NEPOOL
NEW ENGLAND POWER POOL

David T. Doot
Secretary

May 24, 2018

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of June 1, 2018 NEPOOL Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the NEPOOL Participants Committee **will be held via teleconference on Friday, June 1, 2018, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at http://nepool.com/NPC_2018.php.

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 participating in this meeting must 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.

The dial-in number for the meeting, to be used only by those who otherwise attend NEPOOL meetings, is **866-803-2146; Passcode: 7169224.**

We hope you have now registered and made reservations for the NEPOOL Summer Meeting on June 26-28, 2018 at the Water's Edge Resort in Westbrook, CT (coffee & dessert on Monday evening, June 25). We have been advised that the NEPOOL block of rooms is now full. Should you still need to make a reservation, please contact the Water's Edge directly (800-222-5901) to see if they can accommodate you in the event they have received any room cancellations or to be put on a wait list. Alternatively, rooms may be available at the Saybrook Point Inn www.saybrook.com /860-395-2000) in Old Saybrook, Captain Stannard House (www.stannardhouse.com /860-399-4634) in Westbrook, or the Westbrook Inn (www.westbrookinn.com/800-342-3162). Should you have any difficulty in making a reservation, please contact Cindy Jacobs, NEPOOL Administrator (ckjacobs@daypitney.com/ 860-275-0246) and she will try to assist you. Information regarding the 2018 NEPOOL Summer Meeting is available on the NEPOOL website Summer Meeting page http://nepool.com/Summer_Mtg_Info_Page.php and will be circulated and posted with the notices of the Summer Meeting.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the continued Participants Committee meeting held on April 10, 2018, and the meeting held on May 4, 2018. The preliminary minutes of those two meetings 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 Tariff revisions modifying the economic life calculation to determine competitive Permanent De-List Bid and Retirement De-List Bid prices in the FCM, as proposed by the ISO's Internal Market Monitor. Background material and a draft resolution are included and posted with this supplemental notice.

6. **Deferred.** [~~To consider and take action, as appropriate, on changes to the ISO Financial Assurance Policy to conform to changes in the ISO Tariff and Market Rules related to the Zonal Demand Curve.~~]

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

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

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

9. To receive a report on administrative matters.

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

PRELIMINARY

APRIL 10, 2018 SESSION

The April Participants Committee meeting reconvened at 3:00 p.m. on April 10, 2018, with members participating from the DoubleTree Hotel, Milford, MA, following the Markets Committee meeting, and others calling in. Members whose attendance is recorded are identified in Attachment 1.

Ms. Nancy Chafetz, Acting Chair, presided and Mr. David Doot, Secretary, recorded.

Ms. Chafetz reviewed the discussion of fuel security issues that began at the April 6 meeting, clarifying that the topic for discussion at this~~e~~ session was limited to questions and comments concerning the ISO's plans for a waiver filing to retain Mystic 8 and 9 for fuel security during capacity commitment periods covered by FCAs 13 and 14. She referred the Committee to the ISO presentation on the topic that was circulated and posted on April 9 with the meeting materials for this continued session of the April meeting.

Dr. Chadalavada then reviewed the materials with the Committee. He explained that the ISO modeled the fuel security reliability need for Winter 2022/23 and Winter 2023/24 for Mystic 8 and 9, noting the underlying model was the same as that used in the Operational Fuel Security Analysis with the inputs have been adjusted for the two relevant winter periods. He explained that the ISO considered there to be a fuel security need if it projected an inability to maintain Ten-Minute Operating Reserves (TMOR) or a need to shed load in accordance with Operating Procedure (OP) No. 7 (OP-7). He said in response to questions that maintaining TMOR was a core NERC Balancing Authority standard and the ISO did not consider expected load shedding as an appropriate means to maintain reliability. The ISO accepted OP-4 actions as an appropriate means to maintain reliability in instances of periodic shortages, but not load shedding.

Mr. Peter Brandien, ISO Vice President System Operations, went on to explain that the ISO plans operations to ensure its ability to maintain NERC reliability standards throughout each day. He described the ISO's obligations with respect to NERC's Area Control Error (ACE) requirements for maintaining conditions on external ties. He explained that the loss of a major resource in New England directly and substantially impacts external flows, primarily on the New England/New York Interface. The ISO is required within 15 minutes of that event to bring the ACE back to where it was pre-contingency or to zero, and the standard then requires the ISO to restore contingency reserves within 90 minutes of the recovery period.

Focusing on assumptions in the analysis, Dr. Chadalavada explained in response to questions that the ISO~~it~~ was analyzing as a package the loss of Mystic 8 and 9 and its fuel source, based on input from Exelon. He said the ISO viewed the loss of Mystic 8 and 9 and the LNG supply for those units as a fuel security issue. The ISO acknowledged that this was a different analysis than what the region does for defining capacity needs in the region. Rather, it looked more closely at whether reliability could be maintained in operations during winter periods, including ~~. Mr. Brandien opined in~~ time to allow fuel supplies to be replenished. The ISO committed to identify its assessment of aggregate potential outages that might occur because of limited fuel supply, but would not list particular units that might be exposed.

Further describing the ISO's analysis, Dr. Chadalavada explained that the model the ISO used shows trend lines and did not predict actual future outcomes. He reviewed assumptions as laid out in the presentations. He noted that the model did not predict or seek to reflect market response. It assumed that all resources that cleared in FCA12 would~~ill~~ be available at their stated capacity in FCA13 and FCA14, except for Mystic 7, 8, and 9 for 2022/23 and 2023/~~24 and that cleared resources will be available at their stated capacity~~. The ISO used for Winter 2022/23 the peak load, photovoltaic (PV) forecasts, and renewables as reflected in the 2018 CELT report. It reflected reductions~~ed~~ in operating reserve requirements from 2,300 MW to 2,100 MW and ~~reduced~~ TMOR requests from 1,600 MW to 1,400 MW. The only variables adjusted in the model were assumptions concerning the LNG cap, imports and dual fuel replenishments.

Members questioned why the ISO assumed Distrigas would retire if the Mystic units were retired, noting that Canaport operates without an anchor tenant like the Mystic Units. Dr. Chadalavada stated the ISO would rely on expert testimony about impact on Distrigas of the loss of revenue from Mystic 8 and 9. The ISO did not assume that LNG not consumed by the Mystic Units would be injected in the pipelines for other generators. The ISO did not assume any additional pipeline capacity into the region.

Reviewing the model results for Winter 2022/23 and Winter 2023/24, he explained that the ISO was not relying on a single scenario or set of inputs, but rather a continuum of cases that all showed reserve depletions. He reminded members that the ISO planned to discuss FCA14 issues at the April 25 Reliability Committee meeting to initiate discussions for FCA14. He said the ISO would explain its modeling and results in its FERC waiver filing~~ at the FERC and supporting testimony~~. He said t~~T~~he ISO was open to running alternative scenarios for the model years, subject to its need to submit the waiver filing soon.

Some members questioned the implications of the waiver for the CASPR substitution auction~~ in CASPR~~. In response, Dr. Chadalavada noted that there wa~~i~~s still over 500 MWs of renewable exemption available for new renewable capacity resources. For other renewable resources that would not qualify for the exemption, the retirements of Mystic 7 and the Mystic

Jet would create the potential for substitution, but the ISO had~~s~~ not sought to predict how FCA13 or FCA~~-~~14 might unfold. He acknowledged that retention of resources for fuel security theoretically reduced liquidity in the substitution auction and the ISO would watch the issue closely.

Responding to questions concerning allocation of costs associated with the potential reliability agreement, Dr. Chadalavada stated the ISO viewed fuel security as a regional concern, but was leaving for stakeholder discussion the issue of whether such regional costs should be allocated based on network load or Real-Time load in the markets. He acknowledged that retaining resources for fuel security under current market arrangements could suppress prices in the capacity market. He reminded members that the ISO had been told by Exelon that a two-year cost-of-service agreement approved by the FERC was needed for Exelon to agree not to retire the resources. He expressed an openness to consider alternative ways to address the fuel security concerns but the ISO had not identified any acceptable alternatives.

Ms. Maria Gulluni, ISO's counsel, clarified that any viable alternatives must be identified promptly, because if Exelon agreed to remain in operation with a 2-year cost-of-service agreement that FERC approved and the ISO signed, the region would be bound by that agreement. She said the ISO was planning to file its waiver request by the end of April and Exelon had a plan to file its proposed cost-of-service arrangements early in May.

Dr. Chadalavada agreed in response to questions that there needed to be discussion of potential Market Rule changes that balance the desire for Market Participants to have broader latitude to identify what they need to remain in operation, and the needs of the Market Monitor to ensure workably competitive markets.

Concluding the continued meeting, members of the Committee expressed appreciation to the ISO for sharing its plans and information with stakeholders ahead of its planed filing. Ms. Chafetz reminded the Committee that discussion of the Chapter 2 issues — potential changes to the Tariff for FCA14 —~~--~~ would begin at the April 25 Reliability Committee meeting in Milford.

Mr. Doot reminded the Committee that the May 4 Participants Committee meeting was scheduled to take place at the Danvers, MA Doubletree Hilton North Shore Hotel~~ in Danvers, MA~~.

There being no further business, the meeting adjourned at 5:00 p.m.

Respectfully submitted,

David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
APRIL 10, 2018 SESSION

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
AR Small Load Response (LR) Group Member	AR-LR	Doug Hurley	Brad Swalwell (tel)	
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Reading Municipal Light Department	Publicly Owned		Jane Parenteau (tel)	
Belmont Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Block Island Power Company	Supplier	Dave Cavanaugh		
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	
Citigroup Energy Inc.	Supplier	Barry Trayers		
CLEAResult Consulting, Inc.	AR-DG	Doug Hurley		
Competitive Energy Services, LLC	Supplier			Glenn Poole
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop. (CMEEC)	Publicly Owned	Brian Forshaw		
Conservation Law Foundation	End User		Jerry Elmer	
Consolidated Edison Energy, Inc. (ConEd)	Supplier	Jeff Dannels		
CPV Towantic, LLC	Generation	Dan Pierpont		
Cross-Sound Cable Company (CSC)	Supplier		Jose 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
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Emera Energy Services	Transmission			Bill Fowler
Enerwise Global Technologies Inc. d/b/a CPower	AR-LR		Herb Healy	
Entergy Nuclear Power Marketing, LLC	Generation			Bill Fowler
Environmental Defense Fund	End User	Liz Delaney		
Eversource Energy	Transmission			Dave Errichetti
Exelon Generation Company	Supplier		Bill Fowler	
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation	Dennis Duffy	Abby Krich (tel)	Bob Stein
Georgetown Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Great River Hydro, LLC	AR-RG			Bill Fowler
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	
Harvard Dedicated Energy Limited	End User			Doug Hurley
H.Q. Energy Services (U.S.) Inc.	Supplier		Bob Stein	
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Jericho Power, LLC	AR	Tom Hoatson		
Littleton (MA) Electric Light and Waster Department	Publicly Owned		Dave Cavanaugh	
Long Island Lighting Company (LIPA)	Supplier		William Killgoar	
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	
Massachusetts Attorney General’s Office (MA AG)	End User	Fred Plett (tel)	Christina Belew	
Mass. Municipal Wholesale Electric Company	Publicly Owned			Brian Forshaw
Mercuria Energy America, Inc.	Supplier			Nancy Chafetz
Merrimac Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
Nautilus Power, LLC	Generation		Bill Fowler	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 10, 2018 SESSION

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
New Hampshire Electric Cooperative (NHEC)	Publicly Owned	Steve Kaminski (tel)		Brian Forshaw
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
PowerOptions, Inc.	End User	Cindy Arcate (tel)		
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned	Jane Parenteau (tel)		Brian Forshaw
Repsol Energy North America Company	Gas Industry Part.		Nancy Chafetz	
Rowley Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Shipyard Brewing LLC	End User		Stacy Dimou (tel)	
Stowe Electric Department	Publicly Owned		Dave Cavanaugh	
Taunton Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
The Energy Consortium	End User			Fred Plett (tel) Doug Hurley
Vermont Energy Investment Corporation	AR-LR	David Westman (tel)	Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw
Verso Energy Services LLC	Generation	Glenn Poole		
Vitol Inc.	Supplier	Joe Wadsworth (tel)		
Wallingford DPU Electric Division	Publicly Owned		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Westfield Gas & Electric Department	Publicly Owned		Dave Cavanaugh	
Wheelabrator/Calpine	AR-RG	~~John Flumerfelt (tel)~~ Brett Kruse	~~Brett Kruse~~John Flumerfelt (tel)	Bill Fowler

PRELIMINARY

A meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, May 4, 2018, at the Doubletree Hilton Boston North Shore Hotel, Danvers, MA, pursuant to notice duly given. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates attending the meeting.

Mr. Thomas Kaslow, Chair, presided and Mr. David Doot, Secretary, recorded.

EXECUTIVE SESSION

CONFIDENTIAL VOTE ON SLATE OF CANDIDATES FOR ISO BOARD

Mr. Kaslow introduced Mr. Barney Rush, Chairman of the Joint Nominating Committee (JNC), who had joined this portion of the meeting by phone. Mr. Kaslow explained that the identities of the candidates on the proposed slate must remain confidential until the ISO Board takes its final vote on the slate. Accordingly, he said the full discussion of the slate would be held in Executive Session.

Mr. Rush then described the JNC process and identified the slate that was unanimously recommended by the JNC for Participants Committee consideration, referring to the confidential package of materials that was circulated to the members and alternates of the Committee in advance of the meeting. Following his introduction and in the absence of questions, he then left the meeting.

The slate was discussed among the members and alternates and, after that discussion, the following motion was duly made, seconded and approved by more than the 70% Vote required for NEPOOL endorsement, with the vote accomplished by secret written ballot per prior agreement of the Participants Committee:

> RESOLVED, that the Participants Committee endorses the slate of candidates for the ISO Board that has been recommended by the Joint Nominating Committee and presented to the Participants Committee in Executive Session at this meeting.

GENERAL SESSION

Mr. Kaslow opened the General Session portion of the meeting by reporting that Mr. Frederick Plett, End User Sector Vice-Chair and Participants Committee member for the Massachusetts Attorney General's Office, was retiring and this would be his last in-person Participants Committee meeting in those capacities. On behalf of the Committee, Mr. Kaslow expressed appreciation to Fred for his contributions to the Committee. He stated the Committee would invite Fred back at a future meeting for a more formal to acknowledgement of his contributions to the Pool.

APPROVAL OF APRIL 6, 2018 MEETING MINUTES

Mr. Kaslow referred the Committee to the preliminary minutes for the April 6, 2018 meeting, revised following multiple circulations in advance of the meeting, and to the preliminary minutes of the April 10, 2018 continuation of the meeting, which had been circulated later with the supplemental materials for this~~e~~ meeting. He asked that the Committee act on the minutes of the April 6 meeting, and consider the April 10 minutes at the June 1 Participants Committee meeting to allow additional time for review for the later-circulated minutes. With no objection to that request, and following motion duly made and seconded, the preliminary minutes of the April 6 meeting were unanimously approved without change.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries, which had been circulated and posted in advance of the meeting, of the ISO

Board and Board Committee meetings that had occurred since the April 6 meeting. There were no questions or comments on the summaries.

Mr. van Welie then provided a high-level overview of the ISO's perspective on fuel security. He noted multiple meetings on the topic with State officials and Federal regulators, NESCOE and NECPUC, Electric Power Supply Association, and the New England Council. He reported by way of context PJM's recent announcement of its intent to conduct a fuel security risk analysis that he thought would be similar to the ISO~~-NE~~'s analysis. He explained that PJM's decision not to act to retain First Energy's coal or nuclear units would likely result in the FERC seeking assurance that fuel security and resilience were~~as~~ being adequately addressed by PJM. He referred to PJM's acknowledgement of fuel security risk and its desire to price that risk in its capacity market. He committed that the ISO~~-NE~~ would maintain open communications with PJM so each could benefit from the other's respective discussions and analyses. He went on to explain his view that any action by New England would be considered by the FERC in this broader context. He suggested that actions taken in connection with Mystic and Distrigas may be considered by the FERC to be analogous, from a price formation and market point of view, to the various State efforts in PJM to retain nuclear plants. He referred to PJM's "jump ball" filing that could result in broader guidance to all RTOs.

Dr. Vamsi Chadalavada then reviewed the ISO's plans with respect to the three chapters for addressing the circumstances presented by the Mystic retirement request:

- *Chapter 1* would address the ISO's waiver request and the subsequent Exelon filing for a reliability agreement. He reminded members that Exelon was seeking confirmation by the end of 2018 that it would have an acceptable agreement for two years or it planned to retire Mystic 8 and 9 unconditionally. He committed the ISO to review with the Reliability Committee additional information in response to questions relating to the scope of the waiver request.

- *Chapter 2* would focus on tools the ISO might need in the medium or longer term to assure fuel security in the absence of successful market signals to achieve that outcome. Specifically, the ISO planned in Chapter 2 to identify and to file Tariff changes authorizing the ISO to retain resources for fuel security during FCA14 and beyond, including in those changes the criteria that the ISO would apply in deciding whether an out-of-market arrangement is justified. He acknowledged that there were questions from the last Reliability Committee meeting that needed to be worked through and that the ISO was considering limiting how long the Chapter 2 changes would remain in effect. Chapter 2 also would focus on how the costs of any reliability agreements for fuel security would be allocated, with a request that the resolution of that issue apply for payments in the Capacity Commitment Period associated with FCA13 as well. The ISO planned to file Chapter 2 changes in November and planned to address price suppression concerns in that filing if possible, although such concerns would likely not be fully addressed until ~~Chapter 3~~FCA14.
- *Chapter 3*, as then envisioned, would replace Chapter 2 changes with changes identified in Chapter 3. The intent would be first to ensure a more complete understanding of the challenges to be addressed and then to find market solutions that would help achieve the necessary fuel security through attributes that could be identified and competitively valued. The ISO planned to complete Chapter 3 by the end of the second quarter of 2019.

The Committee then commented and asked clarifying questions. Members noted that, in contrast to the ISO~~-NE~~, PJM was engaging stakeholders to talk about the assumptions and scenarios before performing its fuel-risk analysis. Concerns were raised about the ISO's reliance on the Operational Fuel Security Analysis (OFSA) published in January while failing to acknowledge in its discussion the other scenarios that had been run since then that showed a very different picture for 2024/2025. There were also questions about the ISO's decision to link the retirement of the Mystic units with the continued operation of Distrigas.

In response to those comments and questions, Mr. van Welie acknowledged that there were, and would remain, differences of opinions that he did not think would be resolved through further discussion. He underscored the ISO's paramount role to use its best judg~~e~~ment in addressing its independent assessment of future risks. The ISO had explained its position to stakeholders and he intended for the ISO to present its best case to the FERC. He expected others would do the same, and the ISO would look to the FERC to resolve the differences of opinions on what was best for the region. He made clear the ISO's desire to ensure that the region could maintain Ten-Minute Operating Reserves during future winters, and the ISO's desire to assure that market prices reflect scarcity conditions. He was not willing for the ISO to delay implementation of solutions while arguing about input assumptions, and preferred instead that time be spent defining the services needed to ensure fuel security and reliability and then defining market mechanisms to value those services.

Dr. Chadalavada clarified that the ISO's analysis in its waiver filing did accept stakeholder encouragement that the ISO model higher levels of LNG injection and imports than those previously experienced. ~~, and e~~Even with those assumptions the case to ensure the availability of Mystic 8 and 9 and Distrigas remained very compelling. He stated that the Chapter 2 process was expected to run May through November, with a filing at the end of that process on both the criteria to be met to justify out-of-market action and the trigger conditions to be applied in future FCAs. He explained that the ISO was thinking that overlapping changes in

Chapters 2 and 3 might be dealt with, for example, by Chapter 2 Tariff changes sunsetting after two or three auctions, thereby giving the region time to implement Chapter 3 changes. He said the ISO was thinking about limiting the duration of Chapter 2 changes based in part on feedback about the difficulty of establishing a bright-line trigger that could be acceptable in the long-term given all the other changes in play. He also saw value in the region together reviewing and addressing its experiences in the context of other market developments both inside and outside New England. He wanted the key efforts of the region to focus on enduring Chapter 3 changes, rather than investing substantial time and effort on interim, Chapter 2 changes.

In response to questions regarding price suppression that results from out-of-market arrangements, he explained that the ISO's focus was on addressing potential price suppression in the Forward Capacity Market and not the other markets. He also clarified in response to questions that Chapter 2 changes were planned for FCA14, with a desire to file such changes in time for reflection in retirement bids for FCA14. He acknowledged the schedule was aggressive since the challenges were universal and had not been solved anywhere, and the possibility that some Chapter 2 changes would not be ready by November. He suggested that the region could work together to phase in changes for FCA14 should some elements take longer to identify or implement.

Mr. van Welie reinforced the observation that the issues confronting New England were also being discussed elsewhere. He said the FERC was likely to provide additional thoughts on the matter while New England was working on solutions. He cautioned that the FERC may provide guidance that seeks consistency on the approach taken by all the RTOs.

The Committee discussed the intent for a market solution in Chapter 3 that would result in acceptance of the retirement of Mystic and potentially other units considered under current provisions to be necessary for fuel security. Mr. van Welie acknowledged the theoretical possibility that Mystic and Distrigas continue in operation in the market following the expiration of the reliability agreements because future market products produce sufficient economic support for such continued operation of Mystic 8 and 9 in the market.

The ISO was urged to move more quickly to address potential price suppression in FCA13. The ISO indicated the potential to begin Chapter 3 discussions as early as June. The suggestion for a sunset on Chapter 2 was designed in part to maintain time pressure on the region to work through the Chapter 3 issues. Dr. Chadalavada expressed his desire that by the end of June 2019 the region will have~~has~~ agreed on a filing that could be implemented shortly thereafter. He also explained that the ISO was in the process of evaluating its Work Plan for the next 18 months given the intensity required to move this issue forward, and would come back to stakeholders with any necessary or suggested adjustments to that Work Plan given the need for accelerated consideration of the fuel security issues.

Dr. Chadalavada responded to questions concerning the trigger conditions and criteria for discussion in Chapter 2, stating the feedback already received on that issue was in part why the ISO would only seek to keep Chapter 2 provisions in place for a short time. He explained that resources would only be able to receive out-of-market support if they submitted Permanent or Retirement De-List Bids. Such treatment would not be available for resources just seeking to de-list for a limited duration. The ISO agreed to ~~in discussion that, in Chapter 3, it would~~ consider emissions impacts in Chapter 3 discussions.

There were a number of questions on what might be expected in Exelon's proposed reliability agreement. The ISO explained that negotiations were ongoing and would necessarily continue once Exelon filed its proposed cost-of-service filing. The ISO expected that issues related to the cost-of-service filing would be addressed in the FERC proceeding and possibly in settlement discussions. The ISO clarified that it expected Exelon's cost-of-service filing to reflect, minimally, ~~costs~~ operations for an additional ~~spread out over at least~~ five years, explaining that there were already three years of existing capacity commitments for the units and the reliability agreement would extend the units' operations for another two years (2022-2024) from there.

Dr. Chadalavada expressed optimism that the region would find a solution that works for New England. While such a solution may not be perfect, the ISO was committed to find a solution with stakeholders that would address this problem for the foreseeable future.

In closing remarks, a NESCOE representative expressed appreciation for the ISO's acknowledgement that discussion in Chapter 3 must begin with a clearly-defined problem statement before advancing to discussions exploring solutions. The NESCOE representative reported that NESCOE's written communication of this point to the ISO in April was posted on the NESCOE website Resource Center page. Mr. Doot reported that the ISO's waiver filing had been publicly noticed and comments were due on or before May 23, 2018.

ISO COO REPORT

Dr. Chadalavada, ISO Chief Operating Officer (COO), referred to the May COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. He said the May COO report reflected data through April 25, 2018. During that time: (i) Energy Market value was $401 million, up $31 million from March 2018 and up $121 million from April 2017; (ii) average natural gas prices were 37% higher than average prices in March 2018; (iii) average Real-Time Hub LMPs ($46.66/MWh) were 42% higher than March 2018 LMPs; (iv) average daily (peak-hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 96.2% in April, down from 97.2% in March 2018; and (v) daily Net Commitment Period Compensation (NCPC) for April (based on data through April 25, 2018) totaled $11.4 million, up $7.6 million from March 2018 and up $8.5 million from April 2017. He noted that the high NCPC in April represented 2.8% of total Energy Market value, and was comprised of the following components: (a) $4.3 million in first contingency payments, up $1.9 million from March 2018; (b) $7.1 million in second contingency payments, up from zero in March 2018, $6.8 million of which would be charged to Northeast Massachusetts and Boston Load Zone (NEMA), and $251,000 (combined) charged to the Southeast Massachusetts (SEMA), Rhode Island and New Hampshire Load Zones; and (c) $31,000 in voltage payments, down $1.4 million from March. Continuing discussion of NCPC, he said that the ISO expected about $1.9 million of the $6.8 million in second contingency payments charged to NEMA to be reallocated to Network Load regionally. He explained that the ISO had to commit out-of-merit resources in NEMA because there was a 345 kV transmission line outage until June 2 (Line 346) and there were forced and planned outages of units in both NEMA and SEMA impacting the power flow into NEMA. He noted the generation resources experiencing outages were then back in service and the volume of uplift experienced in April was expected to be much lower in May. He said that outcome, though, depended on resources not again experiencing outages in May at a similar level experienced in April. He noted that, with completion of the transmission work by June 2, the region will have much less need to call on resources in out-of-merit order. He said there was also a 345-kV line (Line 323) that was out of service until early June and that impacted imports into SEMA, but once it returned to service the ISO did not expect the need for additional out-of-merit commitments associated with that work.

Dr. Chadalavada went on to report that, on April 21, New England experienced for the first time ever a mid-day load that was lower than the overnight load. He said that load curve was the result of record high output from solar panels in the region. He committed to have distributed following the meeting a slide of the April 21 load curve.

Dr. Chadalavada concluded his presentation, reporting on the ISO press release concerning its expectations to have adequate resources for the summer, and its expectations that ~~noting the ISO expected to have adequate resources, with~~ the tie line from New York to Connecticut~~T expected to~~would be back in service by the end of May. Responding to questions from members, he explained that the ISO did not count on oil generation during the summer, recognizing that emission restrictions prevented operations during many summer hours~~ of the summer~~.

FERC ORDER 842 COMPLIANCE: FREQUENCY RESPONSE REVISIONS

Ms. Mariah Winkler referred the Committee to materials circulated and posted in advance of the meeting concerning revisions to Section II of the ISO Tariff in response to requirements of Order No. 842, the FERC's final rule on frequency response (Docket No. RM16-6) (Order No. 842 Revisions). She stated that compliance filings in response to Order 842 were due on May 15. She reported that the recommended support for the Tariff changes would have been on the Consent Agenda but for the timing of the Transmission Committee meeting.

Following motion duly made and seconded, the Committee considered and unanimously approved the following motion:

> RESOLVED, that the Participants Committee supports the Order No. 842 Revisions, as recommended by the Transmission Committee at its April 24, 2018 meeting and as reflected in the materials distributed to the Participants Committee for its May 4, 2018 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

OPERATING PROCEDURE REVISIONS (OP-23, 23J AND 14B)

Ms. Winkler referred the Committee to materials circulated and posted in advance of the meeting concerning revisions to OP-23, Appendix J to OP-23 (23J), and Appendix B to OP-14

(14B and collectively with OP-23 and 23J, the OP Revisions). The OP-23 and 23J revisions related to Price Responsive Demand (PRD) and generator response rate auditing provisions. The 14B revisions related to PRD, reactive capability data, and certain other editorial changes. She reported that support for the OP Revisions was unanimously recommended by the Reliability Committee at its April 25 meeting, and that this item also would have been on the Consent Agenda but for the timing of the Reliability Committee meeting.

A member expressed concern that neither OP-23 nor the Tariff reflected a methodology for the ISO's proposed new auditing of ramp rates. He requested that the methodology at least be memorialized in the OP so Market Participants could understand how those audits would be performed. The ISO referred the Committee to supporting materials which were presented at the Reliability Committee that explained this methodology for OP-23. The ISO committed to consider including that detail as an attachment or supplement to OP-23, which it would review with the Reliability Committee and have addressed by the Participants Committee thereafter as appropriate. Since audits of ramping capability were likely to take place in the interim, the ISO agreed to post the methodology on the ISO website.

With that understanding and commitment, the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the Revisions to OP-23, Appendix K to OP-23 and Appendix B to OP-14, as recommended by the Reliability Committee at its April 25, 2018 meeting, together with the changes identified in the materials distributed to the Participants Committee for its May 4, 2018 meeting and such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

The Committee considered and unanimously approved the motion with abstentions noted by Brookfield, CLF, CPower/Enerwise, EnerNOC, PSEG, and NRG.

NEPOOL COMMENTS -- FERC GRID RESILIENCE PROCEEDING (AD18-7)

Ms. Winkler referred the Committee to materials circulated and posted in advance of the meeting concerning NEPOOL's proposed comments in the FERC's Grid Resilience proceeding (AD18-7) (the NEPOOL Comments). She explained that the NEPOOL Comments focused on fuel security in New England and NEPOOL's input into the work on fuel security risks, including the Operational Fuel Security Analysis and subsequent studies requested by stakeholders, and the deliberations on any potential fuel security market-based solutions related to fuel security risks. She reported that the Reliability Committee recommended Participants Committee approval of the NEPOOL Comments at its April 24 meeting with no opposition. She said, but for the timing of the vote at the Reliability Committee, this item would have been on the Consent Agenda.

Following motion duly made and seconded, the Committee considered and unanimously approved the following motion, with abstentions noted by Cross-Sound Cable and Eversource:

> RESOLVED, that the Participants Committee approves the filing of the NEPOOL Comments in the Grid Resilience proceeding in Docket No. AD18-7-000, as recommended by the Reliability Committee at its April 24, 2018 meeting and as reflected in the materials distributed to the Participants Committee for its May 4, 2018 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.

GUIDANCE ON PENDING NEPOOL MEMBERSHIP APPLICATION

Mr. Doot referred the Committee to the confidential memorandum circulated in advance of the meeting concerning a request for guidance to the Membership Subcommittee (Subcommittee) and to NEPOOL Counsel regarding (1) whether to change NEPOOL's policy of not permitting press attendance at NEPOOL meetings and (2) desired action on an application for membership as a Governance Only End User by a member of the press. The Committee discussed those two points at length. Following that discussion, NEPOOL Counsel committed to review the discussion with the Subcommittee so that, based on the input provided, the Subcommittee could make recommendations to the Participants Committee for Committee action at a later meeting on these two issues.

LITIGATION REPORT

Mr. Doot referred the Committee to the May 2 Litigation Report that had been circulated and posted in advance of the meeting. Mr. Gerity highlighted, as reported earlier in the meeting, that comments on the ISO's waiver filing we~~a~~re due on May 23. He requested that ~~if ~~anyone with ~~had ~~questions on the report ~~to ~~contact NEPOOL Counsel.

COMMITTEE REPORTS

Mr. William Fowler reported that the Markets Committee was scheduled to meet on May 8 and 9 in Westborough. He highlighted a key agenda item would be discussion of the Internal Market Monitor (IMM) proposal to change before FCA13 how it calculates ~~r~~Retirement ~~d~~De-list ~~b~~Bids. He said that the IMM had requested a vote by the Participants Committee at its June 1 meeting for immediate implementation. An additional Markets Committee teleconference meeting had been scheduled for May 17 to act on the proposal.

Mr. José Rotger reported that the Transmission Committee was scheduled to meet on May 24 in Westborough. The main agenda item would be to begin discussions on compliance with Order 845, which required changes to the standard large and small generation interconnection processes.

Mr. Ken Dell Orto reported that the Budget & Finance Subcommittee was scheduled to meet on May 10, with a full agenda, including ~~and ~~review of financial reports. He highlighted that, following the May meeting, the Subcommittee would not meet again until August 10. At its

August meeting, the principle agenda item would be to review 2019 budgets for the ISO and NESCOE.

OTHER BUSINESS

Mr. Kaslow reported that the June 1 Participants Committee meeting was scheduled to be held as a teleconference meeting. Mr. Doot reminded the Committee that the next Membership Subcommittee was scheduled for~~on~~ May 14 as a teleconference meeting and to pay attention to notices for that and subsequent meetings to address the issues discussed earlier in the meeting~~by the Participants Committee~~. He reminded members that the 2018 NEPOOL Summer Meeting was scheduled to take place June 26-28 at the Water's Edge Resort in Westbrook, CT and encouraged those interested to register and to make their reservations. He also reminded the Committee of the NECPUC Symposium scheduled for May 20-23 at the Cliff House in Maine and encouraged those interested to participate.

There being no further business, the meeting adjourned at 12:55 p.m.

Respectfully submitted,

David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
MAY 4, 2018 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
American PowerNet Management	Supplier			Mary Smith (tel)
Anbaric Development Partners LLC	Provisional Group	Steve Conant		
AR Small Load Response (LR) Group Member	AR-LR	Doug Hurley	Brad Swalwell (tel)	
AR Small Renewable Generation (RG) Group Member	AR-RG	Erik Abend (tel)		
Ashburnham Municipal Light Plant	Publicly Owned		Brian Thomson	
AVANGRID: CMP/UI	Transmission	Adam Sokoloski (tel)	Alan Trotta (tel)	
Belmont Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Block Island Power Company	Supplier	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned		Brian Thomson	
BP Energy Company	Supplier			Nancy Chafetz
Braintree Electric Light Department	Publicly Owned			Dave Cavanaugh
Brookfield Energy Marketing	Supplier	Aleksandar Mitreski		
Chester Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Doug Hurley		
Competitive Energy Services, LLC	Supplier			Glenn Poole
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop. (CMEEC)	Publicly Owned	Brian Forshaw		
Conn. Office of Consumer Counsel	End User			Dave Thompson
Conservation Law Foundation (CLF)	End User	David Ismay (tel)		
Consolidated Edison Energy, Inc. (ConEd)	Supplier	Jeff Dannels		
CPV Towantic, LLC	Generation	Dan Pierpont		
Cross-Sound Cable Company (CSC)	Supplier		Jose Rotger	
Danvers Electric Division	Publicly Owned		Dave Cavanaugh	
Direct Energy Business, LLC	Supplier	Ron Carrier		Nancy Chafetz
Dominion Energy Generation Marketing, Inc.	Generation		James Davis	
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier		Carol Holahan	Bill Fowler
Emera Energy Services	Transmission	Sandi Hennequin		Bill Fowler
EnerNOC, Inc.	AR-LR		Herb Healy	
Enerwise Global Technologies Inc. d/b/a CPower Corp.	AR-LR		Herb Healy	
Entergy Nuclear Power Marketing, LLC	Generation	Ken Dell Orto		Bill Fowler
Eversource Energy	Transmission		Cal Bowie	Vandan Divatia
Environmental Defense Fund	End User	Liz Delaney		
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Resources Management	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation		Abby Krich (tel)	Bob Stein Susan Muller (tel)
Georgetown Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Great River Hydro, LLC	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned		Brian Thomson	
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	Supplier		Bob Stein	Abby Krich (tel)
Harvard Dedicated Energy Limited	End User	Mary Smith (tel)	Mike Macrae	Paul Peterson Doug Hurley
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	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MAY 4, 2018 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Holyoke Gas & Electric Department	Publicly Owned		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned		Brian Thomson	
Littleton (MA) Electric Light and Waster Department	Publicly Owned		Dave Cavanaugh	
Long Island Lighting Company (LIPA)	Supplier		William Killgoar	
Maple Energy LLC	AR-LR		Rick Drom (tel)	
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	
Marble River, LLC	Supplier		John Brodbeck (tel)	
Massachusetts Attorney General's Office (MA AG)	End User	Fred Plett	Christina Belew	
Mass. Municipal Wholesale Electric Company	Publicly Owned	Brian Thomson		
Mercuria Energy America, Inc.	Supplier			Nancy Chafetz
Merrimac Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned		Brian Thomson	
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan	Tim Martin	
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative (NHEC)	Publicly Owned	Steve Kaminski (tel)		Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned		Brian Thomson	
PowerOptions, Inc.	End User	Cindy Arcate		Paul Peterson
Princeton Municipal Light Department	Publicly Owned		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned			Brian Forshaw
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	
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned		Brian Thomson	
Stowe Electric Department	Publicly Owned		Dave Cavanaugh	
Taunton Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson	
The Energy Consortium	End User		Mary Smith (tel)	Paul Peterson, Fred Plett Doug Hurley
Utility Services Inc.	End User			Paul Peterson
Vermont Electric Power Company	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw
Verso Energy Services LLC	Generation	Glenn Poole		
Vitol Inc.	Supplier	Joe Wadsworth		
Wakefield Municipal Gas & Light Department	Publicly Owned		Brian Thomson	
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	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
MAY 4, 2018 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Westfield Gas & Electric Department	Publicly Owned		Dave Cavanaugh	
Wheelabrator/Calpine	AR-RG	Brett Kruse ~~John Flumerfelt~~	John Flumerfelt ~~Brett Kruse~~	Bill Fowler

CONSENT AGENDA

Markets Committee

From the notice of actions of the Markets Committee's ***May 8-9, 2018*** meeting,[1] dated May 10, 2018, which has been previously circulated:

1. **Revisions to OP-9 (PRD Design and Clean-Up Changes)**

Support revisions to ISO New England Operating Procedure No. 9 (OP-9) (Scheduling and Dispatch of External Transactions), consisting of Price Responsive Demand (PRD)-conforming changes and other revisions, as recommended by the Markets Committee at its May 8-9, 2018 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously with one Supplier Sector abstention noted.

Reliability Committee

From the notice of actions of the Reliability Committee's ***May 15, 2018*** meeting,[2] dated May 16, 2018, which has been previously circulated:

2. **PP-4 New Attachment G**

Support the addition of new Attachment G (Guidance for Submission of TCA Applications for Asset Condition Projects) to ISO-NE Planning Procedure (PP) No. 4 (PP-4) (Procedure for Pool-Supported PTF Cost Review), which provides guidance to Asset Owners for determining when a Planning Advisory Committee presentation and Transmission Cost Allocation (TCA) submittal are required, as recommended by the Reliability Committee at its May 15, 2018 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 Supplier Sector abstention noted.

From the notice of actions of the Reliability Committee's ***April 24-25, 2018*** meeting, dated April 25, 2018, which has been previously circulated:

3. **Operating Procedure Changes (PRD Implementation-Related Changes)**

Support revisions to the following OPs to reflect changes related to the implementation of PRD, as recommended by the Reliability Committee at its April 24-25, 2018 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve:

- **OP -1** (Central Dispatch Operating Responsibilities and Authority) and Appendix A to OP-1 (Assignment of Responsibilities);

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[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: http://iso-ne.com/committees/reliability/reliability-committee.

CONSENT AGENDA (cont.)

- **OP-4** (Action During a Capacity Deficiency) and **Appendix A to OP-4** (Estimates of Additional Generation and Load Relief);
- **OP-5** (Generator, Dispatchable Asset Related Demand and Alternative Technology Regulation Resource Maintenance and Outage Scheduling) and **Appendices A** (Operable Capacity Calculations), **B** (Outage Request Form) and **D** (Demand Response Activation Analysis) to OP-5;
- **OP-13** (Standards for Voltage Reduction and Load Shedding Capability);
- **OP-18** (Metering and Telemetering Criteria) and **Appendix C to OP-18** (Minimum Accuracy Standards for New and Upgraded Metering, Recording and Telemetering Installations and Calibration of Existing Equipment);
- **OP-19** (Transmission Operations); and
- **OP-21** (Energy Inventory Accounting and Actions During an Energy Emergency).

The motion to recommend Participants Committee support for these changes was approved unanimously.

Summary of ISO New England Board and Committee Meetings

June 1, 2018 Participants Committee Meeting

Since the last update, the Audit and Finance Committee, the Markets Committee, and the Nominating and Governance Committee each met on May 17 via teleconference.

The Audit and Finance Committee reviewed the Company's financial performance against the 2018 budget, and approved the first quarter's unaudited financial statements after management confirmed that all relevant disclosures were included in the financial statements. Next, the Committee discussed the preliminary 2019 operating and capital budgets. The Committee then undertook its annual risk assessment and reviewed the key risks within the scope of the Committee's oversight of Company operations. The Committee also reviewed the structure of the Company's compliance and risk management programs, and received an overview of the Company's physical security and plans for business continuity. Next, the Committee reviewed the annual vendor report, which showed the top fifteen vendors. The Committee also reviewed a draft of the Company's 2017 tax return on Form 990.

The Markets Committee received an update on the waiver and cost-of-service agreement related to the pending Mystic retirements. The Committee also reviewed highlights of the External Market Monitor's draft annual markets report for 2017, and discussed the recommendations that will be contained in the report.

The Nominating and Governance Committee discussed the status of the new director candidate and procedures for orienting a new director. The Committee also discussed assignments to Board committees and issues related to board succession planning. Finally, the Committee met in executive session to examine the Board's and the committees' annual self-evaluation results.

NEPOOL PARTICIPANTS COMMITTEE
06/01/18 MEETING, AGENDA ITEM #4

NEPOOL Participants Committee Report

June 2018

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 over the period was $174M, down $263M from April 2018 and down $109M from May 2017
  - May 2018 natural gas prices over the period were 53% lower than April 2018 average values
    - Average RT Hub Locational Marginal Prices ($21.78/MWh) over the period were 50% lower than April averages
    - Average May 2018 natural gas prices and RT Hub LMPs over the period were down 22% and 26%, respectively, from May 2017 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 94.7% during May, down from 96.4% during April*
    - The minimum value for the month was 85.1% on Friday, May 11**

Data are through May 23, 2018 unless otherwise noted.

Underlying natural gas data furnished by:

***DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market**
****Daily values shown on slide 32**

Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - May NCPC payments totaled $3.9M over the period, down $8.2M from April 2018 and down $1.4M from May 2017
    - First Contingency* payments totaled $3.7M, down $1.2M from April 2018
      - $2.6M paid to internal resources, down $1.9M from April
        - » $1.1M charged to DALO, $992K to RT Deviations, $422K to RTLO
      - $1.1M paid to resources at external locations, up $704K from April
        - » $1.1M to RT Deviations
    - Second Contingency payments totaled $169K, down $7M from April
    - Voltage payments were negligible
  - NCPC payments over the period as percent of Energy Market value were 2.2%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $223K; Rapid Response Pricing (RRP) Opportunity Cost - $154K; Posturing - $23K; Generator Performance Auditing (GPA) - $22K;**

Highlights, cont.

- Final 2017 Northeast Coordinated System Plan (NCSP) was posted on May 4
- 2017 Economic Study draft report scheduled to be posted by July for review by the Planning Advisory Committee (PAC)
- New Capacity Qualification Packages are due by June 22 for Capacity Commitment Period #13 (June 2022 – May 2023)
- ISO-NE expects to model three zones for Capacity Commitment Period #13: Rest-of-Pool zone, Southeast New England as an import-constrained zone, and Northern New England as an export-constrained zone

Forward Capacity Market (FCM) Highlights

- CCP #8 (2017-2018)
  - New, non-commercial resources are expected to be commercial by the start of CCP #9
- CCP #9 (2018-2019)
  - Resources greater than 100 MW are being tracked closely via monthly CPS monitoring, and are expected to meet their reported COD
  - Monthly activities to trade/cover a CSO have commenced
- CCP #10 (2019-2020)
  - Second bilateral transaction window closed on May 4 and results will be posted by June 8
  - The second reconfiguration auction will be August 1-3, and results to be posted by August 17
  - Third bilateral transaction window will be December 5-7, and results to be posted by January 11, 2019

CCP – Capacity Commitment Period
CPS – Critical Path Schedule
COD – Commercial Operation Date
CSO – Capacity Supply Obligation

FCM Highlights, cont.

- CCP #11 (2020-2021)
    - Seasonal and annual bilateral transactions will no longer be available beginning CCP #11
    - First reconfiguration auction will be June 1-5, and results to be posted by June 19
    - Second reconfiguration auction will be August 1-5, 2019, and results to be posted by September 3, 2019
- CCP #12 (2021-2022)
    - First reconfiguration auction will be June 3-5, 2019, and results to be posted by June 3, 2019

FCM Highlights, cont.

- CCP #13 (2022-2023)
  - Potential capacity zone boundaries have been established. Final capacity zones were discussed at the May 29 Power Supply Planning Committee.
    - For FCA 13, there will be three Capacity Zones modeled: Southeast New England as an import-constrained zone, Northern New England as an export-constrained zone and Rest-of-Pool zone. These are the same zones as FCA #12.
  - Static and export delist bids are due June 8.
  - New Capacity Qualification Packages are due June 22.
    - Renewable technology resource election cap is approximately 481 MW.
  - Stakeholder discussions continue at the RC regarding the Installed Capacity Requirement/Local Sourcing Requirement.

FERC Order 1000

- Intraregional Planning
  - 20 companies have achieved Qualified Transmission Project Sponsor (QTPS) status
  - 2018 Annual QTPS Certification
    - All 20 QTPSs submitted completed Annual QTPS Certification forms within the January 1 - 31 Certification Window
    - ISO notified the 20 QTPSs on February 16 that they met the 2018 Annual Certification requirements and, as such, QTPS status is maintained

Highlights, cont.

- The lowest 50/50 and 90/10 Preliminary Summer Operable Capacity Margin Week is projected for week beginning June 2, 2018.
  - **Note**: Summer projections reflect 2018-2019 Capacity Supply Obligations.
  - As of June 1, 2018 the active demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and have the ability to participate in the Day-Ahead and Real-Time Energy Markets.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (3.9°F) Max: 90°F, Min: 44°F Precipitation: 1.90" – Below Normal Normal: 3.11"	Hartford	Temperature: Above Normal (4.7°F) Max: 94°F, Min: 41°F Precipitation: 2.47" - Above Normal Normal: 3.86"

Peak Load:	16,052 MW	May 26, 2018	18:00 (ending)

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

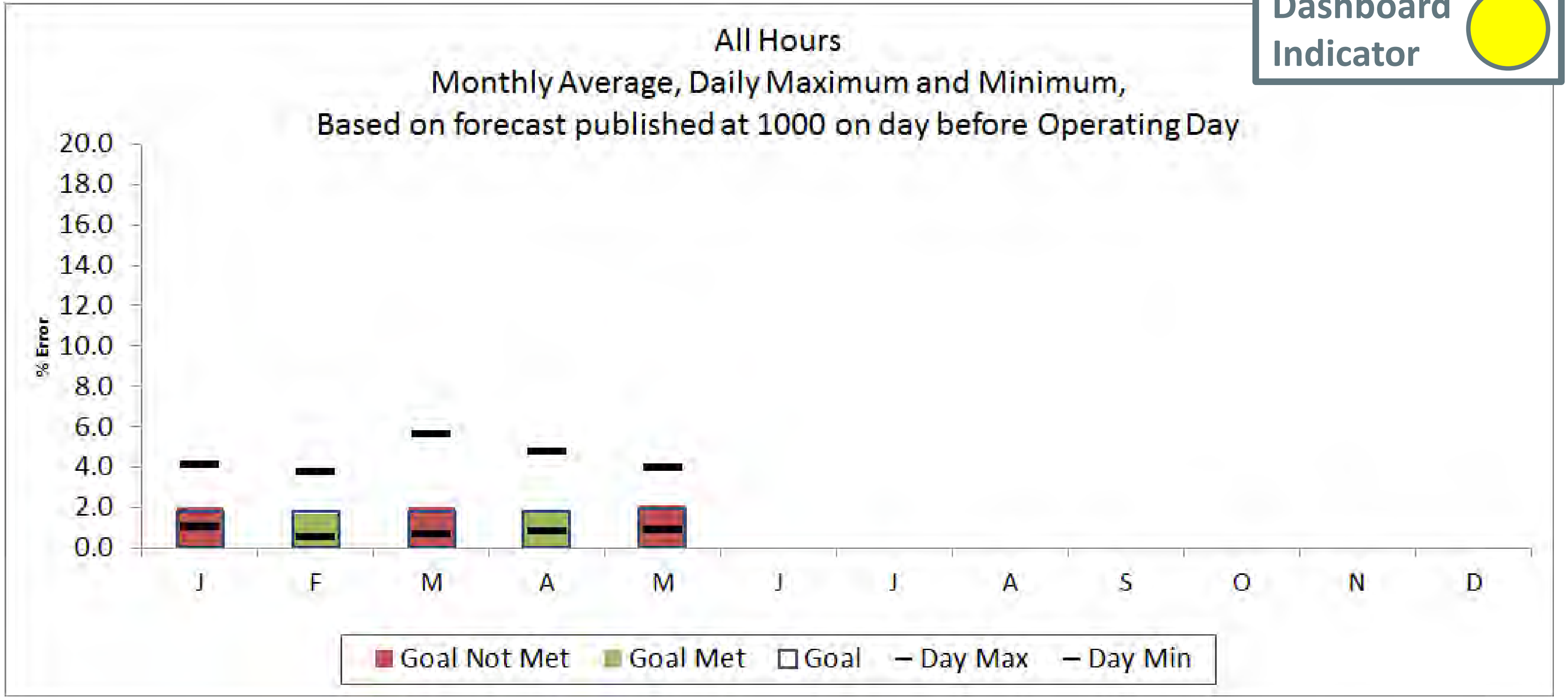
Procedure	Declared	Cancelled	Note
No Events in May			

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
May 6, 2018	IESO	865
May 16, 2018	NBPSO	440

2018 System Operations - Load Forecast Accuracy

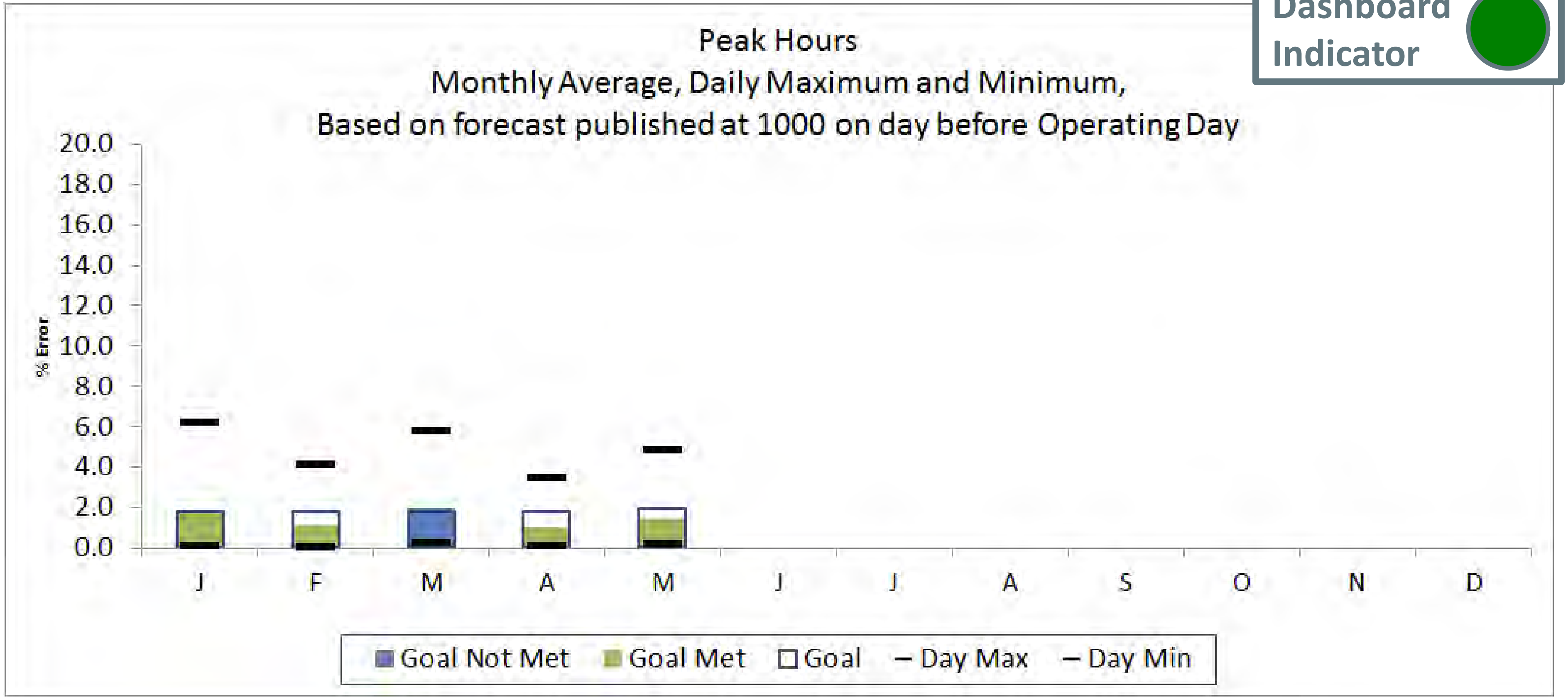
Dashboard Indicator 🟡



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	3.69	5.58	4.70	3.93								5.58
Day Min	1.02	0.53	0.63	0.82	0.83								0.53
MAPE	2.04	1.67	2.05	1.74	2.08								1.92
Goal	1.80	1.80	1.80	1.80	2.00								

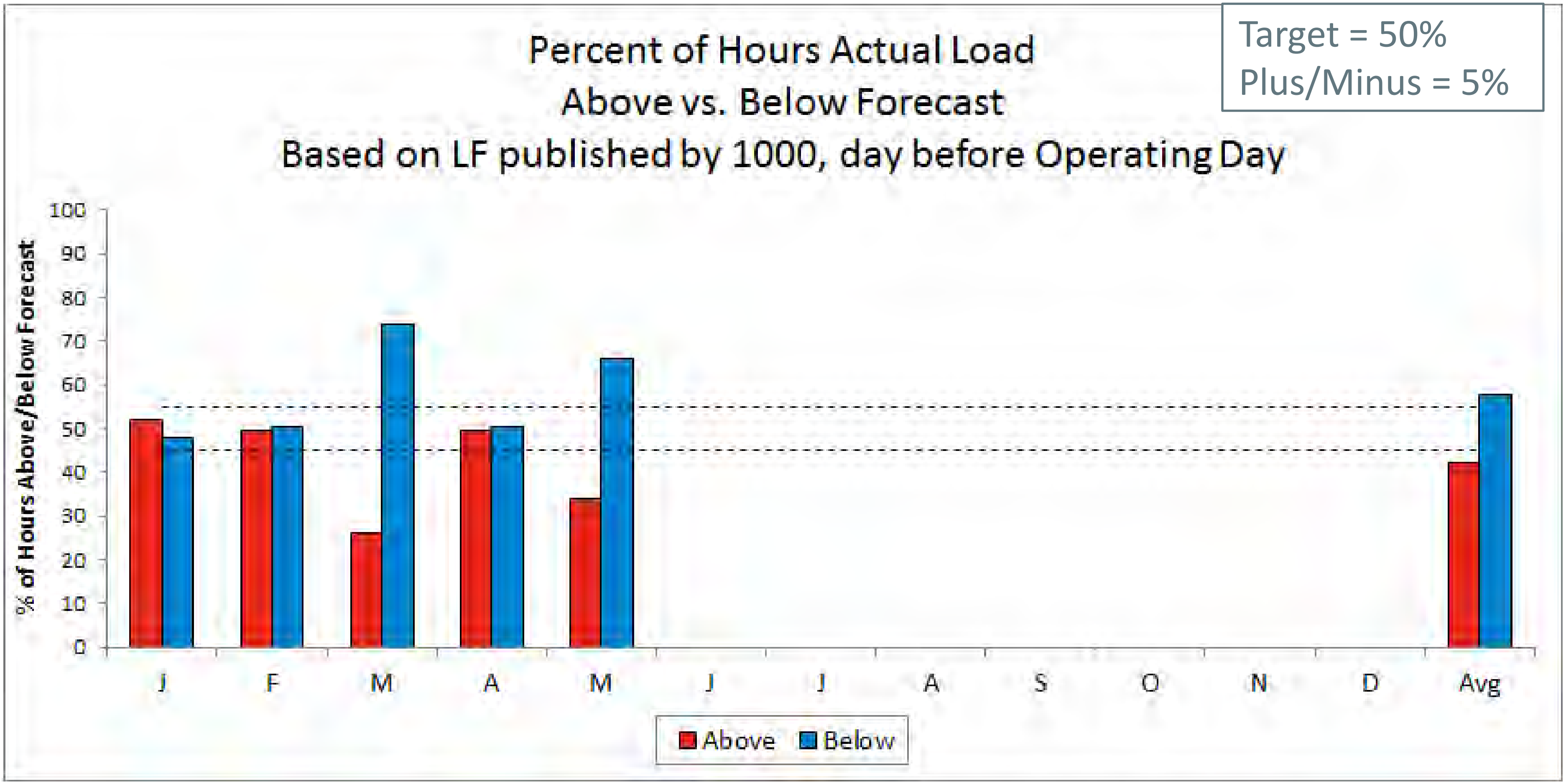
2018 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator ●



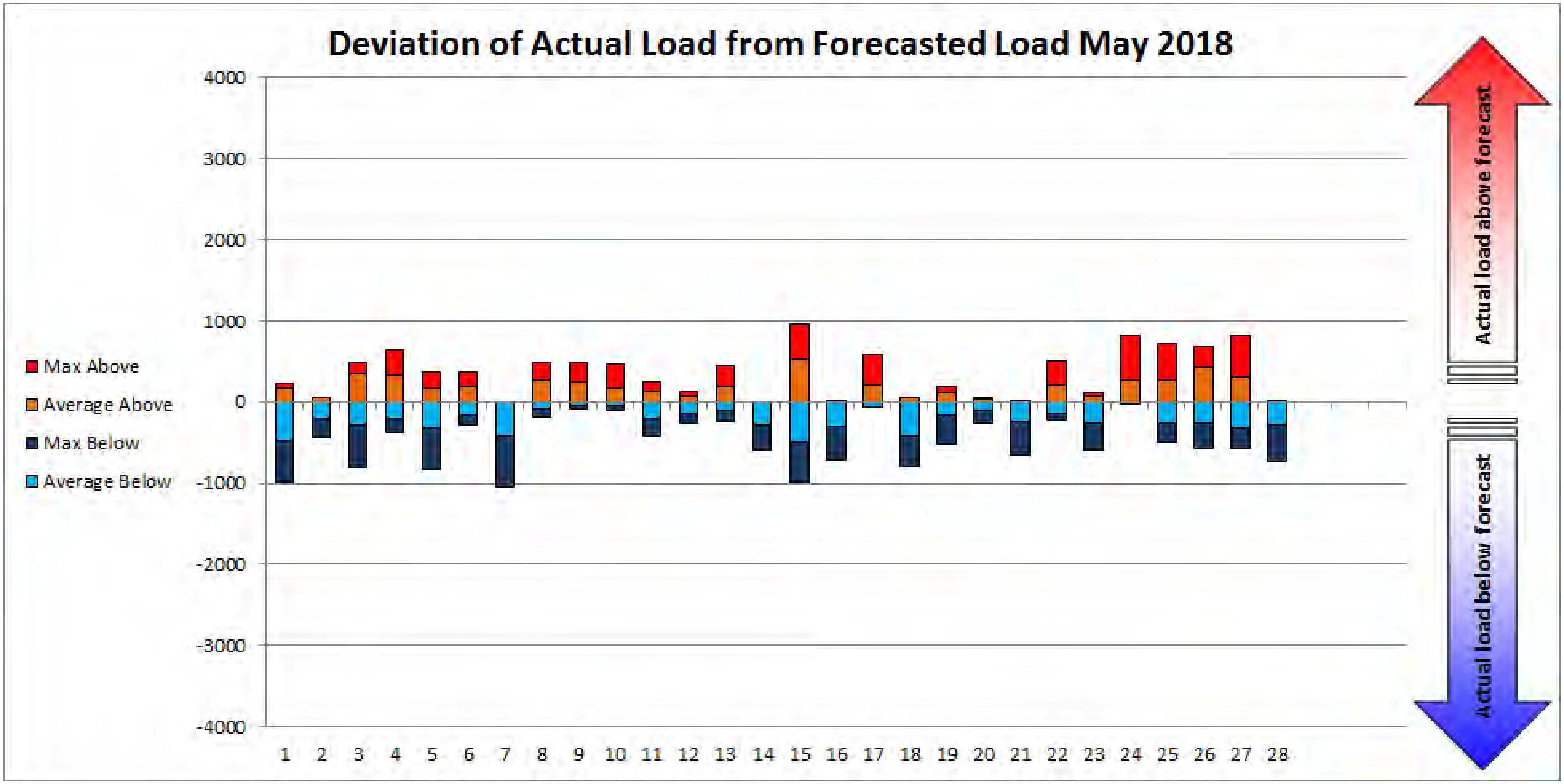
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.15	4.08	5.76	3.42	4.80								6.15
Day Min	0.04	0.03	0.25	0.04	0.13								0.03
MAPE	1.73	1.14	1.91	1.01	1.47								1.46
Goal	1.80	1.80	1.80	1.80	2.00								

2018 System Operations - Load Forecast Accuracy cont.

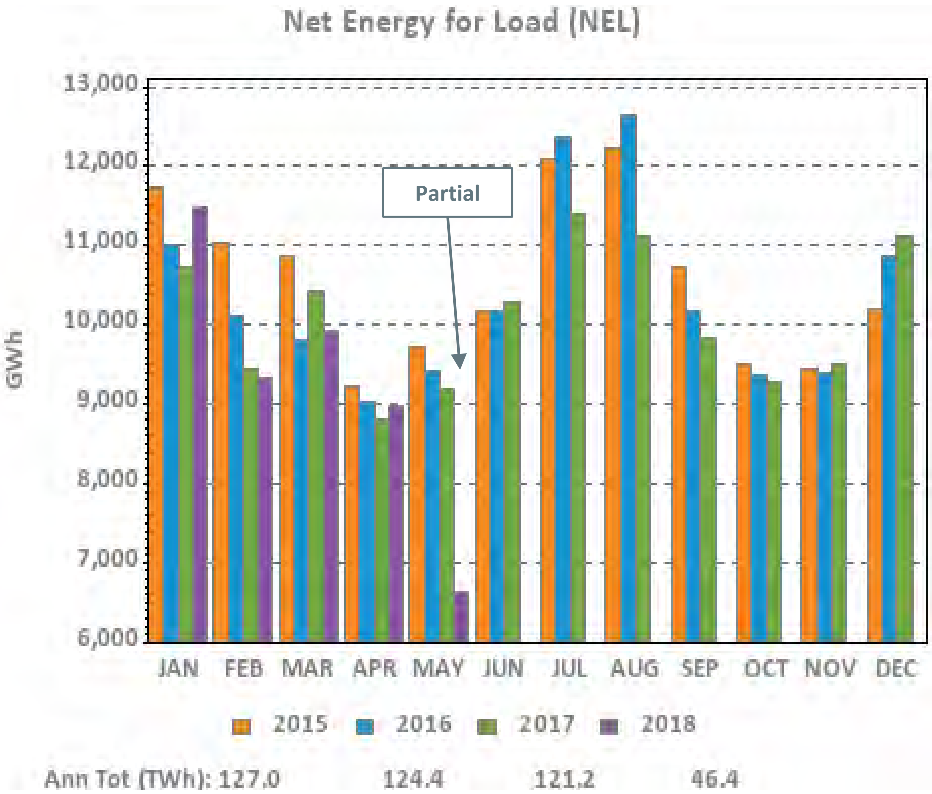


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	52	49.7	26.1	49.6	34.1								42
Below %	48	50.3	73.9	50.4	65.9								58
Avg Above	222.2	193.9	98.9	177.2	156.6								222
Avg Below	-242.4	-180.6	-278.3	-177.8	-204.7								-278
Avg All	0	14	-192	1	-92								-55

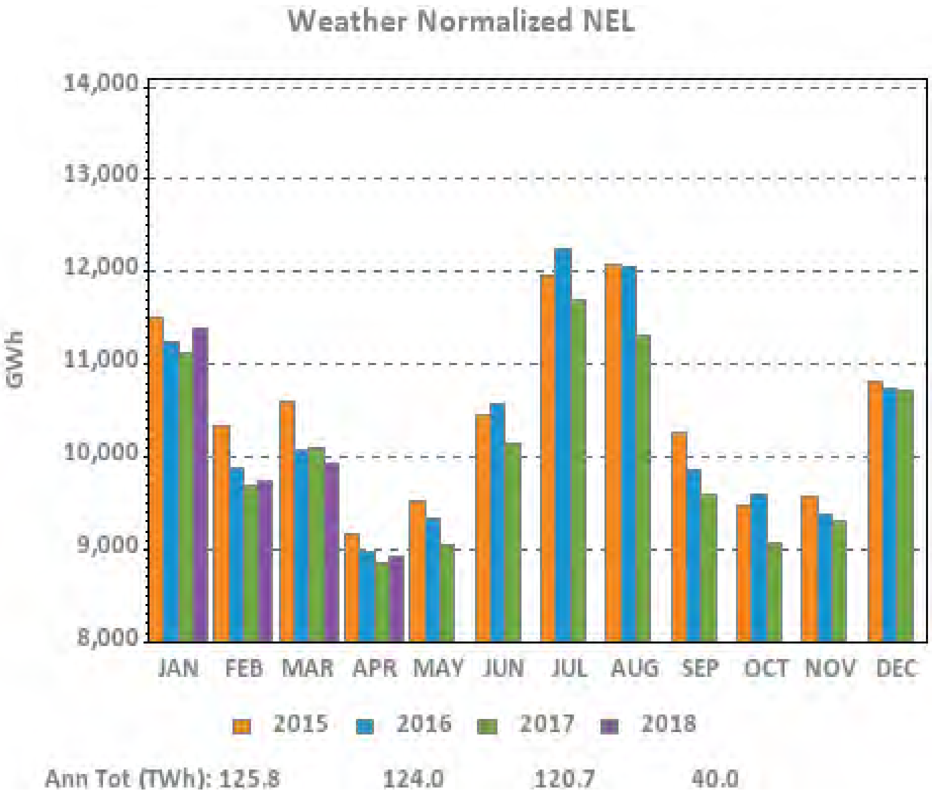
2018 System Operations - Load Forecast Accuracy cont.



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

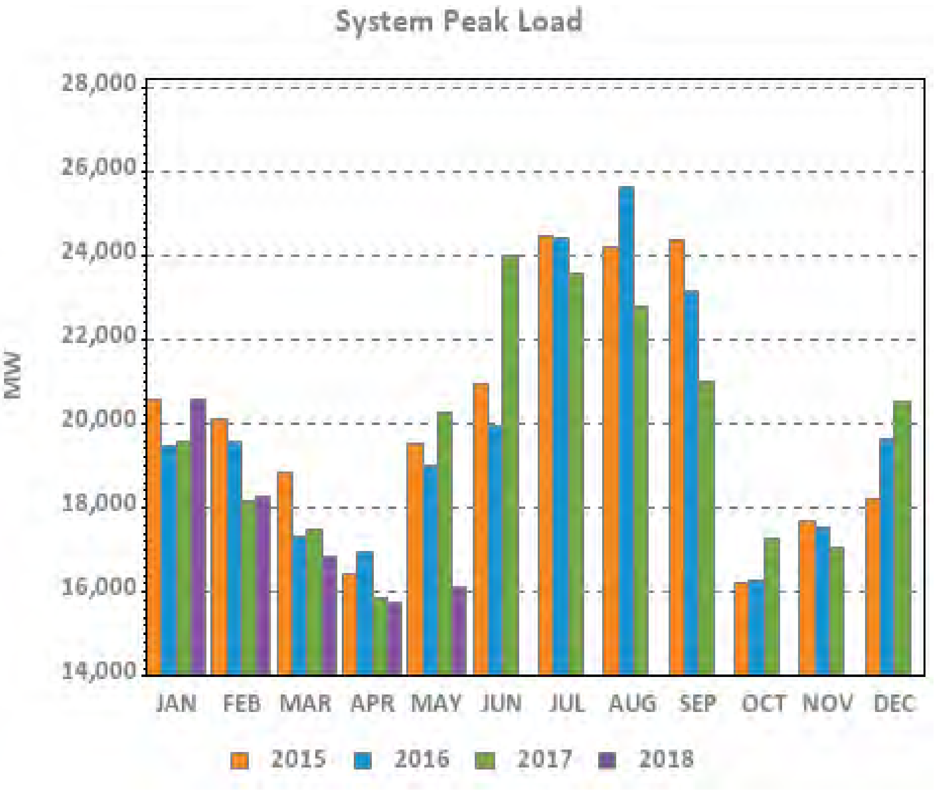


Partial

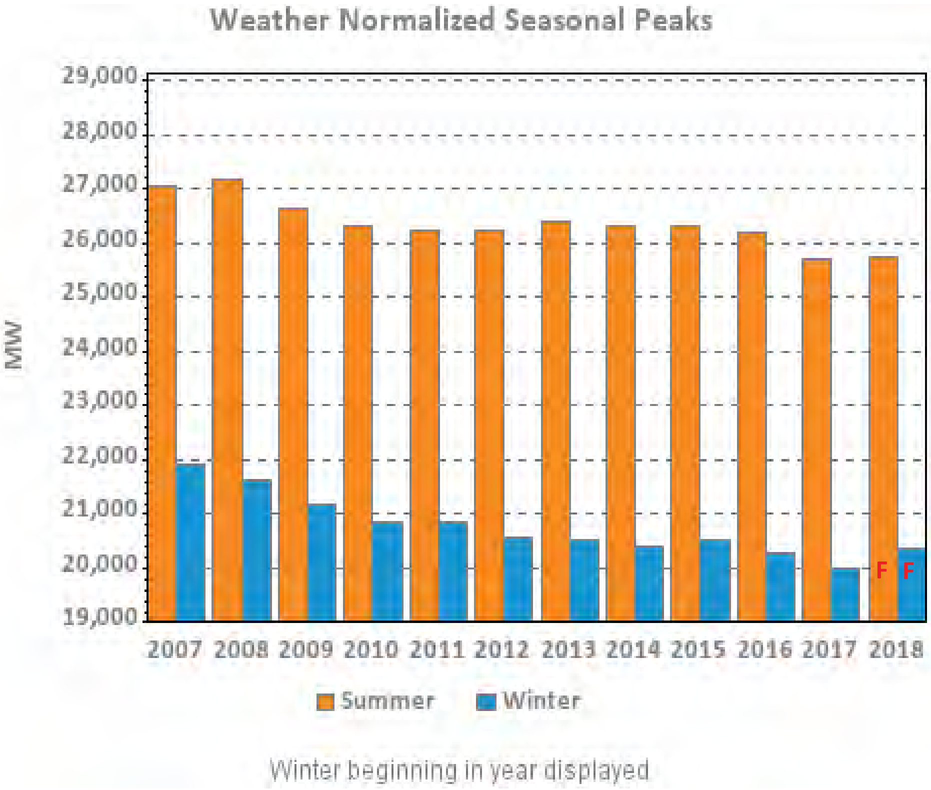


NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.
Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



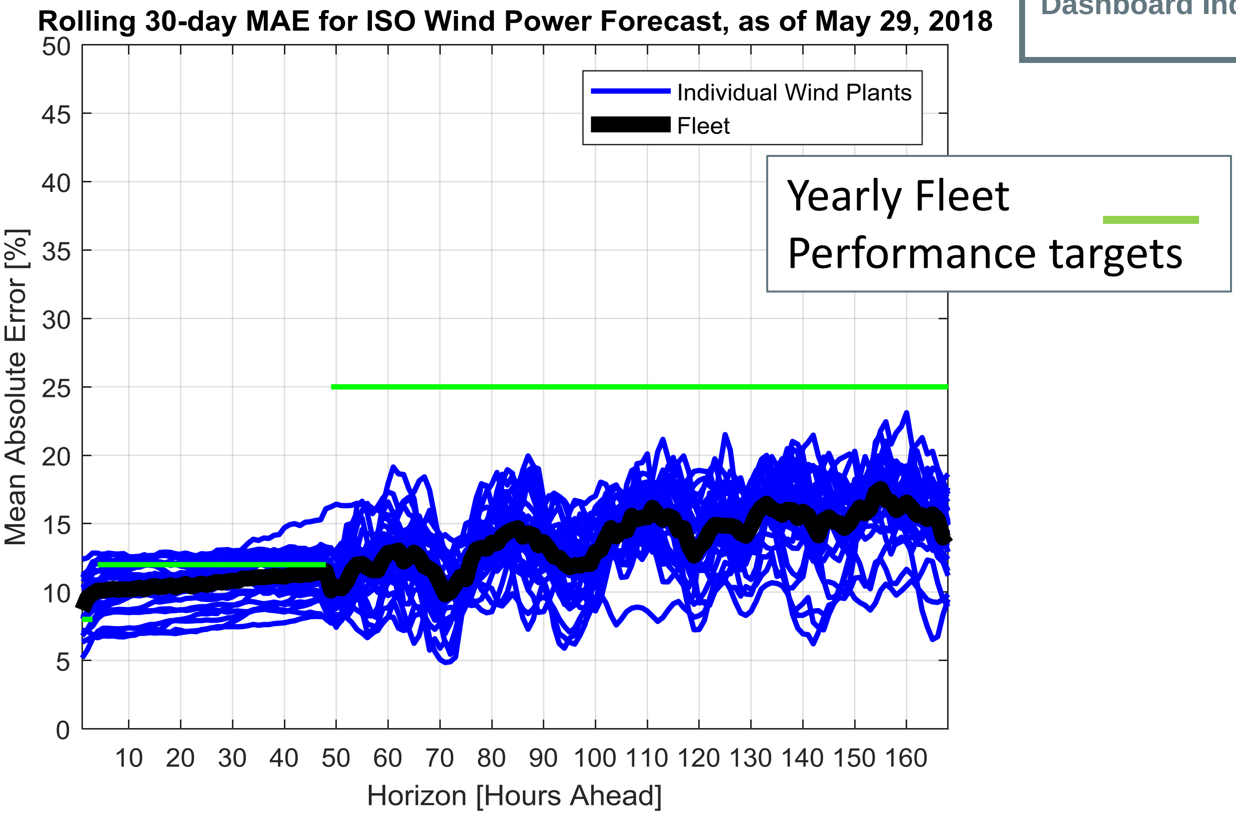
*Revenue quality metered value



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

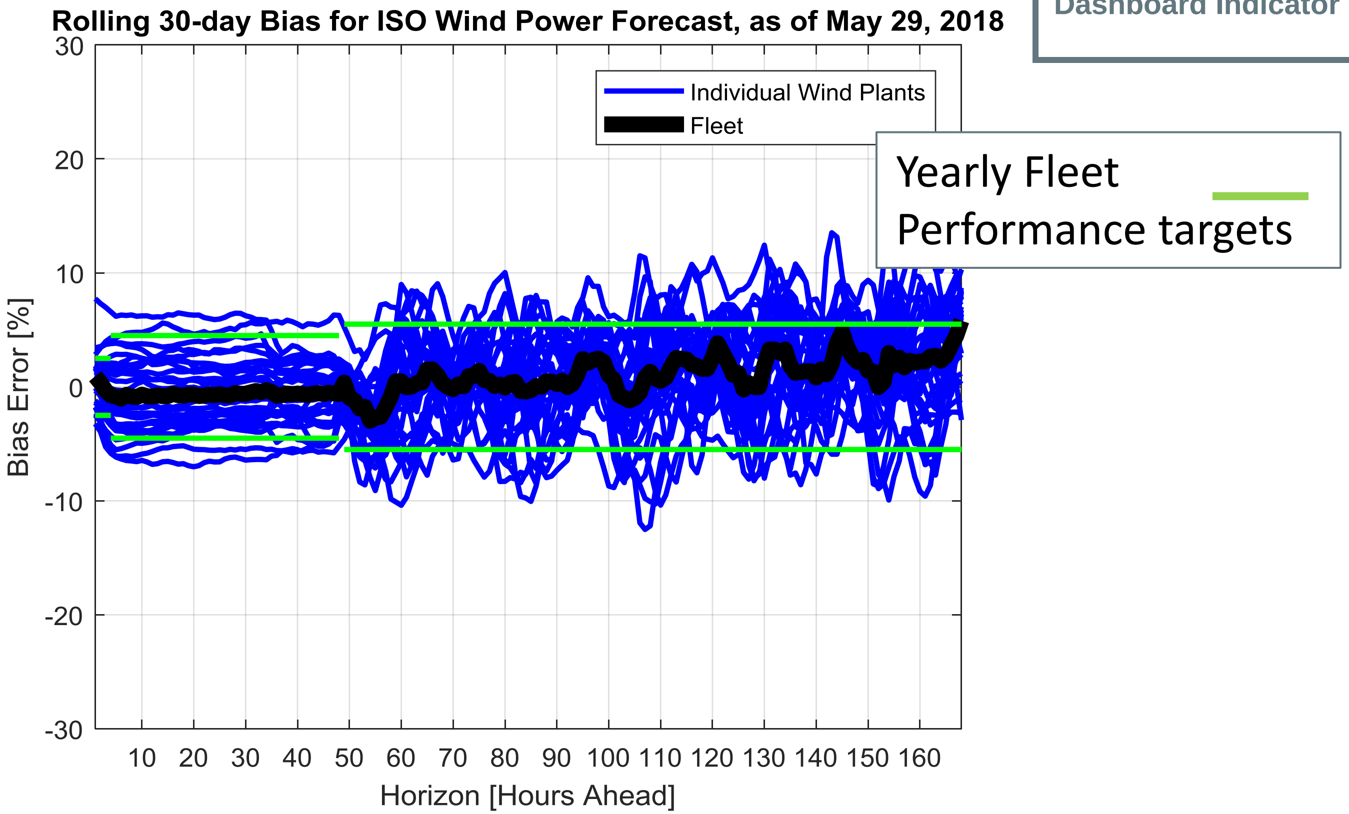
Dashboard Indicator 🟢



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.

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

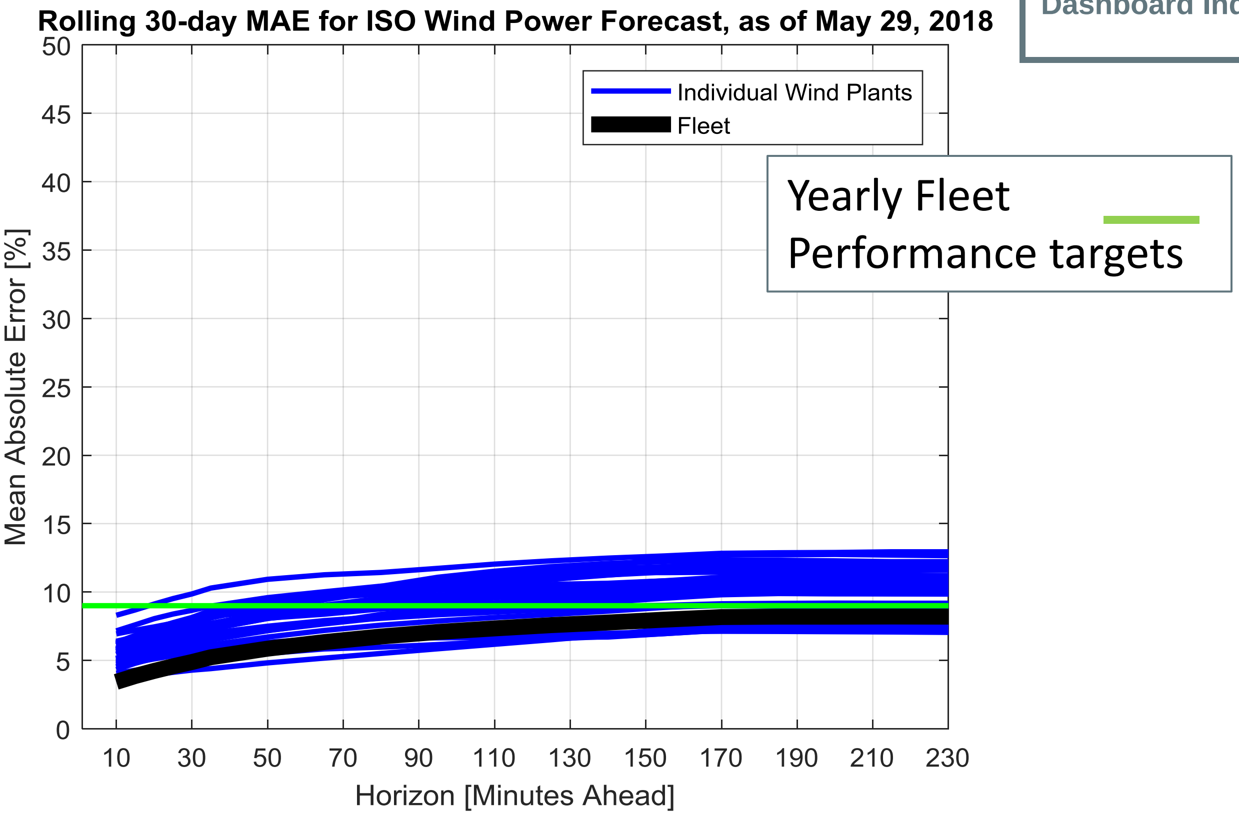
Dashboard Indicator ●



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator ●

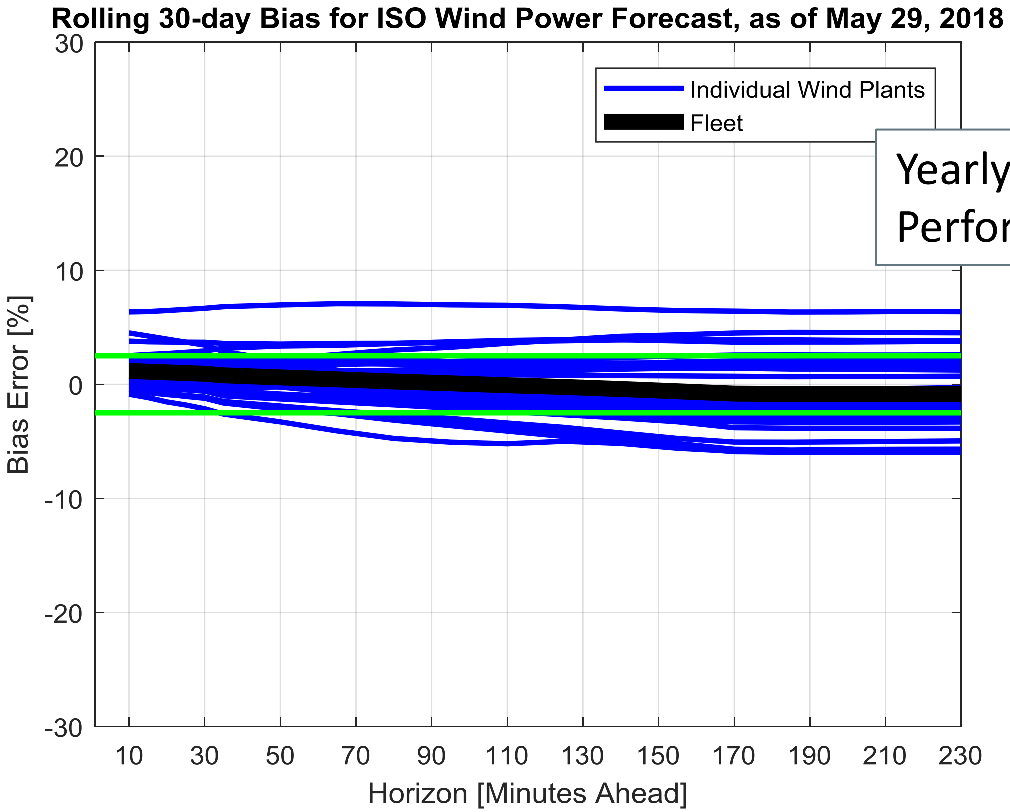


Yearly Fleet Performance targets

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 ●

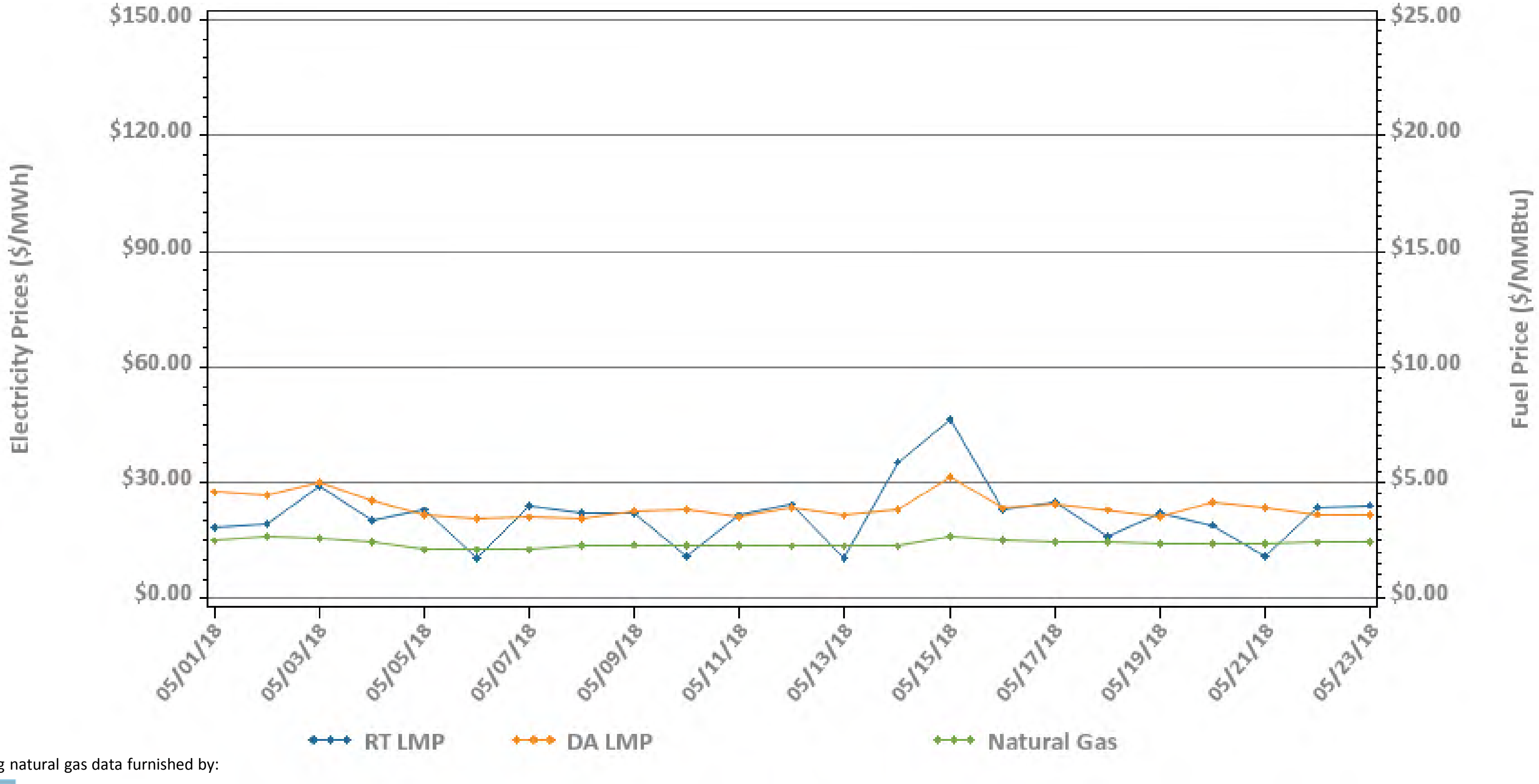


Yearly Fleet Performance targets

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: May 1-23, 2018

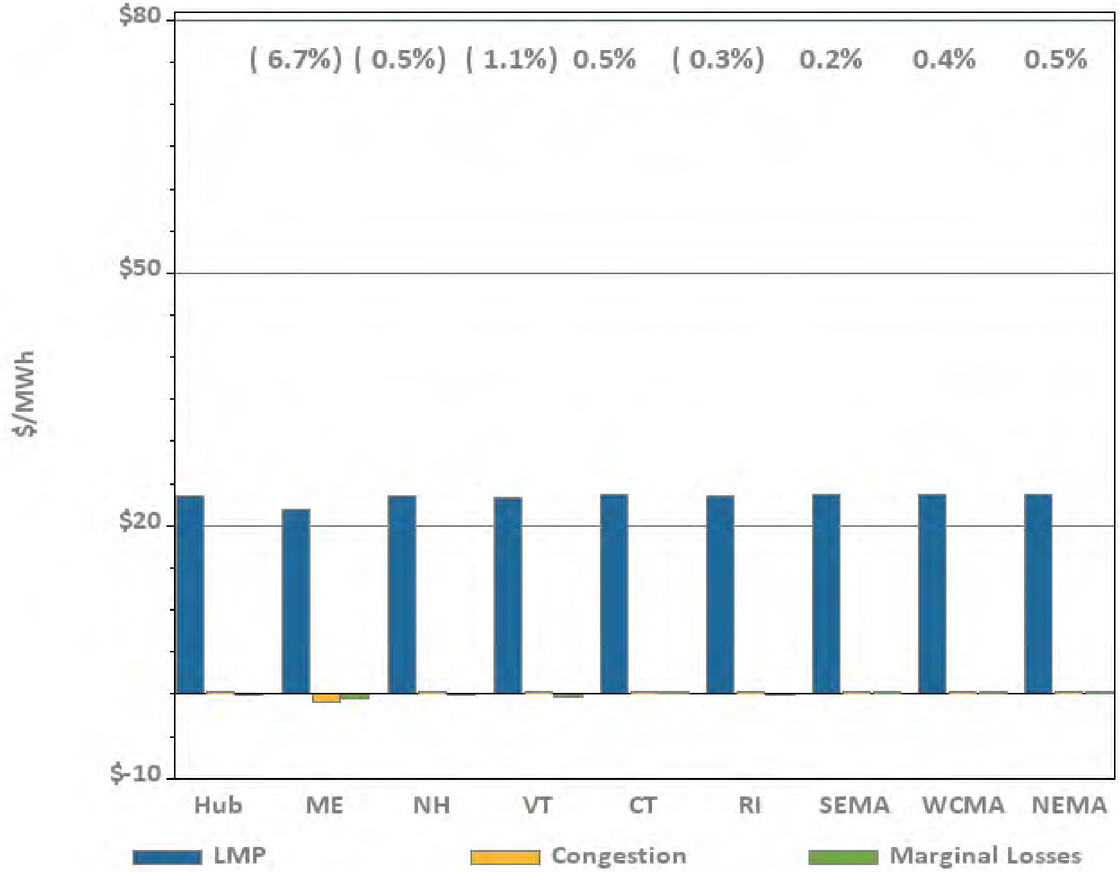


Underlying natural gas data furnished by:

ICE Global markets in clear view

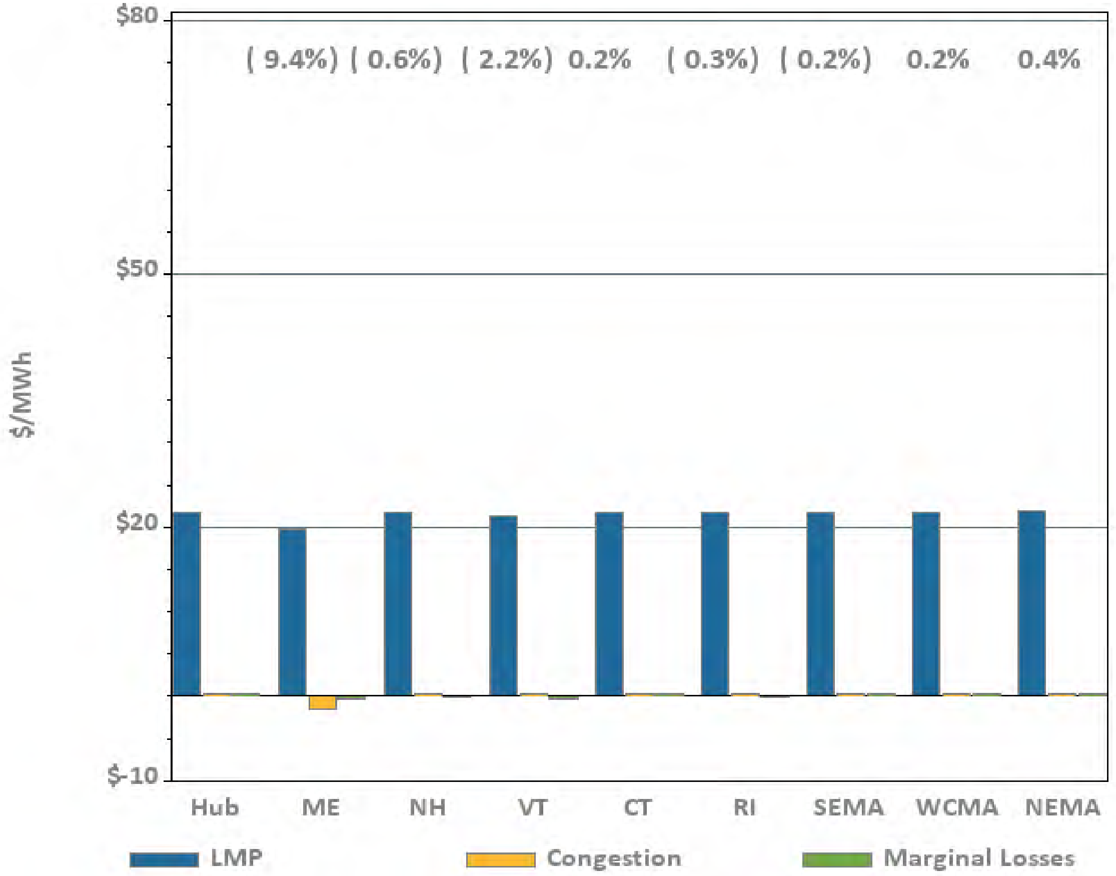
Average price difference over this period (DA-RT): $1.83
Average price difference over this period ABS(DA-RT): $5.32
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 24%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, May 2018



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

RT LMPs Average by Zone & Hub, May 2018

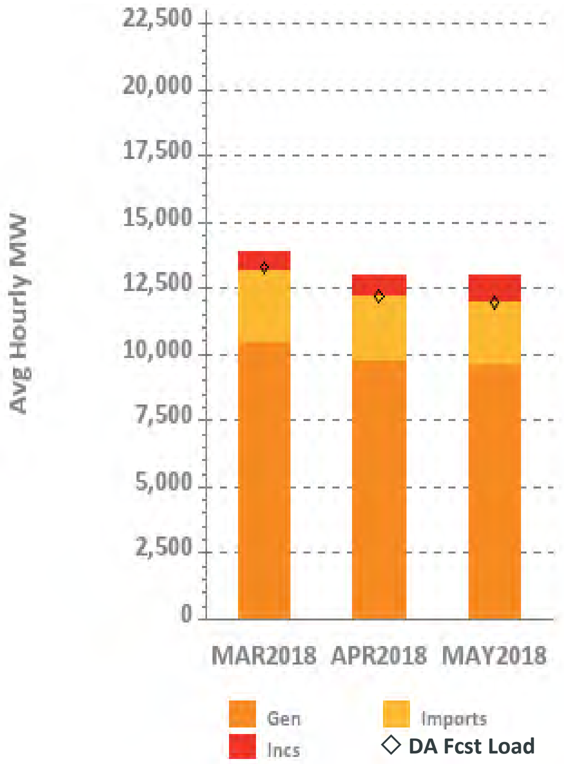


Definitions

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

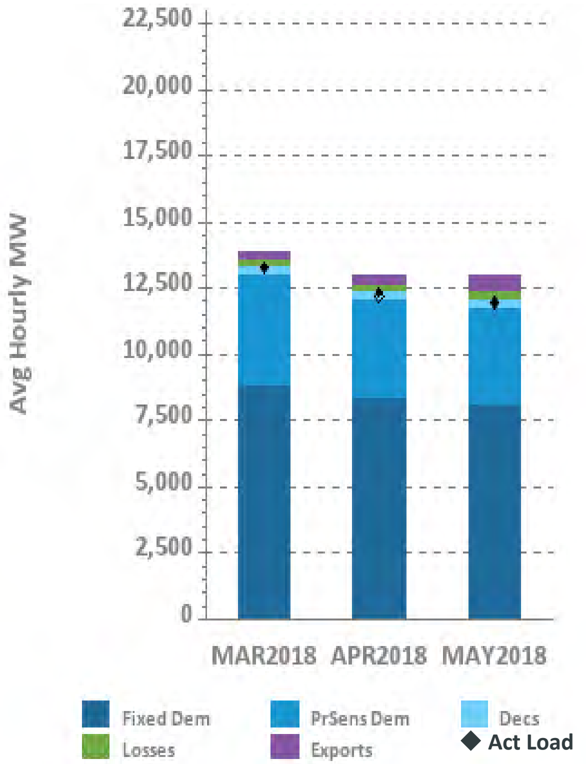
Components of Cleared DA Supply and Demand – Last Three Months

Supply



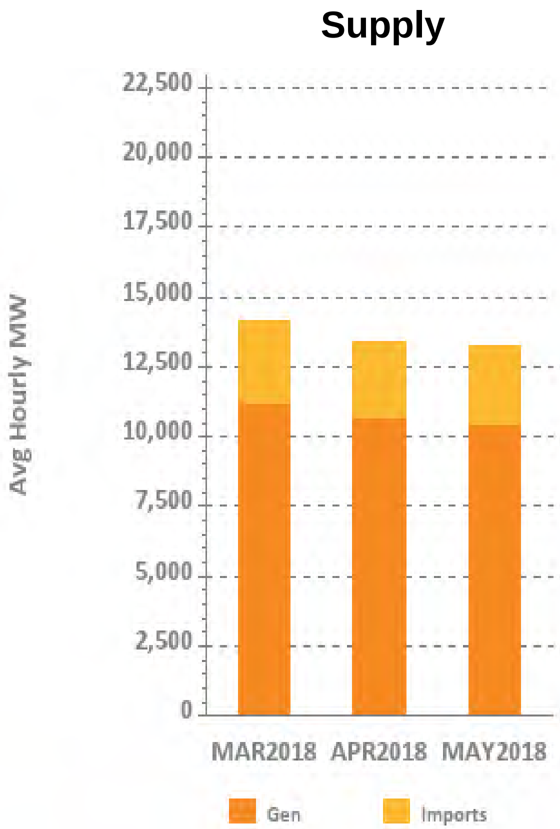
Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

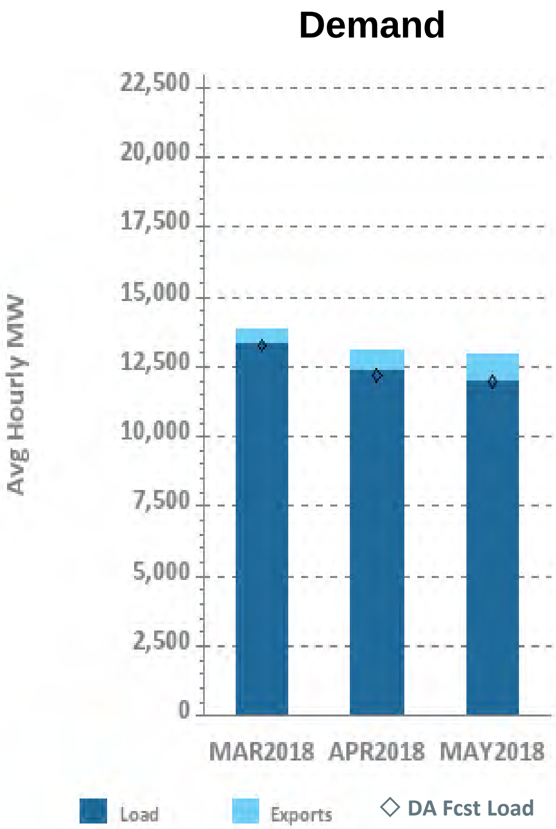
Demand



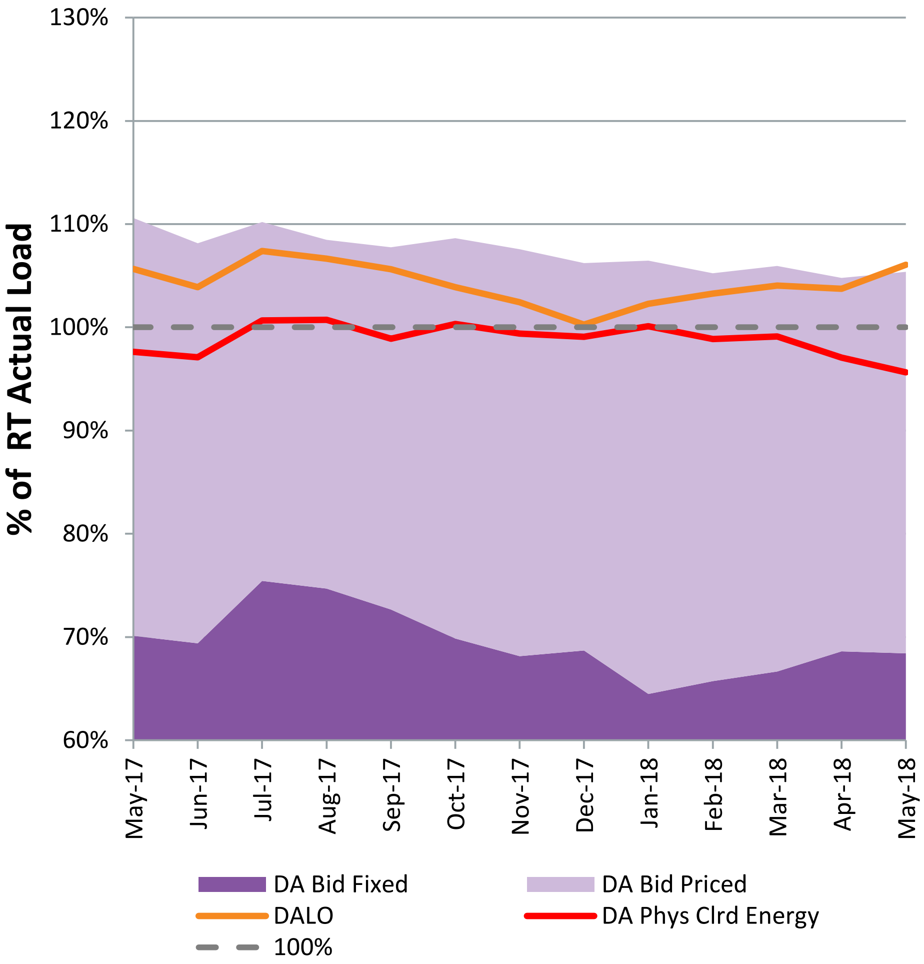
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

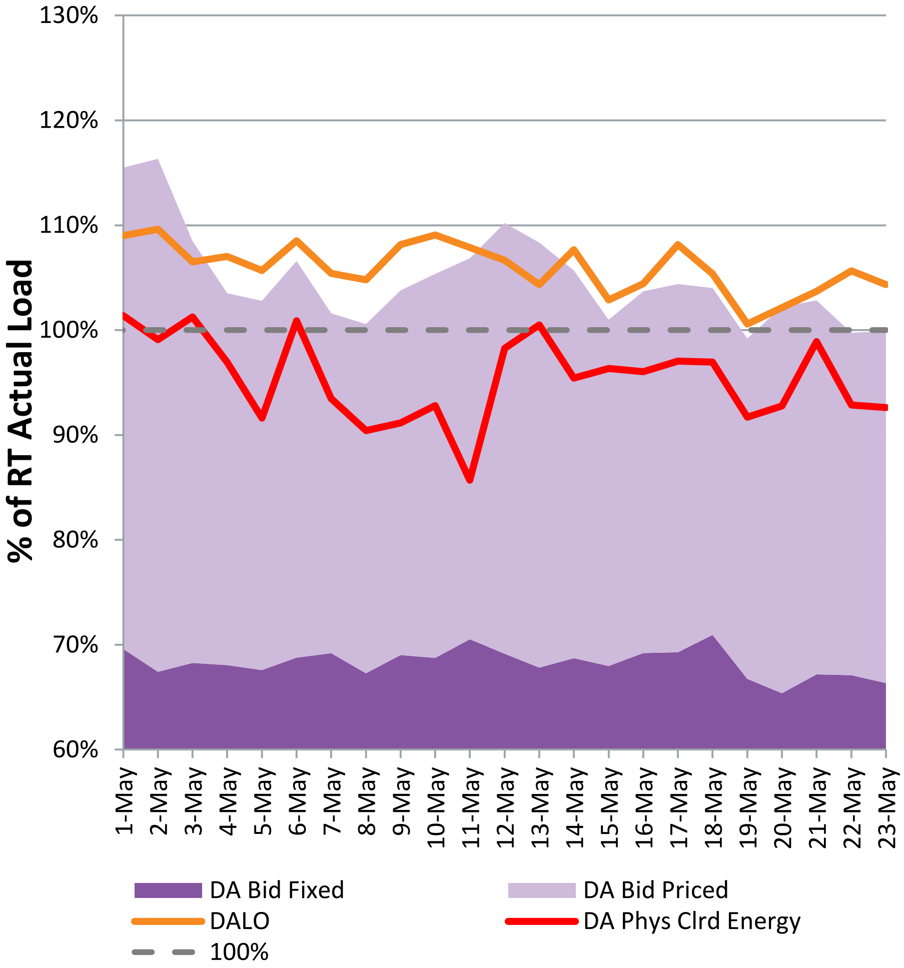
Components of RT Supply and Demand – Last Three Months





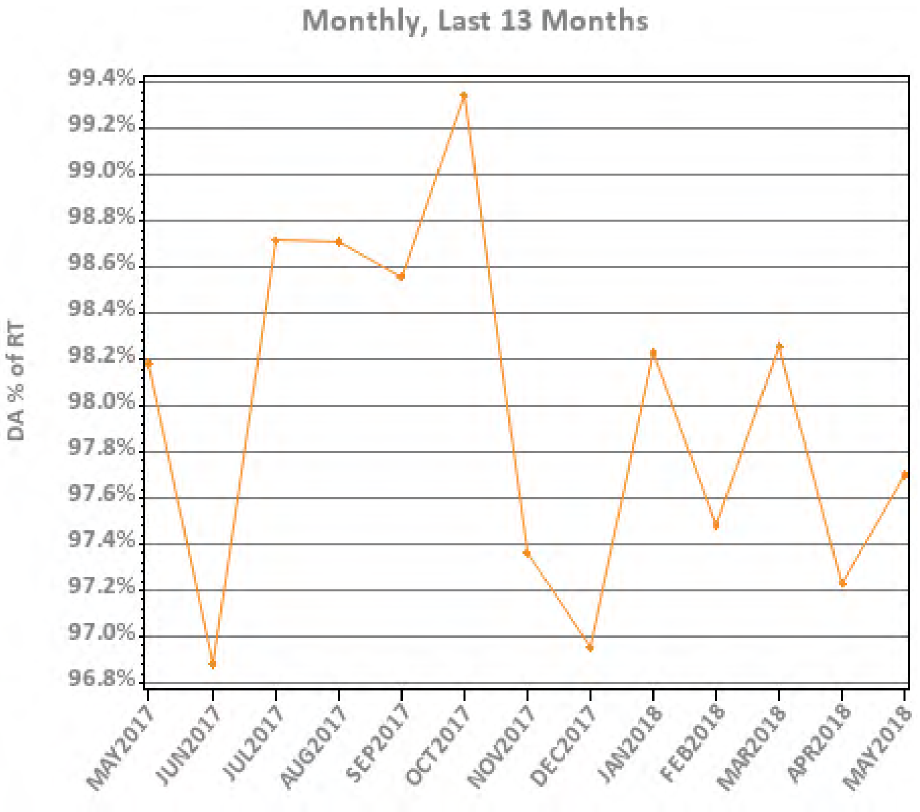
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

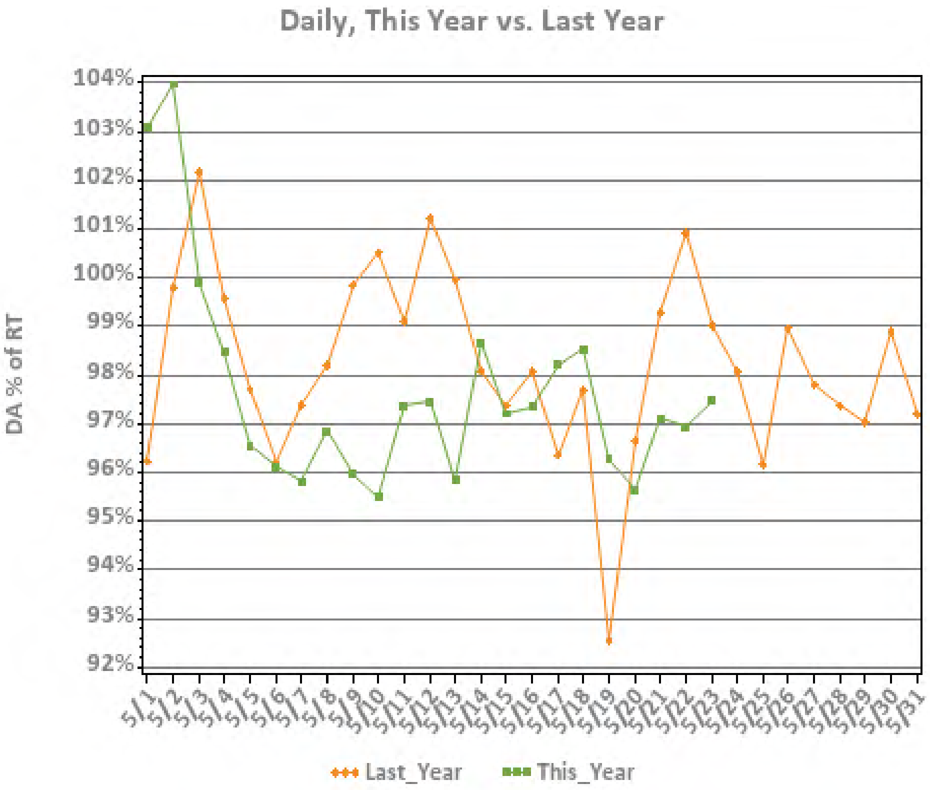




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

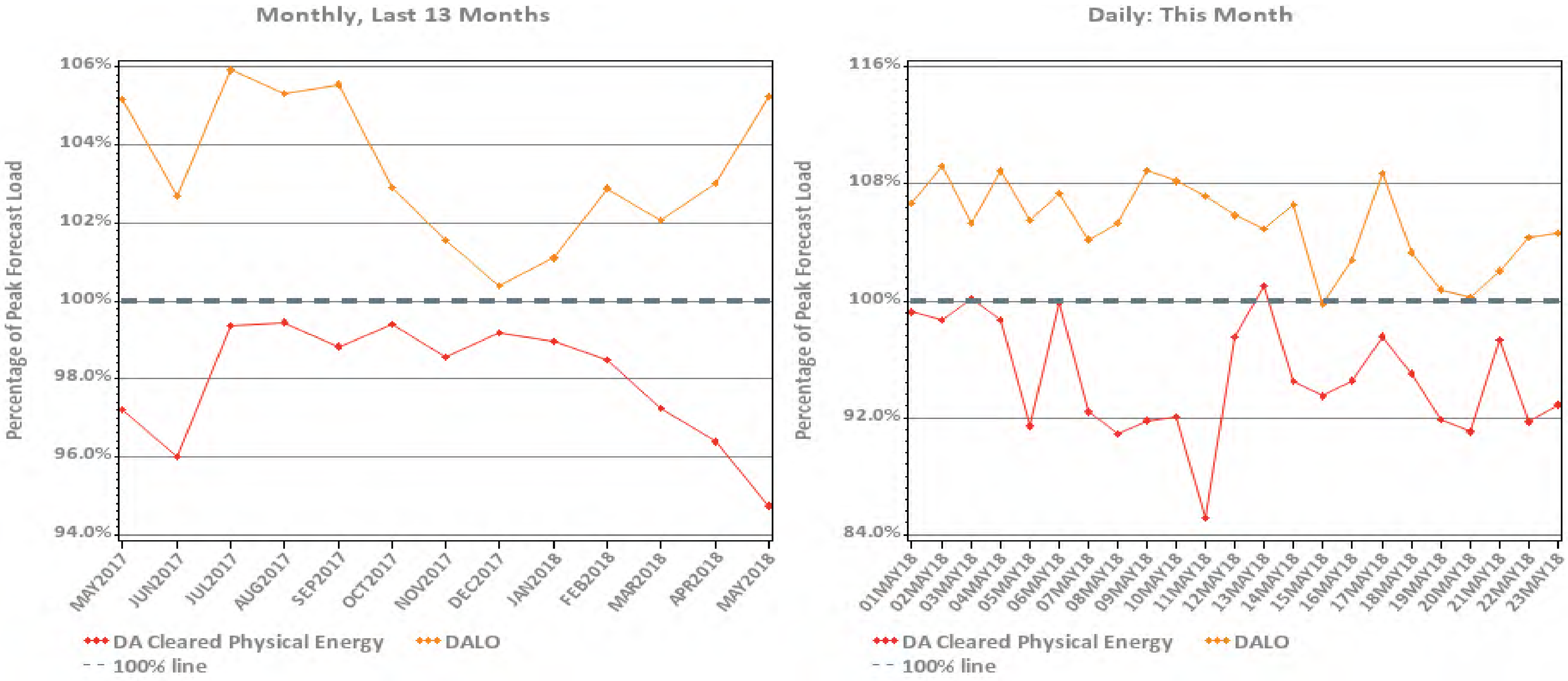
DA vs. RT Load Obligation: May, This Year vs. Last Year





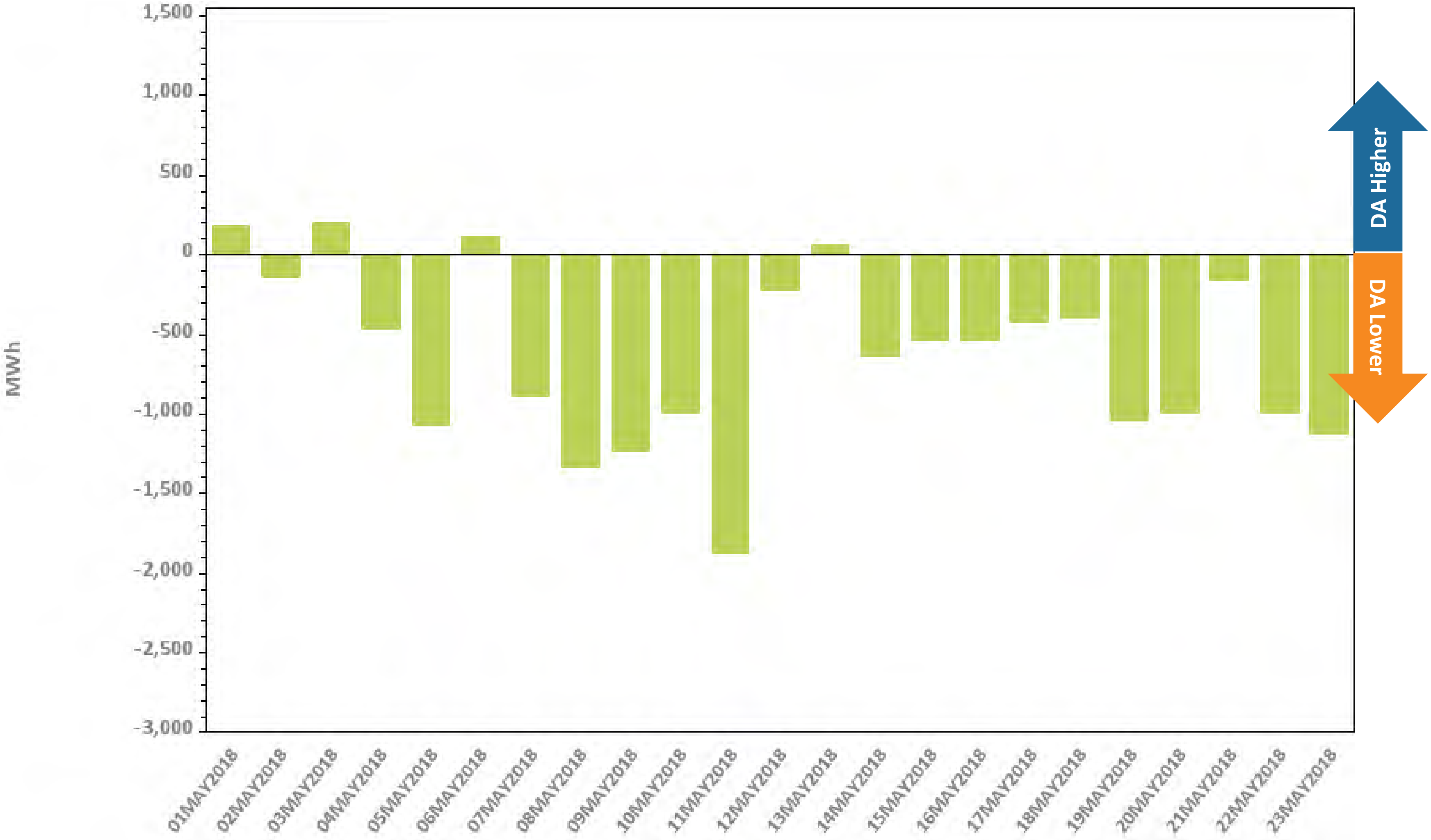
***Hourly average values**

DA Volumes as % of Forecast in Peak Hour



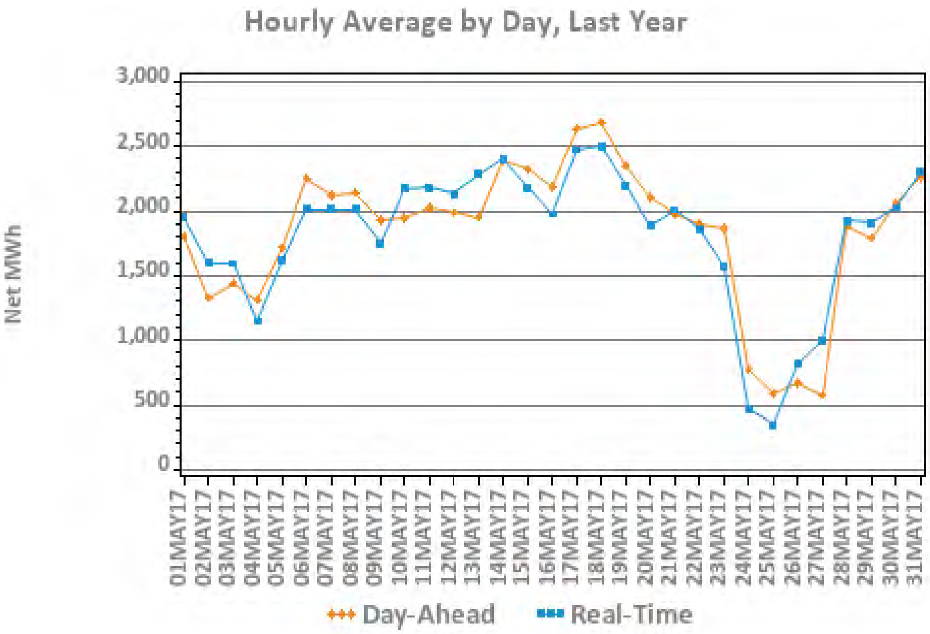
***There were three supplemental commitments required for capacity during the Reserve Adequacy Assessment (RAA) during May.**

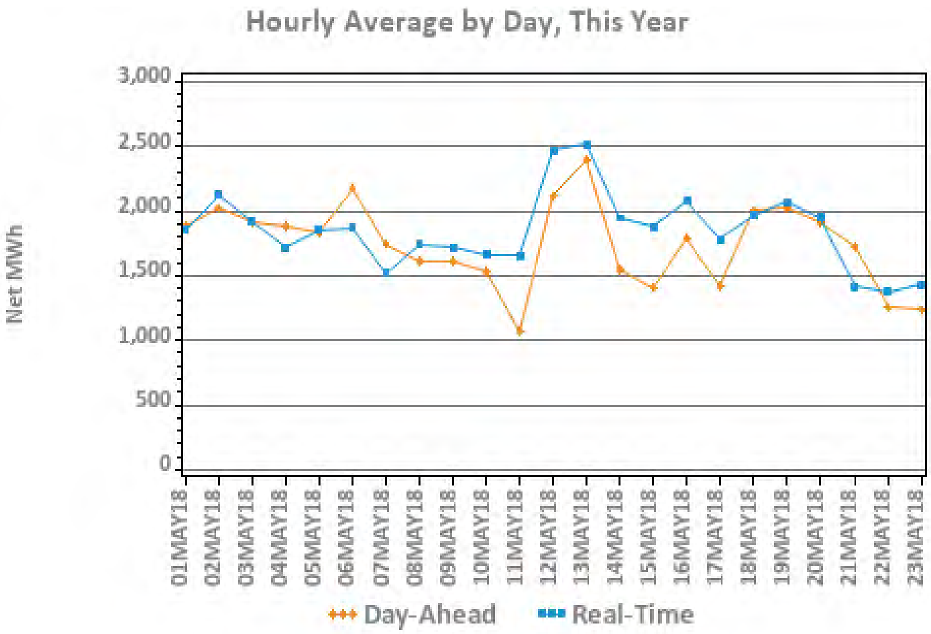
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

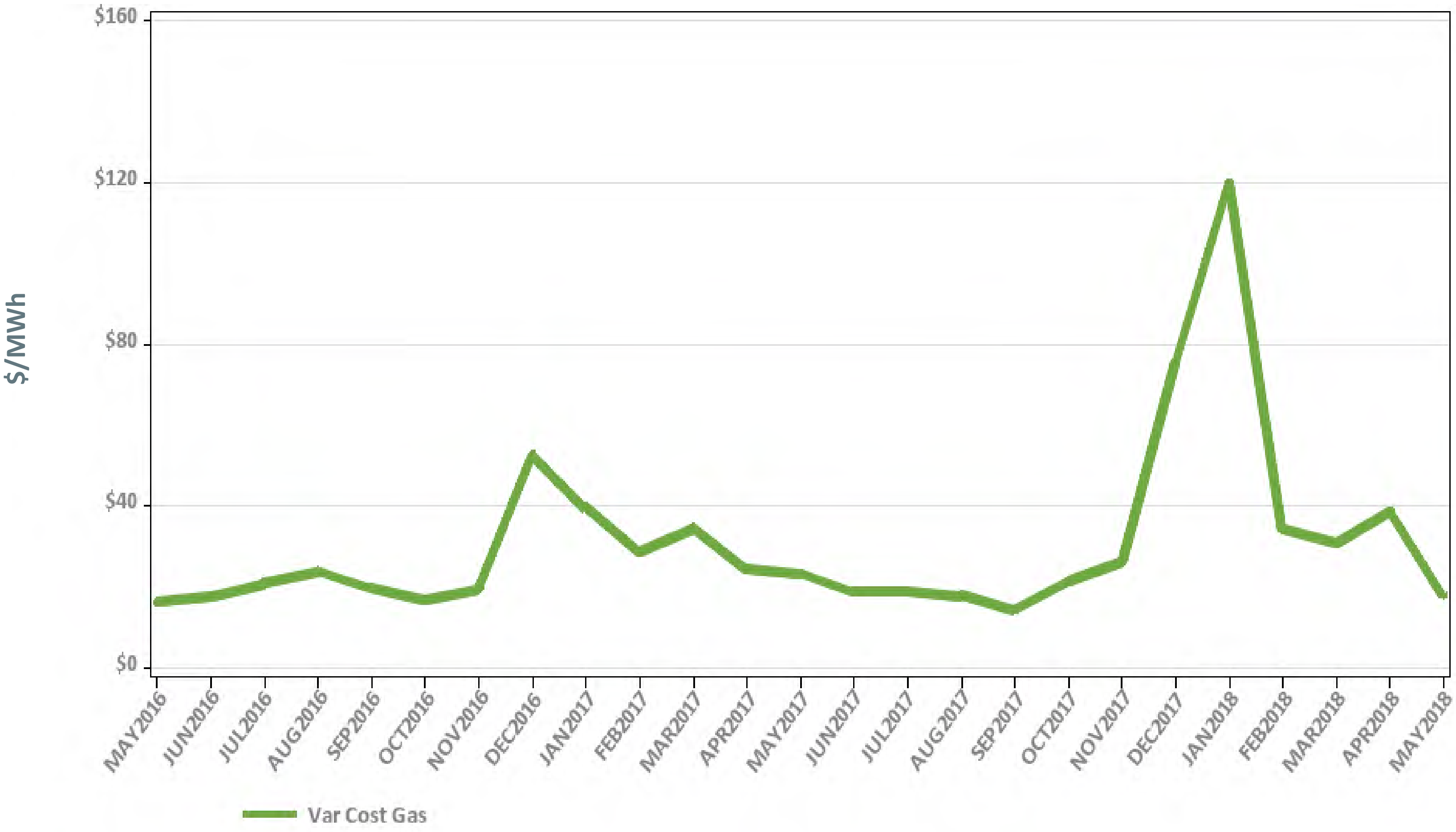
DA vs. RT Net Interchange May 2018 vs. May 2017


Hourly Average by Day, Last Year


Hourly Average by Day, This Year

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

Variable Production Cost of Natural Gas: Monthly



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.

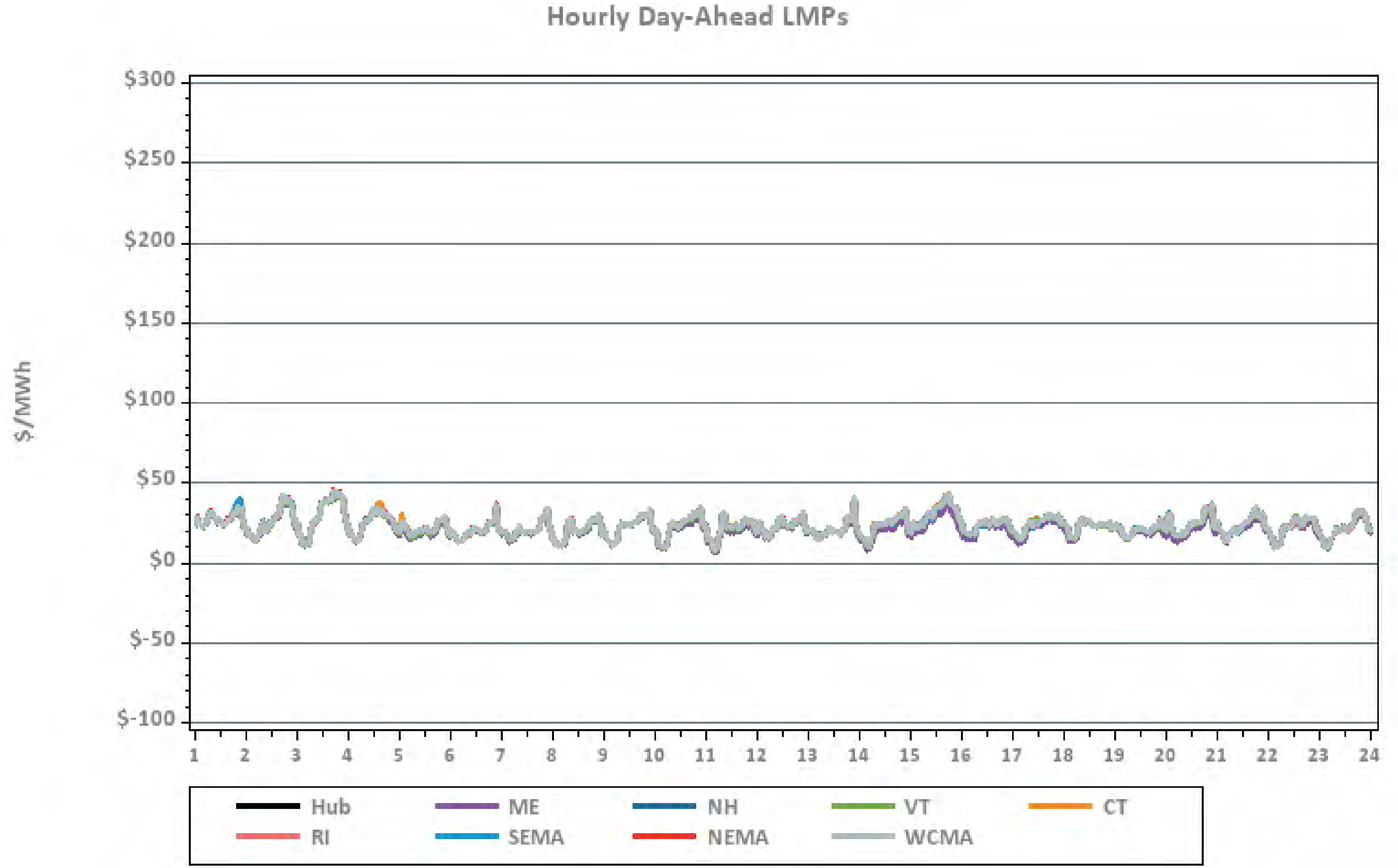
Variable Production Cost of Natural Gas: Daily

Underlying natural gas data furnished by:

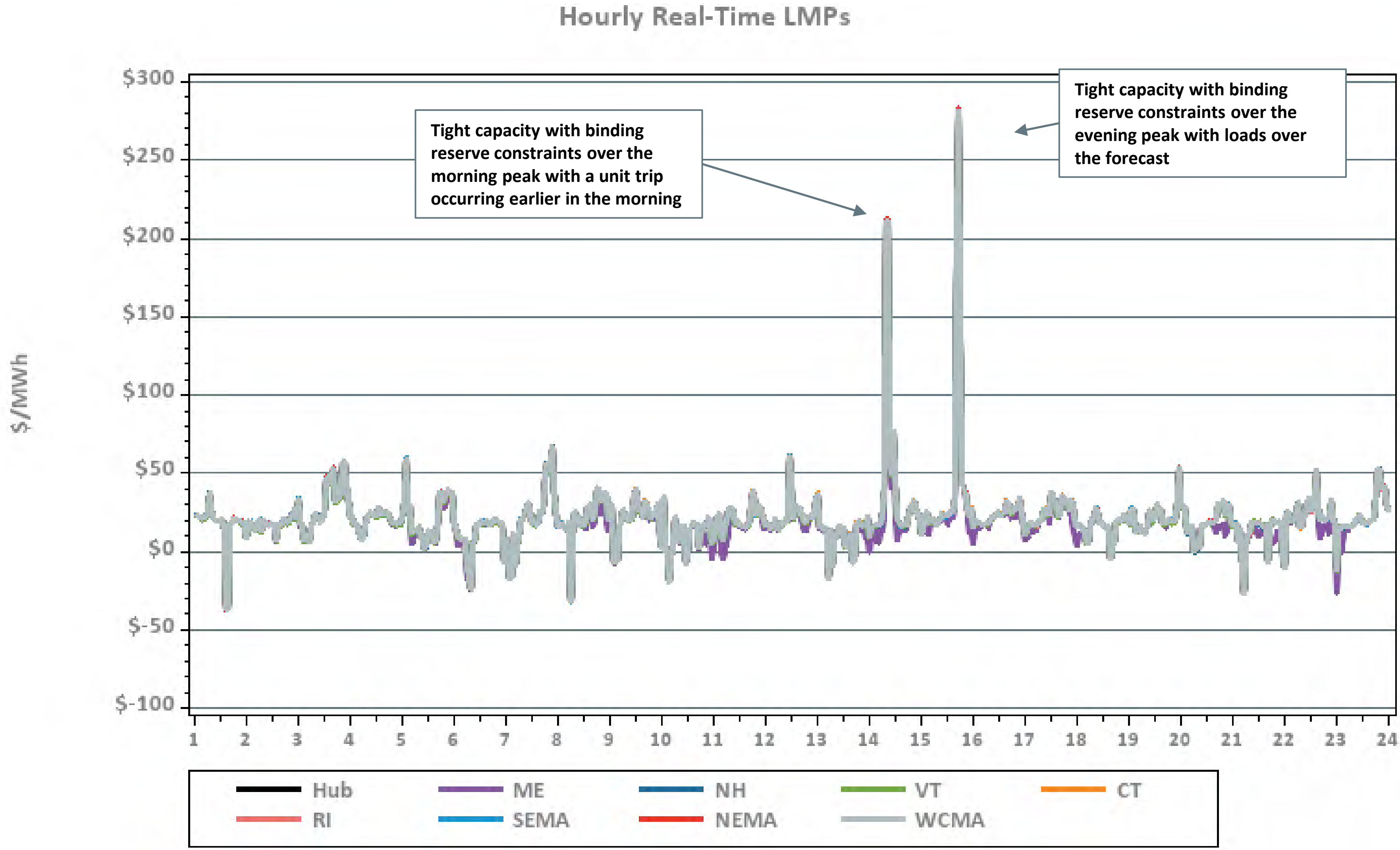
ICE Global markets in clear view

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

Hourly DA LMPs, May 1-23, 2018



Hourly RT LMPs, May 1-23, 2018

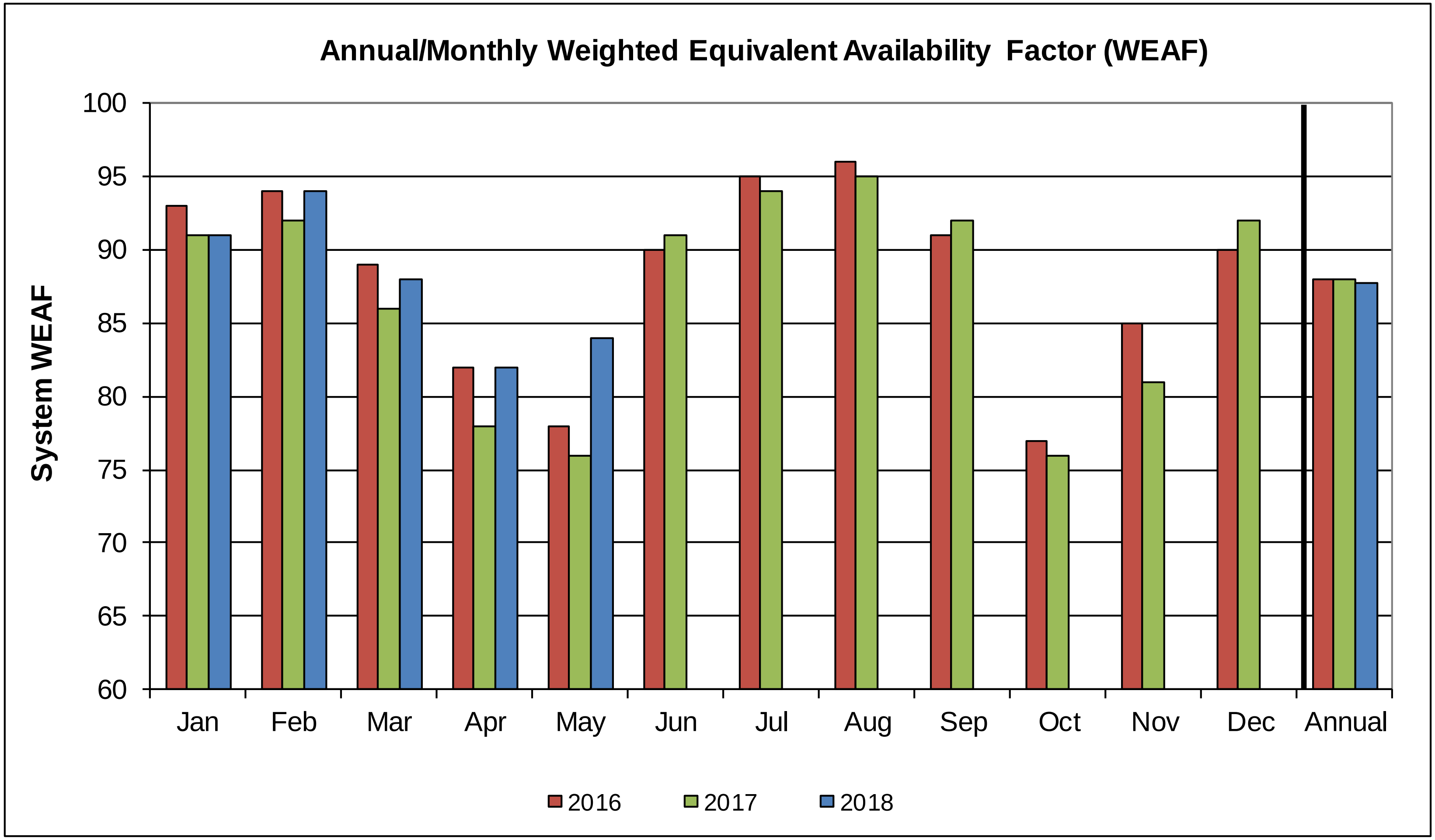


Tight capacity with binding reserve constraints over the morning peak with a unit trip occurring earlier in the morning

Tight capacity with binding reserve constraints over the evening peak with loads over the forecast

* No Minimum Generation Emergencies were declared during May.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2018	91	94	88	82	84								88
2017	91	92	86	78	76	91	94	95	92	76	81	92	88
2016	93	94	89	82	78	90	95	96	91	77	85	90	88

Data as of 5/28/18

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for June 2018

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	96.0	170.0	0.0	266.0
NH	20.2	90.2	0.0	110.5
VT	26.0	118.8	0.0	144.7
CT	87.6	87.5	414.0	589.2
RI	18.8	237.9	0.0	256.7
SEMA	23.6	378.8	0.0	402.4
WCMA	43.4	359.9	53.0	456.2
NEMA	37.7	667.5	0.0	705.2
Total	**353.3**	**2,110.6**	**467.0**	**2,930.8**

*** Active Demand Capacity Response**

**** Real Time Emergency Generation**

[1] Negative CSO resulting from reconfiguration auction activity

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

NEW GENERATION

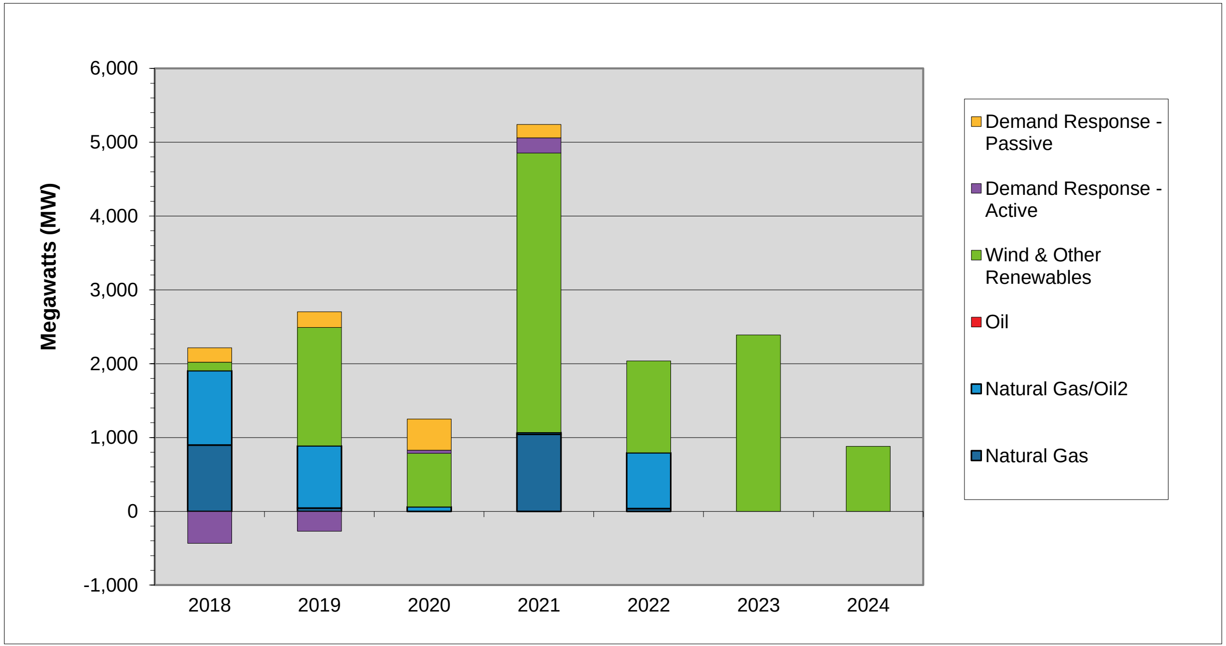
New Generation Update

Based on Queue as of 5/25/18

- Four projects totaling 28 MW have applied for interconnection study since the last update, with in-service dates ranging from 2018 to 2019
  - 3 photovoltaic (25 MW)
  - 1 increase to an existing hydro plant (3 MW)
- No projects withdrew from the queue and two projects went commercial, resulting in a net decrease in new generation projects of 880 MW
- In total, 110 generation projects are currently being tracked by the ISO, totaling approximately 14,500 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Demand Response - Passive	196	212	422	184	0	0	0	1,014	6.3
Demand Response - Active	-433	-270	42	204	0	0	0	-456	-2.8
Wind & Other Renewables	116	1,604	724	3,786	1,247	2,391	880	10,748	67.1
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	1,009	844	62	23	755	0	0	2,693	16.8
Natural Gas	896	43	0	1,045	37	0	0	2,021	12.6
Totals	**1,784**	**2,434**	**1,251**	**5,242**	**2,039**	**2,391**	**880**	**16,020**	**100.0**

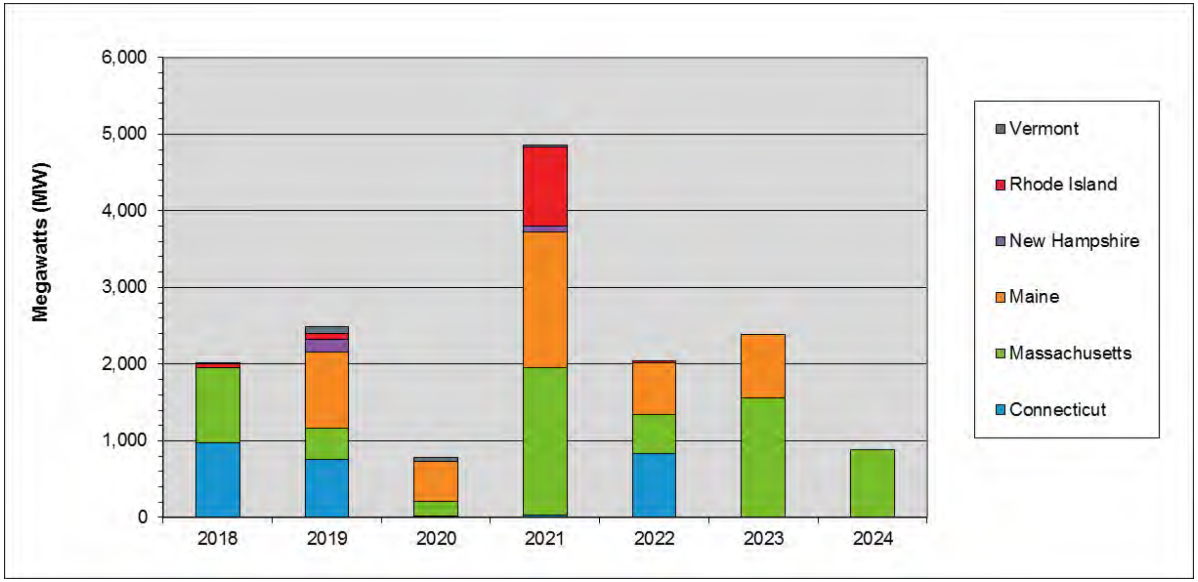
[1] Sum may not equal 100% due to rounding

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

- 2018 values include the 921 MW of generation that has gone commercial in 2018
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2018	2019	2020	2021	2022	2023	2024	Total MW	% of Total[1]
Vermont	20	93	55	20	0	0	0	188	1.2
Rhode Island	41	79	0	1,030	27	0	0	1,177	7.6
New Hampshire	0	158	0	85	0	0	0	243	1.6
Maine	0	994	526	1,768	670	828	0	4,786	31.0
Massachusetts	989	411	185	1,913	514	1,563	880	6,455	41.7
Connecticut	971	756	20	38	828	0	0	2,613	16.9
Totals	**2,021**	**2,491**	**786**	**4,854**	**2,039**	**2,391**	**880**	**15,462**	**100.0**

- 2018 values include the 921 MW of generation that has gone commercial in 2018

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Fuel Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/wood waste	1	37	0	0	1	37
Hydro	3	74	0	0	3	74
Landfill Gas	0	0	0	0	0	0
Natural Gas	9	1,984	1	716	8	1,268
Natural Gas/Oil	7	1,892	1	208	6	1,684
Oil	0	0	0	0	0	0
Solar	52	1,530	0	0	52	1,530
Wind	27	7,165	1	30	26	7,135
Battery storage	11	1,859	0	0	11	1,859
Total	110	14,541	3	954	107	13,587

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	5	123	0	0	5	123
Intermediate	8	2,407	1	716	7	1,691
Peaker	70	4,846	2	541	68	4,305
Wind Turbine	27	7,165	1	30	26	7,135
Total	110	14,541	4	1,287	106	13,254

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

New Generation Projection

By Operating Type and Fuel Type

	Total		**Baseload**		**Intermediate**		**Peaker**		**Wind Turbine**	
Fuel Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/wood waste	1	37	1	37	0	0	0	0	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	9	1,984	2	78	6	1,896	1	10	0	0
Natural Gas/Oil	7	1,892	0	0	2	511	5	1,381	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	52	1,530	0	0	0	0	52	1,530	0	0
Wind	27	7,165	0	0	0	0	0	0	27	7,165
Battery storage	11	1,859	0	0	0	0	11	1,859	0	0
Total	110	14,541	5	123	8	2,407	70	4,846	27	7,165

- 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

** 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.

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

Capacity Supply Obligation FCA 10

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	377.525	367.227	-10.298	464.715	97.488								
	Passive Demand	2,368.631	2,366.783	-1.848	2,363.949	-2.834								
Demand Total		**2,746.156**	**2734.01**	**-12.146**	**2,828.664**	**94.654**								
Generator	*Non-Intermittent*	30,520.433	30,462.67	-57.763	30,048.398	-414.272								
	Intermittent	850.143	893.189	43.046	904.311	11.122								
Generator Total		**31,370.576**	**31,355.86**	**-14.716**	**30,952.709**	**-403.151**								
Import Total		**1,449.8**	**1,449.8**	**0**	**1,451**	**1.2**								
*****Grand Total**		**35,566.532**	**35,539.668**	**-26.864**	**35,232.373**	**-307.295**								
Net ICR (NICR)		**34,151**	**33,755**	**-396**	**33,755**	**0**								

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

** 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.

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

Capacity Supply Obligation FCA 11

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

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

** 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.

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

Capacity Supply Obligation FCA 12

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*	624.445												
	Passive Demand	2,975.361												
Demand Total		**3,599.806**												
Generator	*Non-Intermittent*	29,130.754												
	Intermittent	880.317												
Generator Total		**30,011.071**												
Import Total		**1217**												
*****Grand Total**		**34,827.877**												
Net ICR (NICR)		**33,725**												

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

** 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.

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

Active/Passive Demand Response

CSO Totals by Commitment Period

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

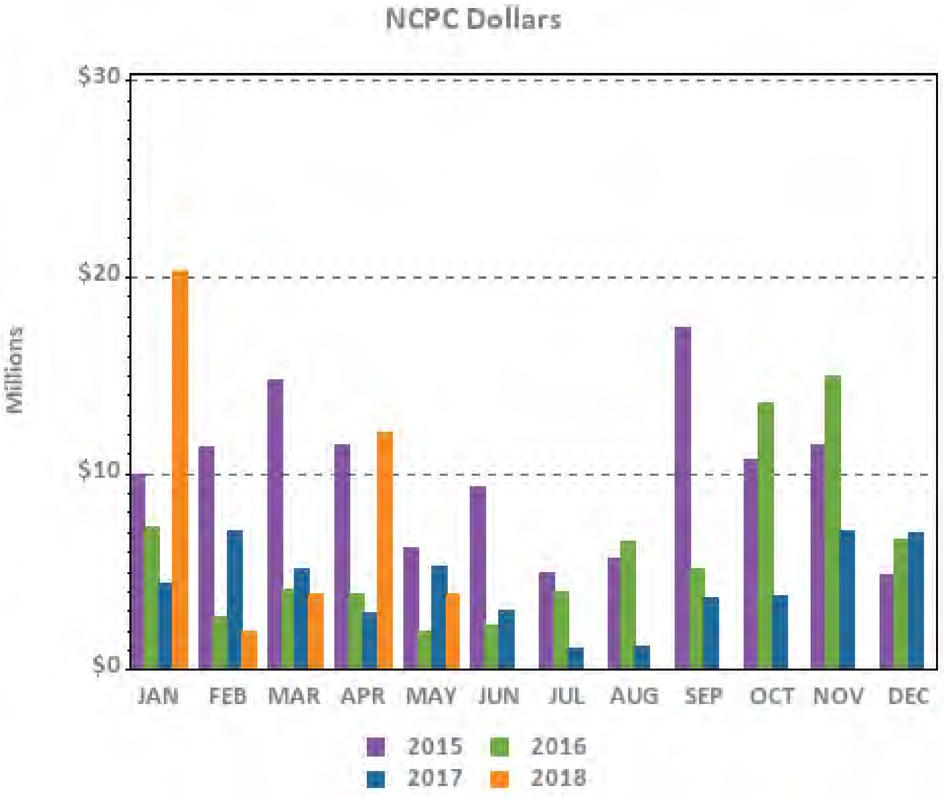
Definitions

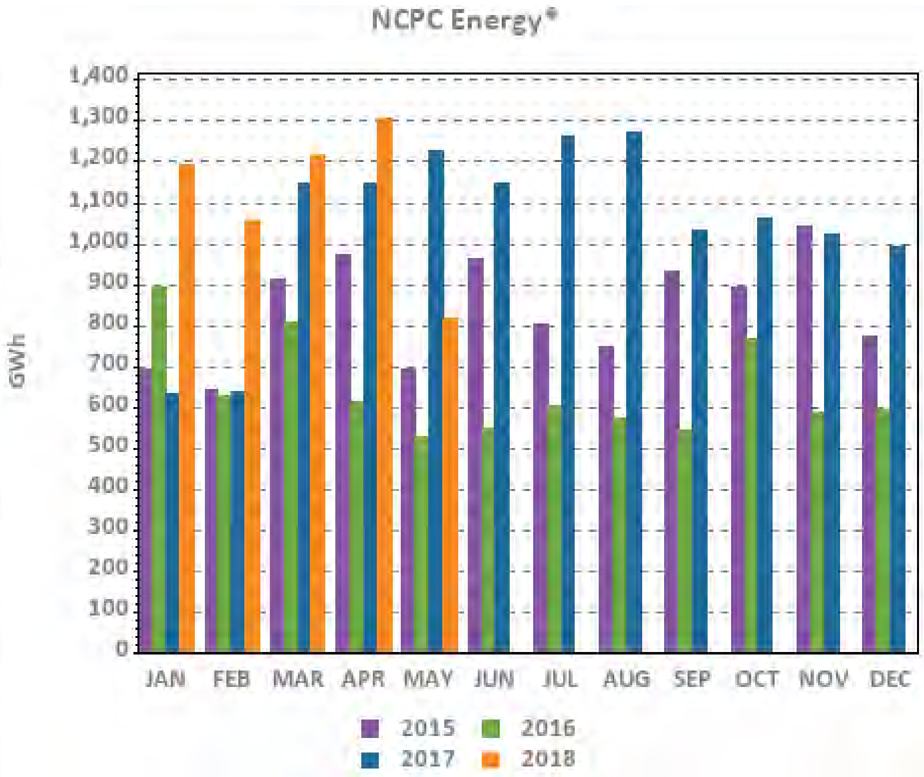
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

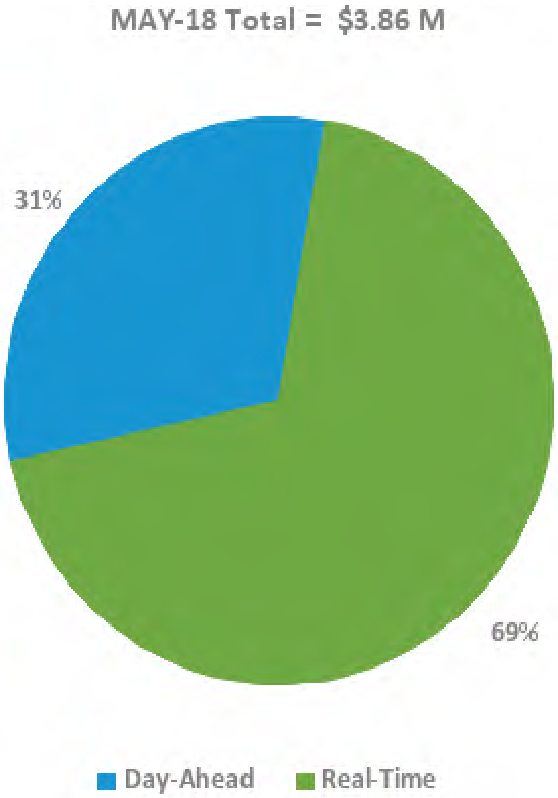
Year-Over-Year Total NCPC Dollars and Energy



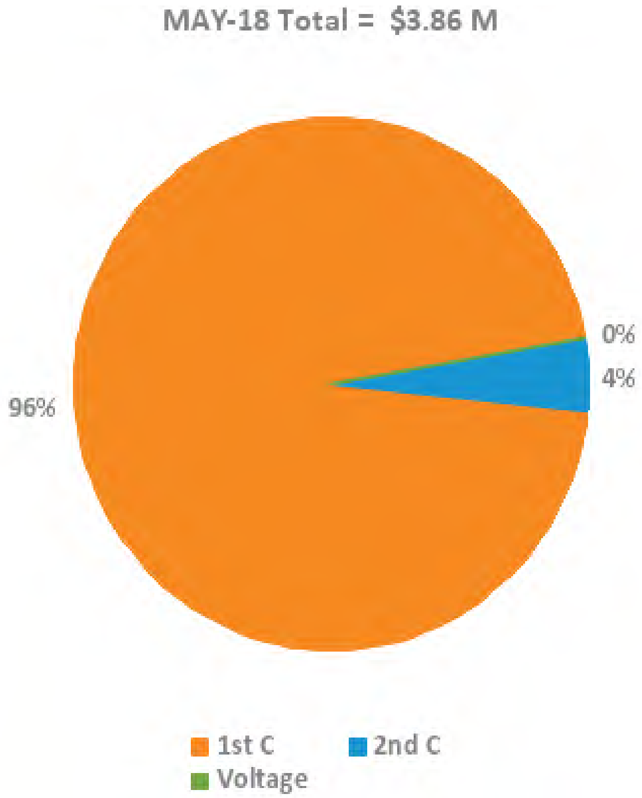


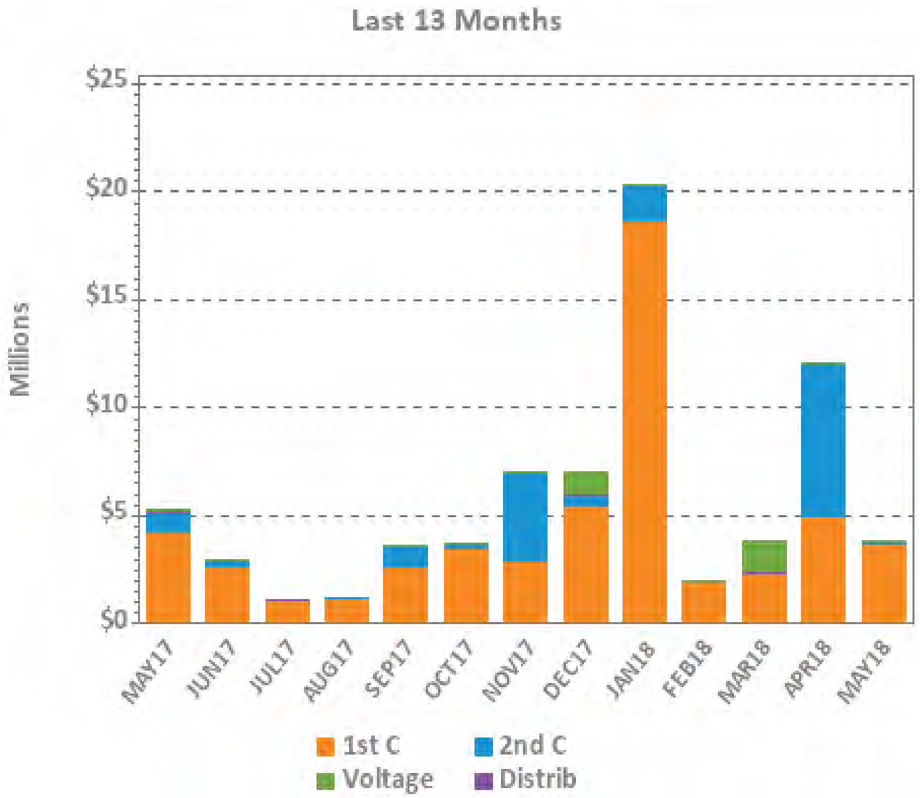
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



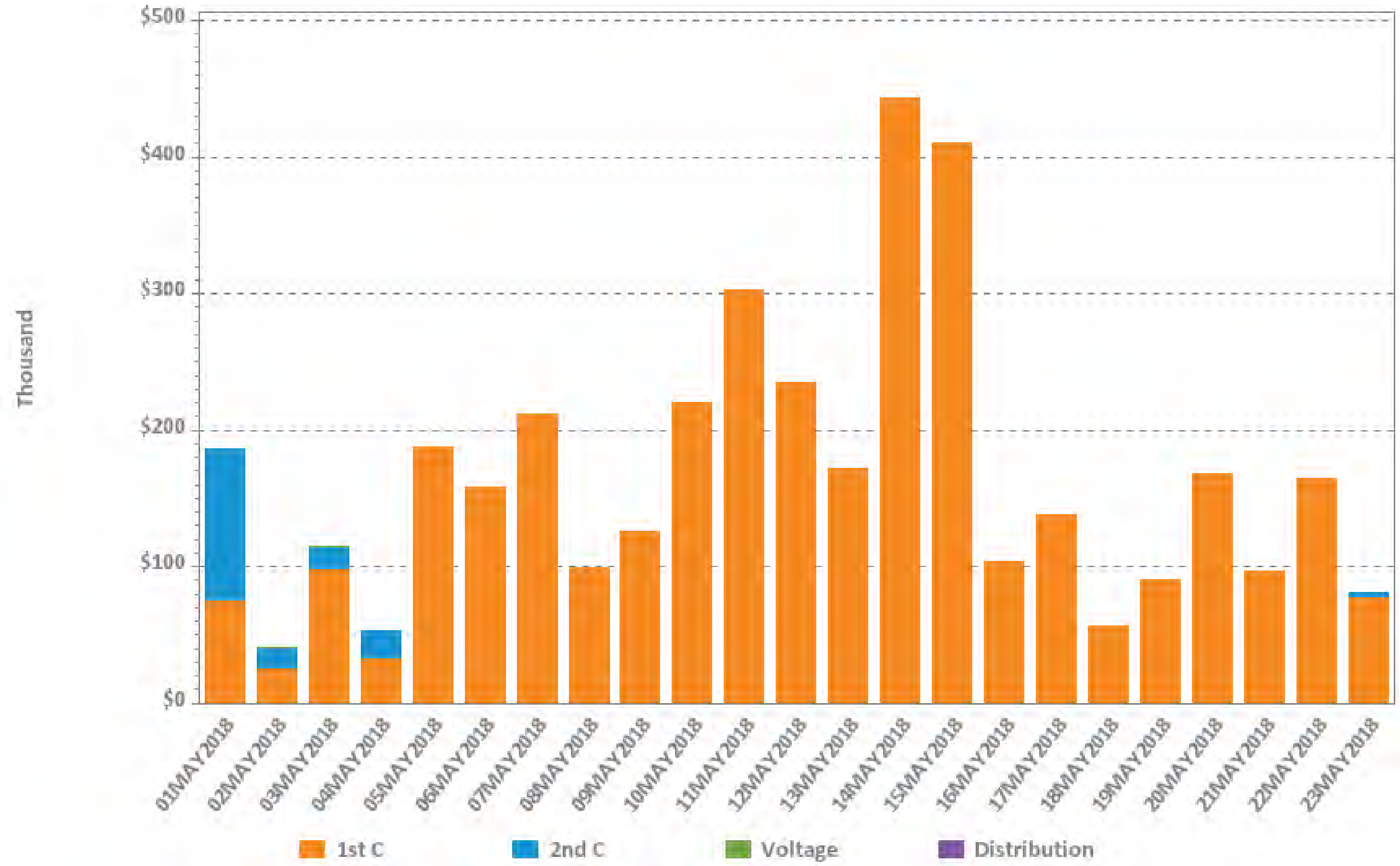
NCPC Charges by Type



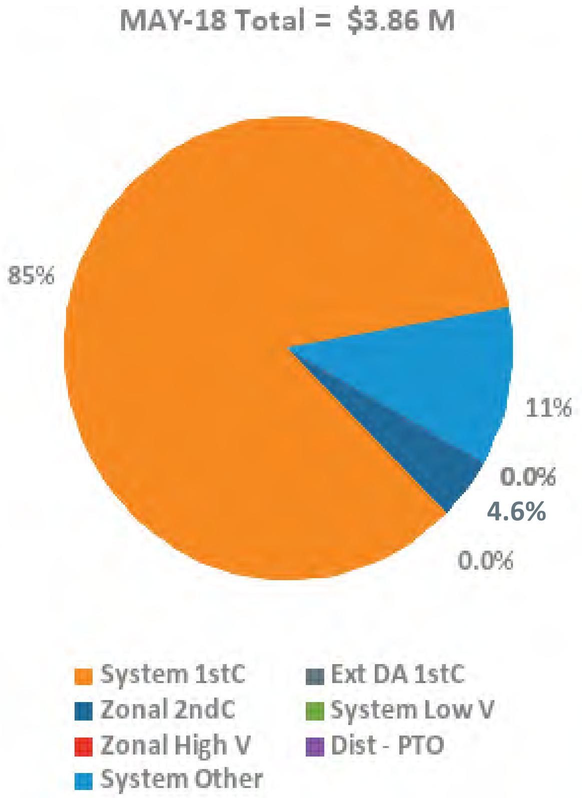


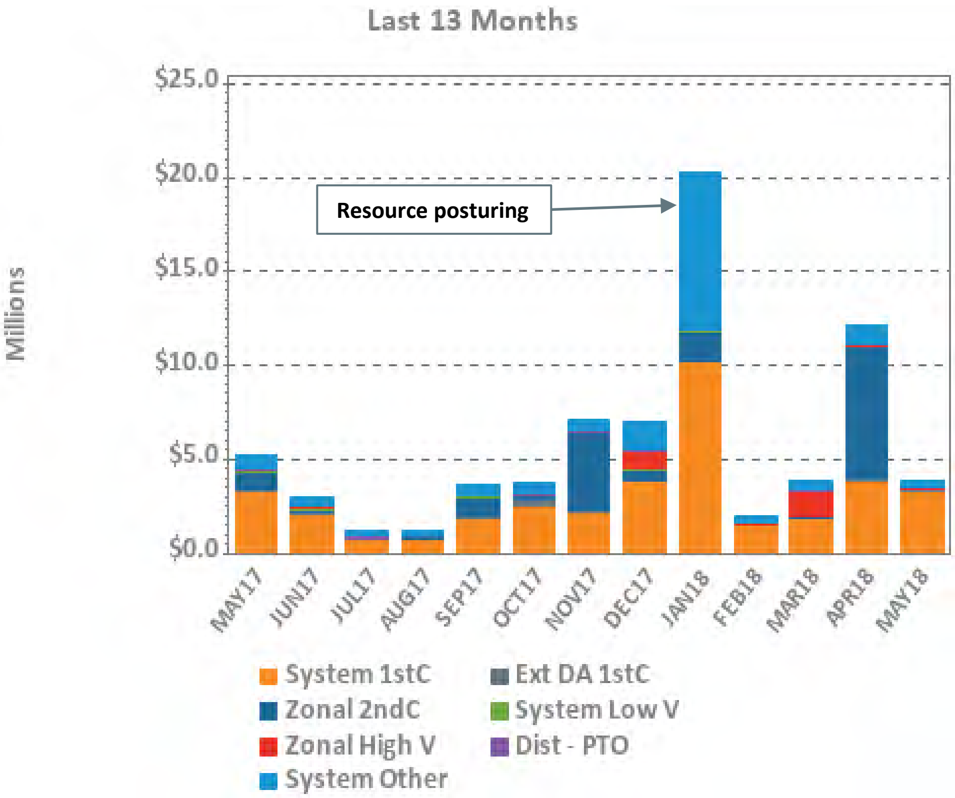
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



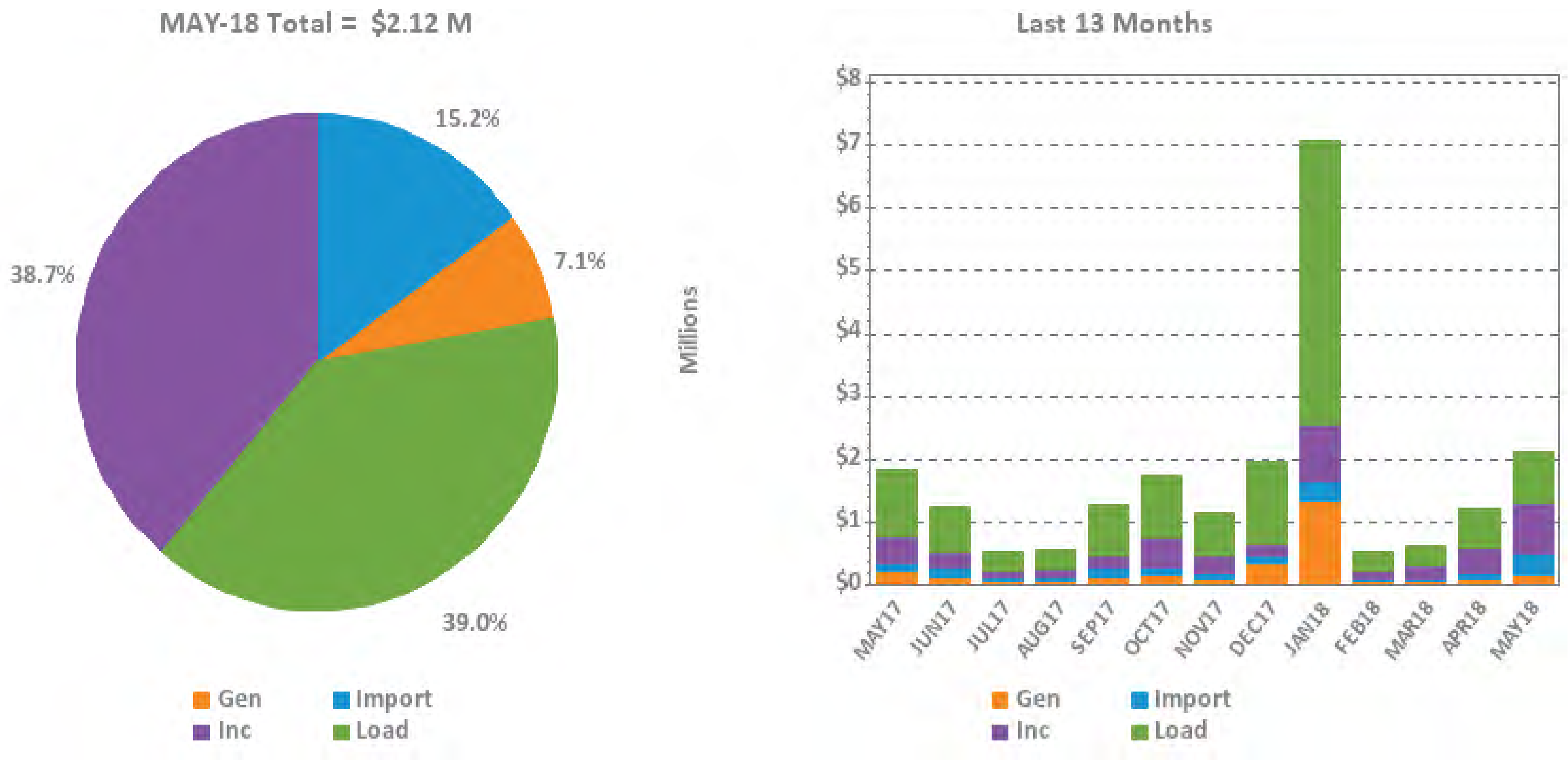
NCPC Charges by Allocation





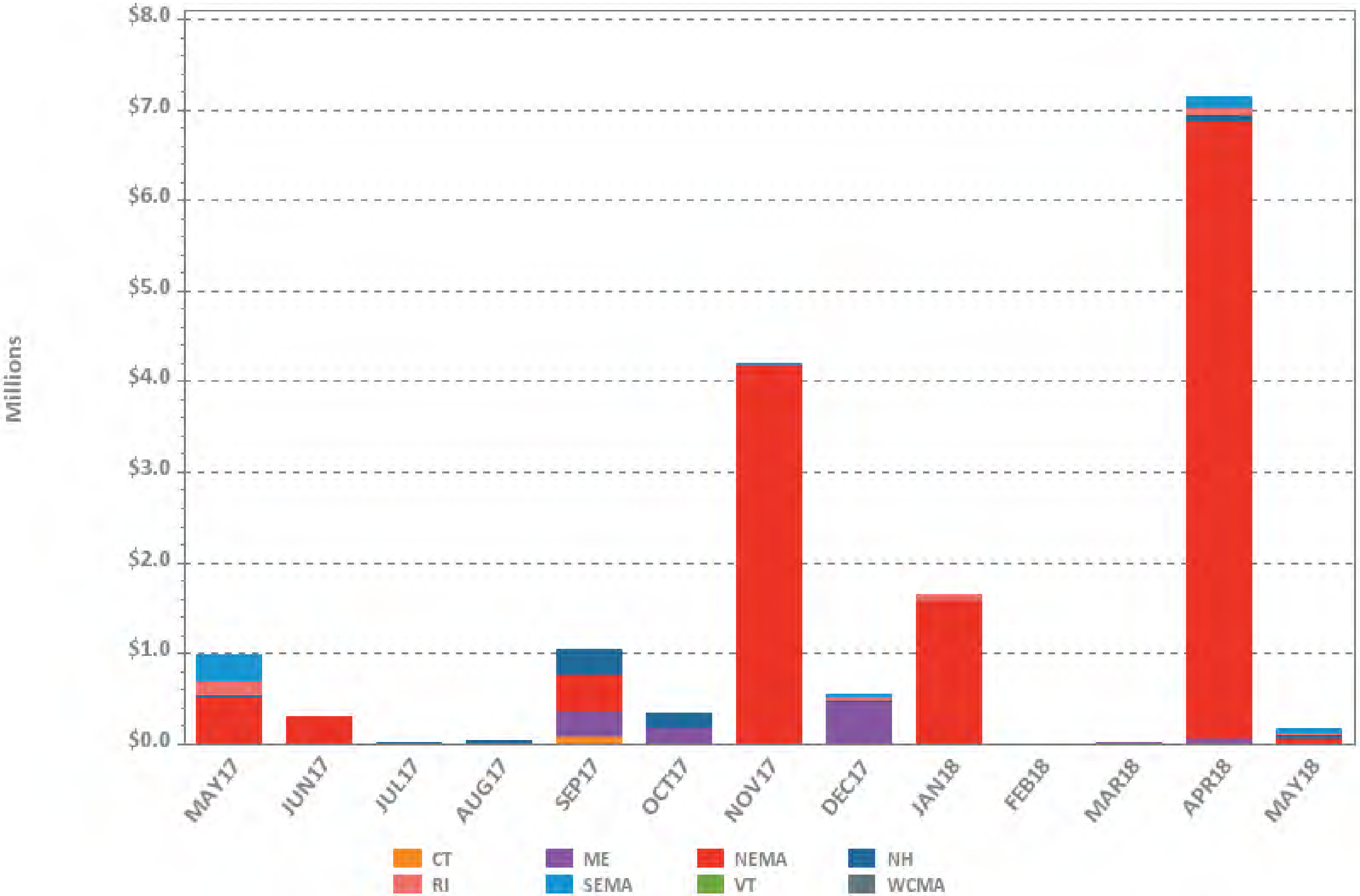
Note: ‘System Other’ includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

RT First Contingency Charges by Deviation Type



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

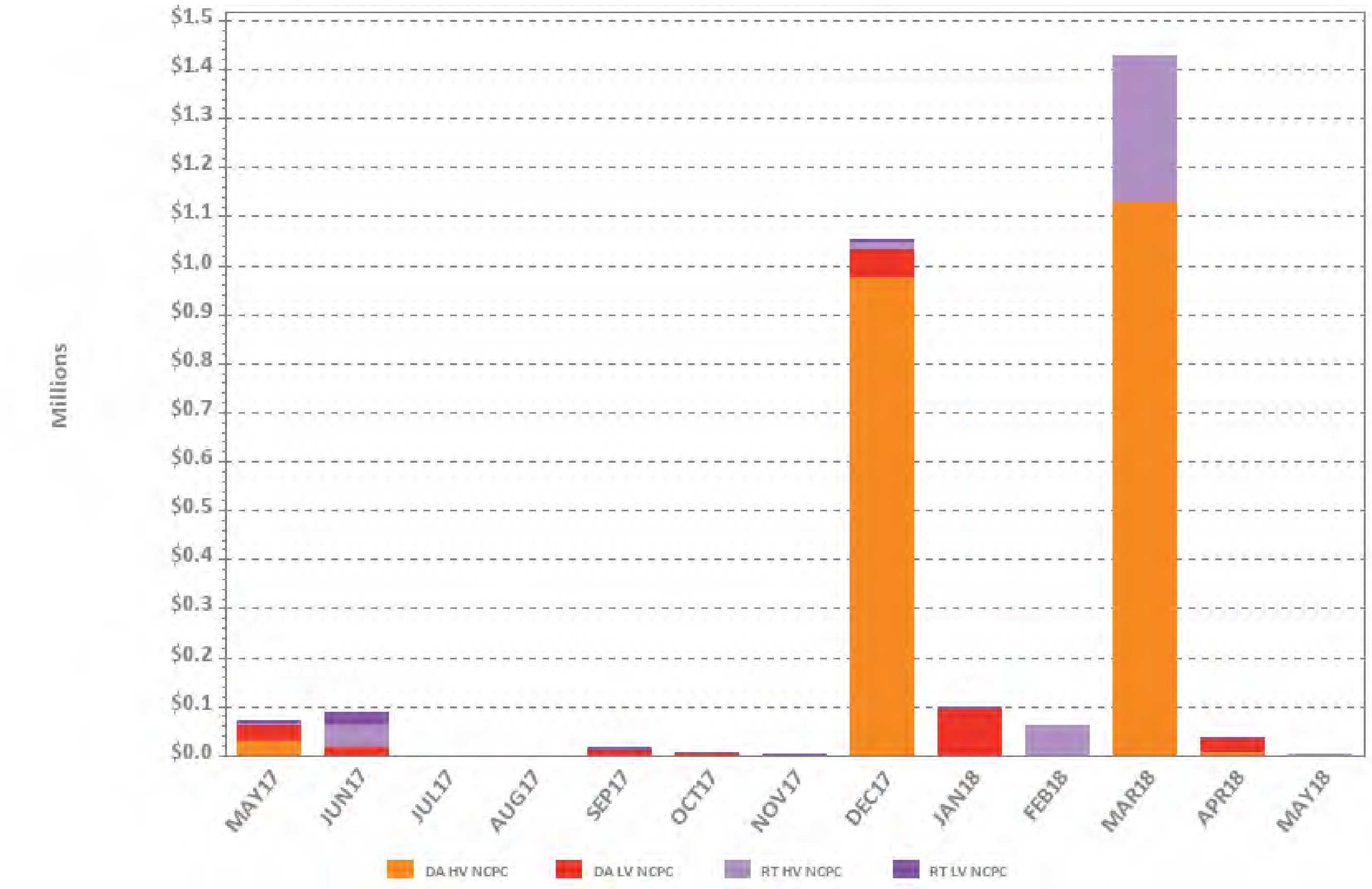
LSCPR Charges by Reliability Region



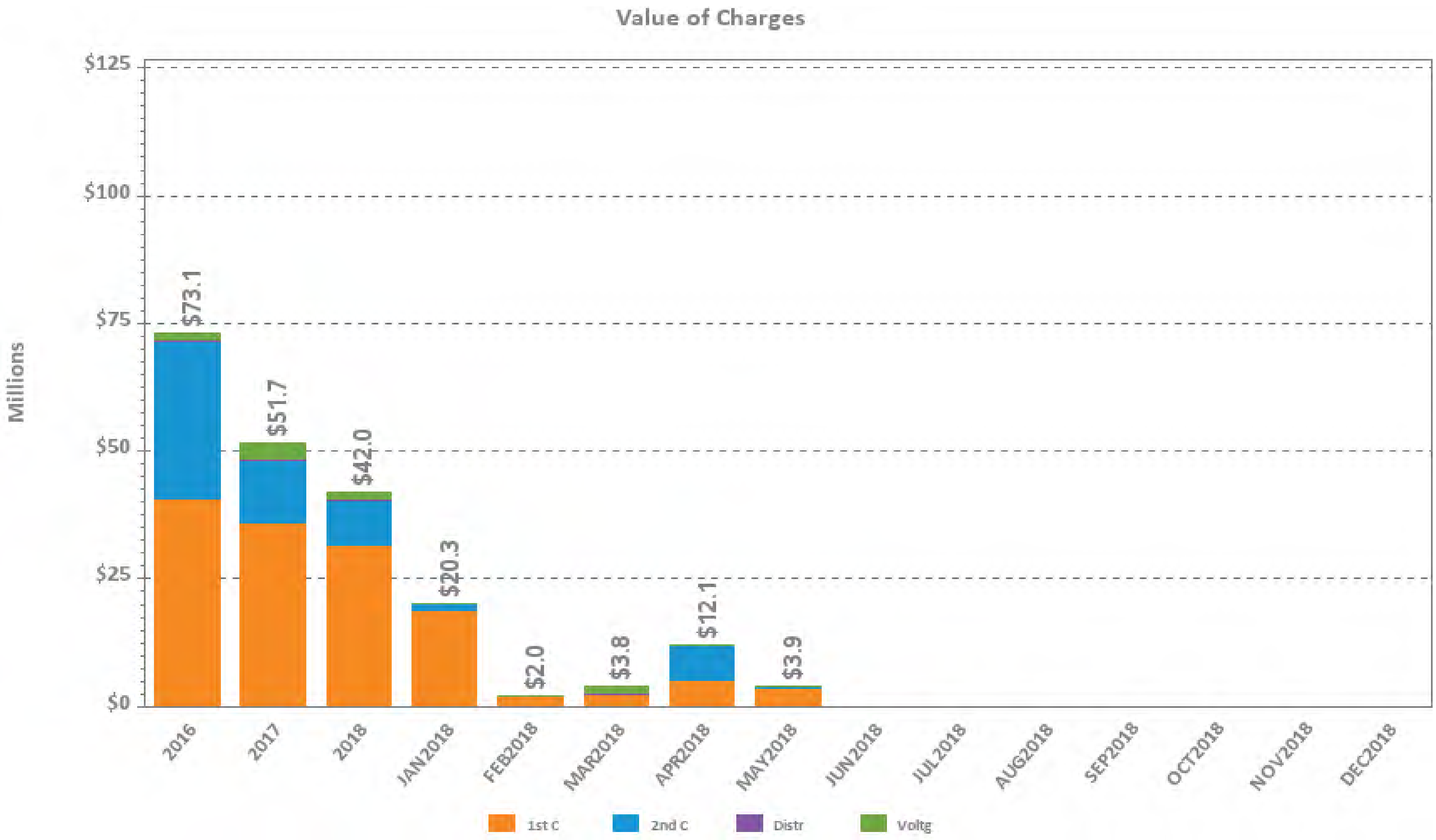
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

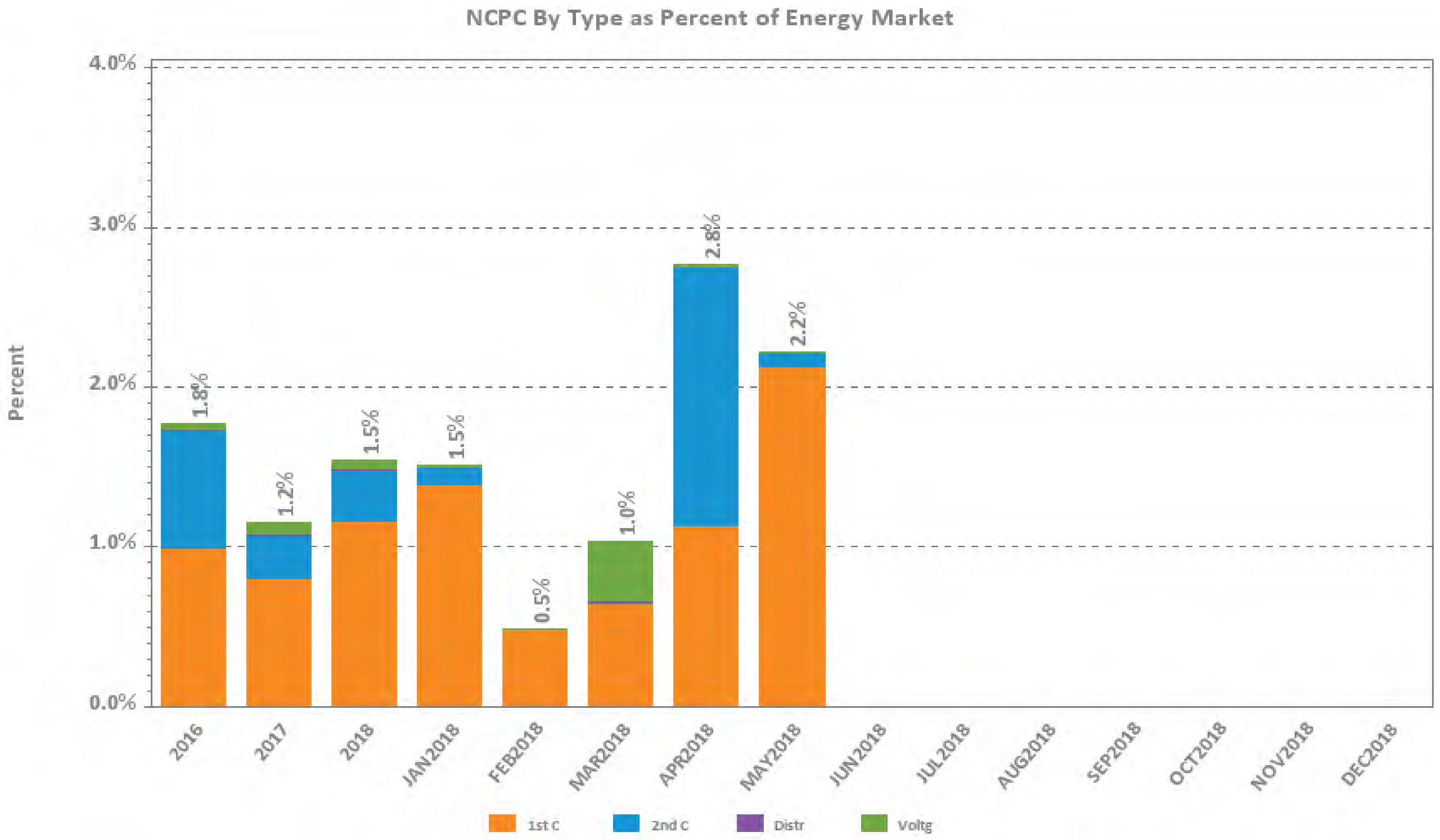
NCPC Charges for Voltage Support and High Voltage Control



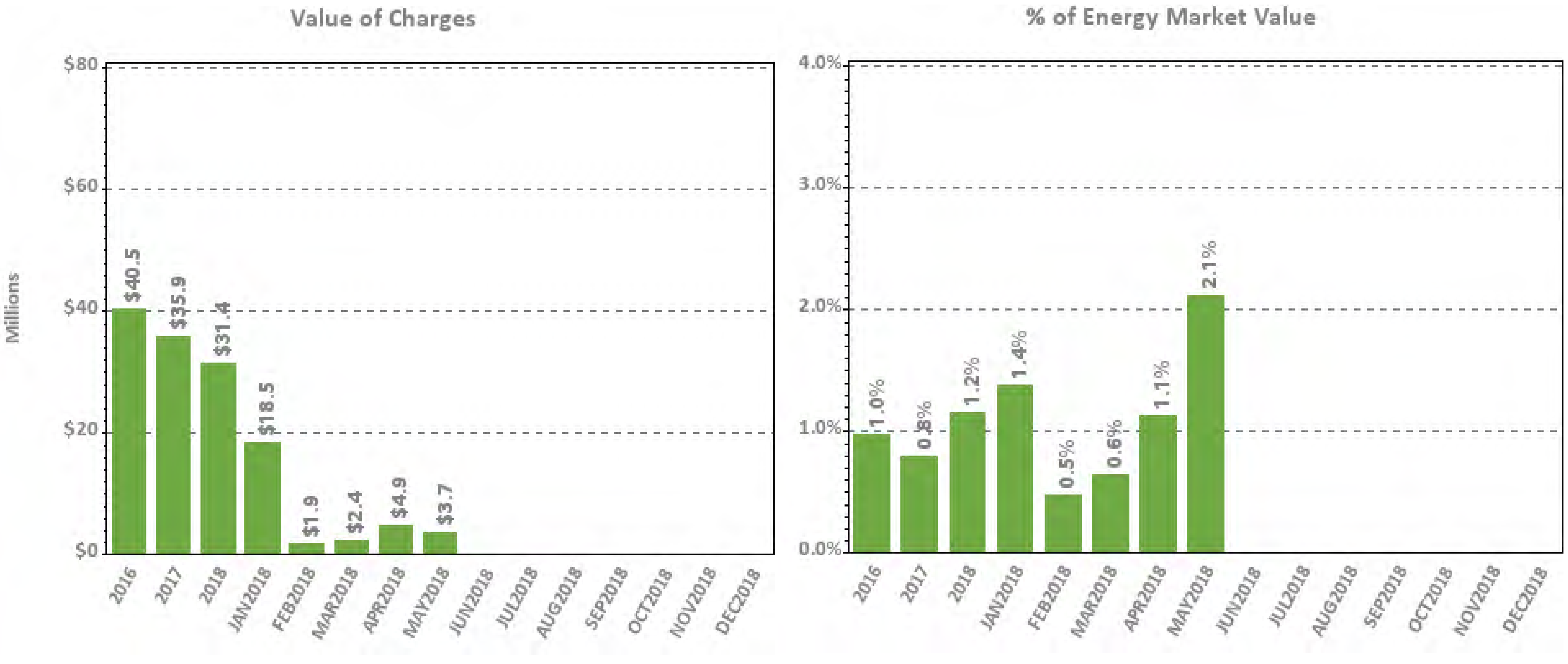
NCPC Charges by Type



NCPC Charges as Percent of Energy Market

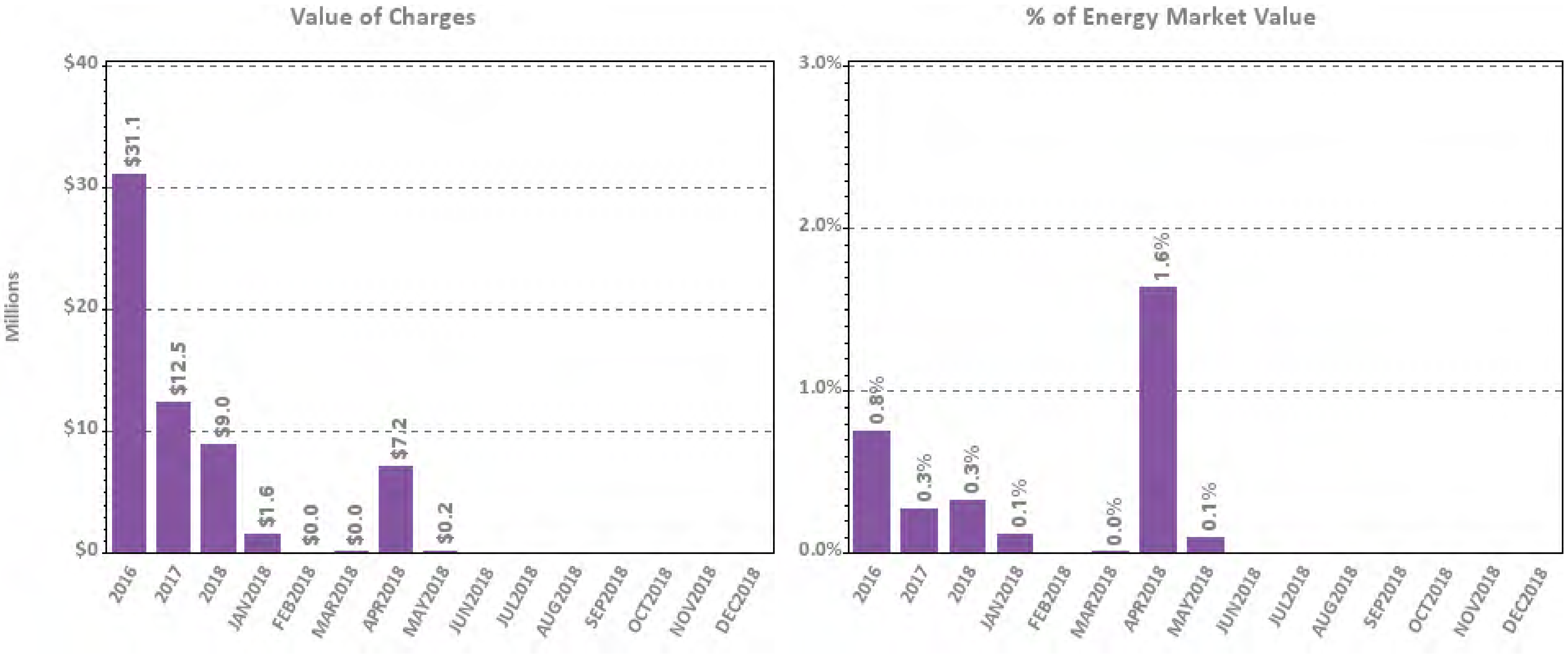


First Contingency NCPC Charges



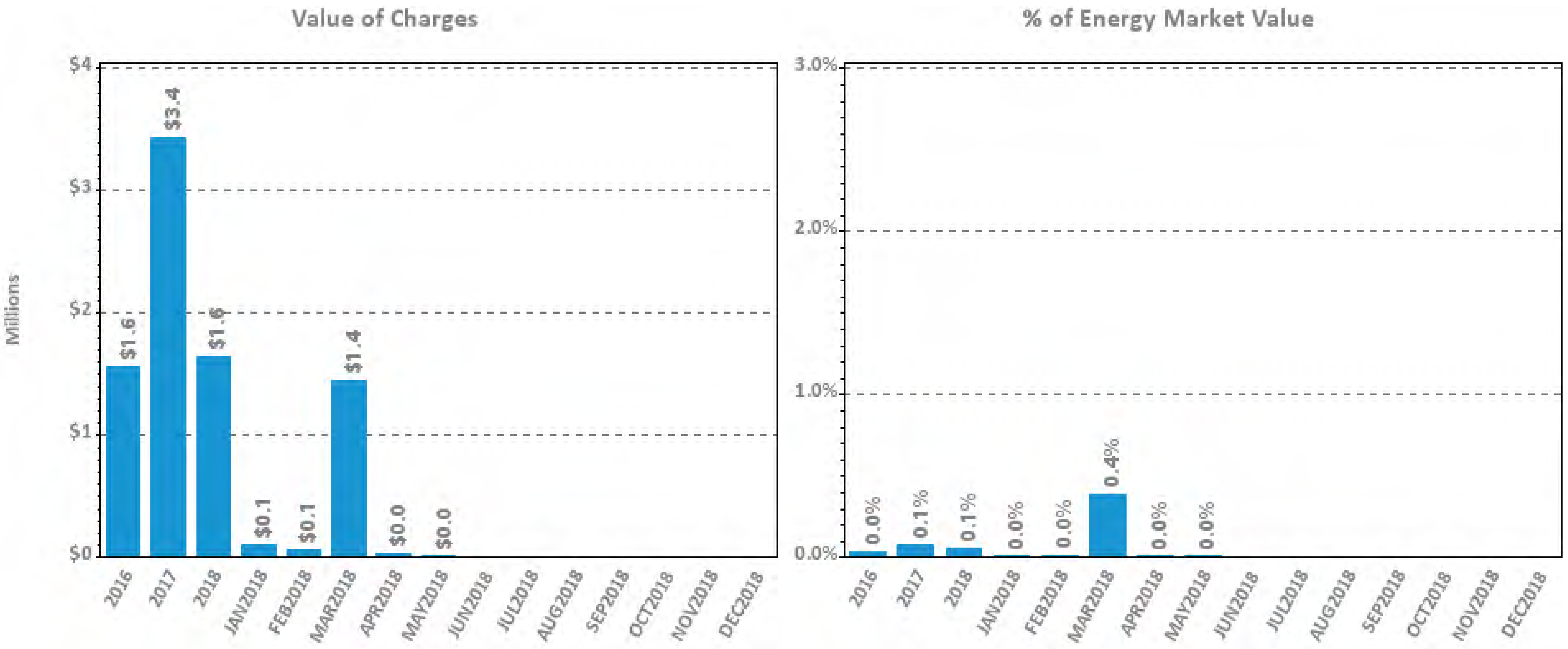
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

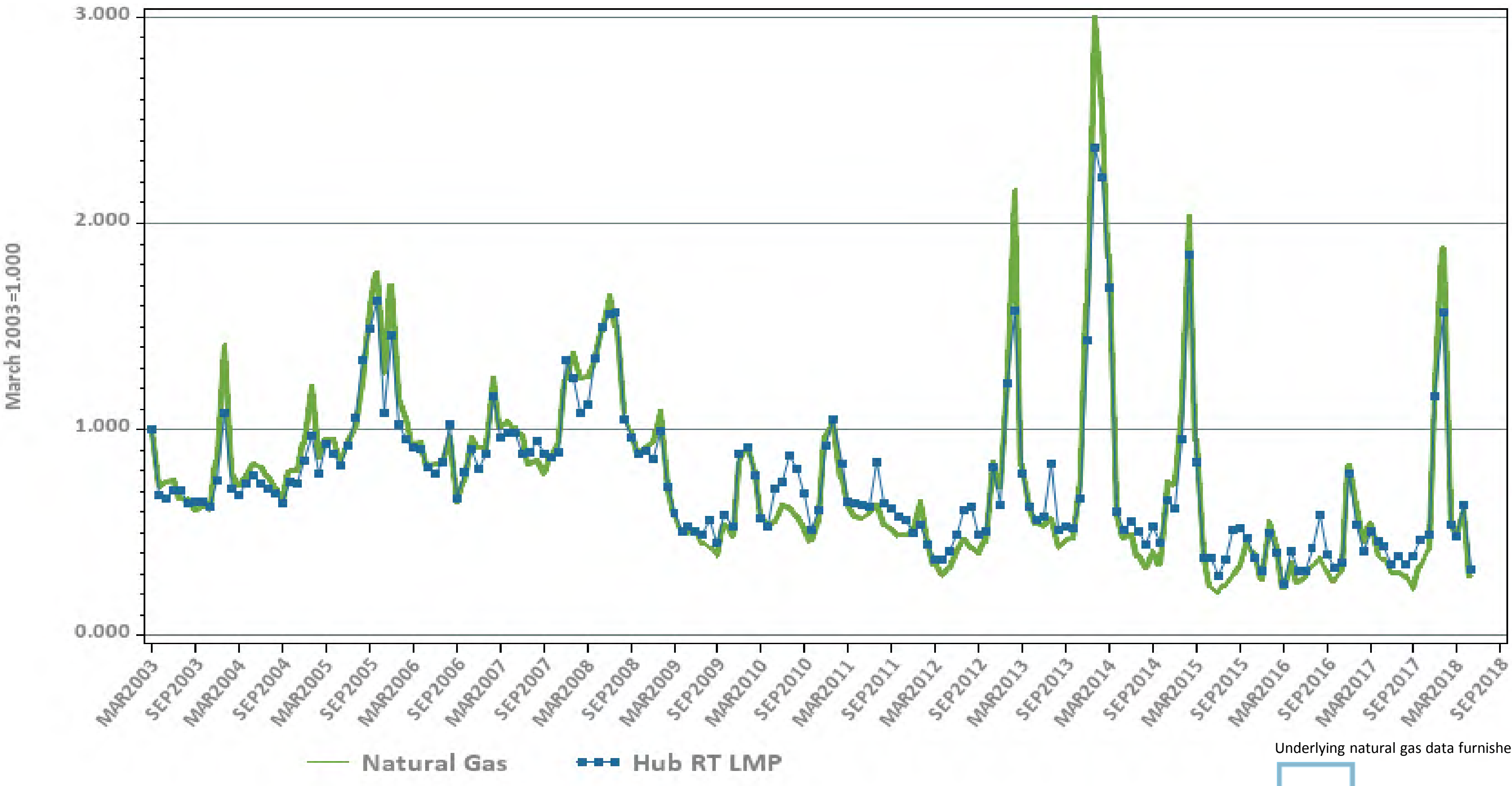
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2016	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$30.66	$29.77	$29.07	$29.64	$29.66	$29.66	$29.88	$29.85	$29.78
Real-Time	$29.74	$29.00	$27.81	$28.60	$28.49	$28.87	$29.01	$28.98	$28.94
RT Delta %	-3.0%	-2.6%	-4.3%	-3.5%	-3.9%	-2.7%	-2.9%	-2.9%	-2.8%
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%

May-17	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$27.76	$27.56	$25.15	$26.26	$26.51	$27.15	$27.34	$27.34	$27.31
Real-Time	$34.30	$28.99	$18.95	$23.00	$26.09	$29.49	$29.90	$29.31	$29.44
RT Delta %	23.6%	5.2%	-24.6%	-12.4%	-1.6%	8.6%	9.4%	7.2%	7.8%
May-18	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$23.73	$23.72	$22.04	$23.50	$23.35	$23.54	$23.66	$23.71	$23.61
Real-Time	$21.87	$21.83	$19.73	$21.66	$21.30	$21.71	$21.74	$21.83	$21.78
RT Delta %	-7.9%	-8.0%	-10.5%	-7.8%	-8.8%	-7.8%	-8.1%	-7.9%	-7.7%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	-14.5%	-13.9%	-12.4%	-10.5%	-11.9%	-13.3%	-13.5%	-13.3%	-13.5%
Yr over Yr RT	-36.3%	-24.7%	4.1%	-5.8%	-18.4%	-26.4%	-27.3%	-25.5%	-26.0%

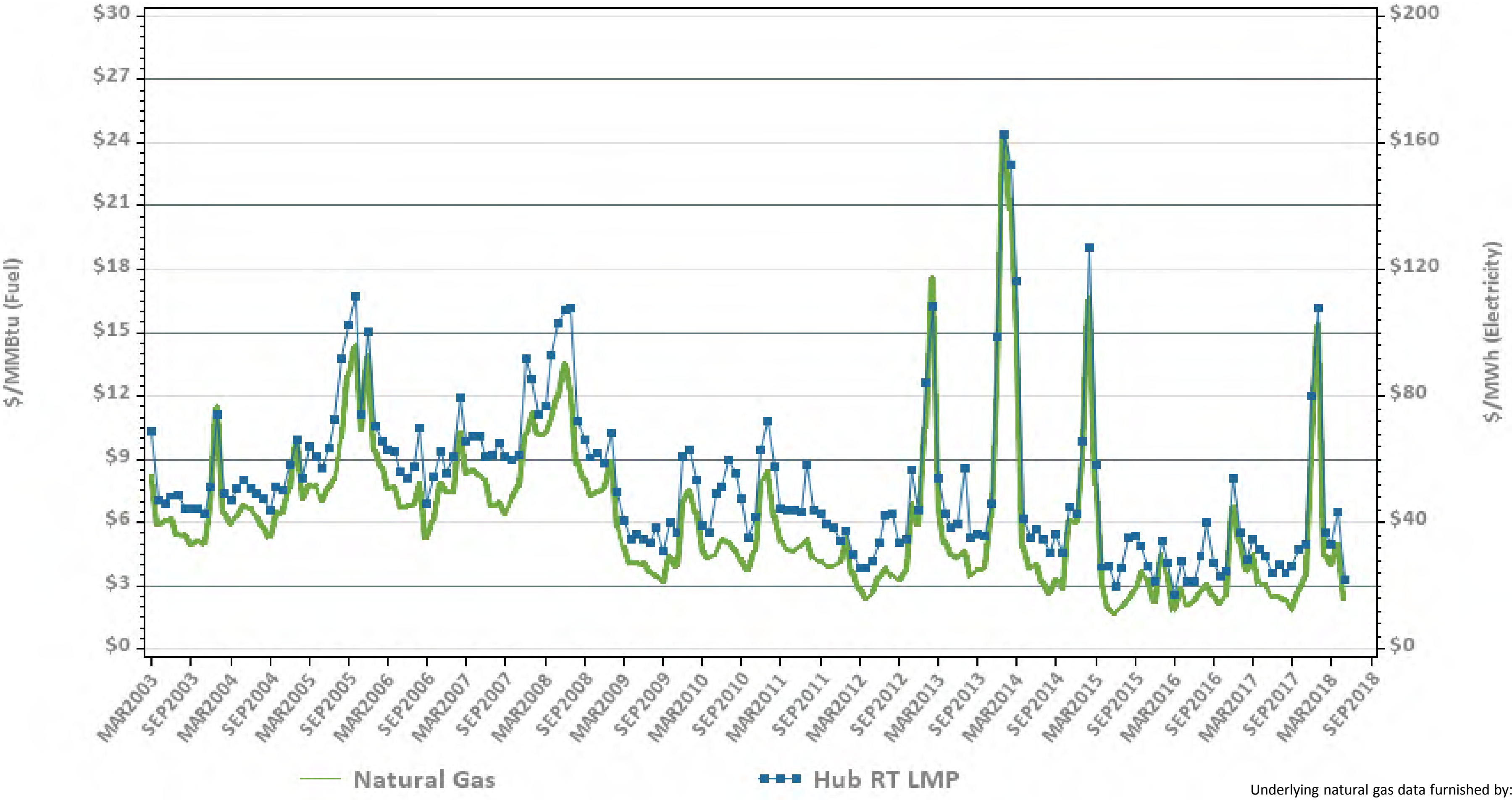
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

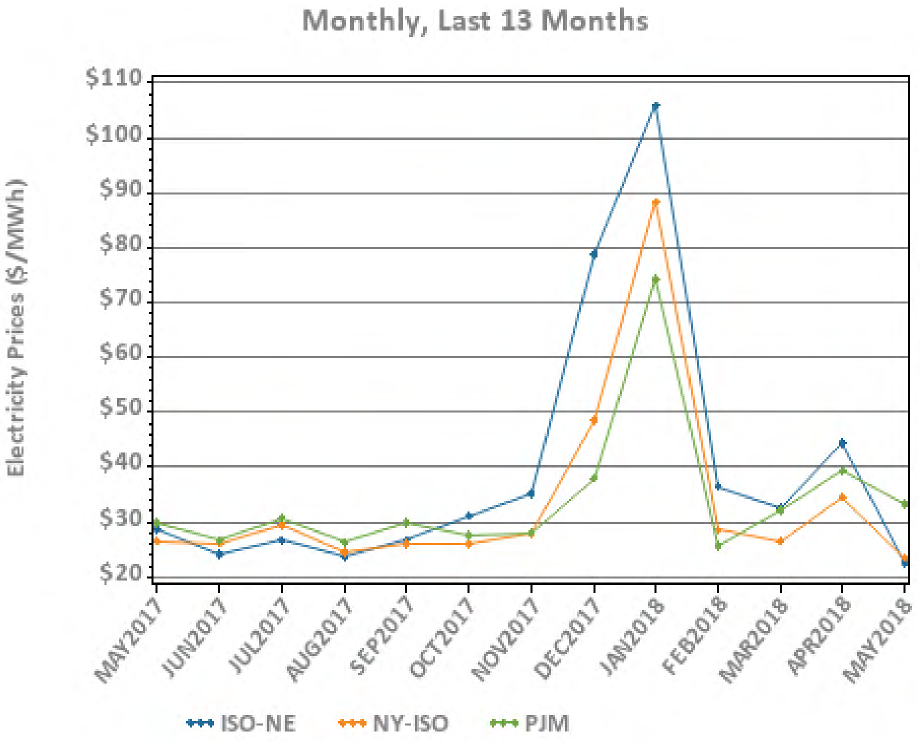
Monthly Average Fuel Price and RT Hub LMP



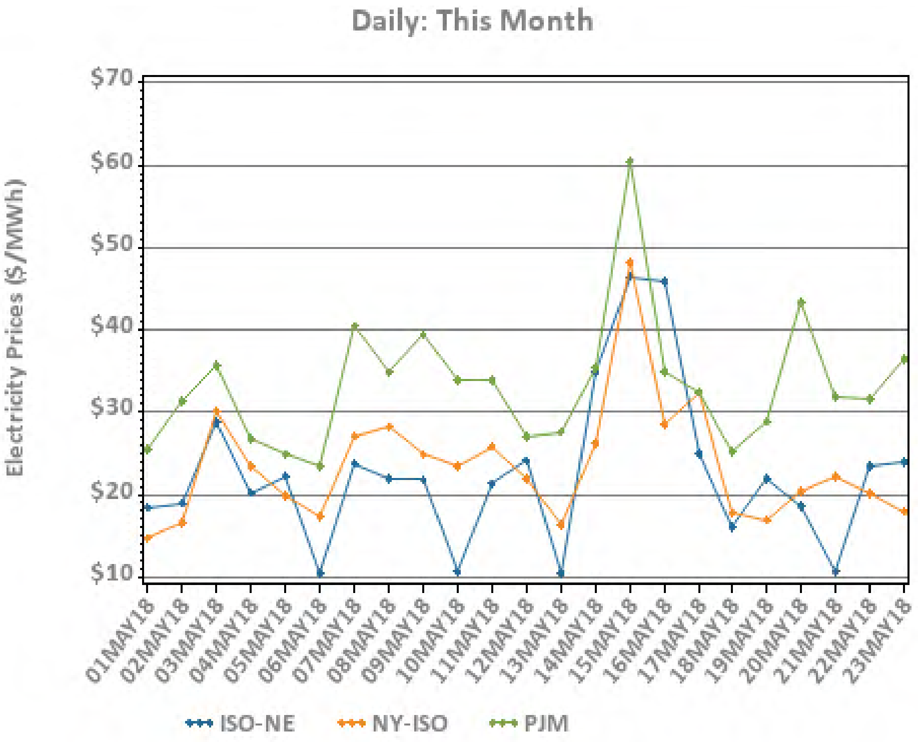
Underlying natural gas data furnished by:

ice Global markets in clear view

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

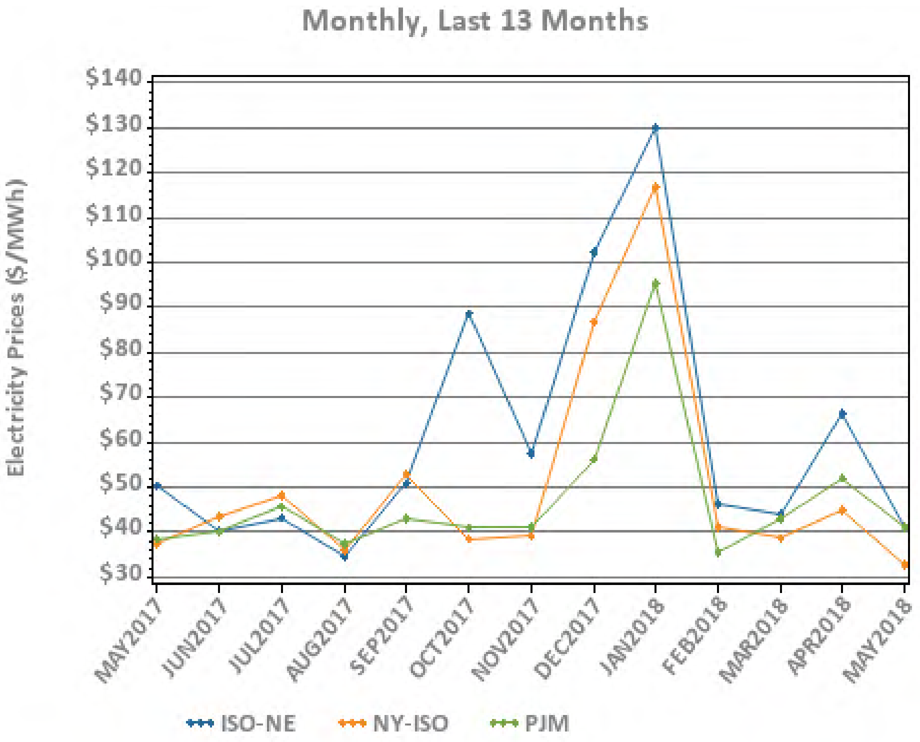


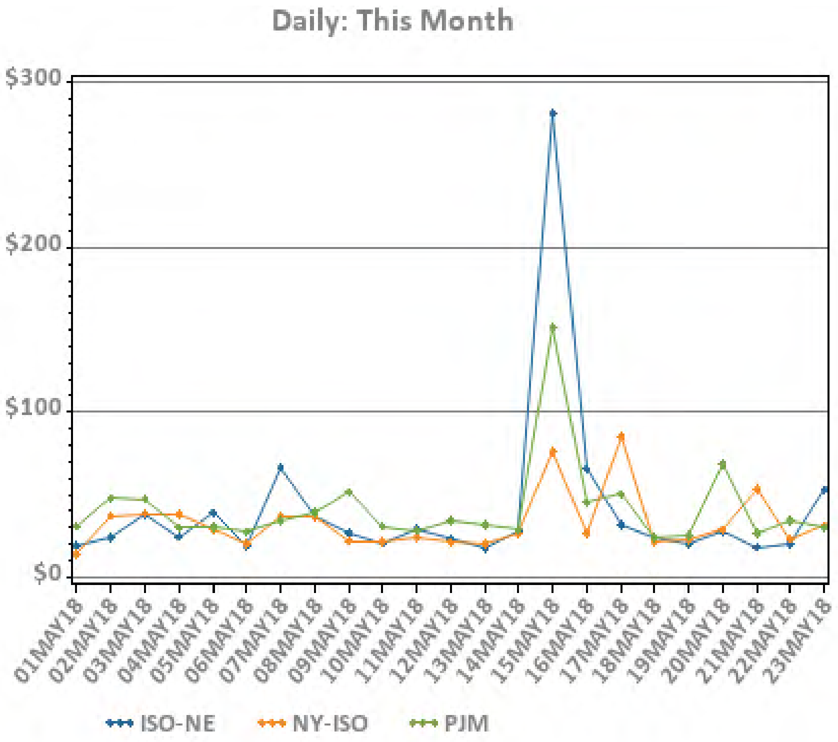
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





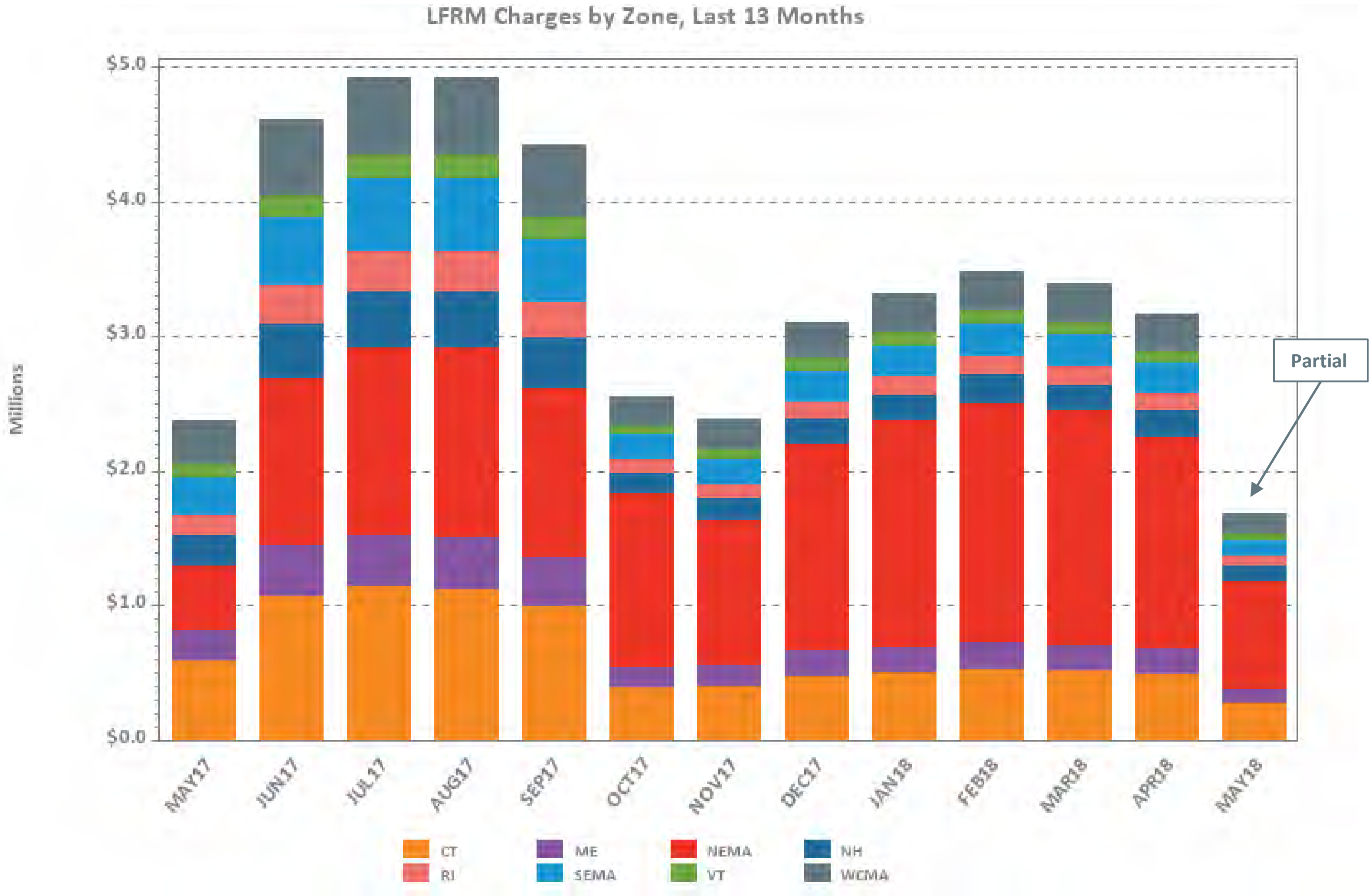
***Forecasted New England daily peak hours reflected**

Reserve Market Results – May 2018

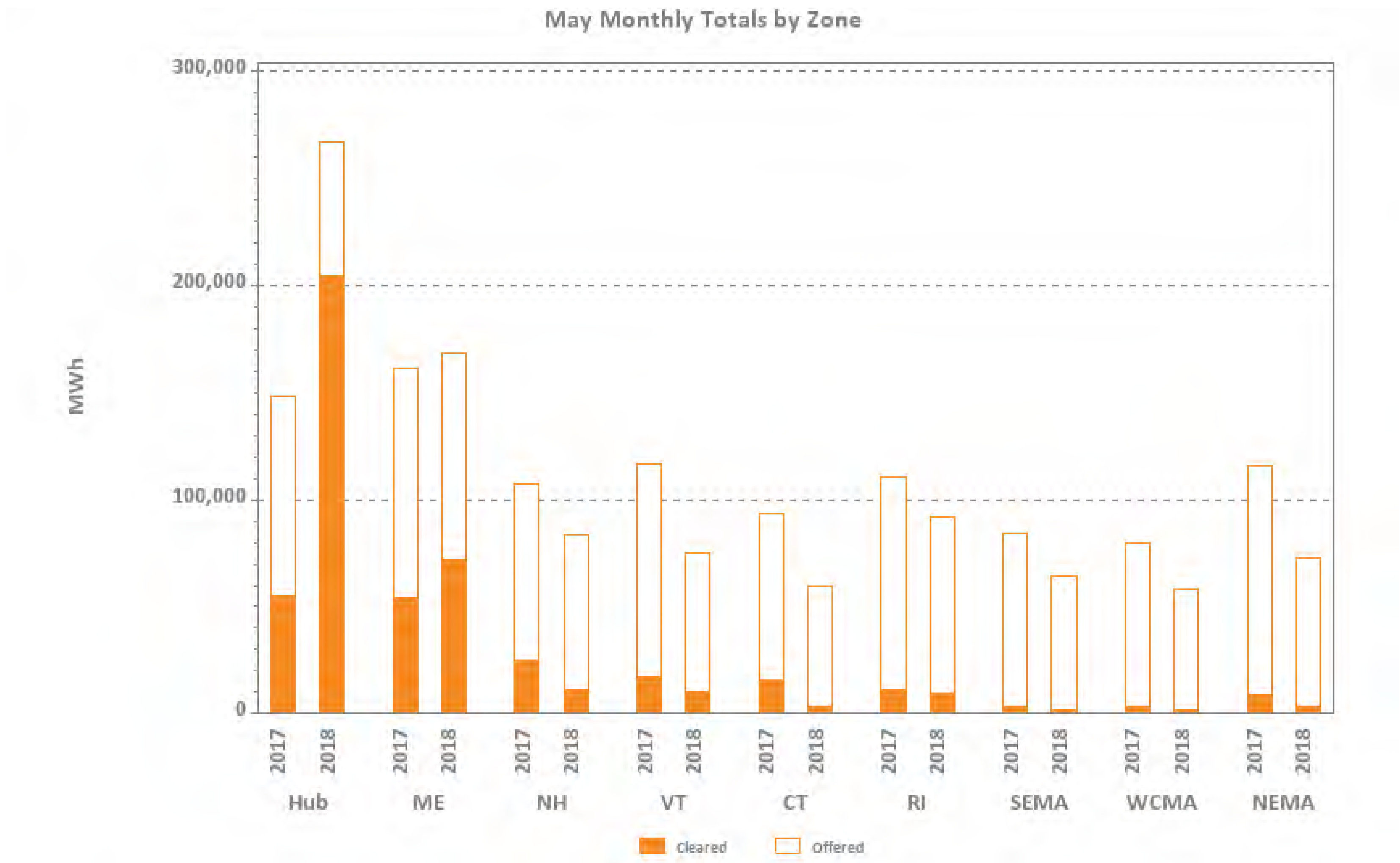
- Maximum potential Forward Reserve Market payments of $2.8M were reduced by credit reductions of $386K, failure-to-reserve penalties of $710K and failure-to-activate penalties of $443, resulting in a net payout of $1.7M or 61% of maximum
  - Rest of System: $0.78M/0.97M (80%)
  - Southwest Connecticut: $0.07M/0.12M (56%)
  - Connecticut: $0.4M/0.42M (95%)
  - NEMA: $0.4M/1.3M (34%)
- $3.5M total Real-Time credits were reduced by $887K in Forward Reserve Energy Obligation Charges for a net of $2.6M in Real-Time Reserve payments
  - Rest of System: 264 hours, $1805K
  - Southwest Connecticut: 264 hours, $462K
  - Connecticut: 264 hours, $250K
  - NEMA: 264 hours, $102K

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

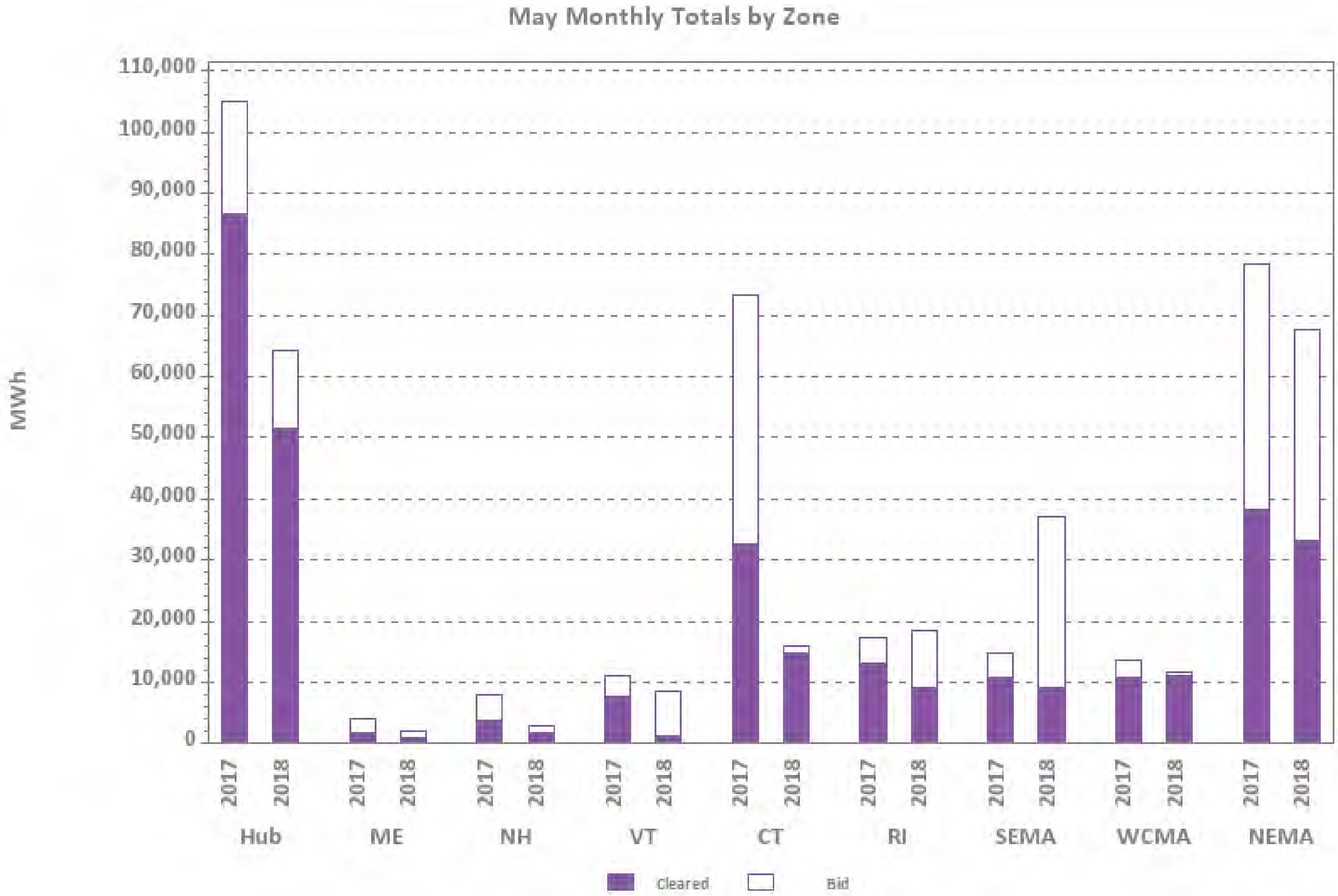
LFRM Charges to Load by Load Zone ($)



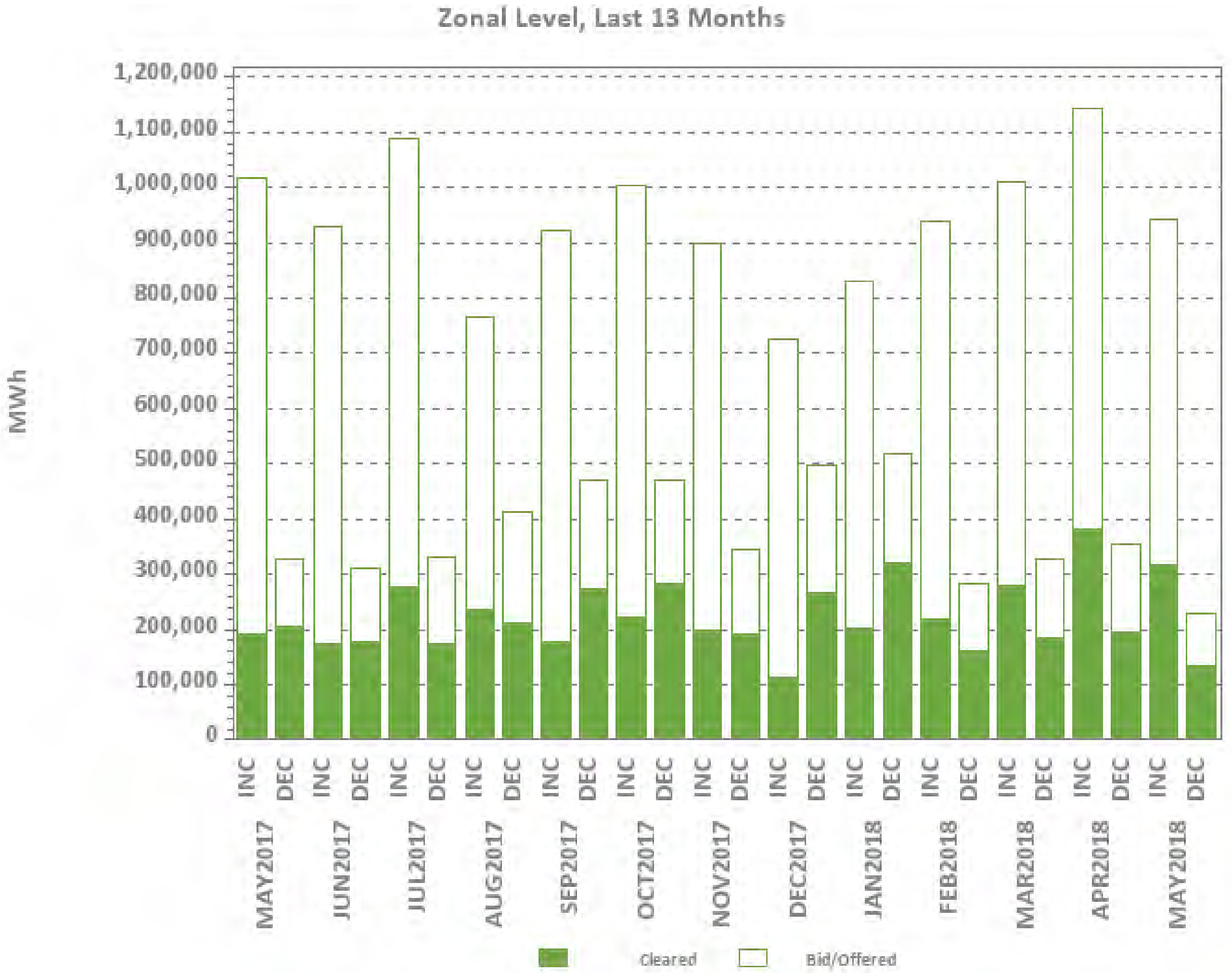
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

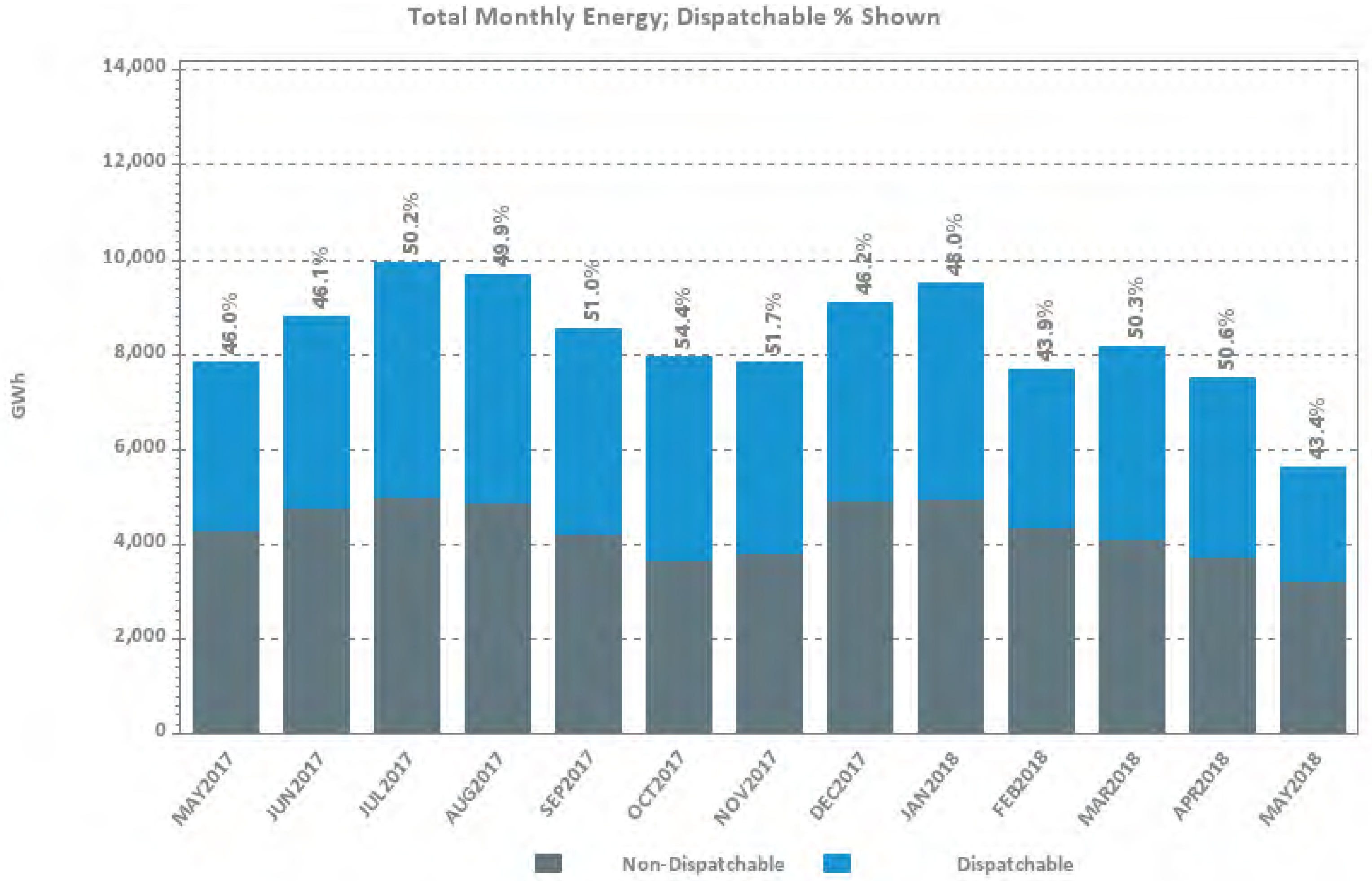


Total Increment Offers and Decrement Bids



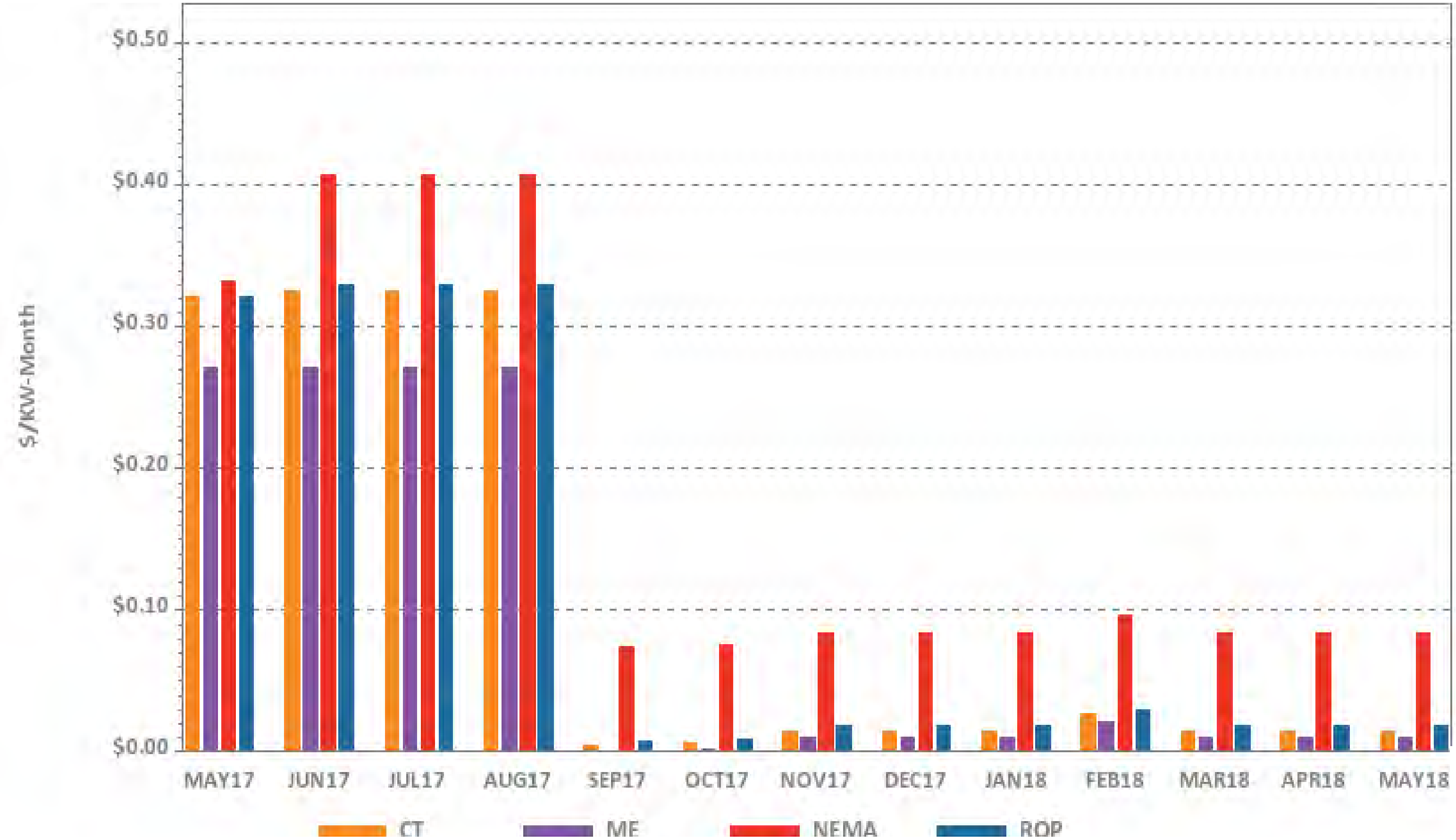
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

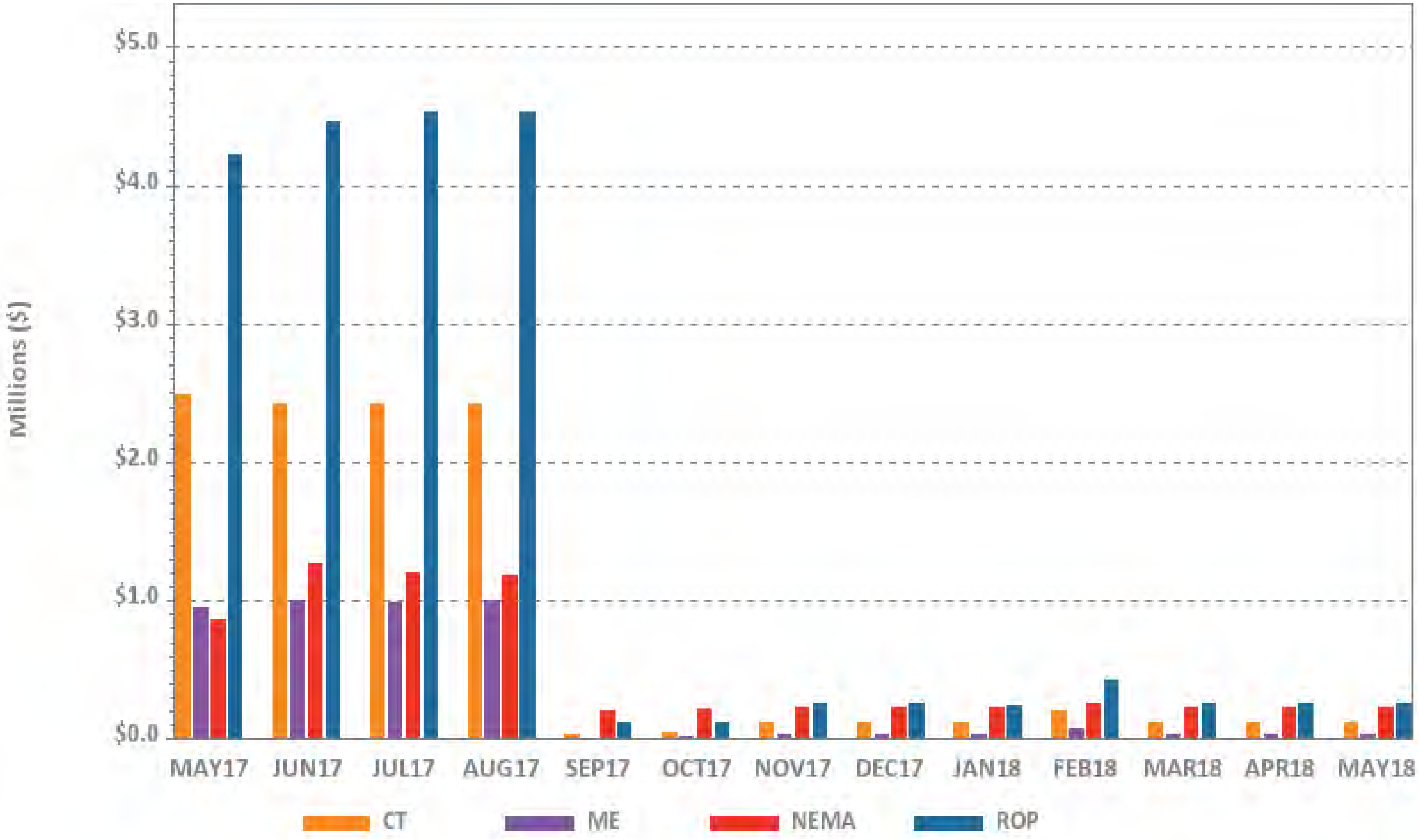
Rolling Average Peak Energy Rent (PER)



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

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

PER Adjustments



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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- June 13 PAC Meeting Agenda Topics*
  - Regional System Plan Transmission Projects and Asset Condition June 2018 Update
  - SWCT 2027 Needs Assessment Results
  - Representative Future Locational Reserve Needs for Major Import Areas
  - Future Representative Capacity Requirements for CCP 2023-2024 through CCP 2027-2028
  - Railroad Corridor Transmission Line Asset Condition Assessment
  - Canal Station #980 BPS and Asset Condition Upgrade Project
  - GHCC Southwest Hartford to Newington 115 kV Line Project Update
  - Robinson Ave Station 115 kV Asset Condition Need and Solutions
  - Second Maine Resource Integration Study

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

Load, Energy Efficiency, and Photovoltaic Forecast

- The forecast development process is complete and forecasts were published in the 2018 CELT report on May 1
- Staff continues to explore the potential impact of emerging technologies (e.g., heat pumps, battery walls) on the load forecast
- Next Load Forecast Committee meeting will be held on July 27

Interregional Planning

- Final 2017 Northeast Coordinated System Plan (NCSP) was posted on May 4
- Inter-Area Planning Stakeholder Advisory Committee (IPSAC) meeting was held on May 18
  - Summary of Final 2017 NCSP and the Interregional Planning Process
  - Regional Planning Needs and Solutions for PJM, NYISO, and ISO-NE
  - Interconnection Coordination – Interconnection Queue and Long-Term Firm Transmission Requests for PJM, NYISO, and ISO-NE
  - Process for Additional Stakeholder Input and Next Steps
  - Next meeting is planned for December

Environmental Matters

- The ISO tracks environmental regulatory developments affecting new and existing generators and transmission infrastructure
  - 5/24/2018: RGGI releases 2017 Market Monitoring Report
    - RGGI market monitor found no issues in program administration
    - Allowances prices declined in 2017, trending lower in 2018
    - 108 million surplus allowances remain in circulation (nearly 18-month supply for entire 9-state region) after deducting allowances for compliance
  - In Massachusetts, GWSA 310 CMR 7.74 generator emissions cap update:
    - Year-to-date 2018 CO_2 emissions (January-April) 2.72 million short tons, compared to 2.53 million short tons for 3-year average for same period
    - 5.76 million short tons left for 2018 out of 8.48 million cap total
    - New units (Salem 5 & 6) can tap separate set-aside of 1.5 million short tons for 2018, and smaller new unit set-asides in 2019 and 2020

RGGI – Regional Greenhouse Gas Initiative
GWSA – Global Warming Solutions Act

2017 Economic Study Update

- The 2017 Study examined three cases with the same basic assumptions that were used in the 2016 Study Scenario 3, but with changes in the resource mix to reflect differing amounts of energy efficiency, onshore wind, offshore wind, and a case with 2,100 MW of nuclear retirements
  - Draft report is scheduled to be posted by July

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.

Connecticut River Valley

Status as of 5/29/18

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

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 5/29/18

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 5/29/18

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 5/29/18

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 5/29/18

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	3
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-15	4
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	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 5/29/18

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

Upgrade	Expected/ Actual In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-18	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-18	3
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-18	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 5/29/18

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-18	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	3
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 5/29/18

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	3
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	Dec-18	3
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-16	4
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-15	4
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-15	4
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Apr-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 5/29/18

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Mar-16	4
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Dec-18	3
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	3
Loop the 1570 line in and out the Pootatuck substation	Jul-18	3
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 5/29/18

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	3
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Oct-18	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	Oct-18	3
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 5/29/18

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)	Jun-19	2
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Jun-19	2

Southwest Connecticut Projects, cont.

Status as of 5/29/18

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	3
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 5/29/18

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

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

Greater Boston Projects

Status as of 5/29/18

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	Dec-18	2
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn	Jun-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	Dec-18	2

Greater Boston Projects, cont.

Status as of 5/29/18

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	Jun-18	3
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	Sep-19	3
Install third 115 kV line from West Walpole to Holbrook	Sep-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-19	2

Greater Boston Projects, cont.

Status as of 5/29/18

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	Dec-18	3
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	May-19	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	May-19	2

Greater Boston Projects, cont.

Status as of 5/29/18

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.	Dec-18	3
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Dec-18	3
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 5/29/18

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	Dec-18	3
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	Jun-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 5/29/18

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 5/29/18

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

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

Pittsfield/Greenfield Projects, cont.

Status as of 5/29/18

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	Dec-19	1

SEMA/RI Reliability Projects

Status as of 5/29/18

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	2
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Nov-20	2
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	2

SEMA/RI Reliability Projects

Status as of 5/29/18

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-19	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 5/29/18

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 5/29/18

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	Apr-21	1
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	3
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap	Nov-18	2
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Dec-18	2

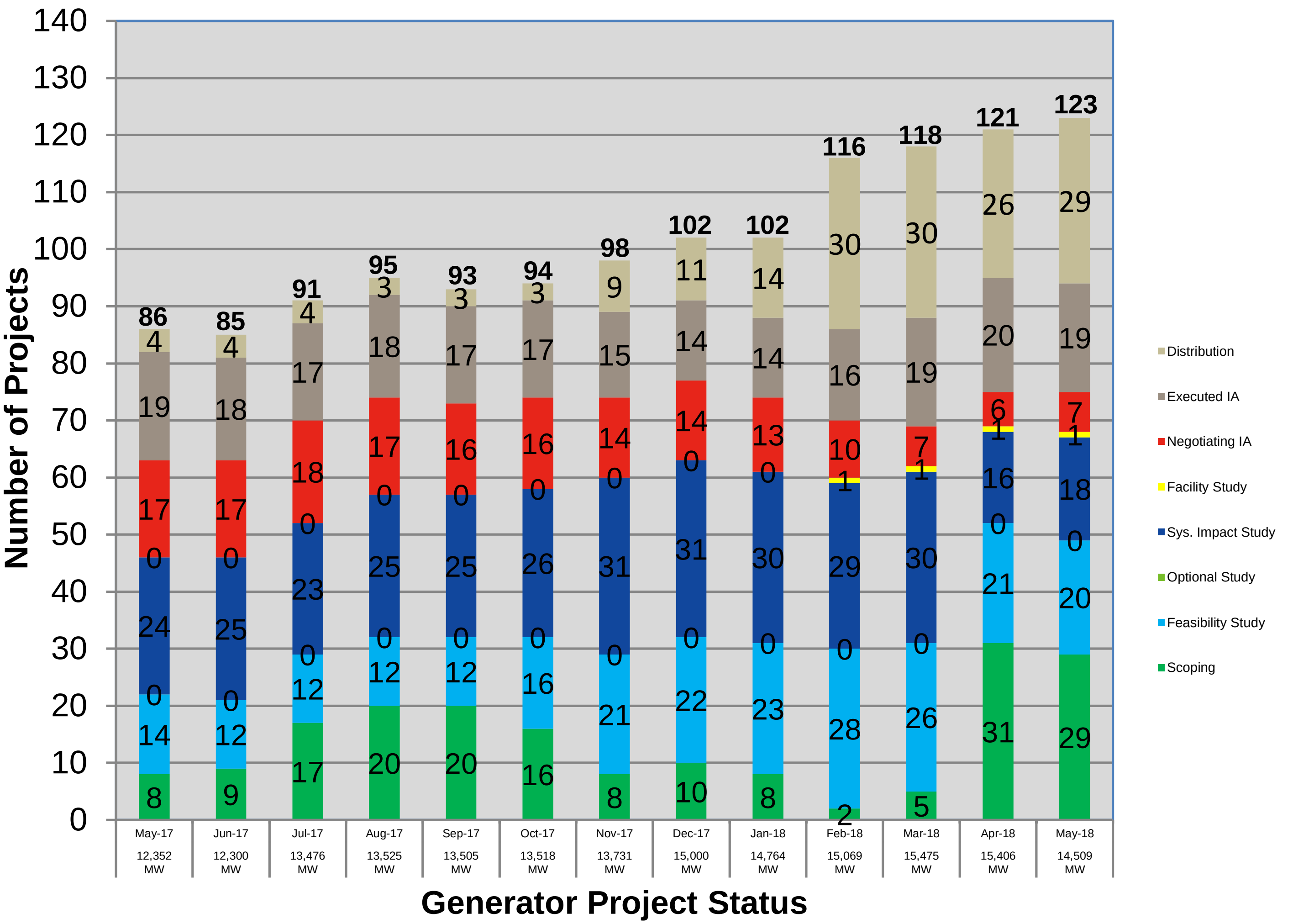
SEMA/RI Reliability Projects

Status as of 5/29/18

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	Dec-19	1
1782	Reconductor the J16S line	Dec-20	2
1724	Replace the Kent County 345/115 kV transformer	Nov-20	2

Status of Tariff Studies



Note: May 2018 based on partial data

Note: As of May 2018, there are 6 ETU's in SIS, 3 in FS, 7 in Scoping, 1 in FAC, and 3 in Neg. IA

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OPERABLE CAPACITY ANALYSIS

Summer 2018

Summer 2018 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2018[2] CSO	June - 2018[2] SCC
Operable Capacity MW [1]	30,229	30,452
Active Demand Capacity Resource (+) [5]	408	408
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,553	1,553
Non Commercial Capacity (+)	9	9
Non Gas-fired Planned Outage MW (-)	168	168
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	29,231	29,454
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	25,729	25,729
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,034	28,034
Operable Capacity Margin [3]	1,197	1,420

[1] Operable Capacity is based on data as of **May 16, 2018** 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 **May 16, 2018.**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 2, 2018.**

[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.

Summary 2018 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	June - 2018[2] CSO	June - 2018[2] SCC
Operable Capacity MW [1]	30,229	30,452
Active Demand Capacity Resource (+) [5]	408	408
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,553	1,553
Non Commercial Capacity (+)	9	9
Non Gas-fired Planned Outage MW (-)	168	168
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	29,231	29,454
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	28,120	28,120
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	30,425	30,425
Operable Capacity Margin [3]	-1,194	-971

[1] Operable Capacity is based on data as of **May 16, 2018** 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 **May 16, 2018.**

[2] Load forecast that is based on the CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 2, 2018.**

[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.

Summer 2018 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

June 1, 2018 - 50/50 FORECAST using CSO values

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]
6/2/2018	**30,229**	**408**	**1,553**	**9**	**168**	**0**	**2,800**	**0**	**29,231**	**25,729**	**2,305**	**28,034**	**1,197**
6/9/2018	30,229	408	1,553	9	126	0	2,800	0	29,273	25,729	2,305	28,034	1,239
6/16/2018	30,229	408	1,553	9	97	0	2,800	0	29,302	25,729	2,305	28,034	1,268
6/23/2018	30,229	408	1,553	9	14	0	2,800	0	29,385	25,729	2,305	28,034	1,351
6/30/2018	30,326	408	1,468	9	14	0	2,100	0	30,097	25,729	2,305	28,034	2,063
7/7/2018	30,326	408	1,468	9	27	0	2,100	0	30,084	25,729	2,305	28,034	2,050
7/14/2018	30,326	408	1,468	9	20	0	2,100	0	30,091	25,729	2,305	28,034	2,057
7/21/2018	30,326	408	1,468	9	13	0	2,100	0	30,098	25,729	2,305	28,034	2,064
7/28/2018	30,326	408	1,468	9	27	0	2,100	0	30,084	25,729	2,305	28,034	2,050
8/4/2018	30,326	408	1,468	9	13	0	2,100	0	30,098	25,729	2,305	28,034	2,064
8/11/2018	30,326	408	1,468	9	13	0	2,100	0	30,098	25,729	2,305	28,034	2,064
8/18/2018	30,326	408	1,468	9	27	0	2,100	0	30,084	25,729	2,305	28,034	2,050
8/25/2018	30,326	408	1,468	9	13	0	2,100	0	30,098	25,729	2,305	28,034	2,064
9/1/2018	30,326	408	1,468	9	191	0	2,100	0	29,920	25,729	2,305	28,034	1,886

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 preliminary 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)

Summer 2018 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2018 OPERABLE CAPACITY ANALYSIS

June 1, 2018 - 90/10 FORECAST using CSO values

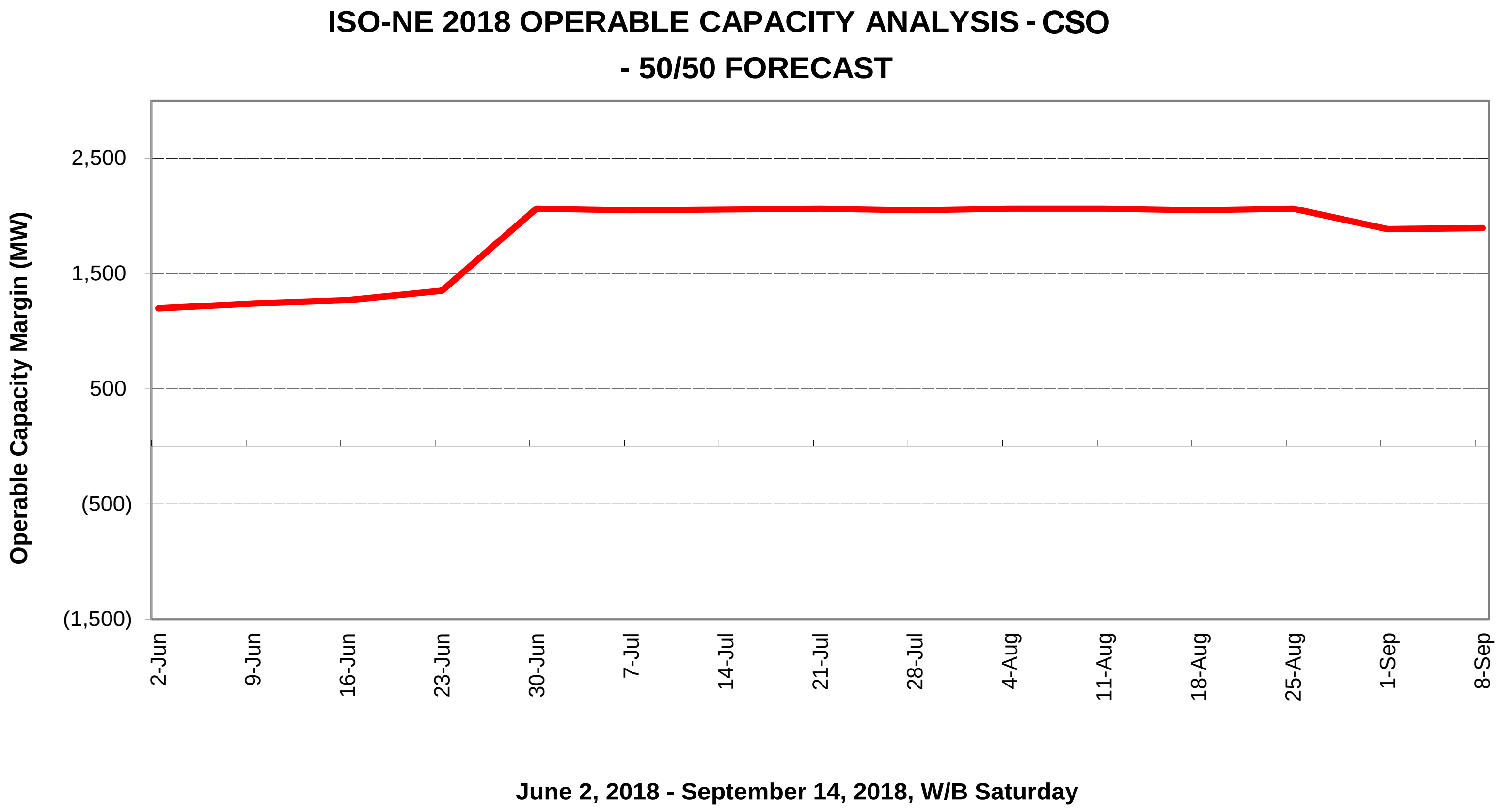
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August and Mid September.

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]
6/2/2018	**30,229**	**408**	**1,553**	**9**	**168**	**0**	**2,800**	**0**	**29,231**	**28,120**	**2,305**	**30,425**	**(1,194)**
6/9/2018	30,229	408	1,553	9	126	0	2,800	0	29,273	28,120	2,305	30,425	(1,152)
6/16/2018	30,229	408	1,553	9	97	0	2,800	0	29,302	28,120	2,305	30,425	(1,123)
6/23/2018	30,229	408	1,553	9	14	0	2,800	0	29,385	28,120	2,305	30,425	(1,040)
6/30/2018	30,229	408	1,468	9	14	0	2,100	0	30,000	28,120	2,305	30,425	(425)
7/7/2018	30,326	408	1,468	9	27	0	2,100	0	30,084	28,120	2,305	30,425	(341)
7/14/2018	30,326	408	1,468	9	20	0	2,100	0	30,091	28,120	2,305	30,425	(334)
7/21/2018	30,326	408	1,468	9	13	0	2,100	0	30,098	28,120	2,305	30,425	(327)
7/28/2018	30,326	408	1,468	9	27	0	2,100	0	30,084	28,120	2,305	30,425	(341)
8/4/2018	30,326	408	1,468	9	13	0	2,100	0	30,098	28,120	2,305	30,425	(327)
8/11/2018	30,326	408	1,468	9	13	0	2,100	0	30,098	28,120	2,305	30,425	(327)
8/18/2018	30,326	408	1,468	9	27	0	2,100	0	30,084	28,120	2,305	30,425	(341)
8/25/2018	30,326	408	1,468	9	13	0	2,100	0	30,098	28,120	2,305	30,425	(327)
9/1/2018	30,326	408	1,468	9	191	0	2,100	0	29,920	28,120	2,305	30,425	(505)
9/8/2018	30,326	408	1,468	9	182	0	2,100	0	29,929	28,120	2,305	30,425	(496)

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 preliminary 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)

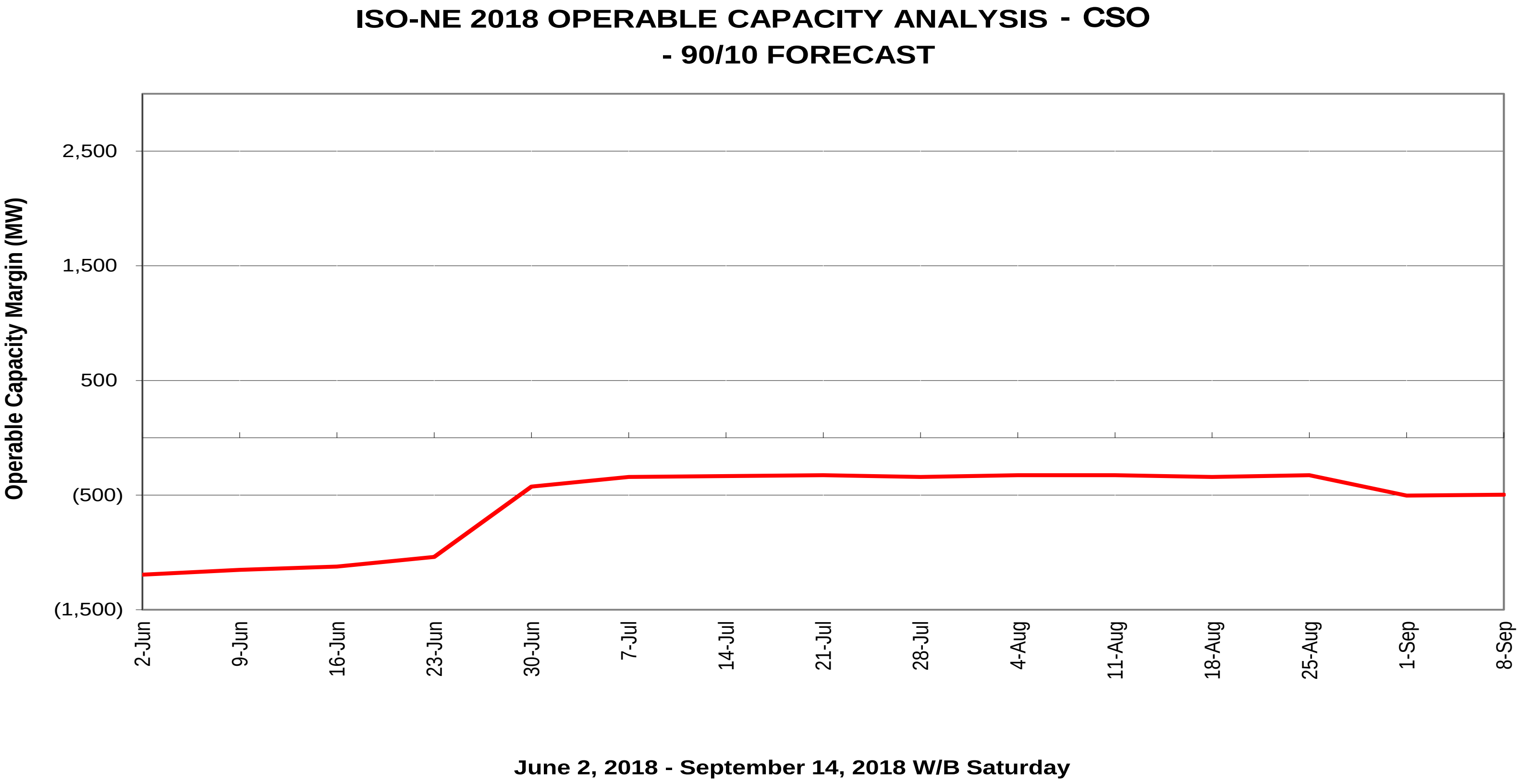
Summary 2018 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)



Summer 2018 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow 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, cont.

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	Voltage Reduction requiring 10 minutes or less	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		**June 2,542 [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

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian M. Lombardi, NEPOOL Counsel

DATE: May 24, 2018

RE: New Economic Life Calculation for Permanent & Retirement De-List Bids

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At the June 1, 2018 Participants Committee meeting, you will be asked to consider supporting Markets Committee-recommended Tariff revisions modifying the economic life calculation to determine competitive Permanent De-List Bid and Retirement De-List Bid prices in the FCM, as proposed by the ISO's Internal Market Monitor (IMM). A copy of these recommended changes are included with this memorandum as Attachment A.

By way of brief background, the Market Rules specify a methodology that determines the expected remaining economic life of a resource that submits a Permanent or Retirement De-List Bid in the FCM. Economic life is the number of Capacity Commitment Periods that a resource is assumed to remain in the market if it retains an obligation in the primary auction as part of the competitive bid price calculation for its Permanent or Retirement De-List Bid. Under the current rules, a resource's economic life is set to the maximum period for which a resource's cumulative future expected profits are positive. The IMM has identified a concern that this current methodology may overstate the true economic life of a de-listing resource in some cases, and is therefore proposing to modify the Tariff such that a resource's economic life is set to the period when expected profits are maximized. Further detail on this newly proposed methodology, including a numerical example, is provided in the IMM's supporting materials included with this memorandum as Attachment B.

At its May 17, 2018 teleconference meeting, the Markets Committee voted to recommend Participants Committee support for the IMM's proposed changes to Section III.13.1.2.3.2.1.2.C of Market Rule 1, with a 68.92% Vote in favor.[1]

The IMM proposes to use this new economic life calculation methodology beginning with its review of Permanent and Retirement De-List Bids for FCA13, which have already been submitted. To support a potential modified schedule for FCA13, the ISO may be separately seeking waiver of certain FCA13 qualification deadlines that are fast approaching. The ISO will confirm with stakeholders whether they will seek waiver at the June 1 meeting.

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[1] The individual Sector votes at the Markets Committee were: *Generation* - 0% in favor, 17.13% opposed, 1 abstention; *Transmission* - 17.13% in favor, 0% opposed, 1 abstention; *Supplier* – 11.42% in favor, 5.71% opposed, 7 abstentions; *Alternative Resources* - 6.13% in favor, 8.25% opposed, 2 abstentions; *Publicly Owned Entity* - 17.13% in favor, 0% opposed; and *End User* - 17.13% in favor, 0% opposed, 1 abstention.

The following form of resolution may be used for Participants Committee action on this matter:

> RESOLVED, that the Participants Committee support the revisions to Section III.13.1.2.3.2.1.2.C of Market Rule 1, as recommended by the Markets Committee at its May 17, 2018 meeting and circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

III.13.1.2.3.2.1.2.C Permanent De-List Bid and Retirement De-List Bid Calculation of Remaining Economic Life.

The Internal Market Monitor shall calculate the Existing Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Forward Capacity Auction Starting Price and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the ~~maximum~~ evaluation period in which a resource's net present value is ~~non-negative~~maximized.

ISO new england

memo

To: NEPOOL Markets Committee

From: Robert Laurita

Date: May 17, 2018

Subject: Permanent and Retirement De-List Economic Life Calculation

The Internal Market Monitor (IMM) is requesting a vote on revisions to Section III.13.1.2.3.2.1.2.C – Permanent De-List Bid and Retirement De-List Bid Calculation of Market Rule 1. The revisions address the IMM's concern that the current methodology for determining the remaining economic life may overstate the true economic life of a resource in some cases. By way of background, the Market Rules specify a methodology that determines the expected remaining economic life of the de-listing resource if it retains an obligation in the primary auction as part of the competitive bid price calculation for Permanent and Retirement De-List bids. Under the current rules, a resource's economic life is set to the maximum duration for which its net present value of cumulative future expected cash flows is positive. This assumption is inconsistent with how a competitive resource would operate a resource. To address this inconsistency, the IMM proposes to modify the Tariff such that a resource's economic life is set to the period with the maximum positive net present value of cumulative future expected cash flows.

Based on the IMM's preliminary assessment, this issue with economic life calculations could materially affect bid prices and outcomes in FCA 13. In order to ensure that the FCA 13 outcome is competitive, the IMM proposes to correct this determination on an accelerated basis and use an updated economic life calculation when determining competitive Permanent and Retirement De-List Bid prices for FCA 13.

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

- May 8-9, 2018 agenda item #6
  - 2018-05-08 and 2018-05-09 MC A06 Market Rule Redlines – Permanent and Retirement De-List Economic Life Calculations
  - 2018-05-08 and 2018-05-09 MC A06 Permanent and Retirement De-List Bids Updates
  - 2018-05-08 and 2018-05-09 MC A06 IMM Memo re: Permanent and Retirement De-list Bid Determinations

MAY17, 2018 | TELECONFERENCE

Permanent and Retirement De-List Bids Updates

Modify the Economic Life Calculation Used in Permanent and Retirement De-List Bids

Bob Laurita

413-535-4398 | rlaurita@iso-ne.com

Permanent/Retirement De-List Bid Updates

WMPP ID: 123

Proposed Effective Date: August 2018 (for FCA 13)

- The Internal Market Monitor (IMM) is proposing to modify the economic life calculation used to determine competitive Permanent and Retirement De-List Bid prices:
  - Calculate economic life consistent with competitive bidding behavior
  - Apply this change for De-List Bids submitted for FCA 13
- Today:
  - We intend to explain the economic life calculation, and
  - Discuss the proposed tariff language

Presentation contents

- Economic Life Calculation
- Tariff Language
- The IMM distributed a memorandum to the Markets Committee explaining the need for the proposed change
  - Available at: https://www.iso-ne.com/static-assets/documents/2018/04/a6_imm_memo_economic_life_calculation_04262018.pdf

ECONOMIC LIFE CALCULATION

Role of Economic Life in De-List Bid Prices

- The competitive price for Permanent or Retirement De-List Bid is based (in part) on the resource's expected economic life
- Economic life is the number of commitment periods that a resource is assumed to remain in the market, if it retains a CSO in the coincident FCA
- De-List Bid calculations determine the lowest price at which the resource would sell capacity for the coincident FCA, based on its expected profit/loss over its remaining economic life

Calculation of Economic Life

- In reviewing the existing methodology, the IMM has identified an error in the economic life calculation
- **Currently** the economic life is the maximum period for which the resource's cumulative profits are positive
- **However**, this definition erroneously assumes (in some cases) that a resource that earned positive profits in early periods would willingly operate and sustain losses in later periods
  - Assumes that resource would 'gives back' a portion of its profits
  - Inconsistent with competitive behavior, as resources would retire rather than incur the losses in later periods
- **Correction** is straight forward: define economic life as the period when expected profits are maximized
  - Consistent with how we expect competitive suppliers to behave

Numerical Example

- Uses the same framework as the economic life example presented at the September 30, 2015 MC Meeting
  - Available at: https://www.iso-ne.com/static-assets/documents/2015/08/a12_imm_retirement_cost_review_scenarios_09_03_15.xlsx
- The example is updated with the FCA13 auction starting price and revised cash flows to illustrate the problem and proposed solution.

Generator Retirement Capacity (MW)	50				
Discount Rate	10%				
Auction Starting Price	$13.02				
Market Participant's Submittal for Retirement starting in CCP1					
Capacity Commitment Period	1	2	3	4	5
Capacity Price ($/kW-Month)	Auction Starting Price	Forecast	Forecast	Forecast	Forecast
	$13.02	$5.00	$5.00	$5.00	$5.00
Cash Flow Model					
Net Operating Profit ($M)	$3.00	$1.00	($1.00)	($3.00)	($5.00)
Capital Expenditure ($M)	($4.00)	($10.00)	($4.00)	($1.00)	$0.00
Cash Flow without Capacity Revenue ($M)	($1.00)	($9.00)	($5.00)	($4.00)	($5.00)
Capacity Revenue ($M)	$7.81	$3.00	$3.00	$3.00	$3.00
Cash Flow with Capacity Revenue ($M)	$6.81	($6.00)	($2.00)	($1.00)	($2.00)
Net Present Value of Cash Flow	*$6.19*	*$1.23*	*($0.27)*	*($0.95)*	*($2.19)*
Current Method: Maximum Year with Positive NPV = Year 2					
Proposed Method: Year with Maximum NPV = Year 1					

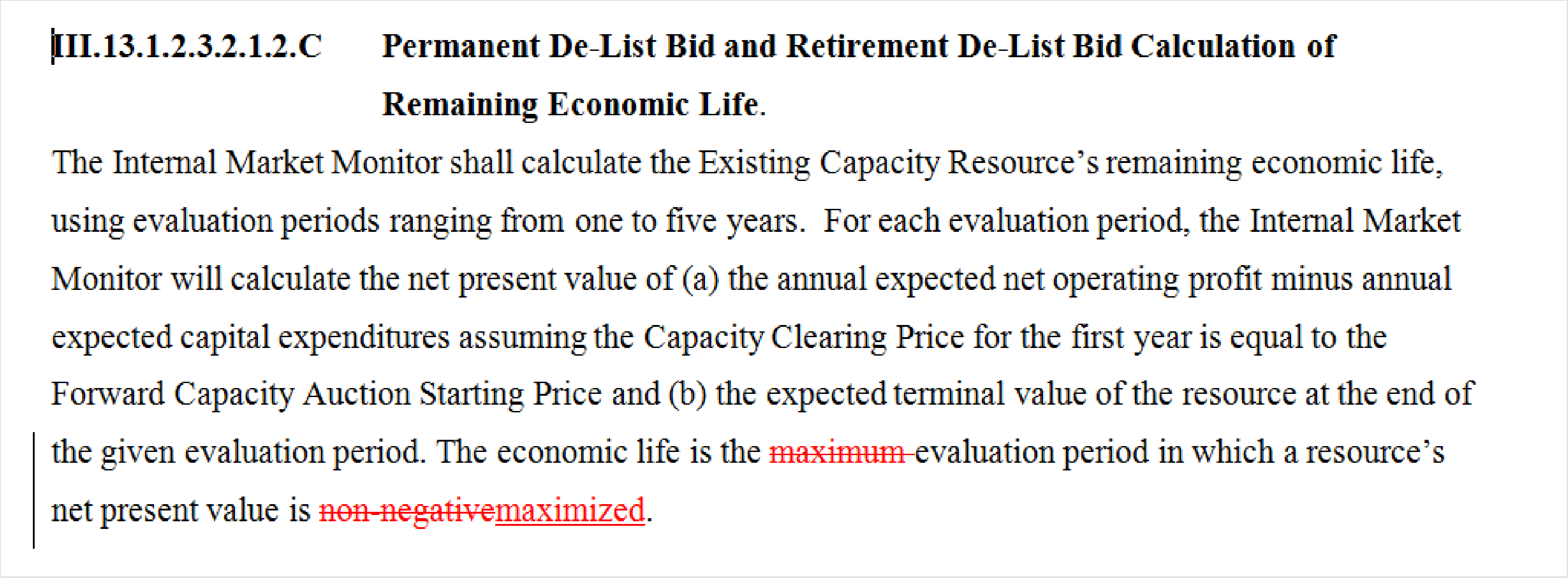
Economic Life Determination

- Corrected economic life calculation determines that the resource will operate for only period one
  - This duration maximizes the resource's cumulative profits
- Current economic life calculation (erroneously) determines the resource would also operate for period two
  - Cumulative NPV for the 2nd year is slightly positive, but the resource would 'give back' approx. $5M of its earned profits

TARIFF LANGUAGE

Tariff Revision

Section	Change	Description
III.13.1.2.3.2.1.2.C	Revise economic life determination	Economic life is calculated as the evaluation period in which the resource's net present value is maximized



III.13.1.2.3.2.1.2.C Permanent De-List Bid and Retirement De-List Bid Calculation of Remaining Economic Life.

The Internal Market Monitor shall calculate the Existing Capacity Resource's remaining economic life, using evaluation periods ranging from one to five years. For each evaluation period, the Internal Market Monitor will calculate the net present value of (a) the annual expected net operating profit minus annual expected capital expenditures assuming the Capacity Clearing Price for the first year is equal to the Forward Capacity Auction Starting Price and (b) the expected terminal value of the resource at the end of the given evaluation period. The economic life is the ~~maximum~~ evaluation period in which a resource's net present value is ~~non-negative~~maximized.

NEXT STEPS

Anticipated Stakeholder Schedule

Stakeholder Meetings	Scheduled Project Milestone
May 8-9, 2018 Markets Committee	Begin Markets Committee Discussion
May 17, 2018 Markets Committee (Extra)	Markets Committee Vote
June 1, 2018 Participants Committee	Participants Committee vote

Anticipated Implementation Schedule - Updated

Milestone	Current Date(s)	Proposed Date(s)
FERC Filing Date		6/1
Requested Effective Date		8/1
Resource Determination Notification (RDN) Deadline	6/21 Will issue RDNs with two prices (if warranted)	~~8/2~~
Participant Action Window to elect Conditional vs. Unconditional Treatment	6/21 to 7/6	8/2 to 8/16 Will seek FERC waiver
IMM filing of De-List Bid determinations with FERC	6/20	8/20 Will seek FERC waiver
ISO to review reliability needs with the Reliability Committee for Permanent and Retirement De-List Bids		8/20 – 9/20
Participant notified whether the capacity associated with a Retirement or Permanent De-List Bid is needed for reliability	As soon as practicable after the RC Meeting	
Participant informs the ISO whether it declines to provide capacity for reliability	No later than 10 business days after being notified the resource is needed for reliability	

Questions

Acronyms and Abbreviations in this Presentation

- CSO: Capacity Supply Obligation
- FCA: Forward Capacity Auction
- IMM: Internal Market Monitor

memo

To: NEPOOL Markets Committee

From: Jeff McDonald, Vice President - Market Monitoring

Date: April 26, 2018

Subject: Permanent and Retirement De-List Bid Determinations

One of the business functions of the Internal Market Monitor (IMM) is to review de-list bids submitted by existing resources to gauge whether these prices are consistent with competitive bidding behavior. The Forward Capacity Auction (FCA) allows various types of de-list bids, and each requires different inputs to calculate the competitive bid price.

As part of the competitive bid price calculation for Permanent and Retirement De-List bids, [1] the Market Rules specify a methodology that determines the expected remaining economic life of the de-listing resource if it retains an obligation in the primary auction. In reviewing the process which determines competitively based de-list bid prices, the IMM has identified a concern with the remaining economic life calculation as currently conducted.

Based on the IMM's preliminary assessment, this issue with economic life calculations could materially affect bid prices and outcomes in FCA 13.[2] In order to ensure that the FCA 13 outcome is competitive, we propose to correct this determination on an accelerated basis and use an updated economic life calculation when determining competitive Permanent and Retirement De-List Bid prices for FCA 13.

1. Economic Life Calculation

As part of the competitive Permanent and Retirement De-List Bid price determination, the cost workbooks used by market participants and the IMM calculate an economic life that reflects the number of years that the resource is likely to remain active in the Forward Capacity Market if it retains its obligation in the coincident FCA. Under the current rules, a resource's economic life is set to the maximum duration for which its net present value of cumulative future expected cash flows is positive. However, in some cases, the economic life calculation codified in the Tariff under Section III.13.1.2.3.2.1.2.C of the Tariff may overstate the true economic life of a resource.

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[1] 155 FERC ¶ 61,029 (2016), *Order Accepting Compliance Filing,* 156 FERC ¶ 61,067 (2016), *Order Denying Rehearing and Request for Clarification,* 161 FERC ¶ 61,115 (2017).

[2] While the Permanent and Retirement De-List Bid window closed on March 23rd, the IMM review of these bids is ongoing and bid prices for these units have not been finalized.

This is most easily illustrated with a numerical example. Consider a resource that expects to earn $5 million in profits in year one and to lose $3 million in year two and all future years. The current Tariff would calculate an economic life of two years because the resource could operate for two years with cumulative positive cash flows of $2 million.[3] The Tariff determination presumes that a competitive resource would continue to operate past year one despite incurring losses in all later years as long as these losses are fully offset by positive cash flows in an earlier year. This assumption is inconsistent with how a competitive resource would operate a resource. In the example above, the resource would not choose to operate in year 2 at a loss of $3 million. Rather, it would instead choose to exit the market after one year in order to maximize its cumulative cash flows at $5 million.

To address this inconsistency, the IMM proposes to modify the economic life determination in the Tariff to reflect that a competitive resource facing years of continual losses will seek to exit the market before the losses begin, rather than continuing to operate into years where negative cash flows occur. To reflect this change, the economic life determination in the Tariff must be updated to represent the duration that maximizes the resource's net present value of future expected cash flows. In the example above, this net present value is maximized with an economic life of one year, as this produces cash flows of $5 million.

For some Permanent and Retirement De-List Bids, the proposed change will not impact a resource's estimated economic life.[4] In such instances, the results of the competitive bid price determination will be unchanged. However, in cases where this correction affects the economic life determination (as in the example above), the estimated competitive Permanent or Retirement De-List Bid price will decrease. A price reduction occurs because the competitive bid price is calculated to ensure that the resource 'breaks even' for the duration of its economic life when it retains an obligation in the coincident auction. When the current economic life calculation incorrectly presumes that the resource would operate at a loss in future years, the workbook requires a higher FCM payment in year one to offset these losses. In correcting the economic life calculation to reflect that the resource would exit the FCM rather than incur losses, the 'break even' bid price can be reduced because these losses no longer need to be recovered in year one.

2. Stakeholder and Regulatory Schedule

In order to change Section III.13.1.2.3.2.1.2.C of the Tariff to apply the corrected economic life calculation to Permanent and Retirement De-List Bids submitted for FCA 13, we will need to compress the timing of our stakeholder process, which will require an additional Markets Committee meeting in May. More specifically, we plan to discuss this proposed change and corresponding Tariff language with stakeholders

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[3] If the resource continued to operate in year 3, it would lose an additional $3 million thereby pushing its cumulative cash flows below $0.

[4] Consider the example above where the resource now expects to lose $6 million in year two and all future years. In this scenario, the economic life is calculated as one year under the current Tariff because the resource's cumulative cash flows would be negative after two years. Similarly, the updated Tariff would also specify an economic life of one year because cumulative cash flows are maximized after one year.

at the May 8-9 MC meeting. We plan to seek votes at the extra May MC meeting (to be scheduled) and at the June 1 PC, with an anticipated FERC filing following shortly thereafter.

For this Tariff correction to be in effect for the February 2019 auction (FCA 13), we may need to modify dates and deadlines relating to the FCA 13. We plan to discuss any such changes with stakeholders during the committee process.

ISO new england

memo

To: Participants Committee

From: Erin Wasik-Gutierrez, Secretary, Markets Committee

Date: May 17, 2018

Subject: Actions of the Markets Committee

This memo is notification to the Participants Committee of the following action taken by the Markets Committee (MC) at its May 17, 2018 teleconference meeting. All sectors had a quorum.

1. (Agenda Item 2) Permanent and Retirement De-List Economic Life Calculation

ACTION: RECOMMEND SUPPORT

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

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Tariff section III – Market Rule 1 modifying the economic life calculation to determine competitive Permanent De-List Bid and Retirement De-List Bid prices, as proposed by ISO New England Inc. (the "ISO") and as circulated for this meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve.

The motion was then voted. The motion passed with a vote of 68.92% in favor. The individual sector votes were Generation (0% in favor, 17.13% opposed, 1 abstention), Transmission (17.13% in favor, 0% opposed, 1 abstention), Supplier (11.42% in favor, 5.71% opposed, 7 abstentions), Alternative Resources (6.13% in favor, 8.25% opposed, 2 abstentions), Publicly Owned Entity (17.13% in favor, 0% opposed), and End User (17.13% in favor, 0% opposed, 1 abstention).

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: NEPOOL Counsel

DATE: May 30, 2018

RE: Summary of Responsive Pleadings in ISO-NE Waiver Proceeding (ER18-1509)

This memorandum provides a brief summary of the pleadings submitted in response to ISO New England's (the ISO) May 1, 2018 request for waiver of certain of its Tariff provisions (the Waiver Request) submitted in Federal Energy Regulatory Commission (FERC) Docket No. ER18-1509-000. The Waiver Request seeks FERC approval in order to permit the ISO to retain two of the generating units at the Mystic Generating Station (Mystic 8 & 9) to provide fuel security for the 2022-23 and 2023-24 Capacity Commitment Periods (CCPs associated with FCAs 13 and 14).

Without taking any substantive position on the Waiver Request, NEPOOL submitted on May 17, 2018 limited comments: (1) to report on the ISO's engagement with regional stakeholders prior to the Waiver Request filing; and (2) to emphasize the importance that any future changes to the Tariff or Market Rules to address system reliability issues be explored through the long-standing, FERC-approved NEPOOL Participant Processes, which will minimize the need for subsequent waivers of the filed rate for that purpose.[1]

For purposes of organization, the remaining pleadings are grouped and summarized in one of the three following sections: (1) pleadings protesting or offering comments against the Waiver Request, (2) pleadings offering conditional support or not opposing the Waiver Request, and (3) pleadings providing additional information.[2]

NEPOOL Counsel is still in the process of reviewing these pleadings and will work with your Officers to determine if any further responsive pleading from NEPOOL may be warranted. If Participants have any questions regarding the pending ISO Waiver Request proceeding (or related proceedings), please let us know.

PLEADING SUMMARIES

1) Parties Protesting and/or Offering Comments Against the Waiver Request:

Public Interest Organizations[3] – Public Interest Organizations' joint protest argues, in part, that fuel security concerns are not appropriate for waiver and that granting the "Waiver Request

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[1] NEPOOL's comments are *available at* https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14922549.

[2] Links to all pleadings are available on the NEPOOL website: http://nepool.com/Litigation_Reports.php.

[3] "Public Interest Organizations" are the Sierra Club, Natural Resources Defense Council, and Sustainable FERC Project.

would create a troubling precedent for the use of non-market measures." The Public Interest Organizations further argue that the Waiver Request does not meet the FERC's waiver standard, that the ISO has not sufficiently justified the Waiver Request, and the ISO has sufficient time to develop market-based mechanisms that would not "threaten the transparency and efficiency of the competitive market."

New England Power Generators Association, Inc. (NEPGA) – NEPGA's conditional protest argues that the ISO's requested waiver will cause "significant harm to capacity suppliers and displace otherwise economic resources" in the Forward Capacity Market by suppressing capacity prices in FCA 13 and FCA 14. NEPGA further asserts that the Tariff does not allow or require the ISO to re-price Mystic 8 & 9 retained for reliability as price takers. For relief, NEPGA asks that the FERC adopt a proposal included as part of a separate complaint filed by NEPGA pursuant to Section 206 of the Federal Power Act (FPA).[4]

FirstLight Power Resources, Inc. (FirstLight) – FirstLight's conditional protest argues that, depending on how it is interpreted, the Waiver Request may not satisfy the conditions for waiver because it will harm third party sellers of capacity in FCA 13 and FCA 14. FirstLight posits that if the FERC adopts the NEPGA Proposal so as to mitigate harm to third parties through FCM price suppression, FirstLight would not oppose the Waiver Request.

NextEra Energy Resources, LLC and New Hampshire Transmission, LLC (NextEra) – NextEra protests the Waiver Request, asking the FERC to deny the requested waivers and direct the parties to enter into a one-year cost-of-service agreement, which may be renewed annually until such time as a solution is found to address the fuel security concern. NextEra further raises concerns related to Exelon's affiliate, Constellation LNG, asserting unfair advantage over third parties, and asks the FERC to consider potential means of mitigating such harm. NextEra also expresses support for the NEPGA Proposal, or another Tariff-based solution that would address potential price suppression.

Eastern New England Consumer-Owned Systems (ENECOS) – In their protest, ENECOS argue that the Waiver Request does not satisfy the FERC's standards for waiver and that, were the Waiver Request granted, it may set a precedent such that other generators similarly seek to retire in order to secure revenues. ENECOS also take issue with the lack of meaningful opportunity for stakeholder discussion or FERC deliberation regarding the ISO's basis for the Waiver Request. ENECOS urge the FERC, however, to grant waiver of those Tariff provisions that would delay the deadline by which a capacity seller must select unconditional retirement to allow for a "more reasoned" evaluation of the appropriate response to the Mystic 8 & 9 retirement.

LS Power Associates, L.P. (LS Power) – LS Power's comments argue that the Waiver Request is premature and that the fuel security issues and reliability concerns are not yet ripe for a waiver

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[4] *See* Docket No. EL18-154. The proposal put forth in NEPGA's concurrently filed complaint seeks to require the ISO to implement an approach in the FCM that accounts for the capacity of fuel security resources in a way that simultaneously prevents potential price suppression related to the retention of Mystic 8 & 9 (NEPGA Proposal).

or other action by the FERC, and that, in any event, the Waiver Request does not satisfy the FERC's standard for waiver. LS Power avers, instead, that Mystic 8 & 9 should be allowed to delist so that other resources could receive appropriate price signals from the capacity market, including from the soon to be implemented Pay-for Performance construct (PFP).

NRG Companies (NRG) – NRG argues that the FERC should deny the waiver in favor of a market-based solution to address fuel security issues, which should be developed instead of an out-of-market solution. NRG includes an affidavit from David R. Hill, a senior advisor at NRG and former official at the U.S. Department of Energy, which explains that Section 202(c) of the FPA allows the Secretary of Energy to take extraordinary measures to protest system reliability. Therefore, NRG states, the FERC should allow the markets to function and rely on Section 202(c) to serve as a last resort should a market-based alternative not meet the region's fuel security concerns, and further asks that the FERC establish the principle that "emergency efforts to meet . . . regional fuel security needs should not be allowed to undermine the competitive markets." NRG also argues that the market implications of retaining a unit for "fuel security" is different than retaining a unit for "local reliability," and that the FERC should require the ISO to follow the cost of service compensation rules set forth by the tariff.

Vistra Energy Corp. and Dynegy Marketing and Trade (Vistra) – In its protest, Vistra argues that the ISO's Waiver Request does not satisfy the waiver standard and that the ISO should instead be directed to work on market solutions to address fuel security risks. Vistra states that the Waiver Request is therefore not narrowly tailored to address an immediate reliability need. Vistra also raises concerns that the Waiver Request is premature given that the likely reliability and/or fuel security issues will not arise for more than four years, and urges that the ISO, instead, should allow the market to work to address any potential gap.

Vitol Inc. (Vitol) – Vitol's protest contends that the Waiver Request fails to meet the FERC's waiver standard, and instead the ISO must instead allow its markets to work. Rather than proceed with the ISO's proposed three-chapter approach, Vitol would like to see the ISO proceed quickly and directly to Tariff amendments to effectuate additional market solutions, as well as identifying how PFP and other market design features could better address reliability challenges.

Maine Governor's Energy Office (MGEO) – In its protest, the MGEO argues that the ISO failed to justify the need for the Waiver Request, that the proposed cost-of-service contract is not the appropriate solution to the fuel security problem in New England, and that an out-of-market temporary solution may have long-term implications on the health of the market. Alternatively, if the FERC grants the Waiver Request, the MGEO argues that Maine should not share in the cost of the cost-of-service contract because Maine has taken steps to bring additional natural gas into the region while other states have blocked access to natural gas infrastructure.

Electric Power Supply Association (EPSA) – EPSA submitted a protest arguing that the Waiver Request is not justified as proposed, and that the ISO should first be required to explore other options that would be more consistent with its Tariff and that will cause less distortion to the market or harm to other resources. EPSA further argues that, should the FERC approve any kind of cost-of-service agreement for Mystic 8 & 9 or another resource, the FERC should require the

ISO to address pricing issues in advance of FCA 13 to mitigate the impact/distortions caused by FCM participation and the harm inflicted on third parties.

New Hampshire Public Utilities Commission (NH PUC) and New Hampshire Office of the Consumer Advocate (NH OCA) – The NH PUC submitted comments arguing that fuel security is not a concrete problem that justifies the granting of Tariff waivers on an urgent basis. Instead, the NH PUC posits, the PFP rules should be a sufficient market-based solution to mitigate the fuel security risks. If state environmental laws render PFP ineffective, then those states that impose the environmental regulations should be responsible for the costs of any cost-of-service agreement for Mystic 8 & 9. NH PUC also questions whether the costs associated with the liquefied natural gas (LNG) facility can be recovered through an FPA electric tariff. The NH OCA filed brief comments incorporating by reference the comments of the NH PUC.

Repsol Energy North America Corporation (Repsol) – Repsol notes that the Waiver Request will benefit one LNG supplier, the Distrigas Terminal, to the possible detriment of other competitors seeking to supply natural gas to New England. Because the Waiver Request does not address, or require ISO to develop, market rules that create the proper incentives to enable all generators to secure LNG supplies from any supplier, Repsol further opines that the Waiver Request as it relates to LNG may lead to unjust and unreasonable rates.

Industrial Energy Consumer Group (IECG) [5]– IECG argues that the ISO has repeatedly failed to put forth market changes that would promote the construction of needed pipeline facilities and has instead relied on short-term, out-of-market solutions to address ongoing issues. IECG argues that the Waiver Request fails to meet the FERC's waiver standard. IECG further avers that if the circumstances warrant granting some level of support to Mystic 8 & 9, the FERC should reject the ISO's proposal and instead direct the ISO to either enter into a two-year agreement under the Tariff's existing provisions addressing maintaining units in transmission constrained areas, or to reinstate the ISO's Winter Reliability Program.

Clean Energy Industry Associations[6] – The Clean Energy Industry Associations protest the Waiver Request, arguing that it does not meet the FERC's standard for granting waiver requests, and that it is counter to FERC precedent because out-of-market actions should only be used as a last resort. The Clean Energy Industry Association assert that the same application could instead be made in 2021 when reliability concerns are more easily assessed. Clean Energy Industry Associations also argue that the ISO conflates "fuel security" with "reliability" and asks that the ISO ensure that reliability solutions are designed on a technology-neutral basis.

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[5] IECG represents the interests of industrial energy consumers before regulatory and legislative bodies in New England. Many of IECG's members have significant manufacturing and other commercial operations, including purchases of energy and capacity, in the markets managed by the ISO.

[6] "Clean Energy Industry Associations" are the American Council on Renewable Energy, American Wind Energy Association, Energy Storage Association, RENEW Northeast, and Solar Energy Industries Association.

2) Comments Offering Conditional Support or Not Opposing the Waiver Request:

***Exelon Corporation (Exelon)* –** Exelon's comments in support of the Waiver Request state that while stakeholders and the ISO will address fuel security issues in the long-term, in the short-term the FERC should approve the waiver request prior to the time when retirement decisions need to be made.[7] Exelon further argues a two-year agreement will ensure reliability of the system until the ISO and its stakeholders can develop a market-based fuel security solution for the region. Exelon also disagrees with the ISO's statement in the Waiver Request that "comments on the effects of the cost of service contract for Mystic 8 & 9 should be considered in the separate docket in which Exelon will file that agreement."

***Potomac Economics (the EMM)* –** The EMM supports the finding that fuel security issues present a risk to reliability in New England and recommends that that the FERC accept the Waiver Request. The EMM provides its analysis of the role that oil and LNG play in ensuring fuel adequacy in the winter. The EMM notes, however, that while a cost-of-service contract for Mystic 8 & 9 may be necessary in the short-term, it is essential that the ISO work with stakeholders to develop a long-term solution. The EMM recommends that the FERC require the ISO to file a market-based solution by a deadline established by the FERC to provide an "additional impetus" for stakeholders to work together on a market solution.

***Massachusetts Department of Public Utilities (MA DPU)* –** The comments of the MA DPU comments state that, given the specific reliability risks, the Waiver Request is acceptable as a limited, short-term, and time-sensitive reliability measure.

***New England Local Distribution Companies (New England LDCs)* –** The New England LDCs' comments in support of the Waiver Request argue that the Distrigas LNG facility is an important component of fuel security in the region and its multi-faceted supply and operational role in the region must be maintained. Because the operation of Distrigas itself may depend in large part on the continued operation of Mystic 8 & 9, and the possible retirement of Mystic 8 & 9 place the continued operation of Distrigas in jeopardy, the New England LDCs urge the FERC to grant the Waiver Request.

3) Other Pleadings:

***Massachusetts Attorney General (MA AG)* –** The comments of the MA AG acknowledge the need to maintain reliability, but raise three concerns with the Waiver Request: (1) issues regarding the legality of using the waiver process for fuel security, a term not defined in the FPA, (2) the breadth of the Waiver Request with respect to one generator, and (3) the lack of sufficient information from the ISO to support FERC action at this time. The MA AG therefore requests that the FERC first order the ISO to conduct additional analyses regarding (a) a probabilistic analysis of the alleged fuel security risks inherent in the retirement of Mystic 8 & 9 and the Everett LNG facility; (b) a re-run of the ISO's deterministic Mystic 8 & 9 scenarios using assumptions outlined in a letter dated February 15, 2018 (attached to the MA AG's

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[7] Exelon submitted its related cost-of-service proceeding on May 16, 2018, in Docket No. ER18-1639 (Cost-of-Service Proceeding).

pleading); (c) an analysis of the impact of the Waiver Request on other FERC-approved programs such as CASPR and PFP; and (d) an exploration and presentation of options that the ISO or the FERC could take to mitigate the impact of the Waiver Request.

New England States Committee on Electricity (NESCOE) **–** NESCOE does not take a position on the Waiver Request, but instead raises a number of issues for the FERC to consider, including (1) the need to limit the waiver to the immediate need, (2) that nothing in the Waiver Request proceeding should limit the opportunity for interested parties to review and respond and/or effect the outcome of the Exelon Cost-of-Service proceeding, and (3) that the FERC be mindful of the representation made in the Waiver Request regarding Mystic 8 & 9 entering the FCM as price takers.

Eversource Energy Service Company (Eversource) **–** In its comments, Eversource states that it reluctantly does not oppose granting the Waiver Request but is concerned that it (as well as the related cost-of-service agreement) is a short-term solution to the problems facing the region and is not the most cost-effective option for solving New England’s fuel security challenge. Eversource therefore conditions its lack of opposition on the ISO outlining a long-term solution to the region’s fuel security problem that results in selection of resource(s) that are consistent with the region’s environmental goals and are the most cost effective in the long-run.

Connecticut Public Utilities Regulatory Authority (CT PURA) and the ***Connecticut Department of Energy and Environmental Protection (CT DEEP)*** **–** The joint comments and protest of CT PURA and CT DEEP explain that the CT state agencies do not oppose the Waiver Request. CT PURA and CT DEEP, however, submit a limited protest, urging the FERC to condition any approval of the Waiver Request on Mystic 8 & 9 being entered into the relevant FCAs as price takers without administrative adjustments to the market clearing price to negate the effect of the units’ presence in the auctions.

Environmental Defense Fund (EDF) – EDF’s comments highlight the unique situation the Waiver Request presents. EDF argues that the FERC should (1) require the ISO file a long-term market-based solution to fuel security issues by the second quarter of 2019; (2) require sufficient accountability and transparency around services and pricing—for both Mystic 8 & 9 and the Distrigas facility—to ensure there is no undue discrimination, and (3) ensure that any approval of the Waiver Request is conditioned such that the risks and rewards related to the operation and costs for both Mystic 8 & 9 and Distrigas are effectively balanced.

Calpine Corporation (Calpine) **–** Calpine does not oppose the Waiver Request, but emphasizes that the Waiver Request is a symptom of broader price formation issues that are preventing the ISO-NE Forward Capacity Market from achieving its objective of attracting sufficient investment in new and existing resources to maintain reliability. Calpine takes issue with certain underlying price formation issues affecting the FCM, including the requirement that generators lock-in prices, that generators retained for reliability issues be offered in as price takers, the exemption from the Minimum Offer Price Rule for Renewable Technology Resources, the reduction in the Installed Capacity Requirement, and the reduction in the Net Cost-of-New-Entry. Calpine therefore argues that the FCM requires significant holistic changes and urges FERC to approve the NEPGA Proposal.

***Northeast Gas Association (NGA)* –** NGA's comments highlight the importance of LNG to the New England natural gas and electricity markets, and urge the FERC to consider importance of maintaining the regional LNG access.

***Algonquin Gas Transmission, LLC (Algonquin)* –** Algonquin's comments acknowledge the fuel security risk identified by the ISO, but note that the Waiver Request is a short-term solution that does not address the region's problems. Algonquin therefore stresses the need for long-term solutions, included possible additional natural gas pipeline infrastructure development.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of May 31, 2018 (12pm)

The following activity, as more fully described in the attached litigation report, has occurred since the report dated May 2, 2018 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

*	2	NEPGA Mystic 8/9 Price Suppression Complaint (EL18-154)	May 23	NEPGA files Complaint; response/comment date Jun 6
			May 23-31	NEPOOL, ConEd CPV Towantic, CT DEEP, CT PURA, Eversource, EPSA, LS Power, MA AG, NESCOE, NRG/GenOn, PSEG intervene
			May 25	NESCOE requests 14-day extension of time, to June 20, of comment date; CT PURA supports NESCOE request
			May 29	NEPGA answers and opposes NESCOE request
			May 31	FERC denies NESCOE's request; comment date remains Jun 6
	3	Base ROE Complaint IV (2016) (EL16-64)	May 7	FERC grants TOs' requested extension to May 23 for briefs opposing exceptions and answers to CAPs' motion
			May 23	TOs, EMCOS, CAPs, FERC Trial Staff file briefs opposing exceptions; TOs oppose CAPs' motion for limited reopening of record

II. Rate, ICR, FCA, Cost Recovery Filings

*	5	Mystic 8/9 Cost of Service Agreement (ER18-1639)	May 16	Mystic files cost of service agreement; comment date Jun 6
			May 16-30	NEPOOL, Calpine, CT DEEP, CT PURA, ConEd, Cavus Energy, Dighton Power, Direct, Dominion, Emera, ENECOS, EPSA, Eversource, LS Power, MA AG, Milford Power, MPUC, NESCOE, NH OCA, NH PUC, NRG/GenOn, PJM IMM, PSEG, Vitol, VT PUC intervene
			May 23	Engie files comments supporting filing
	6	VTransco Recovery of Highgate Ownership Share Acquisition Costs (ER18-1259)	May 7	VTransco answers MA AG April 20 protest
			May 14	MA AG answers VTransco May 7 answer
			May 29	FERC rejects cost recovery request
	6	Emera MPD OATT Attachment J Revision (ER18-210)	May 21	FERC Trial Staff files comments supporting uncontested Joint Offer of Settlement to resolve all issues pending in this proceeding
			May 24	Settlement Judge Dring issues status report
	7	MPD OATT Annual Informational Filing (ER15-1429)	May 15	Emera Maine submits annual update of charges under the MPD OATT

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

*	8	Waiver Request: FCA13 Qual. Deposit Deadline (Bay State Wind) (ER18-1691)	May 25	BSW, an Eversource Related Person, requests one-day waiver of qualification deposit deadline; comment date Jun 15
	8	ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509)	May 3-29	Over 40 parties file comments and/or protests, others file doc-less motions to intervene
	9	FCM Enhancements – Phase II (ER18-1287)	May 8	FERC accepts changes, most eff. Jun 1, 2018; a few eff. Jun 1, 2020
	10	PFP Enhancements (ER18-1223)	May 11	FERC accepts changes, eff. Jun 1

	10	CASPR (ER18-619)	May 7	FERC issues tolling order affording it additional time to consider NextEra/NRG, ENECOS, Clean Energy Advocates, and Public Citizen requests for rehearing of *CASPR Order*

IV. OATT Amendments / TOAs / Coordination Agreements

*	13	*Order 842* (Frequency Response) Compliance Filing (ER18-1523)	May 4 May 8	ISO-NE, NEPOOL, PTO AC jointly submit *Order 842* Tariff changes Dominion intervenes

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

	14	Schedule 21-EM: BHD Tax Law & Settlement Changes (ER18-1213)	May 14	FERC issues deficiency letter; Emera Maine response due Jun 14
	15	Schedule 21-EM 2017 Annual Update (ER15-1434) Settlement Agreement (ER18-960)	May 4	FERC approves Settlement Agreement and Settlement Agreement changes, eff. Jun 1, 2017
	14	Schedule 21-EM: Brookfield LSA (ER18-901)	May 2	FERC accepts LSA, eff. May 16
	14	Schedule 21-EM: Recovery of Bangor Hydro/MPS Merger-Related Costs (ER15-1434 et al.)	May 8	Emera Maine filed the MPS Merger Cost Recovery Settlement to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *June 2 Order*

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	16	Capital Projects Report - 2018 Q1 (ER18-1571)	May 10 May 30 May 31	ISO-NE files Q1 Report; comment date May 31 NEPOOL intervenes and files comments supporting Q1 Report Eversource, National Grid intervene
*	16	IMM 2017Annual Markets Report (ZZ18-4)	May 17	IMM files annual report covering calendar year 2017
*	17	IMM Quarterly Markets Reports - 2018 Winter (ZZ17-4)	May 3	IMM files Winter 2018 Report
*	17	ISO-NE FERC Form 3Q (2018/Q1) (not docketed)	May 29	ISO-NE submits 2018 Q1 FERC From 3Q

IX. Membership Filings

*	18	Suspension Notices – (not docketed)	May 11	ISO-NE files notices of suspension from New England Markets: Chris Anthony; Cumulus Master Fund; Energy Federation Inc.; MPower Energy; VCharge

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

	19	NOPR: Revised Rel. Standards: CIP-005-6, CIP-010-3, CIP-013-1 (RM17-13)	May 11	APPA and NRECA submit white paper for consideration in this proceeding

	20	Revised GMD Research Work Plan (RM15-11)	May 17-22	D. Bardin and FRS submit comments

XI. Misc. - of Regional Interest

	21	203 Application: NEP (Vuelta and Old Wardour Interconnection Assets) (EC18-85)	May 24	New England Power submits addendum to application; comment date Jun 14
	21	203 Application: NRG Canal/Stonepeak (EC18-83)	May 31	FERC authorizes transaction
	21	203 Application: XOOM Energy/NRG Retail (EC18-82)	May 29	FERC authorizes transaction
	21	203 Application: HIKO Energy/Spark HoldCo (EC18-69)	May 29	FERC authorizes transaction
	22	203 Application: NRG/GIP III Zephyr Acquisition Partners (EC18-61)	May 18	FERC authorizes transaction
*	23	NSTAR/Milford Related Facilities Agreement (ER18-1574)	May 11	NSTAR files Milford RFA; comment date Jun 1
*	23	Emera/MPD OATT *Order 842* Compliance Filing (ER18-1569)	May 11	Emera Maine submits MPD OATT changes; comment date Jun 1
	23	Nat'l Grid/Granite Reliable Power Reimbursement Agreement Cancellation (ER18-1350)	May 14	FERC accepts notice of cancellation of National Grid Reimbursement Agreement with Granite Reliable Power, eff. Nov 1, 2017
	23	D&E Agreement Cancellation: CL&P/Beacon Falls (ER18-1306)	May 24	FERC accepts notice of cancellation, eff. Mar 9
	24	D&E Agreement: NSTAR/National Grid (ER18-1290)	May 9	FERC accepts Agreement, eff. Apr 3
	24	MPD OATT Changes (ER18-1244)	May 4 May 10 May 14	Emera Maine answers April 20 answers Maine Customer Group answers May 4 Emera answer FERC issues deficiency letter; Emera Maine responses due Jun 14
	24	IA: CL&P/Fusion Solar (ER18-1192)	May 25	FERC accepts IA, eff. May 26, 2018 (denying CL&P's request for waiver of 60-day notice req.); time-value refund report due Jun 26

XII. Misc. - Administrative & Rulemaking Proceedings

	26	Grid Resilience in RTO/ISOs; DOE NOPR (AD18-7; RM18-1)	May 4-22 May 23-30	Over 100 parties, including NEPOOL, submit comments Parties, including NEPOOL, submit supplemental comments and responses
	27	NOI: 2017 Tax Law Effect on FERC-Jurisdictional Rates (RM18-12)	May 22	Over 45 parties submit comments
	27	NOPR: Pipeline Rates (RM18-11)	May 10-22	Over 10 parties submit answers and reply comments
	28	*Order 845*: LGIA/LGIP Reforms (RM17-8)	May 17 May 18-22 May 23	IRC requests 70-day extension (to Oct 16) of compliance filing deadline APPA, Arizona Public Service Company, AWEA, California Utilities, Duke, EEI, EON, MISO TOs, NYISO, SCE, and So. Co. Services request rehearing and/or clarification of *Order 845* NEPOOL supports IRC compliance filing deadline extension request

	30	*Order 833-A*: Critical Energy/Electric Infrastructure Information (CEII) Procedures (RM16-15)	May 17	FERC issues *Order 833-A* granting EEI's request for clarification in part and denying rehearing of *Order 833*
	31	*Order 842*: Primary Frequency Response - Essential Reliability Services and the Evolving Bulk-Power System (RM16-6)	May 9	PJM requests expedited action on its request for clarification and answers Competitive Suppliers' and PJM Utilities Coalition's responses thereto
	31	NOI: Certification of New Interstate Natural Gas Facilities (PL18-1)	May 10-29	Individual commenters and Del. Riverkeeper Network file comments
			May 23	FERC extends comment deadline to Jul 25, 2018

XIII. Natural Gas Proceedings

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	36	Non-New England Pipeline Proceed'gs • Southeast Mrk't Pipelines Project (CP14-554, CP15-16, CP15-17)	May 11	FERC issues tolling order affording it additional time to consider Apr 13 request for rehearing and motion for stay of the FERC's Order on Remand
*	40	Engie/Exelon: Temp. Waiver of Capacity Release Regs. & Policies (RP18-806)	May 7	As part of the Everett LNG Terminal sale, Engie and Exelon jointly request waiver of natural gas capacity release regs. and policies to facilitate assignment and permanent release of several long-term firm natural gas transportation agreements at existing rates
			May 18-24	NESCOE, MA AG, Taunton intervene
			May 21	ENECOS file protest

XIV. State Proceedings & Federal Legislative Proceedings

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No Activity to Report

XV. Federal Courts

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	41	Base ROE Complaint IV (2016) (18-1077)	May 10	TOs oppose and CAPs support April 30 motion to dismiss case for lack of jurisdiction
			May 17	TOs and EMCOS file answers to the May 10 motions
	42	Base ROE Complaints II & III (2012 & 2014) (15-1212)	May 12	Parties file 11th status report indicating that proceedings upon which request for abeyance was requested remain ongoing

MEMORANDUM

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: May 31, 2018

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 noon on May 31, 2018. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **PER Settlement Agreement (ER17-2153; EL16-120)**

On February 20, the FERC approved[2] the Offer of Settlement and settlement materials ("PER Settlement") filed by the Settling Parties[3] to resolve the issue set for hearing and settlement judge procedures by the FERC in this proceeding.[4] Under the FERC-approved PER Settlement, ISO-NE will calculate Adjusted Hourly Strike Price as the sum of the daily Strike Price (as calculated under the existing Tariff) and a newly-defined Hourly PER Adjustment. The Hourly PER Adjustment will be equal to the average over each hour of a newly-defined Five-Minute PER Strike Price Adjustment. The Five-Minute Strike Price Adjustment[5] will be equal to any positive difference between a five-minute Thirty-Minute Operating Reserves Clearing Price or Ten-Minute Non-Spinning Reserves Clearing Price that exceeds the maximum allowable reserves clearing

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

[2] *New England Power Generators Assoc. v. ISO New England Inc.*, 162 FERC ¶ 61,144 (Feb 20, 2018), *clarif. requested* ("*PER Settlement Order*").

[3] PER "Settling Parties" are: NEPGA, NESCOE, the Retail Energy Supply Association ("RESA"), NEPOOL, Exelon, H.Q. Energy Services (U.S.) ("HQUS"), Eversource, Dominion, Entergy, NRG, and Cogentrix. Intervenors in the proceeding not opposing the Settlement ("Non-Opposing Intervenors") are: ISO-NE, PSEG, Consolidated Edison Energy, Inc. ("ConEd"), Verso Corp., GenOn Energy Management LLC, National Grid, NextEra, the New Hampshire Electric Coop. ("NHEC"), and Calpine.

[4] *See New England Power Generators Assoc., Inc. v. ISO New England Inc., 158 FERC ¶ 61,034 (Jan. 19, 2017) ("PER Complaint Order"), reh'g and clarif. denied, 161 FERC ¶ 61,193 (Nov. 16, 2017)* ("*PER Complaint Rehearing Order*"). The *PER Complaint Order* (i) granted in part NEPGA's complaint and (ii) set in part for hearing and settlement judge procedures the question of the appropriate method of calculating the PER Strike Price under Market Rule 1 Section III.13.7.2.7.1.1.1. The FERC found that "for the period at issue in NEPGA's complaint (September 30, 2016 – May 31, 2018), the PER mechanism has become unjust and unreasonable as a result of the interaction between the PER mechanism and the higher Reserve Constraint Penalty Factors." Accordingly, the FERC required ISO-NE to revise the method by which it calculates the PER Strike Price as set forth in Tariff section III.13.7.2.7.1.1.1. But, finding NEPGA's request that the PER Strike Price be increased by $250 per MWh "raises issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures", the FERC set the question of for hearing and settlement judge procedures under section 206 of the FPA. The FERC established a refund effective date of September 30, 2016 (the date of the complaint). In establishing a September 30, 2016 effective date, the FERC clarified that "any changes to the calculation of the PER Strike Price under ISO-NE Tariff section III.13.7.2.7.1.1.1 would be prospective only from September 30, 2016, as required by FPA section 206, and would not impact the application of any PER Adjustment occurring before September 30, 2016."

[5] Five-Minute PER Strike Price Adjustment will be calculated according to the following formula: Five-Minute PER Strike Price Adjustment = MAX (Thirty-Minute Operating Reserves Clearing Price - $500/MWh, 0) + MAX (Ten-Minute Non-Spinning Reserves Clearing Price – Thirty-Minute Operating Reserves Clearing Price - $850/MWh, 0).

prices for those reserves products (i.e., the Reserve Constraint Penalty Factors) in effect before December 2014.

Clarification Requested. As previously reported, the PER Settlement did not resolve the issues of the applicability of the Strike Price methodology to FCA9.[6] In its comments, in which it neither supported nor objected to the proposed PER strike price methodology, ISO-NE requested that the FERC resolve how the Average Monthly PER will be calculated on and after June 1, 2018. NESCOE asked the FERC to reject the position advocated by NEPGA that the agreed-upon Adjusted Hourly Strike Price as defined in the Settlement should extend beyond May 31, 2018. NEPGA, NRG, HQUS, Dominion, and Verso jointly asked the FERC to approve the Settlement and order ISO-NE to make a compliance filing, but decline to address NESCOE's request until some later date. In the *PER Settlement Order*, the FERC found the issues of the applicability of the Strike Price methodology to FCA9 beyond the scope of the settlement agreement proceeding.[7] On March 1, NESCOE requested clarification of the *PER Settlement Order* on this issue. NEPGA answered NESCOE's request on March 16.

Compliance Filing. ISO-NE was directed to make a compliance filing in eTariff format to reflect the FERC's action in the *PER Settlement Order*.[8] That compliance filing was submitted on March 22, 2018 (*see* ER18-1153 below). The FERC stated that the *PER Settlement Order* "terminates Docket Nos. EL16-120-000 and ER17-2153-000."[9]

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

- **NEPGA Mystic 8/9 Price Suppression Complaint (EL18-154)**

On May 23, NEPGA filed a Complaint asking the FERC, should it grant ISO-NE's Mystic 8/9 Waiver Request Filing (*see ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509)* below), to "provide relief now, in time for the next capacity auction, by requiring ISO-NE to adopt an approach that accounts for the capacity of fuel security resources in a way that prevents price suppression." Specifically, the NEPGA Complaint seeks modifications to the ISO-NE Tariff, suggesting "a market-based approach" to clear the Mystic 8 & 9 capacity in both FCAs modeled on New England's CASPR design. NEPGA urged the FERC to grant its Complaint and requested relief on an expedited basis by July 2, 2018 (the date on which ISO-NE has requested FERC action on its Mystic 8/9 Waiver Request Filing) to provide Market Participants with certainty as they develop and submit for IMM review their FCA13 priced offers. The FERC has set the comment date deadline for June 14, 2018. NESCOE, supported by CT PURA, asked that the comment date deadline be extended by 14 days, to June 20, and that the FERC act on its motion by May 30. NEPGA opposed NESCOE's request and asked the FERC to maintain the June 6 comment date. On May 31, the FERC denied NESCOE's request. Comments thus remain due on or before June 6. Doc-less motions to intervene have thus far been filed by NEPOOL, ConEd, CPV

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[6] In its *PER Complaint Rehearing Order*, the FERC clarified that it "intended for ISO-NE to use the difference between the former strike price and the LMP for event hours that occurred prior to September 30, 2016, and for ISO-NE to use the new strike price only for event hours that occur after September 30, 2016 … [t]he Commission's order is clear in that it addresses a change to the calculation of the PER strike price as set forth in section 111.13.7.2.7.1.1.1 and such change is prospective only."

[7] *PER Settlement Order* at P 3.

[8] While the *PER Settlement Order* acknowledged NEPOOL's s request that, "in order to accommodate participation in the stakeholder process for modifying the market rules, the Commission allow at least sixty days following any Settlement approval for ISO-NE to file tariff revisions to implement the Settlement," the *PER Settlement Order* is silent on the timing for the compliance filing directed. Pursuant to Rule 1907 of the FERC's Rules of Practice and Procedure, unless otherwise provided, "when any … person subject to the jurisdiction of the Commission is required to do or perform any act by Commission order, … there must be filed with the Commission within 30 days following the date when such requirement became effective, a notice, under oath, stating that such requirement has been met or complied with." 18 CFR § 385.1907.

[9] *PER Settlement Order* at P 4.

Towantic, CT DEEP, CT PURA, Eversource, EPSA, LS Power, MA AG, NESCOE, NRG/GenOn, and PSEG. 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).

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

As previously reported, Judge Glazer issued on March 27, 2017 his initial decision[10] addressing Eastern Massachusetts Consumer-Owned Systems' ("EMCOS") Complaint[11] that the TOs' return on equity ("ROE") used in the Tariff's formula rate revenue requirement is too high on. The *Base ROE IV Initial Decision* concluded instead that the currently-filed base ROE of 10.57 %, which may reach a maximum ROE of 11.74 % with incentive adders, is ***not*** unjust and unreasonable, and hence is not unlawful under section 206 of the Federal Power Act ("FPA").[12] The *Base ROE IV Initial Decision* found that "Neither the Complainants nor Staff has met their burden to produce a properly-specified [Discounted Cash Flow ("DCF")] analysis that demonstrates the [TOs'] existing base ROE is unjust and unreasonable."[13] In light of those conclusions, the *Base ROE IV Initial Decision* finds it unnecessary to reach the issue of what a just and reasonable alternative base ROE ought to be. Briefs on exceptions to the *Base ROE IV Initial Decision were filed on* April 26, 2018 by EMCOS, CAPs, TOs, and FERC Trial Staff. In addition, CAPs requested on April 26 that the record be re-opened to receive three documents that CAPs assert demonstrate that there has been a significant factual change since the close of the record that calls into question the *Initial Decision*'s reliance on one DCF in establishing the Base ROE. On April 27, TOs requested that answers to the CAPs motion to re-open the record and briefs opposing exceptions be extended to May 23, 2018, which the FERC granted on May 7.

On May 23, Briefs Opposing Exceptions were filed by TOs, EMCOS, CAPs, and FERC Trial Staff. The TOs also opposed CAPs' motion for limited reopening of record. The *Base ROE IV Initial Decision,* as well as all of the related briefs and motions, are pending before the FERC. 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: TOs' Motion to Dismiss or Consolidate Complaints I-IV (EL16-64; EL14-86; EL13-33; EL11-66)**

The TOs' October 5, 2017 motion to dismiss all four ROE complaints (captioned above) in light of the DC Circuit's *Emera Maine*[14] decision remains pending. The October 5 motion alternatively requested that the FERC consolidate the four ROE complaints for decision and use expedited procedures to resolve them. The TOs stated that this motion was motivated in part by *Emera Maine*, but also by what they describe as the "enormous investment uncertainty" resulting from the various litigation proceedings. On October 20,

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[10] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 162 FERC ¶ 63,026 (Mar. 27, 2018) ("*Base ROE Complaint IV Initial Decision*").

[11] 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.

[12] *Id.* at P 2.; Finding of Fact (B).

[13] *Id.* Finding of Fact (A).

[14] *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).

Complainant-Aligned Parties and EMCOS submitted answers opposing TOs' requests. The TOs' motion and the motions filed in response remain pending before the FERC.

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

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

Settlement Judge Procedures. As previously reported, John P. Dring was designated the Settlement Judge in these proceedings. Five settlement conferences were held in 2016: January 19, March 24, April 28, August 30, and November 18 (telephonically); four settlement conferences were held in 2017: April 5, May 9, July 7, and November 13, 2017; and two settlement conferences, on January 9 and February 1, in 2018. Judge Dring's most recent status report was issued on April 3, noting that the parties have reached a settlement in principle, and are memorializing their agreement. Accordingly, he recommended that settlement procedures be continued. The Transmission Committee is being kept apprised, as appropriate, of settlement efforts. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

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[15] *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).

[16] *Id.* at P 8.

[17] *Id.* at P 11.

[18] *Id.*

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

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

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

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

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

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

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

II. Rate, ICR, FCA, Cost Recovery Filings

- **Mystic 8/9 Cost of Service Agreement (ER18-1639)**

On May 16, Constellation Mystic Power, LLC ("Mystic") filed for approval an agreement between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE that provides 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 ("Mystic 8/9 Cost of Service Agreement"). Mystic stated that the 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 Everett liquefied natural gas ("LNG") facility, and on the continued provision of surplus LNG from Everett to third parties. Mystic explained the importance of the timing of action on the Agreement, so that Mystic has the information it needs to accept the reliability service obligation or unconditionally retire by the January 4, 2019 deadline that, if extended as requested in ISO-NE's Mystic 8/9 Waiver Filing (see ISO-NE Waiver Filing: Mystic 8 & 9 *(ER18-1509)* below), would apply. Comments on the Mystic 8/9 Cost of Service Agreement are due on or before June 6, 2018. Thus far, comments in support have been filed by ENGIE Gas & LNG LLC; doc-less interventions, by NEPOOL, Calpine, CT DEEP, CT PURA, ConEd, Cavus Energy, Dighton Power, Direct, Dominion,

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

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

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

[26] *Environment Northeast 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*").

Emera, ENECOS, EPSA, Eversource, LS Power, MA AG, Milford Power, MPUC, NESCOE, NH OCA, NH PUC, NRG/GenOn, PJM IMM, PSEG, Vitol, and VT PUC. If you have questions on this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Sunita Paknikar (202-218-3904; spaknikar@daypitney.com).

- **VTransco Recovery of Highgate Ownership Share Acquition Costs (ER18-1259)**

On May 29, the FERC rejected, without prejudice, the request by Vermont Transco, LLC ("VTransco") 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.[27] In rejecting the request, the FERC found that "VTransco has not made a showing … that these transaction-related costs have 'specific, measurable, and substantial benefits to ratepayers.' Accordingly, we reject VTransco's filing, without prejudice to it making a future filing that makes this showing."[28] The FERC also rejected "the pass-through of transaction-related costs to ratepayers in any Commission-jurisdictional rate, without prejudice to VTransco submitting a request with the required showing of 'specific, measurable, and substantial benefits' to ratepayers."[29]

As previously reported, VTransco filed, on March 30, 2018, 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.[30] 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.

The Massachusetts Attorney General ("MA AG") protested, asserting that VTransco did not meet its commitment, made in the earlier Section 203 proceeding (EC17-76) in which the Highgate ownership shares acquisition was approved,[31] to make a showing of "specific, measurable, and substantial benefits to ratepayers" of the transaction-related costs for which recovery is sought here. In addition, MA AG challenged the position that VTransco need only meet, or if so, met, the "just and reasonable" standard under FPA Section 205.

Unless the May 29 order rejecting the VTransco cost recovery request is challenged, with any challenges due on or before June 28, 2018, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Emera MPD OATT Attachment J Revision (ER18-210)**

On April 30, 2018, Emera Maine submitted an uncontested Joint Offer of Settlement ("MPD OATT Attachment J Settlement") between itself, Houlton Water Company ("Houlton"), Van Buren Light and Power

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[27] *Vermont Transco, LLC*, 163 FERC ¶ 61,152 (May 29, 2018).

[28] *Id.* at P 16.

[29] *Id.* at P 18.

[30] *See Green Mountain Power Corp.*, 159 FERC ¶ 62,191 (May 19, 2017) (order authorizing VTransco's acquisition of Green Mountain Power's ("GMP") ownership share in the Highgate Facilities). Of the Joint Owners, GMP was the only FERC-jurisdictional public utility (the other Joint Owners were the City of Burlington Electric Department, Vermont Public Power Supply Authority ("VPPSA"), Vermont Electric Cooperative, Inc. ("VEC"), and the Village of Johnson Water and Light Department). In the 203 application, VTransco stated that the transfer will result in efficiencies in operation and management of the facility by VELCO.

[31] Should VTransco or GMP seek to recover any transaction-related costs, they state that they will seek Commission approval by making a separate filing under section 205 of the FPA and making the required showing of specific, measurable, and substantial benefits to ratepayers. Therefore, according to Applicants, the Proposed Transaction will have no adverse effect on the rates of transmission customers

District, Eastern Maine Electric Cooperative, Inc., and the Maine Office of the Public Advocate ("MOPA") that, if approved, will resolve all issues pending in this proceeding. The MPD OATT Attachment J Settlement establishes revised Attachment J Protocols to be effective January 1, 2018, to substitute for those filed that initiated this proceeding, and establishes the timing (not prior to June 1, 2019) and notice (120 calendar days' notice) provisions for Houlton to interconnect its electrical system with that of NB Power, as well as an exit fee in case of a breach of those timing and notice provisions. On May 21, FERC Trial Staff filed comments supporting the MPD OATT Attachment J Settlement. No reply comments were filed.

As previously reported, the FERC accepted Emera's proposed revision to Attachment J of the Open Access Transmission Tariff ("OATT") for the Maine Public District ("MPD"),[32] but established hearing & settlement judge procedures because its "preliminary analysis indicates that Emera Maine's proposed tariff revision has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful."[33] The prosed tariff revision was to permit adjustments to formula rate inputs (historical load, revenue, sales data) to reflect "known and measurable" anticipated changes, subject to a true-up. Emera stated that, absent an ability to adjust its formula rate calculations to account for material losses of load, like that of Houlton expected to occur early next year, Emera Maine would suffer a significant under-recovery in its transmission revenue requirement. The Maine Customer Group ("MCG")[34] protested the revision for a number of reasons, with the principal objection being the fact that "Emera already has a true-up mechanism in place under the MPD OATT to accommodate loss of Houlton load". Judge John P. Dring served as the Settlement Judge in these proceedings and, since the last Report, issued a May 24 report recommending that settlement judge procedures be continued.

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

- **MPD OATT Annual Informational Filing (ER15-1429)**

On May 15, 2018, Emera Maine submitted its annual informational filing setting forth, for the June 1, 2018 to May 31, 2019 rate year, the charges for transmission service under the MPD OATT ("MPD Charges") and an updated transmission real power loss factor. The May 15 filing, submitted in accordance with the Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas, noted that the 2018-19 MPD Charges reflect: (i) application of a 21 % Federal tax rate; (ii) the impact of the MPS Merger Cost Recovery Settlement (which permits Emera Maine to recover $86,667 through the MPD OATT during the 2018-2019 rate year) (*see* ER15-1434 in section VI below); (iii) the MPD OATT Changes (*see* MPD OATT Changes (ER18-1244) unten); and (iv) corrections for errors in the 2017-18 retail charges assessed ("Retail Charge Corrections"). This filing will not be noticed for public comment. 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.[35] 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*[36] decision. In its *Order Rejecting Filing*, the FERC required the TOs to continue collecting their ROEs currently on file, subject

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[32] *Emera Maine*, 162 FERC ¶ 61,131 (Feb. 15, 2018).

[33] *Id.* at P 24.

[34] MCG consists of consists of: Maine's Office of the Public Advocate ("MOPA"), Houlton Water Company ("Houlton"), Van Buren Light and Power District ("Van Buren"), and Eastern Maine Electric Cooperative, Inc. ("EMEC").

[35] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*"), *reh'g requested*.

[36] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*").

to a future FERC order.[37] 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 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.[38] 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).

- **ISO Securities: Authorization for Future Drawdowns (ES18-25)**

On March 28, the ISO requested the necessary FERC authorization for drawdowns under a new $20 million Revolving Credit Line and a new $4 million line of credit supporting the Payment Default Shortfall Fund, each of which are with TDBank, are for a term of three years ending June 30, 2021, and replace similar arrangements that will expire June 30, 2018.[39] Comments on this filing were due on or before April 18; none were filed. National Grid filed a doc-less intervention (out-of-time). This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

- **Waiver Request: FCA13 Qual. Deposit Deadline (Bay State Wind) (ER18-1691)**

On May 25, BSW ProjectCo LLC ("BSW"),[40] which is developing the Bay State Wind Project,[41] requested a one-day waiver of the FCA13 qualification deposit deadline. Comments on BSW's waiver request are due on or before June 15, 2018. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509)**

On May 1, 2018 (officially May 2), ISO-NE requested waiver of its Tariff to the extent necessary (i) for the retention of Mystic 8 & 9 for fuel security, rather than for local transmission needs, and (ii) to extend certain deadlines to accommodate Exelon's requirements. ISO-NE stated that the waiver was necessary to ensure reliable electric service for New England consumers during the 2022-2023 and 2023-2024 Capacity Commitment Periods. ISO-NE stated that its analyses establish that retirement of Mystic 8 & 9 would cause depletion of Ten-Minute Operating Reserves ("TMOR") (a violation of mandatory reliability criteria) on numerous occasions, trigger load shedding—rolling blackouts—during the 2022-23 and 2023-24 winter periods, and, because the Mystic units are the largest customers of Distrigas, substantially diminish Distrigas' financial viability (the loss of which would

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[37] *Order Rejecting Filing* at P 1.

[38] *Id.* at P 36.

[39] *See ISO New England Inc.*, 139 FERC ¶ 62,248 (June 22, 2012) (initially authorizing borrowings through June 30, 2014); *ISO New England Inc.*, 147 FERC ¶ 62,091 (May 6, 2014) (continuing authorization through June 30, 2015); *ISO New England Inc.*, 151 FERC ¶ 62,185 (June 15, 2015) (continuing authorization through June 30, 2017); *ISO New England Inc.*, 159 FERC ¶ 62,143 (May 9, 2017) (continuing authorization through June 30, 2019).

[40] BSW is a 50/50 joint venture between Orsted North America Inc. and Eversource Investment, LLC, an affiliate of Eversource Energy.

[41] The BSW project is a proposed utility-scale offshore wind farm, including a battery storage solution, located approximately 25 miles of the south coast of Massachusetts and 15 miles off the coast of Martha's Vineyard.

increase the region's risks of reserve depletion and load shedding and the length and severity of such events). Specifically, ISO-NE requested waiver of the following Tariff provisions:

- Attachment K of the OATT, relating to evaluating upgrades to the transmission system to address a local reliability need
- Market Rule 1 ("MR1") § III.13.1.2.3.1.5.1, relating to review of Retirement De-List Bids for local reliability needs.
- MR1 § III.13.2.5.2.5, relating to the criteria applied in reviewing a Retirement De-List Bid for a local reliability need.
- MR1 §§ III.13.2.5.2.5 and III.13.2.5.2.5.1, relating to retaining a capacity resource until the underlying reliability need is addressed.
- MR1 § III.13.2.3.2(c), relating to permitting a supplier whose resource is being retained for reliability to submit a Dynamic De-List Bid in the auction.
- MR1 §§ III.13.1.2.3.1.5.1(c) and III.13.2.5.2.5.1(b), relating to compensation for a resource that is retained for reliability.
- MR1 § III.13.2.5.2.5.2, relating to capital expenditures for a resource retained for reliability.
- MR1 §§ III.13.1.2.4.1 and III.13.1.2.3.1.5.1(d), relating to the deadlines for a capacity supplier that has submitted a Retirement De-List Bid to elect unconditional retirement or elect to be retained for an identified reliability need.

ISO-NE requested a decision on its waiver request no later than July 2, 2018 (just ahead of the July 6, 2018 date by which Participants, including Exelon, must decide whether or not to participate in FCA13).

Comments on this filing were due on or before May 23, 2018. NEPOOL filed limited comments (1) to report on ISO-NE's engagement with regional stakeholders prior to the Waiver Request filing; and (2) to emphasize the importance that any future changes to the Tariff or Market Rules to address system reliability issues be explored through the long-standing, FERC-approved NEPOOL Participant Processes, which will minimize the need for subsequent waivers of the filed rate for that purpose. Comments from nearly 40 additional parties were also filed. Those comments were separately summarized by NEPOOL counsel in materials circulated and posted for the June 1 meeting. Doc-less interventions only were filed by APPA, Avangrid Networks, Calpine, Cavus Energy, ConEd, CT OCC, Dominion, EDP Renewables, Emera, Engie, EPSA, HQUS, LS Power, MA AG, Maine Public Advocate, National Grid, NRG/GenOn, NSTAR/Yankee Gas, PJM IMM, Public Citizen, Solar RTO Coalition, and Taunton. This matter 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).

- **FCM Enhancements – Phase II (ER18-1287)**

On May 8, the FERC accepted changes designed to streamline and improve various aspects of the FCM rules, and in particular, the rules governing the FCA qualification process ("FCM Enhancements – Phase II").[42] As previously reported, the FCM Enhancements - Phase II (i) streamline the process used to increase the capability of an Existing Capacity Resource; (ii) revise ISO-NE processes that can delay the return of financial assurance to intermittent generating and energy efficiency resources that are operational and able to meet their Capacity Supply Obligations; (iii) memorialize the existing process by which ISO-NE determines that a new resource has become operational such that it is appropriate to release its financial assurance; (iv) make several additional improvements to the FCM qualification process; and (v) clarify existing language related to the retirement and Permanent De-Listing of capacity resources, and make a number of other minor changes. The FCM Enhancements – Phase II were accepted, with a few exceptions,[43] effective as of June 1, 2018, as requested. Unless the *FCM*

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[42] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER18-1287 (May 8, 2018) (unpublished letter order) ("*FCM Enhancements Phase II Order*").

[43] To become effective June 1, 2020 are revisions to the final sentence of Section III.13.6.1.5.3 ("The summer and winter commercial capacity of a Demand Capacity Resource consisting solely of Energy Efficiency measures may be verified in any month of the year") and to Section III.13.6.1.5.4(g).

Enhancements Phase II 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).

- **PFP Enhancements (ER18-1223)**

On May 11, the FERC accepted changes jointly filed by ISO-NE and NEPOOL that enhance and clarify the Pay-For-Performance ("PFP") Market Rules ("PFP Enhancements").[44] As previously reported, the PFP Enhancements (i) delete provisions that would, in certain circumstances, result in an inappropriate disconnect between a resource's capacity "base" payment and its capacity "performance" payment during a scarcity event; (ii) add detail regarding how the Actual Capacity Provided (a component used in determining a resource's capacity performance payment during a scarcity event) will be calculated for Demand Capacity Resources; (iii) revise how the Capacity Balancing Ratio (another component used in determining a resource's capacity performance payment during a scarcity event) will be determined in cases where more than one reserve requirement violation caused the scarcity event; and (iv) effect conforming and clean-up changes. The PFP Enhancements were accepted effective as of June 1, 2018 (the date PFP is to be implemented), as requested. Unless the *PFP Enhancements 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).

- **PER Settlement Compliance Filing (ER18-1153)**

The PER Settlement Compliance Filing remains pending. As previously reported, on March 22, 2018, in accordance with the Commission-accepted PER Settlement Agreement, ISO-NE filed changes to Market Rule section 13.7.2.7.1.1.1 revising the methodology for calculating the PER Strike Price for the period September 30, 2016 through May 31, 2018 (the "Refund Period"). The revised language increases the Daily PER Strike Price for the Refund Period. ISO-NE requested the changes become effective as of September 30, 2016. Comments on this filing were due on or before April 12, 2018. NEPOOL submitted comments supporting the compliance changes. NESCOE submitted a limited protest requesting that the FERC reject the March 22 Filing as non-compliant with the *PER Settlement Order,* asserting that the Compliance Changes, if accepted, would "use the Adjusted PER Strike Price to calculate monthly capacity payments to resources for at least some, and potentially all, of Capacity Commitment Period 9 ... [an] outcome []inconsistent with the Settlement Order." NEPGA answered NESCOE's protest on April 24. NEPOOL answered NESCOE's protest on April 27 (to clarify that (i) NEPOOL fully supports the compliance changes as filed and (ii) on the disagreements among NESCOE and NEPGA, which are broader than the filed Tariff changes, NEPOOL has not and does not take any substantive position). ConEd, Dominion, Eversource, Exelon (out-of-time), National Grid, NESCOE, and NRG/GenOn filed doc-less interventions. 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).

- **CASPR (ER18-619)**

The FERC accepted,[45] and ISO-NE's Competitive Auctions with Sponsored Policy Resources ("CASPR") revisions became effective on, March 9, 2018 (with the exception of revisions to Section III.13.7 that are to become effective June 1, 2018). Highlights from the *CASPR Order* included the following:

- ♦ ***Overall***. Guided by what the Order describes as "the first principles of capacity markets," the FERC found "ISO-NE's proposal to be an acceptable means of managing the impact of state policies in the New England region while maintaining just and reasonable rates."[46]

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[44] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER18-1223 (May 11, 2018) (unpublished letter order) ("*PFP Enhancements Order*").

[45] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*").

[46] Id. at P 22.

- ***Sponsored Policy Resource Definition***. The FERC found that the definition of Sponsored Policy Resource "does not unduly discriminate against resources that do not fit within that definition because those two classes of resources are not similarly situated."[47]
- ***Auction Design***. The FERC found the proposed auction design to be just and reasonable, persuaded by the ISO's arguments that requiring new, non-sponsored resources to participate in the substitution auction could discourage development of those resources, and that allowing new non-sponsored resources to participate in the substitution auction introduces concerns about fictitious entry that are difficult to address while still supporting the FCM's key function of attracting and sustaining investment in new capacity when needed.[48] While acknowledging that allowing existing resources to submit spread bids in the substitution auction (spread bidding) could present existing resources with an alternative way to express their willingness to exit the market at a specific severance payment amount, and thus could enhance liquidity in the substitution auction, the Order found such an allowance unnecessary for CASPR to be a just and reasonable means to accommodate the exit of certain existing resources and the entry of new Sponsored Policy Resources into the FCM over time.[49] The FERC found it reasonable for load to assume additional costs associated with balancing the goals of providing Sponsored Policy Resources an opportunity to receive CSOs with the FCM's need to secure private investment in the long term.[50]
- ***Offer Behavior and Market Power***. The FERC agreed with the ISO that the likelihood and potential price impact of bid shading (lowering bids in the primary auction to improve the probability of retaining CSOs that would be bought out in the substitution auction) will be mitigated by various factors and does not render the changes unjust and unreasonable. Nevertheless, the FERC encouraged the ISO to work with its stakeholders to pursue market enhancements that will further protect against potentially uncompetitive market results.[51] The FERC disagreed with the position that demand-side market power in the substitution auction may render ISO-NE's proposal unjust and unreasonable.[52]
- ***Renewable Technology Resource ("RTR") Exemption Phase Out***. The FERC accepted the RTR exemption phase out, finding the transition proposal "a balanced approach for implementing CASPR's alternative means of accommodating state policies, while attenuating any potential adverse impacts on pending investments that could result from an immediate change to the market rules."[53]
- ***Other Issues***. The FERC disagreed with arguments that CASPR's restriction on inter-zonal CSO transfers is not just and reasonable, or that CASPR will increase the region's dependence on natural gas-fired generation and exacerbate current fuel security concerns. The FERC found unnecessary requests that it require periodic filings on ways to improve, or take additional actions with respect to, CASPR or the FCM.[54]
- ***MOPR***. Of general but particular interest, and specifically challenged in the separate concurrences/dissents of Commissioners LaFleur and Glick, is the *CASPR Order*'s discussion of the Minimum Offer Price Rule ("MOPR"). The *CASPR Order* states that, "absent a showing that a different method would appropriately address particular state policies, [the FERC] intend[s] to use the MOPR to address the impacts of state policies on the wholesale capacity markets." And, while the MOPR will be used "as our standard solution, we will consider supplemental or alternative

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[47] Id. at P 45.

[48] Id. at P 74.

[49] Id. at P 77.

[50] Id. at P 78.

[51] Id. at P 85.

[52] Id. at P 86.

[53] Id. at P 99.

[54] Id. at PP 115-122.

> proposals to manage the impact of state policies, provided that those proposals are sufficiently consistent with the above-mentioned principles of capacity markets."[55]

The *CASPR Order* included a concurrence in part from Commissioner LaFleur, a concurrence in part and dissent in part from Commissioner Glick, and a dissent from Commissioner Powelson.

- ***LaFleur***. In her concurrence in part, Commissioner LaFleur strongly supported the FERC's approval of CASPR, but noted her disagreement with the generic guidance set forth in the order regarding how the FERC intends to address the impacts of state policies on the wholesale capacity markets, which she explained was "not directly pertinent to the CASPR proposal, and in my view is not necessary to support the [*CASPR Order*]". Commissioner LaFleur stated her intent to "closely monitor the effectiveness of this market construct in practice" and her appreciation for "ISO-NE's commitment to continue to work with stakeholders on the definition of sponsored policy resources if state laws and regulations change."
- ***Glick***. In his concurrence in part and dissent in part, Commissioner Glick agreed with the decision to accept the CASPR proposal, but disagreed strongly with the *CASPR Order*'s suggestion that state sponsored resources must either be subject to a MOPR or some alternative mechanism for "accommodating" the effects of state public policies, finding that rationale "ill-conceived, misguided, and a serious threat to consumers, the environment and … the long-term viability of the [FERC]'s capacity market construct." He expressed his concern that a "broad application of the MOPR usurps the authority over generation resource decisions that Congress left to the states when it enacted the Federal Power Act" and should be applied "in only the limited circumstance for which it was originally intended: to prevent the exercise of buyer-side market power."
- ***Powelson***. In his dissent, Commissioner Powelson found that the two goals that CASPR tries to achieve (allowing states to accomplish certain policy goals, while also protecting the viability of the FCM) are fundamentally in conflict, cannot coexist in one market and CASPR will likely only accomplish one goal at the expense of the other. In his view, the CASPR proposal "will not provide a meaningful [price] signal to the market place" and may send a message "that the best way to ensure the future viability of a particular resource is to seek state support." He acknowledged that states "are entitled to procure any resources they prefer," but "if states do want to be in control of those choices, they should also assume the responsibility for resource adequacy and reliability." Commissioner Powelson ultimately opined that the *CASPR Order* "threatens the viability of the FCM to serve as a mechanism to ensure resource adequacy in ISO-NE, and therefore, it is unjust and unreasonable and should be rejected."

Requests for Rehearing of CASPR Order. Requests for rehearing of the *CASPR Order* were filed by (i) ***NextEra/NRG*** *(which* challenge the RTR Exemption Phase Out); (ii) ***ENECOS***[56] (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***[57] (which challenge the CASPR construct in its entirety, asserting that state-sponsored resources should not be subject to the MOPR); and (iv) ***Public Citizen*** (which also challenges the CASPR construct in its entirety and the CASPR Order's failure to define "investor confidence"). On April 24,

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[55] Id. at P 22.

[56] 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.

[57] "Clean Energy Advocates" are, collectively the Natural Resources Defense Council, Sierra Club, Sustainable FERC Project, Conservation Law Foundation, and RENEW Northeast, Inc.

ISO-NE answered Clean Energy Advocates' answer. On May 7, 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 order accepting updated FCM Cost of New Entry ("CONE"), Net CONE and Offer Review Trigger Price ("ORTP") values filed by ISO-NE in January.[58] 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 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).

- **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.[59] 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 the ISO's recommendation as to the reasonableness of the bids, so that the FERC can further consider the question of whether the Bid Results were just and reasonable.[60] 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 is 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

- ***Order 842* (Frequency Response) Compliance Filing (ER18-1523)**

On May 4, 2018, ISO-NE, NEPOOL and the PTO AC filed changes to Schedules 22 and 23 of the ISO-NE OATT to incorporate *Order 842*'s *pro forma* revisions, as well as some conforming modifications to the defined

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[58] *ISO New England Inc.*, 161 FERC ¶ 61, 035 (Oct. 6, 2017)("*CONE/ORTP Updates Order*"), *reh'g requested*.

[59] *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).

[60] *2013/14 Winter Reliability Program Remand Order* at P 17.

terms and article numbers used in the OATT's *pro forma* LGIA and SGIA, and changes to address the time lag between System Impact Studies and LGIA/SGIA execution ("*Order 842* Compliance Changes"). A May 15, 2018 effective date (the effective date of *Order 842*) was requested. The *Order 842* Compliance Changes were supported by the Participants Committee at its May 4, 2018 meeting (Agenda Item # 6). Comments on this filing were due on or before May 25, 2018; none were filed. Dominion filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-EM: BHD Tax Law & Settlement Changes (ER18-1213)**

As previously reported, Emera Maine filed changes to the Emera Maine, Bangor-Hydro District ("BHD") Formula Rate on March 29, 2018 to reflect: (i) the reduction to the marginal corporate income tax rate resulting from the 2017 Tax Law and the 2017 Annual Update Settlement Agreement (*see* ER18-960 below) and (ii) recent IRS guidance regarding tax normalization accounting for ratemaking. Comments on this filing were due on or before April 19, 2018. On April 19, MPUC requested that the FERC accept the filing, but subject to refund and to hearing and settlement judge procedures. MPUC stated that, although it agreed conceptually that the tariff changes were necessary to address recent changes in the tax law, it identified that some questions remain regarding the implementation of the concept and asked for an opportunity through settlement and hearings if necessary to better understand Emera Maine's proposed changes and to ensure that Emera Maine's ratepayers receive the full benefit of the lower tax rate resulting from the 2017 Tax Law. MPUC's request was supported by a motion from MOPA. On May 14, the FERC issued a deficiency letter requiring Emera Maine to file responses providing additional information. Given the similarities with Emera Maine's MPD OATT Changes (ER18-1244) (see Section XI below), the deficiency letter addressed both filings. Emera Maine's responses are due on or before June 14, and will re-set the 60-day clock for FERC action. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: Brookfield LSA (ER18-901)**

On May 2, The FERC accepted a non-conforming three-party Local Service Agreement ("LSA") between Brookfield Energy Marketing, LP ("Brookfield"), Emera Maine and ISO-NE for Firm Local Point-to-Point Service under Schedule 21-EM.[61] Under the LSA, Emera Maine will continue to provide 85 MW of firm, point-to-point transmission service from its Powersville Road Substation at the $13.82/kW-yr. rate set forth in a 2003 transmission service agreement that will expire May 16, 2018. On March 5, the Filing Parties submitted a corrected transmittal letter to correct certain errors regarding the physical configuration of Emera Maine's lines and substations. The LSA was accepted effective as of May 16, 2018, as requested. Unless the May 2 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).

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

On June 2, 2016, the FERC accepted, but established hearing and settlement judge procedures for,[62] March 31, 2016 filings by Emera Maine in which Emera Maine sought authorization to recover certain merger-

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[61] *ISO New England Inc. and Emera Maine*, Docket No. ER18-901 (May 2, 2018) (unpublished letter order).

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

related costs viewed by the FERC's Office of Enforcement's Division of Audits and Accounting ("DAA") to be subject to the conditions of the orders authorizing Emera Maine's acquisition of, and ultimate merger with, Maine Public Service ("Merger Conditions"). As previously reported, the Merger Conditions imposed a hold harmless requirement, and required a compliance filing demonstrating fulfillment of that requirement, should Emera Maine seek to recover transaction-related costs through any transmission rate. Following 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.

In the *June 2 Order*, the FERC found that the Compliance Filings raised issues of material fact that could not be resolved based on the record, and were more appropriately addressed in hearing and settlement judge procedures.[63] The FERC reiterated several points with respect to transaction-related cost recovery explained in prior FERC orders and provided guidance on other transaction-related cost recovery points.[64] The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and indicated it would hold the hearing in abeyance pending the outcome of settlement judge procedures.[65] The separate compliance filing dockets were consolidated for the purposes of settlement, hearing and decision.[66]

Settlement Judge Procedures. ALJ John Dring is the settlement judge for these proceedings. There have been five settlement conferences: three in 2016 -- June 29, October 25, and December 1; and two in 2017 -- September 6 and November 9, 2017. In his most recent May 24, 2018 status report, Judge Dring indicated that the parties reached a settlement in principle, and filed a joint offer of settlement on May 8 ("MPS Merger Cost Recovery Settlement"). Accordingly, he recommended that settlement judge procedures be continued.

MPS Merger Cost Recovery Settlement. On May 8, Emera Maine filed the MPS Merger Cost Recovery Settlement to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *June 2 Order*. 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.

If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM 2017 Annual Update (ER15-1434) Settlement Agreement (ER18-960)**

On May 4, the FERC approved the uncontested Settlement Agreement filed by Emera Maine that resolves the MPUC's challenges raised in connection with Emera Maine's 2017 annual charges update (2017 Annual Update) under the Emera Maine Open Access Transmission Tariff for Maine Public District (MPD OATT).[67] As previously reported, the MPUC challenged the application of the Attachment J Formulas under the "Protocols for Implementing and Reviewing Charges Established by the Attachment J Formulas". Pursuant to the Settlement, Emera Maine (i) filed in ER15-1434 a corrected version of the spreadsheet submitted with the 2017 Annual Update showing Emera Maine's charges under Schedule 21-EM for the June 1, 2017 to May

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[63] *Id.* at P 24.

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

[65] *Id.* at P 27.

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

[67] *Emera Maine*, 163 FERC ¶ 61,093 (May 4, 2018) ("*May 4 Order*").

31, 2018 rate year; and (ii) filed "changes to the Attachment J Formulas, effective June 1, 2018, … to reflect the [Federal Tax Cuts and Jobs] Act's reduction to the marginal corporate income tax rate" in ER18-1213. Unless the *May 4 Order* is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- **Capital Projects Report - 2018 Q1 (ER18-1571)**

On May 10, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the first quarter ("Q1") 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 Storage Device Market Participation ($3.62 million); (ii) Identity and Access Management ("IAM") Phase I ($1.22 million); and (iii) 2018 Issue Resolution Phase I ($400,000). One project with a significant change was the FCM PFP Project (2018 Budget decrease of $125,000). Comments on this filing are due on or before the end of the day on May 31. NEPOOL intervened and filed comments on May 30 supporting the Q1 Report. Eversource and National Grid filed doc-less interventions. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- ***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*[68] *and 531-B*[69] 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
♦ VT Transco

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

- **2017 IMM Annual Markets Report (ZZ18-4)**

On May 17, the ISO's IMM filed its 2017 Annual Markets Report, which covers the 2017 calendar year period.[70] The report addresses the development, operation, and performance of the New England Markets and presents an assessment of each market based on market data, performance criteria, and independent studies, providing the information required under Section 17.2.4 of Appendix A to Market Rule 1. On the basis

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

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

[70] Please note that Annual Markets Reports filings are not noticed for public comment by the FERC.

of its review of market outcomes and related information, the IMM concluded, as it has for many years in a row, that the New England Market operated competitively in 2017. The Day-Ahead and Real-Time Energy Markets prices reflected changes in underlying primary fuel prices and electricity demand. There were few periods in the Real-Time Energy Market when relative shortage of energy and reserves impacted price, and overall price-cost markups in the Day-Ahead Energy Market "were within a reasonable range for a competitive market. For the fourth consecutive year, the forward capacity auction procured surplus capacity, and clearing prices were the result of a competitive auction." Other highlights included:

- 2017 Total wholesale costs ($9.1 billion) were 20% higher than 2016, with the increase driven primary by capacity market costs associated with FCA 8, which took effect in the second half of 2017, and increased capacity costs $1.1 billion (93%) over 2016 costs. Capacity costs will increase further in 2018, to an estimated $3.5 billion, as higher capacity prices from FCA9 take effect, but will decline after June 2019, as new resources enter the market and a higher capacity surplus applies downward pressure to capacity prices.
- 2017 Energy costs totaled $4.5 billion, up 9% from 2016, with the increase driven by higher natural gas prices, which averaged $3.72/MMBtu, up 19% from 2016 prices. The upward pressure of natural gas prices on energy costs was mitigated by lower wholesale electricity demand, particularly in the third quarter ("Q3") of 2017.
- Wholesale electricity demand continued to decline, down 2% (by an hourly average of 341MW) from 2016 demand. Q3 demand was down by 8% (nearly 1,280 MW/hour on average), compared to the prior year. The downward trend was driven primarily by the increase in state-sponsored energy efficiency measures, and to a lesser but growing extent, the increase in behind-the-meter photovoltaic installations.

In light of its review, the IMM made a number of recommendations for Market Rule changes and identified areas for additional analysis in 2018. These recommendations will be discussed in more detail at the Participants Committee June 26-28 Summer Meeting.

- **IMM Quarterly Markets Reports – Winter 2018 (ZZ17-4)**

On May 3, the IMM filed with the FERC its report for the Winter quarter of 2018 of "market data regularly collected by [it] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC.

- **ISO-NE FERC Form 3Q (2018/Q1) (not docketed)**

On May 29, the ISO submitted its 2018/Q1 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

IX. Membership Filings

- **May 2018 Membership Filing (ER18-1485)**

On April 30, NEPOOL requested that the FERC accept (i) the memberships of Anbaric Development Partners (Provisional Member); Appian Way Energy Partners East (Supplier Sector); Canton Mountain Wind (Related Person to Spruce Mountain Wind, Generation Group Seat); GSP Lost Nation, GSP Merrimack, GSP Newington, GSP Schiller, and GSP White Lake (Related Persons to Castleton Commodities Merchant Trading (Supplier Sector)); Marco DM Holdings (Generation Sector); and WATTIFI (Supplier Sector); (ii) the termination of the Participant status of AmericaWide Energy and Optik Energy; and (iii) the name change of Energy Rewards (f/k/a Fairpoint Energy). This matter is pending before the FERC.

- **Suspension Notices (not docketed)**

Since the last Report, ISO-NE filed, pursuant to Section 2.3 of the Information Policy, notices with the FERC noting that the following Participants were suspended from the New England Markets on the date indicated (at 8:30 a.m.) (each the result of a Financial Assurance Policy Default):

Date of Suspension/ FERC Notice	***Participant Name***	***Date Reinstated***
May 9/11	Chris Anthony	Remains suspended
May 9/11	Cumulus Master Fund	Termination requested
May 9/11	Energy Federation Inc.	Remains suspended
May 9/11	MPower Energy, LLC	May 11
May 9/11	VCharge Inc.	Termination requested

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: PRC-025-2 (RD18-4)**

On May 2, the FERC approved revised Reliability Standard PRC-025-2 (Generator Relay Loadability).[71] The Revised Standard was revised to better address risks of unnecessary generator tripping where the voltage is depressed and the generator is capable of increased Reactive Power output and voltage support during the disturbance ("PRC-025 Changes"). Specifically, the PRC-025 Changes: (i) add a provision to the Relay Loadability Evaluation Criteria in Attachment 1, Table 1 ("Table 1") to address dispersed power producing resources that are unable to be set at 130% of the calculated current due to physical limitations of the protection equipment; (ii) add to Table 1 relay type description the protective relay 50 Element associated with instantaneous (i.e., without intentional time delay) tripping of overcurrent based protection; (iii) clarify in the Table 1 that an entity must apply settings to all the applications described therein; (iv) clarify that an entity, when employing simulation for setting relays associated with the transmission line interconnecting the generator or plant to the Transmission system, must simulate the 0.85 per unit depressed voltage at the remote end (i.e., Transmission system side) of the line; (v) replaces "Pick Up" with "Setting Criteria" in Table 1 heading, to better align the setting to the calculated or simulated capability of the generator with an associated margin; and (vi) clarify certain terminology and references. The PRC-025 Changes were accepted effective as of the date of the order. Unless the May 2 order is challenged, this proceeding will be concluded.

- **NOPR: Cyber Security Incident Reporting Reliability Standards (RM18-2)**

On December 21, 2017 the FERC issued a NOPR proposing to direct NERC to develop and submit modifications to the Critical Infrastructure Protection ("CIP") Reliability Standards to improve the reporting of Cyber Security Incidents, including incidents that might facilitate subsequent efforts to harm the reliable operation of the bulk electric system (e.g. (incidents that compromise, or attempt to compromise, a responsible entity's Electronic Security Perimeter ("ESP") or associated Electronic Access Control or Monitoring Systems ("EACMS")).[72] The mandatory reporting requirements are intended to improve awareness of existing and future cyber security threats and potential vulnerabilities. The reports would continue to go to the Electricity Information Sharing and

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[71] *N. Am. Elec. Rel. Corp.*, Docket No. RD18-4 (May 2, 2018) (unpublished letter order).

[72] *Cyber Security Incident Reporting Reliability Standards*, 161 FERC ¶ 61,291 (Dec. 21, 2017) ("*Cyber Security Incident Reporting NOPR*").

Analysis Center ("E-ISAC"), but reports would also go to the Industrial Control Systems Cyber Emergency Response Team ("ICS-CERT"), with an annual, public, and anonymized summary of the reports. Comments on the *Cyber Security Incident Reporting NOPR* were due on or before February 26, 2018,[73] and were filed by over 15 parties, including by NYPSC, NRG and a number of individual commenters. This matter is pending before the FERC.

- **NOPR: Revised Reliability Standards: CIP-005-6, CIP-010-3, CIP-013-1 (RM17-13)**

On January 18, 2018, the FERC issued a NOPR proposing to approve revised CIP Reliability Standards -- CIP-005-6 (Cyber Security – Electronic Security Perimeter(s)), CIP-010-3 (Cyber Security – Configuration Change Management and Vulnerability Assessments) and CIP-013-1 (Cyber Security – Supply Chain Risk Management) (together, the "Supply Chain Cybersecurity Risk Management Changes").[74] The Supply Chain Cybersecurity Risk Management Changes are designed to further mitigate cybersecurity risks associated with the supply chain for BES Cyber Systems, consistent with *Order 829*. With respect to the proposed Reliability Standards' implementation plan and effective date, the FERC proposed to reduce the implementation period as proposed by NERC to the first day of the first calendar quarter that is 12 months following the effective date of a FERC order. In addition, the FERC proposed to direct NERC (i) to develop modifications to the CIP Reliability Standards to include Electronic Access Control and Monitoring Systems ("EACMS") associated with medium and high impact BES Cyber Systems within the scope of the supply chain risk management Reliability Standards; (ii) to evaluate the cyber security supply chain risks presented by Physical Access Control Systems ("PACS") and Protected Cyber Assets ("PCAs") in the study of cyber security supply chain risks requested by the NERC Board of Trustees ("BOT") in its resolutions of August 10, 2017; and (iii) to file the BOT-requested study's interim and final reports with the FERC upon their completion. Comments on the *Supply Chain Risk Management Standards NOPR* were due on or before March 26, 2018,[75] and were filed by over 20 parties, including NERC, ISO/RTO Council, EEI, Joint Trade Associations,[76] and the MPUC. Since the last Report, the American Public Power Association ("APPA") and National Rural Electric Cooperative Association ("NRECA") submitted their white paper, "Managing Cyber Supply Chain Risk – Best Practices for Small Entities" for consideration in this proceeding. This matter is pending before the FERC.

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

Comments on the *Protection System Changes NOPR*[77] remain pending. As previously reported, the FERC issued a NOPR on November 16, 2017 proposing to approve (i) two new Reliability Standards -- PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for Personnel), (ii) associated Glossary definitions, (iii) an implementation plan, (iv) VRFs and VSLs, and (v) the retirement of PRC-001-1.1(ii) (together, the "Protection System Changes"). In addition, the FERC proposed to direct NERC to develop certain modifications to PRC-027-1. NERC stated that the purpose of the Protection System Changes is to: (1) maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System ("BES") Elements, such that those Protection Systems operate in the intended sequence during Faults; and (2) require registered entities to provide training to their relevant personnel on Protection Systems and Remedial Action Schemes ("RAS") to help ensure that the BES is reliably operated. NERC requested that the new Standards and definitions become effective on the first day of the first calendar quarter that is 24 months following the effective date of the FERC's order approving the Standards. Comments on the *Protection*

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[73] The *Cyber Security Incident Reporting NOPR* was published in the *Fed. Reg.* on Dec. 28, 2017 (Vol. 82, No. 248) pp. 61,499-61,505.

[74] *Supply Chain Risk Management Reliability Standards*, 162 FERC ¶ 61,044 (Jan. 18, 2018) ("*Supply Chain Risk Management Standards NOPR*").

[75] *Supply Chain Risk Management Reliability Standards NOPR* was published in the *Fed. Reg.* on Jan. 25, 2018 (Vol. 83, No. 17) pp. 3,433-3,442.

[76] For purposes of this proceeding, "Joint Trade Associations" are the American Public Power Association ("APPA"), the Electricity Consumers Resource Council ("ELCON"), the Large Public Power Council ("LPPC"), the National Rural Electric Cooperative Association ("NRECA"), and the Transmission Access Policy Study Group ("TAPS").

[77] *Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Rel. Standards*, 161 FERC ¶ 61,159 (Nov. 16., 2017) ("*Protection System Changes NOPR*").

System Changes NOPR were due on or before January 29, 2018[78] and were filed by over 15 parties. Since the last Report, Hydro One Networks Inc. submitted comments. The Protection System Changes are pending before the FERC.

- **Revised GMD Research Work Plan (RM15-11)**

In accordance with *Order 830,*[79] NERC submitted on April 19, 2018, a revised work plan for research on topics related to geomagnetic disturbances ("GMD") and their impacts on the reliability of the Bulk-Power System ("BPS"). The Revised Plan demonstrates the improvements that have been made (the work plan was last accepted in October 2017) as a result of further work on the plan and with the benefit of early experience implementing some of the research activities. Specifically, the Revised Plan includes additional background information and specificity regarding the research activities that will be performed under the plan's nine broad work categories and an updated project timeline specifying the anticipated completion dates for each of the research activities. NERC encouraged anyone interested in NERC's GMD research activities to participate in GMD Task Force meetings, which are open to the public, with remote participation available. Comments on the Revise Plan were due on or before May 21 and were filed by D. Bardin and FRS. This matter is pending before the FERC.

- **Compliance and Certification Committee Charter Amendments (RR18-4)**

On March 15, 2018, NERC filed for approval amendments to the Compliance and Certification Committee ("CCC") Charter to reflect the participation of CCC observers in NERC audits of the Regional Entities in accordance with Appendix 4A of the NERC Rules of Procedure. Comments on this filing were due on or before April 5, 2018; none were filed. This matter is pending before the FERC.

- **Rules of Procedure Changes (RR17-6)**

NERC's revisions to Sections 600 (Personnel Certification Program) and 900 (Training and Education) of the NERC Rules of Procedure ("ROP") remain pending. The purpose of the June 26, 2017 revisions is to (i) clarify the scope of the Personnel Certification Program, the Training and Education Program and the Continuing Education Program; and (ii) streamline and align the language of the ROP with current practices of those programs. NERC stated that the changes are part of its first comprehensive review to modernize and align the language of the ROP with current NERC practices. NERC requested that the proposed revisions be made effective upon FERC approval. Comments on this filing were due on or before July 17, 2017 and were filed jointly by the Alberta Electric System Operator ("AESO"), The California Independent System Operator ("CAISO"), The Independent Electricity System Operator ("IESO"), ISO-NE and PJM ("System Operators"). System Operators, while agreeing that changes to Sections 600 and 900 are needed, nevertheless disagreed with the proposed changes as written and the rationale for making those changes in the first instance. On October 17, NERC answered System Operators' comments. This matter remains pending before the FERC.

- **Rules of Procedure Changes (Consolidated Hearings Process) (RR17-2)**

On February 27, NERC amended its December 9, 2016 filing that proposed changes to the compliance hearing process. Under the 2016 changes, Regional Entities would be provided an option to select NERC to manage the hearing process, rather than just allowing for the Regional entities to conduct the hearing process. The February 27 amendments adjust how members are appointed to the Hearing Body to address concerns raised by FERC Staff in response to the initial filing. In addition, NERC proposes changes related to the use of the terms "segment" and "sector", such that they will align with the Appendix 2 definitions and the Regional Delegation Agreements between NERC and each Regional Entity. NERC requested that the proposed revisions be made effective upon FERC approval. Comments on this filing were due on or before March 20, 2018; none were filed. AEP filed a doc-less motion to intervene. This matter is again pending before the FERC.

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[78] The *Protection System Changes NOPR* was published in the *Fed. Reg.* on Nov. 22, 2017 (Vol. 82, No. 224) pp. 55,535-55,541.

[79] *Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Rel. Standards*, 161 FERC ¶ 61,159 (Nov. 16., 2017) ("*Protection System Changes NOPR*").

XI. Misc. - of Regional Interest

- **203 Application: NEP (Vuelta and Old Wardour Interconnection Assets) (EC18-85)**

On April 16, 2018, New England Power ("NEP") requested authorization to acquire from Vuelta Solar, LLC certain interconnection assets associated with the 9.88 MW Vuelta and Old Wardour solar facilities located in East Brookfield, Massachusetts. Comments on the application were due on or before May 7, 2018; none were filed. On May 24, NEP submitted an addendum to its application, clarifying that (i) NEP's accounting journal entry for the transaction would be to credit FERC Account 131 (Cash) and debit FERC Account 101 (Electric Plant in Service) each for $1; and (ii) the book value of equipment ($1,682,409) will be used by NEP in the calculation of the Direct Assignment Facilities ("DAF") charge to be invoiced to Old Wardour Holdings, LLC and Vuelta Solar, LLC pursuant to Schedule 21 - NEP, Attachment DAF of the ISO-NE Tariff. Comments, if any, on the addendum are due on or before June 14.

- **203 Application: NRG Canal/Stonepeak (EC18-83)**

On May 31, the FERC authorized a transaction pursuant to which NRG Canal will be ultimately be acquired indirectly by Stonepeak Holdings, LLC ("Stonepeak").[80] Following consummation of the transaction, NRG Canal will no longer be a Related Person to the NRG/GenOn Companies.[81] Among other conditions, the May 31 order required notice within 10 days of the transaction's consummation.

- **203 Application: XOOM Energy/NRG Retail (EC18-82)**

On May 30, the FERC authorized NRG's acquisition of all of the membership interests in XOOM Energy.[82] Upon consummation, XOOM Energy will become a Related Person to the NRG/GenOn Companies. Among other conditions, the order required notice within 10 days of the acquisition's consummation, which has not yet been filed.

- **203 Application: HIKO Energy/Spark HoldCo (EC18-69)**

On May 29, 2018, the FERC authorized Spark HoldCo, LLC, a subsidiary of Spark Energy (Spark), to acquire all of the membership interests in HIKO Energy.[83] As a result of the acquisition,[84] HIKO became a Related Person to Spark Energy (Spark Energy and its Related Persons[85] are also members of the Supplier Sector). Unless the May 29 order is challenged, this proceeding will be concluded.

- **203 Application: Boston Energy/Diamond Energy (EC18-64)**

On April 19, 2018, the FERC authorized the acquisition by Diamond Energy Trading and Marketing, LLC of all of the membership interests in Boston Energy Trading and Marketing LLC ("Boston Energy"), until then a

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[80] *GenOn Holdco 10, LLC, NRG Canal LLC and Stonepeak Kestrel Holdings LLC*, 163 FERC ¶ 62,134 (May 31, 2018).

[81] The "NRG/GenOn Companies" are, currently: NRG Power Mkt'g, LLC; Conn. Jet Power LLC; Devon Power LLC; Middletown Power LLC; Montville Power LLC; Norwalk Power LLC; Somerset Power LLC; Energy Plus Holdings LLC; Independence Energy Group LLC; GenConn Energy LLC; GenOn Energy Management, LLC; NRG Canal LLC; Green Mountain Energy Co.; Reliant Energy Northeast LLC; NRG Curtailment Solutions, Inc.; and Boston Energy Trading and Mkt'g LLC.

[82] *BlueGreen Holding, LLC et al.*, 163 FERC ¶ 62,128 (May 29, 2018).

[83] *HIKO Energy, LLC*, 163 FERC ¶ 62,127 (May 29, 2018).

[84] Contrary to the requirements of FPA Section 203, HIKO Energy stated that Spark HoldCo acquired 100 percent of the ownership interests in HIKO Energy on March 1, 2018 without prior FERC approval.

[85] Spark Energy's Related Person Participants are: National Gas & Electric, LLC; Oasis Power, LLC (d/b/a Oasis Energy), Electricity Maine, LLC; Electricity NH, LLC (d/b/a ENH Power); Major Energy Electric Services LLC; Perigee Energy, LLC; Provider Power Mass, LLC; and Verde Energy USA, Inc.

Related Person to NRG Power Marketing.[86] Among other conditions, the order required notice within 10 days of the acquisition's consummation, which has not yet been filed.

- **203 Application: NRG/GIP III Zephyr Acquisition Partners (EC18-61)**

On May 18, the FERC authorized the acquisition by GIP III Zephyr Acquisition Partners, L.P. ("Buyer") of, among other things, interests currently held by NRG in NRG Yield, NRG Renew and their public utility subsidiaries and Carlsbad.[87] Following the acquisition, GenConn will remain a Related Person to UI, and will become a Related Person of CPV Towantic, but will no longer be an NRG Related Person. Among other conditions, the order required notice within 10 days of the acquisition's consummation, which has not yet been filed.

- **203 Application: PSNH/HSE Hydro NH (EC18-42)**

On February 28, the FERC authorized[88] the acquisition by HSE Hydro NH AC, LLC ("HSE Hydro NH")[89] of PSNH's portfolio of hydroelectric generation assets (the "PSNH Hydro Transaction").[90] Among other conditions, the February 28 order required notice within 10 days of the consummation of the transaction. Subject to the required consummation notice, this proceeding will be concluded.

- **203 Application: GenOn Reorganization (EC17-152)**

On October 31, 2017, the FERC approved certain conversions of GenOn notes into common equity of, and corporate structure changes that will result in, a "reorganized GenOn".[91] Reorganized GenOn will emerge as a result of a plan of reorganization to be confirmed by the United States Bankruptcy Court for the Southern District of Texas in connection with GenOn's Chapter 11 restructuring (the "Restructuring"). As a result of the Restructuring, Reorganized GenOn will likely not be a subsidiary of, and GenOn Energy Management will thus likely no longer be a Related Person to, NRG. Among other conditions, the order required notice within 10 days of the consummation of the transaction. Subject to that notice, this proceeding will be concluded.

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

On May 9, 2017, the FERC authorized GMP's acquisition of the following small hydroelectric generation facilities (each a QF, collectively 8.39 MW of total generating capacity) from subsidiaries of Enel Green Power North America, Inc.: Hoague-Sprague, Kelley's Falls, Lower Valley, Glen, Rollinsford, South Berwick, Somersworth, and Woodsville.[92] Among other conditions, the order required notice within 10 days of the consummation of the transaction, which as of date of this Report has not been filed. On April 12, 2018, QF self-recertifications were filed for the facilities with a rated capacity of more than 1 MW identifying that the change in ownership became effective May 31, 2017. There will be no further reporting on this proceeding.

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

In two proceedings which, unless narrowly limited solely to the unique facts of the directly applicable markets (PJM in EL16-49; NYISO in EL13-62), could impact the New England market through FERC jurisdictional or other determinations, NEPOOL filed limited comments requesting that any Commission action or decision be limited narrowly to the facts and circumstances as presented in the applicable market. NEPOOL urged that any changes that may be ordered by the Commission in the proceedings not circumscribe the results of

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[86] *Boston Energy Trading and Mkt'g LLC*, 163 FERC ¶ 62,052 (Apr. 19, 2018).

[87] *NRG Yield, Inc., NRG Renew LLC and Carlsbad Energy Center LLC*, 163 FERC ¶ 62,101 (May 16, 2018).

[88] *Pub. Srvc. Co. of NH and HSE Hydro NH AC, LLC*, 162 FERC ¶ 62,122 (Feb. 28, 2018).

[89] HSE Hydro NH is a Related Person to Generation Sector Group Seat members Nautilus Hydro and Pawtucket Power.

[90] PSNH's hydro portfolio (61.8 MW) includes the following facilities: Smith (15.78 MW); Amoskeag (17.5 MW); Garvins Falls/Hooksett (7.09 MW); Ayers Island (8.94 MW); Eastman Falls (6.1 MW); Jackman (3.54 MW); Gorham (1.68 MW); Canaan (1.17 MW).

[91] *GenOn Energy Inc.*, 161 FERC ¶ 62,063 (Oct. 31, 2017).

[92] *Green Mountain Power Corp.,* 159 FERC ¶ 62,144 (May 9, 2017).

NEPOOL's stakeholder process or predetermine the outcome of that process through dicta or a ruling concerning different markets with different history and different rules. NEPOOL's comments were filed on January 24, 2017 in the NYISO proceeding; January 30, 2017 in the PJM proceeding, and, as with the proceedings themselves, remain pending before the FERC. If you have any questions concerning these proceedings, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **NSTAR/Milford Related Facilities Agreement (ER18-1574)**

On May 11, NSTAR filed its Related Facilities Agreement ("RFA") with Milford Power LLC. The RFA provides the terms and conditions governing NSTAR's activities, and Milford's associated cost responsibility, for upgrades to its Medway #65 relay equipment at the line terminals of the 201-501 Line ("Related Facilities") to accommodate the capacity expansion of Milford's facility. An April 30, 2018 effective date, the date of the most recent LGIA between Milford, National Grid and ISO-NE that triggered the need for the RFA, was requested. Comments on this filing are due on or before June 1. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Emera/MPD OATT *Order 842* Compliance Filing (ER18-1569)**

On May 11, Emera Maine filed changes to the Large and Small Generator Interconnection Procedures and Agreements in its Open Access Transmission Tariff for Maine Public District (the "MPD OATT") in compliance with *Order 842*. A May 15, 2018 effective date (the effective date of *Order 842*) was requested. Comments on this filing are due on or before June 1. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **National Grid/Granite Reliable Power Reimbursement Agreement Cancellation (ER18-1350)**

On May 14, the FERC accepted National Grid's Notice of Cancellation of the Cost Reimbursement Agreement ("Reimbursement Agreement") between NEP and Granite Reliable Power, LLC ("Granite Reliable Power").[93] The execution and acceptance of a Related Facilities Agreement ("RFA")[94] fully satisfied each party's obligations under the Reimbursement Agreement. The cancellation notice was accepted effective as of November 1, 2017, the date the RFA became effective, as requested. Unless the May 14 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).

- **D&E Agreement Cancellation: CL&P/Beacon Falls Energy Park (ER18-1306)**

On May 24, the FERC accepted CL&P's notice of cancellation of an Engineering, Design and Procurement Services agreement between itself and Beacon Falls Energy Park.[95] The purpose of the Agreement was to set forth the terms and conditions under which CL&P would provide design and/or engineering necessary to complete a cost estimate for the modification of CL&P's Beacon Falls substation and to interconnect the proposed 63.3 MW fuel cell project's switchyard. The Agreement terminated as of the effective date of a three-party conforming LGIA between CL&P, Beacon Falls and ISO-NE ("2018 LGIA") – March 9, 2018. The notice of cancellation was accepted for filing as of the effective date of the 2018 LGIA, as requested. Unless the May 24 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[93] *The Conn. Light and Power Co.*, Docket No. ER18-1306 (May 24, 2018) (unpublished letter order).

[94] The RFA addresses costs associated with upgrades to NEP's equipment at the Moore Generating Station and modifications to NEP's protection system in connection with the Dummer, New Hampshire interconnection of Granite Reliable Power's 99 MW wind generation facility. The RFA was accepted in delegated letter order, *New England Power Co.*, Docket No. ER18-346 (Jan. 24, 2018).

[95] *New England Power Co.*, Docket No. ER18-1350 (May 14, 2018) (unpublished letter order).

- **D&E Agreement: NSTAR/National Grid (ER18-1290)**

On May 9, the FERC accepted an Agreement for Design, Engineering and Construction services between NSTAR and National Grid (the "D&E Agreement").[96] The purpose of the D&E Agreement is to set forth the terms and conditions under which National Grid will reimburse NSTAR for the costs associated with performing design, engineering and construction services on jurisdictional transmission facilities necessary for NEP to interconnect one of its retail customers (the Wynn Casino). The D&E Agreement was accepted for filing as of April 3, 2018, as requested. Unless the May 9 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 Changes (ER18-1244)**

As previously reported, On March 30, 2018, Emera Maine filed changes to Attachment J of the MPD OATT to reflect the reduction to the marginal corporate income tax rate resulting from the 2017 Tax Law and the 2017 Annual Update Settlement Agreement (*see* ER18-960 above). Comments on this filing were due on or before April 20, 2018. On April 20, MPUC requested that the FERC accept the filing, but subject to refund and to hearing and settlement judge procedures. MPUC stated that, although it agreed conceptually that the tariff changes were necessary to address recent changes in the tax law, it identified that some questions remain regarding the implementation of the concept and asked for an opportunity through settlement and hearings if necessary to better understand Emera Maine's proposed changes and to ensure that Emera Maine's ratepayers receive the full benefit of the lower tax rate resulting from the 2017 Tax Law. MPUC's request was supported by motions from MOPA and from the Maine Customer Group.[97] On May 4, Emera Maine answered the MPUC, MOPA and Maine Customer Group. The Maine Customer Group answered that May 4 answer on May 10.

Deficiency Letter. On May 14, the FERC issued a deficiency letter requiring Emera Maine to file responses providing additional information. Given the similarities with Emera Maine's Schedule 21-EM: BHD Tax Law & Settlement Changes (ER18-1213) (see Section VI above), the deficiency letter addressed both filings. Emera Maine's responses are due on or before June 14, and will re-set the 60-day clock for FERC action. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA: CL&P/Fusion Solar (ER18-1192)**

On May 25, the FERC accepted a two-party IA between CL&P and Fusion Solar that governs the interconnection of Fusion Solar's 20 MW solar generating facility in Sprague, CT to CL&P's distribution system.[98] In accepting the IA, the FERC denied the waiver requested by CL&P with respect to the IA's effective date. Rather than accept the IA as of the date filed (March 27, 2018, the commercial operation date of the facility), the FERC accepted the agreement as of May 26, 2018, 61 days after the date of filing, having found CL&P did not make the required showing of good cause for the waiver requested. The FERC directed CL&P to refund the time-value of the revenues collected for the period prior to the May 26 effective date, subject to the usual condition that the refunds not cause CL&P to have provided the service at a loss, and directed CL&P to submit its Refund Report within 30 days of the date of the May 25 order. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[96] *NSTAR Elec. Co.*, Docket No. ER18-1290 (May 9, 2018) (unpublished letter order).

[97] For purposes of this proceeding, Maine Customer Group ("MCG") consists of: Houlton Water Co., Van Buren Light and Power District and Eastern Maine Electric Coop., Inc.

[98] *The Conn. Light and Power Co.*, 163 FERC ¶ 61,145 (May 25, 2018) ("*Fusion Solar IA Order*").

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

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

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

- **DER Participation in RTO/ISOs (AD18-10; RM18-9)**

In *Order 841*[99] (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*.[100] All comments filed in response to the *Storage NOPR* will be incorporated by reference into Docket No. RM18-9 and any further comments regarding the proposed distributed energy resource aggregation reforms, including comments regarding the technical conference described below, should be filed in RM18-9.

Technical Conference (AD18-10). On April 10-11, 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. Panel topics included:

- Economic Dispatch, Pricing and Settlement of DER Aggregations
- Discussion of Operational Implications of DER Aggregation with State and Local Regulators
- DER Participation in RTO/ISO Markets
- DER Installation Data Collection and Availability
- Incorporating DERs in Modeling, Planning and Operations Studies
- Coordination of DER Aggregations Participating in RTO/ISO Markets
- Ongoing Operational Coordination

Speaker materials are posted on the FERC's eLibrary.

On April 27, the FERC issued a notice inviting all interested persons 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 should be filed in Docket No. RM18-9. Comments on the potential effects of DERs on the bulk power system should be separately filed in Docket No. AD18-10. Comments should be submitted on or before June 26, 2018 and should not exceed 30 pages.

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[99] *Electric Storage Participation in Markets Operated by Regional Transmission Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018), *clarif. requested* ("*Order 841*").

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

- **Grid Resilience in RTO/ISOs; DOE NOPR (AD18-7; RM18-1)**

On January 8, 2018, the FERC terminated the DOE NOPR rulemaking proceeding (RM18-1)[101] and initiated a new Grid Resilience in RTO/ISOs proceeding (AD18-7).[102] 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, Foundation for Resilient Societies ("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). In the January 8 order, the FERC initiated AD18-7 to evaluate the resilience of the bulk power system in RTO/ISO regions, 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[103] 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 3 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, 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 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 4 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, and EDF. This matter is 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

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[101] 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.

[102] *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012 (Jan. 8, 2018), *reh'g requested*.

[103] 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."

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 request is pending.

- **NOI: 2017 Tax Law Effect on FERC-Jurisdictional Rates (RM18-12)**

On March 15, the FERC opened an inquiry ("NOI")[104] seeking comments on the effect of the 2017 Tax Cuts and Jobs Act ("2017 Tax Law") (which reduced the federal corporate income tax rate from a maximum 35% to a flat 21%) on FERC-jurisdictional rates. Of particular interest is whether, and if so how, the FERC should address changes relating to accumulated deferred income taxes ("ADIT"),[105] bonus depreciation,[106] or other rates (not otherwise being addressed in the concurrently issued show cause orders). Comments on the NOI were due on or before May 21, 2018,[107] and were filed by over 45 parties, including Avangrid, Eversource, Exelon MA AG et al., National Grid, PSEG, APPA, and EEI. This matter is pending before the FERC.

- **NOPR: Pipeline Rates (RM18-11)**

On March 15, 2018, the FERC issued a NOPR[108] that proposes a procedure 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. The *Pipeline Rates NOPR* would require interstate pipelines to (a) file a one-time report, FERC Form No. 501-G, that would 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. Pipelines can 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).[109]

Comments to the *Pipeline Rates NOPR* were due on or before April 25, 2018,[110] and were submitted by over 30 parties. Since the last Report, answers and reply comments were submitted by 10 parties. This matter is pending before the FERC.

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[104] *Inquiry Regarding the Effect of the Tax Cuts and Jobs Act on Comm.-Jurisdictional Rates*, 162 FERC ¶ 61,223 (Mar. 15, 2018).

[105] ADIT arises from differences between the methods of computing taxable income for IRS reporting purposes and computing income for regulatory accounting and ratemaking purposes. As a result of the Tax Cuts and Jobs Act, a portion of an ADIT liability that was collected from customers will no longer be due to the IRS, is considered excess ADIT, and must be returned to customers in a cost-of-service ratemaking context.

[106] Bonus depreciation is a tax incentive given to companies to encourage certain types of investment. Bonus depreciation allows companies to deduct a percentage of the cost of a qualified property in the year the property is placed into service, in addition to other depreciation deductions. Under the Act, bonus depreciation is no longer available for "assets acquired in the trade or business of the furnishing or sale of electrical energy, water, or sewage disposal services; gas or steam through a local distribution system; or transportation of gas or steam by pipeline."

[107] The NOI was published in the *Fed. Reg.* on Mar. 21, 2018 (Vol. 83, No. 55) pp. 12,371 – 12,376.

[108] *Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate*, 162 FERC ¶ 61,226 (Mar. 15, 2018) ("*Pipeline Rates NOPR*").

[109] If the pipeline chooses the latter two options, FERC will consider after reviewing both the one-time report and the comments of others whether to initiate an NGA Section 5 investigation.

- **NOPR: Withdrawal of Pleadings (RM18-7)**

On February 15, 2018, the FERC issued a NOPR proposing to adopt a more accurate title for, and clarify the text of, Rule 216 of the FERC's Rules of Practice and Procedure.[111] The FERC proposes to change Rule 216's the title from "Withdrawal of pleadings and tariff or rate filings (Rule 216)" to "Withdrawal of pleadings (Rule 216)", to change the first sentence of Rule 216(a) to read, "Any person may seek to withdraw its pleading by filing a notice of withdrawal," and to refer to "person" rather than "party," in Rule 216(c). Comments on the *Pleadings Withdrawal NOPR* were initially due on or before March 26, 2018,[112] later extended to March 28. A single comment, addressing what was described as a "jarring grammatical error", was filed. The *Pleadings Withdrawal NOPR* remains pending before the FERC.

- ***Order 845*: LGIA/LGIP Reforms (RM17-8)**

On April 19, 2018, the FERC issued its final rule,[113] *Order 845*, revising its *pro forma* Large Generator Interconnection Procedures ("LGIP") and *pro forma* Large Generator Interconnection Agreement ("LGIA") to implement 10 specific reforms designed to improve certainty for interconnection customers,[114] promote more informed interconnection decisions,[115] and enhance the interconnection process.[116] Based on the comments received on its December 15, 2016 NOPR[117] 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* will become effective July 23, 2018, and requires compliance filings to be filed on or before August 7, 2018. On May 17, the ISO/RTO Council ("IRC") requested a 70-day extension of time, to October 16, 2018, for the submission of compliance filings, which NEPOOL supported in comments submitted on May 23. The IRC request for an extension of the compliance filing deadline is pending.

Requests for rehearing and/or clarification of *Order 845* were filed by APPA, Arizona Public Service Company, AWEA, California Utilities,[118] Duke, EEI, EON Climate & Renewables, MISO Transmission Owners, NYISO, SCE, and Southern Company Services. The requests for rehearing are pending, with FERC action

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[110] The *Pipeline Rates NOPR was* published in the *Fed. Reg.* on Mar. 26, 2018 (Vol. 83, No. 58) pp. 12,888 – 12,901.

[111] *Withdrawal of Pleadings*, 162 FERC ¶ 61,111 (Feb. 15, 2018) ("*Pleadings Withdrawal NOPR*").

[112] The *Pleadings Withdrawal NOPR* was published in the *Fed. Reg.* on Feb. 23, 2018 (Vol. 83, No. 37 pp. 8,019-8,020.

[113] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043 (Apr. 19, 2018) ("*Order 845*").

[114] 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.

[115] 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.

[116] 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.

[117] *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.

[118] "California Utilities" are Pacific Gas and Elec. ("PG&E"), So. Cal. Edison ("SCE"), and San Diego Gas & Elec. ("SDG&E").

required on or before June 18, 2018 (the first business day 30 days from the date the first (Duke) request for clarification was filed), or the requests will be deemed denied by operation of law.

- ***Order 844*: Uplift Transparency in RTO/ISO Markets (RM17-2)**

Also on April 19, the FERC issued *Order 844* which requires each RTO/ISO to establish in its tariff requirements to report on, on a monthly basis, the following three uplift transparency requirements to be reported on a monthly basis:

(1) ***Zonal Uplift*** – a report of all uplift, paid in dollars, and categorized by transmission zone, day, and uplift category ("We define transmission zone as a geographic area that is used for the local allocation of charges, such as a load zone that is used to settle charges for energy. Transmission zones with fewer than four resources may be aggregated with one or more neighboring transmission zones, until each aggregated zone has at least four resources, and reported collectively."). This report must be posted on a publicly-accessible portion of the RTO/ISO's website within 20 calendar days of the end of each month;

(2) ***Resource-Specific Uplift*** - a report containing the resource name and total amount of uplift paid in dollars aggregated across the month to each resource that received uplift payments. This report must be publicly accessible on the RTO/ISO's website within 90 calendar days of the end of each month; and

(3) ***Operator-Initiated Commitment*** – a report listing the commitment size, transmission zone, commitment reason, and commitment start time of each operator-initiated commitment ("We define an operator-initiated commitment as a commitment made after the day-ahead market for a reason other than minimizing the total production costs of serving load. Commitment reasons shall include, but are not limited to, system-wide capacity, constraint management, and voltage support."). This report must be posted on a publicly accessible portion of the RTO/ISO's website within 30 calendar days of the end of each month.

In addition to these reporting requirements, each RTO and ISO must include in its tariff the ***transmission constraint penalty factors*** used in its market software, as well as any circumstances under which those penalty factors can set locational marginal prices, and any process by which the penalty factors can be temporarily changed. In response to a number of concerns raised, including by ISO-NE, *Order 844* withdraws the FERC's proposal in the *Uplift/Transparency NOPR* to require that each RTO/ISO that currently allocates the costs of Real-Time uplift to deviations allocate such Real-Time uplift costs only to those market participants whose transactions are reasonably expected to have caused the real-time uplift costs.

Order 844 requires that each RTO/ISO submit a compliance filing within 135 days of *Order 844*'s publication in the *Federal Register* (or by early in September 2018).[119] The draft Final Rule allows each RTO or ISO a further 120 days from the compliance filing due date to implement *Order 844*.

- ***Order 841*: Electric Storage Participation in RTO/ISO Markets (RM16-23; AD16-20)**

On February 15, 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." The participation model must:

(4) 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;
(5) 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;

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[119] *Order 844* was published in the *Fed. Reg.* on Apr. 25, 2018 (Vol. 83, No. 80) pp. 18,134-18,157.

(6) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and
(7) establish a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW.

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. RTO/ISOs must file any necessary tariff changes on or before November 30, 2018 (270 days from *Order 841*'s publication in the Federal Register)[120] and implement those tariff provisions within one year of that compliance filing. *Order 841* will become effective June 4, 2018.

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* AD18-10/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.[121] 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[122] and were filed by over 30 parties, including: APPA, Avangrid, Brookfield, EPSA, Macquarie/DC Energy/Emera Energy Services, NextEra, and NRG.

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

On May 17, the FERC issued *Order 833-A*,[123] granting EEI's request for clarification in part and denying rehearing of *Order 833.*[124] As previously reported, *Order 833* amended FERC regulations to implement provisions

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[120] *Order 841* was published in the *Fed. Reg.* on Mar. 6, 2018 (Vol. 83, No. 44) pp. 9,580-9,633.

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

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

[123] Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information, Order No. 833-A, 163 FERC ¶ 61,125 (May 17, 2018).

[124] *Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Info.; Availability of Certain N. Amer. Elec. Rel. Corp. Databases to the Comm.*, Order No. 833, 157 FERC ¶ 61,123 (Nov. 17, 2016) ("*Order 833*"), *order on clarif. and reh'g,* 163 FERC ¶ 61,125 (May 17, 2018).

of the Fixing America's Surface Transportation ("FAST") Act that pertain to the designation, protection and sharing of Critical Electric Infrastructure Information ("CEII") and amend other regulations that pertain to CEII. The amended procedures will be referred to as the Critical Energy/Electric Infrastructure Information (CEII) procedures. *Order 833* became effective February 21, 2017.[125] On December 19, 2016, EEI requested clarification and/or rehearing of *Order 833,* with clarification granted in part and rehearing denied, as noted above.

- ***Order 842*: Primary Frequency Response - Essential Reliability Services and the Evolving Bulk-Power System (RM16-6)**

On February 15, the FERC issued *Order 842*,[126] which requires all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of interconnection. The FERC also established certain uniform minimum operating requirements, including maximum droop and deadband parameters and provisions for timely and sustained response. *Order 842* requirements will also apply to *existing* large and small generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after *Order 842*'s effective date. These requirements will not apply to existing generating facilities, a subset of combined heat and power ("CHP") facilities, or generating facilities regulated by the Nuclear Regulatory Commission. The FERC did not impose a headroom requirement for new generating facilities, and did not mandate that new generating facilities receive compensation for complying with the primary frequency response requirements. To implement these requirements, the FERC modified the *pro forma* LGIA and the *pro forma* SGIA. *Order 842* will become effective May 15, 2018.[127] Requests for rehearing and/or clarification and reconsideration of *Order 842* were filed by PJM, the AES Companies and Arizona Public Service. Answers to the PJM request were filed by PJM Power Providers Group ("P3") and EPSA ("Competitive Suppliers"), the PJM Utilities Coalition, and the PJM IMM. 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. Since the last Report, PJM requested expedited action on its request for clarification and answered Competitive Suppliers' and PJM Utilities Coalition's responses thereto. This matter remains pending before the FERC.

- **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[128] 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) the efficiency and effectiveness of the FERC certificate process. Pursuant to a May 23 order extending the comment deadline by 30 days,[129] comments are now due on or before July 25, 2018. Notwithstanding that order, since the last Report, comments were filed by a several individual commenters and the Delaware Riverkeeper Network.

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

[126] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, Order No. 842, 162 FERC ¶ 61,128 (Feb. 15, 2018) ("*Order 842*"), *reh'g requested*.

[127] *Order 842* was published in the *Fed. Reg.* on Mar. 6, 2018 (Vol. 83, No. 44) pp. 9,636-9,677.

[128] The NOI was published in the *Fed. Reg.* on Mar. 6, 2018 (Vol. 83, No. 44) pp. 9,636-9,677.

[129] *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,138 (May 23, 2018).

- **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.[130] 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[131] 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*[132] 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, NGAA, SPPP, LP, Oil Pipe Lines, Plains Pipeline, Tailgrass Pipelines, and TransCanada. On April 27, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending before the FERC.

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*[133] 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.[134] Specifically, after extensive discovery and hearing procedures, Judge Cintron found that BP's Texas team engaged in market manipulation by changing their trading patterns, between September 18, 2008 through the end of November 2008, in order to suppress next-day natural gas prices at the Houston Ship Channel ("HSC") trading point in order to benefit correspondingly long position at the Henry Hub trading point. The FERC agreed, finding that the "record shows that BP's trading practices during the Investigative Period were fraudulent or deceptive, undertaken with the requisite scienter, and carried out in connection with Commission-jurisdictional transactions."[135] 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*

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[130] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs*, 162 FERC ¶ 61,227 (Mar. 15, 2018).

[131] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs,* 157 FERC ¶ 61,210 (Dec. 15, 2016).

[132] *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.

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

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

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

Order also denied BP's request for rehearing of the order establishing a hearing in this proceeding.[136] 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, 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.[137]

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 is again 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[138] 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.[139]

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.

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

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

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

[139] 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.

Staff Notices of Alleged Violations (IN__-___)

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.[140] 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:

- ***Portland Express Project (CP18-251)***
  - On April 20, 2018, Portland Natural Gas Transmission System LP ("PNGTS") submitted an abbreviated application for a certificate of public convenience and necessity seeking authorization for 40,000 Dth/d of increased pipeline capacity; intended to be the first phase of a three-phase system expansion known as the Portland Xpress ("PXP") Project.
  - Phase I is intended to increase PNGT's certificated capacity on its Northern Facilities from Pittsburg, NH, to Westbrook, ME, and its certificated capacity by 1,641 Mcf/d on its Joint Facilities (shared with Maritimes and Northeast Pipeline LLC) from Westbrook, ME to Dracut, MA.
  - PNGTS has also asked for authorization to amend its Presidential Permit under NGA Section 3 that would permit it to increase its import/export capacity from 210,000 Mcf/d to 274,216 Mcf/d at border-crossing facilities at the US/Canadian border in NH.
  - No new construction or modifications are being proposed to the existing pipeline infrastructure. Rather, the addition of 40,000 Mcf/d of capacity on the Northern Facilities is being created through pressure reductions at Westbrook, ME into the Joint Facilities.
  - Eight precedent agreements have been executed with firm shippers totaling 137,378 Dth/d under PNGT's Rate Schedule FT, and have been filed under seal at the FERC as part of the certificate application.
  - PNGTS seeks FERC certificate authorization on or before September 30, 2018, with a targeted in-service date of November 1, 2018. Action on this matter is pending 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.

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[140] *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).

  - 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.[141]
  - Certain facilities,[142] 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 November 1, 2017.[143] 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.

- ***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.
    - 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.

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[141] 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*").

[142] 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).

[143] *Algonquin Gas Transmission, LLC*, 158 FERC ¶ 61,061 (Oct. 27, 2017).

        - 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.[144] 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.[145]
        - On February 12, 2018, Constitution Pipeline requested rehearing of the January 11, 2018 order. The FERC issued a tolling order on March 14 affording it additional time to consider Constitution Pipelines' request, which remains pending.
    - 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. Constitution will submit its monitoring reports monthly rather than weekly until activities resume in 2018.

- **Non-New England Pipeline Proceedings**
  The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:
    - **Southeast Market Pipelines Project (CP14-554, CP15-16, CP15-17)**
        - Florida Southeast Connection, LLC, Transcontinental Gas Pipe Line Company, LLC and Sabal Trail Transmission, LLC (Sabal Trail) filed for a Section 7(c) certificates in Sept. – Nov. 2014.
        - The three separate but connected natural gas transmission pipeline projects total approximately 685.5 miles of natural gas transmission pipeline and provide transportation service for up to approximately 1.1 billion cubic feet per day of natural gas to markets in Florida and the southeast United States ("SMP Project").

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[144] *Constitution Pipeline Co.*, 162 FERC ¶ 61,014 (Jan. 11, 2018), *reh'g requested*.

[145] *Id.* at P 23.

  - Certificates of public convenience and necessity were granted Feb. 2, 2016.[146]
    - Project construction began in August 2016, and in June and July 2017, Commission Staff authorized the pipelines to commence service on the completed facilities.
  - On August 22, 2017, the DC Circuit vacated and remanded the FERC's certificate order, holding that the FERC's environmental review of the SMP Project failed to adequately consider the downstream effects of greenhouse gas emissions resulting from increased power generation.[147]
    - The DC Circuit held that FERC must either quantify and consider the project's downstream carbon emissions or explain in more detail why it cannot do so.
  - On September 27, 2017, the FERC issued a Draft Supplemental EIS, estimating the pipeline would potentially increase the Florida GHG emission inventory between 3.7 and 9.7 percent.
    - In the supplemental EIS, the FERC stated that it "could not find a suitable method to attribute discrete environmental effects to GHG emissions."
  - On March 14, 2018, the FERC issued an Order on Remand reinstating the certificates of public convenience and necessity. The majority found that while the FERC calculated the gross and net emissions, there was nothing to do with that information as there is "no widely accepted standard to ascribe significance to a given rate or volume of GHG emissions." The FERC also noted that it is only approving the means of transportation, and it is not the Commission's job to "decide national policy on the use of natural gas."
    - Commissioner LaFleur dissented in part because she could not "support the Commission's responses to the Court on downstream GHG emissions and the Social Cost of Carbon."
    - Commissioner Glick also dissented, arguing that the FERC must consider the reasonably foreseeable indirect effects of the SMP Project. Glick argues that the "Commission must take a 'hard look' at climate change – the ultimate environmental impact," and should be more transparent in its decision-making. He concluded by noting "that t[he] order, by limiting analysis of the environmental impacts of a proposed pipeline, will both increase the Commission's litigation risk and contribute further to the cynicism of the pipeline siting process."
    - On April 13, 2018, several intervenors (including the Sierra Club) jointly filed a rehearing request and motion for stay of the FERC's Order on Remand. On April 27, 2018, Florida Southeast Connection, LLC and Florida Power & Light filed an answer in opposition to the joint motion for stay. On May 11, 2018, the FERC issued a tolling order affording it additional time to consider the April 13 request for rehearing, which remains pending.

- **Millennium Pipeline Valley Lateral Project (CP16-17)**
  - On July 21, 2017, Millennium Pipeline Company, L.L.C. ("Millennium") filed a Request for Notice to Proceed with Construction of its Valley Lateral Pipeline in Orange County, New York. Originally, the subject of a November 13, 2015 FERC certificate application, the Valley Lateral Pipeline was authorized by FERC on November 9, 2016.[148]
    - The Valley Lateral Pipeline will connect the existing Millennium Pipeline to the 680 MW CPV Valley Energy Center.

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[146] *Fla. Southeast Connection, LLC*, 154 FERC ¶ 61,080, 61 (Feb. 2, 2016) (order issuing certificate).

[147] *Sierra Club v. FERC*, 2017 U.S. App. LEXIS 15911 (D.C. Cir. Aug. 22, 2017).

[148] *Millennium Pipeline Co., L.L.C.,* 157 FERC ¶ 61,096 (Nov. 9, 2017).

- To receive a notice to proceed, Millennium was required to demonstrate that it had obtained all federally-required environmental permits and authorizations, including authorizations under the Clean Water Act (CWA). Millennium stated that the New York State Department of Environmental Conservation (New York DEC) had waived its authority to issue a water quality certification under Section 401 of the CWA by failing to act before the statutorily-imposed deadline.
  - In August 2017, the NY DEC denied the water quality certification to the Valley Lateral Project, citing the D.C. Circuit's recent ruling in *Sierra Club v. FERC* and the FERC's "lack of a complete environmental review."
- By Letter Order issued on September 15, 2017, the FERC agreed with Millennium, finding that the New York DEC had waived its authority to issue or deny a water quality certification. Because the NY DEC had received Millennium's Section 401 certification in November 2015, but did not rule on it until August 2017, FERC ruled that NY DEC, as the certifying agency, had therefore failed to act within the statutory timeframe and had waived its certification authority.[149] The FERC's order effectively nullified the NY DEC's August 2017 rejection of the water quality certification.
  - The NY DEC, on October 13, 2017, filed a Request for Rehearing and Stay of the FERC's September 15, 2017, Order. On November 15, the FERC denied the requests for rehearing, stay, and rescission.[150]
  - The NY DEC sought review of the FERC's Orders in the Second Circuit. On March 12, 2018, the 2nd Circuit upheld the FERC's determination that the NY DEC waived its authority to act on Millennium's application for a CWA water quality certification by not acting on the application within one year of receipt. In doing so, the Second Circuit rejected the NY DEC's argument that the one-year statutory deadline begins when a state agency deems the application complete, rather than when the application is received.
- Millennium sought, and on October 3, 2017, the FERC granted, a one year extension of time to complete construction of the Valley Lateral Project and make it available for service by November 2018.
- On October 27, 2017, the FERC issued a Notice to Proceed, granting Millennium's request to begin construction of the Valley Lateral.
  - The NY DEC, on October 30, 2017, filed a Request for Stay of the Notice to Proceed. The *November 15 Order* also denied the October 30 request for stay.[151]
- A related project, the Millennium Eastern System Upgrade (CP16-486) received its certificate of public convenience and necessity on November 28, 2017. On March 19, 2018, the FERC denied a request for stay filed by Delaware Riverkeeper Network filed with its request for rehearing of the certificate order.
- On April 4, the FERC approved an amendment to the November 9, 2016 certificate of public convenience and necessity authorizing the Valley Lateral Project to reflect an overall increase in the cost of construction of the facilities.[152]

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[149] *Millennium Pipeline Co., L.L.C.,* 160 FERC ¶ 61,065 (Sept. 15, 2017), *reh'g denied*, 161 FERC ¶ 61,186 (Nov. 15, 2017).

[150] *Millennium Pipeline Co., L.L.C.,* 161 FERC ¶ 61,186 (Nov. 15, 2017) ("*November 15 Order*").

[151] On Oct. 30, 2017, NY DEC also petitioned the United States Court of Appeals for the Second Circuit for a temporary stay of the FERC's Notice to Proceed until the FERC acts on NY DEC's request for rehearing of the Declaratory Order. *In re New York State Department of Environmental Conservation v. FERC*, 2d Cir. No. 17-3503, Petitioner's Emergency Petition for a Writ of Prohibition (Oct. 30, 2017) (Emergency Petition). NY DEC also requested the court to stay the effectiveness of the Notice to Proceed on an interim basis while the court considers the merits of its petition. *Id.* at 34. On Nov. 2, 2017, the court granted an administrative stay pending consideration of the petition by the next available three-judge panel. *In re New York State Dep't of Envtl. Conservation v. FERC*, 2d Cir. No. 17-3503 (Nov. 2, 2017). NY DEC's Emergency Petition is pending at the court.

- **Northern Access Project (CP15-115)**
    - On Feb. 3, 2017, the FERC issued an order authorizing National Fuel Gas Supply Corporation and Empire Pipeline, Inc. 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").
    - In March 2017, Allegheny Defense Project and Sierra Club (collectively Allegheny) filed a request for rehearing of the FERC's order and on August 31, 2017, FERC issued an Order Denying Stay.
        - Consistent with its previous authorization, FERC found no evidence of irreparable harm in letting the project go forward.
    - Despite the FERC's Order, the project remains 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 the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[153] Oral argument was held on November 16, 2017. The Court's decision is pending.
- **PennEast Project (CP15-558)**
    - On September 24, 2015, PennEast Pipeline Company, LLC ("PennEast") filed an application pursuant to NGA Section 7(c) requesting authorization to construct and operate 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").
    - 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.
    - The project is designed to provide up to 1,107,000 Dth/d of firm transportation service.
    - Certificates of public convenience and necessity were granted by FERC on January 19, 2018.[154]
        - Requests for rehearing and motions for stay were filed by opponents of the PennEast Project of FERC's order granting authorization of the project. FERC issued a tolling order on these rehearing requests on February 22, 2018.
        - Delaware Riverkeeper Network sought rehearing of FERC's tolling order arguing that the use of tolling orders deprive it of Constitutional due process. The FERC issued a tolling order of this rehearing request on April 13, 2018.
    - 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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[152] *Millennium Pipeline Co., L.L.C.*, 163 FERC ¶ 61,009 (Apr. 4, 2018).

[153] *National Fuel Gas Supply Corp. v. NYSDEC et al.*, , 2d Cir. No. 17-1164.

[154] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018).

- **Engie/Exelon: Request for Temp. Waiver of Capacity Release Regs. & Policies (RP18-806)**

On May 8, Engie and Exelon, as part of the Everett LNG Terminal sale, jointly request waiver of FERC's capacity release regulations and related natural gas pipeline transportation policies to facilitate the assignment and permanent release of several long-term firm natural gas transportation agreements at existing rates. Comments on the waiver request were due on or before May 21, 2018. ENECOS protested the waiver request. ENECOS asserted that the waiver request does not "constitute a 'fully justified proposal' for the 'non-discriminatory and transparent' release of capacity in connection with the Everett Terminal," a non-open access terminal, because it does not describe the relationship of the waivers sought "to the larger transaction of which those waivers area part". In addition, ENECOS question the assertion that no approval under Section 3 of the Natural Gas Act ("NGA") is required in light of the unaddressed potential for vertical market power associated with the larger transaction. Interventions were filed by NESCOE, MA AG and Taunton Municipal Lighting Plant (out-of-time. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

XIV. State Proceedings & Federal Legislative Proceedings

- **Massachusetts Emissions Allowance Auctions: Stakeholder Input on Auction Design Parameters**

In an action that could have implications for the New England Markets, the Massachusetts (MA) Department of Environmental Protection ("MassDEP") issued on August 11, 2017 final regulations to ensure that MA will meet the 2020 statewide greenhouse gas ("GHG") emissions limits mandated by MA's 2008 Global Warming Solutions Act ("GWSA"). Section 7.74[155] of those regulations reduces carbon dioxide ("CO_2") emissions from MA-based power plants by imposing an annually declining aggregate emissions cap on MA's 21 large fossil fuel-fired generators. Operators of those facilities will have to offset their CO_2 production with allowances (a limited authorization to emit one metric ton of CO_2 in a calendar year). Allowances will be allocated directly in 2018 based on historical generation. Beginning with compliance year 2019, Section 7.74 requires auctioning of the emissions allowances that facilities must use to comply with the regulation. Allowances may be traded between facilities and a limited quantity may be banked from year to year.

On December 15, 2017, MassDEP filed final amendments to correct errors for two facilities in the 2018 allowance allocations. These amendments were published in the Massachusetts register on December 29, 2017. In addition, MassDEP has committed to post on its website compliance forms and an "FAQ" document.

The allowance tracking system will be deployed In the Spring of 2018. Detailed instructions for regulated facilities will be provided at that time. Stakeholder comments on the auction design solicited in the Fall of 2017 will be considered as the MassDEP develops procedures in preparation for allowance auctions that begin in 2019. MassDEP anticipates additional opportunities for stakeholders to participate in the auction design process in 2018, possibly including an opportunity to comment on proposed regulatory amendments. MassDEP is also in the process of soliciting market monitoring services, and will hire an auction administrator in 2018. Questions regarding 310 CMR 7.74 can be directed to Will Space (william.space@state.ma.us; 617-292-5610).

- **NG Advantage (NY) Permit Challenge (RJI No.: 2017-0799; RJI No.: 2017-0800)**

Chenango Valley Central School District and various nearby residents Petitioners have initiated proceedings against the Town of Fenton, New York Planning Board and NG Advantage, LLC to halt NG Advantage, LLC's ("NG Advantage") proposed construction of a natural gas compressor facility that would extract gas up to 4000 psi and transport the compressed natural gas to NG Advantage customers. Petitioners are concerned that the project infringes on the rights of those who live near the transfer station. They are specifically concerned about the site's proximity to schools, and the burden it could place on local roads.

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[155] Additional information about 310 CMR 7.74 (Reducing CO_2 Emissions from Electricity Generating Facilities) is available at: http://www.mass.gov/eea/agencies/massdep/climate-energy/climate/ghg/electricity-generatoremissions-limits.html.

A judicial decision on whether the Town of Fenton followed proper procedures with respect to zoning laws in approving the Project has been held in reserve while Supreme Court Judge Ferris Lebo's reviews oral arguments and submissions. The Project is currently halted pending judgment.

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).

- **Base ROE Complaint IV (2016) (18-1077)**
  Underlying FERC Proceedings: EL16-64[156]
  Petitioner: TOs

On March 15, 2018, the TOs petitioned the DC Circuit Court of Appeals for review of the FERC's *Base ROE Complaint IV Orders*. On April 16, TOs submitted their initial materials, including certificates, docketing statement form, procedural motions, and its statement of issues. The TOs also requested that the Court hold the appeal in abeyance while the FERC completes its proceedings with respect to Base ROE Complaints II and III, committing to submit a report on a periodic basis (e.g. every 90 days) regarding the developments in those proceedings. On April 30, EMCOS moved to dismiss the case for lack of jurisdiction, arguing that TOs seek review of orders that are not final and therefore not subject to judicial review under Section 313(b) of the FPA. On May 10, the TOs opposed and CAPs supported the April 30 motion. TOs and EMCOS filed answers to the May 10 motions on May 17. These motions are pending before the Court.

- **FCM Resource Retirement Reforms (17-1275)**
  Underlying FERC Proceedings: ER16-551[157]
  Petitioner: Constellation

As previously reported, Constellation ("Petitioner") petitioned the DC Circuit Court of Appeals on December 28, 2017 for review of the FERC's *FCM Resource Retirement Reforms Orders*. On April 17, Exelon filed Petitioner's Brief. Respondent FERC's Brief is due next on July 2, 2018. From there, Petitioner's Reply Brief is due July 30, 2018; Deferred Appendix, August 13, 2018; and Final Briefs, August 20, 2018.

- **Demand Curve Changes (17-1110**)**
  Underlying FERC Proceedings: ER14-1639[158]
  Petitioners: NextEra, NRG, PSEG

NextEra, NRG and PSEG ("Petitioners") petitioned the DC Circuit Court of Appeals for a second time for review of the FERC's Demand Curve orders, which, as previously reported, had been remanded back to the FERC at the FERC's request following the first appeal by Petitioners. Briefing was completed on February 1, 2018 and oral argument, before Circuit Judge Wilkins and Senior Circuit Judges Sentelle and Randolph, held April 13, 2018. This matter is pending before the Court.

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[156] *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) ("*Base ROE Complaint IV Orders*").

[157] *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*").

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

- **FCA10 Results (16-1408) and FCA9 Results (16-1068)**
  Underlying FERC Proceedings: ER16-1041[159] ER15-1137[160]
  Petitioners: UWUA Local 464 and Robert Clark

UWUA Local 464 and Robert Clark ("Petitioners") filed petitions for review of the FERC's orders on the FCA10 and FCA9 Results Filings, consolidated by the Court on January 31, 2017. All briefing is complete and oral argument was held before Judges Rogers, Millett and Pillard on February 9, 2018. This matter is pending before the Court.

- **Base ROE Complaints II & III (2012 & 2014) (15-1212)**
  Underlying FERC Proceedings: EL13-33; EL14-86[161]
  Appellants: New England Transmission Owners

As previously reported, the TOs filed a petition for review of the FERC's orders in the 2012 and 2014 ROE complaint proceedings on July 13, 2015. On August 14, 2015, the TOs filed an unopposed motion to hold this case in abeyance pending final FERC action on the 2012 and 2014 ROE Complaints (*see* Section I above). On August 20, 2015, the Court granted the TOs' motion to hold the case in abeyance, subject to submission of status reports every 90 days. The most recent status report, the eleventh such report filed, was filed on May 12, 2018. In that report, the parties again indicated, ultimately, that the proceedings upon which the TOs based their request for abeyance of this appeal remain ongoing. This case continues to be held in abeyance.

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[162] EL15-23[163]
  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).[164] 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 to 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.

Other Federal Court Developments of Interest

- ***California Public Utilities Commission v. FERC* (9th Cir., 16-70481)** (Jan. 8, 2018)

In a decision that could impact how the FERC approaches future orders on ROE filings, the Ninth Circuit Court of Appeals held that the FERC acted arbitrarily and capriciously, and erred, by granting a transmission owner (PG&E) an incentive adder for its participation in an RTO (CAISO) where the participation by the TO was not voluntary. Doing so created a generic incentive adder (for TO participation in an RTO) in contravention of Order 679's requirement of case-by-case review of adders to be granted, which were designed to induce voluntary RTO participation. The Ninth Circuit remanded the matter back to the FERC with instructions to follow the appeals court's reasoning.

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[159] 155 FERC ¶ 61,273 (June 16, 2016); 157 FERC ¶ 61,060 (Oct. 27, 2016).

[160] 153 FERC ¶ 61,378 (Dec. 30, 2015); 151 FERC ¶ 61,226 (June 18, 2015).

[161] 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).

[162] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[163] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

[164] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018).

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