13 rates and results, effective June 28, 2019. Comments on this filing are due on or before April 12, 2019. Thus far, Eversource, Exelon, and Public Citizen have filed doc-less interventions. 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).

- **Dighton Request for Additional Cost Recovery (ER19-853)**

On January 18, 2019, pursuant to Section III.A.15 of Appendix A to Market Rule 1,[31] Consolidated Edison Energy, Inc. ("ConEd Energy"), as lead Market Participant for Dighton Power, LLC ("Dighton"), requested that the FERC authorize recovery of $42,030 in Operating and Maintenance ("O&M") costs that were not recovered due to Reliability Commitment Mitigation applied to Dighton on November 14 and 15, 2018. ConEd Energy also seeks recovery of associated regulatory costs ($18,143 to date). ConEd represented that ISO-NE supports the request. Comments on the Dighton request were due on or before February 8; none were filed. Doc-less interventions were filed by NEPOOL and National Grid. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Mystic 8/9 Cost of Service Agreement (ER18-1639)**

As previously reported, on December 20, 2018, in a 2-1 decision (Commissioner Glick dissenting; Commissioner McIntyre not voting; Commissioner McNamee not participating), which followed an evidentiary proceeding and two rounds of briefing, the FERC conditionally accepted the Cost-of-Service Agreement ("COS Agreement")[32] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE.[33] The COS Agreement will provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. The *Mystic Order* directed Mystic to submit a compliance filing (intended to modify aspects of the COS Agreement that FERC rejected or directed be changed) on or before February 18, 2019, and established a paper hearing to ascertain whether and how the ROE methodology that FERC proposed in *Coakley* should apply in the case. Initial briefs on the ROE issue are due on or before April 19, 2019, and reply briefs are due on or before July 18, 2019.[34] Requests for clarification and/or rehearing of the *Mystic Order* were filed by Constellation Mystic Power, CT Parties, EDF, ENECOS, MA AG, NESCOE, NextEra, and Repsol. On February 6, Constellation answered the other parties' requests for rehearing. CT Parties answered Constellation's request for rehearing on February 8. On February 14, NESCOE answered Constellation's February 6 answer. On February 15, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending.

Mystic's Compliance Filing. On March 1, following a 10-day extension of time granted on February 14, 2019, Mystic submitted its required compliance filing. The compliance filing included the following modifications:

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[31] 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.

[32] The COS Agreement, submitted on May 16, 2018, is between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE. The COS Agreement is to provide cost-of-service compensation to Mystic for continued operation of Mystic 8 & 9, which ISO-NE has requested be retained to ensure fuel security for the New England region, for the period of June 1, 2022 to May 31, 2024. The COS Agreement provides for recovery of Mystic's fixed and variable costs of operating Mystic 8 & 9 over the 2-year term of the Agreement, which is based on the pro forma cost-of-service agreement contained in Appendix I to Market Rule 1, modified and updated to address Mystic's unique circumstances, including the value placed on continued sourcing of fuel from the Distrigas liquefied natural gas ("LNG") facility, and on the continued provision of surplus LNG from Distrigas to third parties.

[33] *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Mystic Order*").

[34] *Id.* at PP 31-34.

- Modification to Section 2.2 (Termination) which provides ISO-NE will be required to seek FEC authorization to extend the term of the COS Agreement beyond May 31, 2024; deletion of Section 2.2.1 in its entirety;
- Inclusion of a clawback provision;
- Modification to Section 4.4 related to settlement of over- and underperformance credits;
- A clarification that fuel opportunity costs will not be included as part of the Stipulated Variable Costs used to calculate the revenue credits;
- Modifications to information access provisions (§ 6.2) both to allow ISO-NE full access to information and to support verification of third-party sales;
- Modifications to Schedule 3 supporting multiple compensation-related directives (e.g. cost of capital/cost of service, fuel supply charge, settlement of over- and under-performance credits);
- Schedule 3A modifications related to Mystic's true-up process; and
- Non-substantive conforming changes.

In addition, Mystic's compliance filing included for informational purposes changes to the Fuel Supply and Terminal Services Agreements. Comments on Mystic's compliance filing are due on or before March 22, 2019.

July Mystic COS Agreement Order. Rehearing remains pending of the FERC's July order. As previously reported, the FERC issued an initial order regarding the COS Agreement, accepting the COS Agreement but suspending its effectiveness and setting it for accelerated hearings and settlement discussions.[35] The *Mystic COS Agreement Order* was approved by a 3-2 vote, with dissents by Commissioners Powelson and Glick. Challenges to the *July Mystic COS Agreement Order* were filed by NESCOE, ENECOS, MA AG, and the NH PUC. Constellation answered the NESCOE request for reconsideration on August 21. On September 10, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have questions on this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com); Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Sunita Paknikar (202-218-3904; spaknikar@daypitney.com).

- **VTransco Recovery of Highgate Ownership Share Acquistion Costs (ER18-1259)**

On February 21, the FERC granted clarification but denied rehearing[36] of its May 29 order[37] rejecting, without prejudice, VTransco's request for authorization to recover in transmission rates property transfer taxes, closing fees, and advisory fees related to its acquisition of ownership shares in the Highgate Transmission Facility. In the *Highgate Acquisition Cost Recovery Order*,[38] the FERC found that "VTransco has not made a showing … that these transaction-related costs have 'specific, measurable, and substantial benefits to ratepayers.' [and rejected] VTransco's filing, without prejudice to it making a future filing that makes this showing."[39] The FERC also rejected "the pass-through of transaction-related costs to ratepayers in any

[35] *Constellation Mystic Power,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July Mystic COS Agreement Order*"), *reh'g requested*.

[36] *Vermont Transco, LLC*, 166 FERC ¶ 61,126 (Feb. 21, 2019) ("*Rehearing Order*").

[37] *Vermont Transco, LLC*, 163 FERC ¶ 61,152 (May 29, 2018) ("*Highgate Acquisition Cost Recovery Order*"), *clarif. granted and reh'g denied*, 166 FERC ¶ 61,126 (Feb. 21, 2019).

[38] VTransco requested (and the MA AG challenged its request for) authorization to recover, under the regional formula rate, $639,780 in costs, including property transfer taxes, closing fees, and advisory fees, related to its acquisition recent of Highgate Transmission Facility ownership shares. VTransco stated that, absent FERC action, it would recover the expenses solely from Vermont customers (under its grandfathered 1991 Vermont Transmission Agreement ("VTA")). VTransco asserted that, because the costs are related to VTransco's acquisition of ownership shares in the Highgate Transmission Facility, a facility utilized solely to provide Regional Network Service, it is just and reasonable to allow VTransco to recover the Highgate Transaction costs through the ISO-NE Tariff formula rate, rather than through the VTA.

[39] *Id.* at P 16.

Commission-jurisdictional rate, without prejudice to VTransco submitting a request with the required showing of 'specific, measurable, and substantial benefits' to ratepayers."[40]

In its *Rehearing Order*, the FERC granted clarification that it did not establish a new policy regarding commitments in Section 203 proceedings[41] but denied rehearing of VTransco's request that it find that VTransco need not make showing that the transaction-related costs have "specific, measurable, and substantial benefits to ratepayers."[42] Unless the *Rehearing 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).

- **MPD OATT Annual Informational Filing (ER15-1429)**

On December 31, 2018, the Maine Customer Group[43] filed a formal challenge (the "2018 Challenge") to Emera Maine's May 15, 2018 annual informational filing.[44] The 2018 Challenge seeks certain cost reductions/ exclusions to be effective June 1, 2018. Maine Customer Group stated that the relief sought[45] had already been sought, unsuccessfully, directly from Emera Maine MPD through informal resolution procedures in accordance with the Protocols. On February 1, Emera Maine answered the 2018 Challenge, stating that three issues raised by the Maine Customer Group warranted changes to Emera Maine's 2018-19 charges and, because the other issues raised lacked merit, requested that the FERC direct Emera Maine to make the changes it acknowledged were warranted (to the extent not already accomplished in its 2019 Annual Update Filing) and to decline the request for additional changes or process. On February 19, the Maine Customer Group, including the MPUC, answered Emera's February 1 answer. No formal notice of the 2018 Challenge has been issued. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **TOs' *Opinion 531-A* Compliance Filing Undo (ER15-414)**

Rehearing remains pending of the FERC's October 6, 2017 order rejecting the TOs' June 5, 2017 filing in this proceeding.[46] As previously reported, the June 5 filing was designed to reinstate TOs' transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[47] decision. In its *Order Rejecting Filing*, the FERC required the TOs to continue collecting their ROEs currently on file, subject to a future FERC order.[48] The FERC explained that it will "order such refunds or surcharges as necessary to replace the rates set in the now-vacated order with the rates that the Commission ultimately determines to be just and reasonable in its order on remand" so as to "put the parties in the position that they would have been

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[40] *Id.* at P 18.

[41] *Rehearing Order* at P 16.

[42] *Id.* at PP 17-19.

[43] For purposes of this proceeding, "Maine Customer Group" is the MPUC, MOPA, Houlton water Co., and Van Buren Light & Power District, and Eastern Maine Electric Cooperative.

[44] The May 15 filing, submitted in accordance with the Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas ("Protocols"), set forth for the June 1, 2018 to May 31, 2019 rate year, the charges for transmission service under the MPD OATT ("MPD Charges"). *See* May 31, 2018 Litigation Report.

[45] The formal challenge seeks (i) exclusion of certain regulatory expenses allocated or directly assigned to the MPD transmission customers; (ii) exclusion of costs that would otherwise constitute a double-recovery for amortization of losses incurred as a result of a merger; (iii) correction of MPD-acknowledged errors in its Annual Update Filing; (iv) exclusion of certain costs for land associated with a project not in service; (v) exclusion from transmission rates certain costs for distribution equipment; (vi) exclude of costs improperly attributed to line 6901; and (vii) a flowback of excess ADIT resulting from the corporate tax reduction, and a requirement for Emera MPD to include a worksheet in its tariff to track excess/deficient ADIT.

[46] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*"), *reh'g requested*.

[47] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*").

[48] *Order Rejecting Filing* at P 1.

in but for [its] error." For the time being, so as not to "significantly complicate the process of putting into effect whatever ROEs the Commission establishes on remand" or create "unnecessary and detrimental variability in rates," the FERC has temporarily left in place the ROEs set in *Opinion 531-A*, pending an order on remand.[49] On November 6, the TOs requested rehearing of the *Order Rejecting Filing*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider the TOs' request for rehearing of the *Order Rejecting Filing*, which remains pending. 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).

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

- **Post-PRD Implementation Conforming and Clean-Up Changes (ER19-614)**

On February 13, 2019, the FERC accepted changes to the Tariff to reflect the full implementation of Price-Responsive Demand ("PRD") and related clean-up changes ("Post-PRD Implementation Changes").[50] The Post-PRD Implementation Changes, jointly filed by ISO-NE and NEPOOL, revised Tariff provisions related to: demand resource audits; the injection into the grid of electric power by demand resources; defined terms describing the measurement of facility load; Distributed Generation; and rules governing the aggregation of Demand Response Resources. The Post-PRD Implementation Changes were accepted effective as of February 19, 2019, as requested. Unless the February 13 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Waiver Request: Vineyard Wind FCA13 Participation (ER19-570)**

As previously reported, Vineyard Wind petitioned the FERC on December 14, 2018 for a waiver of the ISO-NE Tariff provisions necessary to allow Vineyard Wind to participate in FCA13 as a Renewable Technology Resource ("RTR"). Vineyard Wind's request for RTR designation was earlier rejected by ISO-NE on the basis that the resources is to be located in federal waters. Under the CASPR Conforming Changes, Vineyard Wind would not have been precluded from utilizing the RTR exemption. Consistent with the discussion in the CASPR Conforming Changes filing, Vineyard Wind asked that the proration requirement that would be triggered by Vineyard Wind's participation in FCA13 as an RTR be limited for FCA13 to it and any other similarly situated entities (i.e. new offshore wind resources located in federal waters seeking RTR treatment); there would be no impact on resources currently qualified to use the RTR exemption in FCA13. Comments on Vineyard Wind's request were due on or before January 4, 2019. ISO-NE filed comments not opposing the Waiver Request, but requesting FERC action by January 29, 2019 if the waiver is to be effective for FCA13. NEPGA protested the Waiver Request. Answers to NEPGA's protest were filed by Vineyard Wind and NESCOE. On January 15, the Massachusetts Department of Energy Resources ("MA DOER") intervened out-of-time and submitted comments supporting the Waiver Request. Doc-less interventions were filed by NEPOOL, Avangrid, Dominion, ENE, National Grid, and NextEra.

Since the last Report, there was a flurry of pre-FCA13 activity and pleadings submitted in response to that activity. On January 31, Vineyard Wind requested the immediate issuance of order on its request. Massachusetts Governor Baker submitted a request on February 1 that the FERC grant Vineyard Wind's waiver request that day. Also on February 1, ISO-NE reported at the Participants Committee meeting, and confirmed later that evening that, in the absence of a FERC order issued early that afternoon, it would proceed to run the auction without granting Vineyard Wind's MWs treatment under the RTR exemption. Early on February 4, Vineyard Wind submitted an emergency motion for immediate stay of FCA13 or, in the alternative, a requirement that FCA13 be re-run following FERC action. The FERC took no action ahead of FCA13 and FCA13

[49] *Id.* at P 36.

[50] *ISO New England Inc., et al.*, Docket No. ER19-614-000 (Feb. 13, 2019).

was run without Vineyard Wind receiving RTR treatment. Following FCA13, answers opposing Vineyard Wind's emergency motion were submitted by ISO-NE and NEPGA. A joint statement addressing the FERC's failure to act was issued by Commissioners LaFleur and Glick (to which Chairman Chatterjee responded via Twitter). The Massachusetts Attorney General filed a statement addressing the FERC's failure to act on February 13. On February 15, ISO-NE submitted a letter that addressed two concerns raised in Commissioner Glick's dissent from the *CASPR Conforming Changes Order.* On February 19, Vineyard Wind answered the NEPGA and ISO-NE protests to its motion to vacate and rerun FCA13 upon Commission approval of the waiver sought.

This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Order 841* Compliance Filing (ER19-470)**

On December 3, 2018, ISO-NE and NEPOOL jointly filed changes to Market Rule 1 and the OATT (and the PTO AC joined in the filing of the OATT revisions) in response to the requirements of *Order 841*.[51] For the majority of the revisions, ISO-NE requested a December 3, 2019 effective date; for a limited number of revisions, ISO-NE requested a January 1, 2024 effective date. The *Order 841* compliance changes were supported by the Participants Committee at its November 2, 2018 meeting. Following a request for a 45-day extension of time,[52] comments on this filing were due February 7, 2019. Doc-less interventions were filed by Exelon, LS Power, NESCOE, APPA, EPSA, NRECA, GlidePath Development, Lincoln Clean Energy, and Voith Hydro. Protests and comments were filed by Calpine, EDF Renewables, RENEW Northeast ("RENEW"), Advanced Energy Economy ("AEE"), Energy Storage Association ("ESA"), and Tesla. On February 22, NEPOOL, ISO-NE and NRECA filed answers to the comments and protests. On March 1, Voith Hydro submitted comments regarding advanced pumped storage hydro technology. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Enhanced Storage Participation Changes (ER19-84)**

On February 25, the FERC accepted the changes to the Tariff to enable emerging storage technologies to more fully participate in the New England markets (the "Storage Revisions").[53] As previously reported, the Storage Revisions will allow emerging storage technologies to be dispatched in the Real-Time Energy Market in a manner that more fully recognizes their ability to transition continuously and rapidly between a charging state and a discharging state and that provides a means for their simultaneous participation in the energy, reserves, and regulation markets. The Storage Revisions were accepted effective as of April 1, 2019, as requested. In accepting the Storage Revisions, and in part in response to a protest filed by the Energy Storage Association ("ESA"), the FERC noted that New England's *Order 841* compliance filing was pending, and it would "determine whether ISO-NE's Tariff complies with the requirements of Order No. 841 in Docket No. ER19-470-000 and will address any concerns regarding ISO-NE's compliance in that proceeding."[54] Unless the February

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[51] *See Electric Storage Participation in Mkts. Operated by Regional Transmission Organizations and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*").

[52] The request for an extension of the previously noticed Dec. 24 comment deadline was requested by the Energy Storage Association ("ESA") and by a group comprised of Advanced Energy Economy ("AEE"), American Wind Energy Association ("AWEA"), Solar Energy Industries Association ("SEIA"), Solar RTO Coalition, and The Wind Coalition. The request was supported by the Acadia Center, NRDC, UCS, and the Sierra Club Environmental Law Program ("Public Interest Organizations").

[53] *ISO New England Inc. and New England Power Pool Participants Comm.*, 166 FERC ¶ 61,146 (Feb. 25. 2019).

[54] *Id.* at P 39. ESA protested one element of the Storage Changes, specifically the proposal to automatically de-rate the amount of energy that a continuous storage facility can discharge into the energy market (the "automatic redeclaration" of Economic Maximum Limit and Maximum Consumption Limit). ESA asserted that the operational result of that approach "fails to account for the physical and operational characteristics of electric storage resources and imposes a market-inefficient choice on energy storage to forgo selling all of their stored energy rather than to conserve a significant fraction as operating reserves – for which they receive no compensation more often than not." The issue is likely to be addressed in the FERC's order on New England's *Order 841* compliance filing.

25 order is challenged, with any challenges due on or before March 27, 2019, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Fuel Security Retention Proposal (ER18-2364)**

Requests for rehearing and/or clarification of the *Fuel Security Retention Proposal Order*[55] remain pending before the FERC. As previously reported, the *Fuel Security Retention Proposal Order* accepted ISO-NE's Proposal[56] in all respects, despite the various protests and alternative proposals filed. There was a concurring decision from Commissioner Glick, and a partial dissent from Chairman Chatterjee on the FCA price treatment issue. Challenges to the *Fuel Security Retention Proposal Order* were filed by NEPGA, NRG, Verso, Vistra/Dynegy Marketing & Trade, MPUC, and PIOs.[57] On February 1, 2019, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have further questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Economic Life Determination Revisions (ER18-1770)**

Rehearing of the FERC's November 9 order,[58] accepting the revised Tariff language that changed the determination of economic life under Section III.13.1.2.3.2.1.2.C of the Tariff, remains pending before the FERC. As previously reported, the Economic Life Revisions provide that the economic life of an Existing Capacity Resource is calculated as the evaluation period in which the net present value of the resource's expected future profit is maximized. The Economic Life Revisions were accepted effective as of August 10, 2018, as requested. In accepting the revisions, the FERC found that "it is just and reasonable to consider as part of the Economic Life calculation that a rational resource, in exercising competitive bidding behavior, would seek to exit the market, or retire, before it starts incurring consecutive losses."[59] The FERC found, contrary to NEPGA's assertions, that the "Economic Life Revisions do not represent a violation of the filed rate doctrine or constitute retroactive ratemaking."[60] Further, while the FERC was "mindful of the importance of not disrupting settled expectations

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[55] *ISO New England Inc.*, 165 FERC ¶ 61,202 (Dec. 3, 2018), *reh'g requested* ("*Fuel Security Retention Proposal Order*"). In accepting the ISO-NE Proposal, the FERC, among other things: (i) found ISO-NE's trigger and assumptions for the fuel security reliability review for retention of resources be reasonable, but required ISO-NE at the end of each winter to "to submit an informational filing comparing the study assumptions and triggers from the modeling analysis to actual conditions experienced in the winter of 2018/19; (ii) found cost allocation on a regional basis to Real-Time Load Obligation just and reasonable and consistent with precedent regarding the past Winter Reliability Programs; (iii) found that entering retained resources into the FCAs as price takers would be just and reasonable to ensure that they clear and are counted towards resource adequacy so that customers do not pay twice for the resource; and (Iv) found that it was appropriate to include FCAs 13, 14 and 15 in the term. The FERC agreed that it is necessary to implement a longer-term market solution as soon as possible, and required ISO-NE to file its longer-term market solution no later than June 1, 2019. The FERC declined to provide guidance on what the long-term solution(s) should be.

[56] As previously reported, ISO-NE filed, in response to the *Mystic Waiver Order*, "interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns". ISO-NE proposed three sets of provisions to expand its authority on a short-term basis to enter into out-of-market arrangements in order to provide greater assurance of fuel security during winter months in New England (collectively, the "Fuel Security Retention Proposal"). ISO-NE stated that the interim provisions would sunset after FCA15, with a longer-term market solution to be filed by July 1, 2019, as directed in the *Mystic Waiver Order*. In addition, the ISO-NE transmittal letter described (i) the generally-applicable fuel security reliability review standard that will be used to determine whether a retiring generating resource is needed for fuel security reliability reasons; (ii) the proposed cost allocation methodology (Real-Time Load Obligation, though ISO-NE indicated an ability to implement NEPOOL's alternative allocation methodology if determined appropriate by the FERC); and (iii) the proposed treatment in the FCA of a retiring generator needed for fuel security reasons that elects to remain in service. The ISO-NE Fuel Security Changes were considered but not supported by the Participants Committee at its August 24, 2018 meeting. There was, however, super-majority support for (1) the Appendix L Proposal with some important adjustments to make that proposal more responsive to the FERC's guidance in the Mystic Waiver Order and other FERC precedent, and (2) the PP-10 Revisions, also with important adjustments (together, the "NEPOOL Alternative").

[57] "PIOs" for purposes of this proceeding are Sierra Club, NRDC, Sustainable FERC Project, and Acadia Center.

[58] *ISO New England Inc. and New England Power Pool Participants Comm.*, 165 FERC ¶ 61,088 (Nov. 9, 2018) ("*Economic Life Determination Revisions Order*").

[59] *Economic Life Determination Revisions Order* at P 23.

[60] *Id.* at P 24.

based on existing market rules," the FERC concluded "that under these specific facts, the benefits of the proposed Economic Life Revisions outweigh potential disruptions to market participants' settled expectations and harm caused by reliance on the existing FCM rules."[61] On December 10, 2018, NEPGA requested rehearing of the *Economic Life Determination Revisions Order*. On January 8, 2019, the FERC issued a tolling order affording it additional time to consider NEPGA's request for rehearing, which remains pending. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509; EL18-182)**

On July 2, 2018, the FERC issued an order[62] that (i) denied ISO-NE's request for waiver of certain Tariff provisions that would have permitted ISO-NE to retain Mystic 8 & 9 for fuel security purposes (ER18-1509); and (ii) instituted an FPA Section 206 proceeding (EL18-182) (having preliminarily found that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022). The *Mystic Waiver Order* required ISO-NE, on or before August 31, 2018 to either: (a) submit interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement (COS Agreement) to address demonstrated fuel security concerns (and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns "Chapter 3 Proposal"); or (b) show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both of Tariff revisions filings is not necessary.

Addressing the waiver element, the FERC found the waiver request "an inappropriate vehicle for allowing Mystic 8 and 9 to submit a [COS Agreement] in response to the identified fuel security need" and further that the request "would not only suspend tariff provisions but also alter the existing conditions upon which a market participant could enter into a [COS Agreement] (for a transmission constraint that impacts reliability) and allow for an entirely new basis (for fuel security concerns that impact reliability) to enter into such an agreement." The FERC concluded that "[s]uch new processes may not be effectuated by a waiver of the ISO-NE Tariff; they must be filed as proposed tariff provisions under FPA section 205(d)."[63] Even if it were inclined to apply its waiver criteria, the FERC stated that it would still have denied the waiver request as "not sufficiently limited in scope."[64]

Although it denied the waiver request, the FERC was persuaded that the record supported "the conclusion that, due largely to fuel security concerns, the retirement of Mystic 8 and 9 may cause ISO-NE to violate NERC reliability criteria." Finding ISO-NE's methodology and assumptions in the Operational Fuel-Security Analysis ("OFSA") and Mystic Retirement Studies reasonable, the FERC directed the filing of both interim and permanent Tariff revisions to address fuel security concerns (or a filing showing why such revisions are not necessary).[65] The FERC directed ISO-NE to consider the possibility that a resource owner may need to decide, prior to receiving approval of a COS Agreement, whether to unconditionally retire, and provided examples of how to address that possibility.[66] The FERC also directed ISO-NE include with any proposed Tariff revisions a mechanism that addresses how cost-of-service-retained resources would be treated in the FCM[67] and an *ex ante* cost allocation proposal that appropriately identifies beneficiaries and adheres to FERC cost causation precedent.[68]

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[61] *Id.* at P 27.

[62] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

[63] *Id.* at P 47.

[64] *Id.* at P 48.

[65] *Id.* at P 55.

[66] *Id.* at PP 56-57.

[67] *Id.* at P 57.

[68] *Id.* at P 58.

Requests for Rehearing and or Clarification. The following requests for rehearing and or clarification of the *Mystic Waiver Order* remain pending before the FERC:

- ***NEPGA*** (requesting that the FERC grant clarification that it directed, or on rehearing direct, ISO-NE to adopt a mechanism that prohibits the re-pricing of Fuel Security Resources in the FCA at $0/kW-mo. or at any other uncompetitive offer price);
- ***Connecticut Parties***[69] (requesting that the FERC clarify that (i) the discussion in the *Mystic Waiver Order* of pricing treatment in the FCM for fuel security reliability resources is not a final determination nor is it intended to establish FERC policy; (ii) the FERC did not intend to prejudge whether entering those resources in the FCM as price takers would be just and reasonable; and (iii) that ISO-NE may confirm its submitted position that price taking treatment for these resources would, in fact, be a just and reasonable outcome. Failing such clarification, Connecticut Parties request rehearing, asserting that the record fails to support a determination that resources retained for reliability to address fuel security concerns must be entered into the FCM at a price greater than zero);
- ***ENECOS*** (asserting that the *Mystic Waiver Order* (i) misplaces reliance on ISO-NE "assertions concerning 'fuel security,' which do not in fact establish a basis in evidence or logic for initiating" a Section 206(a) proceeding; (ii) impermissibly relies on extra-record material that the FERC did not actually review and that intervenors were afforded no meaningful opportunity to challenge; and (iii) speculation concerning potential future modifications to the FCM bidding rules as to retiring generation retained for fuel security misunderstands the problem it seeks to address, and prejudices the already truncated opportunities for stakeholder input in this proceeding), ENECOS suggest that the FERC should grant rehearing, vacate its show cause directive, strike its dictum concerning potential treatment of FCM bidding for retiring generation retained for "fuel security," and direct ISO-NE to proceed either in accordance with its Tariff or under FPA Section 205 to address, with appropriate evidentiary support, whatever concerns it believes to exist concerning "fuel security");
- ***MA AG*** (asserting that the decision to institute a Section 206 proceeding was insufficiently supported by sole reliance on highly contested OFSA and Mystic Retirement Studies; and the FERC should reconsider the timeline for the permanent tariff solution and set the deadline for implementation no later than February 2020);
- ***MPUC*** (challenging the Order's (i) adoption of ISO-NE's methodology and assumptions in the OFSA and Mystic Retirement Studies without undertaking any independent analysis; (ii) failure to address arguments and analysis challenging assumptions in the OFSA and Mystic Retirement Studies; (iii) failure to address the MPUC argument that the Mystic Retirement Studies adopted a completely new standard for determining a reliability problem three years in advance; (iv) unreasonably discounting of the ability of Pay-for-Performance to provide sufficient incentives to Market Participants to ensure their performance under stressed system conditions; and (v) failure to direct ISO-NE to undertake a Transmission Security Analysis consistent with the provisions in the Tariff);
- ***New England EDCs***[70] (requesting clarification that (i) the central purpose of ISO-NE's July 1, 2019 filing is to assure that New England adds needed new infrastructure to address the fuel supply shortfalls and associated threats to electric reliability that ISO-NE identified in its OFSA and (ii) that, in developing the July 1, 2019 filing, ISO-NE is to evaluate Tariff revisions (such as those the EDCs described in their request), through which ISO-NE customers would pay for the costs of natural gas pipeline capacity additions via rates under the ISO-NE Tariff);

[69] "Connecticut Parties" are the Conn. Pub. Utils. Regulatory Authority ("CT PURA") and the Conn. Dept. of Energy and Environ. Protection ("CT DEEP").

[70] The "EDCs" are the National Grid companies (Mass. Elec. Co., Nantucket Elec. Co., and Narragansett Elec. Co.) and Eversource Energy Service Co. (on behalf of its electric distribution companies – CL&P, NSTAR and PSNH).

- ***PIOs***[71] (asserting that (i) the FERC failed to respond to or provide a reasoned explanation for rejecting the arguments submitted by numerous parties that key assumptions underlying and the results of the ISO-NE analyses were flawed; and (ii) the FERC's determination that ISO-NE's analyses were reasonable is not supported by substantial evidence in the record); and
- ***AWEA/NGSA*** (asserting that the FERC erred (i) in finding that ISO-NE's OFSA and subsequent impact analysis of fuel security was reasonable without further examination and (ii) in its preliminary finding that a short-term out-of-market solution to keep Mystic 8 & 9 in operation is needed to address fuel security issues).

On August 13, 2018, CT Parties opposed the NEPGA motion for clarification. On August 14, NEPOOL filed a limited response to Indicated New England EDCs, requesting that the FERC "reject the relief sought in [their motion] to the extent that relief would bypass or predetermine the outcome of the stakeholder process, without prejudice to [them] refiling their proposal, if appropriate, following its full consideration in the stakeholder process." Answers to the Indicated New England EDCs were also filed by the MA AG, NEPGA, NextEra, and CLF/NRDC/Sierra Club/Sustainable FERC Project. On August 29, the Indicated New England EDCs answered the August 14/16 answers. On August 27, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CASPR (ER18-619)**

Rehearing of the FERC's order accepting and ISO-NE's Competitive Auctions with Sponsored Policy Resources ("CASPR") revisions,[72] summarized in more detail in prior Reports, remains pending. Those requests were filed by (i) ***NextEra/NRG*** *(which* challenged the RTR Exemption Phase Out); (ii) ***ENECOS***[73] (challenging the FERC's findings with respect to the definition of Sponsored Policy Resource and the allocation of CASPR side payment costs to municipal utilities); (iii) ***Clean Energy Advocates***[74] (which challenged the CASPR construct in its entirety, asserting that state-sponsored resources should not be subject to the MOPR); and (iv) ***Public Citizen*** (which also challenged the CASPR construct in its entirety and the *CASPR Order*'s failure to define "investor confidence"). On April 24, ISO-NE answered Clean Energy Advocates' answer. On May 7, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

Rehearing remains pending of the FERC's October 6, 2017 order accepting updated FCM CONE, Net CONE and ORTP values.[75] In accepting the changes, the FERC disagreed with the challenges to ISO-NE's choice of reference technology (gas-fired simple cycle combustion-turbine) and on-shore wind capacity factor (32%). The changes were accepted effective as of March 15, 2017, as requested. On November 6, NEPGA requested rehearing of the *CONE/ORTP Updates Order*. On December 4, 2017, the FERC issued a tolling order providing

[71] "PIOs" are the Sierra Club, Natural Resources Defense Council ("NRDC"), and Sustainable FERC Project.

[72] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*").

[73] The Eastern New England Consumer-Owned Systems ("ENECOS") are: Braintree Electric Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Littleton Electric Light & Water Department, Middleton Electric Light Department, Middleborough Gas & Electric Department, Norwood Light & Broadband Department, Pascoag (Rhode Island) Utility District, Rowley Municipal Lighting Plant, Taunton Municipal Lighting Plant, and Wallingford (Connecticut) Department of Public Utilities. Wellesley Municipal Light Plant, which intervened in this proceeding as one of the ENECOS, did not join in the ENECOS' request for rehearing.

[74] "Clean Energy Advocates" are, collectively the NRDC, Sierra Club, Sustainable FERC Project, CLF, and RENEW Northeast, Inc.

[75] *ISO New England Inc.*, 161 FERC ¶ 61, 035 (Oct. 6, 2017)("*CONE/ORTP Updates Order*"), *reh'g requested*.

it additional time to consider NEPGA's request for rehearing of the *CONE/ORTP Updates Order*, which remains pending. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

As previously reported, on December 28, 2018, the DC Circuit Court of Appeals, following oral argument in Exelon's appeal of the FERC's Resource Retirement Reforms Orders,[76] directed the FERC to clarify "what [the FERC] really means" in the context of its orders on the FCM Resource Retirement Reforms.[77] Specifically, the Court directed the FERC to issue an order, not later than February 1, 2019, clarifying its position on the proper reading, process and legal standards associated with the Tariff changes that have ISO-NE file mitigated retirement bids for FERC review under § 205 of the FPA. In its appeal of those orders, Exelon continued its objection to the replacement of its De-List Bid for an IMM-mitigated De-List Bid in that FERC review under FPA § 205, which Exelon asserted "trample[s] on its § 205 rights".

Post-Remand Comments. On January 14, 2019, ISO-NE submitted a filing urging the FERC, in response to the remand decision, to affirm the holdings of its *FCM Resource Retirement Reforms Orders* that (i) suppliers' FCA Retirement Bids are inputs to rates, not "rates" under FPA § 205 and therefore are not entitled to FERC assessment under § 205's "just and reasonable" standard (proposing instead that ISO-NE's filing of Retirement Bids be treated as an informational filing), and (ii) ISO-NE's mitigation of Retirement Bids does not usurp generators' § 205 rights. On January 18, NEPOOL and Exelon submitted limited responses to ISO-NE's January 14 filing.[78] ***NEPOOL*** requested that the FERC reject ISO-NE's January 14 suggestion that its Section 205 filing be deemed an informational filing, and to the extent ISO-NE seeks to revise Section III.13.8.1(a), direct ISO-NE to seek such changes through the NEPOOL stakeholder process. ***Exelon***'s comments suggested the FERC should revise its Orders to be consistent with the position taken by FERC Solicitor's office in oral arguments before the DC Circuit, which indicated that the FERC's Orders intended that a supplier's retirement bid would be accepted so long as it is in the zone of reasonableness—even if the Market Monitor's alternative proxy bid for that supplier is also in the zone of reasonableness and, to the extent there is a disagreement between a supplier and the Market Monitor, the supplier need only demonstrate that its own bid is just and reasonable and if so demonstrated then its bid is to be used in the auction. An order is expected to be issued on February 1. On January 29, ***the IMM*** submitted comments that concurred with ISO-NE's Jan 14 comments, indicating that it was writing separately to emphasize the long-standing practice, as agreed to in the original Settlement Agreement establishing the [FCA], and the practical importance of having only the IMM-reviewed bids, and not the suppliers' own bids, as inputs into ISO's [FCA] in order to mitigate the potential exercise of market power by participants and to ensure that the ultimate clearing prices are just and reasonable."

Order on Remand.[79] On January 29, in response to the DC Circuit Court's opinion and remand, the FERC issued the *FCM Resource Retirement Reforms Remand Order* which (i) revised PP 18, 19 and 25 of its October 30, 2017 order, and (ii) stated that the FERC interprets the relevant Tariff language to mean that (a) ISO-NE's section 205 filing must include the relevant information and justification submitted by both the capacity supplier and the IMM; and (b) the FERC will consider the entirety of the record and accept the capacity supplier's bid so long as the capacity supplier persuades the FERC that its bid is just and reasonable, despite contrary assertions by the IMM.[80] The ERC's Order on Remand is pending before the DC Circuit.

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[76] *ISO New England Inc.,* 155 FERC ¶ 61,029 (Apr. 12, 2016) ("*Resource Retirement Reforms Order*"), *reh'g and clarif. denied*, 161 FERC ¶ 61,115 (Oct. 30, 2017) ("*FCM Resource Retirement Reforms Orders*").

[77] *Exelon Corporation v. FERC*, 911 F.3d 1236 (D.C. Cir., Dec. 28, 2018) (Case No. 17-1275).

[78] The Jan. 14 filing was assigned a Jan. 15 filing date as a result of the FERC's Jan. 14 closure due to adverse weather conditions.

[79] *ISO New England Inc.*, 166 FERC ¶ 61,060 (Jan. 29, 2019) ("*FCM Resource Retirement Reforms Remand Order*").

[80] *Id.* at P 8.

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

Still pending before the FERC is ISO-NE's compliance filing in response to the FERC's August 8, 2016 remand order.[81] In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed ISO-NE 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 ISO-NE'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.[82] ISO-NE submitted its compliance filing on January 23, 2017, reporting the IMM's conclusion that "the auction was not structurally competitive and a 'small 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, ISO-NE recommended that "there is insufficient demonstration of market power to warrant modification of program." In February 13 comments, both TransCanada and the MA AG protested ISO-NE'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, ISO-NE answered the TransCanada and MA AG protests. On March 10, 2017, TransCanada answered ISO-NE's February 28 answer. This matter remains 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

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-NEP: BIPCO LSA Amendments (ER19-707)**

On February 22, the FERC conditionally accepted clarifying and ministerial amendments to National Grid's local service agreement ("LSA") under Schedule 21-NEP with Block Island Power Company ("BIPCO") and ISO-NE.[83] The changes included: (i) clarifications that BIPCO is responsible for telecommunications circuits; (ii) updates to the list of interconnection facilities and associated equipment; (iii) specification that BIPCO has elected to pay for the interconnection facilities via a Direct Assignment Facilities charge with no Contribution in Aid of Construction; (iv) identification of the transformer nameplate rating; (v) clarification as to the point of change in ownership (at the interconnection point); and (vi) other updates and corrections. The changes were accepted effective as of January 1, 2019, as requested. Subject to the compliance filing to correct in eTariff the title of the Agreement, and

[81] *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).

[82] *2013/14 Winter Reliability Program Remand Order* at P 17.

[83] *New England Power Co. and ISO New England Inc.*, Docket No. ER19-707 (Feb. 22, 2019). The FERC conditioned its acceptance on a filing on or before Mar. 25 to correct the title of the Agreement in eTariff from TSA-NEP-82 to TSA-NEP-83 (as it is designated under the ISO-Tariff).

absent any challenges, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-EM: Stored Solar J&WE LSA Extension (ER19-706)**

On February 22, the FERC accepted an amended LSA ("Second Stored Solar LSA") by and among Emera Maine, Stored Solar J&WE, and ISO-NE for Local Non-Firm Point-to-Point Transmission Service under Schedule 21-EM of the ISO-NE OATT (the "Stored Solar LSA").[84] The Second Stored Solar LSA extends the discounted service rate accepted in February 2018 in Docket No. ER18-387. The term of the Second Stored Solar LSA is January 11, 2019 to December 31, 2020. The Second Stored Solar LSA was accepted effective as of January 1, 2019, as requested. Unless the February 22 order is challenged, this proceeding will be concluded. If there are any questions on this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434-001 *et al.*)**

The MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs Order,*[85] remains pending before the FERC. As previously reported, under the Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P-EM of the BHD OATT and $260,000 under the MPD OATT. Comments on the MPS Merger Cost Recovery Settlement were due on or before May 29, 2018; none were filed. On June 11, Settlement Judge Dring[86] certified the MPS Merger Cost Recovery Settlement to the FERC.[87] The MPS Merger Cost Recovery Settlement is pending before the FERC. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

VII. NEPOOL Agreement/Participants Agreement Amendments

- **132nd Agreement (Press Membership Provisions) (ER18-2208)**

On January 30, 2019, the FERC rejected the changes to the NEPOOL Agreement that would have precluded press reporters from becoming NEPOOL End User Participants or representatives of NEPOOL Participants.[88] In rejecting the changes, the FERC concluded that NEPOOL had not supported that "barring

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[84] *ISO New England Inc. and Emera Maine*, Docket No. ER19-706 (Feb. 22, 2019).

[85] *Emera Maine and BHE Holdings*, 155 FERC ¶ 61,230 (June 2, 2016) ("*MPS Merger-Related Costs Order*"). In the *MPS Merger-Related Costs Order*, the FERC accepted, but established hearing and settlement judge procedures for, filings by Emera Maine seeking authorization to recover certain merger-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"). 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 an 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. The *MPS Merger-Related Costs Order* set resolution of the issues of material fact for hearing and settlement judge procedures, consolidating the separate compliance filing dockets.

[86] ALJ John Dring was the settlement judge for these proceedings. There were five settlement conferences: three in 2016 and two in 2017. In his most recent May 24, 2018 status report, Judge Dring indicated that the parties reached a settlement in principle, had filed a joint offer of settlement on May 8 ("MPS Merger Cost Recovery Settlement"), and recommended that settlement judge procedures be continued. The Settlement remains pending before the FERC and settlement judge procedures, for now, have not been terminated.

[87] *Emera Maine and BHE Holdings*, 163 FERC ¶ 63,018 (June 11, 2018).

[88] *New England Power Pool Participants Comm.*, 166 FERC ¶61,062 (Jan. 29, 2019) ("*Press Membership Provisions Order*"). The rejected changes were identified in the One Hundred Thirty-Second Agreement Amending New England Power Pool Agreement ("132nd Agreement"), which was approved in balloting following the 2018 Summer Meeting.

members of the press from exercising the privileges unique to NEPOOL membership—i.e. attending, speaking, and voting at NEPOOL meetings—will meaningfully advance its aim for candid deliberation in light of" NEPOOL's Bylaws and Standard Conditions Waivers & Reminders "currently in place—which this order does not affect—[that] already prohibit reporting on deliberations or attributing statements to other NEPOOL members."[89] The FERC further indicated that the *Press Membership Provisions Order* only addressed NEPOOL's proposed changes to the NEPOOL Agreement, and not the pending RTO Insider Complaint (*see* EL18-196 above) that it will address in a separate order. On February 28, 2019, NEPOOL requested clarification, or in the alternative rehearing, of the *Press Membership Provisions Order* (the "Request"). In the Request, NEPOOL asked the FERC, particularly in light of issues that remain pending in EL18-196, to clarify the extent to which the FERC sought to assert jurisdiction over the NEPOOL Agreement, or in the alternative, grant rehearing of the *Press Membership Provisions Order* on the grounds that it reflects an impermissible exercise of the FERC's jurisdiction. On March 4, Public Citizen submitted comments requesting that the FERC require NEPOOL to describe the notice and approval of its members sought in connection with the Request, insinuating that the request was unauthorized. There are no plans to respond to Public Citizen's unsubstantiated and uninformed comments. NEPOOL's Request is pending, with FERC action required on or before April 1, 2019, or the request will be deemed denied by operation of law. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com), Dave Doot (860-275-0102; dtdoot@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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 ISO-NE in compliance with *Opinions No. 531-A*[90] *and 531-B*[91] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***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
- VTransco

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

- **Capital Projects Report - 2018 Q4 (ER19-1052)**

On February 14, 2019, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2018 (the "Report"). ISO-NE is required to file the Report under Section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) Energy Market Offer Caps (Order 831) ($2.74 million); (ii) CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements ($2.67 million); (iii) IMM Data Analysis Phase II ($2.23 million); (iv) Change Request System

[89] *Id.* at P 50.

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

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

Replacement ($746,400); and (v) FCM Delayed Commercial Resource Treatment ($329,500). Projects with a significant changes were (i) Energy Management Platform 3.2 Upgrade Part I (2018 Budget decrease of $1.25 million, with a reallocation of $0.5 million to 2019, for an overall project decrease of $745,400 and a total project cost of $4,405,500); (ii) Energy Storage Device Phase I (2018 and overall budget decrease of $623,600, for a total project cost of $2,994,400); (iii) Enterprise Application Integration Replacement (2018 and overall budget decrease of $435,100 for a total project cost of $1.79 million); (iv) Balance of Planning Period Financial Assurance (2018 and overall budget decrease of $390,600 for a total project cost of $0.57 million); and (v) Energy Management Platform 3.2 Upgrade Part II (2019 and overall budget decrease of $1 million for a total project cost of $2 million). Comments on this filing were due on or before March 6. NEPOOL filed comments on February 19 supporting the Q4 Report. National Grid filed a doc-less intervention. 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).

- **Transmission Projects Annual Informational Filing (ER13-193)**

On January 30, 2019, ISO-NE filed, as required under Section 4.1(j)(iii) of the OATT, its annual informational filing of projects on the RSP project list that had a year of need three years or less from the completion of the Needs Assessment. The list of prior year designations is maintained on the ISO-NE website at https://www.iso-ne.com/static-assets/documents/2019/01/2018_prior_year_projects_section_4j_iii.pdf. This filing will not be noticed for public comment by the FERC.

IX. Membership Filings

- **March 2019 Membership Filing (ER19-1146)**

On February 28, 2019, NEPOOL requested that the FERC accept (i) the memberships of MidAmerican Energy Services, LLC (Supplier Sector); and NDC Partners (Supplier Sector); and (ii) termination of the Participant status of BlueRock Energy Inc.; OhmConnect, Inc.; and Lotus Danbury LMS100 Two, LLC. Comments on this filing are due on or before March 21.

- **February 2019 Membership Filing (ER19-936)**

On January 31, 2019, as corrected on February 8, NEPOOL requested that the FERC accept (i) the memberships of Manchester Street, Inc. [Related Person of Marco DM Holdings (Generation Sector)]; and McCallum Enterprises 1 LP (AR Sector Large RG Group Seat); (ii) termination of the Participant status of Clear Choice Energy; Covanta Projects of Wallingford; Fairchild Energy and Fairchild Semiconductor Corporation; Noble Environmental Power; StateWise Energy Massachusetts; and Swift River Trading Company; and (iii) the name change of Tomorrow Energy Corp (f/k/a Sperian Energy Corp). This filing is pending before the FERC.

- **January 2019 Membership Filing (ER19-748)**

On February 22, the FERC accepted (i) the memberships of ADG Group (Supplier Sector) and Dominion Bridgeport Fuel Cell LLC [Related Person to Dominion Energy Marketing (Generation Sector)]; and (ii) the termination of the Participant status of: Solea Energy (Supplier Sector), New England Confectionery Company and EmpireCo LP (each, Generation Sector Group Seat).[92] Unless the February 22 order is challenged, this proceeding will be concluded.

- **Suspension Notices (not docketed)**

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

[92] *New England Power Pool Participants Comm.*, Docket No. ER19-748 (Feb. 22, 2019).

Date of Suspension/ FERC Notice	*Participant Name*	*Date Reinstated*
Feb 12/13	BBPC LLC d//b/a Great Eastern Energy	--
Feb 13/15	OhmConnect, Inc.	--

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 Standard: TPL-001-5 (RM19-10)**

On December 7, 2018, NERC filed for approval a revised Reliability Standard -- TPL-001-5 (Transmission System Planning Performance Requirements), and associated implementation plan, VRFs and VSLs (together, the "TPL-001 Changes"). NERC stated that the TPL-001 Changes improve upon the currently effective standard by enhancing Requirements for the study of Protection System single points of failure. Additionally, the TLP-001 Changes address two FERC directives from Order 786: (1) the TPL-001 Changes provide for a more complete consideration of factors for selecting which known outages will be included in Near-Term Transmission Planning Horizon studies, addressing the FERC's concern that the exclusion of known outages of less than six months in TPL-001-4 could result in outages of significant facilities not being studied; and (2) the TPL-001 Changes modify Requirements for Stability analysis to require an entity to assess the impact of the possible unavailability of long lead time equipment, consistent with the entity's spare equipment strategy. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **New Reliability Standard: CIP-012-1 (RM18-20)**

On September 18, 2018, NERC filed for approval a new Reliability Standard -- CIP-012-1 (Cyber Security – Communications between Control Centers), and associated Glossary definitions, implementation plan, VRFs and VSLs (together, the "Control Center Cyber Security Communication Changes"). NERC stated that the changes modify the Critical Infrastructure Protection ("CIP") Reliability Standards to require Responsible Entities to implement controls to protect communication links and sensitive Bulk Electric System ("BES") data communicated between BES Control Centers. CIP-012-1 requires Responsible Entities to develop a plan to mitigate the risks posed by unauthorized modification (integrity) and unauthorized disclosure (confidentiality) of Real-time Assessment and Real-time monitoring data. The plan must include the following three components: (1) identification of security protection used to meet the security objective; (2) identification of where the Responsible Entity applied the security protection; and (3) identification of the responsibilities of each Responsible Entity for applying the security protection. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

XI. Misc. - of Regional Interest

- **203 Application: FirstLight Restructuring (EC19-44)**

On January 2, 2019, FirstLight Hydro Generating Company (FirstLight Hydro) and the FirstLight Project Companies[93] requested FERC authorization for the disposition of jurisdictional facilities that will result from a proposed corporate restructuring involving the transfer of 100% of FirstLight Hydro's electric generating facilities and related assets ("Facilities") to the FirstLight Project Companies ("FirstLight Restructuring"). Following the

[93] The "FirstLight Project Companies" are FirstLight CT Housatonic, FirstLight CT Hydro, FirstLight MA Hydro, and Northfield Mountain.

FirstLight Restructuring, which the parties expect to be completed on or about March 31, 2019, the Facilities will be directly owned by the FirstLight Project Companies. Comments on this application were due on or before January 23, 2019; none were filed. This matter is pending before the FERC.

- **203 Application: Emera / Revere Power (EC19-35)**

On December 14, 2018, Bridgeport Energy LLC ("Bridgeport"), Rumford Power Inc. ("Rumford"), Tiverton Power LLC ("Tiverton", and together with Bridgeport and Rumford, the "Project Companies"), and Revere Power, LLC ("Buyer" or "Revere Power"), requested FERC authorization for a proposed transaction that will result in the transfer of 100% of the indirect ownership interests in the Project Companies from Emera US Holdings Inc. ("Seller") to Revere Power. Following consummation of the transaction, the Project Companies will be wholly-owned, indirect subsidiaries of Revere, and Related Persons to Nautilus Power (Generation Sector) and its affiliates. Comments on this application were due on or before February 12, 2019; none were filed. Revere Power has since applied and has been conditionally approved to become a NEPOOL Participant effective April 1, 2019.

- **203 Application: Dominion Bridgeport Fuel Cell, LLC (EC19-22)**

On December 20, 2018, the FERC authorized the acquisition of Dominion Bridgeport Fuel Cell, LLC, owner of a 15 MW fuel cell power plant in Bridgeport, CT and a new member as of January 1, 2019 (*see* ER19-784 in Section IX above) by FuelCell Energy Finance, LLC ("Fuel Cell"). Fuel Cell is a Related Person of DFC ERG CT, a member of the AR Sector.[94] Among other conditions, the December 20 order required notice within 10 days of the acquisition's consummation, which has not yet been filed.

- **203 Application: ECP/Fawkes Holdings (Wheelabrator) (EC19-14)**

On December 6, 2018, the FERC authorized the acquisition by Fawkes Holdings, LLC (a Related Person to Macquarie Energy) of all of the issued and outstanding shares of common stock of Wheelabrator Technologies Inc. ("Wheelabrator") currently held by the Energy Capital Partners companies ("ECP").[95] On February 15, Fawkes Holdings advised the FERC that the transaction was consummated on February 12. Wheelabrator is now a Related Person to Macquarie and no longer a Calpine Related Person. Going forward, Macquarie and Wheelabrator will vote together in the Renewable Generator Sub-Sector of the AR Sector. Reporting on this matter has concluded.

- **203 Application: Linde Energy Services (EC18-132)**

On September 14, 2018, the FERC authorized a transaction pursuant to which Linde AG will divest the parent of Linde Energy Services ("Linde"), Linde North America, Inc. to an unaffiliated third-party, now known as "Messer Industries GmbH" (the divestiture was expected to be a condition to FTC approval of the Linde AG/Praxair Inc. merger).[96] Among other conditions, the order required notice within 10 days of the acquisition's consummation, which has not yet been filed.

- **203 Application: Wheelabrator Technologies (EC18-130)**

On September 19, 2018, the FERC authorized the disposition of up to 49% of the indirect ownership interests in Wheelabrator Technologies ("WTI") indirectly held public utility subsidiaries resulting from an initial public offering of up to approximately 49% of WTI's common stock. Among other conditions, the order required notice within 10 days of the acquisition's consummation, which has not yet been filed.

- **New England Ratepayers Association Complaint (EL19-10)**

As previously reported, the New England Ratepayers Association ("NERA") filed a complaint on November 2, 2018 seeking declaratory order finding that (i) New Hampshire Senate Bill 365 ("SB 365"),[97]

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[94] *Dominion Bridgeport Fuel Cell, LLC*, Docket No. EC19-22 (Dec. 20, 2018).

[95] *Wheelabrator Technologies Inc.,* 165 FERC ¶ 62,141 (Dec. 6, 2018).

[96] *Linde Energy Services, Inc.*, 164 FERC ¶62,147 (Sep. 14, 2018).

[97] SB 365, 2018 N.H. Laws Ch. 379, An Act relative to the use of renewable generation to provide fuel diversity, codified at N.H. Rev. Stat. Chapter 362-H.

which mandates a purchase price for wholesale sales by seven generators operating in NH, (i) is preempted by the Federal Power Act; (ii) SB 365 violates Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") (because SB 365 does not satisfy the requirement under PURPA and the FERC's implementing regulations[98] that rates set by the states for wholesale sales by QFs may not exceed the purchasing utilities' avoided costs; and (iii) NH is pre-empted from ordering purchases that are contrary to the FERC's order terminating PSNH's mandatory purchase obligation on a service territory-wide basis for QFs with a net capacity in excess of 20 MW. NERA asked the FERC to issue a ruling by February 1, 2019 (the date NH customers may first bear the costs of SB 365). Doc-less interventions were filed by Calpine, Eversource, National Grid, NRG, and the DC Office of People's Counsel. Comments supporting the Petition were filed by: NH OCA, the NH Generator Group,[99] EPSA, and a group of NH customers; a Protest was filed by the State of New Hampshire.[100] The New England Small Hydro Coalition filed comments that, while not taking a position on NERA's preemption argument, disagreed with the premise that underlies NERA's argument as to what constitutes an avoided cost rate in New Hampshire. NH OCA and the NH Generator Group amended/supplemented their December 3 comments. A group of NH Legislators that supported SB 365 filed comments on December 17 urging the FERC to deny the Petition. On December 20, NERA answered the protests and comments.

On January 4, 2019, the NH AG answered NERA's December 20 answer, asserting that NERA's Petition is premature, the evidentiary record before the FERC is inadequate to support the declaratory order sought, and the FERC should dismiss the Petition to allow time for the NHPUC to rule on pending issues before the NHPUC related to the implementation of SB 365. The New Hampshire Generator Group similarly answered NERA's December 20 answer, also asserting that the NERA motion misstated the relevant facts and law. On January 7, PSNH moved to lodge its December 27, 2018 pleading in NHPUC Docket No. DE 18-002 (which objected to the request that the NHPUC determine certain IPP PPAs conform with SB 365/RSA Chap 362-H and noted uncertainties to be resolved in connection with any purchases). On January 22, 2019, the NH Generator Group answered the motion to lodge, providing additional material and context. 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).

- **PJM MOPR-Related Proceedings (EL18-178; ER18-1314; EL16-49)**

On June 29, 2018, the FERC issued an order ("*PJM Order*")[101] regarding out-of-market support affecting the PJM capacity market.[102] Opening with the statement that "the integrity and effectiveness of the capacity market administered by [PJM] have become untenably threatened by out-of-market payments

[98] 18 C.F.R. §§ 292.304(a); 292.101(b)(6) (2018).

[99] The NH Generator Group is comprised of the following entities: Bridgewater Power Company, L.P., DG Whitefield LLC, Pinetree Power – Tamworth LLC, Pinetree Power, Inc., Springfield Power, LLC, and Wheelabrator Concord Company, L.P.

[100] Although the State of New Hampshire requested and was eventually granted a two-week extension of time to file its comments, that extension was noticed on December 4, 2018, after the initial comment date and the submission of NH's comments.

[101] *Calpine Corp. et al.*, 163 FERC ¶ 61,236 (June 29, 2018), *clarif. and/or reh'g requested*.

[102] The *PJM Order* addressed two separate, but related proceedings. The first, EL16-49, was initiated by a complaint originally filed by Calpine, joined by additional generation entities ("Calpine Complaint") on March 21, 2016, and later amended on January 9, 2017. The Calpine Complaint argued that PJM's MOPR was unjust and unreasonable because it did not address the impact of existing resources receiving out-of-market payments on the capacity market, and proposed interim tariff revisions that would extend the MOPR to a limited set of existing resources. The Calpine Complaint also requested the FERC to direct PJM to conduct a stakeholder process to develop and submit a long-term solution. The second proceeding was PJM's filing of its proposed revisions to its Tariff, pursuant to section 205 of the FPA in ER18-1314 ("PJM Filing"). The PJM Filing consisted of two alternate proposals designed to address the price impacts of state out-of-market support for certain resources. The first approach, preferred by PJM but not supported by its stakeholders, consisted of a two-stage annual auction, with capacity commitments first determined in stage one of the auction and the clearing price set separately in stage two ("Capacity Repricing"). The second alternative approach, proposed in the event that the FERC determined that Capacity Repricing was unjust and unreasonable, would have revised PJM's MOPR to mitigate capacity offers from both new and existing resources, subject to certain proposed exemptions ("MOPR-Ex").

provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources," the *PJM Order* determined that the PJM Tariff is currently unjust and unreasonable, rejected PJM's Section 205 Filing, granted in part Calpine's Complaint, and established a paper hearing to resolve the "price-suppressive" effects of out-of-market support for certain resources. Commissioners LaFleur and Glick both dissented, and Commissioner Powelson wrote a separate concurrence.

In the *PJM Order*, the FERC found "that it has become necessary to address the price suppressive impact of resources receiving out-of-market support." The FERC agreed with Calpine and PJM that changes to the PJM Tariff were required, but did not accept the changes proposed in the Calpine Complaint or the PJM Filing, finding that neither had been shown to be just and reasonable, and not unduly discriminatory or preferential. The majority stated that it was unable to determine, based on the record of either proceeding, the just and reasonable rate to replace the rate in PJM's Tariff. The *PJM Order* therefore found the PJM Tariff unjust and unreasonable, granted the Calpine Complaint, in part, and *sua sponte* initiated a new FPA section 206 proceeding (EL18-178), consolidating the record of the two earlier proceedings, and setting for paper hearing the issue of how to address a proposed alternative put forth in the *PJM Order,*[103] which would modify two existing aspects of the PJM Tariff, "or any other proposal that may be presented."

16 requests for clarification and/or rehearing of the *PJM Order* were filed on July 30, 2018. On August 29, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

Paper Hearing; Additional Briefing; PJM's Extended RCO Proposal. Following an August 22 notice of extension of time, interested parties were invited to submit their initial round of testimony, evidence, and/or argument by October 2, 2018. Initial briefs, comments and submissions were filed by over 50 parties. In its October 2 submission, PJM submitted a revised proposal, which includes an expanded MOPR coupled with a "Extended Resource Carve-Out" proposal ("Extended RCO"). The proposed MOPR would apply to all fuel and technology types and to both existing and new resources (a change from the original MOPR, which only applied to new gas-fired units). The Extended RCO would provide a means for states to support particular subsidized generation assets by removing them from certain aspects of the PJM capacity market and not subjecting them to MOPR in PJM's capacity market.

Reply testimony, evidence, and/or argument was due on or before November 6, 2018. Over 60 sets of reply briefs, evidence, etc. were filed. Since that time, a few parties submitted answers and additional comments. On December 6, PJM and Direct Energy/NextEra filed limited answers to reply briefs. In addition, a letter from a group of companies representing competitive new generation built in the PJM region since 2010 ("Generator Letter") urged the FERC to "to consider the broadest ramification of a fundamental change in the regulatory compact and the impact it would have on consumers, investors and even the fundamental American belief that markets drive better outcomes than government."[104] Answers to and comments on PJM's answer were filed by "Clean Energy Industries"[105] and UCS. Responses to the December 6 Generators

[103] The proposed alternative approach would (i) modify PJM's MOPR such that it would apply to new and existing resources that receive out-of-market payments, regardless of resource type, but would include few to no exemptions; and (ii) in order to accommodate state policy decisions and allow resources that receive out-of-market support to remain online, establish an option in PJM's Tariff that would allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time. That option, which is similar in concept to the Fixed Resource Requirement ("FRR") that currently exists in PJM's Tariff, is referred to as the "FRR Alternative." Unlike the existing FRR construct, the FRR Alternative would apply only to resources receiving out-of-market support. Both aspects of the proposed replacement rate, along with a series of questions that need to be addressed, are more fully explained and raised in the *PJM Order*.

[104] Those companies included: Ares Power and Infrastructure Group, Caithness, Calpine, Carroll County and South Field Energy, CPV, J-POWER USA Development Co., Panda Power Funds, and Tenaska Energy.

[105] "Clean Energy Industries" are AWEA, the Solar RTO Coalition, Solar Energy Industries Assoc., Advanced Energy Economy ("AEE"), the American Council on Renewable Energy ("ACORE"), and the Mid-Atlantic Renewable Energy Coalition ("MAREC").

Letter were filed by APPA, ELCON, LPPC, NRECA, and NRDC. On December 28, PSEG submitted supplemental comments. On January 15, PSEG answered PSEG's supplemental comments. These materials, together with all of the initial briefs and reply briefs, are pending before the FERC.

The FERC committed in the *PJM Order* to make every effort to issue an order establishing the just and reasonable replacement rate no later than January 4, 2019 (a date which has since passed). The FERC also established a refund effective date of March 21, 2016, the date of the original Calpine Complaint in EL16-49. For further information on this proceeding, please contact Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Deepwater Wind PURPA Complaint (EL18-171)**

The June 7 complaint filed by Kathryn Leonard, an individual ratepayer and councilwoman for the City of Newport, Rhode Island ("Complainant"), against the RI PUC, National Grid, and Deepwater Wind Block Island ("Deepwater Wind") remains ending before the FERC. The Complaint seeks, among other things, declaratory and injunctive relief barring the continued implementation of the Deepwater Wind Rhode Island PPA and prohibiting the RI PUC from "designating renewable power costs as 'distribution' costs in any way that prevents consumers from the benefits of purchasing power from competitive sources". Following a partially granted request for an extension of time by the RI PUC, answers to and comments on this Complaint were due on or before July 13. Answers were filed by Deepwater Wind, National Grid and the RI PUC. On July 23, 2018, Complainant objected separately to each of the answers. 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).

- **PJM Clean MOPR Complaint (EL18-169)**

This proceeding, which could impact potentially impact New England's markets, remains pending. As previously reported, CPV Power Holdings, L.P. ("CPV"), Calpine Corporation ("Calpine"), and Eastern Generation, LLC ("Eastern Generation") (collectively, "PJM MOPR Complainants") filed a complaint on May 31, 2018 requesting that the FERC protect PJM's Reliability Pricing Model ("RPM") market from below-cost offers for resources receiving out-of-market subsidies by requiring PJM to adopt a "Clean MOPR" (i.e. a MOPR applicable to all subsidized resources and without categorical exemptions like those in PJM's MOPR-Ex proposal). PJM MOPR Complainants state that the Complaint offers the FERC a procedural vehicle to require adoption of the "Clean MOPR" that Complainants opine is not otherwise available in pending FERC proceedings (EL16-49 (PJM MOPR Complaint)[106] and ER18-1314 (PJM's pending MOPR changes)). They assert that the "Clean MOPR" is required to effectively address the impacts of state subsidy programs, and is consistent with the FERC's MOPR principles identified in the *CASPR Order*. Comments on the PJM Clean MOPR Complaint were due on or before June 20. PJM's answer, as well as comments and protests from over 25 parties were filed. Given its potential to impact New England, NEPOOL filed a doc-less motion to intervene. More than 30 other parties also intervened. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Sunita Paknikar (202-218-3904; spaknikar@daypitney.com).

- ***NYISO MOPR Proceeding (EL13-62)***

As in the PJM MOPR Proceeding, NEPOOL filed limited comments requesting that any FERC action or decision be limited narrowly to the facts and circumstances as presented, and that any changes ordered by the FERC not circumscribe the results of NEPOOL's stakeholder process or predetermine the outcome of that process through dicta or a ruling. The NYISO MOPR Proceeding remains pending before the FERC. If you have

[106] The "PJM MOPR Complaint" seeks a FERC order expanding the PJM MOPR in the Base Residual Auction for the 2019/2020 Delivery Year to prevent the artificial suppression of prices in the Reliability Pricing Model ("RPM") market by below-cost offers for existing resources whose continued operation is being subsidized by State-approved out-of-market payments. Complainants in the MOPR Complaint are Calpine, Dynegy, Eastern Generation, Homer City Generation, the NRG Companies, Carroll County Energy, C.P. Crane , the Essential Power PJM Companies, GDF SUEZ Energy Marketing NA, Oregon Clean Energy, and Panda Power Generation Infrastructure Fund.

any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Mystic COS Agreement Amendment No. 1 (ER19-1164)**

On March 1, 2019, Constellation filed (separately from its contemporaneously-submitted compliance filing) and amendment to its COS Agreement to provide "reciprocal early termination rights for ISO-NE and Mystic based on the results of ISO-NE's updated fuel security analysis, to be completed in September of 2019". Comments on this filing are due on or before March 22, 2019. Doc-less interventions have thus far been submitted by MA AG, Verso and the New England Local Distribution Companies. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **SGIA Cancellation: CMP/Sparhawk (ER19-1019)**

On February 8, 2019, CMP filed a notice of cancellation of the Small Generator Interconnection Agreement ("SGIA") between itself and Sparhawk, LLC ("Sparhawk") (designated as service agreement IA-CMP-11-03 and accepted in Docket No. ER11-3223) reflecting the notice that it received from ISO-NE that the Sprahawk facility was retired as a resource as of January 17, 2019 under §III.13.2.5.2.5.3(d) of the Tariff, having last operated on April 16, 2015. A January 17, 2019 effective date for the notice of cancellation was requested. Comments on this filing were due on or before February 25; 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).

- **EPCOM Agreement Cancellation: CL&P/Cricket Valley (ER19-980)**

On February 4, 2019, CL&P filed a notice of cancellation of the Engineering, Procurement, Construction and Operations and Maintenance Agreement ("EPCOM Agreement") between CL&P and Cricket Valley Energy Center "Cricket Valley"(designated as service agreement IA-NU-15). The EPCOM Agreement set forth the terms and conditions for reconductoring approximately five miles of 345 kV transmission line owned by CL&P needed to interconnect Cricket Valley's proposed generation project to ConEd's transmission system. The EPCOM Agreement terminated upon the effectiveness of a Related Facilities Agreement ("RFA") between CL&P and Cricket Valley, which was accepted in Docket No. ER19-590 (see ER19-590 below) on February 1, 2019. A February 17, 2019 effective date for the notice of cancellation was requested. Comments, if any, on this filing were due on or before February 25; 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).

- **D&E Agreement: CL&P/NRG Middletown Repowering (ER19-978)**

Also on February 4, CL&P filed an Agreement for Design, Engineering and Construction services (the "D&E Agreement") between itself and NRG Middletown Repowering LLC ("NRG Middletown"). The D&E Agreement sets forth the terms and conditions under which CL&P will undertake preliminary design and engineering activities related to a large generating facility that is being developed by NRG Middletown (ISO-NE Queue Position 647) and will be subject to an LGIA that is being completed. CL&P requested that the D&E Agreement be accepted for filing as of the date of filing, or February 4, 2019. Comments on this filing were due on or before February 25; 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).

- **D&E Agreement Cancellation: PSNH/Essential Power Newington (ER19-817)**

On February 28, the FERC accepted a notice of cancellation filed by PSNH of the D&E Agreement between PSNH and Essential Power Newington (designated as service agreement IA-ES-44).[107] The D&E Agreement set forth the terms and conditions under which PSNH undertook certain design and engineering activities for the replacement of certain interconnection facilities, the cost for which was the responsibility of

[107] *Pub. Srvc. Co. of NH*, Docket No. ER19-817 (Feb. 28, 2019).

Essential Power pursuant to both the Agreement and a LGIA among PSNH, Essential Power Newington and ISO-NE (LGIA-ISONE-PSNH-16-01). With the work and associated billings completed, the D&E Agreement is now terminated. The notice of cancellation was accepted effective as of January 15, 2019, as requested. Unless the February 28 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).

- **Related Facilities Agreement: NSTAR / Clear River Energy (ER19-693)**

On February 22, the FERC accepted the RFA between NSTAR and Clear River Energy LLC ("Clear River")[108] that provides the terms and conditions governing NSTAR's activities, and Clear River's associated cost responsibility, in completing the required upgrades on NSTAR's transmission line #3361 in connection with Clear River's LGIA with ISO-NE and National Grid.[109] The RFA was accepted effective February 26, 2019, as requested. Unless the February 22 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Related Facilities Agreement: CL&P / Clear River (ER19-689)**

Also on February 22, the FERC accepted an RFA between CL&P and Clear River that provides the terms and conditions governing CL&P's activities, and Clear River's associated cost responsibility, in completing the required upgrades to CL&P's s protection and control facilities in connection with Clear River's LGIA with ISO-NE and National Grid. The Agreement was accepted effective February 26, 2019, as requested. Unless the February 22 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Related Facilities Agreement: CL&P / Cricket Valley (ER19-590)**

On February 1, the FERC accepted the RFA between CL&P and Cricket Valley Energy Center LLC ("Cricket Valley")[110] governing the activities and associated cost responsibility for completing the required reconductoring of approximately five miles of 345 kV transmission line owned by CL&P (Line 398) from the NY-CT border – connecting to ConEd's 345 kV transmission line – to the CL&P Long Mountain Substation, and other associated upgrades described in the RFA ("Cricket Valley Reconductoring Project").[111] The Cricket Valley Reconductoring Project is required under the LGIA among Cricket Valley, NYISO and ConEd. The RFA was accepted effective as of February 17, 2019, as requested. Unless the February 1 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **TSAs: First Amendments to EDC New England Clean Energy Connect TSAs (ER19-324 et al.)**

On February 8, 2019, the FERC accepted first amendments to three of the cost-based transmission service agreements ("TSAs") between CMP and the participants that will fund the construction, operation and maintenance of CMP's portion of a the NECEC Transmission Line.[112] The amendments to the agreements with Eversource (NSTAR), National Grid and Unitil (the "EDC Agreements") made two changes – (i) extension of the date that triggers an increase in monthly transmission service payments by the EDCs to CMP while Regulatory Approval for the Project is pending (from January 25, 2019 to June 25, 2019) and (ii) extension of the date by which any party to the EDC Agreements may terminate the EDC Agreement if Regulatory Approval is not received (from January 25, 2020 to June 25, 2020). The amendments were accepted effective as of January 9,

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[108] *NSTAR Elec. Co.*, Docket No. ER19-693 (Feb. 22, 2019).

[109] Clear River plans to construct an approximately 1,100 MW combined cycle generation project in Burrillville, Rhode Island that will be interconnected to the National Grid transmission system.

[110] *The Conn. Light and Power Co.*, Docket No. ER19-590-000 (Feb. 1, 2019).

[111] Cricket Valley plans to construct an approximately 1,177 MW combined cycle generation project in Dover, New York that will be interconnected to the ConEd transmission system.

[112] *Central Maine Power Co.*, Docket No. ER19-324-000 and -001 (Feb. 8, 2019).

2019, as requested. Unless the February 8 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).

- **FERC Enforcement Action: Show Cause Order – Footprint Power (IN18-7)**

On February 25, 2019, the FERC issued an order terminating this (Show Cause) proceeding.[113] As previously reported, the FERC had issued an order,[114] based on FERC Enforcement Staff allegations,[115] directing Footprint Power LLC and Footprint Power Salem Harbor Operations LLC (collectively, "Footprint") to show cause why they should not (i) be found to have violated the ISO-NE Tariff and FERC regulations by submitting what Enforcement Staff has concluded were false and misleading supply offers for, and by failing to report the fuel status and related operational status of, Salem Harbor Unit 4 in June and July of 2013; and as a result (ii) disgorge $2.05 million in CSO payments and be assessed a $4.2 million civil penalty. Enforcement Staff alleged that from June 26 through July 25, 2013, Footprint submitted supply offers that Unit 4 could not satisfy because Salem Harbor lacked usable fuel, and failed to report to ISO-NE that Salem Harbor's lack of usable fuel reduced Unit 4's output capabilities and availability as a capacity resource. In addition, Staff alleged that Footprint omitted material information from and/or misrepresented the fuel status of Salem Harbor and related operational status of Unit 4 in its communications with ISO-NE.

Following a FERC-granted extension of time to answer, Footprint filed its answer to the Show Cause on August 2, 2018. On September 19, Enforcement Staff submitted its response to Footprint's August 2 answer. Finding merit in Footprint's defense relating to the start-up requirements of Salem Harbor Unit 4, Staff agreed with Footprint that its conduct during the June 27 through July 17, 2013 portion (the "Cold Start Period") of the "Relevant Period" (i.e., June and July 2013) did not violate the ISO-NE Tariff provisions and FERC regulations at issue,[116] re-evaluated its position and recommended that the FERC vacate the *Show Cause Order*. On September 26, Footprint answered OE Staff's residual findings, and urged the Commission to promptly and definitively end this matter. In its *Feb 25 Order*, "in light of the submissions made by Footprint and OE Litigation Staff, as well as OE Litigation Staff's recommendation not to pursue the remaining alleged violations"[117] the FERC terminated the proceeding initiated by the Show Cause Order, making "no findings of fact or conclusions of law concerning the merits of any issues in the proceeding, either procedural or substantive."[118] This proceeding is now concluded.

- **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

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[113] *Footprint Power LLC and Footprint Power Salem Harbor Ops. LLC*, 166 FERC ¶ 61,150 (Feb. 25, 2019) ("*Feb 25 Order*").

[114] *Footprint Power LLC and Footprint Power Salem Harbor Ops. LLC*, 163 FERC ¶ 61,198 (June 18, 2018) ("*Show Cause Order*").

[115] Enforcement Staff alleged that from June 26 through July 25, 2013, Footprint submitted supply offers that Unit 4 could not satisfy because Salem Harbor lacked usable fuel, and failed to report to ISO-NE that Salem Harbor's lack of usable fuel reduced Unit 4's output capabilities and availability as a capacity resource. In addition, Staff alleged that Footprint omitted material information from and/or misrepresented the fuel status of Salem Harbor and related operational status of Unit 4 in its communications with ISO-NE.

[116] Staff still believes that Footprint violated the ISO-NE Tariff and FERC regulations during the remaining portion of the Relevant Period, from July 18 to July 25, when Footprint submitted Day-Ahead Limited Energy Generator ("LEG") offers to which the Cold Start Period defense does not apply.

[117] *Feb 25 Order* at P 10.

[118] *Id.*

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

XII. Misc. - Administrative & Rulemaking Proceedings

- **Grid Resilience in RTO/ISOs; DOE NOPR (AD18-7; RM18-1)**

On January 8, 2018, the FERC initiated a Grid Resilience in RTO/ISOs proceeding (AD18-7)[119] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[120] In terminating the DOE NOPR proceeding, the FERC concluded that the Proposed Rule and comments received did not support FERC action under Section 206 of the FPA, but did suggest the need for further examination by the FERC and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets. On February 7, FRS requested rehearing of the January 8 order terminating the DOE NOPR proceeding. The FERC issued a tolling order on March 8, 2018 affording it additional time to consider the FRS request for rehearing, which remains pending.

Grid Resilience Administrative Proceeding (AD18-7). AD18-7 was initiated to evaluate the resilience of the bulk power system in RTO/ISO regions. The FERC directed each RTO/ISO to submit information on certain resilience issues and concerns, and committed to use the information submitted to evaluate whether additional FERC action regarding resilience is appropriate. RTO submissions were due on or before March 9, 2018.

ISO-NE Response. In its response, ISO-NE identified fuel security[121] as the most significant resilience challenge facing the New England region. ISO-NE reported that it has established a process to discuss market-based solutions to address this risk, and indicated that it believed it will need through the second quarter of 2019 to develop a solution and test its robustness through the stakeholder process. In the meantime, ISO-NE indicated that it would continue to independently assess the level of fuel-security risk to reliable system operation and, if circumstances dictate, would take, with FERC approval when required, actions it determines to be necessary to address near-term reliability risks. ISO-NE's response was broken into three parts: (i) an introduction to fuel-security risk; (ii) background on how ISO-NE's work in transmission planning, markets, and operations support the New England bulk power system's resilience; and (iii) answers to the specific questions posed in the January 8 order.

Industry Comments. Following a 30-day extension issued on March 20, 2018, reply comments were due on or before May 9, 2018. NEPOOL's comments, which were approved at the May 4 meeting, were filed May 7, and were among over 100 sets of initial comments filed. A summary of the comments that seemed most relevant

[119] *Grid Rel. and Resilience Pricing*, 162 FERC ¶ 61,012 (Jan. 8, 2018), *reh'g requested*.

[120] As previously reported, the FERC opened the DOE NOPR proceeding in response to a September 28, 2017 proposal by Energy Secretary Rick Perry, issued under a rarely-used authority under §403(a) of the Department of Energy ("DOE") Organization Act, that would have required RTO/ISOs to develop and implement market rules for the full recovery of costs and a fair rate of return for "eligible units" that (i) are able to provide essential energy and ancillary reliability services, (ii) have a 90-day fuel supply on site in the event of supply disruptions caused by emergencies, extreme weather, or natural or man-made disasters, (iii) are compliant with all applicable environmental regulations, and (iv) are not subject to cost-of-service rate regulation by any State or local authority. More than 450 comments were submitted in response to the DOE NOPR, raising and discussing an exceptionally broad spectrum of process, legal, and substantive arguments. A summary of those initial comments was circulated under separate cover and can be found with the posted materials for the November 3, 2017 Participants Committee meeting. Reply comments and answers to those comments were filed by over 100 parties.

[121] ISO-NE defined fuel security as "the assurance that power plants will have or be able to obtain the fuel they need to run, particularly in winter – especially against the backdrop of coal, oil, and nuclear unit retirements, constrained fuel infrastructure, and the difficulty in permitting and operating dual-fuel generating capability."

to New England and NEPOOL was circulated to the Participants Committee on May 15 and is posted on the NEPOOL website. On May 23, NEPOOL submitted a limited response to four sets of comments, opposing the suggestions made in those pleadings to the extent that the suggestions would not permit full use of the Participant Processes. Supplemental comments and answers were also filed by FirstEnergy, MISO South Regulators, NEI, and EDF. Exelon and American Petroleum Institute filed reply comments. FirstEnergy included in this proceeding its motion for emergency action also filed in ER18-1509 (ISO-NE Waiver Filing: Mystic 8 & 9), which Eversource answered (in both proceedings). Reply comments were filed by APPA and American Municipal Power ("AMP") and the Nuclear Energy Institute ("NEI") moved to lodge presentations by the National Infrastructure Advisory Council. On December 6, the Harvard Electricity Law Initiative filed a comment suggesting that, as a matter of law, "Commission McNamee cannot be an impartial adjudicator in these proceedings" and "any proceeding about rates for 'fuel-secure' generators" and should recuse himself. Similarly, on December 18, "Clean Energy Advocates"[122] requested Commissioner McNamee recuse himself from these proceedings. These matters remain pending before the FERC.

FirstEnergy DOE Application for Section 202(c) Order. In a related but separate matter, FirstEnergy Solutions ("FirstEnergy") asked the Department of Energy ("DOE") in late March to issue an emergency order to provide cost recovery to coal and nuclear plants in PJM, saying market conditions there are a "threat to energy security and reliability". FirstEnergy made the appeal under Section 202(c) of the FPA, which allows the DOE to issue emergency orders to keep plants operating, but has previously been exercised only in response to natural disasters. Action on that 2018 request is pending.

- ***Order 853*: Civil Monetary Penalty Inflation Adjustments (RM19-9)**

On January 8, 2019, the FERC issued *Order 853*[123] to amend its regulations governing the maximum civil monetary penalties assessable for violations of statutes, rules, and orders within FERC's jurisdiction. The FERC is required to update each such civil monetary penalty on an annual basis every January 15.[124] Of particular interest is the increase in potential civil penalties for market manipulation, which were increased from $1,213,503 to $1,269,500 per violation, per day. *Order 853* became effective February 1, 2019.[125]

- **NOPR: Public Util. Trans. ADIT Rate Changes (RM19-5)**

On November 15, 2018, the FERC issued a NOPR ("*ADIT NOPR*") proposing to require all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law").[126] Specifically, for transmission formula rates, the FERC is proposing (i) to require that public utilities deduct excess accumulated deferred income taxes ("ADIT") from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT; (ii) to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information; (iii) to require all public utilities with transmission stated rates to determine the amount of excess and deferred income tax caused by the 2017 Tax Law's reduction to the federal corporate income tax rate and return or recover this amount to or from customers. As previously reported, comments on the *ADIT NOPR*

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[122] For purposes of these proceedings, "Clean Energy Advocates" are NRDC, Sierra Club and UCS.

[123] *Civil Monetary Penalty Inflation Adjustments*, Order No. 853, 166 FERC ¶ 61,041 (Jan. 8, 2019) ("*Order 853*").

[124] *See* Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015, Sec. 701, Pub. L. 114-74, 129 Stat. 584, 599. The FERC made its first adjustment under the Act in July 2016. *See Civil Monetary Penalty Inflation Adjustments*, Order No. 826, 81 FR 43937 (July 6, 2016), FERC Stats. & Regs. ¶ 31,386 (2016). The second adjustment was made January 9, 2017. *Civil Monetary Penalty Inflation Adjustments*, Order No. 834, 158 FERC ¶ 61, 170 (Jan. 9, 2017). The third adjustment was made January 8, 2018. *Civil Monetary Penalty Inflation Adjustments*, Order No. 839, 162 FERC ¶ 61,010 (Jan. 8, 2018). The fourth adjustment was made February 1, 2019. *Civil Monetary Penalty Inflation Adjustments*, Order No. 853, 166 FERC ¶ 61,014 (Jan 8. 2019).

[125] Order 853 was published in the *Fed. Reg.* on Feb. 1, 2019 (Vol. 84, No. 22) pp. 966-968.

[126] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 165 FERC ¶ 61,117 (Nov. 15, 2018).

were due on or before January 22, 2019. Comments were filed by over 14 parties, including Eversource, EEI, and NRECA. The *ADIT NOPR* Is pending before the FERC.

- **Order 855: Amended FPA Section 203(a)(1)(B) (RM19-4)**

On February 21, the FERC issued a final rule that revises its regulations relating to mergers or consolidations by a public utility ("*Order 855*").[127] Specifically, *Order 855* establishes (i) that a public utility must seek authorization under amended section 203(a)(1)(B) of the Federal Power Act to merge or consolidate, directly or indirectly, its facilities subject to the jurisdiction of the Commission, or any part thereof, with the facilities of any other person, or any part thereof, that are subject to the jurisdiction of the FERC *and have a value in excess of $10 million*, by any means whatsoever; and (ii) a notice requirement for mergers or consolidations by a public utility if the facilities to be acquired have a value in excess of $1 million and such public utility is not required to secure FERC authorization under amended section 203(a)(1)(B). Order 855 will become effective 30 days after its publication in the *Federal Register* (which, as of the date of this Report, has not yet happened).

- **NOPR: Refinements to Horizontal Market Power Analysis Requirements (RM19-2)**

On December 20, 2018, the FERC issued a NOPR proposing to relieve market-based rate sellers of the obligation, when seeking to obtain or retain market-based rate authority in any RTO/ISO market with RTO/ISO-administered energy, ancillary services, and capacity markets subject to FERC-approved RTO/ISO monitoring and mitigation, to submit indicative screens ("*Horizontal Market Power Analysis Refinements NOPR*").[128] In RTOs and ISOs that lack an RTO/ISO-administered capacity market, market-based rate sellers would be relieved of the requirement to submit indicative screens if their market-based rate authority is limited to sales of energy and/or ancillary services. The FERC's regulations would continue to require RTO/ISO sellers to submit indicative screens for authorization to make capacity sales in any RTO/ISO markets that lack an RTO/ISO-administered capacity market subject to FERC-approved RTO/ISO monitoring and mitigation. The *NOPR* also proposes to eliminate the rebuttable presumption that FERC-approved RTO/ISO market monitoring and mitigation is sufficient to address any horizontal market power concerns regarding sales of capacity in RTOs/ISOs that do not have an RTO/ISO-administered capacity market. Comments on the *Horizontal Market Power Analysis Refinements NOPR* are due March 18, 2019.[129] Since the last Report, comments were filed by Powerex and Indicated Generation Investors.[130]

- ***Order 849*: Pipeline Rates (RM18-11)**

Rehearing of *Order 849*[131] remains pending. As previously reported, in *Order 849*, the FERC adopted procedures through which the cost-based rates of natural gas pipelines are to be examined to determine which, if any, of those entities are collecting unjust and unreasonable rates in light of the 2017 Tax Law's reduction in the corporate tax rate from 35% to 21% and the disallowance in the Tax Policy Statement (*see* PL17-1 below) of income tax allowances for MLP pipelines. With certain exceptions,[132] the procedures adopted are generally the

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[127] *Implementation of Amended Section 203(a)(1)(B) of the Federal Power Act*, Order No. 855, 166 FERC ¶ 61,120 (Feb. 21, 2019).

[128] *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Trans. Org. and Indep. Sys. Op. Mkts.*, 165 FERC ¶ 61,091 (Dec. 20, 2018)

[129] The *Horizontal Market Power Analysis Refinements NOPR* was published *Fed. Reg.* on Feb. 1, 2019 (Vol. 84, No. 22) pp. 993-1,106.

[130] "Indicated Generation Investors" includes Southwest Generation Operating Co., Ares EIF Management, Northern Star Generation Services Co., Astoria Energy and Astoria Energy II, and Coronal Management.

[131] *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Fed. Income Tax Rate*, Order No. 849, 164 FERC ¶ 61,031 (July 18, 2018) ("*Order 849*").

[132] *Order 849* modifies the *Pipeline Rates NOPR's* proposed treatment of master limited partnership (MLP) pipelines and other pass-through entities in several respects, makes several changes to proposed FERC Form 501-G, and provides a guarantee that the FERC will not initiate a NGA section 5 rate investigation for a three-year moratorium period of an interstate pipeline that makes a limited NGA section 4 rate reduction filing that reduces its ROE to 12 percent or less.

same as the FERC proposed in its March 15, 2018 *Pipeline Rates NOPR*[133] and require interstate pipelines to (a) file a one-time report, FERC Form No. 501-G, that will provide financial information from the pipeline's 2017 FERC Form 2; and (b) voluntarily make a filing to address the changes to the pipeline's recovery of tax costs, or explain why no action is needed.[134] *Order 849* became effective September 13, 2018.[135]

Requests for rehearing of *Order 849* were filed by Enable Mississippi River Transmission and Enable Gas Transmission, Natural Gas Pipeline Company of America, and Process Gas Consumers Group and American Forest and Paper Association. On September 17, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending before the FERC.

- **DER Participation in RTO/ISOs (RM18-9)**

In *Order 841*[136] (*see* RM16-23 below), the FERC initiated a new proceeding in order to continue to explore the proposed distributed energy resource ("DER") aggregation reforms it was considering in the *Storage NOPR*.[137] All comments filed in response to the *Storage NOPR* will be incorporated by reference into Docket No. RM18-9 and further comments regarding the proposed distributed energy resource aggregation reforms, including comments regarding the April 10-11 technical conference in AD18-10,[138] were also to be filed in RM18-9. On June 26, 2018, over 50 parties submitted post-technical conference comments in this proceeding, including comments from ISO-NE, Calpine, Direct, Eversource, Icetec, NRG, Utility Services, EEI, EPRI, EPSA, NARUC, NRECA, and SEI. Since the last Report, on February 11, 2019, a group of 18 US Senators submitted a letter urging the FERC to adopt a final rule that enable all DERs the opportunity to participate in the RTO/ISO markets and requesting an update no later than March 1, 2019. This matter is pending before the FERC.

- ***Orders 845/845-A*: LGIA/LGIP Reforms (RM17-8)**

Order 845. As previously reported, the FERC issued on April 19, 2018, its final rule,[139] *Order 845*, revising its *pro forma* Large Generator Interconnection Procedures ("LGIP") and *pro forma* LGIA to implement 10 specific reforms designed to improve certainty for interconnection customers,[140] promote more informed

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[133] *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Fed. Income Tax Rate*, 162 FERC ¶ 61,226 (Mar. 15, 2018) ("*Pipeline Rates NOPR*").

[134] Pipelines could respond in one of four ways: (1) A limited Natural Gas Act ("NGA") section 4 filing to reduce the pipeline's cost-based rates by the percentage reduction in its cost of service shown in its FERC Form No. 501-G; (2) A commitment to file either a prepackaged uncontested rate settlement or a general NGA section 4 rate case by December 31, 2018; (3) The filing of a statement explaining why no change in rates is required; or (4) The taking of no other action (other than the submittal of the one-time report). If the pipeline chooses options (3) or (4), the FERC will consider, after reviewing both the one-time report and the comments of others, whether to initiate a NGA Section 5 investigation.

[135] *Order 849* was published in the *Fed. Reg.* on July 30, 2018 (Vol. 83, No. 146) pp. 36,672-36,717.

[136] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018), reh'g and/or *clarif. requested* ("*Order 841*").

[137] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

[138] On April 10-11, 2018, the FERC held a technical conference to gather additional information to help the FERC determine what action to take on DER aggregation reforms proposed in the *Storage NOPR* and to explore issues related to the potential effects of DERs on the bulk power system. Technical conference materials are posted on the FERC's eLibrary. Interested persons were invited to file post-technical conference comments on the topics concerning the Commission's DER aggregation proposal discussed during the technical conference, including on follow-up questions from FERC Staff related to the panels. Comments related to DER aggregation were to be filed in RM18-9; comments on the potential effects of DERs on the bulk power system, in AD18-10.

[139] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (Apr. 19, 2018) ("*Order 845*").

[140] To improve certainty for interconnection customers, *Order 845* (1) removes the limitation that interconnection customers may only exercise the option to build a transmission provider's interconnection facilities and stand-alone network upgrades in instances when the transmission provider cannot meet the dates proposed by the interconnection customer; and (2) requires that transmission providers establish interconnection dispute resolution procedures that allow a disputing party to unilaterally seek non-binding dispute resolution.

interconnection decisions,[141] and enhance the interconnection process.[142] Based on the comments received on its December 15, 2016 NOPR[143] in this proceeding as well as other factors, *Order 845* declined to adopt four proposed reforms related to requiring periodic restudies, self-funding of network upgrades, the posting of congestion and curtailment information, and the modeling of electric storage resources. *Order 845* took no action on two additional issues raised in the NOPR -- cost caps for network upgrades and affected system coordination (which is being addressed in a separate proceeding). *Order 845* became effective July 23, 2018.

Order 845-A. On February 21, 2019, the FERC issued its order on rehearing and clarification of *Order 845* ("*Order 845-A*").[144] The FERC granted rehearing in full or in part of four requests and clarification with respect to seven requests. The FERC ***granted rehearing*** with regard to (a) the option to build reform (requiring that transmission providers explain why they do not consider a specific network upgrade to be a standalone network upgrade; and allowing transmission providers to recover oversight costs related to the interconnection customer's option to build), (b) surplus interconnection service reform (explaining that RTOs/ISOs will not be limited in their arguments for an independent entity variation from the requirements), and (c) when an interconnection customer can propose control technologies in connection with interconnection service below generating facility capacity (control technologies may be proposed at any time in the interconnection process that it is permitted to request interconnection service below generating facility capacity). The FERC granted clarification with regard to (w) the option to build provisions (finding *Order 845* applies to all public utility transmission providers, including those that reimburse the interconnection customer for network upgrades, and does not apply to stand alone network upgrades on affected systems), (x) study model and assumption transparency (finding that transmission providers may use the FERC's CEII regulations as a model for evaluating entities that request network model information and assumptions and the phrase "current system conditions" does not require transmission providers to maintain network models that reflect current real-time operating conditions of the transmission provider's system), (y) interconnection study deadlines (transmission providers are not required to post 2017 interconnection study metrics) and (z) transmission providers must provide a detailed explanation of its determination to perform additional studies at the full generating facility capacity for an interconnection customer that has requested service below its full generating facility capacity. All other requests for rehearing and clarification were denied.

Effective Date and Compliance Filing Deadline. *Order 845-A* will become effective May 20, 2019.[145] The *Order 845* compliance filing deadline is now ***May 22, 2019***. Additionally, for each RTO/ISO, "the effective date of the proposed revisions shall be the date established in the Commission's order accepting that RTO's/ISO's compliance filing, which will be no earlier than the issuance date of such an order." *Order 845-A* will be discussed with the Transmission Committee at its March 27 meeting.

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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[141] To promote more informed interconnection decisions, *Order 845* (1) requires transmission providers to outline and make public a method for determining contingent facilities; (2) requires transmission providers to list the specific study processes and assumptions for forming the network models used for interconnection studies; (3) revises the definition of "Generating Facility" to explicitly include electric storage resources; and (4) establishes reporting requirements for aggregate interconnection study performance.

[142] To enhance the interconnection process, *Order 845* (1) allows interconnection customers to request a level of interconnection service that is lower than their generating facility capacity; (2) requires transmission providers to allow for provisional interconnection agreements that provide for limited operation of a generating facility prior to completion of the full interconnection process; (3) requires transmission providers to create a process for interconnection customers to use surplus interconnection service at existing points of interconnection; and (4) requires transmission providers to set forth a procedure to allow transmission providers to assess and, if necessary, study an interconnection customer's technology changes without affecting the interconnection customer's queued position.

[143] *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.

[144] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845-A, 166 FERC ¶ 61,137 (Feb. 219, 2019).

[145] *Order 845-A* was published in the *Fed. Reg.* on Mar. 6, 2019 (Vol. 84, No. 44) pp. 8,156-8,185.

- ***Order 841*: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)**

Requests for clarification and/or rehearing of *Order 841* remain pending. On February 15, 2018, the FERC issued *Order 841*, which requires each RTO/ISO to revise its tariff "to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets."[146] Additionally, each RTO/ISO must specify that the sale of electric energy from the RTO/ISO markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price. *Order 841* became effective June 4, 2018. As previously reported, *Order 841* did not adopt the *Storage NOPR's* proposed reforms related to DER aggregations. Instead, *Order 841* instituted a new rulemaking proceeding and technical conference (*see* RM18-9 above) to gather additional information to help the FERC determine what action to take with respect to DER aggregation. Requests for Clarification and/or Rehearing of *Order 841* were filed by CAISO, MISO, PJM, the AES Companies, AMP/APPA/NRECA, California Energy Storage Alliance, EEI, NARUC, PG&E, TAPS, and Xcel Energy Services. On April 13, 2018, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending.

- **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.[147] 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 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[148] and were filed by over 30 parties, including: APPA, Avangrid, Brookfield, EPSA, Macquarie/DC Energy/Emera Energy Services, NextEra, and NRG.

- **NOI: Certification of New Interstate Natural Gas Facilities (PL18-1)**

On April 19, 2018, the FERC announced its intention to revisit its approach under its 1999 Certificate Policy Statement to determine whether a proposed jurisdictional natural gas project is or will be required by the present or future public convenience and necessity, as that standard is established in NGA Section 7. Specifically, the NOI[149] seeks comments from interested parties on four broad issue categories: (1) project need, including whether precedent agreements are still the best demonstration of need; (2) exercise of eminent domain; (3) environmental impact evaluation (including climate change and upstream and downstream greenhouse gas emissions); and (4)

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[146] The participation model must: (1) ensure that a resource using the participation model is eligible to provide all capacity, energy and ancillary services that the resource is technically capable of providing in the markets; (2) ensure that a resource using the participation model can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price; (3) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and (4) establish a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW.

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

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

[149] The NOI was published in the *Fed. Reg.* on Apr. 26, 2018 (Vol. 83, No. 80) pp. 18,020-18,032.

the efficiency and effectiveness of the FERC certificate process. Pursuant to a May 23 order extending the comment deadline by 30 days,[150] comments were due on or before July 25, 2018. Literally thousands of individual and mass-mailed comments were filed. This matter remains pending before the FERC.

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

On March 15, 2018, the FERC found that an impermissible double recovery results from granting a Master Limited Partnership pipeline ("MLP") both an income tax allowance and an ROE pursuant to the DCF methodology.[151] Accordingly, the FERC issued a revised policy statement that it will no longer permit an MLP to recover an income tax allowance in its cost of service. The finding follows an NOI[152] that sought comments regarding how to address any double recovery resulting from the FERC's income tax allowance and ROE policies in light of the D.C. Circuit's *United Airlines*[153] holding. The FERC indicated that it will address the application of *United Airlines* to non-MLP partnership forms as those issues arise in subsequent proceedings. The revised policy statement took effect on March 21, 2018. Requests for rehearing of the March 15 order were filed by the Dominion, Enable Mississippi River Transmission and Enable Gas Transmission, Enbridge and Spectra Energy Partners, EQT Midstream Partners, Kinder Morgan, Master Limited Partnership Association ("MLPA"), NGAA, SPPP, LP, Oil Pipe Lines, Plains Pipeline, Tallgrass Pipelines, and TransCanada. On July 18, the FERC issued its order on rehearing,[154] dismissing the requests for rehearing and clarification and providing guidance regarding the treatment of Accumulated Deferred Income Taxes ("ADIT") where the income tax allowance is eliminated from cost-of-service rates under the FERC's post-*United Airlines* policy. On August 17, the MLPA requested clarification and/or reconsideration of the *Order on Rehearing*, which is pending before the FERC. On September 4, R. Gordon Gooch answered MLPA's August 17 pleading. Petitions for review were filed in the D.C. Circuit by Enable Mississippi River Transmission, LLC and Enable Gas Transmission, LLC, as well as by SFPP, L.P., in September 2018. Those appeals are pending in Case Nos. 18-1252, et al. in the D.C. Circuit.

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).

- **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*[155] 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 NGA Section 4A.[156] Specifically, after extensive discovery and hearing procedures, Judge

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[150] *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,138 (May 23, 2018).

[151] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs*, 162 FERC ¶ 61,227 (Mar. 15, 2018), *order on reh'g*, 164 FERC ¶ 61,030 (July 18, 2018).

[152] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs,* 157 FERC ¶ 61,210 (Dec. 15, 2016).

[153] *United Airlines Inc. v. FERC*, 827 F.3d 122, 134, 136 (D.C. Cir. 2016) ("*United Airlines*") (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). *Id.* at 137.

[154] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs*, 164 FERC ¶ 61,030 (July 18, 2018) ("*Order on Rehearing*").

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

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

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."[157] 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 order establishing a hearing in this proceeding.[158] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, 2016 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, 2016, 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, 2016, 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.[159]

BP moved, on December 11, 2017, to lodge, to reopen the proceeding, and to dismiss, or in the alternative, for reconsideration based on changes in the law it asserted are dispositive and that have occurred since BP filed its request for rehearing of the *BP Penalties Order*. FERC Staff asked for, and was granted, additional time, to January 25, 2018, to file its Answer to BP's December 11 motion. FERC Staff filed its answer on January 25, 2018, and revised that answer on January 31. On February 9, BP replied to FERC Staff's revised answer. This matter remains pending before the FERC.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[160] 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.[161]

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

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

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

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

[161] 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.

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 filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017. This matter remains pending before the FERC.

- **Staff Notices of Alleged Violations**

Rover. On July 13, 2017, the FERC issued a notice that Staff has preliminarily determined that, between February 2015 and September 2016, Rover Pipeline, LLC and Energy Transfer Partners, L.P. (collectively, "Rover") violated Section 7 of the Natural Gas Act by failing to fully and forthrightly disclose all relevant information to the FERC in Rover's application for a Certificate of Public Convenience and Necessity and attendant filings in Docket No. CP15-93. Staff alleges that Rover falsely promised it would avoid adverse effects to a historic resource that it was simultaneously working to purchase and destroy, and subsequently made several misstatements in its docketed responses to FERC questions about why it had purchased and demolished the resource.

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.[162] 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.

- **New England Pipeline Proceedings**

The following New England pipeline projects are currently under construction or before the FERC:

- ***Atlantic Bridge Project (CP16-9)***
  - 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.
  - 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.[163]
  - Certain facilities,[164] providing 40,000 out of the project's total capacity of 132,705 dekatherms per day of incremental firm transportation service, placed into service on

[162] *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).

[163] Order Issuing Certificate and Authorizing Abandonment, *Algonquin Gas Transmission LLC and Maritimes & Northeast Pipeline, LLC*, 158 FERC ¶ 61,061 (Jan. 25, 2017), *order denying stay*, 160 FERC ¶ 61,015 (2017), *reh'g denied,* 161 FERC ¶ 61,255 (Dec. 13, 2017) ("*Atlantic Bridge Project Order*").

November 1, 2017.[165] Remaining Project capacity will be available when the remaining Project facilities are placed into service following Director of OEP authorization.

- Algonquin files notice that construction of Salem Pike, Needham, Pine Hills and Plymouth meter and regulating stations began on April 2, 2018. Detailed information regarding construction activities can be found in the weekly construction reports filed in this docket.
- On February 16, 2018, Algonquin filed with the DC Circuit Court of Appeals, pursuant to NGA Section 19(d)(2), a petition for review of the MA DEP's failure to issue, condition, or deny a minor-source air permit for Algonquin's proposed natural gas compressor station in the Town of Weymouth, MA by the July 31, 2016 deadline established by the FERC. Algonquin seeks an order establishing a deadline for the MA DEP to issue, condition, or deny the permit.
- On May 31, the DC Circuit issued a *per curiam* order that holds this case in abeyance pending further order of the court.[166] The court based its order on the parties' representation that they have agreed on a schedule by which to resolve their dispute. The parties were directed to file status reports at 90-day intervals and to file motions to govern future proceedings within 30 days of respondents' final decision to issue, condition, or deny petitioner's permit application.
- Status reports have thus far been filed on August 24 and November 21, 2018, and February 20, 2019, each indicating that the case should continue to be held in abeyance. The next status report will be due in late May, 2019.
- On December 26, 2018, the FERC granted Algonquin a two-year extension of time, to January 25, 2021, to complete the Project.[167] In requesting the extension, Algonquin attributed the need for additional time to permitting delays for the Weymouth Compressor Station and ongoing construction of the Horizontal Directional Drill of the Taconic Parkway in New York. Requests for rehearing of the December 26 order were filed by two parties. On February 25, 2019, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

- ***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.
    - By letter order issued July 26, 2016, the Director of the Division of Pipeline Certificates (Director) granted Constitution's requested two-year extension of time to construct the project.

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[164] The following facilities placed into service: Southeast Discharge Take-up and Relay (Fairfield County, CT); Modified Oxford Compressor Station (New Haven County, CT); Modified Chaplin Compressor Station (Windham County, CT); Modified Danbury (CT) Meter Station; and Modified Stony Point Compressor Station (Rockland County, NY).

[165] *Algonquin Gas Trans., LLC*, 158 FERC ¶ 61,061 (Oct. 27, 2017).

[166] *Algonquin Gas Trans. v. Mass. Dept. of Envtl. Protection*, Case No. 18-1045, DC Cir. (May 31, 2018).

[167] *Algonquin Gas Trans., LLC*, Docket No. CP16-9 (Dec. 26, 2018) (unpublished letter order), *reh'g requested*. Absent the extension, and pursuant to the Jan. 25, 2017 Certificate Order, the Project would otherwise have had to have been completed by Jan. 25, 2019.

    - Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays (see below).
- On April 22, 2016, New York State Department of Environmental Conservation (NY DEC) denied Constitution's application for a Section 401 permit under the Clean Water Act.
    - On August 18, 2017, the 2nd Circuit denied Constitution's petition for review of the NY DEC decision, concluding that (1) the court lacked jurisdiction over the Constitution's claims to the extent that they challenged the timeliness of the decision; and (2) the NY DEC acted within its statutory authority in denying the certification, and its denial was not arbitrary or capricious.
    - Constitution filed a petition for a writ of certiorari of the 2nd Circuit's decision at the United States Supreme Court in January 2018 alleging, among other things, that the State's denial of the Clean Water Act permit exceeded the state's authority, and interfered with FERC's exclusive jurisdiction. On April 30, 2018, the Supreme Court denied Constitution's petition, thereby letting stand the 2nd Circuit's ruling.
- On October 11, 2017, Constitution filed with the FERC a petition for declaratory order ("Petition") requesting that the FERC find that NY DEC waived its authority under section 401 of the Clean Water Act by failing to act within a "reasonable period of time." (CP18-5)
    - On January 11, 2018, the FERC denied Constitution's Petition.[168] Although noting that states and project sponsors that engage in repeated withdrawal and refiling of applications for water quality certifications are acting, in many cases, contrary to the public interest and to the spirit of the Clean Water Act by failing to provide reasonably expeditious state decisions, the FERC did not conclude that the practice violates the letter of the statute, found factually that Constitution gave the NY DEC new deadlines, and found that the record did not show that the NY DEC in any instance failed to act on Constitution's application for more than the outer time limit of one year.[169]
    - On February 12, 2018, Constitution Pipeline requested rehearing of the January 11, 2018 order. FERC denied Constitution's request for rehearing of the January 2018 order.[170] On September 14, 2018, Constitution filed a petition for review in the U.S. Court of Appeals for the D.C. Circuit.[171]
- 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.
    - In July 2016, the FERC rejected the NY AG's filing as procedurally deficient, and declined to stay of the Certificate Order. The NY AG sought rehearing, and the Commission denied rehearing on November 22, 2016, noting again that the NY AG's complaint was still procedurally deficient.
- Tree felling and site preparation continues, but the long-term status of the pipeline is currently unknown.
- On June 25, 2018, Constitution requested a further 2-year extension of the deadline to complete construction of its project, given the delays caused by the on-going fight over

[168] *Constitution Pipeline Co.*, 162 FERC ¶ 61,014 (Jan. 11, 2018), *reh'g requested*.

[169] *Id*. at P 23.

[170] *Constitution Pipeline Co., LLC*, 164 FERC ¶ 61,029 (2018) (September 2018 Waiver Rehearing Order).

[171] Constitution, Petition for Review in U.S. Court of Appeals for the D.C. Circuit, Docket No. CP18-5-000 (filed Sept. 14, 2018).

the water quality certification from the NYSDEC. Iroquois made a similar request on August 1, 2018. Constitution's request was opposed by several parties and Constitution answered some of the opposition pleadings. The FERC granted the requested two-year extension of time on November 5, 2018.[172]

- Rehearing of the November 5, 2018 order was requested by Halleran Landowners and a group of intervenors comprised of Catskill Mountainkeeper; Clean Air Council; Delaware-Otsego Audubon Society; Delaware Riverkeeper Network; Riverkeeper, Inc.; and Sierra Club ("Intervenors"). Constitution answered the requests for rehearing on December 21. The FERC issued a tolling order on December 21, affording it additional time to consider the requests for rehearing. This matter is pending before the FERC.

- **Non-New England Pipeline Proceedings**
  The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:
  - **Northern Access Project (CP15-115)**
    - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On September 12, 2018 the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remains pending.
    - On August 6, the FERC dismissed or denied the requests for rehearing of the *Northern Access Certificate Order*.[173] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed Motion for Expedited Action" filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[174] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.
    - As previously reported, the FERC issued an order, on Feb. 3, 2017, authorizing the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project").[175] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.
    - Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed

[172] *Constitution Pipeline Co.*, 165 FERC ¶ 61,081 (Nov. 5, 2018), *reh'g requested*.

[173] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 164 FERC ¶ 61,084 (Aug. 6, 2018) ("*Northern Access Rehearing & Waiver Determination Order*").

[174] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

[175] *Nat'l Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017) ("*Northern Access Certificate Order*"), reh'g denied 164 FERC ¶ 61,084 (Aug 6, 2018) ("*Northern Access Certificate Rehearing Order*").

the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[176] Oral argument was held on November 16, 2017. The Court's decision is pending, and it remains to be seen how the Court will factor in the FERC's waiver determination in the *Northern Access Rehearing & Waiver Determination Order*.

- On November 26, 2018, the Applicants filed a request at FERC for a 3- year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request remains pending.

XIV. State Proceedings & Federal Legislative Proceedings

- **Connecticut Zero-Carbon Resource Selections**

On December 28, 2018, Connecticut announced that, pursuant to Public Act 17-3,[177] it had selected two nuclear power bids,[178] along with nine solar project bids (two of which were paired with energy storage)[179] and one offshore wind project (200 MW from Revolution Wind). Connecticut stated that over 100 renewable energy projects bid into this RFP, including numerous solar projects, land-based and offshore wind, and existing hydropower. Nearly all of Public Act 17-3's procurement authority was utilized. Assuming all of the selected projects successfully enter into contracts and are approved by CT PURA, Connecticut "will retain approximately 17% percent of total load for additional renewable procurement authority in future RFPs".

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).

- **FCM Resource Retirement Reforms (17-1275)**
  Underlying FERC Proceedings: ER16-551[180]
  Petitioner: Exelon

The FERC submitted its *FCM Resource Retirement Reforms Remand Order* to the Court on January 29, 2019, which is now pending before the Court. As previously reported, on December 28, 2018, five weeks after oral argument (held November 19, 2018), the DC Circuit Court of Appeals issued an opinion remanding the record in this case to the FERC for a clarification of "what [the FERC] really means" in the context of its orders

[176] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al.* (2d Cir., Case No. 17-1164).

[177] Public Act 17-3 required Connecticut to conduct an appraisal of nuclear power-generating facilities and solicit bids for zero-carbon electricity-generating resources.

[178] One bid was a 10-year bid from Millstone for roughly 50% of its output; the other, from Seabrook, for 1.9 million MWh beginning in 2022.

[179] The selected solar projects include three in Connecticut (Montville Energy Center, Black Hill Point Energy Center (paired with energy storage) and Gravel Pit Solar), two in New Hampshire (Tilton Heights Energy Center and Steel Mill Solar) and four in Maine (Old Mill Solar, Keay Brook Energy Center, and GRE-3-ME-SACO (also paired with energy storage), and Kennebec PV Partners.

[180] *ISO New England Inc.,* 155 FERC ¶ 61,029 (Apr. 12, 2016) ("*Resource Retirement Reforms Order*"), *reh'g and clarif. denied*, 161 FERC ¶ 61,115 (Oct. 30, 2017) ("*FCM Resource Retirement Reforms Orders*").

on the FCM Resource Retirement Reforms.[181] Specifically, the FERC was directed to issue an order, not later than February 1, 2019, clarifying its position on the proper reading, process and legal standards associated with the Tariff changes that have ISO-NE file mitigated retirement bids for FERC review under § 205 of the FPA. In its appeal, Exelon continued its objection to the replacement of its De-List Bid for an IMM-mitigated De-List Bid in that FERC review under FPA § 205, which Exelon asserted "trample[s] on its § 205 rights". Writing for the Court, Senior Justice Williams observed that FERC counsel "seemed to contend [at oral argument] that the correct meaning of the challenged order was in conformity with the meaning that [Exelon] ascribed to the controlling statue. Because the parties' dispute may be illusory, we remand the record to the [FERC] to sort out what it really means." The Court emphasized that the decision *did not* resolve arguments briefed as to "whether a supplier's retirement bids are "rates" under [Section § 205 of the FPA], and therefore entitled to assessment by FERC under the "just and reasonable" criterion ... nor … whether Exelon can rightly be said to have consented to the new rules by virtue of having participated in the 2006 Forward Capacity Market Settlement."

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[182] EL15-23[183]
  Petitioners: NEPGA, Exelon

On February 2, 2018, DC Circuit granted NEPGA's and Exelon's petitions for review of orders accepting the FCM's 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23).[184] Finding that "the FERC failed to adequately explain why its rationale [for rejecting price lock-in and capacity carry forward rules] in PJM – which seems to foreclose signing off on a Tariff scheme like ISO-NE's – does not apply even more forcefully to the scheme it accepted in the Orders [appealed from]," the DC Circuit granted the Petitions and remanded the case to the FERC for further proceedings in which the FERC, in order to accept the changes filed, must provide some analysis and explanation why it changed course. The remand is pending before the FERC.

Other Federal Court Activity of Interest

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[185]
  Petitioners: NEPGA, Exelon

Pending before the DC Circuit is an appeal of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[186] for the construction and operation of a new 116-mile natural gas pipeline from Luzerne County, Pennsylvania, to Mercer County, New Jersey, along with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities ("PennEast Project"). In separate but related proceedings, the New Jersey Attorney General and several conservation groups have filed actions in federal district court in New Jersey seeking to limit PennEast's use of its NGA eminent domain authority.

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[181] *Exelon Corporation v. FERC*, Case No. 17-1275 (D.C. Cir., Dec. 28, 2018).

[182] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[183] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

[184] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018).

[185] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[186] PennEast is a joint venture owned by Red Oak Enterprise Holdings, Inc., a subsidiary of AGL Resources Inc.; NJR Pipeline Company, a subsidiary of New Jersey Resources; SJI Midstream, LLC, a subsidiary of South Jersey Industries; UGI PennEast, LLC, a subsidiary of UGI Energy Services, LLC; and Spectra Energy Partners, LP.

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