NEW ENGLAND POWER POOL

David T. Doot
Secretary

July 26 , 2019

VIA ELECTRONIC MAIL

TO: NEPOOL PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of August 2, 2019 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, August 2, 2019, 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_2019.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 **866-769-8920; Passcode: 7811245.**

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the Participants Committee Summer Meeting held June 25-27, 2019. The preliminary minutes, marked to show the changes from the version circulated with the initial notice, are included and posted with the meeting materials.

2. To adopt and approve all actions recommended by the Technical Committees set forth on the Consent Agenda included with this 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 the following revisions to implement the ISO's "Import Resource Transaction Requirements & Clean Up" proposal:

   a. Revisions to Market Rule 1, Manual M-11 (Market Operations) and Operating Procedure (OP) No. 9 (Scheduling and Dispatch of External Transactions), as recommended by the Markets Committee at its July 8-10, 2019 meeting; and

   b. Revisions to OP-5 (Resource Maintenance and Outage Scheduling), as recommended by the Reliability Committee at its July 16-17, 2019 meeting.

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

6. 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.

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

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

8. To receive a report on administrative matters.

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

PRELIMINARY

The 2019 Summer Meeting of the NEPOOL Participants Committee was held at Gurney's Resort, Newport, Rhode Island, on Tuesday, June 25, and Wednesday, June 26, pursuant to notice duly given, followed on Thursday, June 27, by meetings between modified Sector groups and ISO Board Members, and state regulators and officials, respectively. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. All motions acted on at the meeting were voted on Tuesday, June 25. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting and voting that day.

Ms. Nancy Chafetz, Chair, presided and Mr. David Doot, Secretary, recorded for the meeting.

JUNE 25, 2019 SESSION

The June 25, 2019 session began at 8:30 a.m. with Ms. Chafetz offering welcome remarks.

EXECUTIVE SESSION: APPROVAL OF BALLOTING FOR PROPOSAL REGARDING AGE LIMITS FOR ISO BOARD NOMINATIONS

Before going into executive session, Ms. Chafetz explained the matter to be discussed in executive session related to a proposed amendment to the Participants Agreement (PA) that would authorize the Joint Nominating Committee (JNC) to waive the current 70-year old age limit for candidates presented for election to the ISO Board. Referring to materials circulated in advance of the meeting and posted with the meeting materials, she explained to the Committee that the authority proposed for the JNC under the amendment would mirror the authority the JNC

had to waive the three consecutive full-term limit. She also explained that the ISO made clear that it was not willing to engage in broad negotiations at that time about other changes to the PA.

Mr. Doot reviewed that, under the NEPOOL process for considering changes to the PA, the Committee needed first to authorize by a 66.67% Vote the balloting of the amendment. If balloting was authorized, the amendment would then need to be balloted and the ballots returned would need both to meet the Minimum Response Requirement and to achieve a 70% Vote in favor. The ISO would also need to approve execution of the amendment, and the amendment would need to be filed with and accepted by the FERC. The JNC, based on all feedback and discussion, would then recommend a slate of three candidates for consideration by the Participants Committee later in the year.

The Committee began discussions while still in general session and while ISO representatives were still in the room. Ms. Janice Dickstein, ISO Vice President, Human Resources, responded to some member questions, referring to the ISO memorandum that had been circulated and posted in advance of the meeting. She noted that not only is the pool of potentially qualified candidates reduced by the current age limit concerns, but that Mr. Roberto Denis, whose second term ends in 2020, would be ineligible for a third term if the age limit remained in place as drafted. The ISO confirmed that, while it would prefer elimination of the age limit or a higher age limit, the proposal was acceptable to the ISO.

Members began conveying their views on the matter with the ISO representatives present. Those views reinforced views summarized in the materials circulated and posted in advance of the meeting. There was discussion about the potential timing for JNC notice of any waiver and the NEPOOL process for soliciting NEPOOL feedback on the potential waiver before it was granted. During that discussion members were assured by current JNC members present and

with Ms. Dickstein's affirmation, of the following: (1) that the Participants Committee would have the opportunity for timely review in executive session of the Board members being considered for an age or term limit waiver before the JNC were to grant any such waiver; and (2) that the JNC acts by consensus where it has not approved actions that are strenuously opposed by one or more of the JNC members. A number of members noted that those assurances were important to and required for their willingness to support the proposal.

ISO representatives and guests then left the room and the Committee went into executive session. At the conclusion of discussions in executive session, the following motion was duly made and seconded:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of changes to Section 9.2.3 of the Participants Agreement, substantially in the form circulated to this Committee in advance of this meeting, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer, together with such non-material changes as the Participants Committee Chair and Vice-Chairs may approve; and
>
> FURTHER RESOLVED that the Chair of the Participants Committee is authorized to execute an amendment on behalf of NEPOOL reflecting those changes if those changes are approved in balloting.

The Committee approved the motion with a 76.88% Vote in favor (Generation Sector – 11.19%; Transmission Sector – 16.79%; Supplier Sector – 13.59%; AR Sector – 16.04%; Publicly Owned Entity Sector – 16.46%; and End User Sector – 2.81%). (See Vote 1 on Attachment 2).

GENERAL SESSION

The Committee came out of executive session at 10:00 a.m. and was joined by ISO representatives and guests. Ms. Chafetz welcomed the members, alternates, federal and state officials and guests who were present.

APPROVAL OF MAY 3, 2019 MEETING MINUTES

Ms. Chafetz referred the Committee to the preliminary minutes of the May 3, 2019 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the May meeting were unanimously approved, with an abstention noted by Michael Kuser.

CONSENT AGENDA

Ms. Chafetz referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Mr. Doot noted that Consent Agenda Item #3 included some but not all of the required updates to the Tariff definitions (those not included stricken from the applicable footnote in the revised Consent Agenda). As a result, the Reliability Committee would be considering further definitional changes for consideration by the Participants Committee at its August meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved, with an abstention noted by Michael Kuser.

NESTED EXPORT-CONSTRAINED CAPACITY ZONE CHANGES

Ms. Chafetz referred the Committee to a package of Markets Committee-recommended changes to the Forward Capacity Market (FCM) rules, circulated and posted with the meeting materials in advance of the meeting. She described that those FCM rule changes would

accommodate nested export-constrained Capacity Zones in the FCM, which may be modeled for the Capacity Commitment Period beginning June 1, 2023 (CCP14) and would clarify certain data submittal of costs and revenues for Static De-list and Export Bids in the FCM. She reported that the Markets Committee recommended Participants Committee support for this package of Tariff revisions at its June 12, 2019 meeting and, but for the timing of the Markets Committee recommendation, this matter would have been on the Consent Agenda.

The following motion was duly made, seconded, and unanimously approved without discussion and with abstentions noted by Brookfield, Calpine, Jericho, Verso, and Michael Kuser:

> RESOLVED, that the Participants Committee supports the package of Tariff revisions to the Forward Capacity Market rules, as recommended by the Markets Committee at its June 12, 2019 meeting, and as reflected in the materials distributed to the Participants Committee for its June 25, 2019 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Markets Committee.

ISO CEO REPORT

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

Mr. van Welie stated that he would like to take the opportunity to continue a conversation initiated by the states at the 2019 New England Conference of Public Utilities Commissioners (NECPUC) Symposium concerning whether the markets original objectives are still relevant, particularly given state procurements in fulfillment of policy goals. He observed that some states clearly believed the market should better accommodate state policies, perhaps by allowing state

sponsored resources to enter the market without mitigation, while other states still strongly supported achieving desired outcomes through the competitive markets. Notwithstanding those differences among the states, he believed all could agree that the region's power system was undergoing a dramatic and rapid transformation. When competitive markets were introduced, he continued, they allowed for the rapid deployment of gas-fired generation, followed by significant investments in energy efficiency and distributed resources, including solar photovoltaic (PV) and demand-side resources. The states' efforts to contract for new, renewable energy was accelerating the change in the generation mix, as evidenced by the ISO's interconnection queue. He stated that the rapid introduction of low- and zero-marginal-cost resources would have a significant impact on energy market prices over time, particularly in the off-peak seasons, and would make merchant resources much more dependent on revenues from the capacity market and the ancillary services markets as their energy market revenues decrease. Further, as states pursue decarbonization policy goals through other supplementary measures, such as emissions limitations, it would become increasingly more difficult for the region's high-carbon resources to continue operating. That combination of factors, he predicted, would lead to retirements in the existing fleet with a likely result that the region's energy constraints would become more severe during periods of very cold weather when the gas pipelines were constrained.

Against this backdrop, Mr. van Welie stated the ISO still believed that the markets' primary objectives remained relevant and the ISO's objective remains to maintain competitive markets that are balanced between buyers and sellers. The ISO also recognized the New England market design had to be adapted to address the power system's transformation over this period, particularly as long-term decarbonization strategies begin to tie other sectors of the economy to the power system. He referred to the ISO's Strategic Themes, which were recently distributed to

the Participants Committee, that outlined the ISO's goal to ensure reliability through competitive markets, including ensuring appropriate price formation for needed reliability services, and making the necessary adjustments to accommodate evolving state policies and new resources coming on the system. The Strategic Themes went beyond the markets to incorporate other changes that would be necessary as a result of the evolution of the power supply, noting state-sponsored behind-the-meter (BTM) resources would have a profound impact not only on system operations but also on the transmission infrastructure, and interconnection of grid-scale renewable resources would have a big impact on the transmission system. Those changes he predicted would clearly push the region to innovate and to make changes to operations and planning practices. Noting his interest in the presentation the following day by National Grid's representative concerning how National Grid was managing this transition in the United Kingdom (UK), Mr. van Welie reported that he had recently attended a U.S./European forum on energy transition. He reported being struck by how similar the discussions were on both sides of the Atlantic, including the importance of appropriate pricing in markets for reliability services, the need for new reliability services as the power system changes operational dynamics, the transmission investments needed in order to enable the deliverability of renewable energy, and the adaptation of operational practices to these new realities.

Mr. van Welie suggested that New England was rapidly catching up to Europe and California with respect to the deployment and integration of renewable energy, and was ahead of those regions with its energy security constraints. He noted that he had not identified another region with winter constraints like New England's, making New England's situation more complex than other regions seeking to decarbonize. New England had a strong, proven record of solving difficult problems and while the journey appeared challenging, he was confident that the

region would work together to produce the innovative solutions that would enable the region's transition to a low-carbon power system.

The Committee then commented and asked questions. A member commented that he hoped the ISO, in its role as the independent arbitrator for reliability in the region, would take a more proactive role going forward rather than a highly reactive role, settling for Reliability-Must-Run (RMR) agreements to retain resources needed for system reliability. Mr. van Welie agreed and said the ISO was committed to solving the challenges through the markets. He noted that other regions taking a power system through a transformation to a low-carbon system each required a balancing energy source, which was predominantly hydro or gas. He stated the ISO would continue to push to try to make sure there was sufficient revenue in the wholesale market to pay for the services that are needed.

Referring to Mr. van Welie's comment that circumstances would incent innovation, a member predicted that the region would have to innovate more quickly over the next 20 years.

In terms of timing, a member asked how this impacted the Chapter 3 discussions underway. Mr. van Welie responded that energy security design was the current focus but would naturally lead to other conversations. Mr. van Welie disagreed with the observations by a member that the ISO's objectives have changed or should change from where they started 20 years ago. He explained that the ISO still viewed the primary objective to ensure reliability through a competitive wholesale power structure. He stressed the need for a set of services from generators in order to accomplish that objective. Concerning whether the market should support additional objectives, as for example market-based solutions to environmental objectives, Mr. van Welie stated that the ISO had concluded such efforts would exceed its jurisdiction and mission as currently defined.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the June COO report that had been circulated in advance of the meeting and posted on the NEPOOL and ISO websites. Summarizing, he reported that May temperatures were quite cool. Real-Time loads were down 5% from loads previously, with average loads of 11,500 MW, the lowest since 2003. He then summarized the following: (i) total Energy Market value was $226 million, down $27 million from April 2019 and $21 million from May 2018; (ii) average natural gas prices in May were 8.9% lower than in April; (iii) average Real-Time Hub locational marginal prices (LMPs) ($22.89/MWh) were 15% lower than April LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 99.1% in May, up from 97.8% in April (the lowest value for the month of May was 94% on May 21); and (v) daily Net Commitment Period Compensation (NCPC) for May totaled $2.1 million, up $0.1 million from April and down $2.6 million from May 2018. May 2019 NCPC was 0.9% of the total Energy Market value and was comprised of (a) $1.6 million in first contingency payments, down $0.4 million from April, and (b) $465,000 in second contingency payments, up $248,000 from April (due to transmission-related outages in Maine). He reported that Pilgrim Station shut down on May 31, which was the second nuclear unit retired in New England over the past several years. He said that May 31 also marked two new resources coming on-line, a fast-start unit in Southeast Massachusetts (SEMA) and a dual-fueled unit in Connecticut, totaling about 1,000 MW.

With respect to June, Dr. Chadalavada observed that the modest temperatures during the first two weeks of June produced low Real-Time loads and NCPC. He said most of the load

cleared in the Day-Ahead Market. He reported that June 1 marked the implementation of the do-not-exceed (DNE) dispatch limit for intermittent resources, which was a must-offer requirement that was placed on mostly wind and hydro resources as part of the continuing implementation path for that resource category. He reported that there was an approximately 125 MW increase in resources offered in the Day-Ahead Energy Market as a result of those market changes, but there was no appreciable change in LMPs given the low load conditions and fairly modest amounts of capacity participating.

Focusing on the future, he reported that the Boston Needs Assessment had been published. He stated the ISO would issue its first request for proposals (RFP) for competitive transmission solutions in late 2019/early 2020. He said that the FCA14 process had begun with the ISO receiving a record number (over 700) Show of Interest applications (SOIs) representing about 18,500 MW of potential new resources. He reported that Maine, for FCA14, would be modeled as a nested zone within the Northern New England zone.

In response to questions from the Committee, Dr. Chadalavada noted that the ISO was continuing to study how passive demand resources are functioning in the market, and would report on the results of those studies to the extent permissible under the Information Policy. He acknowledged concerns voiced by generator representatives over the record number of SOIs in light of pending proposals to reduce the chance for new resources to profit from shedding their Capacity Supply Obligations (CSOs) before becoming commercial. While the ISO agreed there was a problem, it did not support the solution proposed by generators and was working through the stakeholder process a different solution of its own to provide incentives to supply without creating unreasonable barriers to new entry. As for timing, he was uncertain whether a solution could be implemented in time for FCA14. Responding to a question regarding the impact of the

Pilgrim shutdown on out-of-merit commitments, Dr. Chadalavada said that the ISO expected little or no need for out-of-merit commitments if all the transmission lines on the SEMA interface were in-service and loads were under 18,000 MW. Whether such commitments would be needed for loads above 18,000 MW would depend on what resources cleared in the Day-Ahead Energy Market.

FERC REGIONAL UPDATE

Ms. Chafetz welcomed, introduced and thanked FERC Staff for their attendance and participation. Ms. Jette Gebhart, Deputy Director, Office of Energy Market Regulation (OEMR), then provided remarks. She began by making clear that her remarks were her views and opinions, and not those of the Commission. She introduced the other representatives of FERC staff who were present.

Ms. Gebhart described OEMR's functions, summarizing that, in 2018, OEMR had handled approximately 5,500 electric, 1,500 pipeline, and 700 oil rate filings. Following this summary, she noted ~~specifically~~ that OEMR was working through the compliance filings submitted in response to Commission orders on energy storage and generator interconnections.

Ms. Gebhart highlighted the July 15, 2019 publicly-noticed pre-filing conference to discuss New England's upcoming fuel security filing. She explained that holding a pre-filing discussion in this way was somewhat unusual, but had been structured to ensure discussion of the filing could be accomplished without violating the Commission's *ex parte* rules. She said Staff hoped to become better informed about how the proposals would affect other aspects of the New England Markets and various stakeholders. She urged that those communicating with the Commission on this and other matters take into account that a number of the Commissioners

were still relatively new to the Commission. Accordingly, they would benefit from receiving historic and contextual information relating to filings they receive, as well as a clear understanding of the impact of those filings on various interest groups. She acknowledged that NEPOOL had many different interests at the table with differing views on changes being proposed. She said the Commission benefits from hearing from a variety of perspectives, not only on the fuel security issues to be addressed on July 15, but on other important issues facing the region.

Next, Ms. Gebhart summarized the following priorities of Chairman Neil Chatterjee, that he had highlighted in previous public remarks:

- Review of liquefied natural gas (LNG) facility applications
- Cyber security issues facing both the electric sector and natural gas pipelines
- Energy storage, as set forth in Order 841
- , as well as continuing the FERC's work on aggregation of ~~Changes to encourage~~ distributed energy resources (DER)
- Refinements to transmission-related matters before the Commission
    - Order 1000 – was it working? Where could it be improved?
    - Was the right transmission being built?
    - Transmission rate issues, with Notices of Inquiry on setting base returns on equity (ROEs) and transmission rate incentives
- The ongoing inquiry, initiated in January 2018, into ensuring resilient electric bulk power facilities~~, including discussions with the RTOs and ISOs on fuel security issues and states on shared areas of interest~~.

She went on to observe that the other Commissioners also had their individual priorities and interests. Leaving Commissioner LaFleur, who would speak later in the meeting, to outline her own priorities, Ms. Gebhart said Commissioner Glick spoke in public often about his interest in ~~ensuring~~ the increasing deployment on the grid of renewable resources and new technologies and ~~was very focused on what else the Commission could do to reduce the industry's~~

~~contribution to~~the FERC's consideration of climate change in its work. Commissioner McNamee's public statements had emphasized ~~how LNG could impact the system, had focused on rate matters, including rate reductions flowing from the federal Tax Cut and Jobs Act~~the FERC's work on LNG, and had recently raised jurisdictional questions over the authority of the FERC versus the states relating to energy storage~~ and DER~~.

Focusing more broadly, she noted that three of the four sitting Commissioners came to their current positions ~~with deep political~~from backgrounds~~, backgrounds that sometimes change the tenor of the discussions among the~~ different from those of other recent Commissioners. Notwithstanding ~~that difference~~changes on the Commission, she explained, the traditional role of FERC Staff, which is to provide sound, thorough and balanced legal and technical advice, did not change. She then concluded her update, inviting questions from the Committee.

Responding to a question regarding the Chairman's priority on transmission and what he thought the right transmission is, Ms. Gebhart stated she could not speak for the Chair. She went on to note that the Commission continues to hear from a variety of sectors about the need to interconnect new generation and was very aware, given ~~the number of~~recent and pending proceedings on interconnection queues and delays, the issues faced there. In response to how FERC Staff was keeping up with the rapid technology changes and how those changes influenced Staff's thinking on filings before the Commission, Ms. Gebhart stated that each of the Commissioners had publicly recognized the changes, including the new technologies, facing the grid and its many sectors. By way of example, ~~S~~she noted that the FERC had in recent years done more thinking about storage and DER, and how to ~~facilitate the entry~~ensure fair treatment of new technologies~~, a focus that had not subsided, and which she opined was very encouraging~~. She acknowledged that, as technology, the grid and policies change, incremental changes may be

needed where a "one size fits all" solution may not be viable. ~~She contended that incremental changes could and should be acceptable, dismissing suggestions that a particular market design is not just and reasonable when proposed because it did not last for 10 years or more.~~ The just and reasonableness of any proposal at the time proposed is what Staff must ~~and would~~ focus on. She was asked how Commissioners' political backgrounds might affect how Staff prepares the record and their recommendations. Ms. Gebhart responded that Staff works to provide Commissioners with all the background and relevant information they need to address the questions before them. ~~This objective, by its very nature requires staff to take into account the Commissioners' backgrounds.~~

ISO CFO REPORT: 2020/2021 ISO BUDGETS

Mr. Robert Ludlow, the ISO's Chief Financial Officer (CFO), referred the Committee to the presentation of the ISO's 2020 and 2021 preliminary Operating and Capital Budgets (Budgets) included with the materials posted in advance of the meeting. He reported that he had also shared this information with state officials at the 2019 NECPUC Symposium.

Mr. Ludlow discussed the following key components that were driving changes to the 2020 and 2021 Budgets from 2019's Budgets: compensation and inflationary costs; Order 1000 implementation (including project management and legal activities); network modeling and Energy Management System (EMS) maintenance (reflecting significant increases in renewable resources and other new power system technologies and related complexities); cyber security (both compliance and operational costs); and energy security and other market improvements (including implementation costs for the Competitive Auctions with Sponsored Policy Resources (CASPR)). He summarized that the 2020 Operating Budget was projected to reflect an overall

increase over 2019 of about 4.5%, and the 2020 Capital Budget was projected to be $28 million, which remained unchanged from the 2019 Capital Budget.

Beyond 2020, Mr. Ludlow explained that the ISO was not able to project a reliable 2021 "look ahead" forecast because of the significant, but as yet unspecified, scope of investments in software systems and settlement processes to be driven by the energy security market design. He indicated, though, that the changes would likely require an increase in the 2021 Capital Budget.

Focusing on process, Mr. Ludlow reported that the ISO planned to discuss the 2020 Budgets with state officials again on August 12, and with the NEPOOL Budget & Finance Subcommittee on August 9. The 2020 Budgets would then be submitted with any feedback received to the ISO Board's Audit & Finance Committee on August 22. The ISO would then review feedback received with its full Board on September 12. The Participants Committee was scheduled to vote on the final proposed Budgets at its October 4 meeting, and the final ISO Board vote would be taken following that Participants Committee meeting. The ISO plans to file the 2020 Budgets with the FERC later in October, with a requested effective date of January 1, 2020.

ISO IMM ANNUAL REPORT

Dr. Jeffrey McDonald, the ISO's Internal Market Monitor (IMM), presented highlights from the IMM's 2018 Markets Report (IMM Annual Report), which had been circulated and posted in advance of the meeting. Summarizing, he noted that total wholesale costs were 33% higher than 2017, attributed to the cost of electricity, driven by the cost of natural gas, which was also 33% higher than 2017. The uniformly higher capacity prices for Capacity Commitment Periods 8 and 9 also contributed to overall higher wholesale electricity costs.

He reported that there was a higher level of competitiveness in 2018, especially in the Energy Market, and reviewed the measures used by the IMM to gage that, including the use of price cost markups and the Residual Supply Index. Further, the IMM saw a much lower incidence of pivotal suppliers, driven by higher reserve margins (due to improved generator availability and presence of price-responsive demand in the energy and reserve markets) and a dilution of market share (due to a reduction in one major generation portfolio and relatively large new entrants and changes in control of other portfolios).

Dr. McDonald then referred the Committee to charts reflecting mitigation levels and fuel prices. Focusing on mitigation, he reviewed the system-wide Residual Supply Index duration curve and price cost mark-ups and frequency of mitigation events by type, noting the downward trend in mitigation levels over the past several years. Reviewing fuel prices, he reported an increase in prices for all major fuels, noting the increase in oil prices was primarily due to a reduction in oil production by the member countries of OPEC (Organization of the Petroleum Exporting Countries). He reported natural gas prices on average increased in 2018, largely attributed to the prolonged cold snap that ran from the end of December 2017 into the first weeks of January 2018. In response to a question, Dr. McDonald stated natural gas prices were based on the Algonquin pipeline prices, not delivered prices. He noted that the price increases in January were largely the result of transportation constraints into New England.

Turning to CO_2 prices, he reported that New England (RGGI) and Massachusetts (MA) CO_2 prices added to the cost of generation in New England. He stated the RGGI prices increased 25% in 2018 compared to 2017, from $3.59 to $4.50/short ton, which translated to approximately $2/MWh. He attributed some of that price increase to an anticipated 30% reduction in the CO_2 cap by 2030. He reported that, in January 2018, MA began a new CO_2 cap-and-trade program

(MA Program), in addition to RGGI, with prices starting at about $20/short-ton and declining, with increased market certainty, to about $10/short ton by the end of the year. He concluded that MA generators were reflecting their additional costs of the MA Program in their supply offers. In response to questions, he confirmed that affected MA resources saw a $4-8/MWh increase in their costs over non-MA resources, but the IMM did not have enough data to assess what impact, if any, that had had on LMPs. He agreed that it was possible that, as a result of the MA Program, less efficient/higher heat rate units not subject to the MA Program might be dispatched ahead of cleaner MA generators, which could increase CO_2 emissions for the region.

Dr. McDonald then reviewed a chart reflecting annual load by quarter. He reported that, in the third quarter (Summer 2018), compared to the same period in 2017, there was an 8% increase in load, which subsequently contributed to an annual load increase of 2% in 2018. A member noted the considerable load variability reflected not just between years, but between quarters within a year, and asked whether this provided any insights for the IMM's assessment of Chapter 3. Dr. McDonald stated that the IMM would make a point of considering the impact of inter-seasonal variations on forward procurements and the potential price suppressive effects.

Dr. McDonald reviewed a 2014-2018 comparison of weather-normalized load over all hours that had been reconstituted to include the effects of energy efficiency (EE) and BTM solar. The vast majority of the reduction in load (over 2,000 MW in 2018) was attributable to EE, but the impact of BTM solar was growing year-over-year.

He turned to a chart addressing NCPC, which showed an increase in 2018 after four consecutive prior years of decline. He explained that the increase was largely driven by out-of-market posturing and higher fuel prices during the January 2018 cold snap, which saw an increase in both the quantity (given fuel uncertainty during that period) and the price of the

make-whole payments. He explained that, among the lessons learned from the cold snap, was a recognition, particularly in light of the manual posturing undertaken, that the opportunity costs of fuel-limited resources must be appropriately valued in the market clearing and resulting market prices in both the Day-Ahead and Real-Time Energy Markets. He credited Dr. Chadalavada with instituting an expedited internal design and implementation process in response to those lessons learned to ensure that, going into Winter 2019/20, the region would have an appropriate valuation of opportunity costs for, and efficient allocation and dispatch of, fuel-limited resources.

Turning to a slide illustrating the costs of Ancillary Services over the prior five years, he noted that overall costs were relatively unchanged over the last three years. Addressing a question about the Net Forward Reserve component, he explained that the higher values in 2014 and 2015 resulted from the inability of generation to meet certain local requirements, which resulted in prices hitting the cap in those areas, driving up prices. Those circumstances had not occurred since.

Dr. McDonald concluded his presentation by reviewing charts that provided an overview of the FCM over the prior eight periods. He expressed his hope that the charts would provide useful context for the continued discussions assessing the FCM. He noted that the market response was largely consistent with expectations (i.e. higher prices and increased new entry when the system was short and, conversely, lower prices when the system was long). He noted, however, that despite lower prices over the prior few years, retirements had not increased and the system was long on capacity. He acknowledged that the retention of units for fuel security reasons had contributed to that outcome, but opined that the system would still have been long without those units being retained and expressed interest in how future FCM procurements would impact the system's return to equilibrium.

PARTICIPANTS-SPONSORED PROPOSAL: ADDITION OF AFFILIATE GUARANTEES AND SURETY BONDS TO ISO-NE FAP

Mr. Ken Dell Orto, Budget & Finance Subcommittee (Subcommittee) Chair, referred the Committee to the materials circulated and posted in advance of the meeting concerning a Participants-sponsored proposal (the Proposal) to change the ISO New England Financial Assurance Policy (FAP) (i) to permit Market Participants to rely on an affiliate guaranty as a means of obtaining an unsecured Market Credit Limit or Transmission Credit Limit and (ii) to add surety bonds as an acceptable form of financial assurance. He noted that the Proposal was sponsored by Calpine, Direct Energy, Dominion, Exelon, MMWEC, NextEra, and PSEG (the Sponsors). He summarized the process that had been followed to review the Proposal and the input provided at Subcommittee meetings.

The Committee discussed the Proposal. Advocating in favor of the Proposal, the Sponsors and others argued that the Proposal potentially would produce cost savings, which would benefit consumers and that similar financial instruments were available to market participants in other organized markets. A Publicly Owned Entity representative suggested that the changes would reduce the burden on small municipal entities without increasing risk to the region. Another Sponsor representative explained how the Proposal could improve competitiveness in standard service solicitations and other load-related contracts. Sponsors also noted that unsecured credit was already permitted in New England, with risks shared amongst those in the unsecured credit risk pool, rather than more broadly across all Participants.

Other Participants expressed concerns with the proposed changes. They argued that the limited financial instruments proposed would only be available to Participants with significant

market capitalization or access to creditworthy entities. They also referred to points raised by the ISO in explaining its opposition to the Proposal.

The ISO then described its position, referring to its memorandum, which was circulated and posted with the meeting materials. The ISO highlighted the importance of the risk management role of the FAP in ensuring that all Market Participants would be paid on time and in full. The ISO was concerned that would not occur with guarantees and surety bonds. The ISO noted, in response to other questions, that it considered guarantees and surety bonds to present greater risk to the region if bankruptcies of the related Market Participants occur. The ISO added that it would not be in a position to independently verify or monitor the breadth or scope of parent guarantees that an entity might have in place in other regions or for other purposes.

At the conclusion of discussion, the following motion was then duly made, seconded and voted:

> RESOLVED, that the Participants Committee supports revisions to the ISO New England Financial Assurance Policy, as proposed by Calpine Energy Services, LP, Direct Energy Business, LLC, Dominion Energy Generation Marketing, Inc., Exelon Generation Company, LLC, Massachusetts Municipal Wholesale Electric Company, NextEra Energy Resources, LLC and PSEG Energy Resources & Trade LLC and as circulated to this Committee for its June 25, 2019 meeting, together with such non-substantive changes as the Chief Financial Officer of ISO New England and the Chairman of the Budget & Finance Subcommittee may approve.

The motion failed to pass with a 45.13% Vote in favor (Generation Sector – 16.79%; Transmission Sector – 0%; Supplier Sector – 11.55%; AR Sector – 9.44%; Publicly Owned Entity Sector – 7.35%; and End User Sector – 0%;). (See Vote 2 on Attachment 2).

FUELS INDUSTRY PARTICIPANT ARRANGEMENTS

Referring to the materials circulated and posted in advance of the meeting, Mr. Patrick Gerity, NEPOOL Counsel, summarized the reasons for, and substance of, the two actions being requested of the Participants Committee, both in response to the membership application of the American Petroleum Institute (API) and its consideration by the Membership Subcommittee (Subcommittee). First, at the recommendation of the Subcommittee, the Participants Committee was being asked to authorize and direct the Balloting Agent to circulate ballots for approval of limited amendments to the NEPOOL Agreement that would expand the definition of Gas Industry Participant (to be renamed "Fuels Industry Participant") by authorizing the Participants Committee to determine on a case-by-case basis whether applicants, such as API, not meeting the existing eligibility criteria for Gas Industry Participant, should be approved as a Fuels Industry Participant.

The following motion, on this first request, was duly made and seconded:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of changes to the Second Restated NEPOOL Agreement (that define and address the arrangements for Fuels Industry Participants), but with such non-material changes therein as the Chair of the Membership Subcommittee may approve, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.

A member speaking on behalf of two Participants (VEIC and NH OCA) expressed their hesitation to support on a routine basis the participation by Fuels Industry Participants, but also their acknowledgement that such participation could provide perspectives and the benefits of expertise useful to the region's deliberations. Without further discussion, the Committee

considered and approved by a show of hands the motion to authorize and direct the balloting of the limited amendments, with an opposition by VEIC[1] and an abstention by Michael Kuser noted.

Turning to the second requested action, Mr. Gerity explained that the Subcommittee recommended that the Participants Committee make the determination at this meeting that API is a Fuels Industry Participant if the amendments just approved for balloting are finally approved and become effective. He explained that approval of the recommendation now would avoid the need for further Participants Committee action on the API membership application.

The following motion was then duly made, seconded and, subject to the same comment on the prior motion, approved with an opposition by VEIC and an abstention by Michael Kuser noted:[2]

> RESOLVED, that, subject to Participants Committee approval in balloting and FERC acceptance of the amendments to the Second Restated NEPOOL Agreement regarding Fuels Industry Participants, American Petroleum Institute is determined as permitted by those amendments to be a "Fuels Industry Participant".

LITIGATION REPORT

Mr. Doot referred the Committee to the June 21 Litigation Report that had been circulated and posted in advance of the meeting. Noting the high level of activity, he highlighted developments in the following four proceedings: (i) the Regional Network Service/Local Network Service (RNS/LNS) Rates and Rate Protocols proceeding, EL16-19, where the FERC had rejected the proposed settlement and the proceeding was headed to hearings; (ii) the FCA13 results filing, ER19-1166, where the FERC had issued a deficiency letter with the ISO's response

[1] The NH OCA was absent from the meeting but had expressed its opposition to the motion through another Participant representative.

[2] *See* prior note regarding NH OCA opposition.

due July 8; (iii) the ISO's Interim Winter Energy Security (Chapter 2B) proposal proceeding, ER19-1428, where comments on the ISO's response to the FERC's May 8 deficiency letter were due June 27; and (iv) a proceeding addressing retroactive surcharges in PJM, EL08-14, where the FERC had reversed its prior position on the issue of ordering refunds in cost allocation and rate design cases, finding that it has the authority to order refunds to fix errors, even if refunds require surcredits or surcharges on other market participants. He requested that anyone with questions on the Report to contact NEPOOL Counsel.

COMMITTEE REPORTS

Budget & Finance Subcommittee. Mr. Dell Orto reported that the Subcommittee was scheduled to meet twice in August, first on August 9 to review the ISO's proposed 2020 Operating and Capital Budgets and NESCOE's proposed 2020 Annual Budget, and second on August 19 to continue discussion of the ISO's proposal to adjust the FAP to account for non-commercial resources.

Transmission Committee. Mr. José Rotger reported that the Transmission Committee was scheduled to meet next at its July 16-17 joint summer meeting with the Reliability Committee, with topics to include the annual review of the RNS formula rates, continued discussion of Attachment K changes to enable competitive solicitation for the Boston Needs Assessment, and clarification of Schedule 22 and the Interconnection process related to procedures for market exits (retirements and Permanent De-List Bids).

Markets Committee. Mr. Fowler reported that the next regularly-scheduled Markets Committee would be held July 8-10. He noted a special meeting was scheduled for July 30, which would include a first look at the ISO's impact assessment on the energy security program.

OTHER BUSINESS

Mr. Doot reminded members of the public, FERC staff-led meeting to be held July 15 at FERC headquarters. All those interested were encouraged to participate in-person or through the FERC's free webcast. Members were directed to the FERC calendar for details.

He also advised the Committee that the next Participants Committee meeting, scheduled to be held August 2, was likely to be a teleconference meeting.

REMARKS BY FERC COMMISSIONER CHERYL LAFLEUR

Ms. Chafetz welcomed and introduced Commissioner Cheryl LaFleur, noting that Commissioner LaFleur's nine-year tenure at the FERC was coming to an end in August. She thanked Commissioner LaFleur for the time and attention provided to the region.

Commissioner LaFleur noted FERC Staff in the audience and reminded the Committee that her remarks were hers and not the opinions of the Commission, and that she could not talk about any issues pending before the Commission, which would be considered *ex parte*. She outlined the three broad themes facing the electric industry in New England and elsewhere: (1) what resources would be on the system in the future; (2) how payment to those resources would be determined; and (3) how the industry would get the infrastructure built to deliver energy from those resources to market.

As to the first theme, she said that resource selection and who decides on that selection were critical issues everywhere, but especially so in the Eastern markets that rely on mandatory capacity markets. She said the markets in New England and the other Eastern regions reflected an underlying decision that resource selection be accomplished through competition and an auction structure, rather than administratively through integrated resource planning. She

expressed her view that the markets had accomplished well what they were designed to do: they had provided reliability at least cost through regional dispatch, facilitated innovation in new technologies, and shifted investment risks from customers to shareholders. She reported that 54% of the New England resources, on a nameplate capacity basis, became operational after the introduction of the organized markets in 1999, which she said was a larger percentage than any other Eastern market. She noted that New England and PJM states increasingly were playing a more directive role in the transition to the resource mix of the future, either by encouraging distribution companies and their customers to procure energy from new resources that might not be selected in a competitive market, or by requiring retail customers to subsidize certain existing resources. She acknowledged that renewable portfolio standards (RPS) predated the market, but noted that the scope and scale of state involvement has been growing.

Commissioner LaFleur reminded the Committee of the FERC's two-day technical conference on state initiatives and how they would require changes in the markets. She identified three broad paths to effect the necessary markets changes: (1) litigation, which had been done to some extent in New York and Illinois; (2) negotiation; or (3) re-regulation, either in a planned way by handing resource adequacy entirely back to the states, or in an unplanned way through individual and limited state actions cannibalizing the markets. She noted her preference for negotiated solutions, reporting that New England was the only region to successfully do so, filing the CAPSR proposal that was approved by the FERC. She said New York was working with stakeholders on a carbon pricing proposal in that one-state ISO that mirrored the Governor's carbon policies, and she looked forward to seeing that proposal when filed with the FERC. PJM, she said, was unable to reach agreement and, instead, submitted two ideas for review by the

FERC, which produced a decision that the PJM Capacity Market was unjust and unreasonable, over her dissent. She said that region was still working on next steps in response.

She noted three broad models that were currently being employed in the country. The first was organized markets with retail choice and merchant generation, like New England, PJM and New York. The second model was organized markets for energy and ancillary services and accomplishing transmission planning, but with state control over resource adequacy and, usually, vertical integration. She said that MISO, SPP and California fit this second model to some extent. The third model was entirely vertical integration with no organized market, which she said was the model in the Southeast and most of the West.

Continuing, she said that, across the country, these various models were converging. Places without organized markets were looking to meet their resource goals by dispatching resources over a broader footprint, citing as example the Bonneville Power Administration joining the Western Energy Imbalance Market. Organized markets in the East were seeing the states in their footprints taking over resource selection rather than relying on the markets. These developments suggested movement to some kind of hybrid model or menu of hybrid models where markets and state control combine.

Commissioner LaFleur then commented on the second topic of setting prices for payments to those resources. She noted that there was a fundamental shift occurring, in both organized and bilateral markets, in how electricity was being paid for. With persistently low gas prices and growing zero marginal cost renewables on the system, resources were not making money on volume and load curves were changing. More attention was being placed on pricing other services beyond volumetric payments for energy, such as for ramping, fuel security,

different types of reserve products and essential reliability services. There was consideration being given to charging for carbon emissions and there was more focus on scarcity pricing.

On her third topic -- getting infrastructure built to serve customers -- she said that markets were designed to send signals to drive infrastructure decisions. Both New York and some New England states, though, had sent strong signals that they would not support new pipelines even though the markets would support those resources through reduced costs during times of constraints. She noted her conclusion that New England was planning on more renewables but needed a bridge to get there.

Commissioner LaFleur stated her concern about infrastructure went well beyond pipelines, noting that any new central station resources that are needed to keep the lights on would need to be sited and paid for to be built, especially if there is to be more reliance on location-constrained resources like Canadian hydro and big wind. She opined that it would take regional cooperation among the six New England States to get any resources built in New England in the future. She premised that New England has some important advantages over some of the other regions as it navigates these energy challenges, including: (1) it was an actual region that identifies and exists outside of its market structure, with a set of regional organizations that are geographically coterminous and aligned; (2) it was very tightly interconnected with a long history of operating as a power pool since the 1965 Blackout; (3) it had a demonstrated history of doing things together; (4) there was more policy alignment among the New England States; and (5) it had the advantage of having NEPOOL since 1971. She highlighted that she fielded questions about NEPOOL from the New England congressional delegation at the U.S. House of Representatives hearings two weeks earlier (from Congressman Kennedy and Congresswoman Kuster) concerning NEPOOL governance, reflecting that the

existence of NEPOOL seems to be an asset over the other regions. She stressed the ability to work together was at that point at a premium, was preferable to FERC- or court-imposed solutions, and was the best hope for the development of innovative solutions.

She concluded her remarks by responding to questions. Concerning resource adequacy, a member commented that the states had been picking their favored resources but not picking resources for reliability, and questioned how that might be fixed. Commissioner LaFleur stated that was a problem because, if the states choose to take back resource adequacy entirely, then you would have a capacity imbalanced market like they have in PJM, but if the states only choose some of the resources, the existing resources that were built without the benefit of state-supported subsidization would have to rely entirely on the market for their needed revenues. She stated that one solution was some kind of price correction for the resources that were not being subsidized. Another solution was to use some kind of market mechanism to buy out the resources that were not subsidized. The problem she perceived is that, if the resources that were not being subsidized by the states were not being chosen in an RFP and being paid by distribution customers when actually needed for reliability, then they must be compensated to continue to operate if they are needed. In follow up concerning her remarks about ancillary services and reserves, Commissioner LaFleur stated that, in looking at the shape of the supply curves, if you allow the markets to work and prices get low enough, resources will start to retire and then the prices will correspondingly increase. However, resources that you need at certain times of the day must be paid some way other than on a per megawatt hour basis.

ISO EMM REPORT

Dr. David Patton, Ph.D., President of Potomac Economics, the ISO's External Market Monitor (EMM), presented highlights from the EMM's 2018 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. He said that the Report focused on key market issues and comparisons of New England to other markets to highlight the differences and challenges in New England.

Referring to his presentation, Dr. Patton discussed the all-in price comparisons among ERCOT, MISO, NYISO and ISO-NE. He opined that the summary of costs provided a good comparison among the markets and for various services. He reported ISO-NE generally had the highest costs, driven in large measure by the relatively high capacity costs in 2018 and by significantly higher energy costs driven by higher natural gas prices in New England.

He then referenced the comparison of the markets' congestion costs. In this comparison, New England had much lower congestion costs, with congestion at about 10% of what the other markets experienced. He explained the small congestion costs impacted market performance and reduced market power, and he attributed New England's results to the large transmission investments in New England over the past five or so years. He noted that average transmission costs in New England were approaching $18/MWh of load, which was substantially higher than the other markets. In his view, New England had shifted its costs from the markets, reducing the value of transmission rights to below $1/MWh of congestion. He said efficient transmission investment occurs when the value of the congestion being reduced is greater than the cost of the transmission investment, so it would be much more difficult in New England than elsewhere to find efficient transmission investment.

In response to questions, Dr. Patton characterized as artificial any attempt to distinguish between reliability investments and economic investments unless markets were not pricing reliability. He said RTOs should be building transmission based primarily on economic criteria. He questioned whether the congestion experienced in parts of Connecticut and Boston before these transmission investments were sufficient to justify the extent of transmission investments to address that congestion. He opined that there were some differences in how conservative the various RTOs were in identifying transmission security needs, and that New England appeared to be more conservative than other RTOs. In response to a member challenging the suggestion that the RTO could ignore reliability standards and base its transmission expansion decisions solely on economics, Dr. Patton clarified that, in his view, reliability requirements should be fully captured in modeling the transmission system in the energy market, and in setting locational operating reserve requirements. Planning reliability requirements in local areas that are impacted by limited transmission should be reflected in the capacity market price differentials that, in turn should support economically efficient new transmission investment when those price differentials rise to appropriate levels.

Referring to the cost comparison and New England-only energy, Dr. Patton indicated in response to members' questions that some of the increase in average gas and energy prices might be attributed to specific cold snap events, but those costs are increasing even if one sought to back out such events.

Responding to member comments and questions on capacity revenues, Dr. Patton referred to a chart in his presentation capturing peaking capacity market revenues in the all-in prices. He noted the consistent decline in capacity prices as new resources entered the market and capacity needs did not increase. He explained that capacity revenues together with energy and ancillary

service revenues were insufficient in the short-run to support new capacity resources. He referred to CASPR as a mechanism that should help to reduce supply/demand imbalance as subsidized public policy resources are added in the region.

In working to better understand the comparison of transmission costs, Dr. Patton noted in response to a member's comment that the EMM worked to isolate the components of the transmission rates solely to recovery of embedded costs and not to include variable transmission costs like marginal losses. He again advocated for market-based incentives for transmission investments as the best means to focus investors on finding incremental investments that can deliver net economic benefits to the region.

Dr. Patton was asked whether he had reviewed what capacity prices might have been had the Mystic Units been allowed to retire. He stated the EMM did not calculate theoretically alternative prices, but explained that capacity prices would certainly have been higher. He referred to the EMM's filings in the Mystic docket and in similar New York filings, where the EMM opined that it was not competitively inefficient to retain a resource to provide service for which it is demonstrably an efficient provider, but that it was inefficient not to reflect the pricing of the product being provided in the prices everyone else is paid for that same service. For that reason the EMM supported the Chapter 3 solution. He further opined that the EMM saw more value in prompt capacity markets as compared to a longer forward capacity market. He explained his view that running the capacity market three years ahead forces decisions based on incomplete or inaccurate projections of the future. That concern he said is eliminated by running the capacity market immediately prior to the planning year.

Turning back to the comparison of revenues, Dr. Patton observed that New England was the only market in 2018 that showed net revenues above the estimated annual costs of new entry

for additional resources. That result, he said, was largely because of high capacity revenues. He noted that, like other RTOs, New England would not economically support new resources entering its market if the net revenues were limited to energy, ancillary services, and reserves.

He then referred to a chart summarizing the Coordinated Transaction Scheduling (CTS) process and highlighting the benefits he thought were achieved by adjusting the interchange between New York and New England through the CTS process. He attributed the relative success of CTS, when compared to trading between other regions, to the fact that ISO-NE and NYISO agreed to waive transaction fees and transmission fees. In other regions where such fees were not waived, the benefits of interregional trading were much reduced. The EMM continued to recommend that the RTOs work on improving their interface price forecasts so that the benefits of this process could be increased, citing examples of forecast model differences that may be making trades less efficient.

He went on to note that the New England market was very competitive, more so in 2018 than 2017, because of new generation, particularly in Boston where new combined cycle resources significantly reduced pivotal supplier frequency and market concentration. He referenced the higher import capability into Boston and Southwest Connecticut resulting from transmission system upgrades, which he explained was a powerful competitive force in disciplining the concentrated supply in those areas. Thus, he characterized mitigation as relatively infrequent, with mitigation of units most frequently for those that are committed for local reliability, which primarily impacted uplift. There were very few instances of mitigation having a potentially significant impact on prices.

Comparing uplift costs among the various markets over the last three years, he reported reductions in ISO-NE uplift costs, significantly in local reliability uplift costs, but noted that ISO-

NE still had higher market-wide uplift than the other markets. He attributed that primarily to the cold snap in January 2018, which accounted for roughly 25% of the market-wide uplift. Had those January costs been excluded, he explained, uplift costs in 2018 would have been comparable to those in 2017. He said that the primary remaining difference in costs between ISO-NE and the other markets was explained by higher fuel costs. He added that another explanation for the differences in uplift costs was the fact that New England did not have Day-Ahead ancillary services markets. Consequently, ISO-NE met its reserves requirements by committing resources outside the market. Those uplift costs would not be needed if ISO-NE had co-optimized Day-Ahead ancillary services markets. More specifically, the EMM determined that ISO-NE, in 4,000 hours during 2018, committed resources outside the market to supply its system-level Ten-Minute Spinning Reserve (TMSR) requirement. The EMM calculated those out-of-market commitments to have lowered energy prices by $1.00-$1.50/MWh. He clarified in response to questions that the EMM attributed approximately $8 million of NCPC to this cause, but the financial impact was much larger when the price impacts caused by departure from commitment and scheduling through the markets, rather than outside the markets, was factored in.

Turning to the portion of his presentation that reviewed virtual trading and Real-Time NCPC allocation, Dr. Patton repeated his conclusions from prior years that allocating Real-Time NCPC to virtual transactions was bad for the markets. He compared the liquidity of virtual trades across the organized markets and noted that ISO-NE had far less virtual trading activity than other markets. Other markets where virtual traders were not subject to uplift payments had many more trades with much lower profits per trade, further highlighting the relatively low liquidity of ISO-NE markets for virtual trades.

Next he discussed fuel security in New England. Summarizing his conclusions on Chapter 3, Dr. Patton explained his support for establishing requirements to be satisfied through the markets rather than out of market. He stressed his view that doing so with fuel security in mind would improve short-term incentives to procure fuel, optimize commitment and dispatch to account for limited fuel availability, and would provide longer-term incentives to secure firm fuel. He noted his agreement that changes should be made. He explained, though, that the EMM's analysis showed fewer instances of Thirty-Minute Operating Reserve (TMOR) and TMSR depletions and little or no load shedding compared to the results of ISO's Operational Fuel-Security Analysis (OFSA). The EMM's alternative analysis was based on modified dispatch of the marginal units, increased replenishment of oil inventory, and some batteries being added to replace steam turbines. The EMM alternative made reasonable assumptions about the impact of already implemented market design changes that the EMM expected would substantially and positively impact reliability. He noted that the actual reliability impact of the retirements of Mystic and Distrigas facilities would depend on how other sources of supply respond, including alternative sources for LNG imports and how quickly other supply resources enter or leave the market. He concluded by noting his belief that an effective Chapter 3 market mechanism would provide valuable incentives, and could reduce or eliminate the reliability impact of losing Mystic and Distrigas.

Discussion then turned more specifically to the Chapter 3 proposal currently under consideration. Dr. Patton confirmed his view that, in concept, Chapter 3 was a sound design. The EMM and the ISO market design folks had been discussing the Chapter 3 proposal and it had been evolving in ways that addressed earlier concerns of the EMM. He confirmed in response to a question from a New England State representative that the ISO should be applying

a standard of reliability for winter energy security based on probabilistic analysis of potential fuel supply. He went on to note that, from an operational perspective, the ISO importantly must limit the quantities of the products it planned to satisfy through the markets to what is needed for reliability. He was still uncertain about a seasonal forward procurement product, in part because of uncertainty over what may be needed for the season. He acknowledged advantage to buying forward if the need was accurately assessed.

The group then discussed with Dr. Patton his views on how Chapter 3 products were being handled in the Day-Ahead Energy Market and not being carried through the Real-Time Energy Market. The Day-Ahead Markets for new reserve products were characterized as financial, and Dr. Patton confirmed his view that they would be very helpful in establishing and optimizing the scheduling of resources. He was undecided whether or not carrying those associated requirements into the Real-Time, physical market was necessary. The Chapter 2 changes were considered to be focused on physical markets and ISO-NE seemed focused for Chapter 3 on markets that were financial. Dr. Patton agreed that, in theory, purchasing an option seven days' out made sense since it would assist the ISO in optimizing the scheduling of the resources that have limited fuel. Dr. Patton stressed the importance of the proposal implementing the Day-Ahead Reserve Market so that it reflected more precisely what the ISO needed to operate the system. He was not sure that failing to follow the requirement through into Real-Time was essential since the objective of the market requirement was to optimize the commitment in dispatch of the resources that had limited fuel. The EMM's preliminary conclusion was that the Chapter 3 proposal should accomplish the design objective, but he needed to think through more carefully whether there could be problems if that requirement was not carried through into the Real-Time dispatch, particularly with committed resources deciding

for financial reasons to expire their firm fuel ahead of Real-Time. He agreed to think this through more fully and report his evaluations at a Markets Committee meeting before NEPOOL votes on the proposal.

Dr. Patton then discussed the intersection of Pay-for-Performance (PFP) and Chapter 3. He stressed the financial incentives PFP provided for units to be available. He said that incentive would be even greater when a cold snap occurred if Chapter 3 alone was insufficient to satisfy the region's fuel security needs, since the result would be shortages of TMOR, which would provide large incentives for resources to be available. Members asked about the value of battery storage in those instances. Dr. Patton opined that batteries would not materially contribute to fuel security during a cold snap because the need would be for resources that could run for an extended period and the useful storage from current batteries would last only for hours, not days. He expressed his belief that batteries would be overcompensated under PFP, which would be a real problem if it discouraged necessary generation.

Members asked whether the EMM might provide some insight or confidence that Chapter 3 would eliminate the need for the ISO to take further actions outside the market, particularly given the fact that PFP was in place before the current reliability rejection for fuel security purposes. Dr. Patton responded that the EMM analysis was intended to show how the markets could impact fuel security results. He explained that analysis of whether to grant a RMR contract to a resource was heavily impacted by assumptions and the EMM modified some of the ISO's assumptions to provide a less concerning conclusion when looking out two to three years. Implementing market mechanisms designed to drive good decision-making regarding the trade-offs among different types of oil units, the procurement of LNG, and the replenishment of oil

inventories in the winter would decrease the risk of pessimistic assumptions that drive decisions to enter into additional RMR agreements.

Responding to a question as to how big an impact changing the dispatch order would have had on the Mystic retention analysis, Dr. Patton opined that it would have had a significant impact, but not enough to change the conclusion that modified market mechanisms were needed to achieve fuel security. He referred to prior Markets Reports in which the EMM analyzed a variety of scenarios showing in a two-week cold snap the effects of having Mystic and Distrigas available and not available. He confirmed the very significant risk that arises without Distrigas. He clarified that his conclusions were driven in part by both the co-optimization of the reserves Day-Ahead under the Chapter 3 proposal and the proposed multi Day-Ahead Energy Market. He reinforced his view that Day-Ahead commitment would be the most important, but the optimization over the multi-day period looking forward was also important because the decisions of whether to run a higher cost steam unit the next day would be influenced by the desire to conserve fuel on cheaper units two, three and four days out. Dr. Patton agreed to report further to the Markets Committee the relative impacts of the multi Day-Ahead Energy Market versus just co-optimizing the reserves in the Day-Ahead or co-optimizing the reserves in the Day-Ahead Energy Market, with opportunity costs bidding that would include the ability to husband fuel based on future opportunities.

Dr. Patton then referred the Committee to the portion of his presentation concerning PFP. He referenced the first PFP event on September 3 and reviewed his chart of the price at the New England Hub in Real-Time that reflected the period of TMOR shortages when the $2,000/MWh PFP rate applied. He summarized, given PFP and the doubled shortage pricing values, that the Real-Time price during the event was $2,700 and the PFP energy settlement, which occurred

outside of the Energy Market, resulted in total settlement of $4,700/MWh. He stated that units that were not committed in the Day-Ahead Energy Market and were not online, which was the case for many of the steam units that have longer start times, were substantially penalized and units that supplied above their obligation, including imports, received substantial payments. The steam turbine units were charged $22 million in PFP charges during that event, and imports received performance payments of nearly $15 million, roughly half of which was paid to imports with no capacity obligations.

He followed with discussion of the EMM's calculation of the expected $30,000 per MWh value of lost load. He explained that the PFP payments needed to be high enough to provide sufficient revenues during shortage events so that the overall energy settlements could support the addition of a new unit at the margin. The value of lost load decreases as the shortage of reserves decreases, since the probability of a loss of load goes down. Continuing, he opined that the fixed price for payments under PFP were set administratively low to start and would increase over time to a value of $5,455/MWh which, when added to the shortage price in the Energy Market would produce payments over $8,000/MWh.

Dr. Patton concluded his presentation responding to additional questions on his report and committing to continue discussions when he attended a future Markets Committee meeting.

There being no other business, the June 25 session ended at 5:00 p.m., with the Summer Meeting to reconvene the following day, on Wednesday, June 26 at 8:30 a.m.

JUNE 26, 2019 SESSION

The Summer Meeting reconvened at 8:30 a.m. on June 26, 2019.

OPENING AND WELCOMING REMARKS

After welcoming members and guests, Ms. Chafetz introduced Ms. Marissa Gillett, the newly appointed Chair of the Connecticut Public Utility Regulatory Authority (CT PURA), who shared comments on behalf of NECPUC President Michael Caron, who was unable to attend the meeting. Chair Gillette thanked NEPOOL for the invitation to participate and welcomed everyone to Newport. She told the group that the States find the discussions with stakeholders very helpful and welcomed the opportunity for continued constructive dialogue.

NEW ENGLAND ENERGY LEGISLATION SUMMARY

Mr. Doot referred the Committee to the 2019 New England State Energy Legislation Summary circulated at the meeting that morning. He stated that the Summary was current through June 19, 2019 and noted that there continued to be developments in some of the states. He welcomed comments and thoughts, particularly from those tracking some of the legislation more closely and in more detail and nuance. Mr. Doot indicated that NEPOOL Counsel would continue to update and would post any updated versions on the NEPOOL website.

ASSESSING CHALLENGES FACING NEW ENGLAND'S EVOLVING GRID

The UK Experiences

Ms. Chafetz introduced Mr. Michael Calviou, National Grid Senior Vice President for Strategy and Regulation. Mr. Calviou proceeded to review his presentation on the experiences of National Grid as the grid operator for the UK, which was circulated and posted in advance of the meeting. He described the UK bulk power system and how materially decreasing amounts of conventional generation were being used to satisfy load, with increasing amounts of renewable

power being deployed. He showed graphically the impact of increased solar on the UK system. He described the substantial uncertainty created by the transition of resources, including uncertainty of demand with increased deployment of electric vehicles, uncertainty of supply with the very substantial growth in renewables, and uncertainty in the markets. He then summarized with some detail the system operator's efforts to produce financial energy scenarios, informed with substantial engagement of all stakeholders. He showed a short video that was designed to engage consumers in change that supports the grid evolution in the UK and increases flexibility for the operator. He identified the many different studies and reports produced by the grid operator for stakeholders and regulators.

Mr. Calviou completed his presentation observing that change was occurring at an ever-increasing pace and scenario planning was essential. He noted that the system was becoming far more complex and interdependent. There continued to be much more occurring on the distribution system that was impacting the bulk power system and there was more interaction between the gas and electricity markets. He said that the system operator in the UK played a strong role in facilitating change, removing barriers to new technology, identifying new markets to meet operational demands, and working more closely with the connected distribution systems that are supporting increased distributed generation.

Following his presentation, the Committee engaged in discussion of the similarities between the UK and New England and explored whether some of the UK experiences, particularly with an enhanced study process, might provide good lessons for the region.

Reliable Market Operations with Changing Technologies and Public Policies

Ms. Chafetz recognized Ms. Sharon Reishus, President, Reishus Consulting, and former Chair of the Maine Public Utilities Commission (MPUC), to moderate a more specific discussion

of the impact of changing public policy and technology on markets and public policy in New England. Ms. Reishus reminded the Committee of the stated goals of electric restructuring, which included allowing competitive markets to set prices, to shift the risk of business decisions from customers to investors, and to meet consumer needs and preferences through lowest cost options, all without diminishing environmental quality, efficiency or reliability.

She then introduced two panelists who presented the following:

Ari Peskoe's Remarks

Mr. Ari Peskoe, Director of the Electricity Law Initiative at Harvard Law School, noted that the New England States have been leaders in environmental regulation, with changing regulations now affecting the ISO-administered markets. Mr. Peskoe said that fossil-fueled facilities have become difficult to site and the fuel security debate represented a recognition of that constraint. He observed that, within 10 years, about one-half of the region's electric energy would be generated by resources that entered the market through state-mandated, long-term contracts. With increased utility procurements, it was clear that States seeking low-carbon contracts would get them, but the current wholesale market design must change to reflect that fact.

Mr. Peskoe reviewed NEPOOL's historic goals to attain for New England the maximum practical economy, consistent with proper standards of reliability, in the generation and transmission of bulk power through joint planning, central dispatching, and coordinated operation and maintenance of generation and transmission facilities. He said those goals have endured, and were remarkably similar to NEPOOL's current mission: to create and sustain open, non-discriminatory, competitive, unbundled markets for energy, capacity, and ancillary services that are balanced between buyers and sellers. He observed that unbundled markets were now the

vehicle for regional coordination to attain maximum practical economy and equitable sharing of costs and benefits evolved into balance between buyers and sellers, to reflect the transition from vertically integrated utilities to the current markets.

He noted that the New England region had the only regional market that had so extensively achieved that level of balance by separating buyers from sellers. MISO and SPP were both dominated by vertically integrated utilities, and about half of generation in PJM was owned by utility holding companies with distribution utilities in the footprint or vertically integrated utilities. He commented on the positive aspects of New England's regional markets with LMPs and open, non-discriminatory competition.

Mr. Peskoe urged the region as markets evolve to seek to accomplish its objectives as much as possible within a framework that maintains the underlying connection between economics and energy flows. The ultimate benchmark, he noted, would be fidelity to NEPOOL's mission. Each new product, market, or procurement should advance regional coordination that is balanced between buyers and sellers. He characterized the current efforts to decarbonize the regional power system as phase 2 of the regional markets, with phase 1 initiated 20 years ago when the markets opened. He said that carbon emissions in 2019 were approximately one-third lower than 1999, largely accomplished through the displacement of coal and oil by natural gas in the wholesale market. The region, he said, would not be able to achieve much more carbon reduction in that way.

Continuing with his summary, he observed that the policy framework for phase 3 of New England's markets was just starting to take shape. The parameters for phase 3 were being set by states' long-term carbon goals, with five New England states setting targets that required approximately 80 percent carbon emission reductions by 2050. If a regional mechanism for

achieving decarbonization goal is not identified, phase 3 might be characterized by a combination of state procurements and escalating renewable portfolio or clean energy standards. That outcome would largely be a continuation of phase 2 and would be combined with inconsistent regulation of CO_2 emissions from the region's fossil generators. Mr. Peskoe expressed the view that this outcome for phase 3 would threaten the key principles of openness and non-discrimination and would mark a major step backward in the decades-long effort to improve regional coordination. He said, to avoid an outcome in which ISO markets don't drive investment and RMR agreements are needed to keep existing assets operational, the region needed a market-mechanism that reflects if not drives new entry of low-emission resources.

Summarizing, he said that phase 1 reduced emissions through natural gas plants entering the market relying on LMPs and capacity markets. Switching from coal and oil steam turbines to natural gas combined cycle plants was consistent with existing physical operations and market dynamics. In his phase 2, new entry is not based on market expectations but rather on long-term power purchase agreements (PPAs) because LMPs and the capacity markets are not providing an entry path for these resources. State-mandated RFPs were, nonetheless, a market mechanism. Like some ISO product markets, a state-directed mandate facilitates competition among suppliers while dictating to buyers the products they must to buy. But those RFPs isolate the state from the region, and therefore mark a departure from the decades-long regionalization trend.

Focusing on phase 3, Mr. Peskoe noted that regional carbon pricing was an unattractive option for States in Phase 2 in part because it did not facilitate the desired new entry, but it was worth reexamining whether a carbon price could play some role in phase 3. If carbon pricing was not politically viable, he suggested exploration of whether payments for reducing carbon emissions might be more attractive. According to Mr. Peskoe, if neither of these alternatives

proved possible, a sub-optimal solution that uses the LMP framework was better than the alternative of more utility-mandates and inconsistent state CO_2 emission regulations. Mr. Peskoe suggested that the ultimate goal for the region should be based on regional coordination. Absent a regional alternative, states would continue with increasing utility mandates. If that happened, markets would need to adjust to be explicit about the role of state procurements. He noted that the region must also retain resources needed for reliability. The regional capacity construct as designed procures fungible megawatts, which is no longer sufficient to assure resource adequacy and reliability.

He questioned whether volatile energy prices that accompany high penetrations of low marginal cost resources could support the financing of new resources. He asked whether the ISO would oversee future financing mechanisms, or whether Market Participants and financial institutions would develop them without any new FERC-regulated products. He also wondered whether there would be a regional solution to long-duration storage. He noted that large additions of offshore wind would produce surplus renewable energy generation each spring and fall. He expressed uncertainty about whether financing was possible with such seasonal variations in LMPs.

Mr. Peskoe then returned to reviewing NEPOOL history, quoting the following passage from the 1972 Federal Power Commission (FPC) order approving NEPOOL's formation: "The participants to the Agreement have subordinated some of their own self-interest objectives in order to achieve a workable pooling arrangement for their own benefit and for the benefit of the whole geographical area involved." He followed with several questions: Would states be satisfied with a regional solution if a credible proposal is presented, or would they continue to insist on picking their resources? Could states subordinate some of their own self-interest?

Pointing to RPS laws and RGGI, both of which are regional solutions that preceded current procurements, he concluded that there was reason to be optimistic. He observed that leadership in this space must come from those who plan to still be in the market in the future. He said that current opportunities to influence outcomes slip away as states continue passing additional procurement mandates. He acknowledged that politicians could pass laws that effectively dissolve the past 50 years of regionalization. He concluded by noting that New England had a unique cohesiveness that other markets lacked, and that might allow the region to overcome inertia and provide a path forward for a regional, low-carbon power system.

Travis Kavulla's Remarks

Mr. Travis Kavulla, Director of Energy and Environmental Policy at the R Street Institute and a former Chairman of the Montana Public Service Commission and former President of the National Association of Regulatory Utility Commissioners (NARUC), reminded the Committee that he last spoke in New England in March 2016. He predicted then that "vague and indirect environmental objectives" would likely drive state policymakers to continue a regime of long-term supply procurements, rather than rely on a marketplace that must have a clearly defined variable to solve for before it can work toward a cost-minimizing solution.

He then proceeded to review with the Committee a paper that he had circulated to the Committee. He reviewed numerous decisions by regulators across the country that appeared valid at the time but ultimately committed customers to support investments that proved later to be uneconomic. He explained that these examples all failed to require the businesses for whom these investments in generation were accretive to own the risk of the bets in which such planning resulted. He opined that competitive markets are more likely than government-mandated solutions to deliver economic resources, new technology and integrated, reliable solutions.

Mr. Kavulla agreed with Mr. Peskoe that power markets had solved for the public policy demands of affordability and reliability, but fell short where they adopted features resembling the paternalistic elements of regulation. He noted that regulations produce positive results when they provide risks and rewards to utilities for their investments, require competitive solicitations for PPAs, and rely on security-constrained economic dispatch to co-optimize the generation portfolio in the short run.

Mr. Kavulla also agreed with Mr. Peskoe that the power markets are not designed to and were not achieving environmental objectives. He said that power markets could advance environmental objectives by pricing carbon but that is not politically acceptable.

Mr. Kavulla summarized his views of outcomes of the politically driven solutions by the states. He opined that the current path, where legislators decree the construction of particular power projects by particular parties is even worse than "integrated resource planning."

Mr. Kavulla then posed a series of questions to the audience:

1. Was it possible to have the New England States agree, if not on a carbon price, then on some definition of the product that should be acquired to satisfy their clean energy standards?
2. Was there a way to ensure that those faced with a compliance obligation for this product have an economic incentive to engage in least-cost procurements?
3. Was there a way to avoid setting the duration of commitments in a way that allowed the markets to work toward continuing innovations and improvements in efficiency?
4. Was there a way to emphasize the basic framework of a market for electricity that had served us well, while also having a compatible feature to that market that hosts a trade in clean energy attributes?

5. Could the market incorporate sectors other than the power sector?

He concluded his remarks by referring to the history of prior decisions that proved uneconomic and led to the emergence of markets. He said that markets did not get everything right to begin with and there is clear potential in those markets for improvement from the status quo.

There being no further business, the meeting adjourned at 11:45 a.m.

Respectfully submitted,

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David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 25-27, 2019 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
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)		
American PowerNet Management	Supplier			Michael Macrae
Ashburnham Municipal Light Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Associated Industries of Massachusetts	End User			Roger Borghesani
AVANGRID: CMP/UI	Transmission	Eric Stinneford	Alan Trotta	
Bath Iron Works Corporation	End User			Liz Delaney
Belmont Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Block Island Power Company	Supplier	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
BP Energy Company	Supplier			Nancy Chafetz
Braintree Electric Light Department	Publicly Owned			Dave Cavanaugh
Brookfield Energy Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse	Rebecca Hunter	John Flumerfelt Bill Fowler
Chester Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
C.N. Brown Electricity, LLC	Supplier			William P. Short III
Covanta Energy Marketing, LLC	AR-RG		Sharon Abbott	
CPV Towantic, LLC	Generation	Daniel Pierpont		
Competitive Energy Services, LLC	Supplier			Glenn Poole
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User			Dave Thompson
Conservation Law Foundation (CLF)	End User	David Ismay	Jerry Elmer	
Consolidated Edison Energy, Inc. (ConEd)	Supplier	Jeff Dannels		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned		Dave Cavanaugh	
Direct Energy Business, LLC	Supplier	Ron Carrier		Nancy Chafetz
Dominion Energy Generation Marketing, Inc.	Generation	Michael Purdie		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Durgin and Crowell Lumber Co., Inc.	End User			Liz Delaney
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Elektrisola, Inc.	End User		Gus Fromuth	
Emera Maine	Transmission	Lisa Martin		
Enel X North America, Inc.	AR-LR	Greg Geller	Herb Healy	
ENGIE Energy Marketing NA, Inc.	Generation	Sara Bresolin		
Entergy Nuclear Power Marketing, LLC	Generation	Ken Dell Orto		Bill Fowler
Environmental Defense Fund	End User	Liz Delaney		
Eversource Energy	Transmission	James Daly	Cal Bowie	Vandan Divatia
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow	Peter Rider	
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation	Dennis Duffy		Bob Stein Ron Coutu (tel)
Georgetown Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Great River Hydro	AR –RG	Shawn Keniston		Bill Fowler
Groton Electric Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault	Bob Stein	Ron Coutu (tel)

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 25-27, 2019 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Hanover, NH (Town of)	End User			Liz Delaney
Harvard Dedicated Energy Limited	End User		Michael Macrae	Roger Borghesani
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Holyoke Gas & Electric Department	Publicly Owned		Brian Thomson	Brian Forshaw
Hull Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Industrial Energy Consumer Group (IECG)	End User	Kevin Penders		
Ipswich Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Jericho Power, LLC	AR-RG	Mark Spencer		
King Forest Industries, Inc.	End User			Liz Delaney
Littleton (MA) Electric Light and Waster Department	Publicly Owned		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Long Island Lighting Company (LIPA)	Supplier		William Killgoar	
Maine Power LLC	Supplier			Glenn Poole
Maine Public Advocate Office	End User		Barry Hobbins	
Maine Skiing, Inc.	End User	Kevin Penders		Liz Delaney
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	Brian Forshaw
Maple Energy LLC	AR-LR	Angela Fox		
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Mass. Attorney General's Office	End User	Christina Belew		
Mass. Bay Transportation Authority	Publicly Owned		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned	Brian Thomson		Brian Forshaw
Mercuria Energy America, Inc.	Supplier			Nancy Chafetz
Merrimac Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Michael Kuser	End User	Michael Kuser		
Middleborough Gas & Electric Department	Publicly Owned		Dave Cavanaugh	Brian Forshaw
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
The Moore Company	End User			Liz Delaney
National Grid	Transmission	Tim Brennan	Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation	Chris Sherman	Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned	Steve Kaminski		Brian Forshaw
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned		Dave Cavanaugh	
Novatus Energy (Blue Sky West, LLC)	AR-RG		Katie Bellezza	
NRG Power Marketing LLC	Generation		Pete Fuller	
Nylon Corporation of America	End User			Liz Delaney
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Peabody Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
PNE Energy Supply	Supplier			Gus Fromuth
PowerOptions, Inc.	End User	Cindy Arcate		
Princeton Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned			
Rowley Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned		Brian Thomson	Brian Forshaw
Saint Anselm College	End User	Gus Fromuth		
Salem (Footprint Power Salem Harbor Development LP)	Generation			Nancy Chafetz Bob Stein

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 25-27, 2019 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson	Brian Forshaw
South Hadley Electric Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Sterling Municipal Electric Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Stowe Electric Department	Publicly Owned		Dave Cavanaugh	
Sunrun Inc.	AR-DG	Chris Rauscher		
Taunton Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Texas Retail, LLC	Supplier		Alonzo Williams	
The Energy Consortium	End User	Roger Borghesani		Doug Hurley
Union of Concerned Scientists	End User	Michael Jacobs		
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		
Vermont Electric Power Company	Transmission		Mark Sciarrotta	
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw
Verso Energy Services LLC	Generation	Glenn Poole		
Village of Hyde Park (VT) Electric Department	Publicly Owned	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Wallingford DPU Electric Division	Publicly Owned		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Westfield Gas & Electric Department	Publicly Owned		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
Z-TECH, LLC	End User		Gus Fromuth	

VOTES TAKEN AT
JUNE 25-27, 2019 PARTICIPANTS COMMITTEE MEETING

TOTAL

Sector/Group	Vote 1	Vote 2
GENERATION	11.19	16.79
TRANSMISSION	16.79	0.00
SUPPLIER	13.59	11.55
ALTERNATIVE RESOURCES	16.04	9.44
PUBLICLY OWNED ENTITY	16.46	7.35
END USER	2.81	0.00
% IN FAVOR	**76.88**	**45.13**

GENERATION SECTOR

Participant Name	Vote 1	Vote 2
CPV Towantic, LLC	A	F
Dominion Energy Generation Mktg.	O	F
FirstLight Power Management, LLC	F	F
Generation Group Member	A	A
Nautilus Power LLC	F	F
NextEra Energy Resources, LLC	O	F
NRG Power Marketing, LLC	--	A
Salem (Footprint Power Salem)	F	F
Verso Energy Services LLC	F	F
IN FAVOR (F)	4	7
OPPOSED (O)	2	0
TOTAL VOTES	6	7
ABSTENTIONS (A)	2	2

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2
AVANGRID (CMP/UI)	F	O
Emera Maine	S[3]	S
Emera Maine	F	O
Emera Energy Services Subsidiaries	--	--
Eversource Energy	F	O
National Grid	F	O
Vermont Electric Power Co.	F	A
IN FAVOR (F)	4.5	0.0
OPPOSED (O)	0.0	3.5
TOTAL VOTES	4.5	3.5
ABSTENTIONS (A)	0.0	1.0

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2
Renewable Generation Sub-Sector		
Covanta Energy Marketing	A	F
Great River Hydro	F	F
Jericho Power	--	F
Wheelabrator North Andover	F	F
Small RG Group Member	A	O
Distributed Generation Sub-Sector		
Sunrun Inc.	F	F
Load Response Sub-Sector		
Enel X North America, Inc.	F	A
VT Energy Investment Corp.	F	A
Small LR Group Member	F	A
IN FAVOR (F)	6	5
OPPOSED (O)	0	1
TOTAL VOTES	6	6
ABSTENTIONS (A)	2	3

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2
American PowerNet Management	--	O
Block Island Power Company	F	O
BP Energy Company	F	F
Brookfield Energy Marketing Inc.	O	F
C.N. Brown Electricity, LLC	O	O
Calpine Energy Services, LP	F	F
Competitive Energy Services	F	F
Consolidated Edison Energy, Inc.	F	F
Cross-Sound Cable Company	F	A
Direct Energy Business, LLC	F	F
DTE Energy Trading, Inc.	F	A
Dynegy Marketing and Trade, LLC	F	F
Entergy Nuclear Power Marketing	F	A
Exelon Generation Company	O	F
Galt Power	F	F
H.Q. Energy Services (U.S.) Inc.	F	A
Long Island Power Authority (LIPA)	F	A
Maine Power, LLC	F	O
Mercuria Energy America, Inc.	F	A
PNE Energy Supply LLC	O	O
PSEG Energy Resources & Trade	F	F

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

VOTES TAKEN AT
JUNE 25-27, 2019 PARTICIPANTS COMMITTEE MEETING

Texas Retail, LLC	F	F
IN FAVOR (F)	17	11
OPPOSED (O)	4	5
TOTAL VOTES	21	16
ABSTENTIONS (A)	0	6

END USER SECTOR

Participant Name	Vote 1	Vote 2
Associated Industries of Mass.	F	A
Bath Iron Works Corporation	O	O
Conn. Office of Consumer Counsel	A	O
Conservation Law Foundation	O	O
Environmental Defense Fund	O	O
Hanover, NH (Town of)	O	O
Harvard Dedicated Energy Limited	O	O
High Liner Foods (USA) Inc.	O	O
Industrial Energy Consumer Group	A	A
King Forest Industries	O	O
Michael Kuser	A	A
Maine Public Advocate Office	--	O
Maine Skiing, Inc.	A	A
Mass. Attorney General's Office	O	O
Moore Company	O	O
Natural Res. Defense Council	O	O
PowerOptions, Inc.	F	O
The Energy Consortium	F	O
IN FAVOR (F)	3	0
OPPOSED (O)	15	19
TOTAL VOTES	18	19
ABSTENTIONS (A)	4	4

PUBLICLY OWNED ENTITY SECTOR

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

PUBLICLY OWNED ENTITY SECTOR (cont.)

ATTACHMENT 2

VOTES TAKEN AT
JUNE 25-27, 2019 PARTICIPANTS COMMITTEE MEETING

Participant Name	Vote 1	Vote 2
Mansfield Municipal Electric Dep't	F	F
Marblehead Municipal Light Dep't	F	F
Mass. Bay Transportation Authority	F	O
Mass. Mun. Wholesale Electric Co.	F	F
Merrimac Municipal Light Dep't	F	O
Middleborough Gas & Elec. Dep't	F	O
Middleton Municipal Electric Dep't	F	O
New Hampshire Electric Coop.	F	O
North Attleborough Electric Dep't	F	O
Norwood Municipal Light Dep't	F	O
Pascoag Utility District	F	O
Paxton Municipal Light Dep't	F	F
Peabody Municipal Light Plant	F	F
Princeton Municipal Light Dep't	F	F
Reading Municipal Light Dept.	F	O
Rowley Municipal Lighting Plant	F	O
Russell Municipal Light Dep't	F	F
Shrewsbury's Elec. & Cable Ops.	F	F
South Hadley Electric Light Dep't	F	F
Sterling Mun. Elec. Light Dep't	F	F
Stowe (VT) Electric Department	F	O
Taunton Municipal Lighting Plant	F	O
Templeton Mun. Lighting Plant	F	F
Vermont Electric Cooperative	F	A
VT Public Power Supply Authority	F	O
Village of Hyde Park Electric Dep't	F	O
Wakefield Mun. Gas & Light Dep't	F	F
Wallingford, Town of	F	O
Wellesley Municipal Light Plant	F	O
West Boylston Mun. Lighting Plant	F	F
Westfield Gas & Elec. Light Dep't	F	O
IN FAVOR (F)	49	21
OPPOSED (O)	1	27
TOTAL VOTES	50	48
ABSTENTIONS (A)	0	2

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CONSENT AGENDA

Solar & Wind Data Requirements

From the previously circulated notices of actions of (i) the Markets Committee's July 8-10, 2019 meeting, dated July 11, 2019,[1] and (ii) the Transmission Committee's June 13 meeting, circulated June 14:[2]

1. **MR1 Revisions (Solar Data Requirements & Relocation of Wind Data Requirements)**

   Support revisions to Market Rule 1 and Tariff Section 1.2.2 for solar resources to provide meteorological and operational data to support power production forecasting as well as consolidating the wind and solar requirements within Market Rule 1, as recommended by the Markets Committee at its July 8-10, 2019 meeting, with such further non-material changes as the Chair and Vice-Chair of the Markets Committee may approve.

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

2. **Tariff Schedule 22 *Pro Forma* LGIA Revisions (Removal of Wind Data Requirements)**

   Support revisions to Schedule 22 of the Tariff to remove wind forecasting data requirements (which were moved into Market Rule 1 (see Consent Agenda #1 above)), as recommended by the Transmission Committee at its June 13, 2019 meeting, with such further non-material changes as the Chair and Vice-Chair of the Transmission Committee may approve.

   The motion to recommend Participants Committee support was approved unanimously.

Reliability Committee

From the previously circulated June 20, 2019 notice of actions of the Reliability Committee's June 18, 2019 meeting[3]:

3. **OP-8 Revisions (Delete Obsolete NERC Provisions & Align with NPCC Directory #5)**

   Support revisions to ISO New England Operation Procedure (OP) No. 8 (OP-8), which delete obsolete NERC provisions, align the document with NPCC Directory #5 and address small copy edits, as recommended by the Reliability Committee at its June 18, 2019 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

   The motion to recommend Participants Committee support was approved unanimously.

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

4. **OP-13 & OP-13, Appendix B Revisions (Simplify Reference & Incorporate Minor Terminology Clarifications; Identify UFLS Islands, Clarify Requirements & Incorporate NERC References)**

   Support revisions to OP-13 (which simplify the reference to OP-13 Appendix B and incorporate minor clarifications to terminology) and Appendix B to OP-13 (which identify the Under Frequency Load Shedding (UFLS) islands in New England, clarify compensatory load shed requirements, and incorporate references to NERC's Regional Reliability Standard for under frequency set points), each as recommended by the Reliability Committee at its June 18, 2019 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

   The motion to recommend Participants Committee support was approved unanimously.

5. **OP-16, Appendix K Revisions (Monthly ISO Updates & Quarterly Transmission Planner Updates)**

   Support revisions to OP-16, Appendix K (which reflect monthly ISO updates and quarterly Transmission Planner updates to the short circuit base cases (Year N; Year N+5) and reorganize the document to facilitate finding relevant information related to generators, Transmission Owners that are not Transmission Planners, and Transmission Owners that are Transmission Planners), as recommended by the Reliability Committee at its June 18, 2019 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

   The motion to recommend Participants Committee support was approved unanimously.

6. **OP-2, Appendix C Revisions (Changes to Equipment Maintenance Request Form)**

   Support revisions to OP-2, Appendix C (which provide contact information to request an electronic copy of the Equipment Maintenance Request Form and other minor edits), as recommended by the Reliability Committee at its June 18, 2019 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

   The motion to recommend Participants Committee support was approved unanimously.

From the previously circulated July 18, 2019 notice of actions of the Reliability Committee's July 16-17, 2019 meeting:[3]

7. **OP-24 Revisions (Protection Outages, Settings and Coordination)**

   Support revisions to OP-24 to reflect the change in confidential OP-24, Appendix C from being a diagram with relay outage locations to being a list of transmission facilities that Transmission Owners are reporting protection settings, characteristics, failures or degradation, as recommended by the Reliability Committee at its July 16-17, 2019 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

   The motion to recommend Participants Committee support was approved unanimously.

8. <u>OP-12 & OP-12, Appendix D Revisions (Voltage Schedule Annual Transmittal Form)</u>

Support revisions to OP-12 and OP-12, Appendix D to clarify Local Control Center actions for providing voltage schedules to generators, as recommended by the Reliability Committee at its July 16-17, 2019 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

9. <u>Tariff Revisions (Definitions for IROL and SOL)</u>

Support revisions to Section I.2.2 of the Tariff to incorporate definitions for Interconnection Reliability Operating Limit (IROL) and System Operating Limit (SOL), as recommended by the Reliability Committee at its July 16-17, 2019 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

Summary of ISO New England Board and Committee Meetings

August 2, 2019 Participants Committee Meeting

Since the last update, the Nominating and Governance Committee met by teleconference on June 20. The Compensation and Human Resources Committee, the Markets Committee, the System Planning and Reliability Committee, and the Board of Directors each met on June 26 in Newport, Rhode Island.

The Nominating and Governance Committee discussed board leadership, committee membership and state liaison assignments, and agreed to finalize the proposed recommendations in time for Board consideration at the Board's annual meeting in September.

The Compensation and Human Resources Committee met in executive session to review the Company's organizational structure and succession plans for management. The Committee also conducted its annual assessment of the risks within the Committee's purview, and agreed that the primary risks relate to succession planning, recruitment and retention of employees. Finally, the Committee discussed the results of its self-evaluation.

The Markets Committee was provided with an update and design overview of the energy security changes (a/k/a Chapter 3), and noted that efforts are on track for a filing with FERC in October. The Committee also reviewed the results of its self-evaluation in executive session.

The System Planning and Reliability Committee discussed the 2019 Regional System Plan executive summary and reviewed the schedule for the upcoming Regional System Plan Public Meeting. Next, the Committee received an update on the system operations outlook for Summer 2019 and an update on state clean energy requests for proposals. The Committee also reviewed Order 1000 implementation efforts, and discussed its self-evaluation results in executive session.

The Board of Directors meeting began in executive session with reports from the Nominating and Governance Committee and the Compensation and Human Resources Committee. The Board also considered the creation of a special Board committee on IT and cyber security on a trial basis (this function currently resides within the Audit and Finance Committee) and reviewed the results of its self-evaluation. In regular session, the Board considered topics raised in advance by participants for discussion at the sector meetings to be held the next day, and discussed participation in ISO/RTO Council board conferences. Finally, the Board reviewed the Company's Form 990 for 2018 to be filed with the Internal Revenue Service and received reports from the remaining standing committees.

NEPOOL Participants Committee Report

August 2019

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy market value was $317M, up $89M from June and down $143M from July 2018
    - July natural gas prices over the period were 8.8% higher than June average values
    - Average RT Hub Locational Marginal Prices ($27.90/MWh) over the period were 24% higher than June averages
      - Average DA Hub LMP: $29.70/MWh
    - Average July 2019 natural gas prices and RT Hub LMPs over the period were down 18% and 17%, respectively, from July 2018 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.8% during July, up from 99.1% during June*
    - The minimum value for the month was 93.4% on Sunday, July 7

Data is through July 24 unless otherwise noted.

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

Underlying natural gas data furnished by:

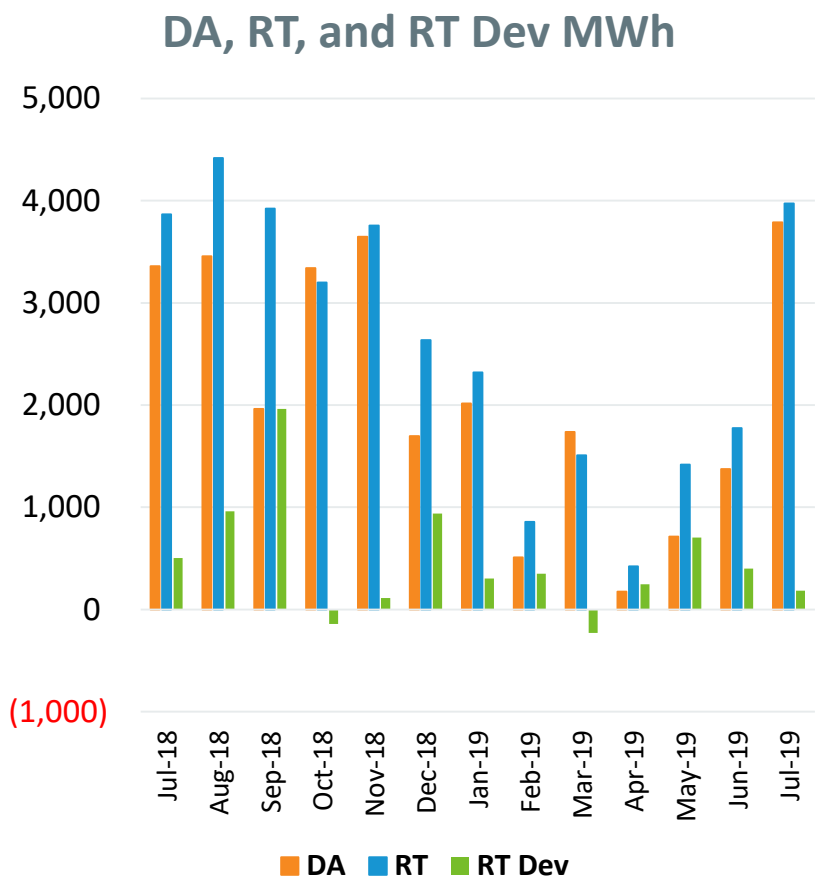
ICE Global markets in clear view

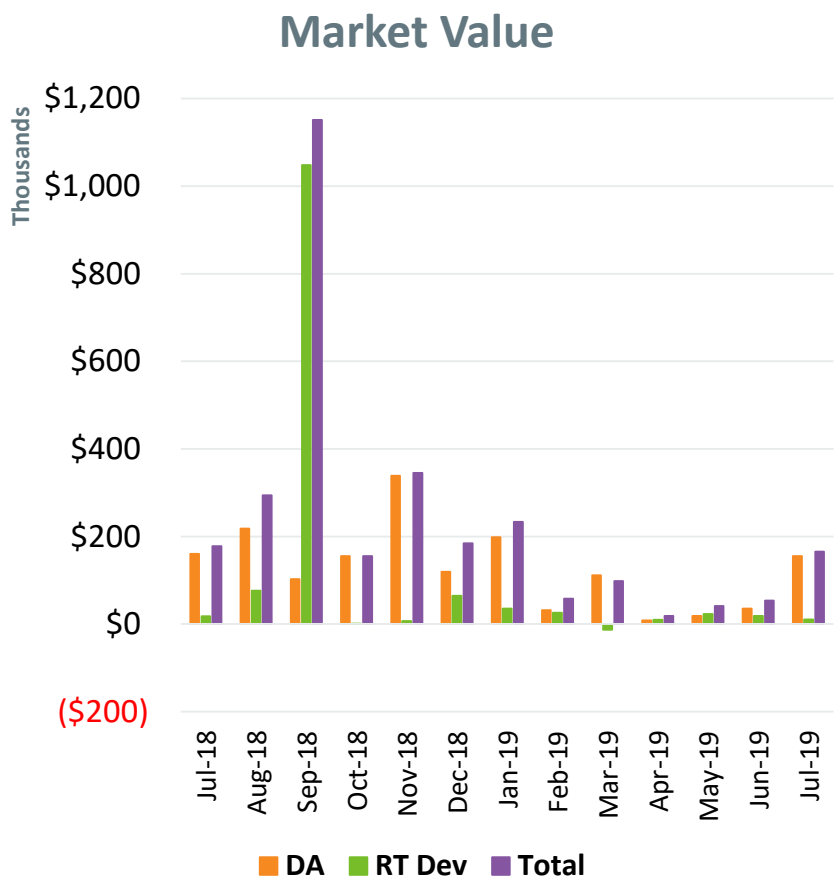
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - July NCPC payments totaled $2.7M over the period, up $1M from June 2019 and down $3.1M from July 2018
    - First Contingency* payments totaled $1.2M, down $0.2M from June
      - $1.2M paid to internal resources, down $0.2M from June
        - » $298K charged to DALO, $427K to RT Deviations, $473K to RTLO
      - $16K paid to resources at external locations, down $66K from June
        - » Charged to RT Deviations
    - Second Contingency payments totaled $1.3M, up $1.1M from June
    - Distribution payments totaled $153K, up $153K from June
  - NCPC payments over the period as percent of Energy Market value were 0.8%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $152K; Rapid Response Pricing (RRP) Opportunity Cost - $112K; Posturing - $21K; Generator Performance Auditing (GPA) - $188K;**

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Highlights

- RSP19 Stakeholder Comment Review at PAC is scheduled for August 8.
- RSP19 public meeting will be held on September 12, from 11:30 AM until 4:00 PM, at The Westin Copley Place in Boston, MA. Registration is available via ISO-TEN.
- ISO continues to meet with the NEPOOL TC and RC on proposed enhancements to the competitive transmission solicitation process in the OATT to support an October filing

Forward Capacity Market (FCM) Highlights

- CCP 10 (2019-2020)
  - Late, new resources (regardless of size) are being monitored closely
- CCP 11 (2020-2021)
  - Second reconfiguration auction will be August 1-5, and results to be posted by September 3
- CCP 12 (2021-2022)
  - Second reconfiguration auction will be August 3-5, 2020 and results to be posted by September 2, 2020
- CCP 13 (2022-2023)
  - Auction results were filed with FERC on February 28; FERC has yet to rule
  - First reconfiguration auction will be June 1-3, 2020 and results to be posted by July 1, 2020

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 14 (2023-2024)
  - New Capacity Resource Qualification is ongoing
    - On schedule to release Qualification Notices on September 27
    - Renewable Technology Resource Exemption: approximately 336 MW
  - Existing Capacity Resource Qualification is complete
  - This will be the first FCA where nested capacity zones will be modeled
    - Tariff changes were filed with FERC and an order is expected by October 1
    - Capacity Zones to be modeled include: Rest of Pool, Southeastern New England, Northern New England, and Maine (nested zone within Northern New England)
  - ICR & related values development discussions are ongoing with the PSPC
- Both the ICR and Informational (qualification) FERC filings will be made on November 5

FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement
PSPC – Power Supply Power Committee
QDN – Qualification Notification Determination

FERC Order 1000

- Intraregional Planning
  - Qualified Transmission Project Sponsor (QTPS)
    - 21 companies have achieved QTPS status
    - One company is currently moving through the QTPS application process
  - Based on the results of the Boston Needs Assessment to date, the ISO plans to release its first request for proposal (RFP) for a competitively developed transmission solution in late 2019 or early 2020
  - Ongoing discussions at the NEPOOL Transmission Committee and Reliability Committee to support an October 2019 Tariff filing
  - Draft RFP templates have been provided to the PAC

Highlights

- The lowest 50/50 and 90/10 Summer Operable Capacity Margins are projected for week beginning August 3, 2019.

- The lowest 50/50 and 90/10 Preliminary Fall Operable Capacity Margins are projected for week beginning November 9, 2019.

JULY 20 – 21 HEAT WAVE

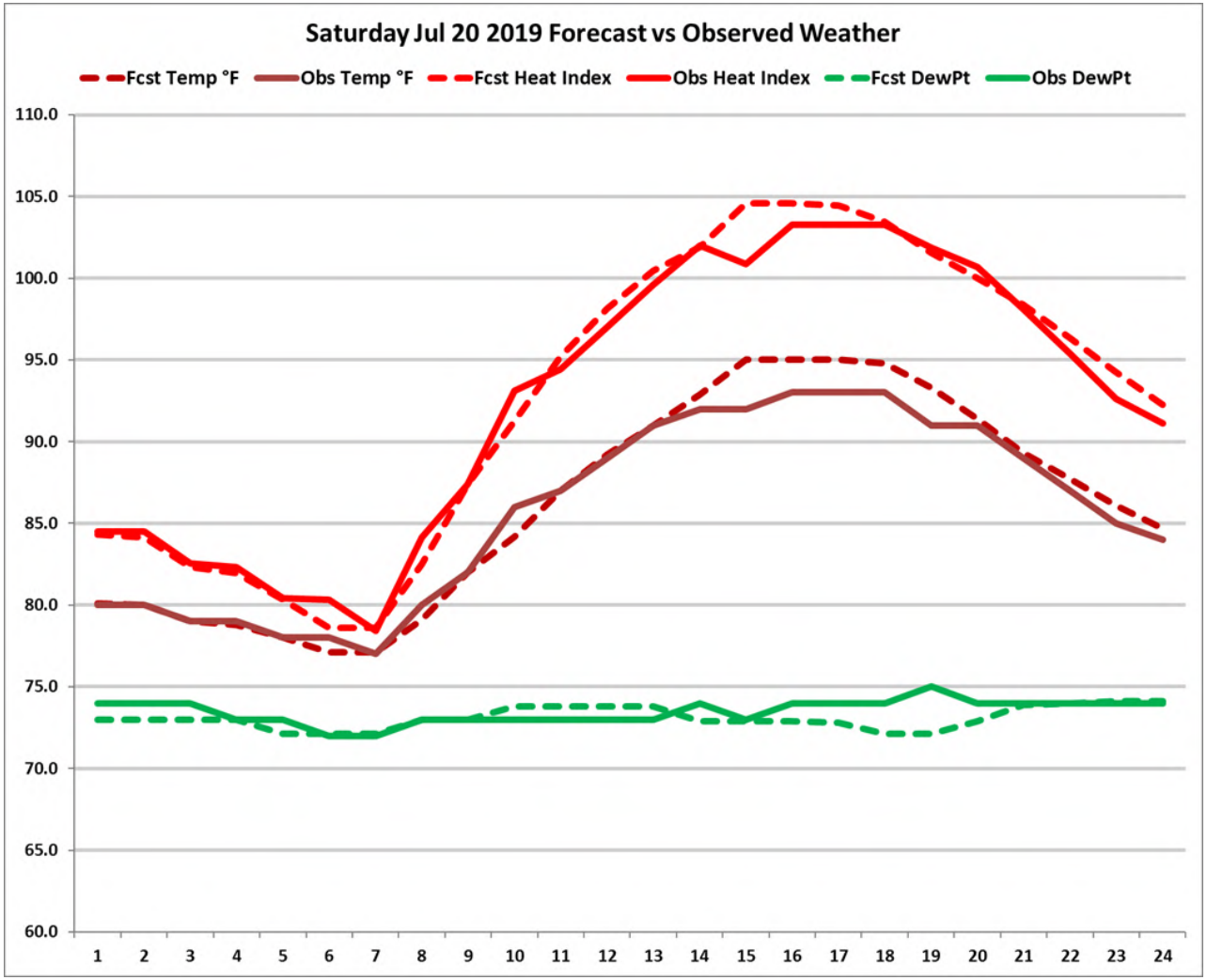
July 20 and 21 Heat Wave Summary

- Weather forecast indicated New England (eight city) weighted average Heat Index over 100°
- Actual peak loads
  - July 20 – 24,130 MW for hour ending 18:00
  - July 21 – 24,106 MW for hour ending 18:00
- A number of resources self-scheduled to perform Claim Capability Audits, particularly on Saturday, July 20
  - ~2000 MWs self scheduled on July 20 and ~400 MWs on July 21
  - This is in addition to the deviation from interchange (Slide 20) and wind production (Slide 22)
- LMPs were generally in the $20 - $60 range
  - Few hours of negative prices in northern Maine driven by New Brunswick imports and wind resources output

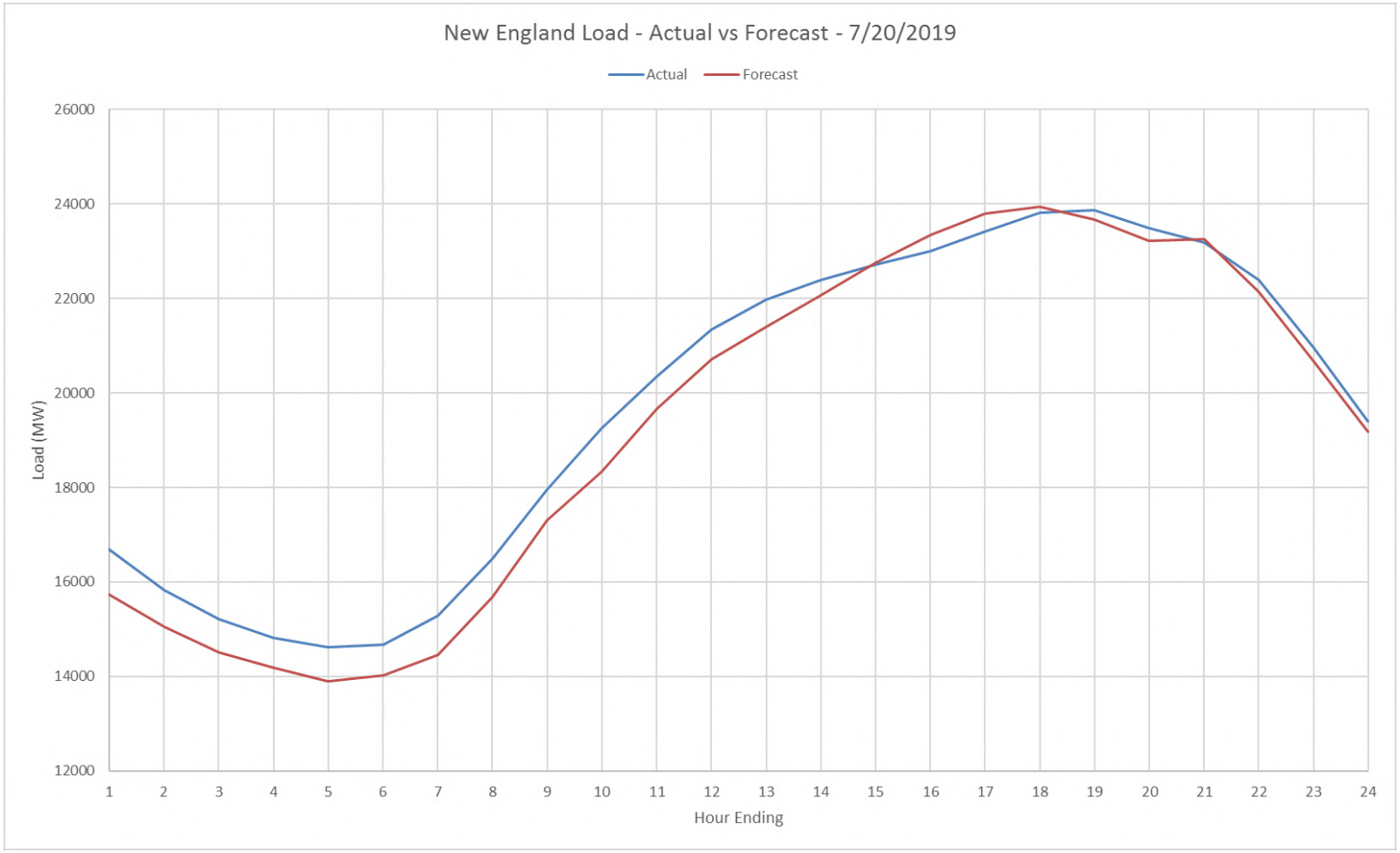
July 20 and 21 Weekend Heat wave

- Weather forecast
  - Temperatures in the upper 90's with dew points in the mid-70's
  - Eight City weighted average Heat Index
    - Saturday 104.6° and Sunday 102.5°
- Actual weather conditions
  - Saturday weather relatively close to forecast
  - Sunday dew points were below forecast resulting in lower than anticipated Heat Index

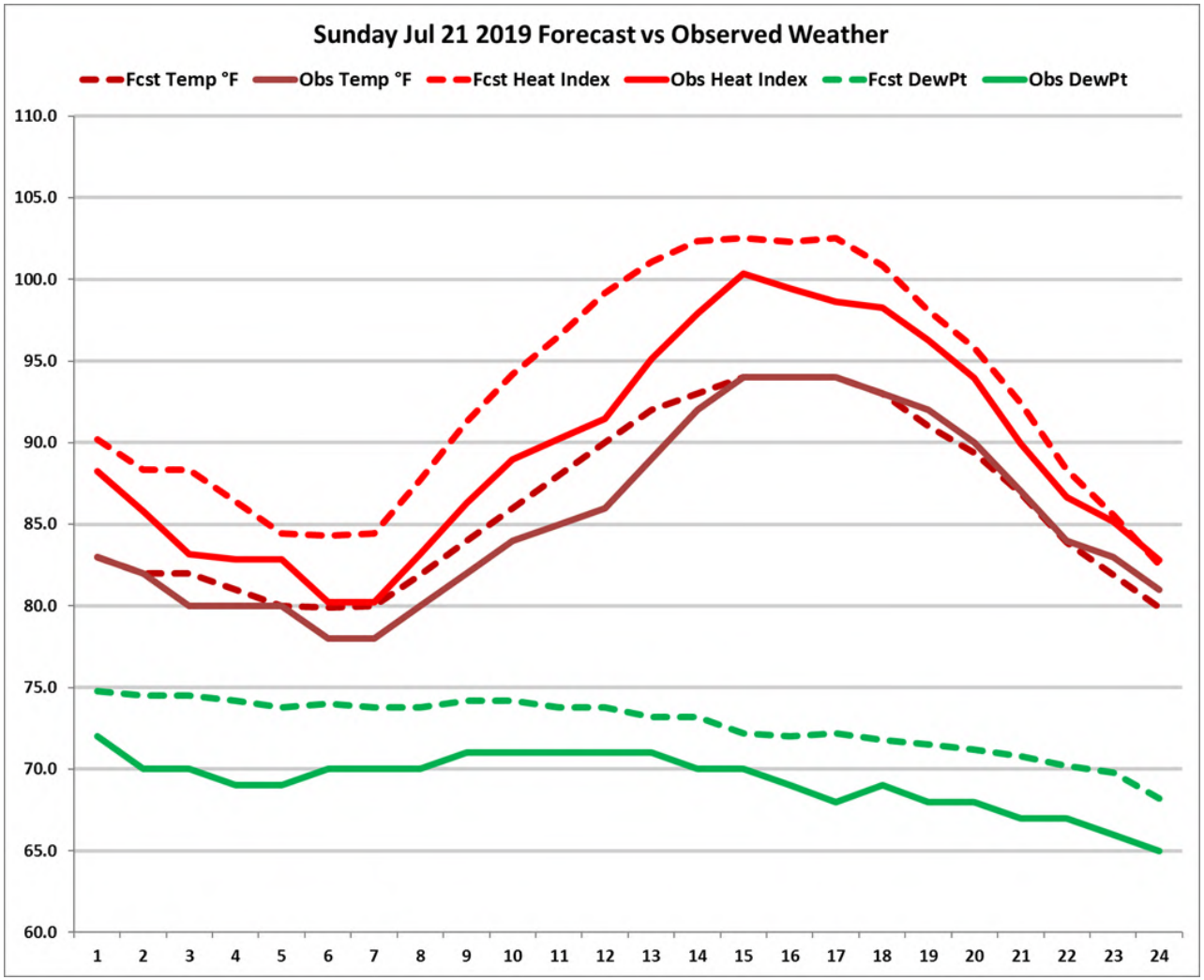
Saturday (7/20) Forecast vs. Observed Weather



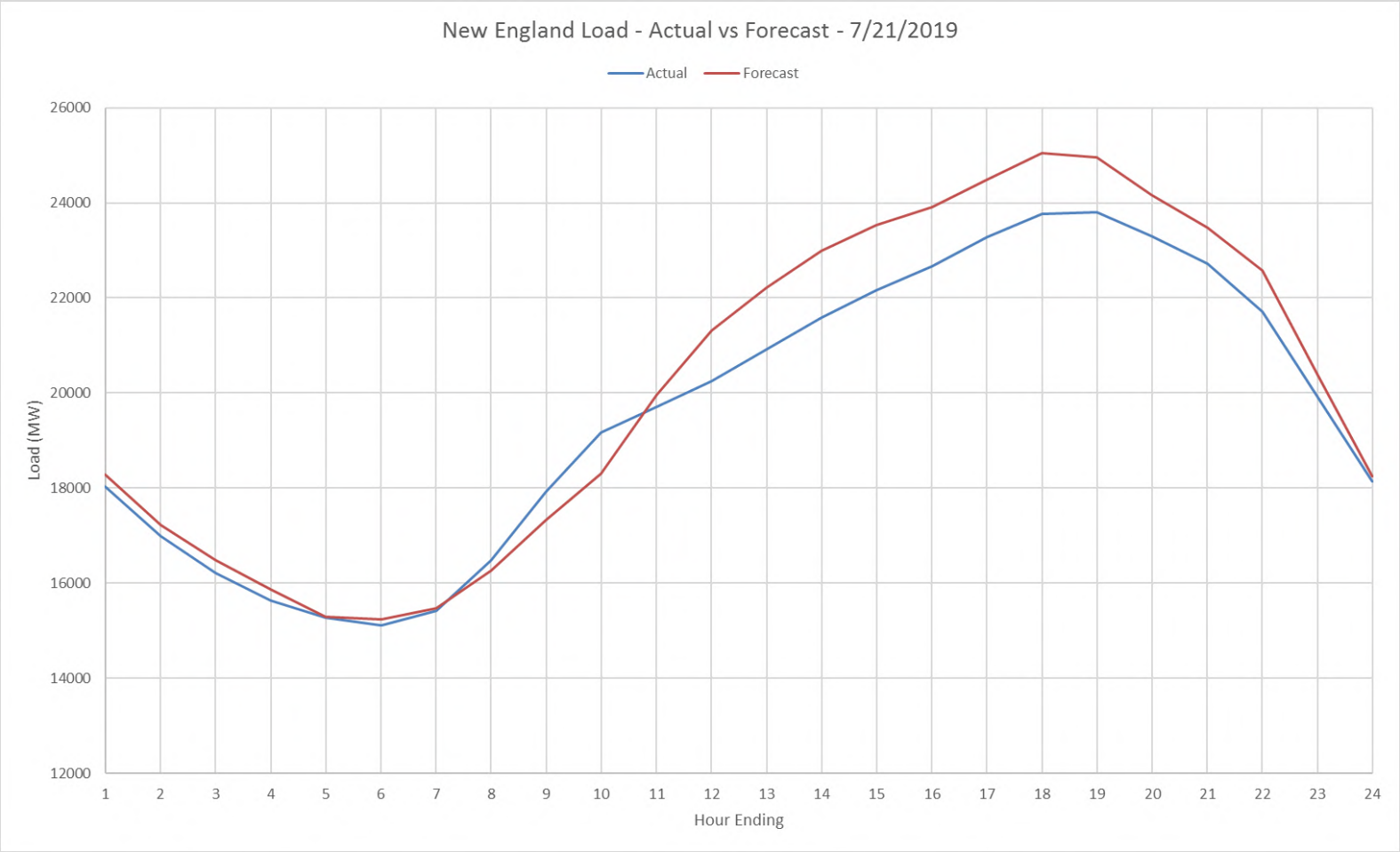
Saturday (7/20) Forecast vs. Actual Load



Sunday (7/21) Forecast vs. Observed Weather

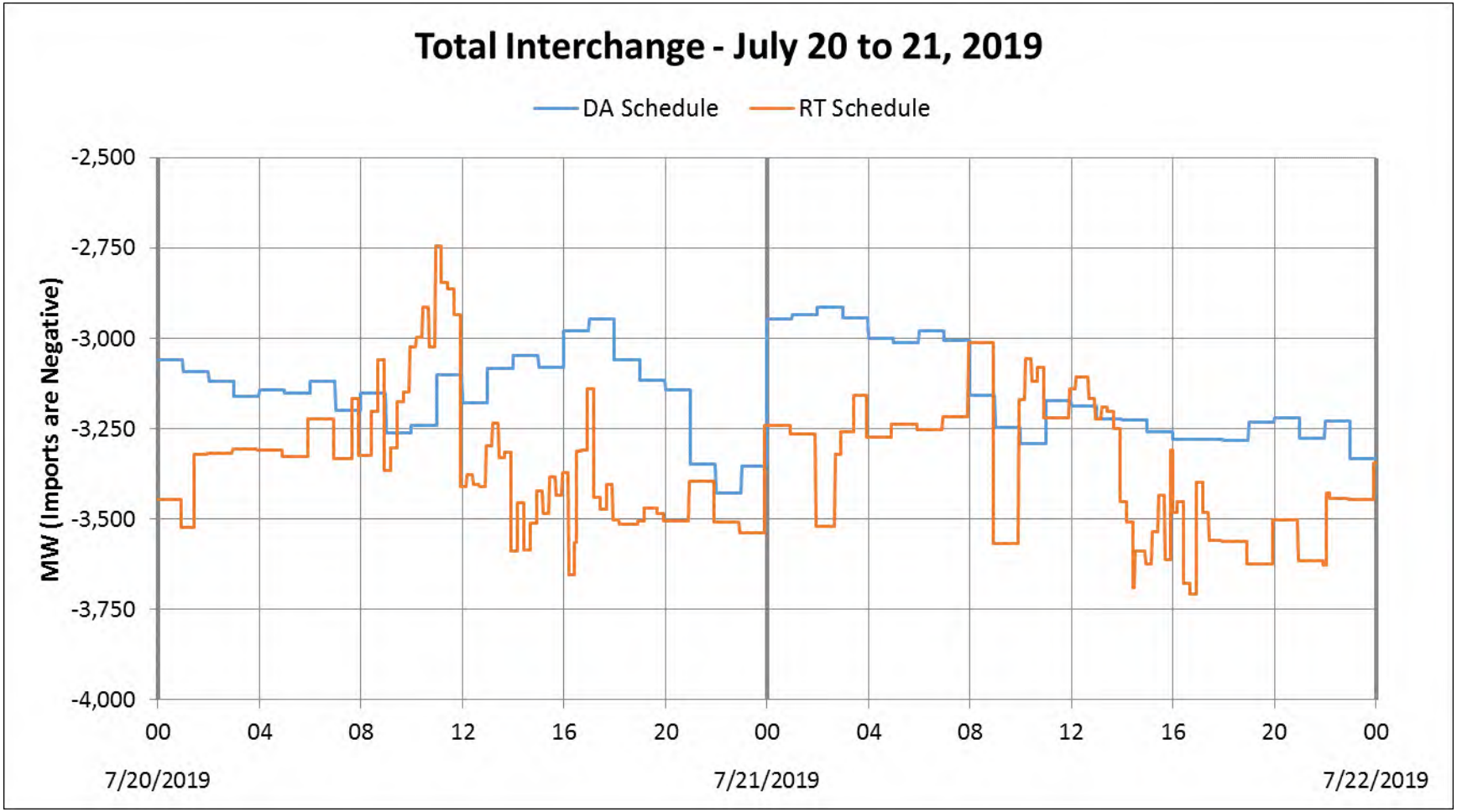


Sunday (7/21) Forecast vs. Actual Load

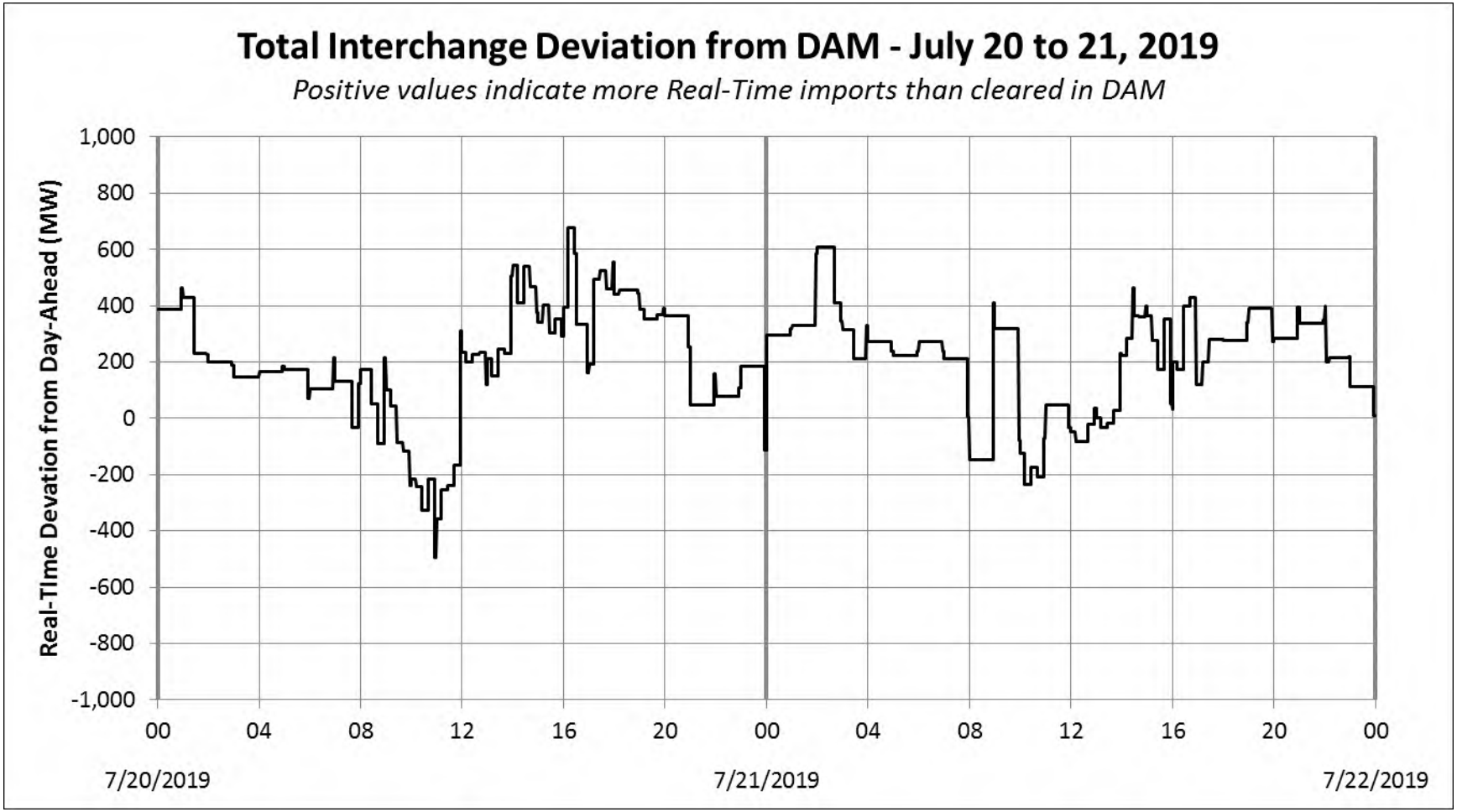


INTERCHANGE

Interchange - Aggregate

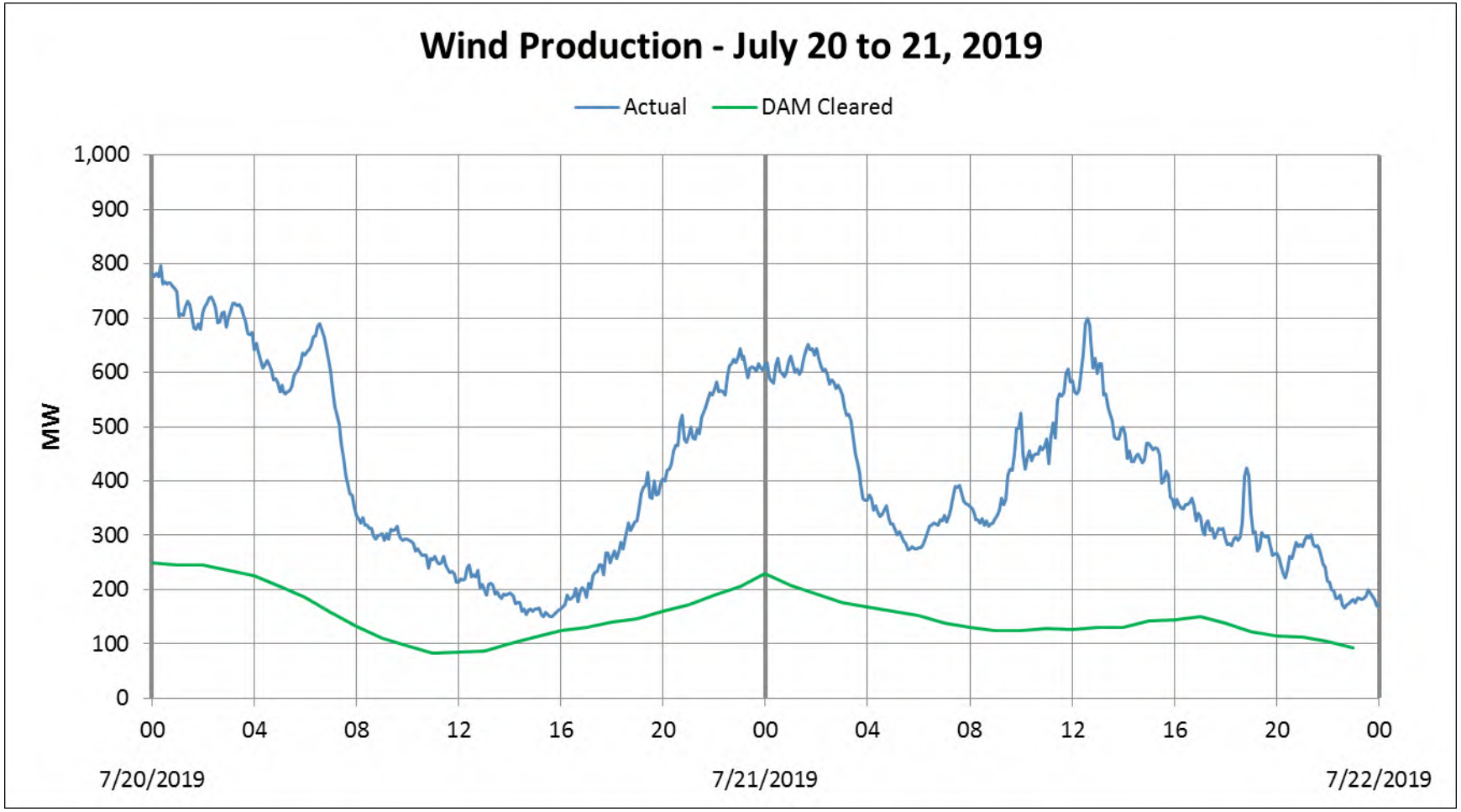


Interchange – Deviation from DAM



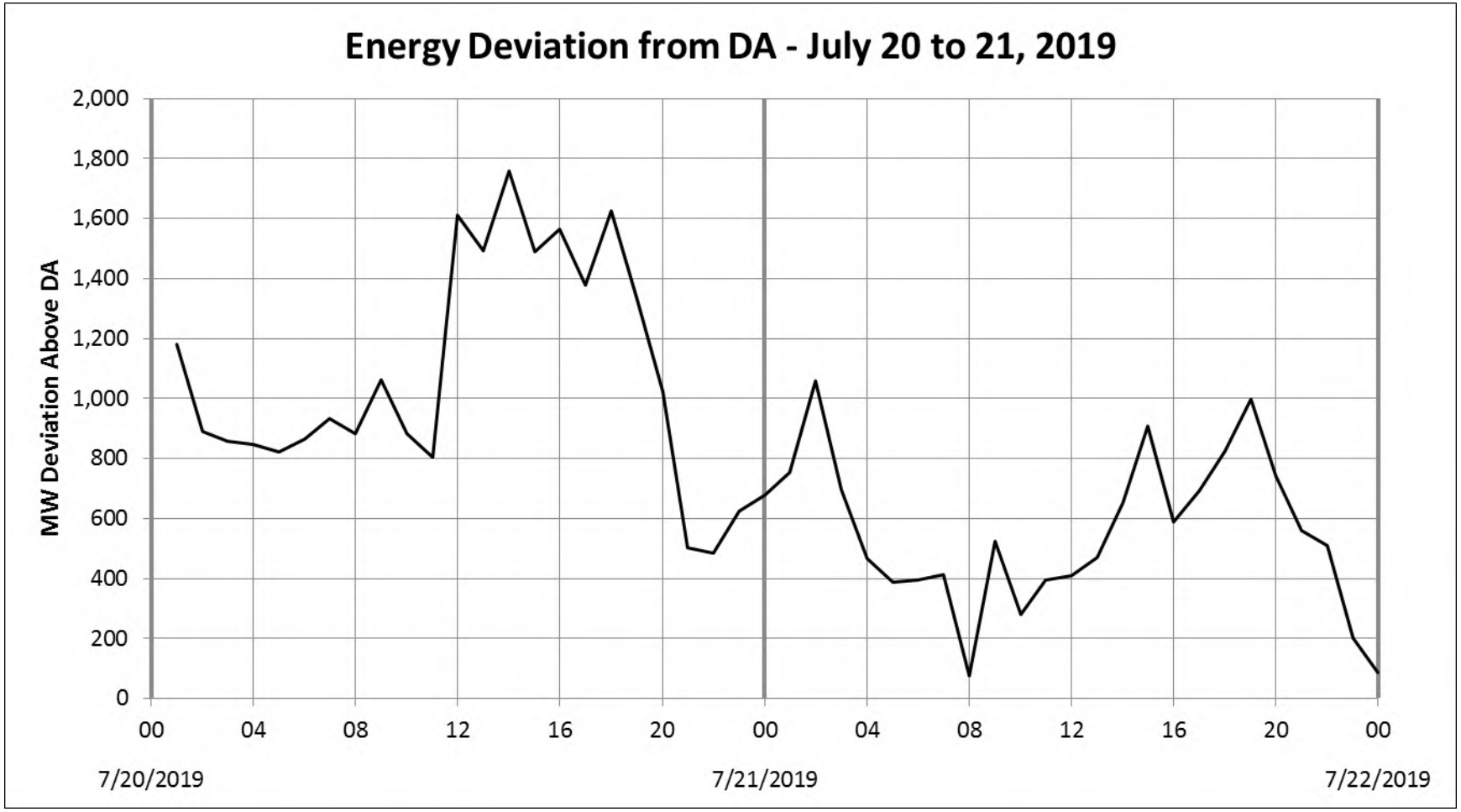
WIND PRODUCTION

Wind Production



TOTAL ENERGY DEVIATIONS FROM DAM

Energy Deviation from DA – Aggregate



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (78.5°F) Max: 98°F, Min: 63°F Precipitation: 4.56" – Above Normal Normal: 3.30"	Hartford	Temperature: Above Normal (78.2°F) Max: 100°F, Min: 56°F Precipitation: 2.47" - Below Normal Normal: 4.03"

Peak Load:	24,004 MW	July 30, 2019	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None for July 2019			

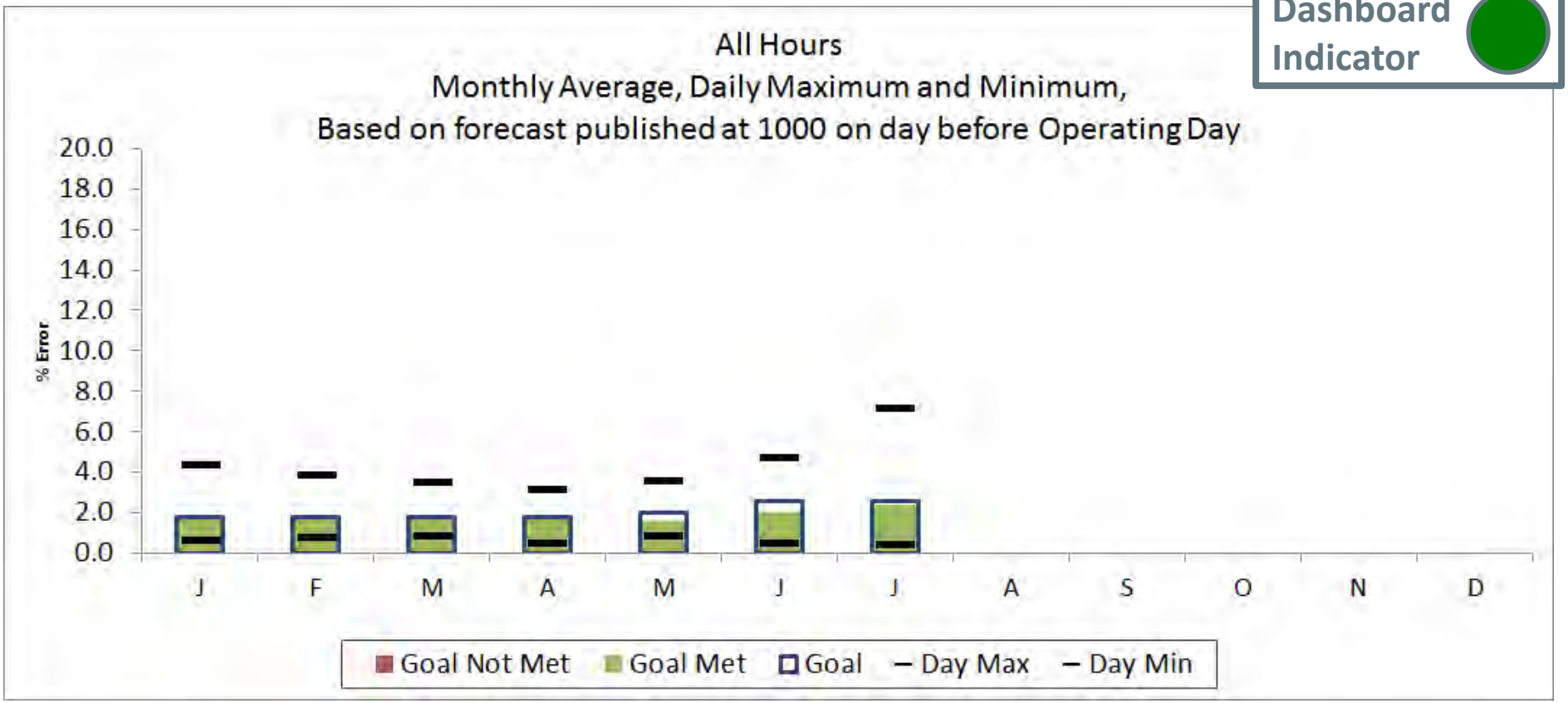
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
7/11/2019	NYISO	1493
7/19/2019	IESO	830
7/23/2019	IESO	900
7/24/2019	IESO	500
7/26/2019	NYISO	1500
7/30/2019	ISO-NE	550

2019 System Operations - Load Forecast Accuracy

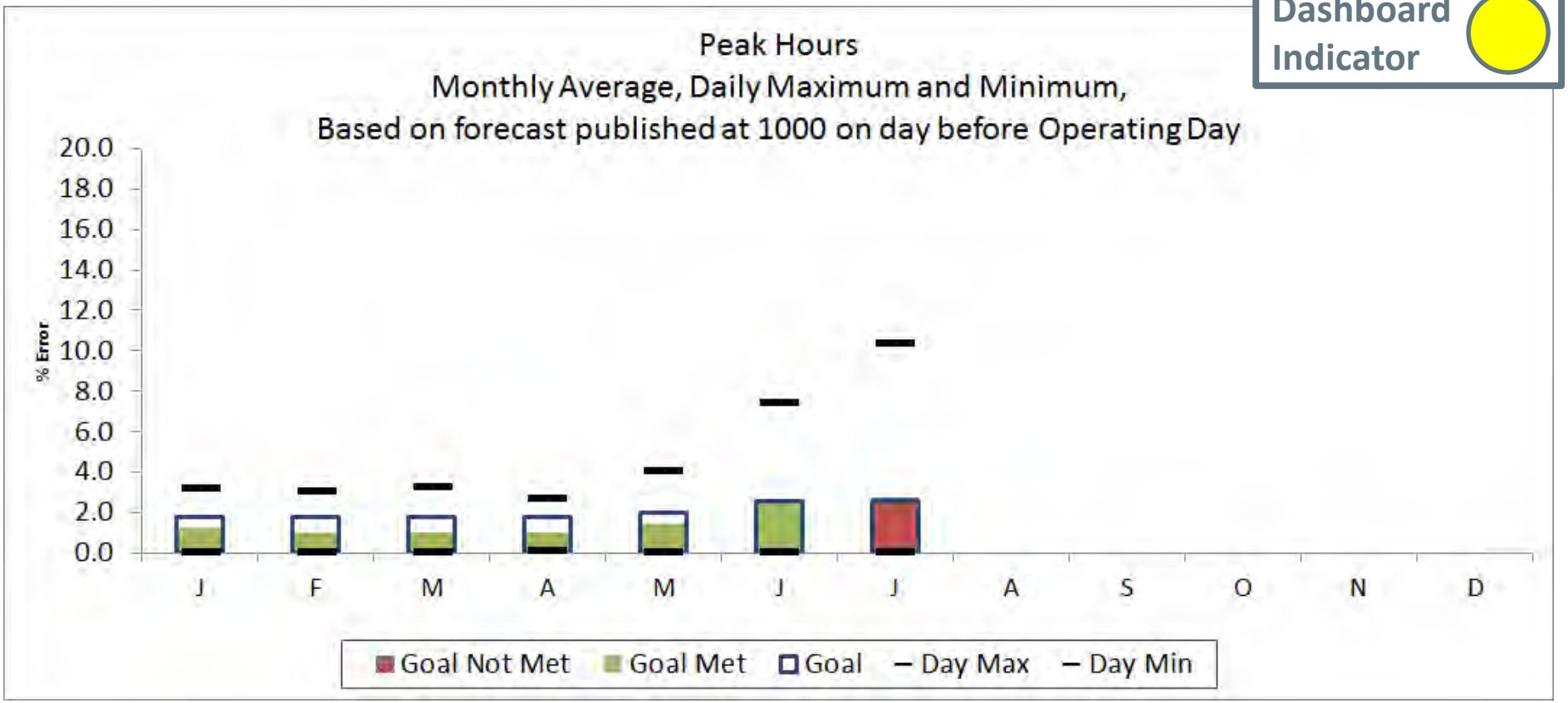
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.36	3.87	3.47	3.11	3.53	4.68	7.14						7.14
Day Min	0.60	0.77	0.81	0.49	0.79	0.49	0.39						0.39
MAPE	1.76	1.68	1.72	1.79	1.64	2.01	2.37						1.85
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

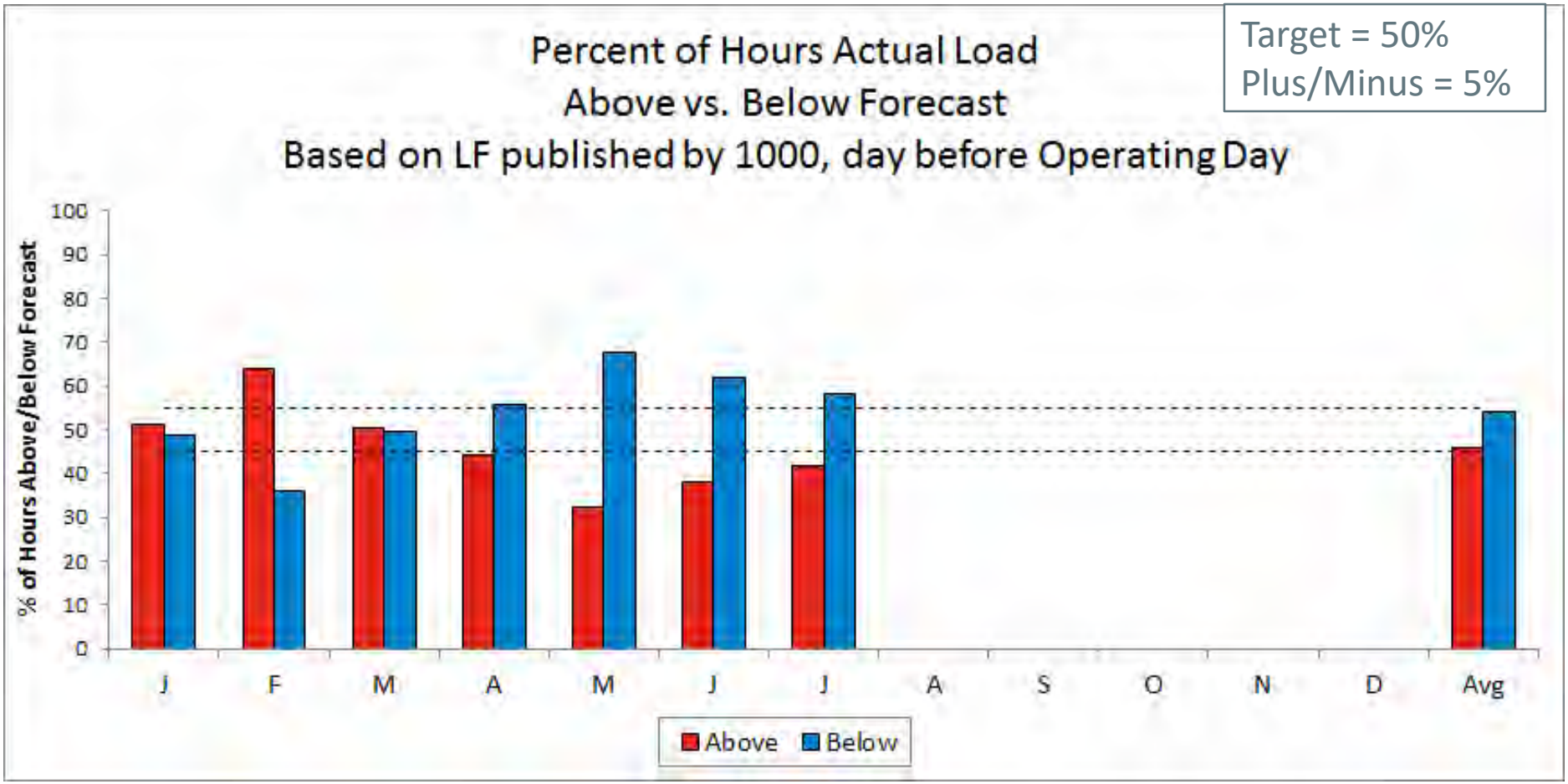
2019 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



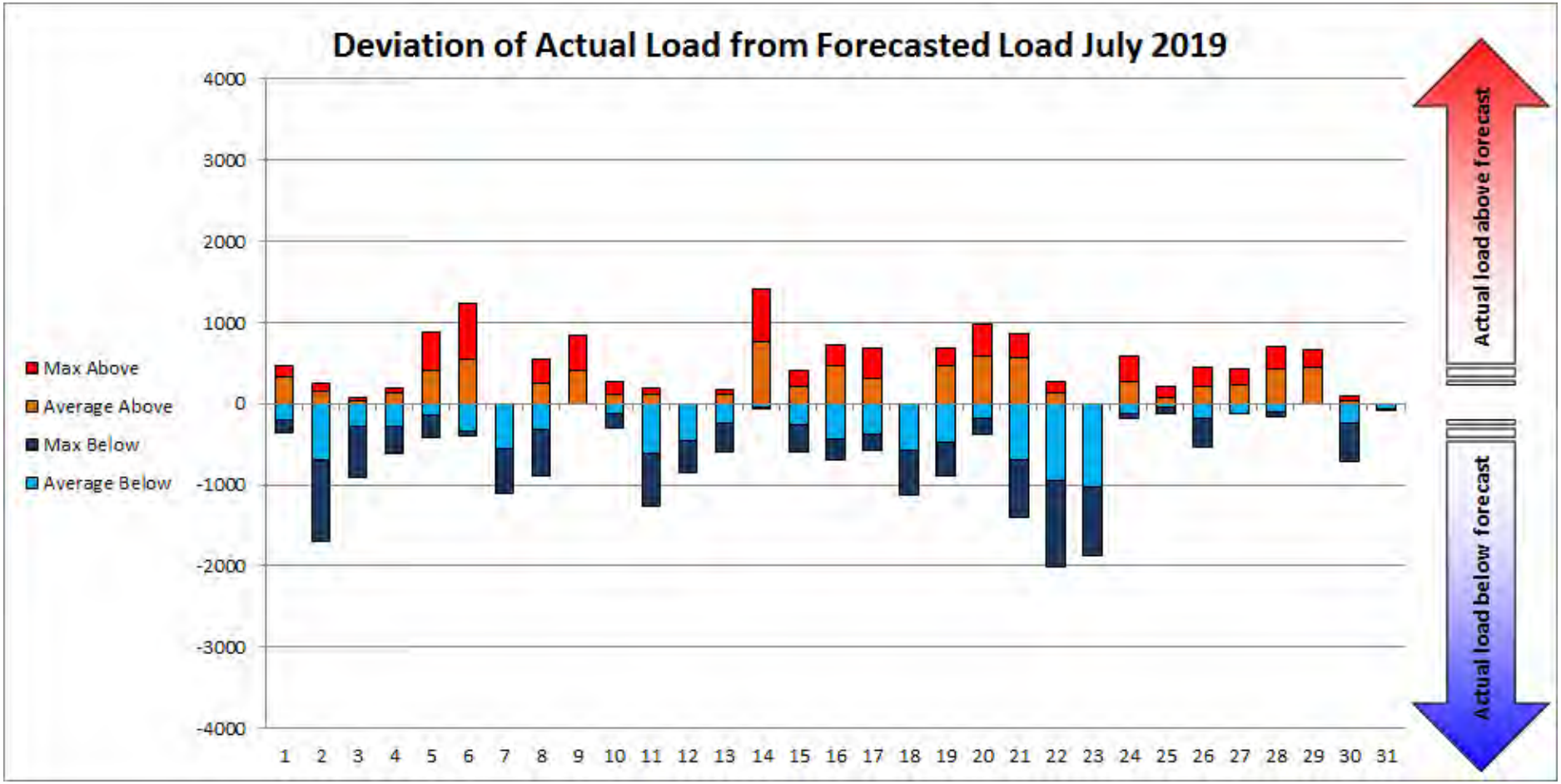
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.17	3.03	3.23	2.71	4.08	7.39	10.38						10.38
Day Min	0.02	0.06	0.06	0.12	0.07	0.07	0.01						0.01
MAPE	1.22	1.04	1.06	1.04	1.45	2.53	2.74						1.59
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

2019 System Operations - Load Forecast Accuracy cont.

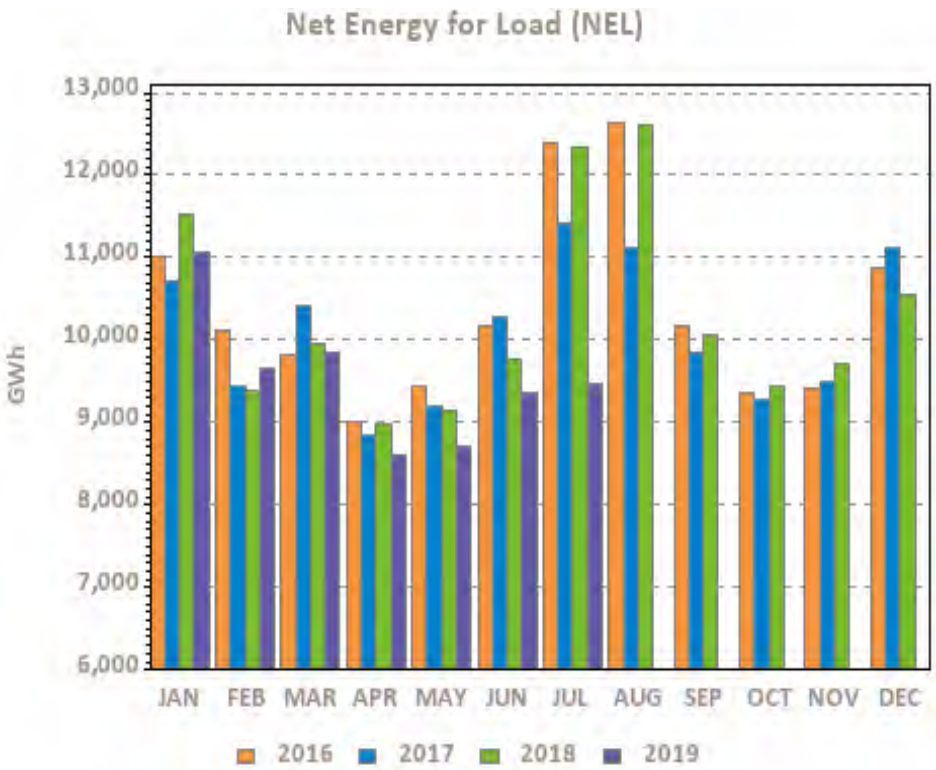


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	51.1	64	50.5	44.2	32.5	37.9	41.7						46
Below %	48.9	36	49.5	55.8	67.5	62.1	58.3						54
Avg Above	211.7	224.2	162.1	184.1	126.1	144.9	252.1						252
Avg Below	-183.0	-174.3	-192.4	-161.7	-179.6	-225.1	-330.0						-330
Avg All	30	88	-12	1	-79	-80	-99						-23

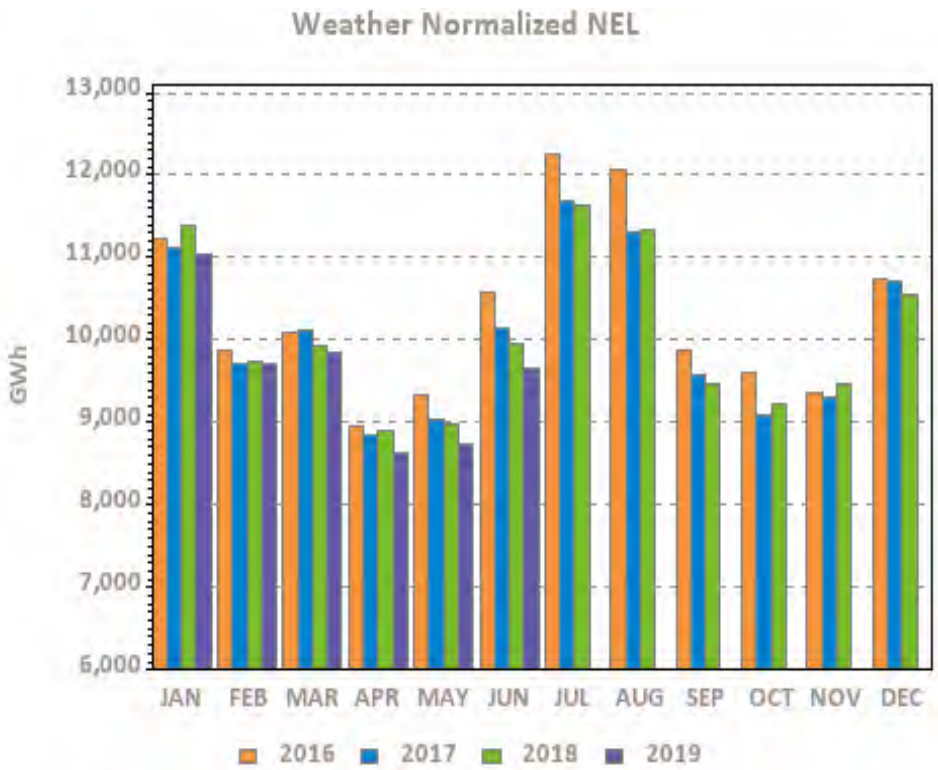
2019 System Operations - Load Forecast Accuracy cont.



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



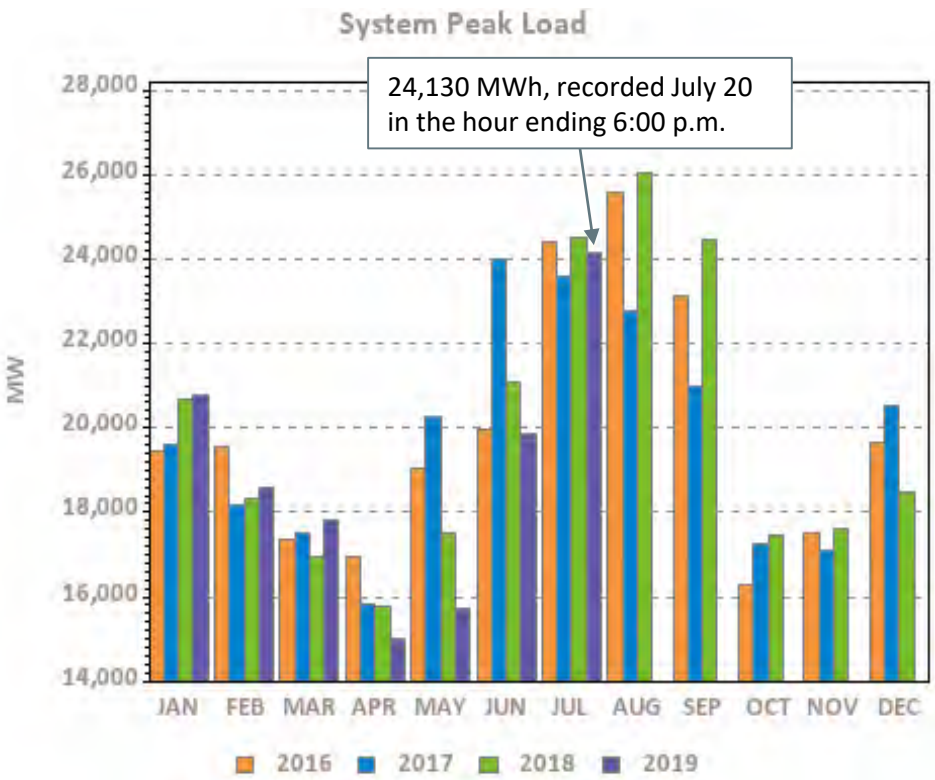
Ann Tot (TWh): 124.4 121.2 123.3 66.7



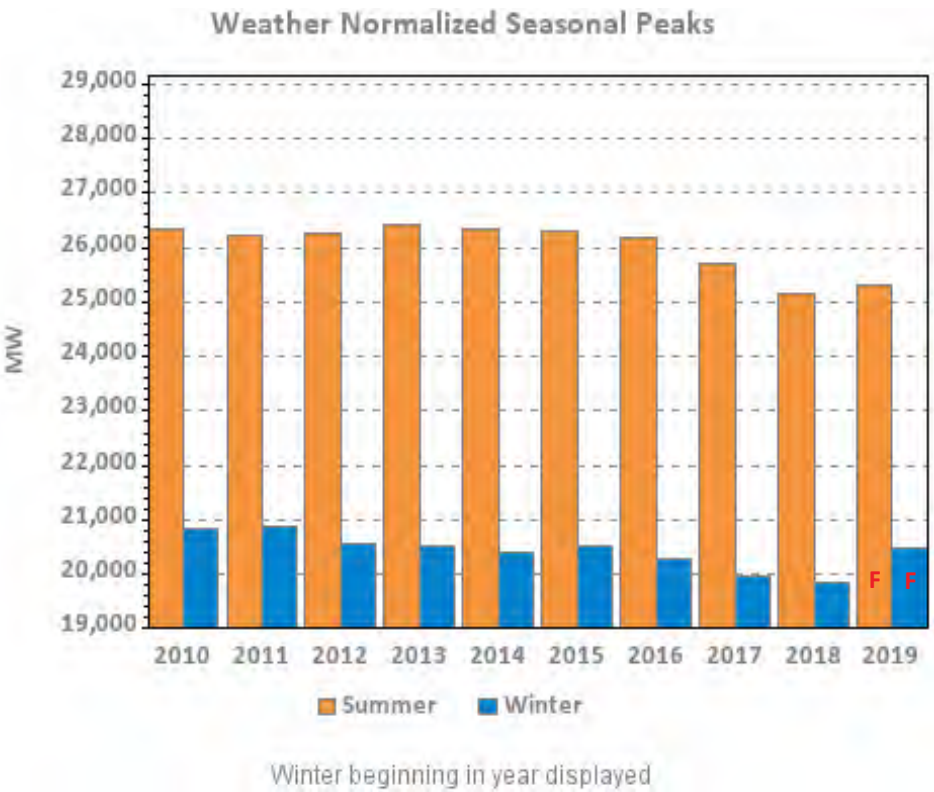
Ann Tot (TWh): 124.0 120.7 120.6 57.7

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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



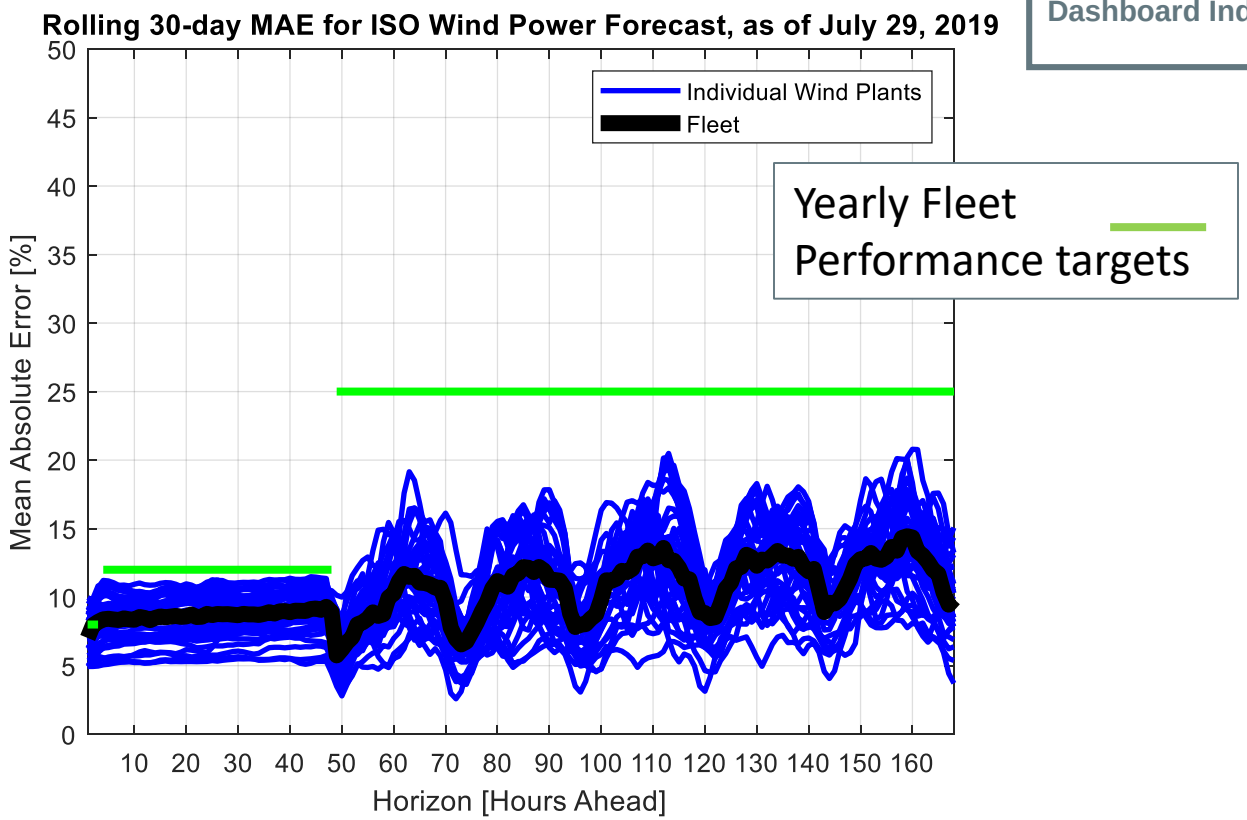
*Revenue quality metered value



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

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

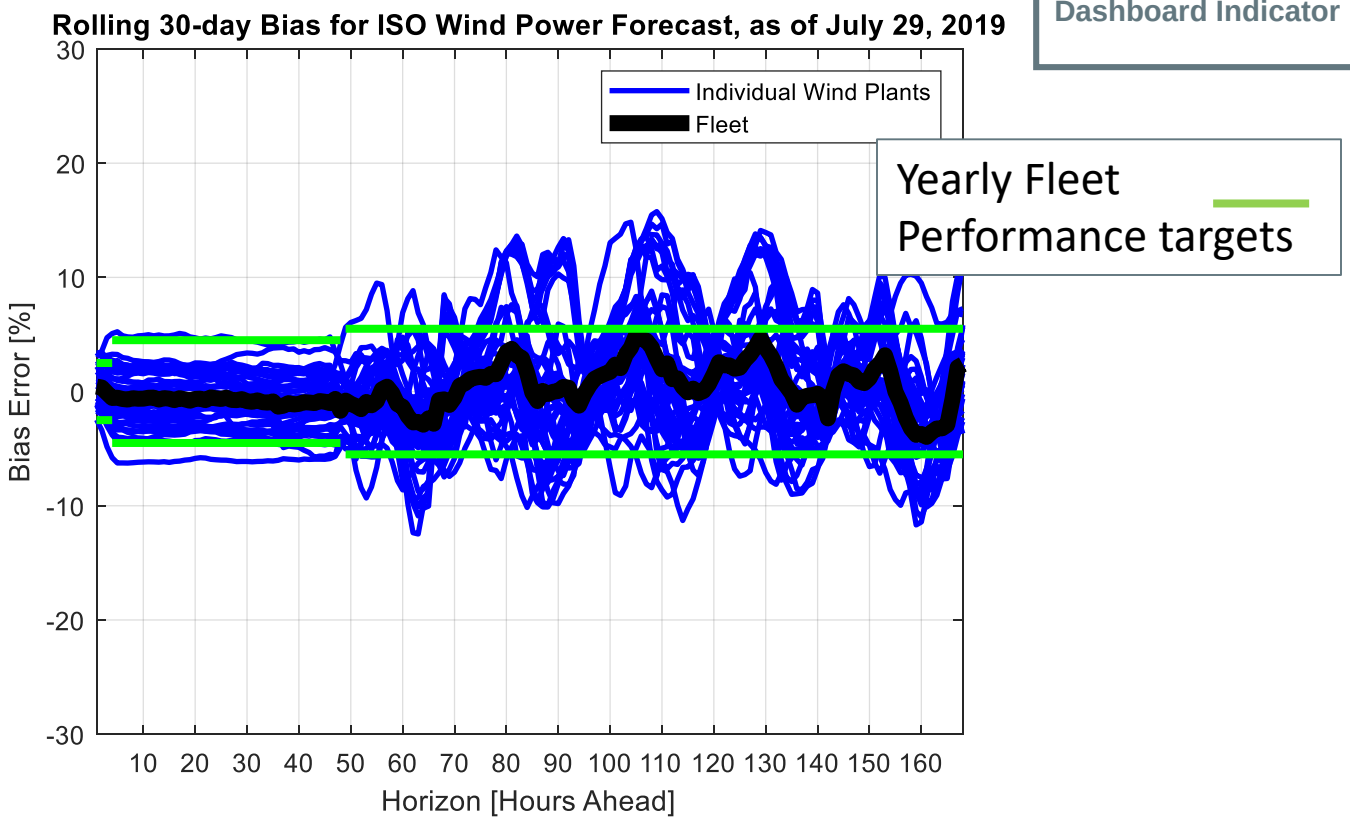
Dashboard Indicator



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

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

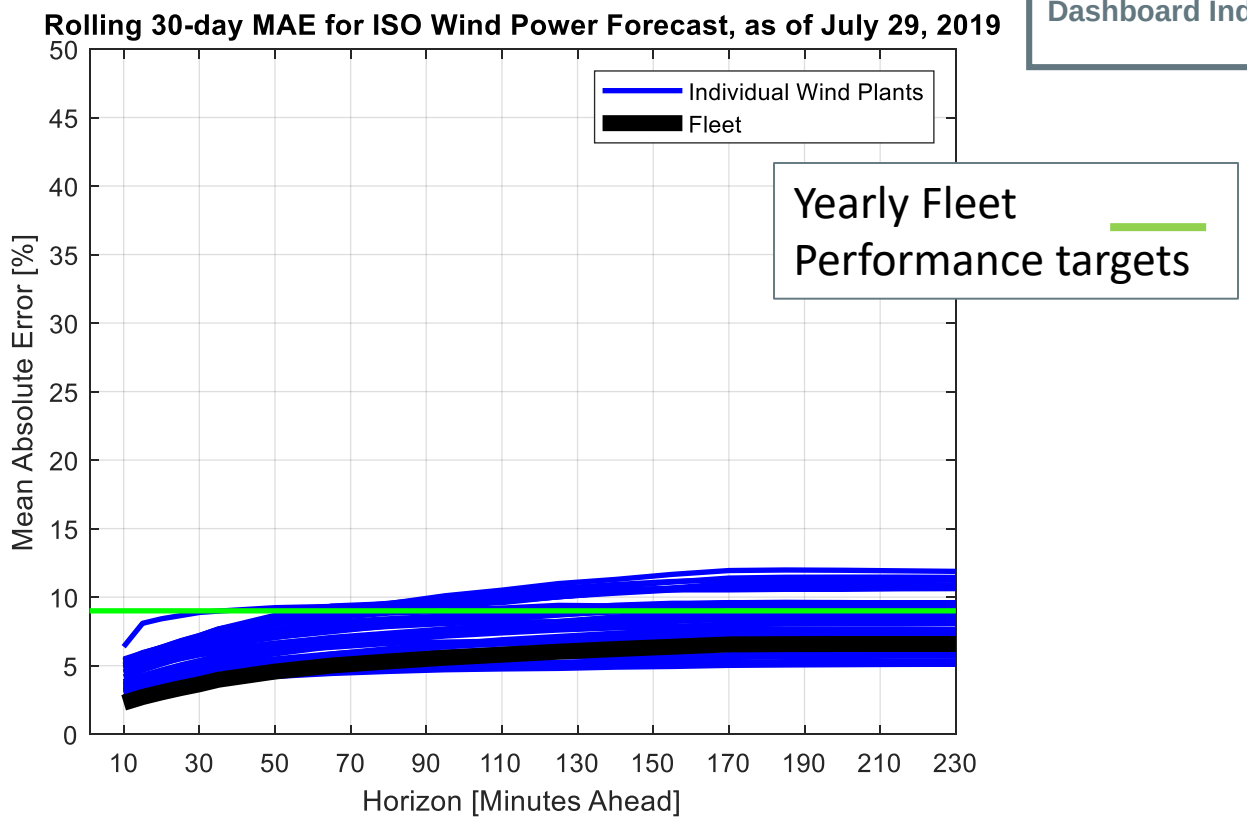
Dashboard Indicator



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



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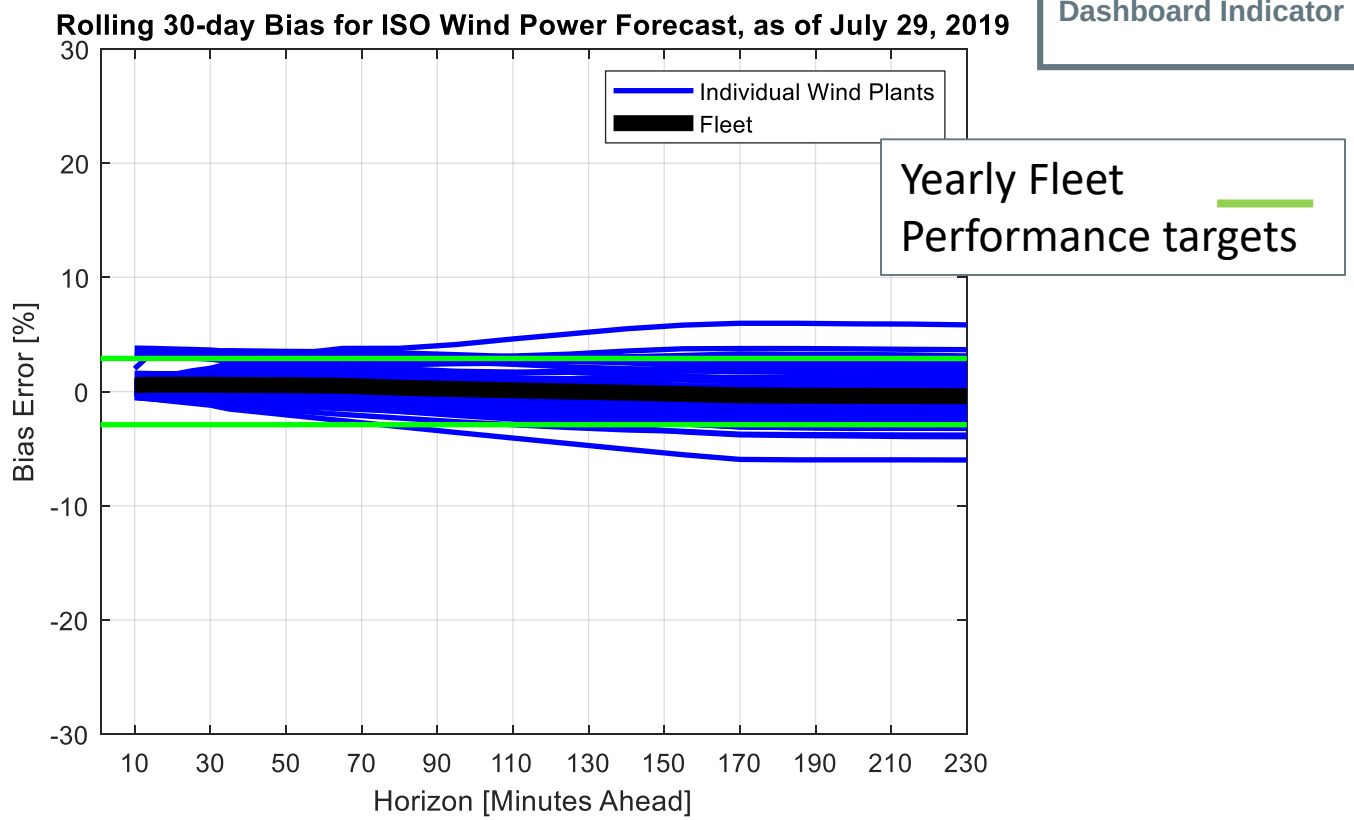
Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator



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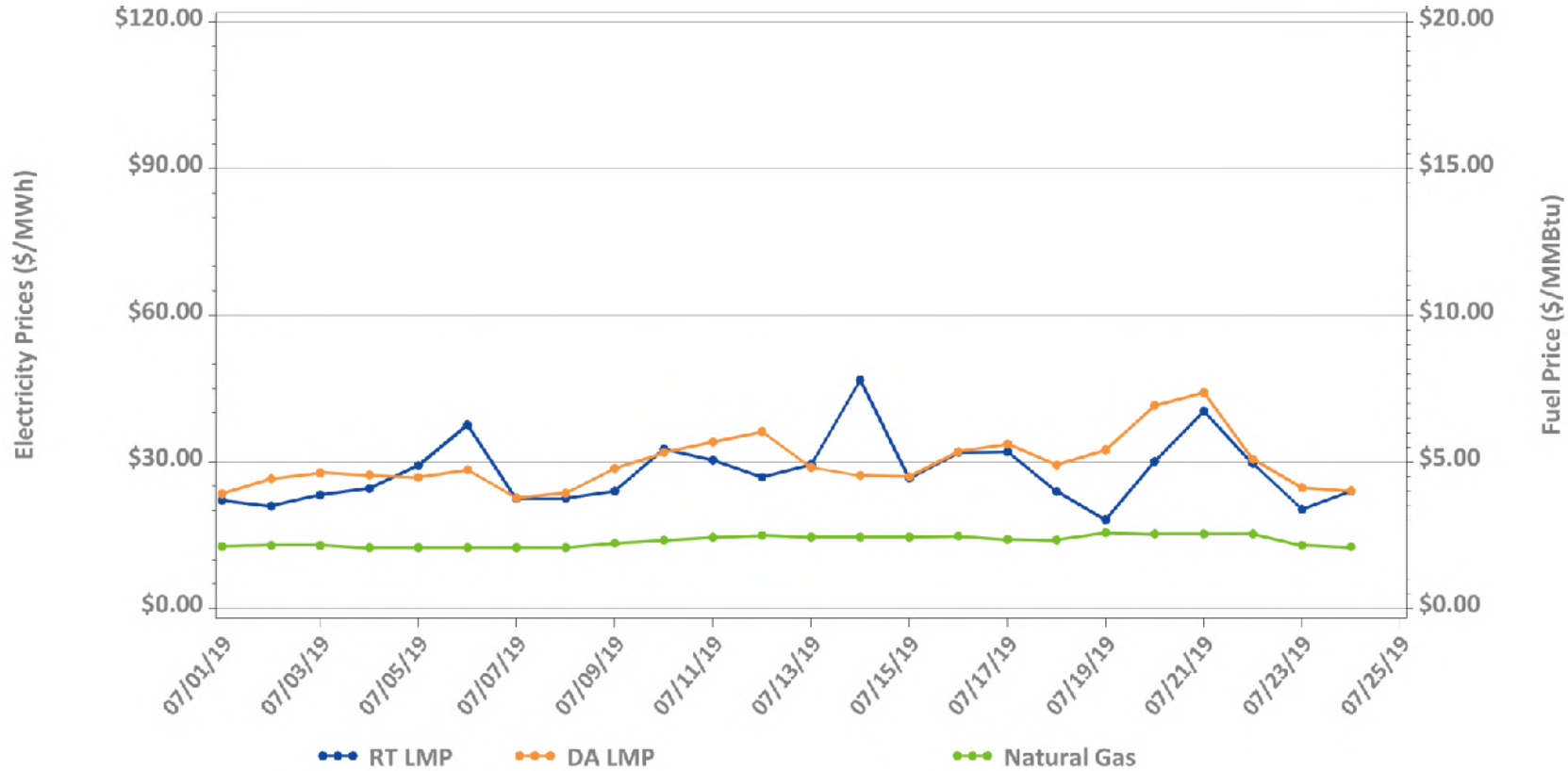
MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: July 1-24, 2019

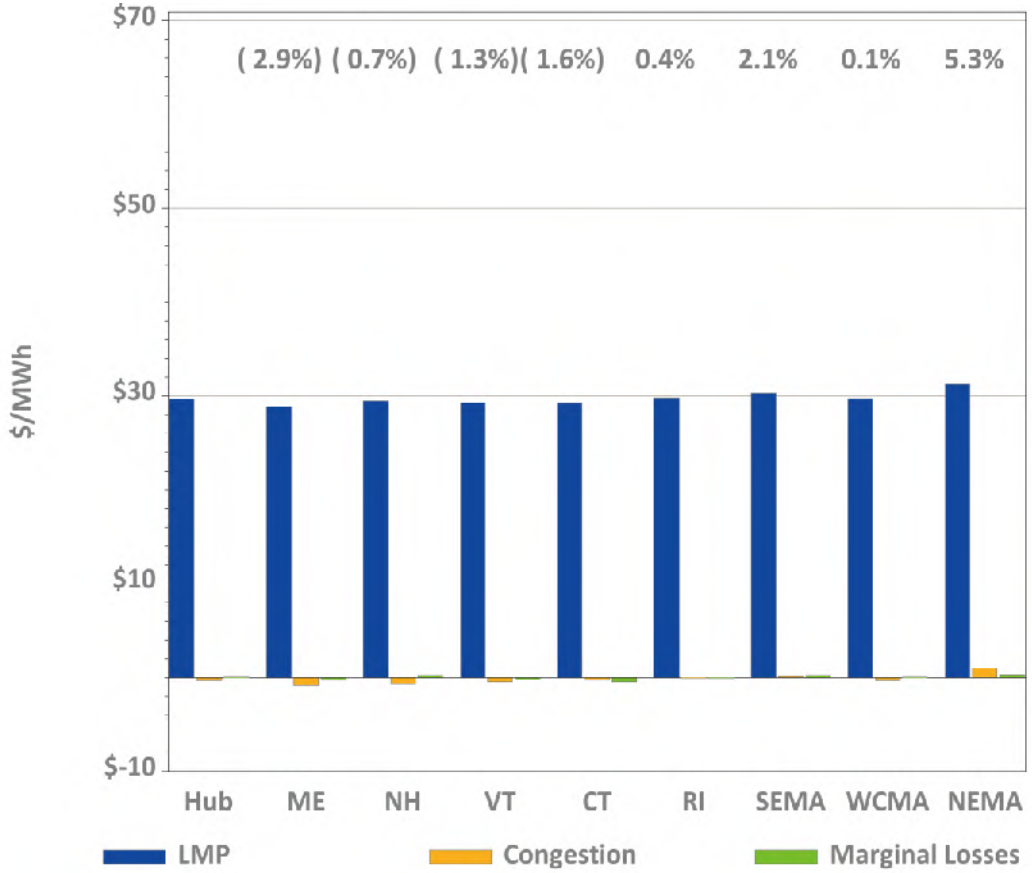


Underlying natural gas data furnished by:

ICE Global markets in clear view

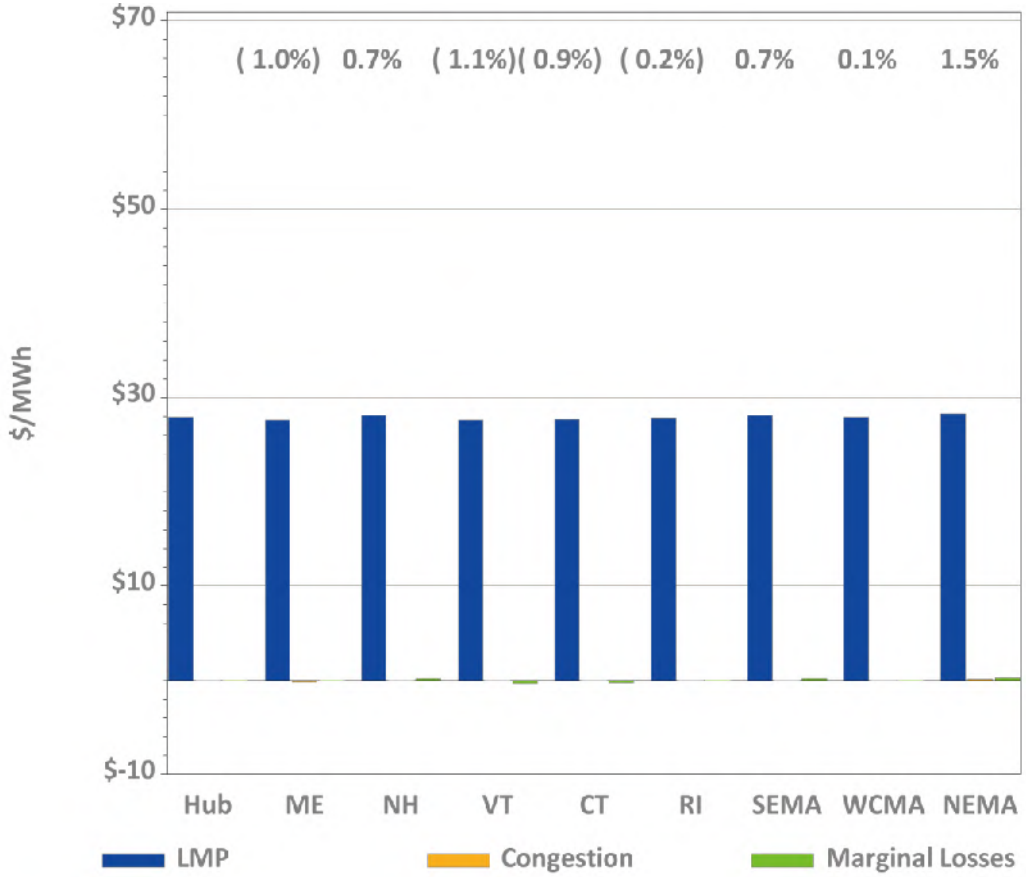
Average price difference over this period (DA-RT): $1.80
Average price difference over this period ABS(DA-RT): $4.50
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 16%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, July 2019



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

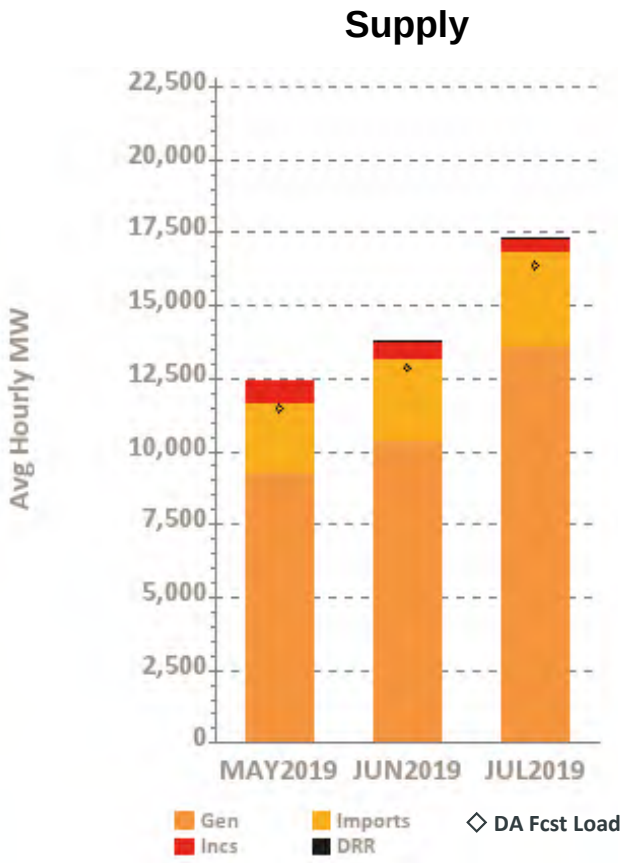
RT LMPs Average by Zone & Hub, July 2019

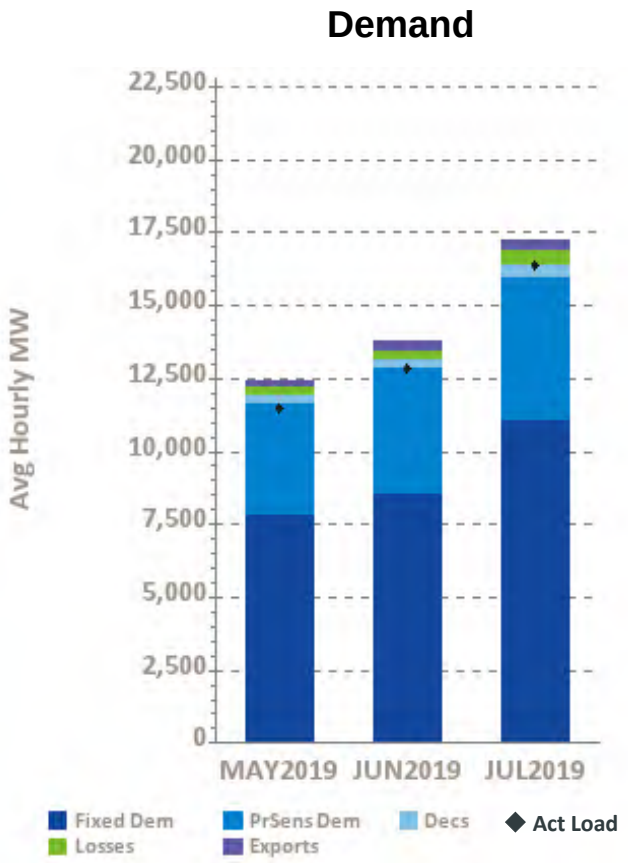


Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

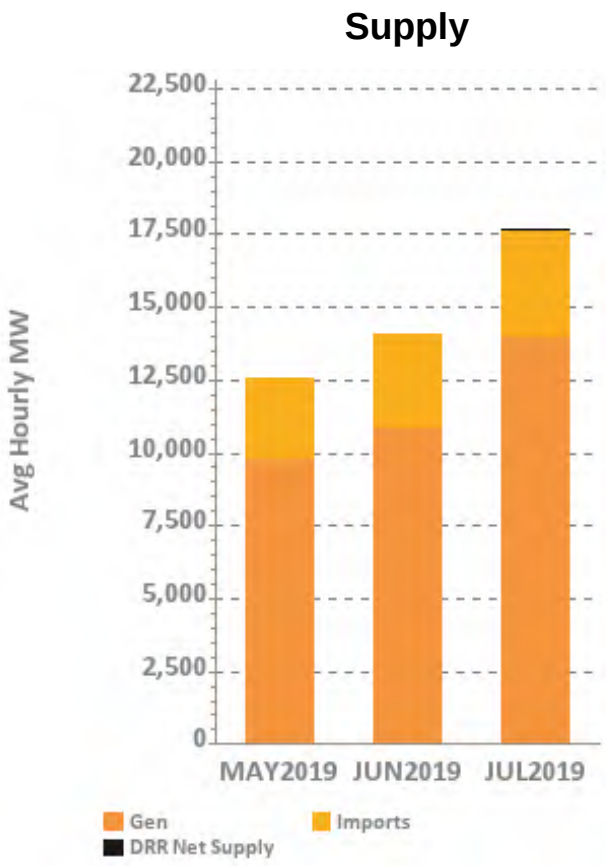


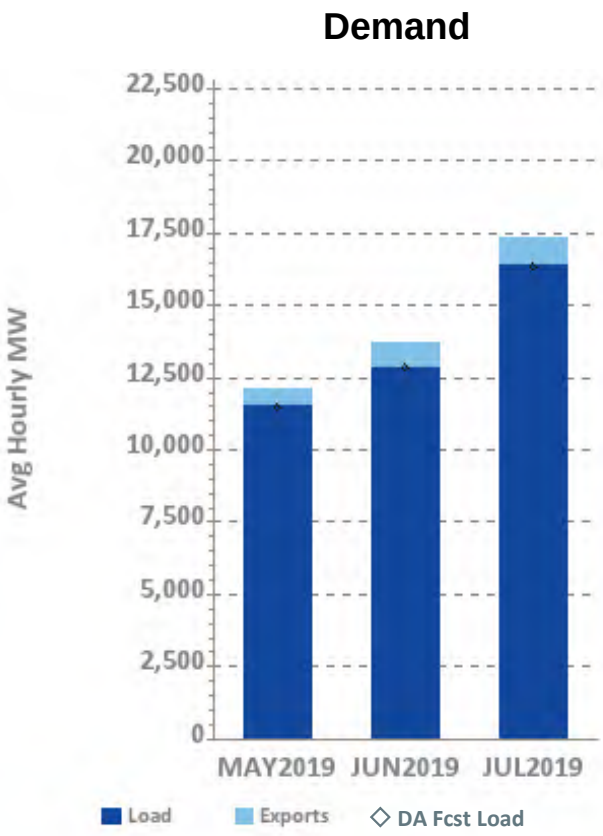


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

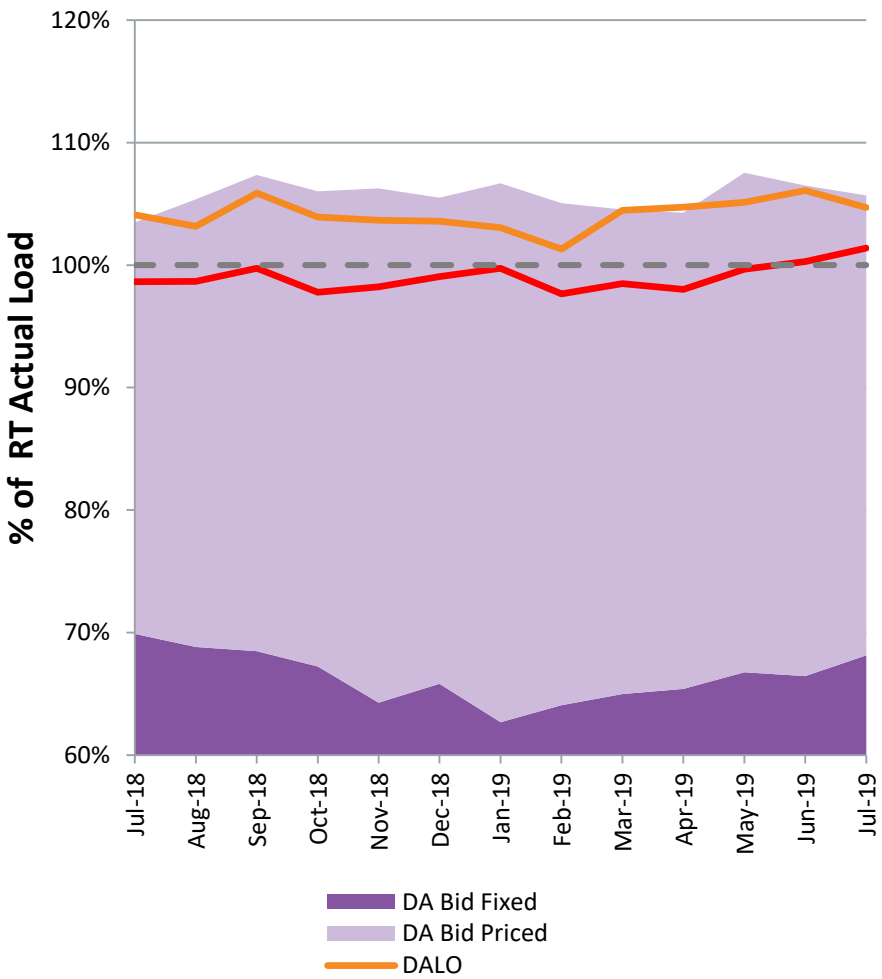
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

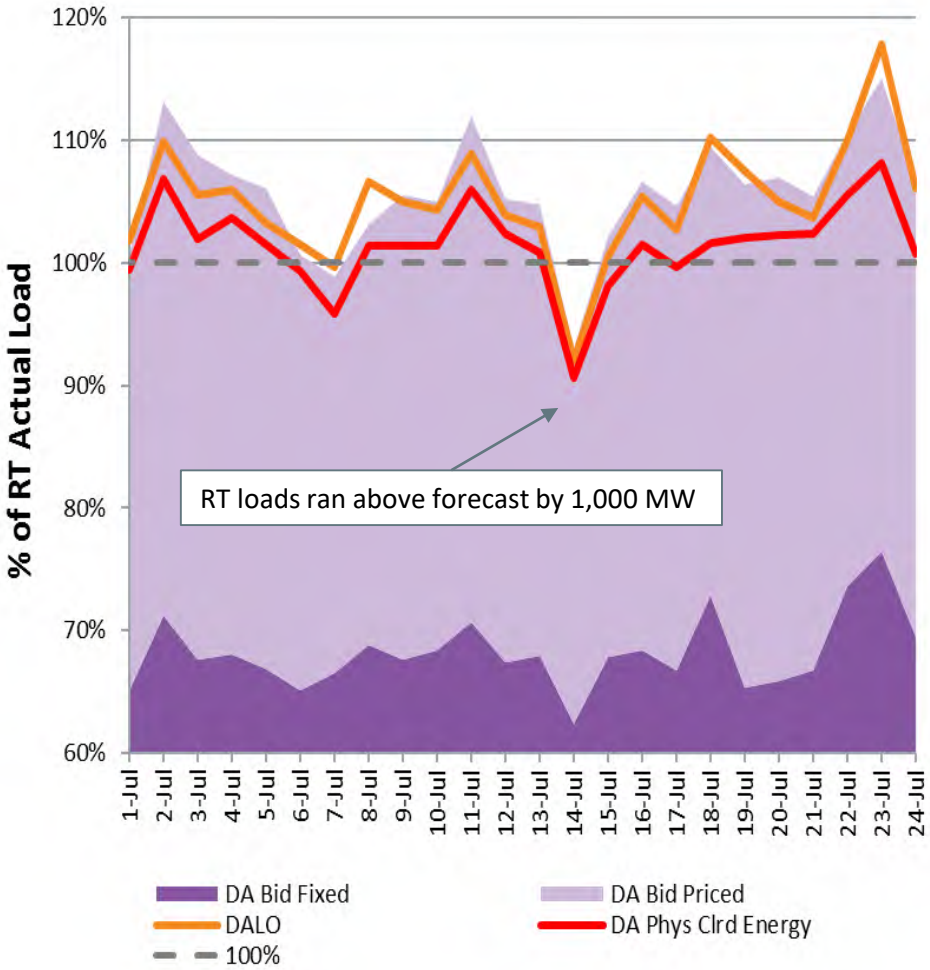
Components of RT Supply and Demand – Last Three Months





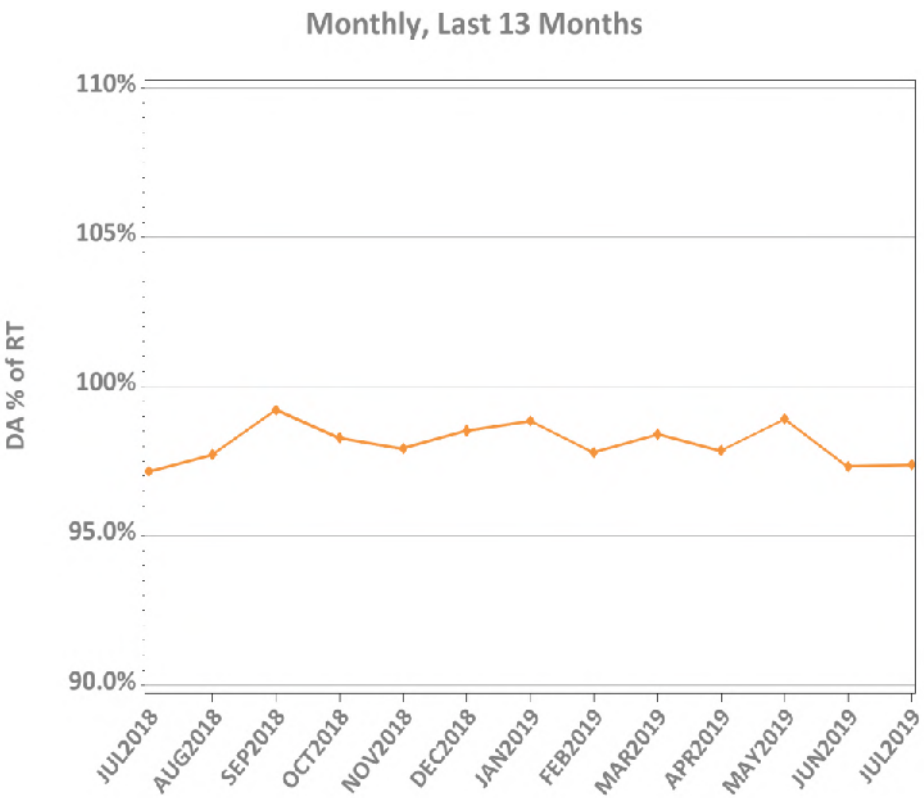
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

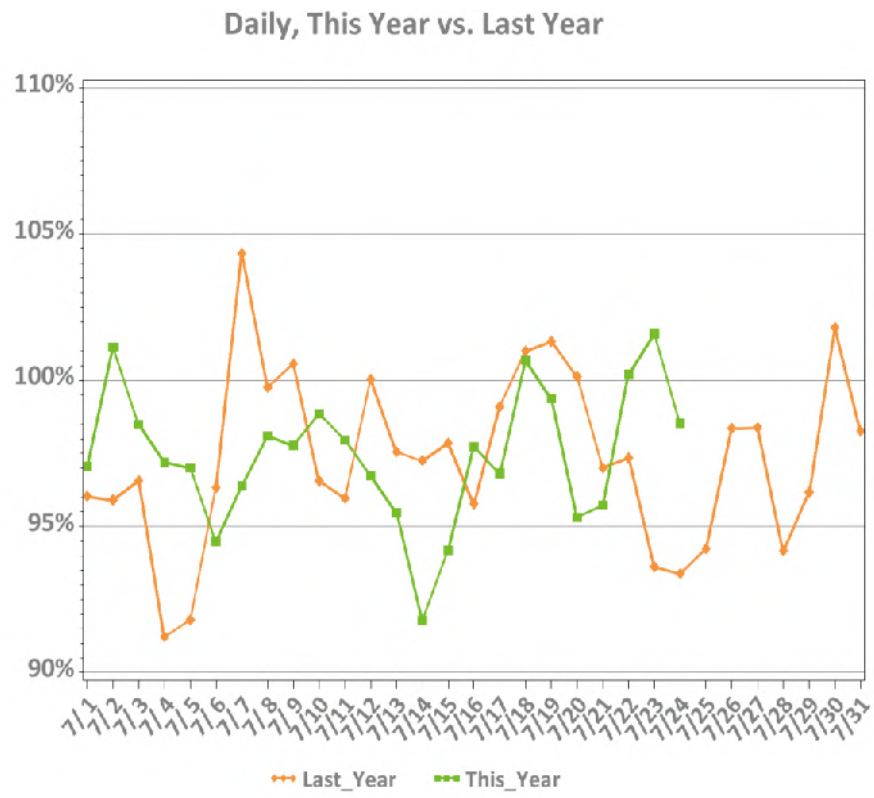




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load. DA Bid categories reflect internal load asset bidding behavior (Virtual demand and export bid behavior not reflected).

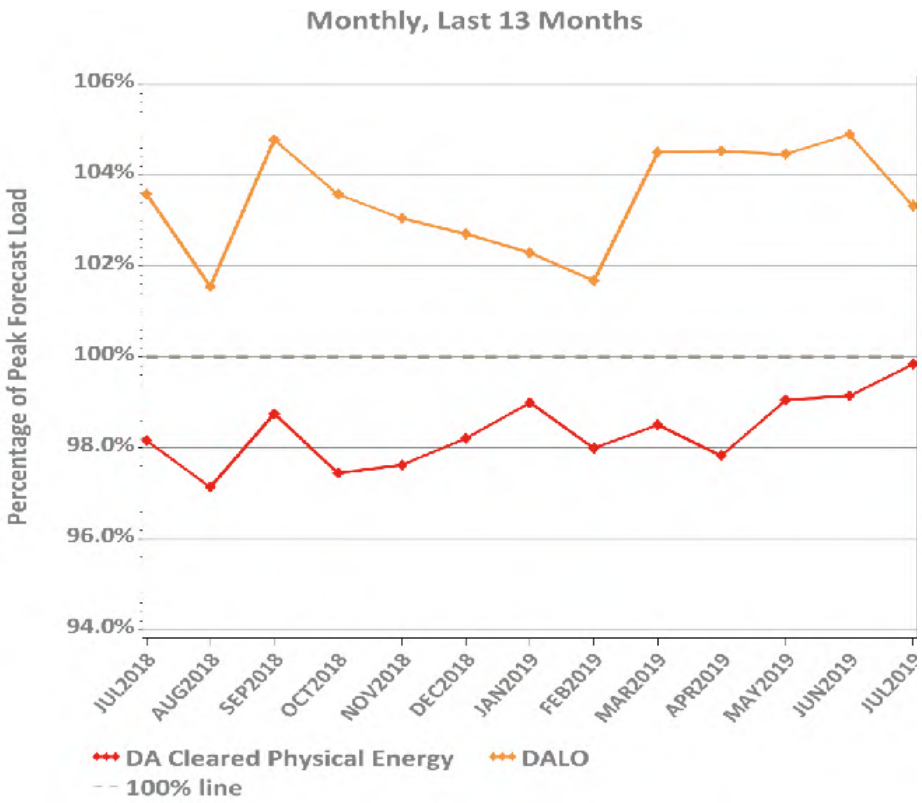
DA vs. RT Load Obligation: July, This Year vs. Last Year

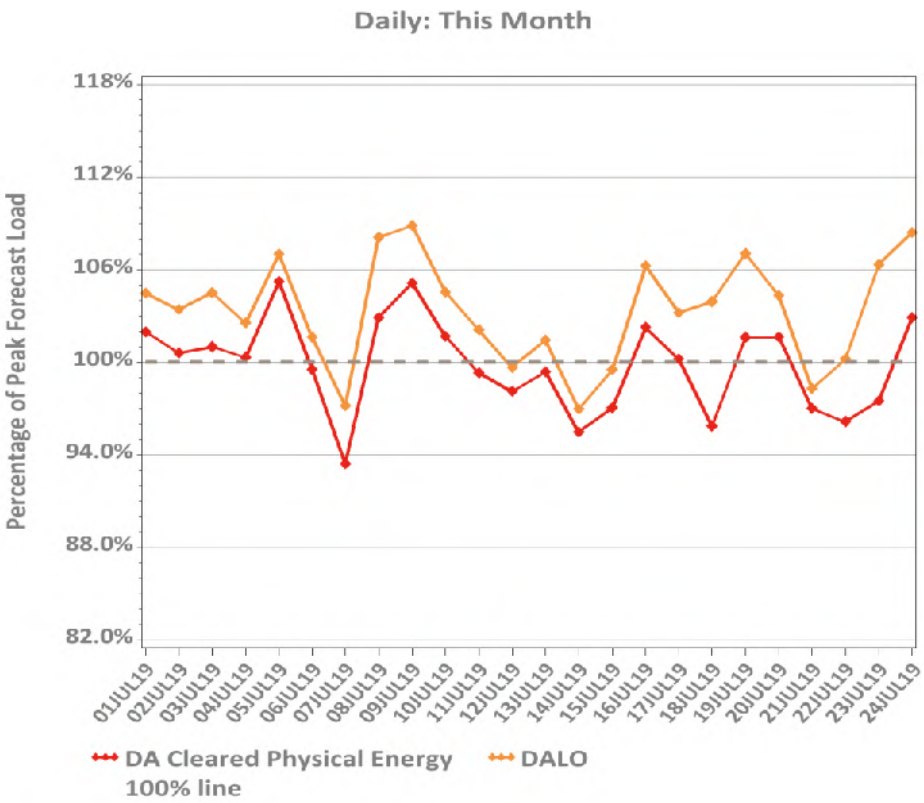




*Hourly average values

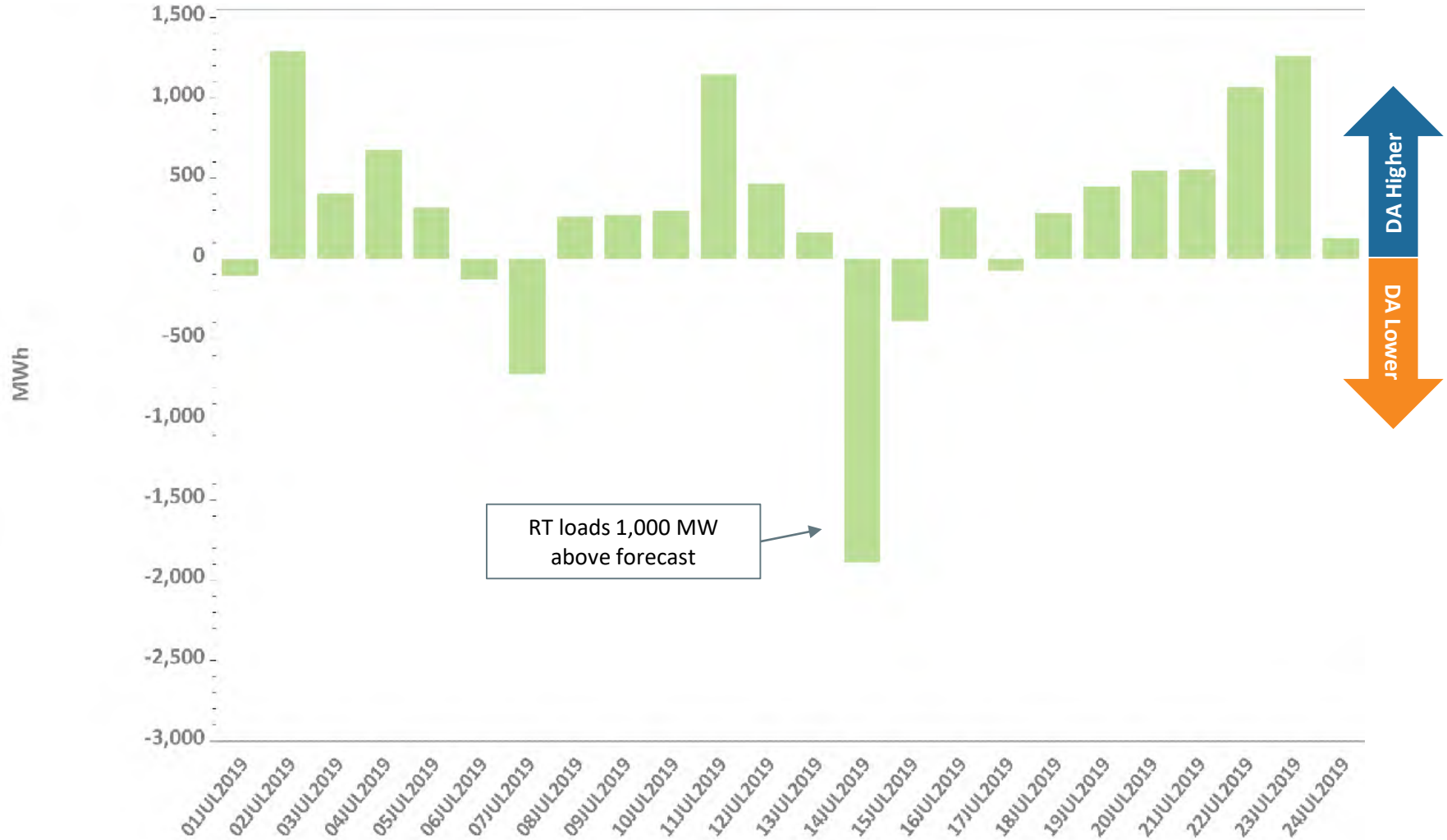
DA Volumes as % of Forecast in Peak Hour





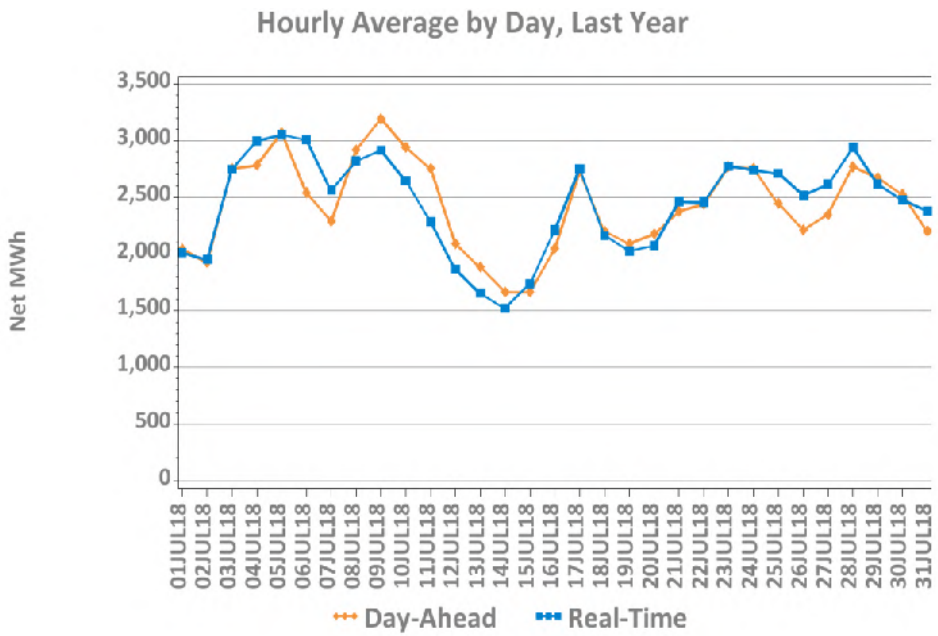
* There were no supplemental commitments required for capacity during the Reserve Adequacy Assessment (RAA) during July. There was one commitment post-RAA during July.

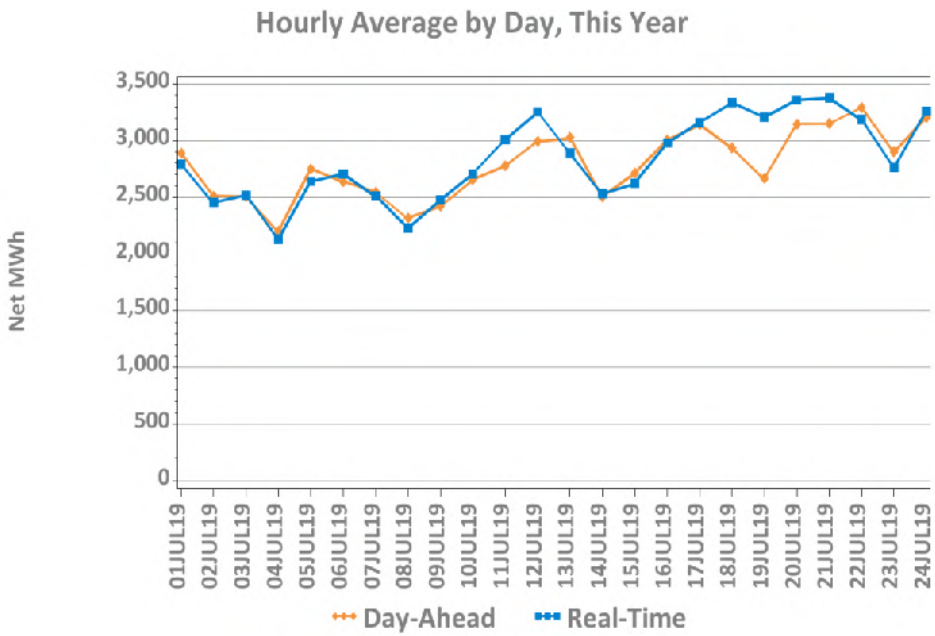
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

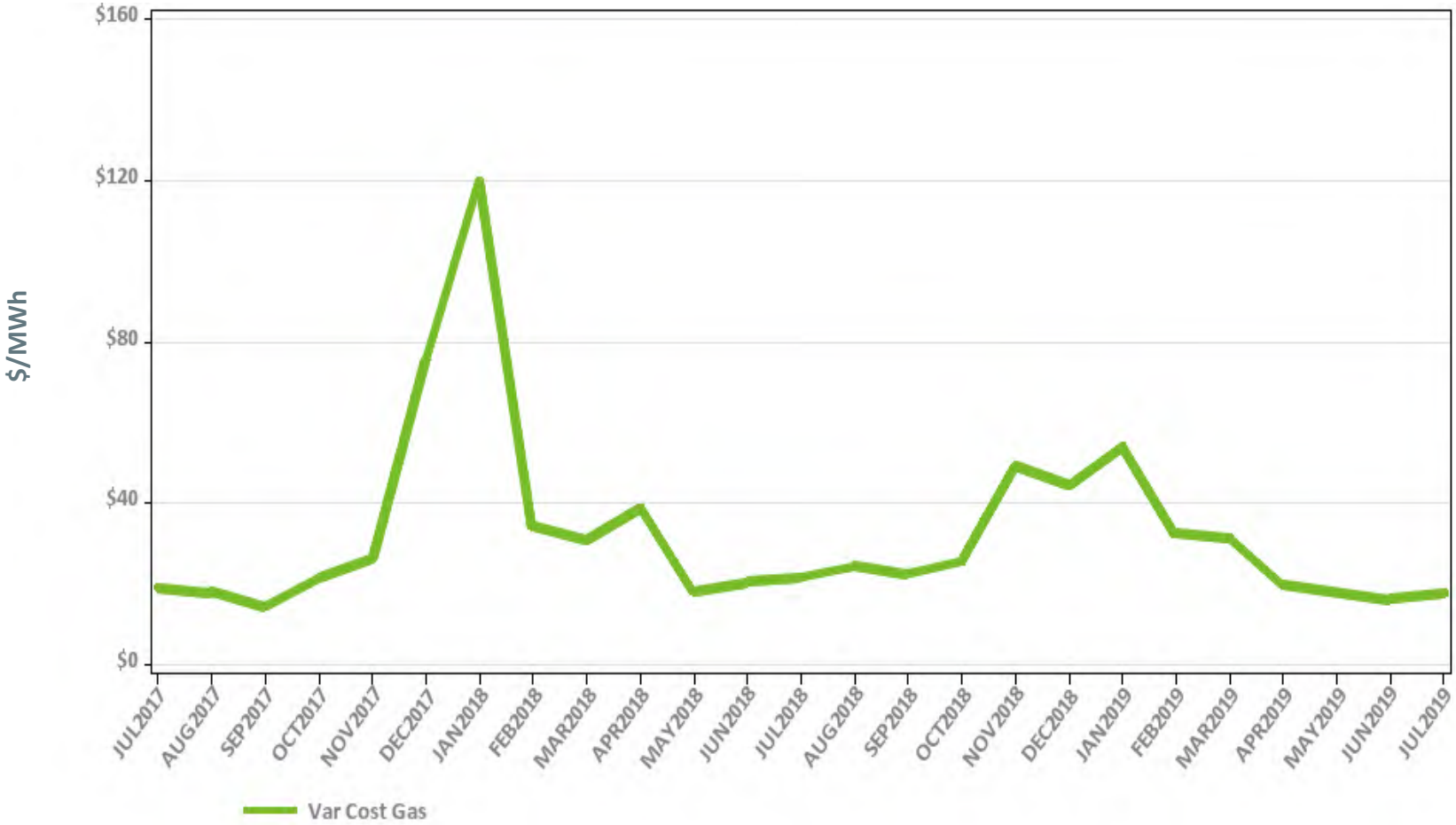
DA vs. RT Net Interchange
July 2019 vs. July 2018





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

Variable Production Cost of Natural Gas: Monthly

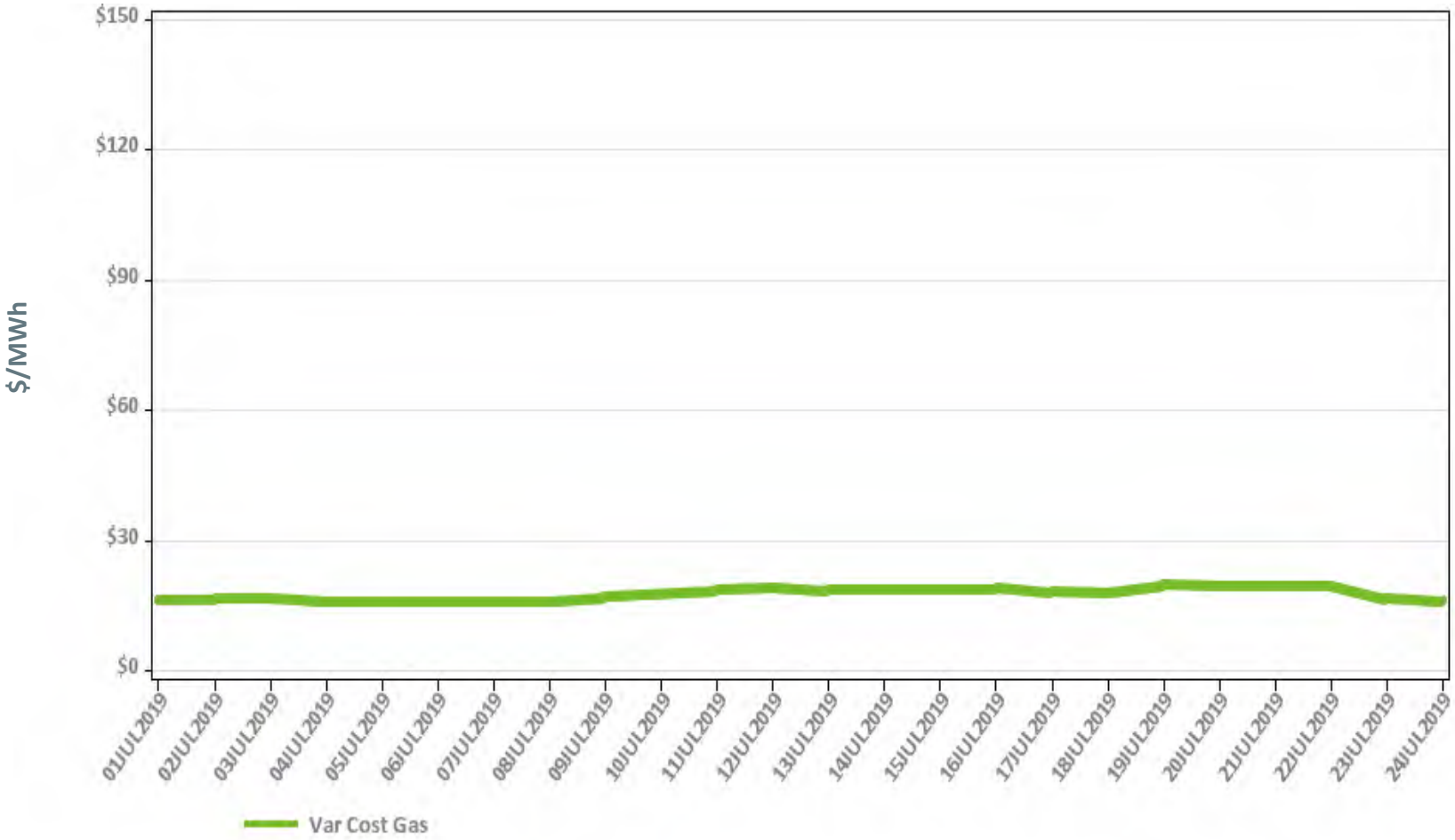


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

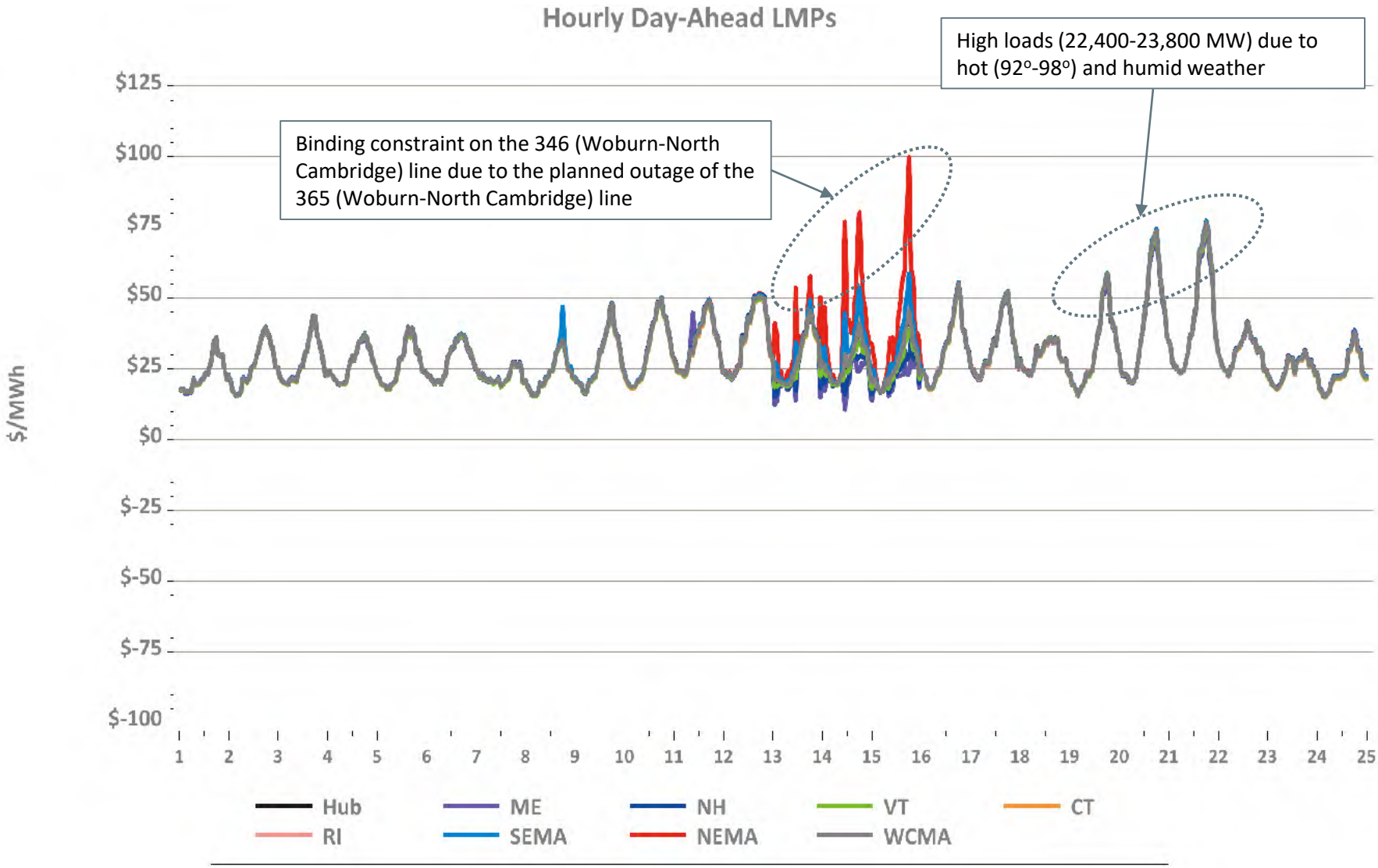


Underlying natural gas data furnished by:

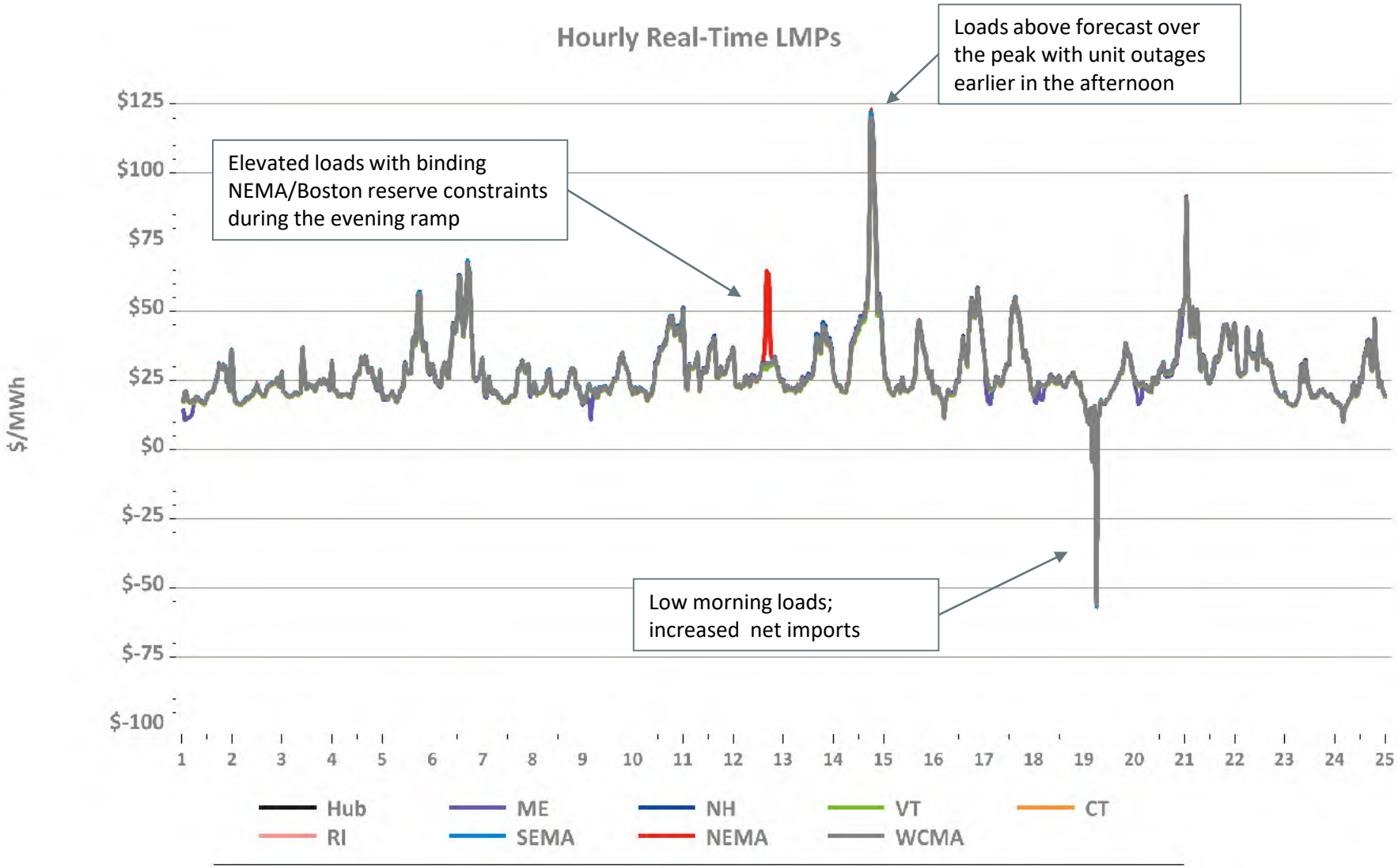
ICE Global markets in clear view

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

Hourly DA LMPs, July 1-24, 2019

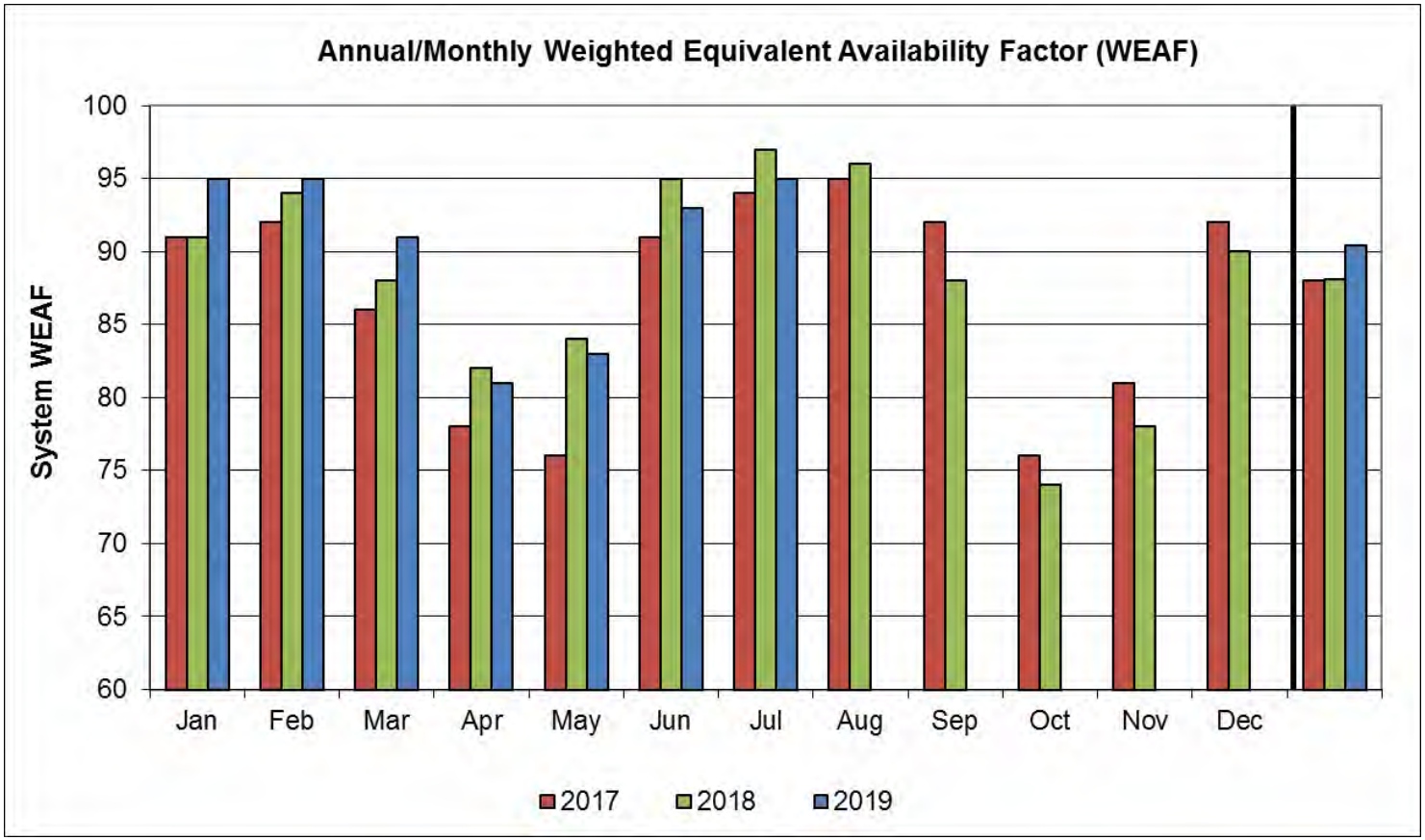


Hourly RT LMPs, July 1-24, 2019



- No Minimum Generation Emergencies were declared during July.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2019	95	95	91	81	83	93	95						90
2018	91	94	88	82	84	95	97	96	88	74	78	90	88
2017	91	92	86	78	76	91	94	95	92	76	81	92	88

Data as of 7/26/19

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	102.1	184.4	0.0	286.5
NH	30.8	107.8	0.0	138.6
VT	30.2	120.0	0.0	150.2
CT	103.5	109.4	457.9	670.8
RI	20.0	230.5	0.0	250.5
SEMA	25.4	390.9	0.0	416.3
WCMA	58.5	404.3	49.6	512.5
NEMA	36.6	669.0	0.0	705.6
Total	**407.1**	**2,216.3**	**507.5**	**3,131.0**

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

NEW GENERATION

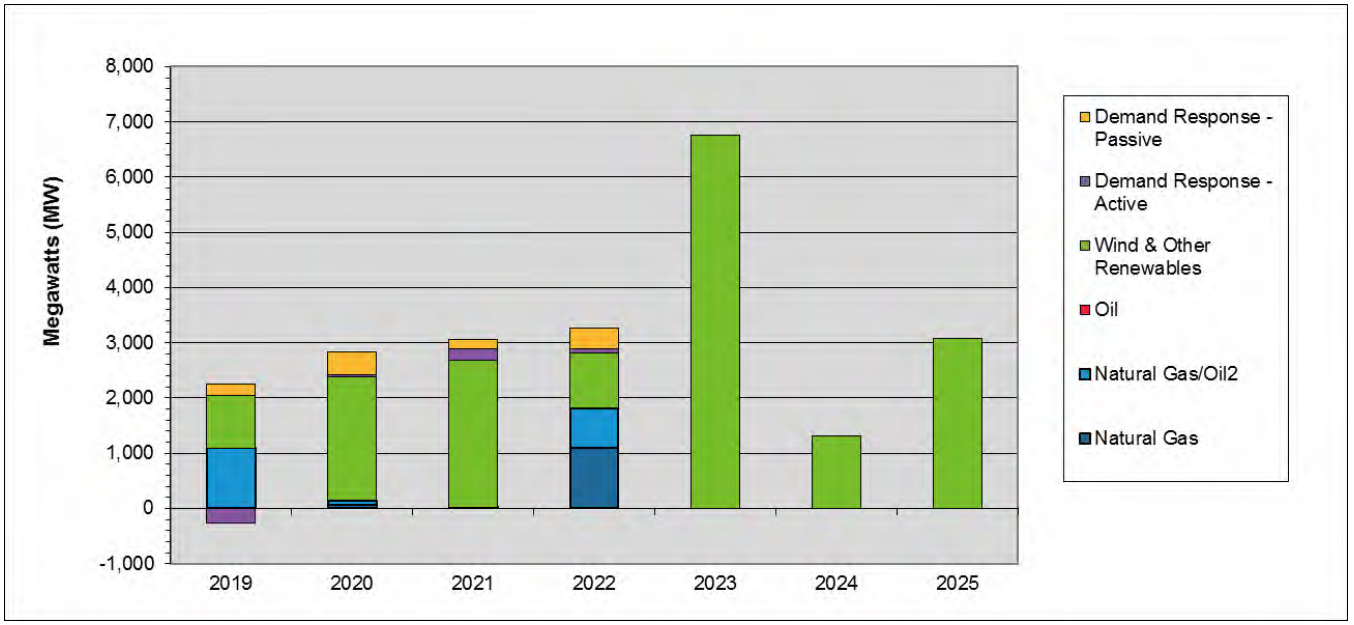
New Generation Update

Based on Queue as of 7/26/19

- Three solar projects totaling 113 MW applied for interconnection study with in-service dates from 2020 to 2022 since the last update
- No withdrawals, one commercial project and decreases in project capacity resulted in a net increase in new generation projects of 45 MW
- In total, 175 generation projects are currently being tracked by the ISO, totaling approximately 19,955 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2019	2020	2021	2022	2023	2024	2025	Total MW	% of Total[1]
Demand Response - Passive	212	422	184	380	0	0	0	1,199	5.4
Demand Response - Active	-270	42	204	62	0	0	0	39	0.2
Wind & Other Renewables	940	2,232	2,653	1,006	6,767	1,312	3,084	17,994	80.6
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	1,097	76	10	711	0	0	0	1,894	8.5
Natural Gas	0	69	15	1,103	0	0	0	1,187	5.3
Totals	**1,980**	**2,842**	**3,066**	**3,262**	**6,767**	**1,312**	**3,084**	**22,313**	**100.0**

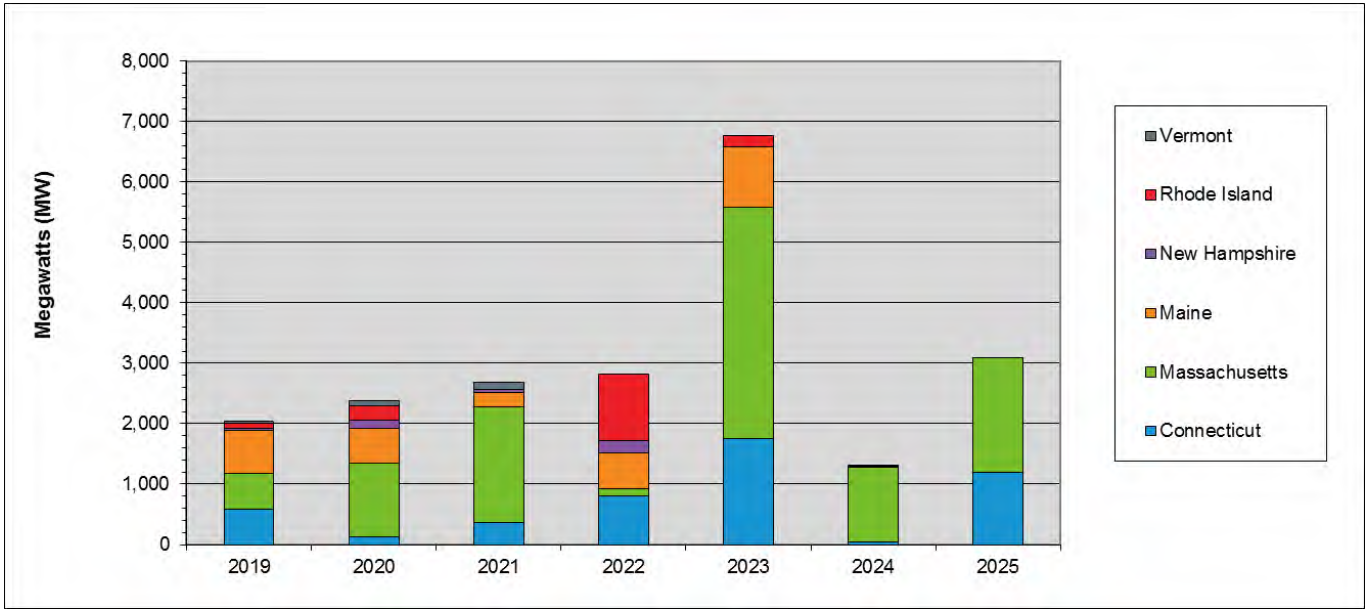
[1] Sum may not equal 100% due to rounding

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

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

Actual and Projected Annual Generator Capacity Additions

By State



	2019	2020	2021	2022	2023	2024	2025	Total MW	% of Total[1]
Vermont	33	75	110	0	0	0	0	218	1.0
Rhode Island	86	246	0	1,103	180	0	0	1,615	7.7
New Hampshire	28	140	58	198	0	20	0	444	2.1
Maine	710	569	228	595	1,003	20	0	3,125	14.8
Massachusetts	597	1,212	1,920	116	3,824	1,232	1,884	10,785	51.2
Connecticut	583	135	362	808	1,760	40	1,200	4,888	23.2
Totals	**2,037**	**2,377**	**2,678**	**2,820**	**6,767**	**1,312**	**3,084**	**21,075**	**100.0**

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

New Generation Projection

By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/wood waste	2	39	0	0	2	39
Hydro	2	71	0	0	2	71
Landfill Gas	0	0	0	0	0	0
Natural Gas	7	1,250	0	0	7	1,250
Natural Gas/Oil	7	842	0	0	7	842
Oil	0	0	0	0	0	0
Solar	115	3,376	2	51	113	3,325
Wind	25	12,159	2	33	23	12,126
Battery storage	17	2,219	0	0	17	2,219
Total	175	19,956	4	84	171	19,872

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	4	120	0	0	4	120
Intermediate	3	1,146	0	0	3	1,146
Peaker	143	6,531	2	51	141	6,480
Wind Turbine	25	12,159	2	33	23	12,126
Total	175	19,956	4	84	171	19,872

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Fuel Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/wood waste	2	39	1	37	0	0	1	2	0	0
Hydro	2	71	1	5	0	0	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	7	1,250	2	78	3	1,146	2	26	0	0
Natural Gas/Oil	7	842	0	0	0	0	7	842	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	115	3,376	0	0	0	0	115	3,376	0	0
Wind	25	12,159	0	0	0	0	0	0	25	12,159
Battery storage	17	2,219	0	0	0	0	17	2,219	0	0
Total	175	19,956	4	120	3	1,146	143	6,531	25	12,159

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 10

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	377.525	367.227	-10.298	464.715	97.488	460.55	-4.165	459.928	-0.622	457.966	-1.962	493.5	35.534
	Passive Demand	2,368.631	2,366.783	-1.848	2,363.949	-2.834	2,363.789	-0.16	2,527.244	163.46	2,529.014	1.77	2594.08	65.066
Demand Total		**2,746.156**	**2,734.01**	**-12.146**	**2,828.664**	**94.654**	**2,824.339**	**-4.325**	**2,987.172**	**162.83**	**2,986.98**	**-0.192**	**3,087.58**	**100.6**
Generator	*Non-Intermittent*	30,520.433	30,462.67	-57.763	30,048.398	-414.272	30,103.684	55.286	30,093.142	-10.54	30,081.64	-11.502	30,146.76	65.115
	Intermittent	850.143	893.189	43.046	904.311	11.122	831.251	-73.06	798.958	-32.293	800.387	1.429	733.668	-66.719
Generator Total		**31,370.576**	**31,355.86**	**-14.716**	**30,952.709**	**-403.151**	**30,934.935**	**-17.774**	**30,892.1**	**-42.84**	**30,882.027**	**-10.073**	**30,880.42**	**-1.604**
Import Total		**1,449.8**	**1,449.8**	**0**	**1,451**	**1.2**	**1,451**	**0**	**1,451**	**0**	**1,459**	**8**	1,428	-31
****Grand Total**		**35,566.532**	**35,539.668**	**-26.864**	**35,232.373**	**-307.295**	**35,210.274**	**-22.099**	**35,330.272**	**120.00**	**35,328.007**	**-2.265**	**35,396**	**67.996**
Net ICR (NICR)		**34,151**	**33,755**	**-396**	**33,755**	**0**	**33,407**	**-348**	**33,407**	**0**	**33,390**	**-17**	33,390	0

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

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

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

Capacity Supply Obligation FCA 11

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

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

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

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

Capacity Supply Obligation FCA 12

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	624.445	659.137	34.692				
	Passive Demand	2,975.36	3,045.073	69.713				
Demand Total		**3,599.81**	**3,704.21**	**104.4**				
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654				
	Intermittent	880.317	806.609	-73.708				
Generator Total		**30,011.07**	**30,051.013**	**39.943**				
Import Total		**1,217**	**1,305.487**	**88.487**				
****Grand Total**		**34,827.88**	**35,060.710**	**232.83**				
Net ICR (NICR)		**33,725**	**33,550**	**-175**				

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

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

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

Capacity Supply Obligation FCA 13

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	685.554						
	Passive Demand	3,354.69						
Demand Total		**4,040.244**						
Generator	*Non-Intermittent*	28,586.498						
	Intermittent	1,024.792						
Generator Total		**2,9611.29**						
Import Total		**1,187.69**						
****Grand Total**		**34,839.224**						
Net ICR (NICR)		**33,750**						

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

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

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/ Passive	Existing	New	Grand Total
2010-11	Active	1,246.40	603.675	1,850.07
	Passive	119.211	584.277	703.488
	Grand Total	1365.61	1187.952	2553.562
2011-12	Active	1,768.39	184.99	1,953.38
	Passive	719.98	263.25	983.23
	Grand Total	2488.372	448.24	2936.612
2012-13	Active	1,726.55	98.227	1,824.78
	Passive	861.602	211.261	1,072.86
	Grand Total	2588.15	309.488	2897.638
2013-14	Active	1,794.20	257.341	2,051.54
	Passive	1,040.11	257.793	1,297.91
	Grand Total	2834.308	515.134	3349.442
2014-15	Active	2,062.20	41.945	2,104.14
	Passive	1,264.64	221.072	1,485.71
	Grand Total	3326.837	263.017	3589.854
2015-16	Active	1,935.41	66.104	2,001.51
	Passive	1,395.89	247.449	1,643.33
	Grand Total	3331.291	313.553	3644.844
2016-17	Active	1,116.47	0.23	1,116.70
	Passive	1,386.56	244.775	1,631.34
	Grand Total	2503.028	245.005	2748.033
2017-18	Active	1,066.59	13.486	1,080.08
	Passive	1,619.15	341.37	1,960.52
	Grand Total	2685.74	354.856	3040.596
2018-19	Active	565.866	81.394	647.26
	Passive	1,870.55	285.602	2,156.15
	Grand Total	2436.415	366.996	2803.411
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	2375.422	370.734	2746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	2571.361	639.586	3210.947
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3085.734	514.072	3599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3386.703	653.541	4040.244

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

What are Daily NCPC Payments?

- Payments made to resources whose commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output during the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area
- NCPC payments are intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule

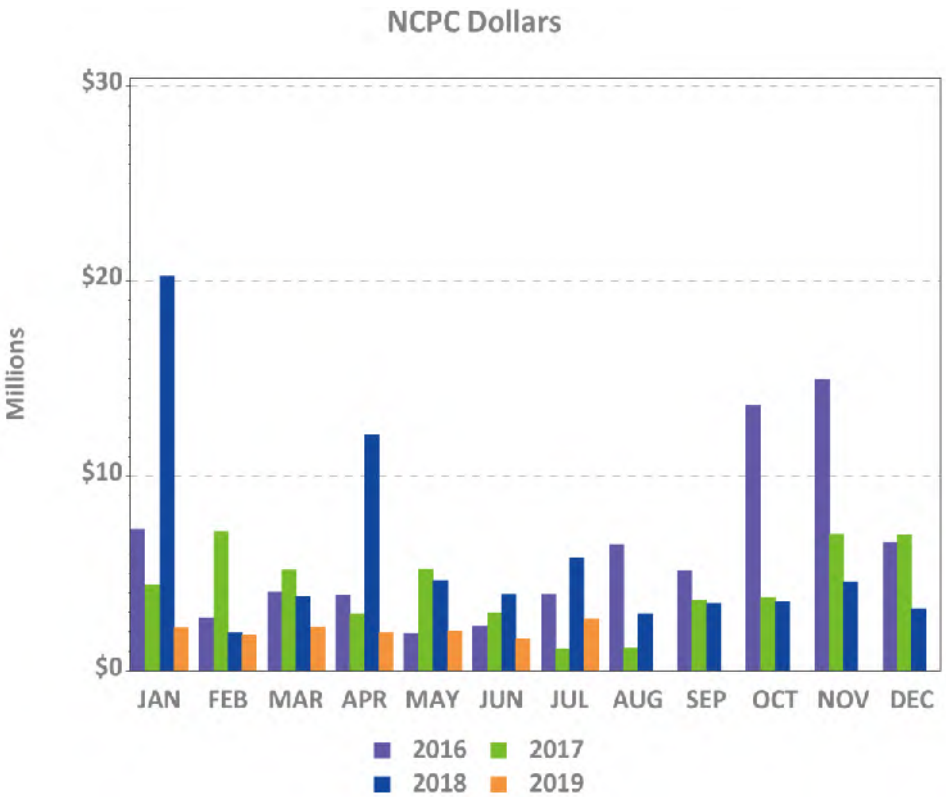
Definitions

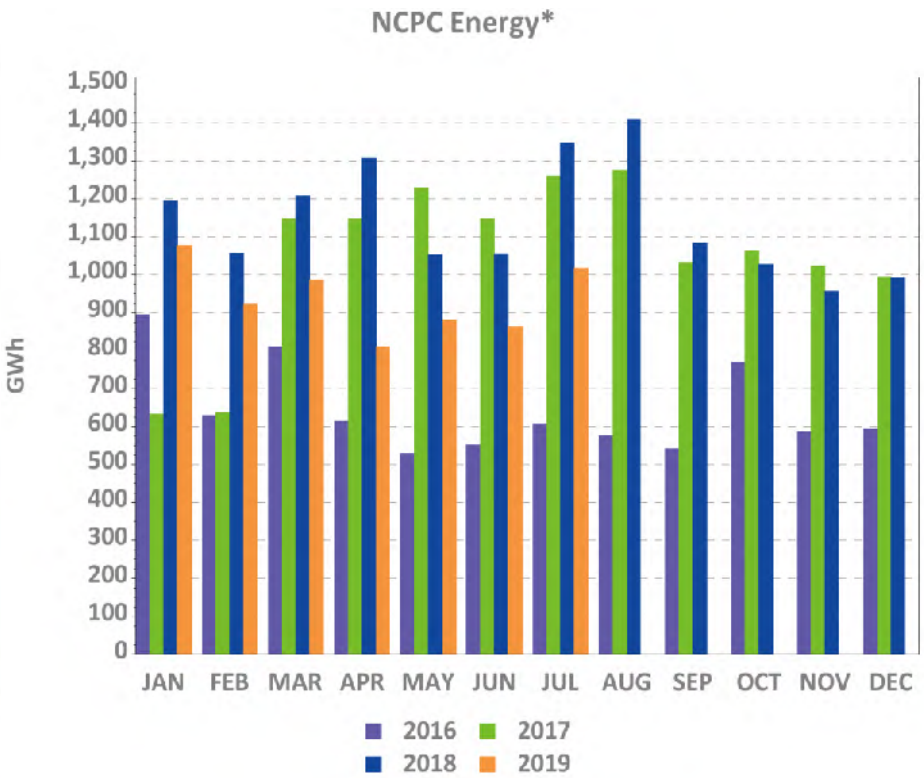
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

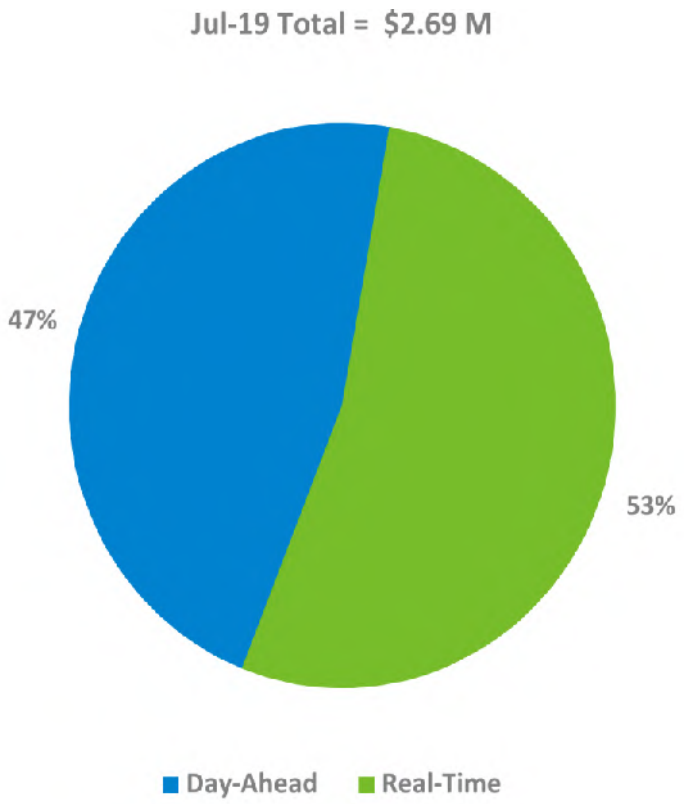
Year-Over-Year Total NCPC Dollars and Energy



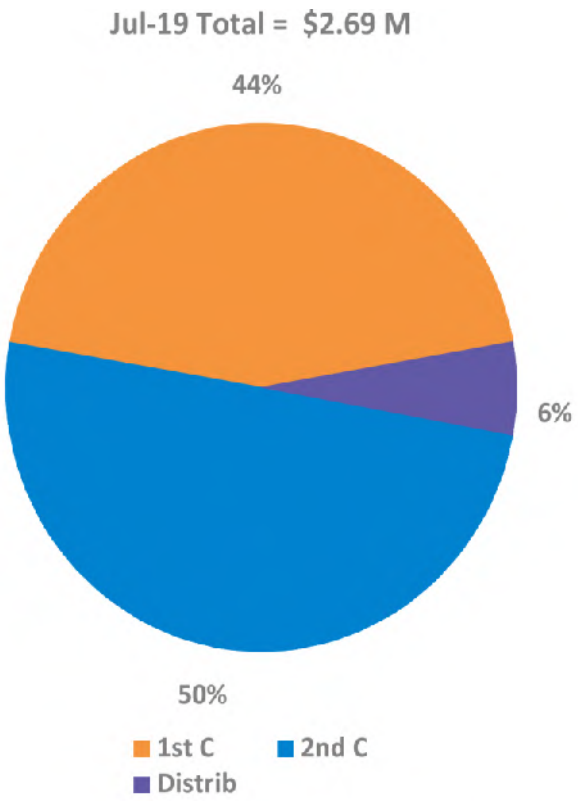


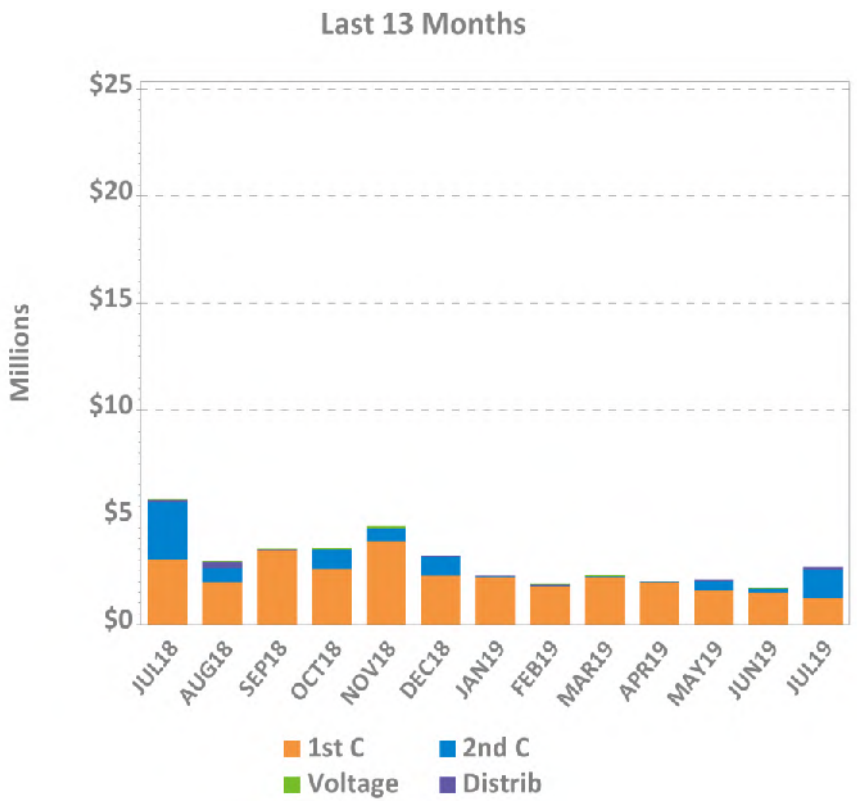
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



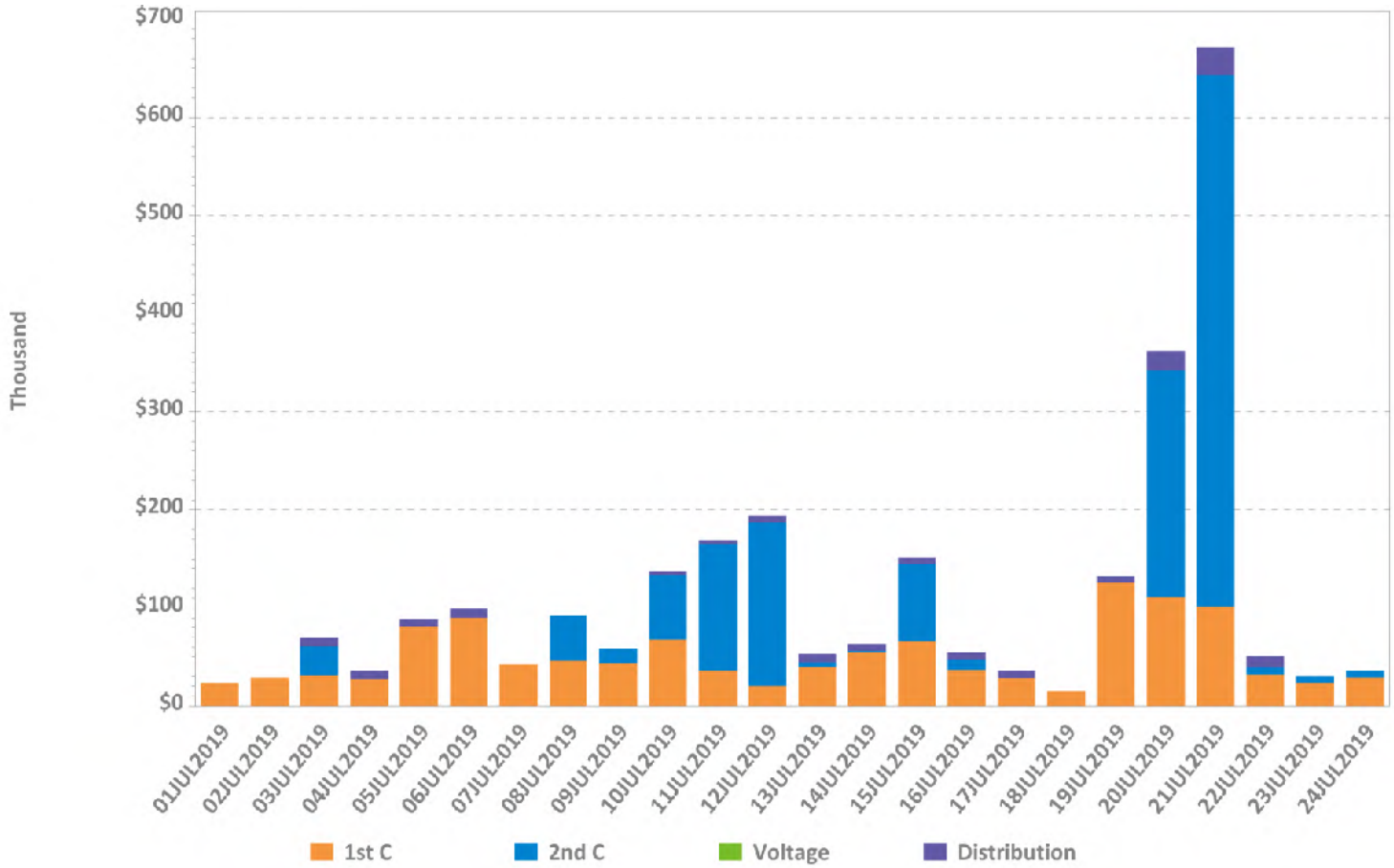
NCPC Charges by Type



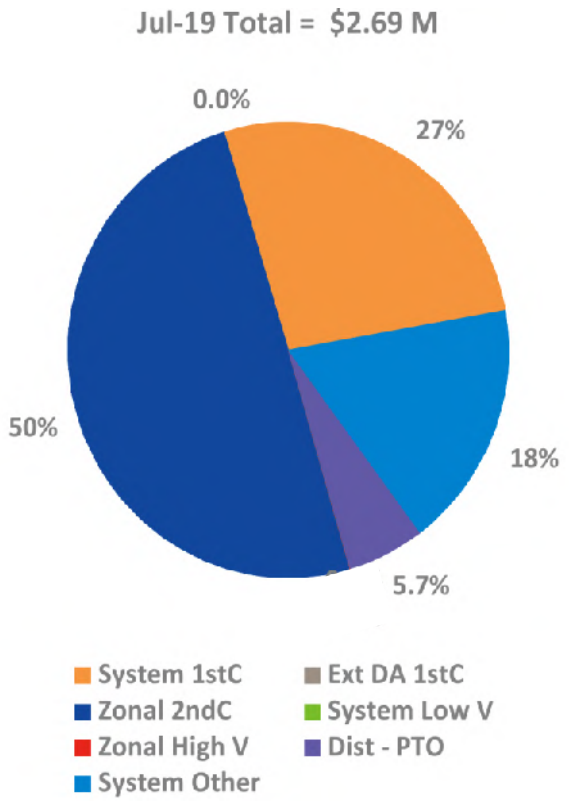


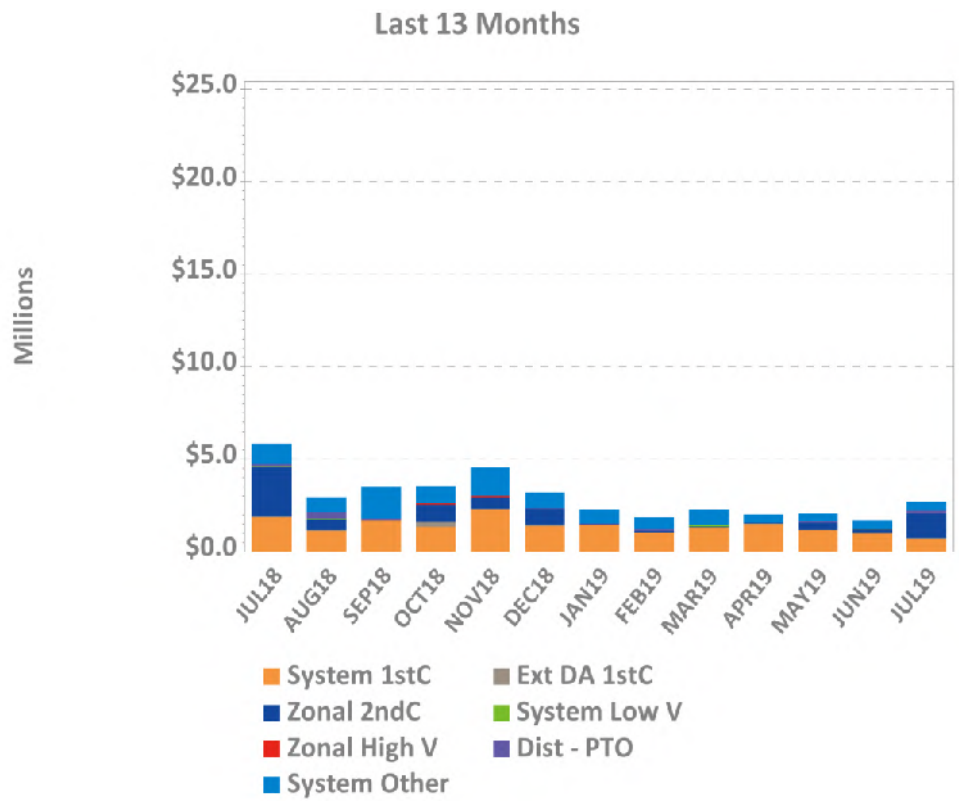
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



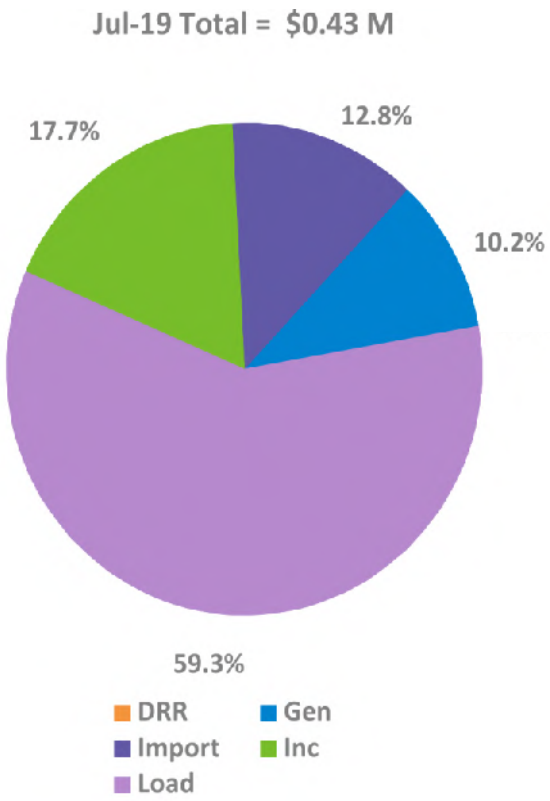
NCPC Charges by Allocation

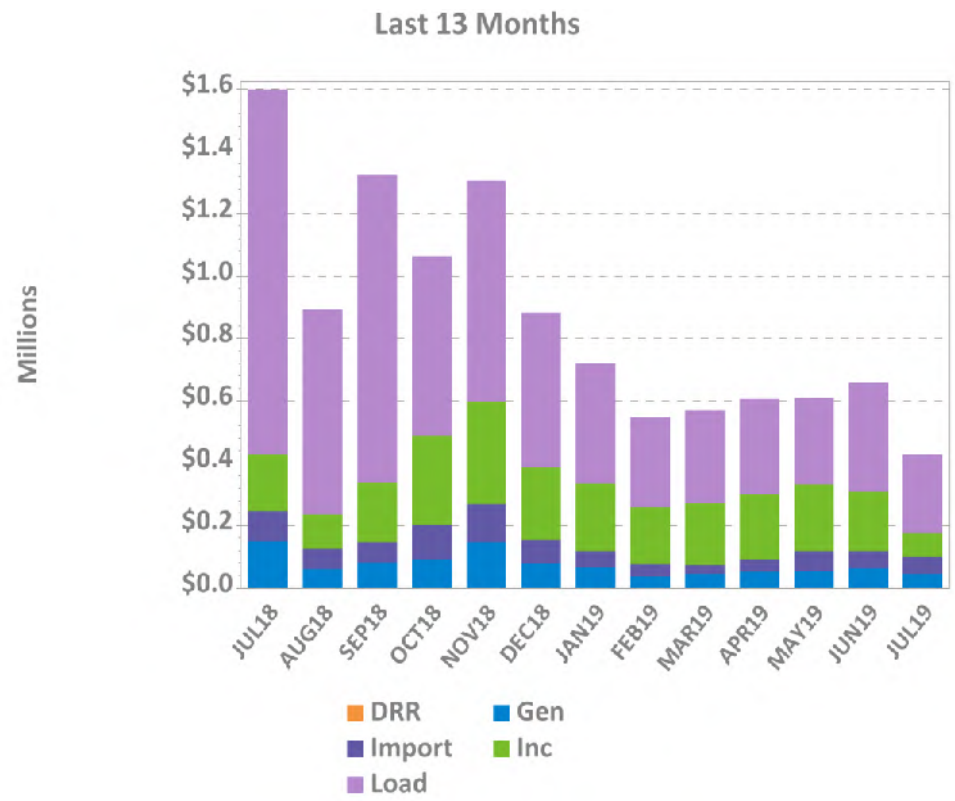




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

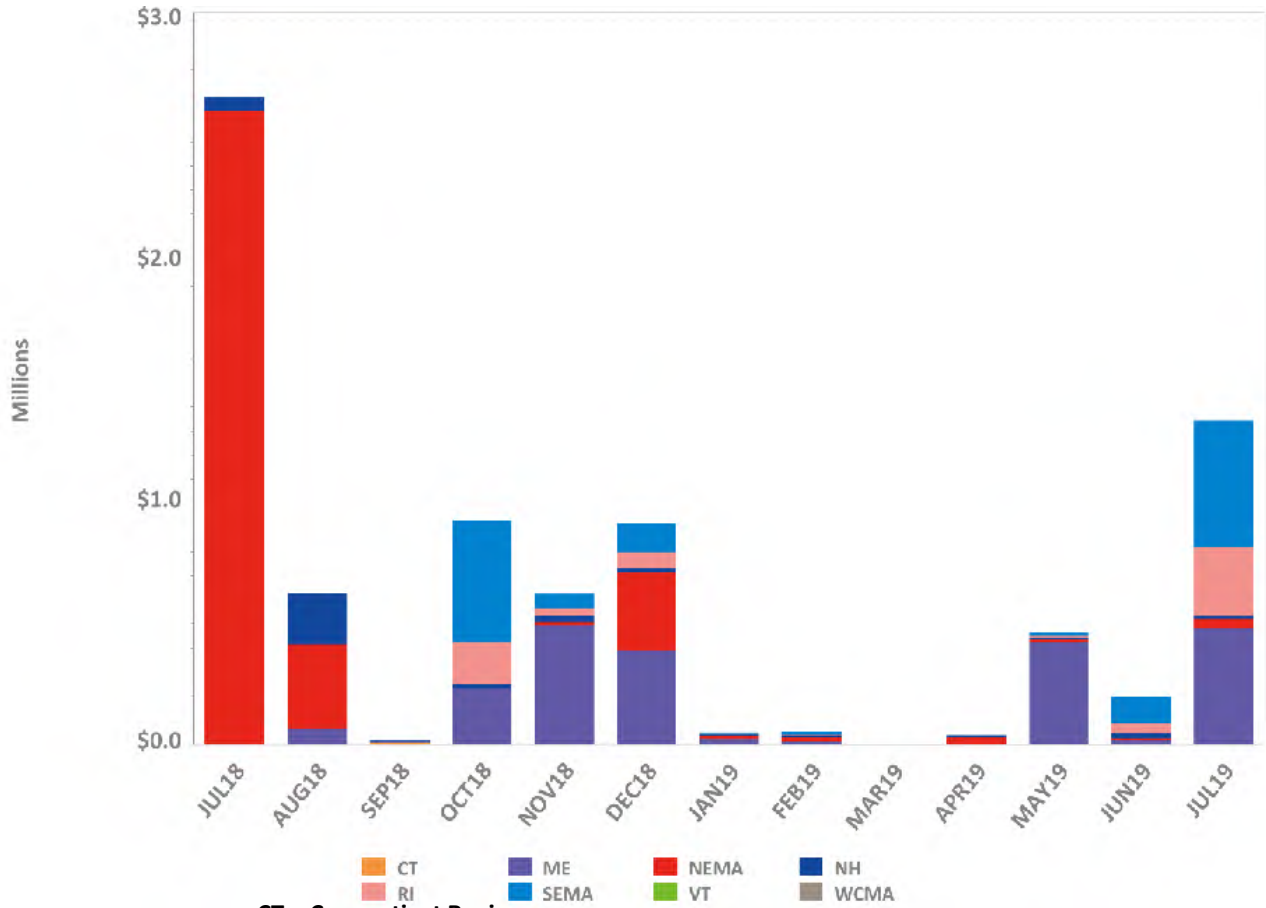
RT First Contingency Charges by Deviation Type





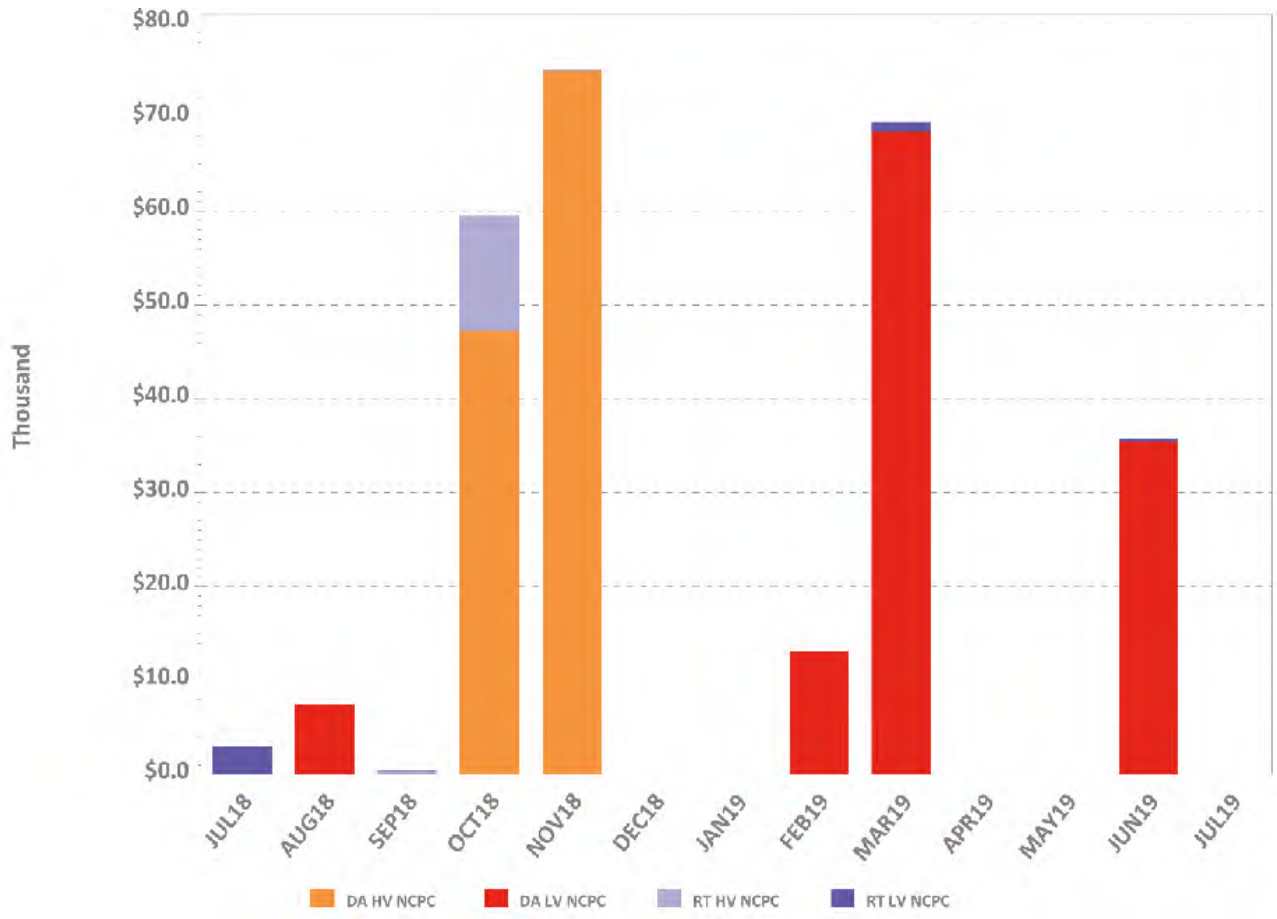
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

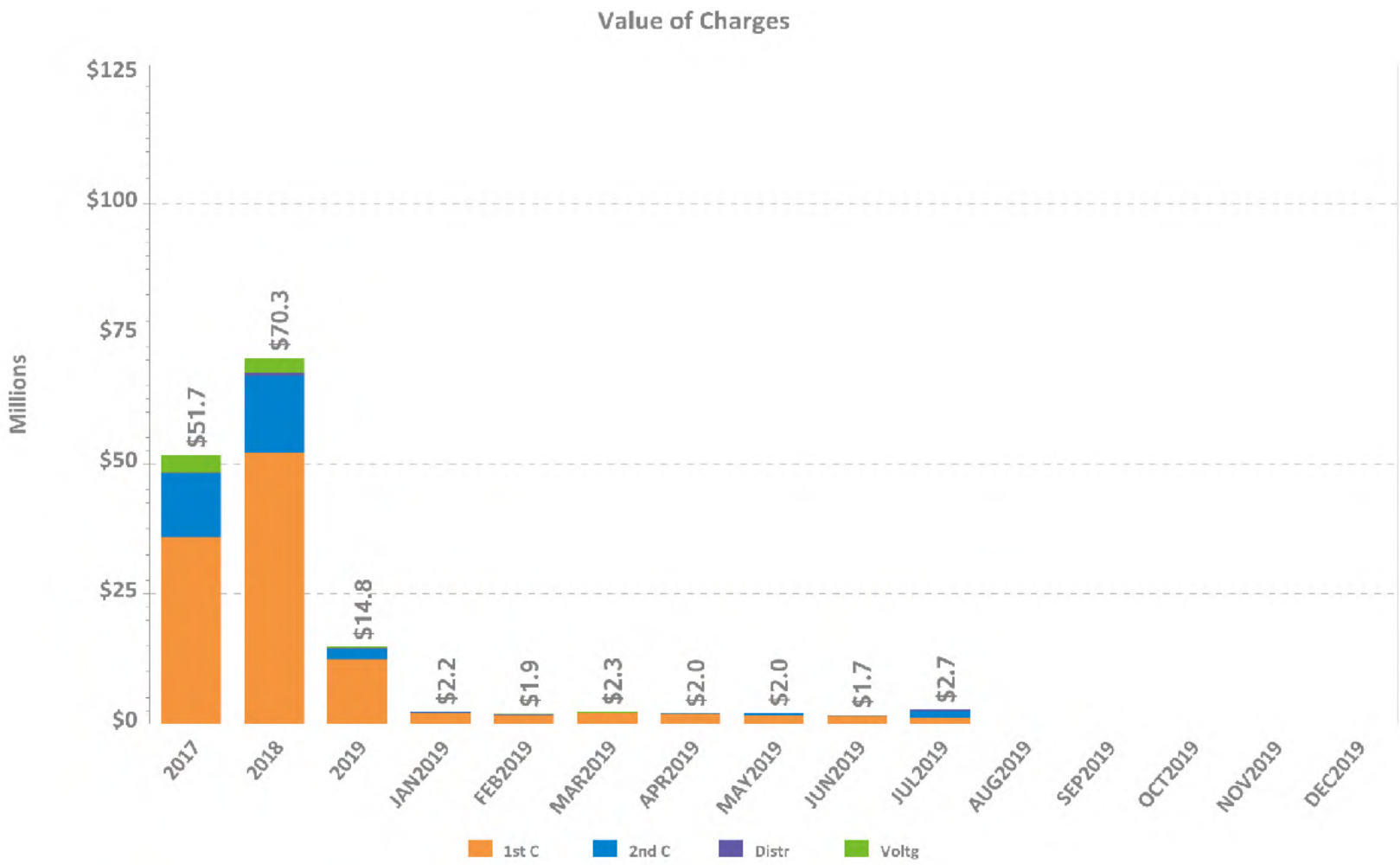


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

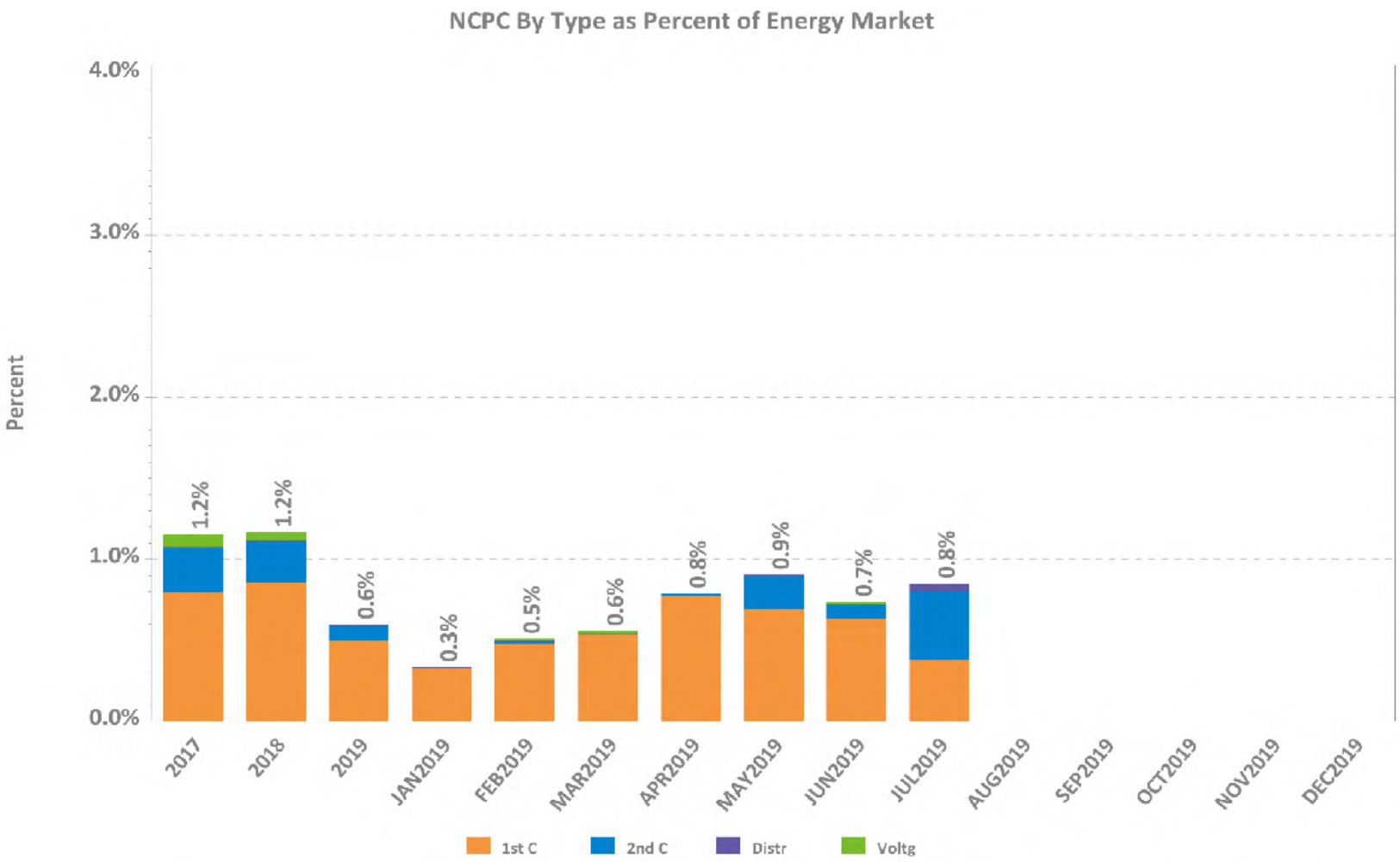
NCPC Charges for Voltage Support and High Voltage Control



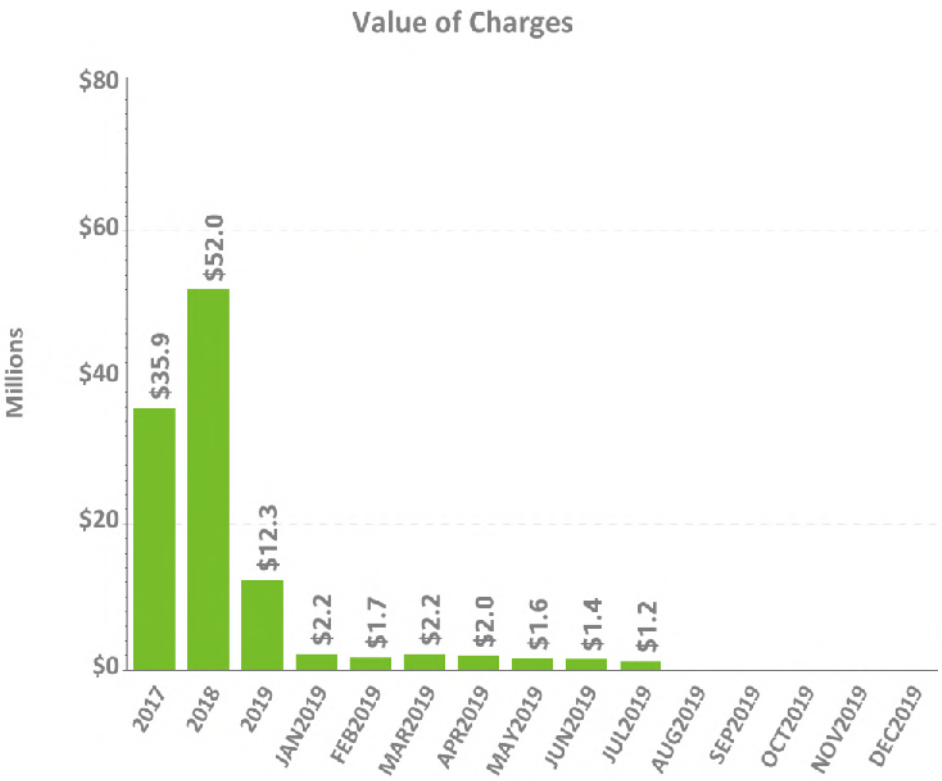
NCPC Charges by Type

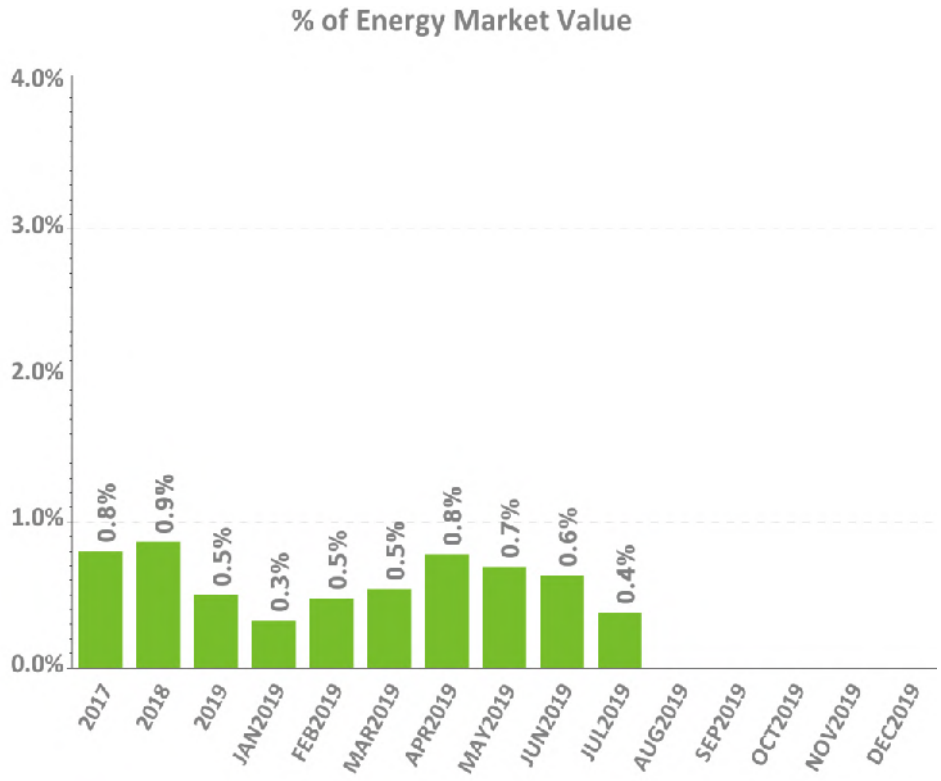


NCPC Charges as Percent of Energy Market



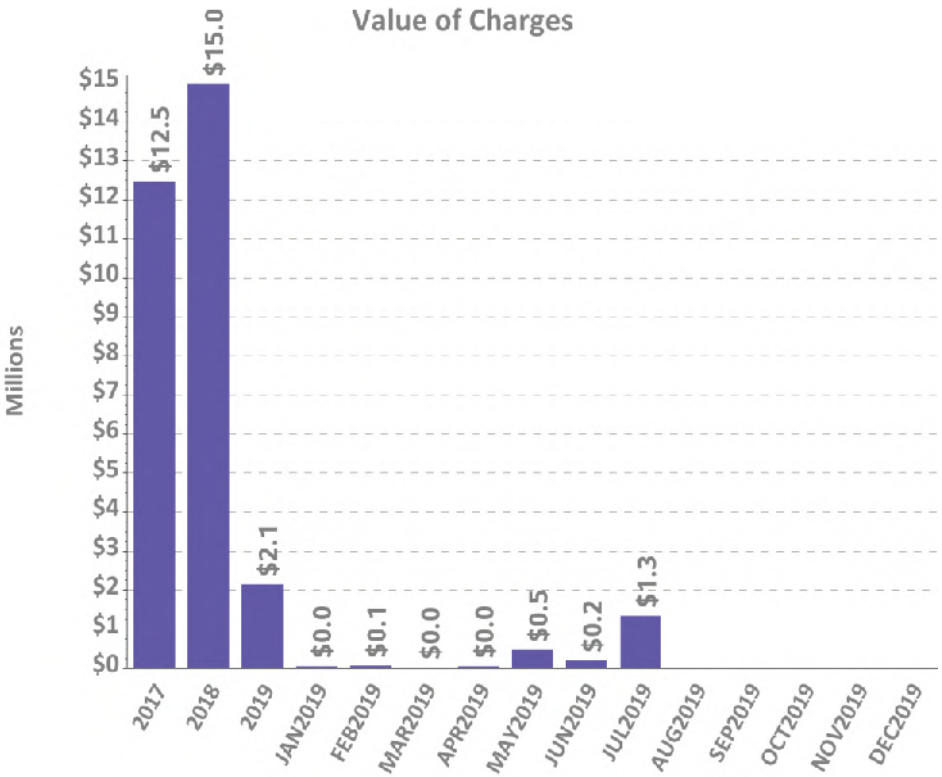
First Contingency NCPC Charges

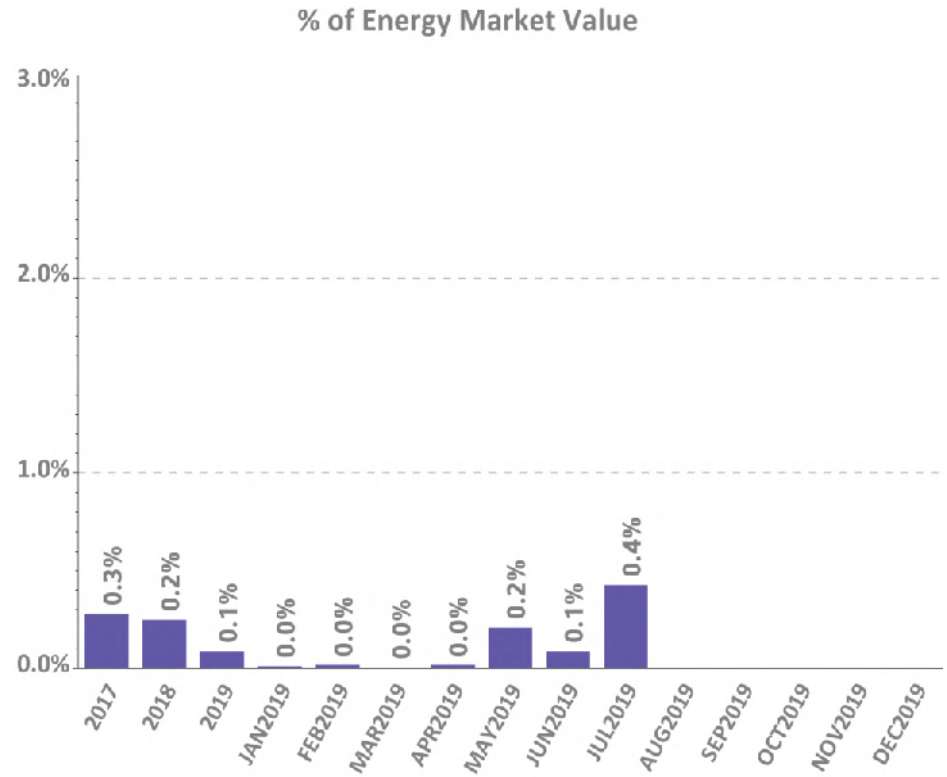




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

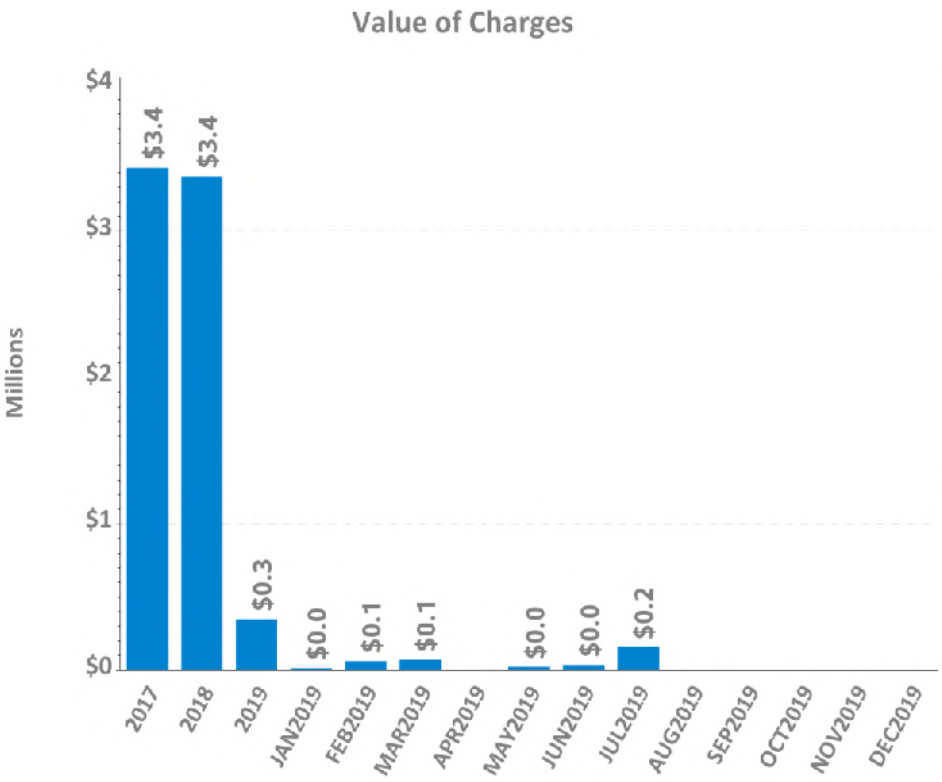
Second Contingency NCPC Charges

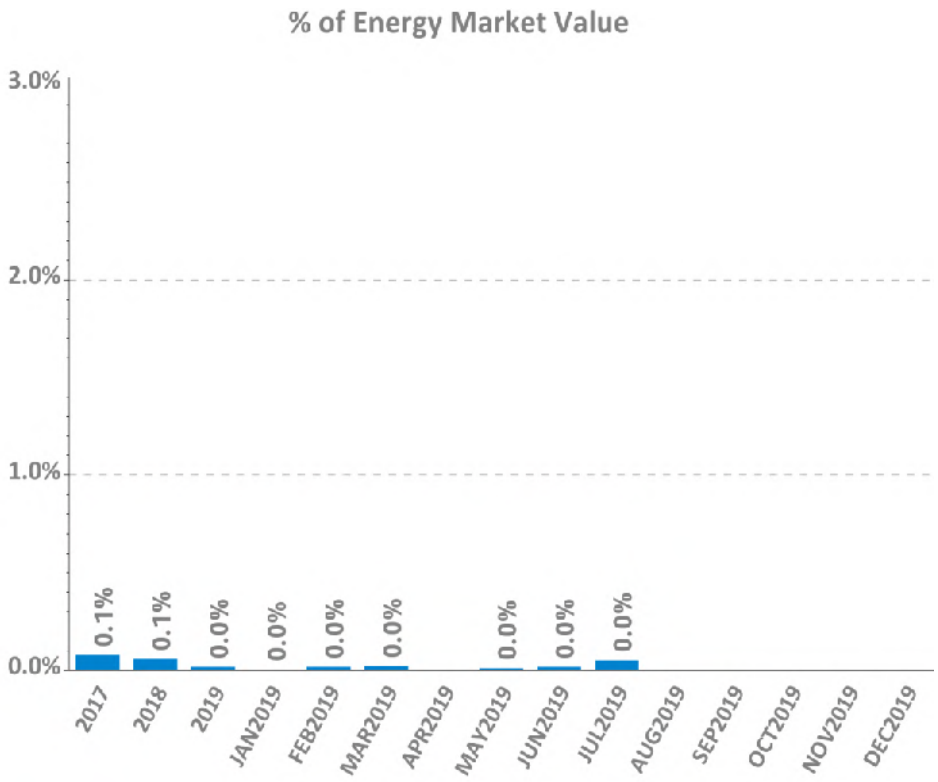




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

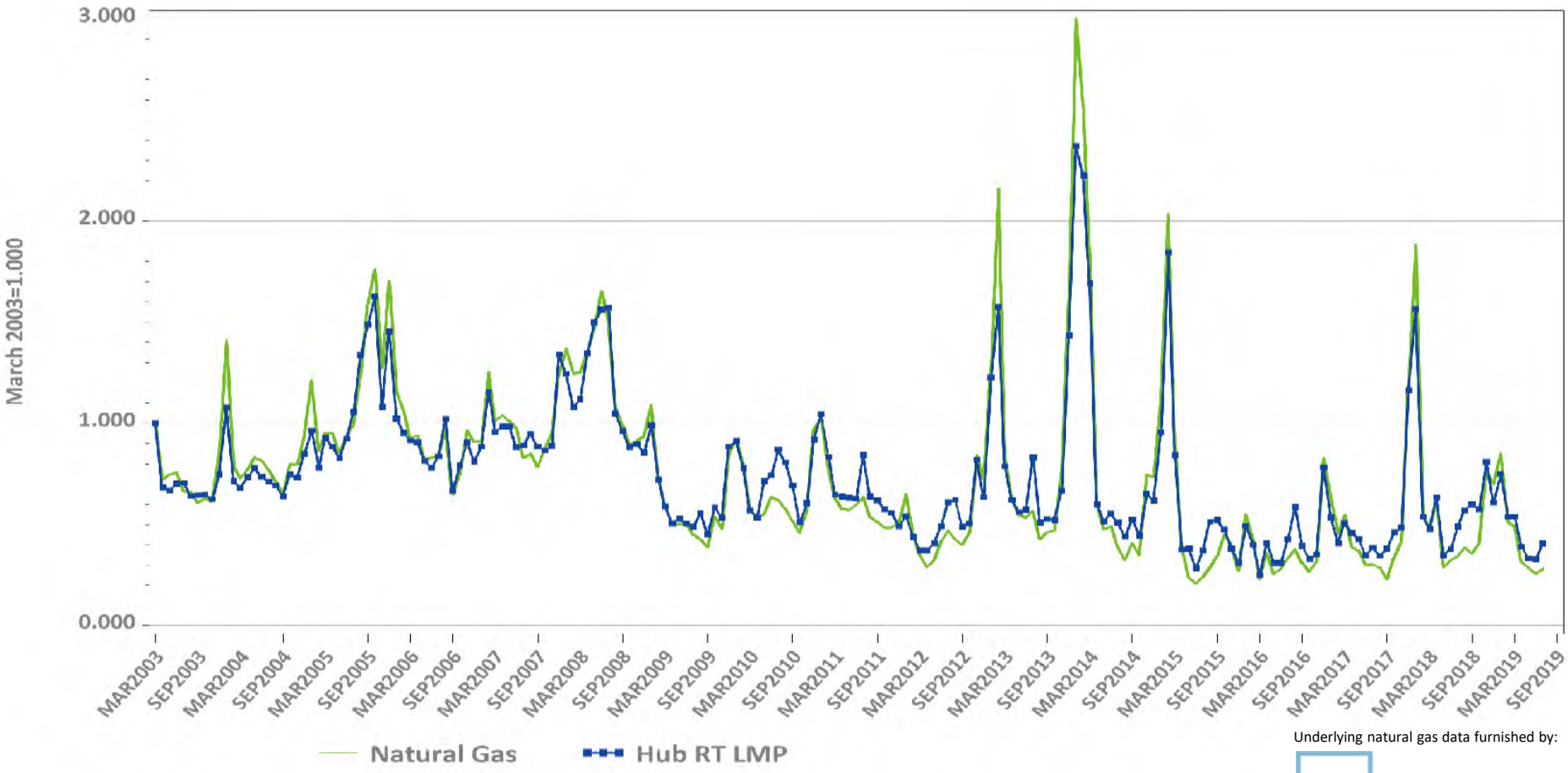
DA vs. RT LMPs ($/MWh)

Arithmetic Average

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

July-18	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$32.92	$32.87	$32.38	$33.02	$33.10	$32.70	$32.84	$33.01	$32.89
Real-Time	$33.76	$33.75	$33.22	$33.85	$33.73	$33.49	$33.58	$33.78	$33.67
RT Delta %	2.5%	2.7%	2.6%	2.5%	1.9%	2.4%	2.3%	2.3%	2.4%
July-19	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$31.27	$29.23	$28.84	$29.48	$29.32	$29.81	$30.31	$29.74	$29.70
Real-Time	$28.31	$27.66	$27.61	$28.10	$27.60	$27.85	$28.09	$27.92	$27.90
RT Delta %	-9.4%	-5.4%	-4.3%	-4.7%	-5.9%	-6.6%	-7.3%	-6.1%	-6.1%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	-5.0%	-11.1%	-10.9%	-10.7%	-11.4%	-8.9%	-7.7%	-9.9%	-9.7%
Yr over Yr RT	-16.1%	-18.0%	-16.9%	-17.0%	-18.2%	-16.8%	-16.4%	-17.3%	-17.1%

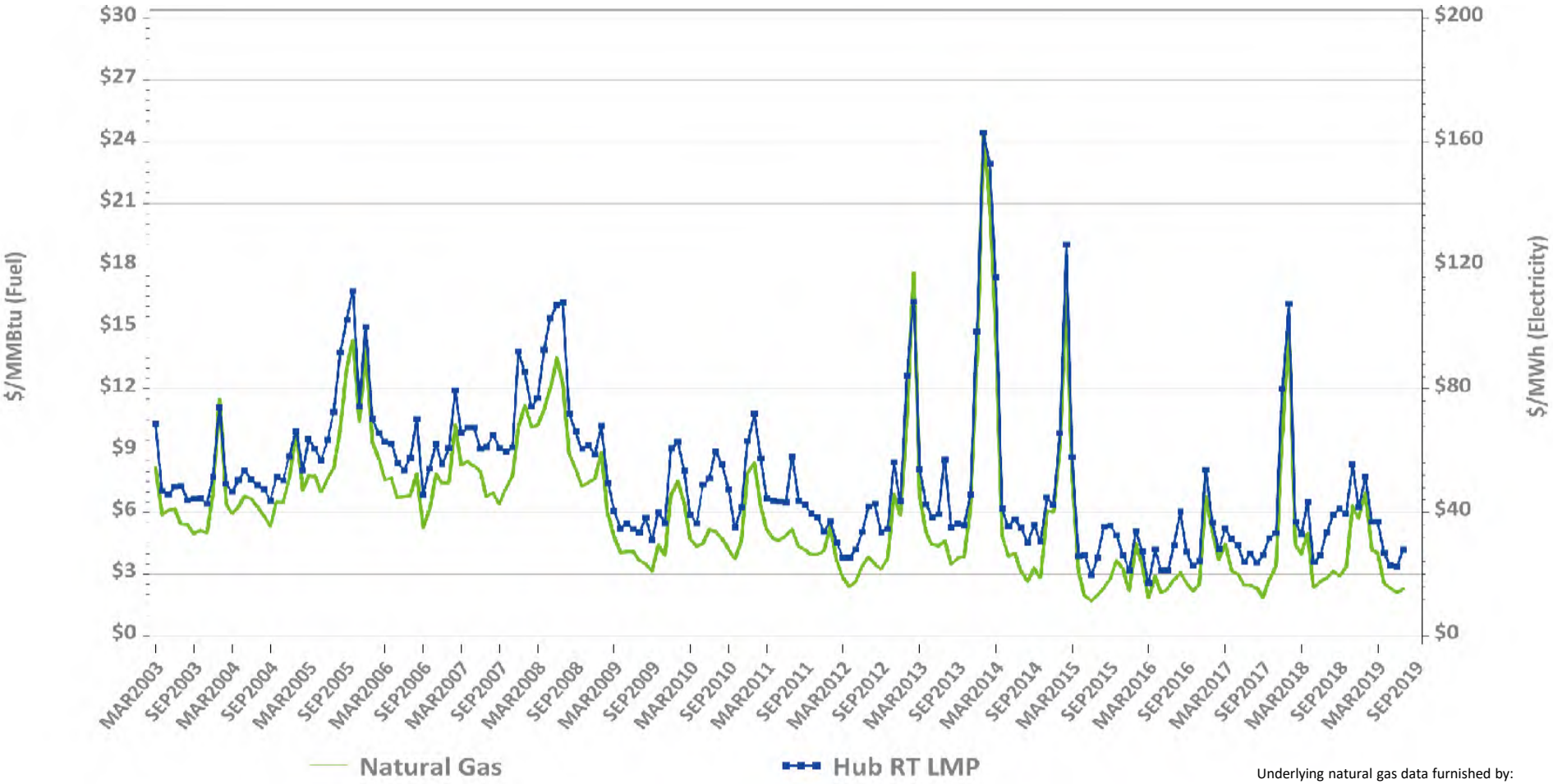
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

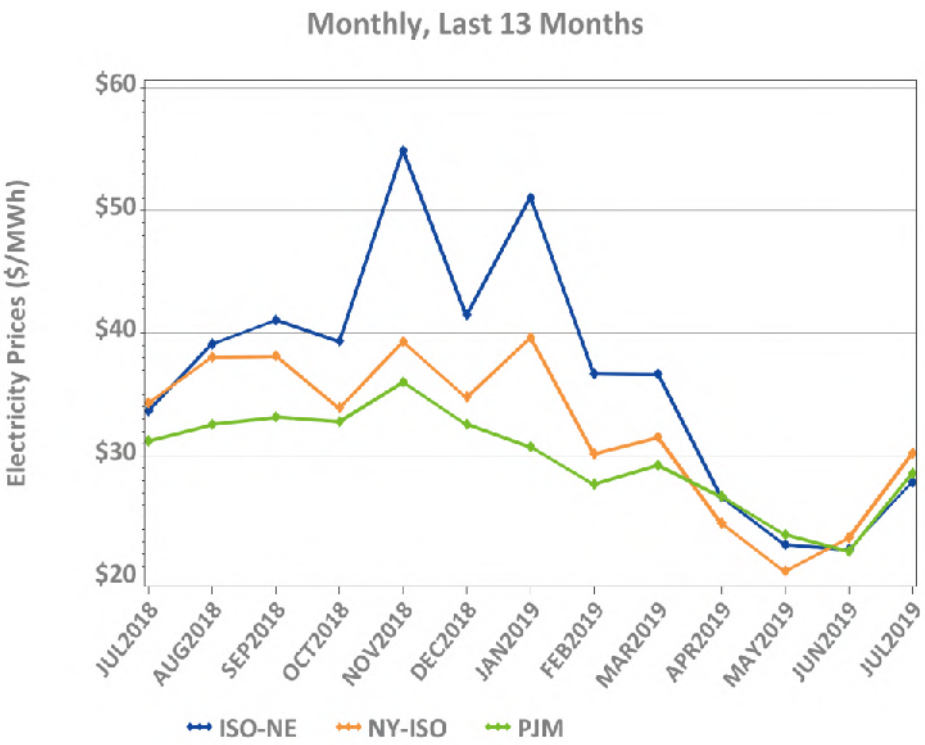
Monthly Average Fuel Price and RT Hub LMP



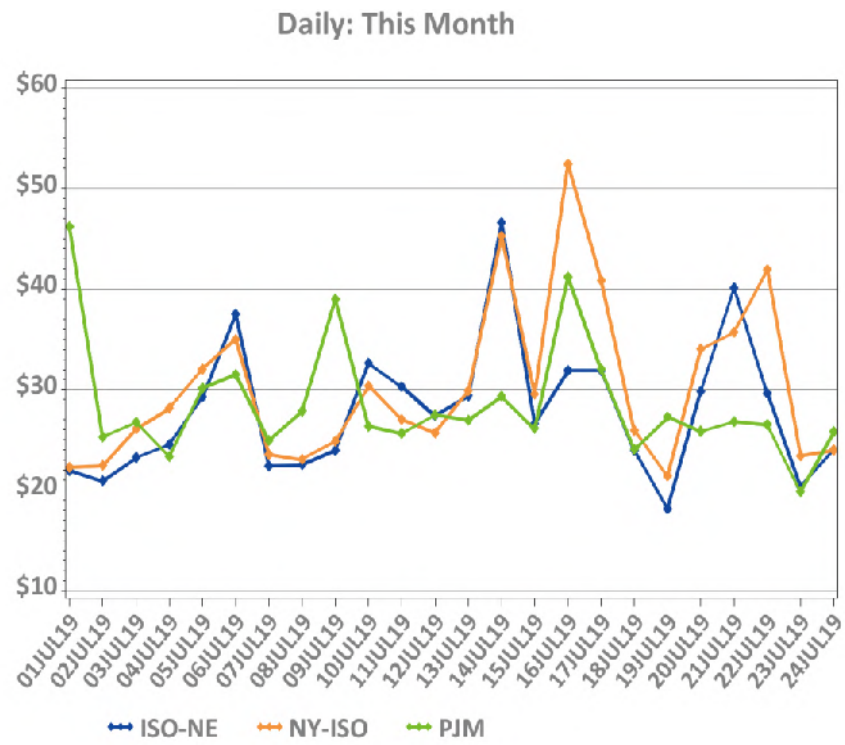
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

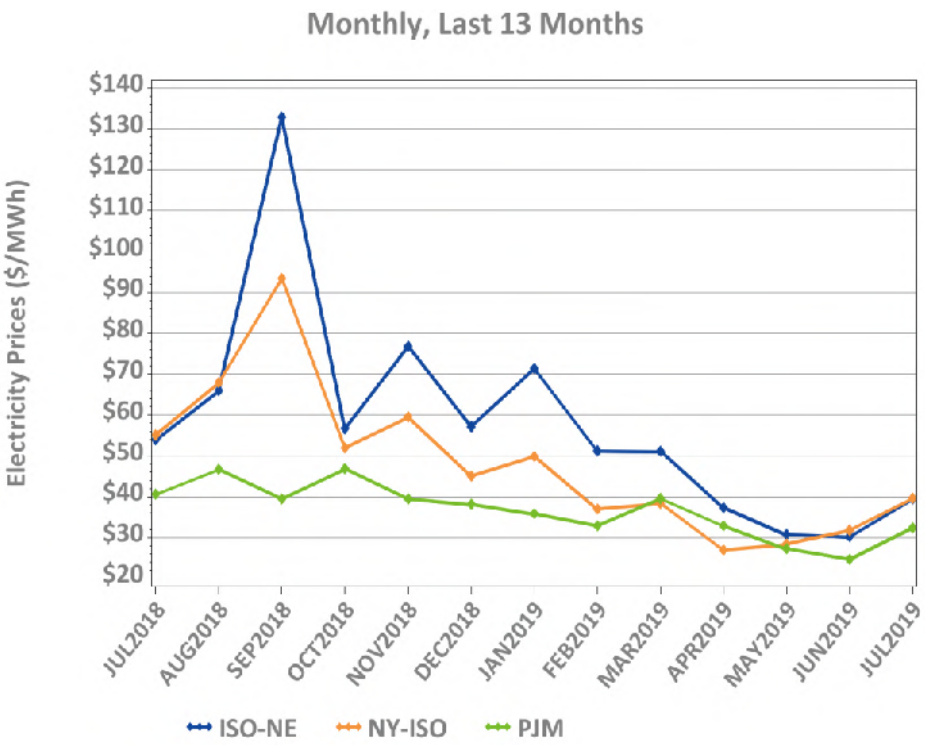


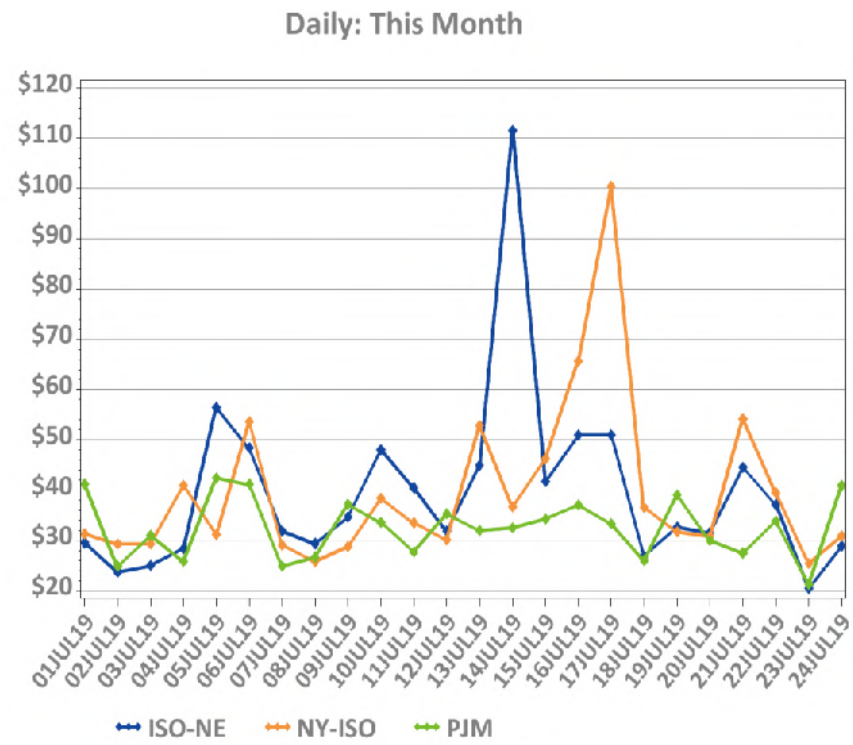
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





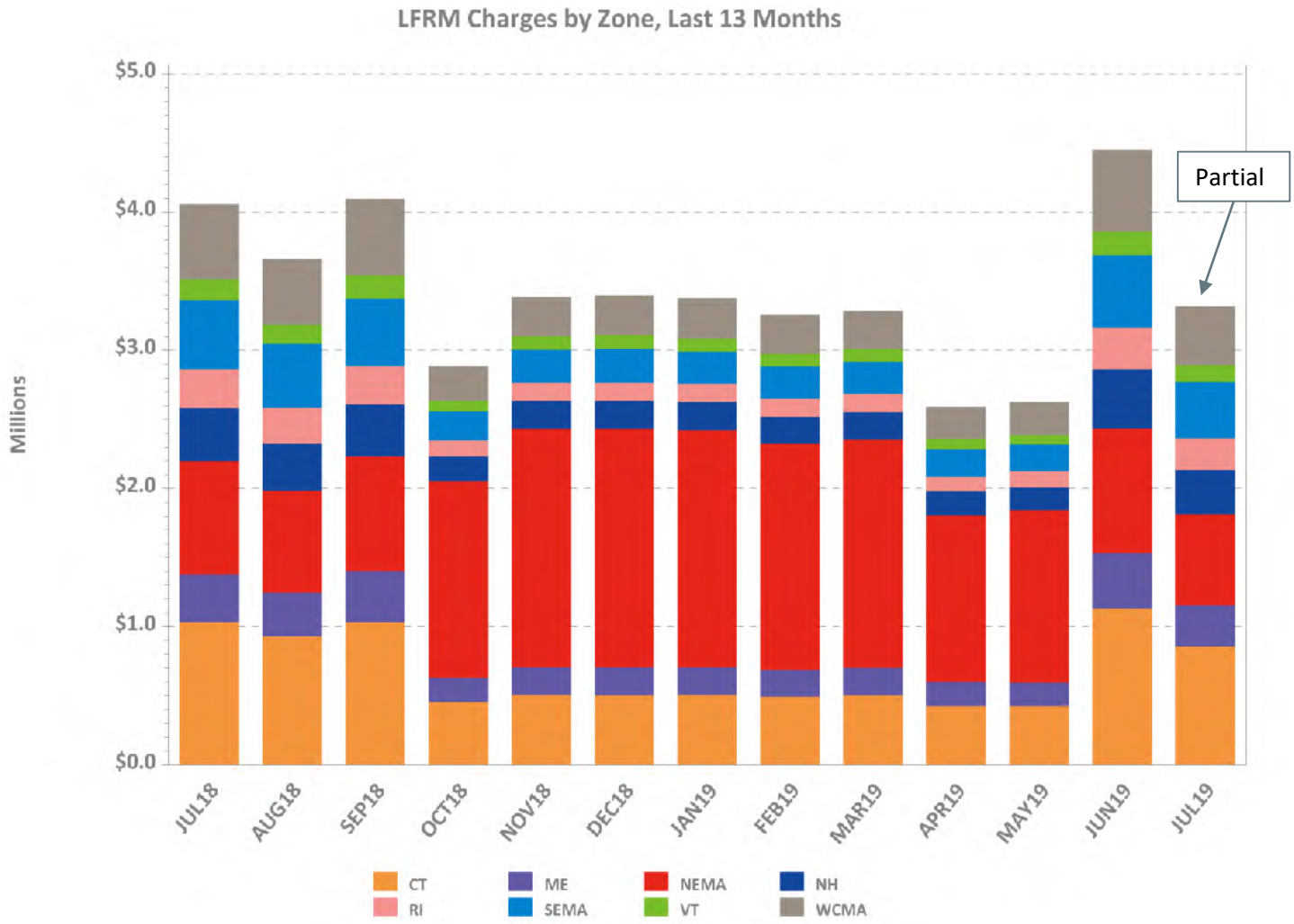
***Forecasted New England daily peak hours reflected**

Reserve Market Results – July 2019

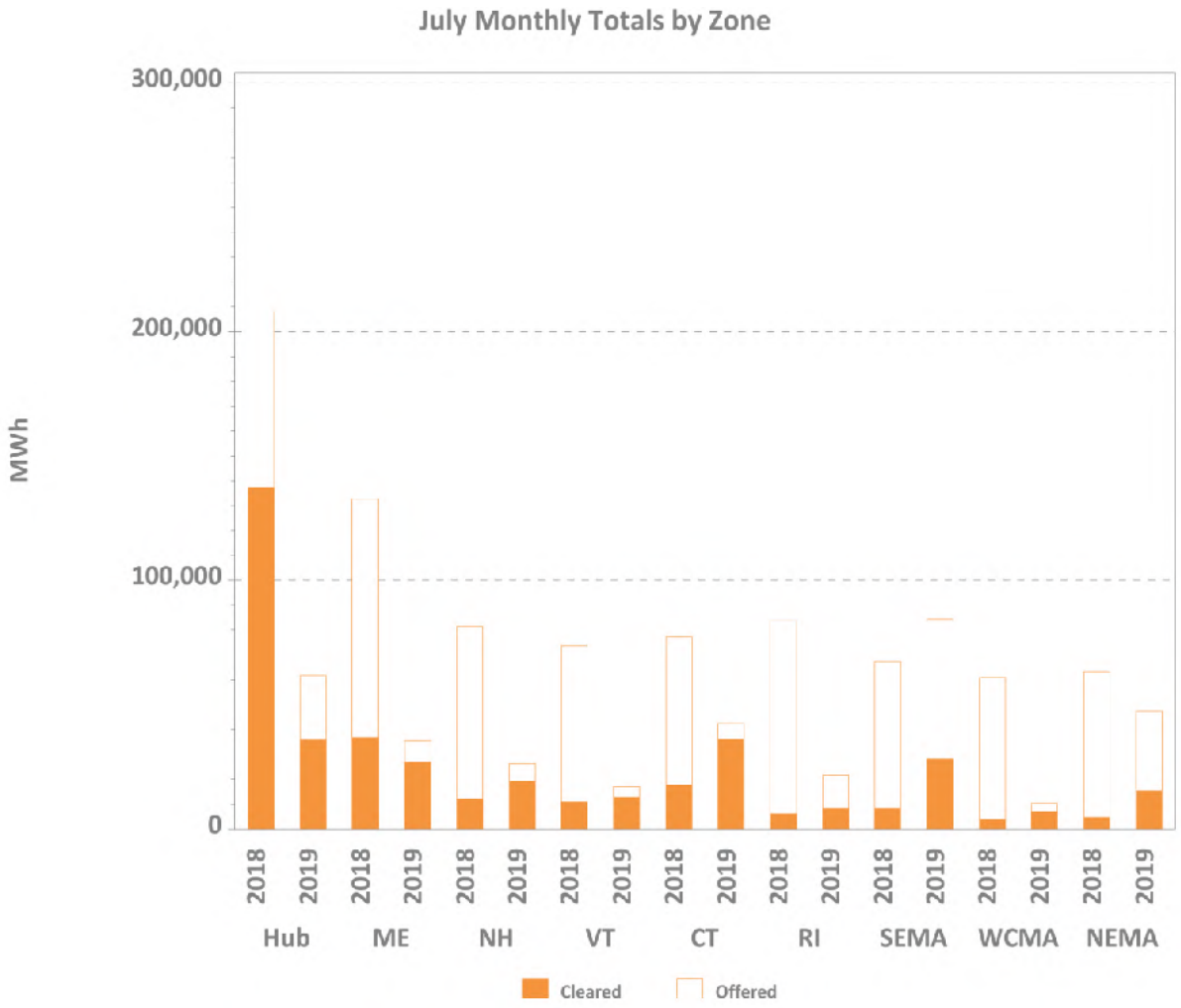
- Maximum potential Forward Reserve Market payments of $3.5M were reduced by credit reductions of $77K, failure-to-reserve penalties of $116K and failure-to-activate penalties of $84, resulting in a net payout of $3.3M or 94% of maximum
  - Rest of System: $2.59M/2.61M (99%)
  - Southwest Connecticut: $0.14M/0.28M (49%)
  - Connecticut: $0.59M/0.62M (96%)
  - NEMA: No requirement
- $485K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $485K in Real-Time Reserve payments
  - Rest of System: 140 hours, $354K
  - Southwest Connecticut: 140 hours, $32K
  - Connecticut: 140 hours, $53K
  - NEMA: 144 hours, $46K

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

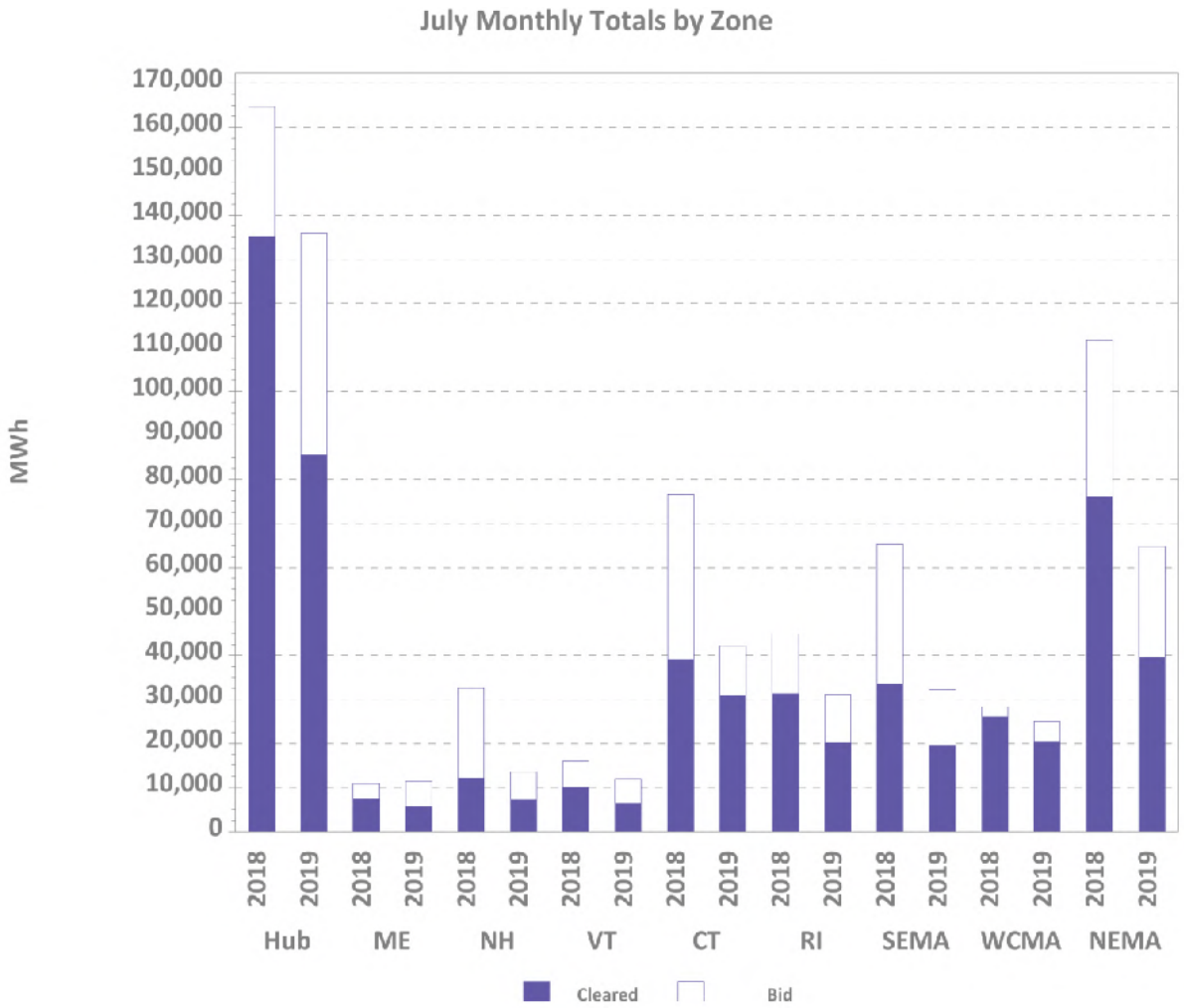
LFRM Charges to Load by Load Zone ($)



Zonal Increment Offers and Cleared Amounts



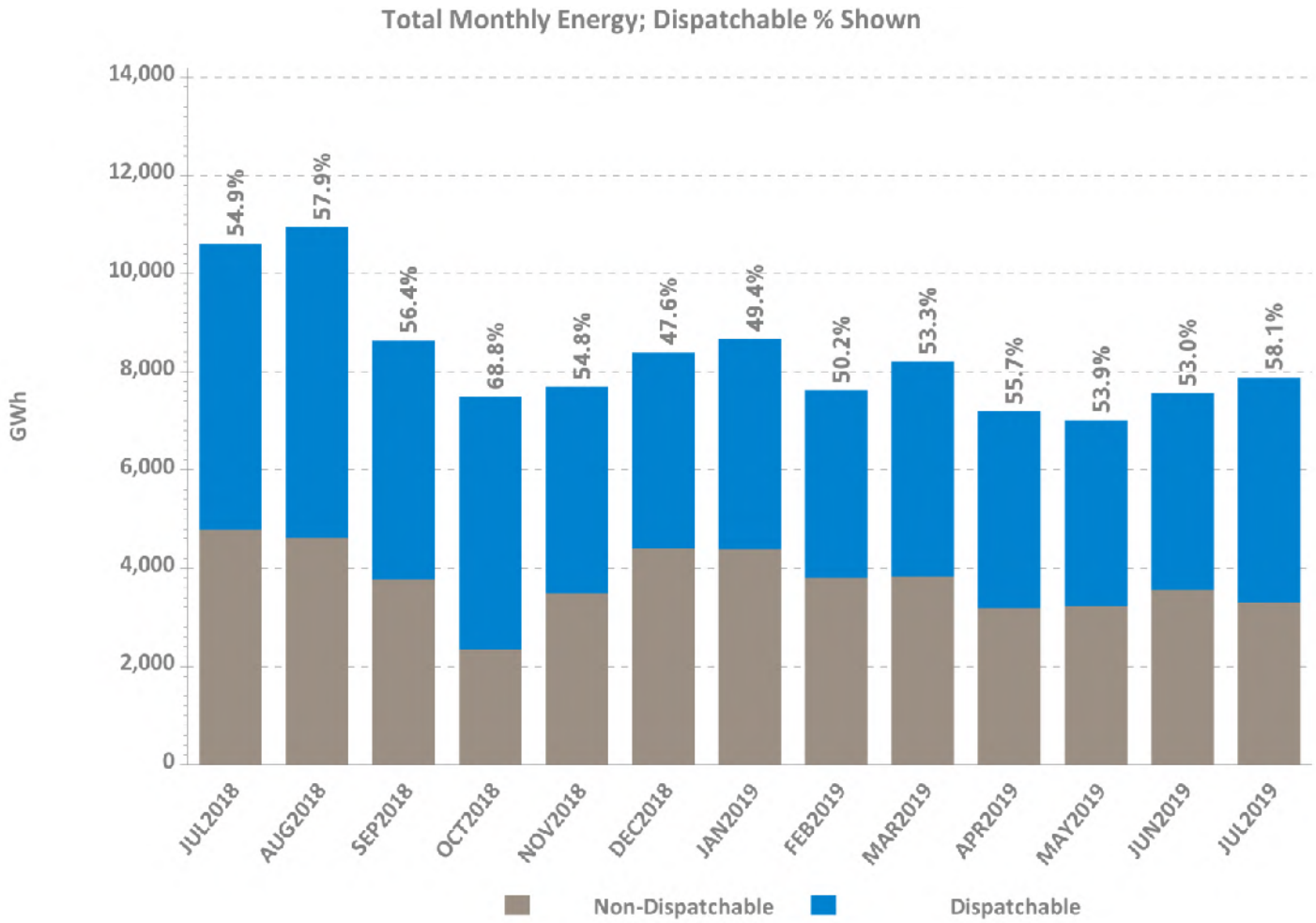
Zonal Decrement Bids and Cleared Amounts



Total Increment Offers and Decrement Bids

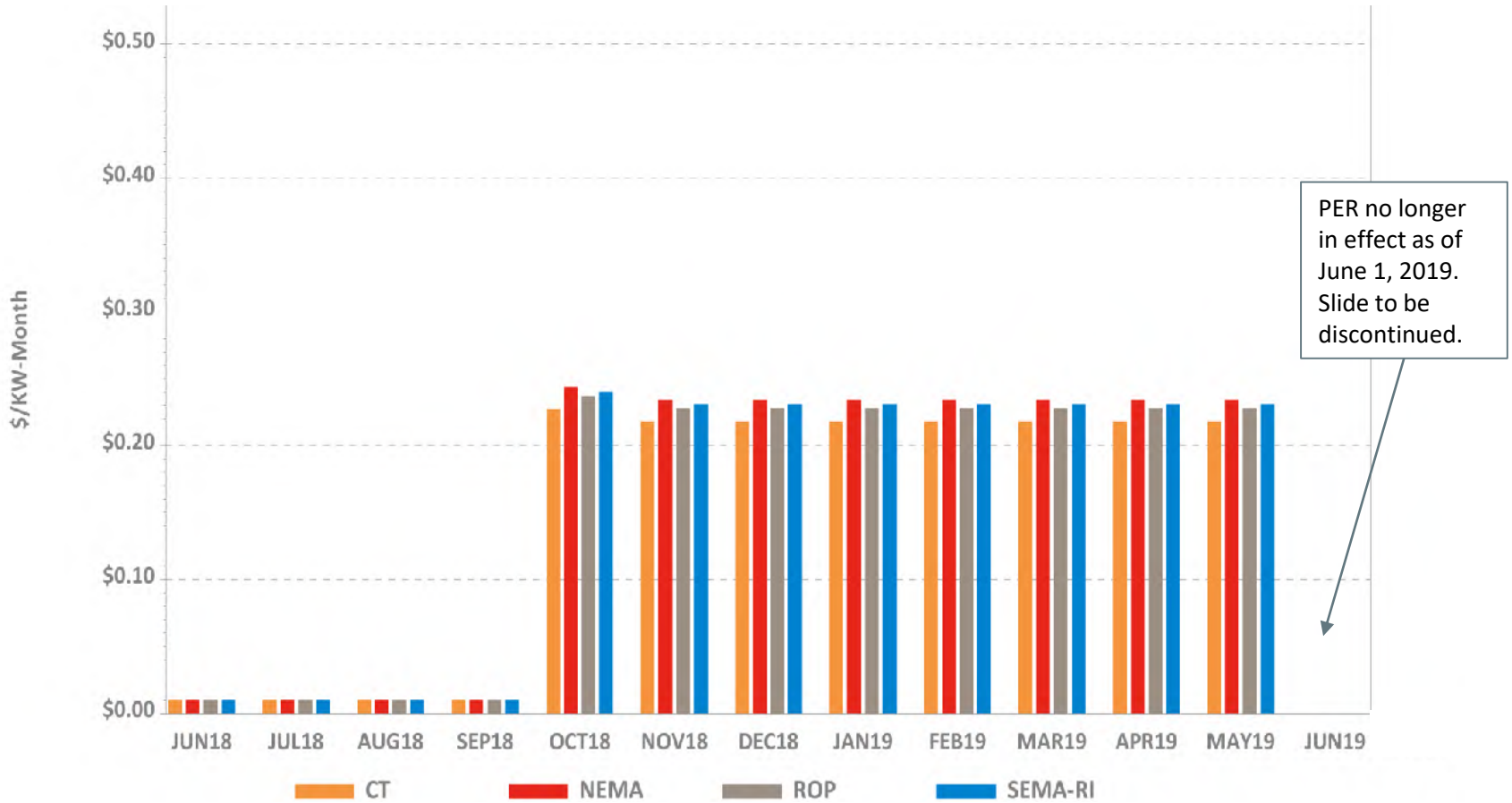
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

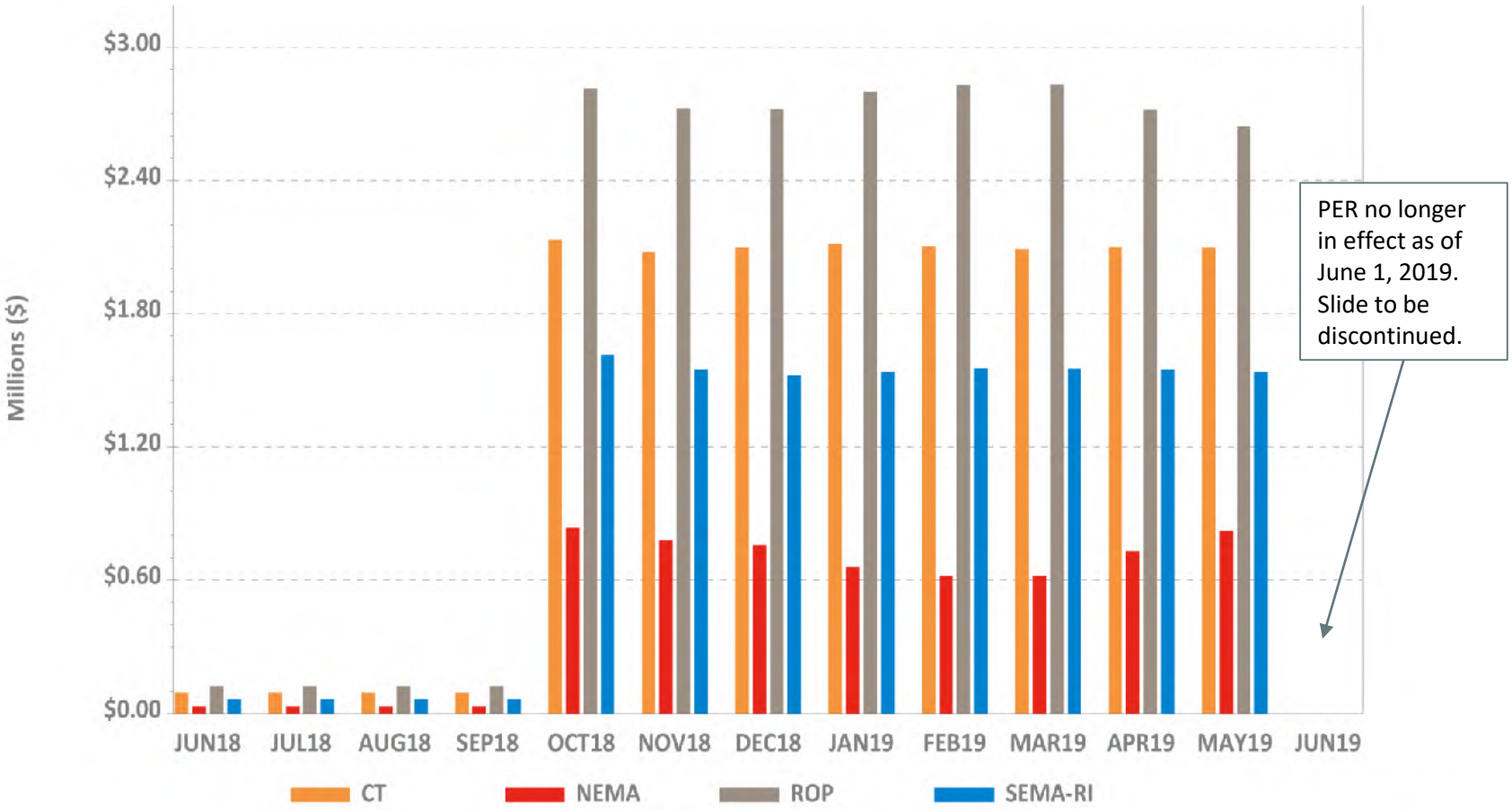
Rolling Average Peak Energy Rent (PER) by Capacity Zone



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

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

PER Adjustments



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

REGIONAL SYSTEM PLAN (RSP)

2019 Regional System Plan

- The 2019 Regional System Plan (RSP19) is under development
  - Draft RSP19 was released for stakeholder review and comment on July 8, and comments were due to the ISO by COB July 24
  - RSP19 Stakeholder Comment Review at PAC is scheduled for August 8
    - Stakeholder comments received will be discussed at this meeting
- RSP19 public meeting will be held on September 12, from 11:30am until 4:00pm, at The Westin Copley Place in Boston, MA
  - Registration is available via ISO-TEN

Planning Advisory Committee (PAC)

- RSP19 Stakeholder Comment Review
- 2019 Economic Studies Assumptions
- Sand Bar Asset Condition Assessment & Solution
- Berlin Substation Condition Assessment and & Solution
- Eversource 345 kV Structure Replacement Projects
- 110-510 & 110-511 Lines 115 kV HPFF Refurbishment
- Boston 2028 Solutions Study and Needs Assessment Update

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

Economic Studies

- Three economic study requests were introduced at the April 25 PAC meeting
  - Study requests were submitted by Anbaric, NESCOE, and RENEW Northeast
- A draft scope of work for each study request was discussed at the May 21 PAC meeting
- The ISO plans on conducting all three economic study requests and will attempt to complete all requests by Q2 of 2020
  - Discussions of detailed assumptions are scheduled for the August 8 PAC meeting

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

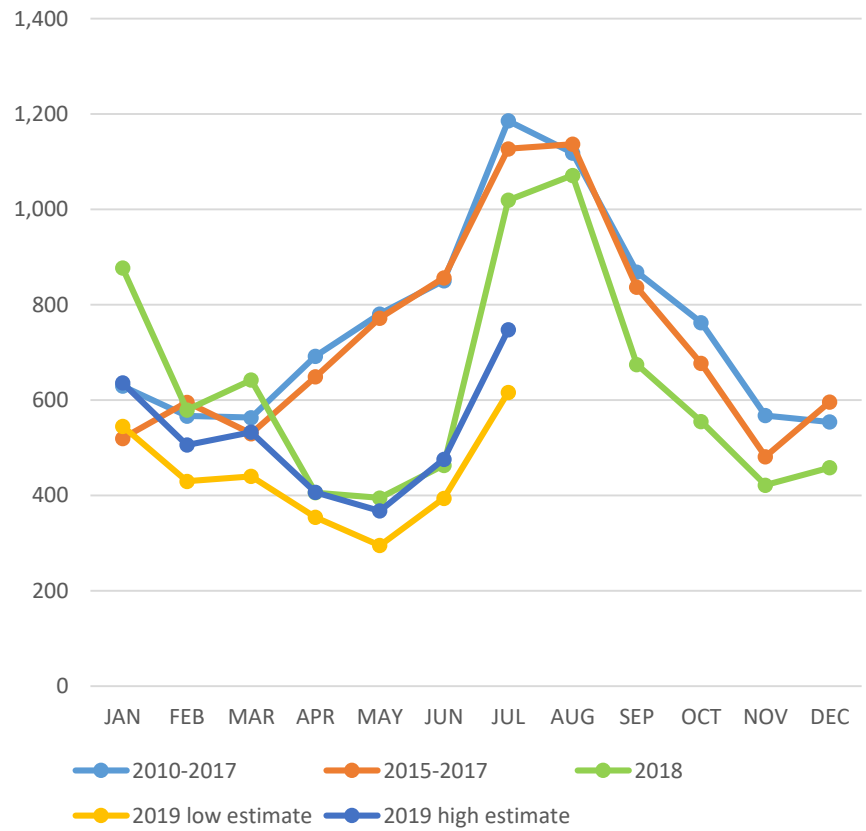
Massachusetts Global Warming Solutions Act (GWSA)

Estimated 2019 Monthly Emissions Trend Lower under GWSA CO_2 Cap

- 2019 cap set at 8.73 million metric tons (MMT)
  - 2018 emissions: 7.56 MMT
- Estimated 2019 monthly emissions range (metric tons):
  - Jan 2019: 545,228 – 635,949
  - Feb 2019: 429,523 – 505,696
  - Mar 2019: 345,470 – 473,633
  - Apr 2019: 224,138 – 257,386
  - May 2019: 264,374 – 329,763
  - Jun 2019: 336,584 – 407,926
  - Jul 2019: 616,343 – 747,649*
  - **YTD 2019: 3.1 MMT – 3.7 MMT**
  - (Jan – Jul 2018: 4.4 MMT)

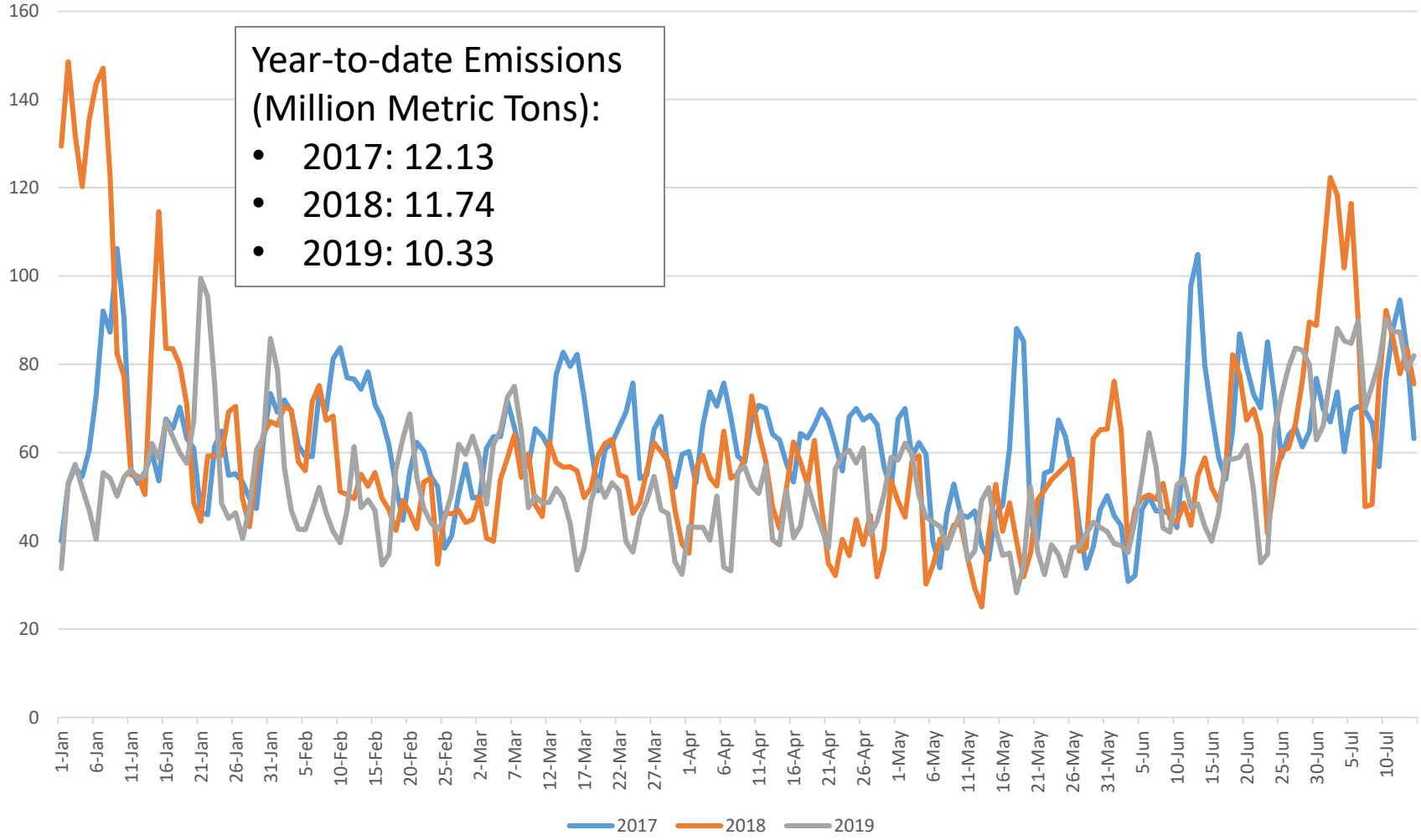
* Jul 2019 estimated emissions through 7/21/19

GWSA Monthly CO_2 Emissions (Thousand Metric Tons)



Jul 2019 estimated emissions through 7/21/19

System Daily Estimated CO_2 Emissions 2017-2019 YTD (Thousand Metric Tons)



* YTD estimated emissions through 7/14 of each year

RSP Project Stage Descriptions

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

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 7/23/19

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	4
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Feb-17	4
New 115 kV overhead line, Scobie Pond-Huse Road	Dec-15	4
New 115 kV overhead/submarine line, Madbury-Portsmouth	May-20	3
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 7/23/19

Project Benefit: Addresses Needs in New Hampshire and Vermont

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

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 7/23/19

Project Benefit: Addresses Needs in New Hampshire and Vermont

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

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 7/23/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Apr-17	4
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Feb-17	4
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add two 115 kV 25.2 MVAR capacitor banks	Jun-18	4
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-15	4
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Mar-17	4
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Jan-17	4
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 7/23/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a 3.7 mile 115 kV hybrid overhead/underground line from Newington to Southwest Hartford and associated terminal equipment including a 1.4% series reactor	Dec-19	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Jun-18	4
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	May-17	4
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Nov-17	4
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-19	3

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 7/23/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	4
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	4
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-19	3
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-18	4
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-19	4
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 7/23/19

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

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

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 7/23/19

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

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

Southwest Connecticut Projects, cont.

Status as of 7/23/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Jun-20	2
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Apr-17	4
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	May-18	4
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	4
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Jun-18	4
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	4

Southwest Connecticut Projects, cont.

Status as of 7/23/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Apr-17	4
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	May-16	4
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Jun-17	4
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-19	3
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-19	3

Southwest Connecticut Projects, cont.

Status as of 7/23/19

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

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

Southwest Connecticut Projects, cont.

Status as of 7/23/19

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

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

Greater Boston Projects

Status as of 7/23/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	May-21	2*
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

* Substation portion of the project is a Present Stage status 4

Greater Boston Projects, cont.

Status as of 7/23/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-18	4
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Dec-19	3
Install third 115 kV line from West Walpole to Holbrook	Dec-19	3
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
Install a new 115 kV line from Sudbury to Hudson	Dec-20	2

Greater Boston Projects, cont.

Status as of 7/23/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	3
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
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	Jan-20	3
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Dec-19	3

Greater Boston Projects, cont.

Status as of 7/23/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-20	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 7/23/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
Install a 345 kV 160 MVAR shunt reactor at K Street	Nov-19	3
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 7/23/19

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

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

Pittsfield/Greenfield Projects, cont.

Status as of 7/23/19

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

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

Pittsfield/Greenfield Projects, cont.

Status as of 7/23/19

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a 115 kV 20.6 MVAR capacitor at the Doreen substation and operate the 115 kV 13T breaker N.O.	Oct-17	4
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	4
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	4
Construct a 115 kV three-breaker ring bus at or adjacent to Pochassic 37R Substation, loop line 1512-1 into the new three-breaker ring bus, construct a new line connecting the new three-breaker ring bus to the Buck Pond 115 kV Substation on the vacant side of the double-circuit towers that carry line 1302-2, add a new breaker to the Buck Pond 115 kV straight bus and reconnect lines 1302-2, 1657-2 and transformer 2X into new positions	Jun-20	2

SEMA/RI Reliability Projects

Status as of 7/23/19

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

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

SEMA/RI Reliability Projects, cont.

Status as of 7/23/19

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

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

SEMA/RI Reliability Projects, cont.

Status as of 7/23/19

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

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

SEMA/RI Reliability Projects, cont.

Status as of 7/23/19

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

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

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

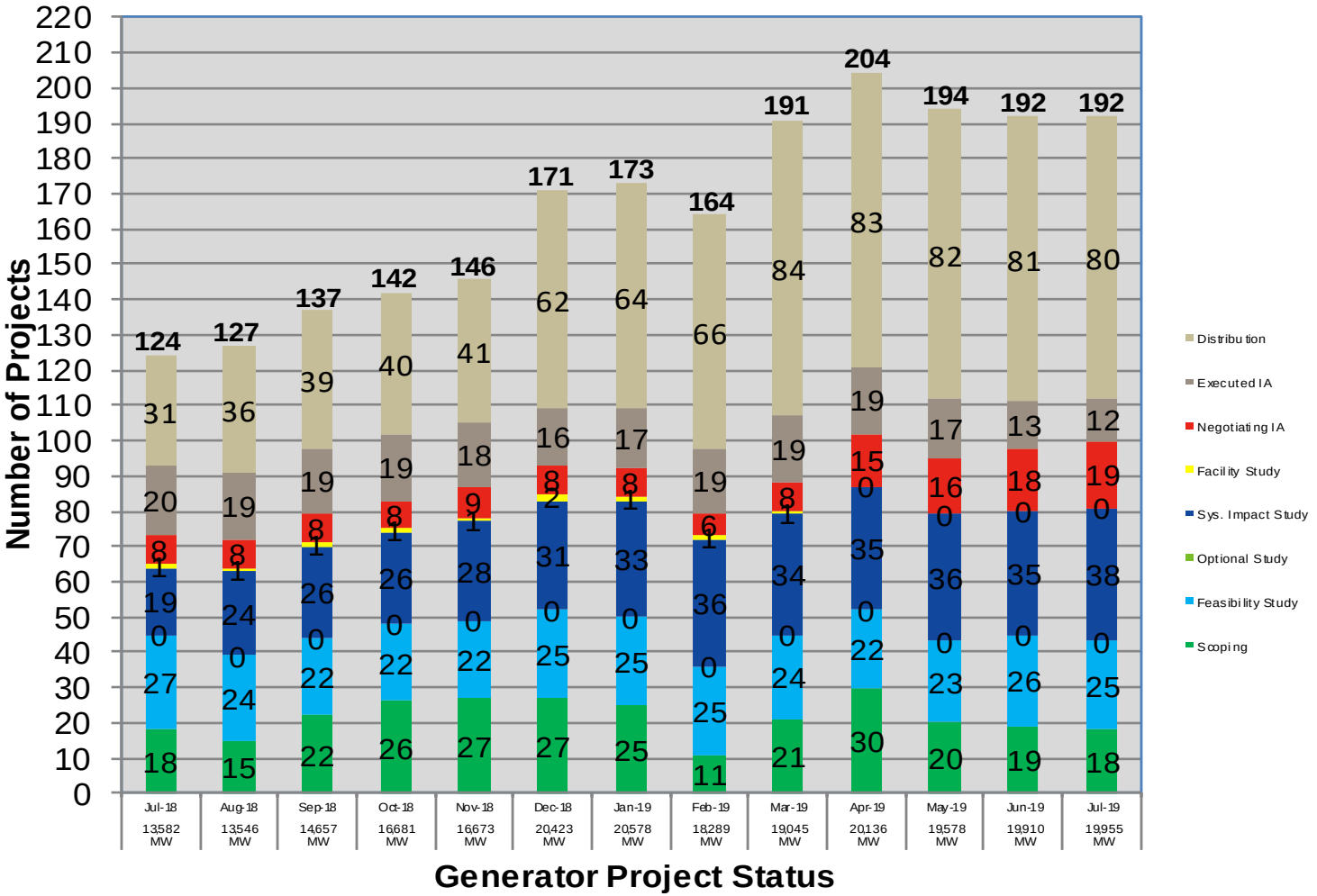
SEMA/RI Reliability Projects, cont.

Status as of 7/23/19

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	Dec-20	2
1724	Replace the Kent County 345/115 kV transformer	Nov-20	2
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	2
1790	Medway 115 kV circuit breaker replacements	Dec-21	2

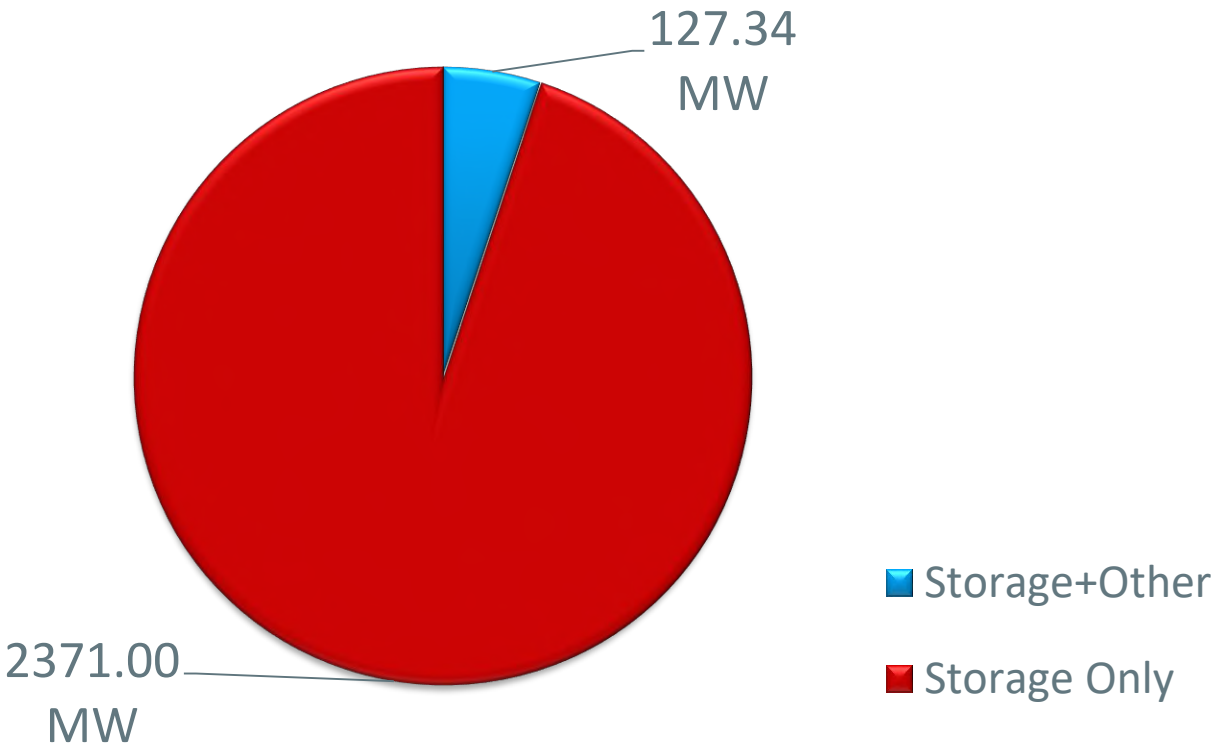
Status of Tariff Studies



Note: July 2019 based on partial data
As of July 2019, there are 8 ETU's in Scoping, 3 in FS, 3 in SIS, 1 in FAC, 1 Negotiating IA, and 2 with Executed IA
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of July 25, 2019)

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



OPERABLE CAPACITY ANALYSIS

Summer 2019 Analysis

Summer 2019 Operable Capacity Analysis

50/50 Load Forecast (Reference)	August - 2019[2] CSO (MW)	August - 2019[2] SCC (MW)
Operable Capacity MW [1]	30,591	30,361
Active Demand Capacity Resource (+) [5]	376	394
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,373	1,373
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	93	137
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	30,175	29,919
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	25,323	25,323
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	27,628	27,628
Operable Capacity Margin	2,547	2,291

[1]Operable Capacity is based on data as of **July 22, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **July 22, 2019 .**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **August 3, 2019.**

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

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

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

Summer 2019 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	August - 2019[2] CSO (MW)	August - 2019[2] SCC (MW)
Operable Capacity MW [1]	30,591	30,361
Active Demand Capacity Resource (+) [5]	376	394
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,373	1,373
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	93	137
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	30,175	29,919
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	27,212	27,212
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,517	29,517
Operable Capacity Margin	658	402

[1]Operable Capacity is based on data as of **July 22, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **July 22, 2019 .**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **August 3, 2019.**

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

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

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

Summer 2019 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 1, 2019 - 50-50 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
8/3/2019	**30591**	**376**	**1373**	**28**	**93**	**0**	**2100**	**0**	**30175**	**25323**	**2305**	**27628**	**2547**
8/10/2019	30591	376	1373	28	61	0	2100	0	30207	25323	2305	27628	2579
8/17/2019	30591	376	1373	28	65	0	2100	0	30203	25323	2305	27628	2575
8/24/2019	30591	376	1373	28	42	0	2100	0	30226	25323	2305	27628	2598
8/31/2019	30674	455	1372	28	76	0	2100	0	30353	25323	2305	27628	2725
9/7/2019	30674	455	1372	28	191	0	2100	0	30238	25323	2305	27628	2610

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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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.
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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 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,323 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 2019 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 1, 2019 - 90-10 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
8/3/2019	**30591**	**376**	**1373**	**28**	**93**	**0**	**2100**	**0**	**30175**	**27212**	**2305**	**29517**	**658**
8/10/2019	30591	376	1373	28	61	0	2100	0	30207	27212	2305	29517	690
8/17/2019	30591	376	1373	28	65	0	2100	0	30203	27212	2305	29517	686
8/24/2019	30591	376	1373	28	42	0	2100	0	30226	27212	2305	29517	709
8/31/2019	30674	455	1372	28	76	0	2100	0	30353	27212	2305	29517	836
9/7/2019	30674	455	1372	28	191	0	2100	0	30238	27212	2305	29517	721

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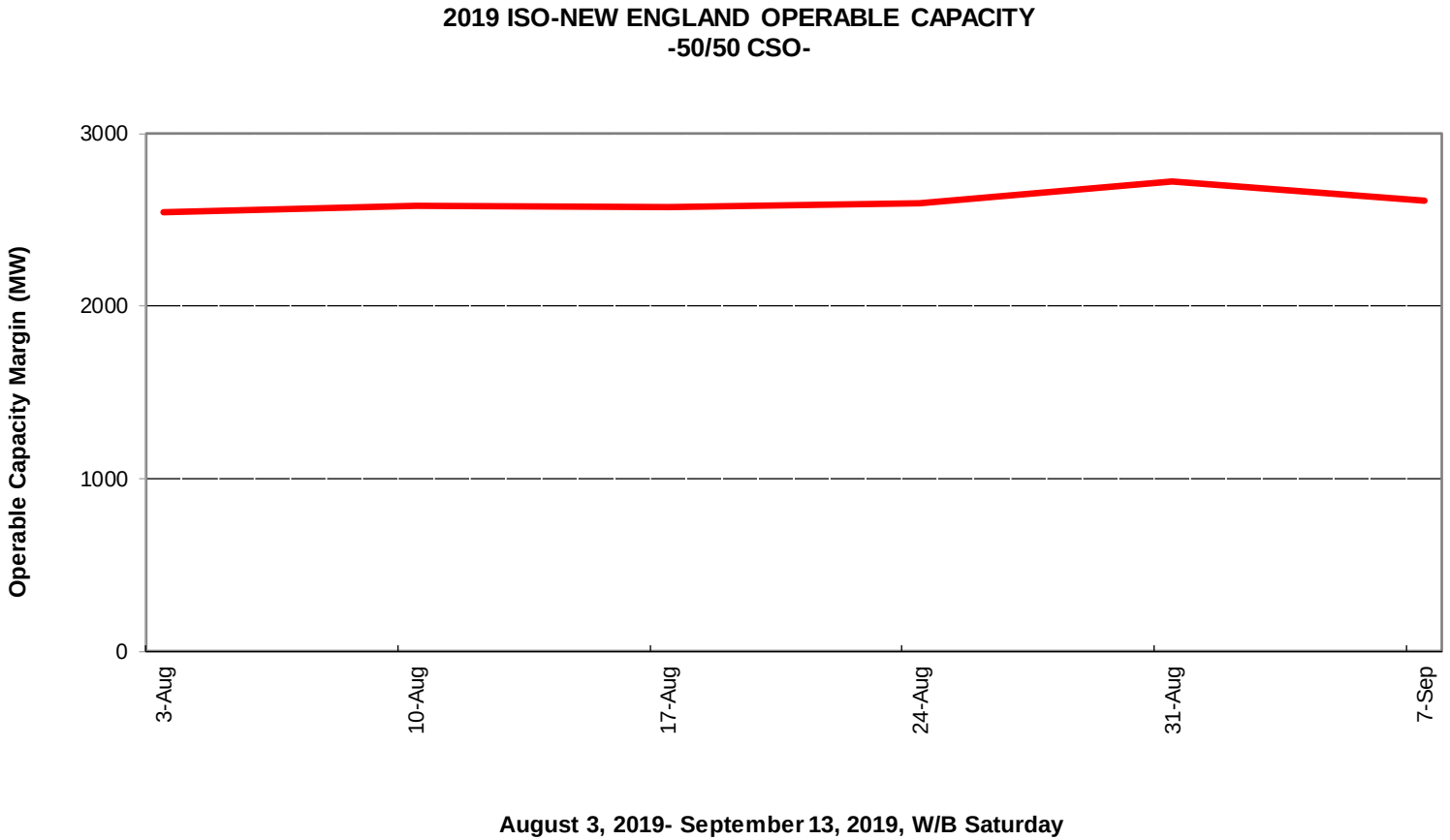
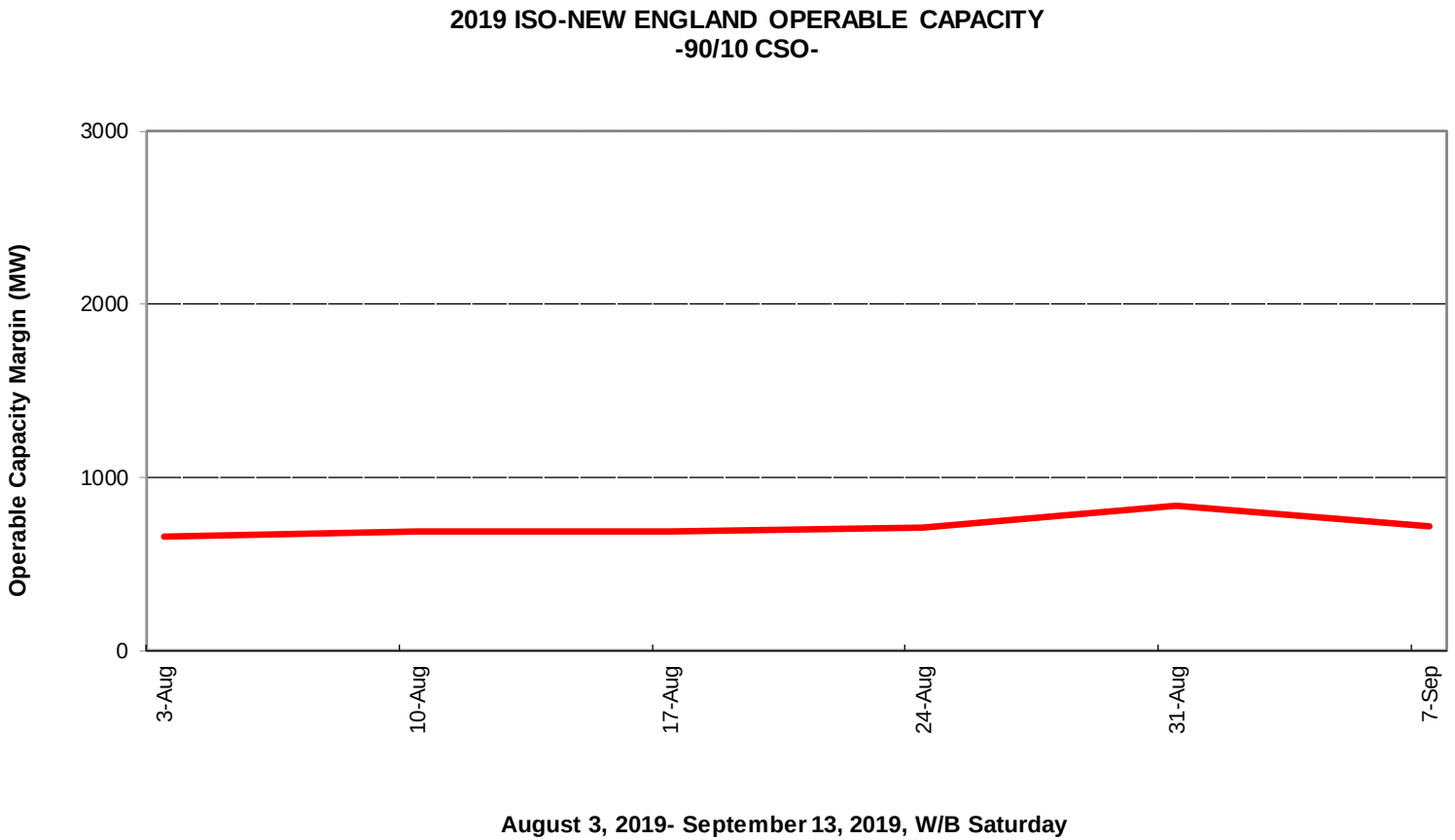
***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week

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



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



OPERABLE CAPACITY ANALYSIS

Preliminary Fall 2019 Analysis

Preliminary Fall 2019 Operable Capacity Analysis

50/50 Load Forecast (Reference)	November - 2019[2] CSO (MW)	November - 2019[2] SCC (MW)
Operable Capacity MW [1]	31,344	33,309
Active Demand Capacity Resource (+) [5]	455	394
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	28	28
Non Gas-fired Planned Outage MW (-)	3,789	3,971
Gas Generator Outages MW (-)	3,044	3,298
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,311	23,779
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,269	17,269
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,574	19,574
Operable Capacity Margin	2,737	4,205

[1]Operable Capacity is based on data as of **July 22, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **July 22, 2019 .**

[2] Load forecast that is based on the 2019 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 9, 2019.**

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

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

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

Preliminary Fall 2019 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	November - 2019[2] CSO (MW)	November - 2019[2] SCC (MW)
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Non Gas-fired Planned Outage MW (-)	3,789	3,971
Gas Generator Outages MW (-)	3,044	3,298
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,311	23,779
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,871	17,871
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,176	20,176
Operable Capacity Margin	2,135	3,603

[1]Operable Capacity is based on data as of **July 22, 2019** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **July 22, 2019.**

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

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[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.

Preliminary Fall 2019 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 1, 2019 - 50-50 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
9/14/2019	30674	455	1372	28	2612	108	2100	0	27709	21176	2305	23481	4228
9/21/2019	30674	455	1372	28	3661	244	2100	0	26524	21080	2305	23385	3139
9/28/2019	31344	455	770	28	5928	5	2800	0	23864	15204	2305	17509	6355
10/5/2019	31344	455	770	28	5001	1311	2800	0	23485	15241	2305	17546	5939
10/12/2019	31344	455	917	28	3508	1307	2800	0	25129	16200	2305	18505	6624
10/19/2019	31344	455	917	28	3095	818	2800	0	26031	16577	2305	18882	7149
10/26/2019	31344	455	917	28	3575	688	3600	0	24881	16792	2305	19097	5784
11/2/2019	31344	455	917	28	4023	3142	3600	0	21979	16912	2305	19217	2762
11/9/2019	**31344**	**455**	**917**	**28**	**3789**	**3044**	**3600**	**0**	**22311**	**17269**	**2305**	**19574**	**2737**
11/16/2019	31344	455	917	28	2967	1754	3600	0	24423	18034	2305	20339	4084
11/23/2019	31344	455	917	28	1041	1421	3600	712	25970	18780	2305	21085	4885

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
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9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2019 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,323 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)

Preliminary Fall 2019 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 1, 2019 - 90-10 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
9/14/2019	30674	455	1372	28	2612	108	2100	0	27709	22794	2305	25099	2610
9/21/2019	30674	455	1372	28	3661	244	2100	0	26524	22692	2305	24997	1527
9/28/2019	31344	455	770	28	5928	5	2800	0	23864	15745	2305	18050	5814
10/5/2019	31344	455	770	28	5001	1311	2800	0	23485	15783	2305	18088	5397
10/12/2019	31344	455	917	28	3508	1307	2800	0	25129	16770	2305	19075	6054
10/19/2019	31344	455	917	28	3095	818	2800	0	26031	17159	2305	19464	6567
10/26/2019	31344	455	917	28	3575	688	3600	0	24881	17380	2305	19685	5196
11/2/2019	31344	455	917	28	4023	3142	3600	0	21979	17503	2305	19808	2171
11/9/2019	**31344**	**455**	**917**	**28**	**3789**	**3044**	**3600**	**0**	**22311**	**17871**	**2305**	**20176**	**2135**
11/16/2019	31344	455	917	28	2967	1754	3600	0	24423	18659	2305	20964	3459
11/23/2019	31344	455	917	28	1041	1421	3600	949	25733	19428	2305	21733	4000

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12. Total Net Load Obligation per the formula(10 + 11 = 12)
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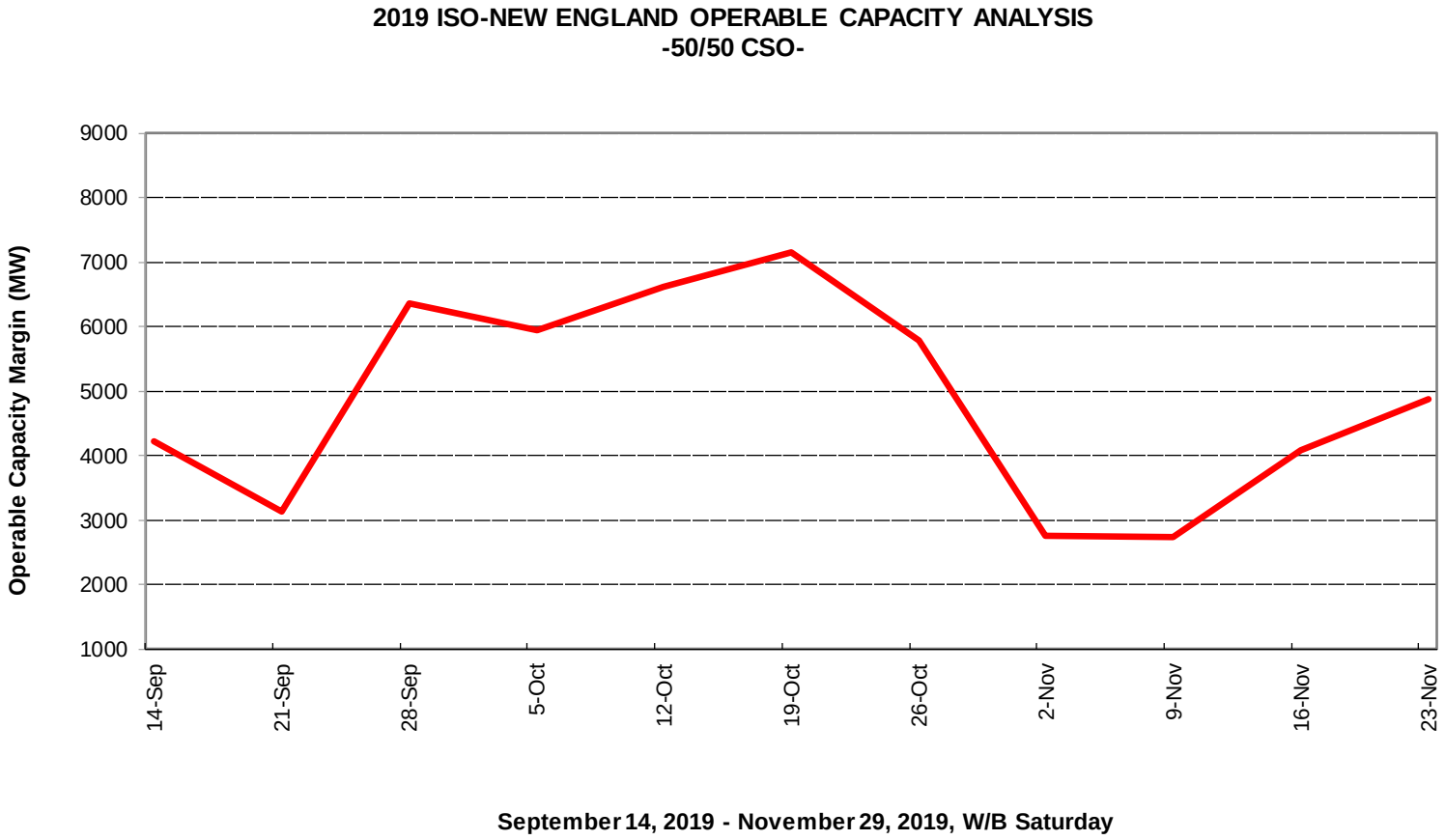
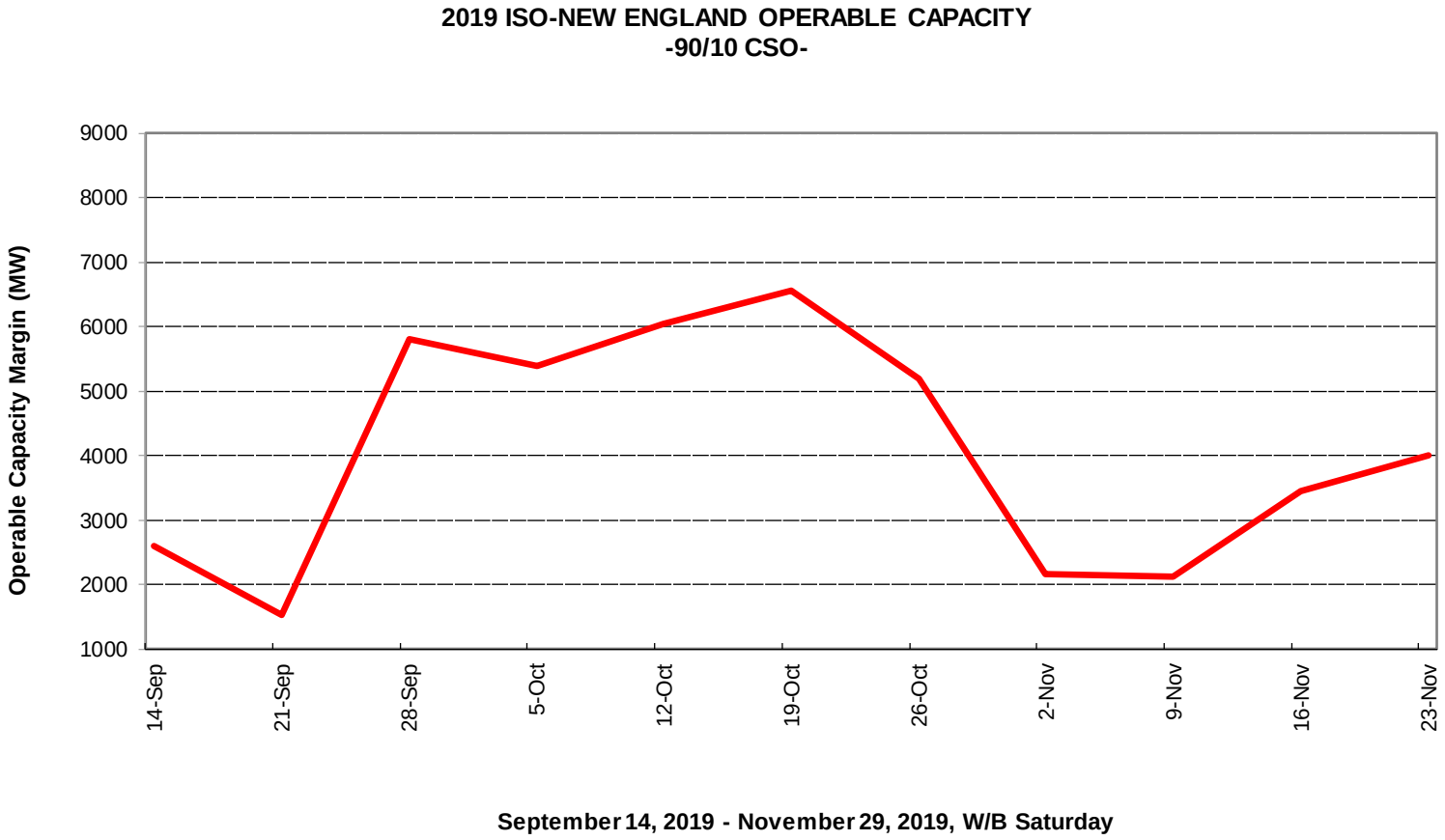
***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week

Preliminary Fall 2019 Operable Capacity Analysis
50/50 Forecast (Reference)



Preliminary Fall 2019 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and advise Resources with a CSO to prepare to provide capacity and notify "Settlement Only" generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow the depletion of 30-minute reserve.	0 [1] 600
2	Declare Energy Emergency Alert (EEA) Level 1[4]	0
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes	125 [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 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntary provide energy for reliability purposes	0
8	5% Voltage Reduction requiring 10 minutes or less	250 [3]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**2,520**

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 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi, Eric Runge and Jamie Blackburn, NEPOOL Counsel

DATE: July 26, 2019

RE: Import Capacity Resource Transaction Requirements & Clean Up Changes

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During its August 2, 2019 teleconference meeting, the Participants Committee will be asked to consider supporting a package of revisions to modify the requirements for submitting external transactions associated with Import Capacity Resources and to make a number of clean up changes, including the proposed removal of certain outdated Tariff provisions. As described in more detail below, the Markets Committee reviewed and recommended Participants Committee support for the Markets Committee related revisions to Market Rule 1 ("Market Rule 1 Revisions"), Manual M-11 ("Manual 11 Revisions"), Operating Procedure No. 9 ("OP-9 Revisions"); and the Reliability Committee reviewed and recommended Participants Committee support for changes to OP-5 (the "OP-5 Revisions"), over which it has authority. The Technical Committee recommendations were opposed by several Participants, and Calpine asked that this subject be included on the discussion agenda for the August 2 meeting. A copy of all of the proposed revisions, as well as background materials prepared by the ISO that provide further detail on the package of changes, are included with this memorandum.

Markets Committee Recommendation (Market Rule 1, Manual 11, OP-9 Revisions)

Most of the revisions considered by the Markets Committee were proposed by the ISO to modify external transaction submittal requirements for capacity imports in the following ways: (1) Day-Ahead and Real-Time Energy Market offers would no longer have to be submitted with the same external transaction; (2) a Day-Ahead external transaction would not be required when the interface's import transfer capability is zero; (3) Real-Time external transactions would no longer be required for import capacity that wheels through the NYISO to a Coordinated Transaction Scheduling ("CTS") interface; and (4) all capacity imports backed by external resources will only have to comply with the procedures of their native control area and notify ISO-NE of outages affecting Capacity Supply Obligations. The Markets Committee also considered proposed clean up changes to remove outdated Tariff provisions related to the now expired two-year performance evaluation of the CTS design and to "placeholder" provisions describing the dynamic scheduling of resources (i.e., inter-area dispatch control).

At its July 8-10 meeting, the Markets Committee voted to recommend Participants Committee support for the package of Market Rule 1, Manual M-11 and OP-9 changes based on a show of hands with opposition from several Participants.[1]

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[1] Based on a show of hands, the motion at the Markets Committee passed with five opposed (1 Supplier Sector, 1 Generation Sector, 1 Alternative Resources ("AR") Sector, 2 End User Sector) and eight abstentions (2 Supplier Sector, 3 Generation Sector, 3 AR Sector).

Reliability Committee Recommendation (OP-5 Revisions)

The OP-5 Revisions, which correspond directly to certain of the Markets Committee recommended changes, would modify the treatment of outage requests for Import Capacity Resources backed by one or more external resources. Market Participants associated with such import capacity would need to notify the ISO if there is a reduction in capability that impacts the CSO of its Import Capacity Resource, but no outage request of ISO-NE would be required.

At its July 16 meeting, the Reliability Committee voted to recommend Participants Committee support for the OP-5 Revisions, with oppositions registered by several Participants.[2] In explaining the basis for their opposition to the OP-5 Revisions, some members objected to external capacity resources being treated differently (and more favorably as they perceived it) to internal capacity resources in the Forward Capacity Market.

August 2 Participants Committee Action; Minimum Voting Thresholds

The minimum threshold for a passing vote at the Participants Committee on the Markets Committee recommended revisions to Market Rule 1, Manual 11, and OP-9 is 60%. The minimum threshold for a passing vote with respect to the OP-5 Revisions is 66.67%.

The following forms of resolution may be used for Participants Committee action, voted either individually or in a single combined vote:

> RESOLVED, that the Participants Committee supports the ***Market Rule 1 Revisions, Manual 11 Revisions, and OP-9 Revisions*** as recommended by the Markets Committee at its July 8, 2019 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 agreed to after the meeting by the Chair and Vice-Chair of the Markets Committee.
>
> RESOLVED, that the Participants Committee supports the ***OP-5 Revisions*** as recommended by the Reliability Committee at its July 16, 2019 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 agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

[2] Based on a show of hands, the motion at the Reliability Committee passed with six opposed (2 Generation Sector, 2 Supplier Sector, 2 AR Sector) and three abstentions (1 Generation Sector, 1 Supplier Sector, 1 AR Sector).

ISO new england

memo

To: NEPOOL Markets Committee

From: Matt Brewster

Date: July 2, 2019

Subject: Import Capacity Resource transaction requirements and clean-up changes

The ISO is requesting a vote on revisions to Market Rule 1 that streamline the requirements for submitting external transactions associated with Import Capacity Resources and better align these requirements with the capacity market Pay for Performance rules. These updates are motivated by the technical project to replace the software platform for submitting external transactions, which is scheduled for implementation by October of this year.

The Market Rule 1 revisions also include clean-ups to remove outdated provisions relating to Coordinated Transaction Scheduling and dynamic scheduling.

In addition, the ISO is requesting votes on corresponding conforming revisions to Manual 11 (Market Operations) and Operating Procedure No. 9 (Scheduling and Dispatch of External Transactions).

The package of changes that the committee is being asked to consider were presented at the meeting dates listed below:

- May 7-8, 2019, agenda item 7: https://www.iso-ne.com/event-details?eventId=137575
- June 10-12, 2019, agenda item 4: https://www.iso-ne.com/event-details?eventId=139121

4851-8131-4459, v. 2

ISO new england

Import Resource Transaction Requirements and Clean Up

Simplifying the requirements for capacity import transactions (energy), and clean-ups to remove outdated tariff provisions

Matt Brewster

(413) 540 – 4547
MBREWSTER@ISO-NE.COM

Project Title: **Import Resource Transaction Requirements and Clean up**	**WMPP ID: 136**

Proposed Effective Dates: October 23, 2019

- The ISO is proposing modifications to the external transaction submittal requirements for Import Capacity Resources that will simplify the requirements and better align with the Pay for Performance (PfP) rules
- These updates are motivated by the technical project to replace the Enhanced Energy Scheduling (EES) application
  - The "Update EES Technical Architecture Project"*
  - Target launch date: October 23, 2019
- The proposal also includes removal of other outdated tariff provisions and clean-ups of related provisions

* https://www.iso-ne.com/participate/support/customer-readiness-outlook/ees-technical-architecture-project

Topics for today

- Review of the proposed modifications
  - Presented at the May 2019 MC *
- Governing document revisions
  - Market Rule 1
  - Manual 11 (Market Operations)
  - OP 9 (Scheduling and Dispatch of External Transactions)

* https://www.iso-ne.com/static-assets/documents/2019/05/a7_presentation_import_resource_transaction_requirements_and_cleanup.pptx

PROPOSAL REVIEW

Streamlining external transaction submittal requirements for capacity imports, and clean-ups of outdated Tariff provisions

Streamlining the external transaction submittal requirements for capacity import resources

- These changes will update or remove requirements that are no longer necessary under the PfP rules
  - Also, they will provide additional flexibility to participants
- Four proposed modifications:
  A. The day-ahead and real-time energy offers will no longer have to be submitted with the same transaction
  B. A day-ahead transaction will not be required when the interface's import transfer capability is zero
  C. Real-time transactions will no longer be required for capacity that wheels through the NYISO to a CTS interface
  D. All capacity imports backed by an external resource will have the same requirements pertaining to resource outages (i.e., to notify ISO-NE of outages and comply with the requirements of the native control area).

Clean-ups to remove outdated Tariff provisions

- The Coordinated Transaction Scheduling (CTS) two-year evaluation provisions were performed and are now expired
  - The entirety of MR1 Section III.1.10.7.B can be removed
- The placeholder provisions describing "dynamic scheduling" of resources (i.e., inter-area dispatch control) lack sufficient detail about the design or operation of the construct and the ISO has no supporting implementation
  - A request for this capability would require ISO-NE and the neighbor control area to develop the design, market rules, operating protocols, and implementation; however, these placeholder rules have caused misperceptions that the construct could be readily implemented
  - MR1 Section III.1.12 establishes the concept, but certain references also appear in Sections III.1.10 and III.3.2

GOVERNING DOCUMENT REVISIONS

Overview of revisions to Market Rule 1, Manual 11, and Operating Procedure No. 9

Governing document revisions

Market Rule 1 Section III.1

Section	Change	Description
III.1.10.1A(b)	Clean-up *Transaction req.*	Remove redundant statement about the real-time treatment of priced transactions that clear in the day-ahead; this is also stated in Section III.1.10.7(b)
III.1.10.1A(b)(iii) & (iv)	Clean-up *Transaction req.*	Clarify that provisions (iii) and (iv) apply to the day-ahead market. Update use of the term "fixed" with the current term "Self-Scheduled."
III.1.10.1A(c)	Clean-up *Dynamic scheduling*	Remove reference to external resources providing generator supply offers. Remove extraneous cross-reference to external transaction submittal rules.
III.1.10.1A(g)	Clean-up *Dynamic scheduling*	Remove reference to external resources in the provisions for carrying-over supply offers to subsequent days.

Governing document revisions

Market Rule 1 Section III.1 (cont.)

Section	Change	Description
III.1.10.4	Clean-up *Dynamic scheduling & transaction req.*	Remove provisions for external resources to provide generator asset supply offers. Clarify the provision for external resources to provide external transactions under the applicable tariff sections. Remove extraneous description of deviation settlement.
III.1.10.7(c)	Clean-up *Transaction req.*	Update reference to M-11 so that it instead points to OP No. 9, where the relevant procedures are now detailed.
III.1.10.7(d)	Modification [A] *Transaction req.*	Remove the exception for providing, upon submittal, the e-Tag ID and transmission reservation (where applicable) for certain capacity import transactions. The related provision in Section III.13.6.1.2.1 that is referenced in this section was also removed. Update the term e-Tag ID.
III.1.10.7A	Clean-up *Transaction req.*	Modify the section title to be consistent with the scope of the provisions and the same defined term. Update the term e-Tag ID. Add reference to OP No. 9 as the relevant procedure, consistent with Section III.1.10.7(c).

Governing document revisions

Market Rule 1 Section III.1 (cont.)

Section	Change	Description
III.1.10.7B	Clean-up *CTS*	Remove the CTS performance analysis section in entirety since it is no longer applicable.
III.1.10.9(b)	Clean-up *Transaction req.*	Clarify the participant's capabilities to revise a real-time priced external transaction. Remove reference to M-11 which no longer contains relevant information; the tariff itself defines the relevant capability. Typo correction.
III.1.12	Clean-up *Dynamic scheduling*	Remove provisions describing the concept of dynamic scheduling.

Governing document revisions

Market Rule 1 Section III.3

Section	Change	Description
III.3.2.1(b)(ii)	Clean-up *Dynamic scheduling*	Remove provision contemplating that real-time generation obligations would accrue to external resources under a dynamic scheduling construct.
III.3.2.6	Clean-up *Dynamic scheduling*	Remove provisions contemplating that deviations would accrue to external resources under a dynamic scheduling construct for emergency energy cost allocation. Update use of the term Dispatch Instruction.
III.3.2.6A	Clean-up	Remove unnecessary reference to M-28 which implies that the manual contains an alternative cost allocation method (which it does not).

Governing document revisions

Market Rule 1 Section III.13

Section	Change	Description
III.13.6.1.2.1	Modification [A-C] & clean-up *Transaction req.*	Revise and streamline the requirements for submitting energy transactions for capacity imports. This section now also addresses topics that previously were in Section III.13.6.1.2.3 (which formerly had separate explanations for import capacity resources at CTS interfaces), or in Section III.13.6.1.2.2 (i.e., linking the Import Capacity Resource identifier)
III.13.6.1.2.2	Modification [D] & clean-up *Transaction req.*	Revise and streamline the additional requirements for import capacity resources during external resource outages. This section now also addresses topics that previously were in Section III.13.6.1.2.3 (which formerly had separate explanations for import capacity resources at CTS interfaces).
III.13.6.1.2.3	Modification [B-D] & clean-up *Transaction req.*	Remove this section in entirety; the rules that remain applicable were incorporated into Sections III.13.6.1.2.1 and III.13.6.1.2.2.

Governing document revisions

Manual 11

Section	Change	Description
3.2.1	Conforming *Transaction req.*	References to "EES" replaced with "NEXTT" (the new application name). Remove reference to the requirement for import capacity resources wheeling through NYISO to provide a real-time transaction to ISO-NE.
3.2.2	Conforming *Transaction req.*	"EES" references replaced. Add explanation of the capability to modify transaction attributes during real time (current).
3.2.3	Conforming *Transaction req.*	Add explanation of transaction CSO validation (current). Remove explanation of customer validation for capacity import transactions (update).
3.2.4	Conforming *Transaction req.*	"EES" references replaced. Remove the "Flex Reservation" attribute which will no longer apply for capacity imports. Style and grammar clean-ups.
3.2.5	Conforming *Transaction req.*	Revise explanations of the validation checks performed for real-time transactions and associated labels (update).

Governing document revisions

Operating Procedure No. 9

Section	Change	Description
II.A.1	Clean-up	Capitalization revisions.
III.B.4	Conforming *Transaction req.*	Remove description of external transactions associated with a wheel through the NYISO to a CTS interface; this transaction will no longer be required.
III.F	Conforming *Transaction req.*	Remove the “Flex Reservation” attribute which will no longer apply for capacity imports.

SUMMARY AND NEXT STEPS

Recap of material and committee schedule

Summary

- The modified external transaction submittal requirements for capacity imports will streamline the participant's obligations and better align with the PfP rules
- The outdated CTS evaluation provisions and dynamic scheduling provisions will be removed
- ISO is planning an October 23, 2019, effective date to align with the EES replacement project schedule

Committee schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee **May 7-8, 2019**	Initial meeting: Topic introduction and review of changes
Markets Committee **June 11-12, 2019**	Second meeting: Further discussion and review of revisions to governing documents
Markets Committee **July 9-10, 2019**	Vote
Participants Committee **August 2, 2019**	Vote

APPENDIX

Proposal detail slides from the May 7-8, 2019, MC meeting

Modification A

The day-ahead and real-time offers no longer have to be submitted with the same transaction

- Currently: capacity import transactions must have matching day-ahead (DA) and real-time (RT) energy profiles on the same transaction and, by extension, all RT offers are due by the DA offer deadline
- Proposed: suppliers can use any combination of allowed transactions to meet their DA and RT offer obligation
  - Capacity imports will be subject to the same deadlines and submittal requirements as all other (i.e., energy-only) transactions
- The current requirement arose from failure-to-offer/deliver
- This affects only capacity imports at non-CTS interfaces
  - RT offers are not required for capacity imports at CTS interfaces

Modification B

A day-ahead transaction will not be required when the interface's import transfer capability is zero

- Currently: suppliers must provide day-ahead imports for the resource's CSO regardless of an interface outage
  - The offer has financial risk since it may clear against offsetting bids at the interface in the day-ahead market
  - The transaction is irrelevant to the ISO's operating plan if the TTC is zero
- Proposed: the day-ahead offer requirement will not apply when the interface's import TTC is zero
  - The real-time offer requirement at non-CTS interfaces will continue to apply regardless of an interface outage
  - The associated financial risks do not exist in real-time scheduling and the TTC rating may be restored during real-time
- This change relates to removing the "matching" requirement (prior)
- This affects capacity imports at all interfaces

Modification C

Real-time transactions will no longer be required for capacity wheeling thru NYISO to CTS interfaces

- Currently: suppliers with capacity imports at CTS interfaces that wheel through NYISO have to provide ISO-NE a real-time transaction associated with the wheel
  - NYISO controls the scheduling of the wheel through its control area and provides ISO-NE with the schedule data for market settlements
  - The transaction provided to ISO-NE is not necessary for scheduling
- Proposed: submittal of the real-time transaction to ISO-NE will not be required
  - NYISO will continue to schedule the wheel and provide ISO-NE with the transaction schedule data necessary for market settlements
- The current requirement arose from failure-to-offer/deliver
- This affects only wheeled capacity imports at CTS locations

Modification D

All imports backed by an external generator will have the same outage notification requirements

- Currently: The ISO-NE outage scheduling procedures apply to external resources backing capacity imports
  - Except New York resources backing capacity imports at CTS interfaces which comply with NYISO procedures and notify ISO-NE of outages
- Proposed: all capacity imports backed by external resources will only have to comply with the procedures of their native control area and notify ISO-NE of outages affecting the CSO
  - i.e., the same as the current requirements for NY resources (above)
- The current requirement related to the pre-PFP "availability score" framework which considered planned outages
- This (potentially) affects capacity imports at all interfaces

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Tariff Sections III.1, III.3, and III.13

Effective: October 23, 2019

Table of Contents updates will reflect removed and modified Section titles as shown in-line below.

III.1.10.1A Energy Market Scheduling.

The submission of Day-Ahead offers and bids shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) **Locational Demand Bids –** Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resources Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) **External Transactions –** All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. ~~A priced External Transaction submitted under Section III.1.10.7 and that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.~~ Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) ~~If~~ In the Day-Ahead Energy Market, if the sum of all submitted ~~fixed~~ Self-Scheduled External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all ~~fixed~~ Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) ~~If~~ In the Day-Ahead Energy Market, if the sum of all submitted ~~fixed~~ Self-Scheduled External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all ~~fixed~~ Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the Energy Offer Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(c) **Generator Asset Supply Offers –** Market Participants selling into the New England Markets from Generator Assets ~~or External Resources~~ may submit Supply Offers ~~or External Transactions~~ for the supply of energy for the following Operating Day. ~~(Coordinated External Transactions shall be submitted to the ISO in accordance with Section III.1.10.7.A of this Market Rule 1.)~~

Such Supply Offers:

(i) Shall specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} X — \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction Offer, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of ~~an External Resource and~~ an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

III.1.10.4 External Resources.

~~(a) Market Participants with External Resources that have dynamic scheduling and dispatch capability may submit Supply Offers to the New England Markets in accordance with the Day-Ahead and Real-Time scheduling processes specified above. Market Participants must submit Supply Offers for External Resources on a Resource specific basis. An External Resource with dynamic scheduling and dispatch capability selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO and shall be compensated on the same basis as other Pool-Scheduled Resources.~~

~~(b) Supply Offers for External Resources with dynamic scheduling and dispatch capability shall specify the Resource being offered, along with the information specified in the Offer Data as applicable.~~

~~(c) For Resources external to the New England Control Area that are not capable of dynamic scheduling and dispatch,~~ Market Participants with External Resources may~~shall~~ submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

~~(d) A Market Participant whose External Resource is capable of dynamic scheduling and dispatch capability or whose External Transaction does not deliver the energy scheduled in the Day-Ahead Energy Market shall replace such energy not delivered as scheduled in the Day-Ahead Energy Market with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.~~

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the ~~applicable~~ procedures governing the Emergency, as set forth in ISO New England ~~Manual 11~~Operating Procedure No. 9, require a change in schedule.

(d) ~~A Market Participant submitting a priced External Transaction supporting Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to linking the transaction to the associated transmission reservation and NERC E-Tag. All other~~ External Transactions submitted to the Real-Time Energy Market must contain the associated ~~NERC E~~e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the

III.1.10.7.A Coordinated Transaction Scheduling~~External Transactions~~.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated ~~NERC E~~e-Tag ID at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless ~~applicable~~ the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

~~**III.1.10.7.B Coordinated Transactions Scheduling Threshold Trigger to Tie Optimization**~~

~~(a) Background and Overview~~

~~This Section III.1.10.B describes the process for filing amendments to the Transmission, Markets and Services Tariff under Section 205 of the Federal Power Act in the event that the production cost savings of the ISO's interchange on the New York – New England AC Interface, including the Northport/Norwalk Line, following the implementation of an inter-regional interchange scheduling process known as Coordinated Transaction Scheduling, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Section III.1.10.7.B. If pursuant to the actions, thresholds and triggers described in this Section III.1.10.7.B, the production costs savings of Coordinated Transaction Scheduling are not satisfactory, and a superior alternative has not become known, the ISO will file tariff amendments with the Commission to implement the inter-regional interchange scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.~~

~~If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Section III.1.10.7.B become null and void and the ISO will continue to implement Coordinated Transaction Scheduling unless and until future Section 205 filings are pursued to amend Coordinated Transaction Scheduling.~~

~~(b) The Two-Year Analysis~~

~~Within 120 days of the close of the first and second years following the date that Coordinated Transaction Scheduling as an interface scheduling tool is activated in the New England and New York wholesale electricity markets, the External Market Monitor will develop, for presentation to and comment by, New England stakeholders, an analysis, of:~~

~~(i) the Tie Optimization interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the ISO and New York Independent System Operator received an infinite number of zero bids in the Coordinated Transaction Scheduling process, which utilizes the supply curves and forecasted prices for each market; and~~

~~(ii) an optimal interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the two ISOs had an infinite number of zero bids in~~

~~the Coordinated Transaction Scheduling process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the Coordinated Transaction Scheduling process.~~

~~The bid production cost savings associated with the Tie Optimization interchange as developed in (i) above for the second year following the date that Coordinated Transaction Scheduling is activated in the New England and New York wholesale electricity markets will reveal the "foregone" production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(b)(1) formula as the term "b." The difference in bid production cost savings between (i) and (ii) above will reveal the "foregone" bid production cost savings of the Tie Optimization interchange as developed in (i) above rather than an optimal interchange as developed in (ii) above, represented in the Section III.1.10.7.B(b)(1) formula as the term "a."~~

~~This analysis will be consistent with presentations made by the External Market Monitor to the New England stakeholders during 2011 on the issue of the benefits of Coordinated Transaction Scheduling.~~

~~(1) Using the above calculations, the External Market Monitor will compute the following ratio:~~

~~b/a~~

~~If, the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.~~

~~(c) Improving Coordinated Transaction Scheduling~~

~~(1) If the ratio, developed pursuant to Section III.1.10.7.B(b)(1), is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.~~

~~(2) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.~~

~~(3) If the ISO declares that the threshold has triggered, the External Market Monitor will provide recommendations of adjustments to the design or operation of Coordinated Transaction Scheduling to improve the production cost savings available from its implementation.~~

~~(4) The ISO, considering the input of the New England stakeholders and the recommendation of the External Market Monitor, will develop and implement adjustments to Coordinated Transaction Scheduling. To the extent tariff revisions are necessary to implement the adjustments to Coordinated Transaction Scheduling, the ISO will file such revisions with the Commission as a compliance filing in the Coordinated Transaction Scheduling docket. If no adjustments to Coordinated Transaction Scheduling have been identified, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing.~~

~~(d) The Second Analysis~~

~~(1) Within 120 days of the close of the twelve months following the date that the adjustments to Coordinated Transaction Scheduling, developed under Section III.1.10.7.B(c), are activated in the New England and New York wholesale electricity markets, the External Market Monitor will present a second analysis to New England stakeholders. The analysis will be consistent with the analysis described in Section III.1.10.7.B(b) but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section III.1.10.7.B(c) are in place.~~

~~(2) The bid production cost savings associated with the Tie Optimization interchange as developed in Section III.1.10.7.B(d)(1) will reveal the "foregone" bid production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(d)(3) formula as the term "b." The different in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section III.1.10.7.B(d)(1), will reveal the "foregone" bid production cost savings of the Tie Optimization interchange rather than the optimal interchange, represented in the Section III.1.10.7.B(d)(3) formula as the term "a."~~

~~(3) Using the above calculations, the External Market Monitor will compute the following ratio:~~

~~b/a~~

~~If the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.~~

~~(4) If the ratio b/a is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.~~

~~(5) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.~~

~~(6) If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the External Market Monitor, the ISO will determine whether a superior alternative has been proposed. If the ISO and the New York Independent System Operator both determine a superior alternative has been proposed, the ISO will prepare tariff amendments to be filed with the Commission to implement the superior alternative, and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments and will not pursue the balance of the actions required by this Section III.1.10.7.B.~~

~~(7) If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing. Tie Optimization was described for stakeholders in the *Design Basis Document* for NE/NY Inter-Regional Interchange Scheduling presented at a NEPOOL Participants Committee meeting on June 10, 2011.~~

~~(c) The Compliance Filing~~

~~The ISO will develop tariff language to implement the inter-regional interchange scheduling practice known as Tie Optimization through a compliance filing with the Commission and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments.~~

~~Within 120 days of the close of the first and second years following the date that Coordinated Transaction Scheduling as an interface scheduling tool is activated in the New England and New York wholesale electricity markets, the External Market Monitor will develop, for presentation to and comment by, New England stakeholders, an analysis, of:~~

~~(i) the Tie Optimization interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the ISO and New York Independent System Operator received an infinite number of zero bids in the Coordinated Transaction Scheduling process, which utilizes the supply curves and forecasted prices for each market; and~~

~~(ii) an optimal interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the two ISOs had an infinite number of zero bids in the Coordinated Transaction Scheduling process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the Coordinated Transaction Scheduling process.~~

~~The bid production cost savings associated with the Tie Optimization interchange as developed in (i) above for the second year following the date that Coordinated Transaction Scheduling is activated in the New England and New York wholesale electricity markets will reveal the "foregone" production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(b)(1) formula as the term "b." The difference in bid production cost savings between (i) and (ii) above will reveal the "foregone" bid production cost savings of the Tie Optimization interchange as developed in (i) above rather than an optimal interchange as developed in (ii) above, represented in the Section III.1.10.7.B(b)(1) formula as the term "a."~~

~~This analysis will be consistent with presentations made by the External Market Monitor to the New England stakeholders during 2011 on the issue of the benefits of Coordinated Transaction Scheduling.~~

~~(1) Using the above calculations, the External Market Monitor will compute the following ratio:~~

~~b/a~~

~~If, the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.~~

~~(c) Improving Coordinated Transaction Scheduling~~

~~(1) If the ratio, developed pursuant to Section III.1.10.7.B(b)(1), is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.~~

~~(2) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.~~

~~(3) If the ISO declares that the threshold has triggered, the External Market Monitor will provide recommendations of adjustments to the design or operation of Coordinated Transaction Scheduling to improve the production cost savings available from its implementation.~~

~~(4) The ISO, considering the input of the New England stakeholders and the recommendation of the External Market Monitor, will develop and implement adjustments to Coordinated Transaction Scheduling. To the extent tariff revisions are necessary to implement the adjustments to Coordinated Transaction Scheduling, the ISO will file such revisions with the Commission as a compliance filing in the Coordinated Transaction Scheduling docket. If no adjustments to Coordinated Transaction Scheduling have been identified, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing.~~

~~(d) The Second Analysis~~

~~(1) Within 120 days of the close of the twelve months following the date that the adjustments to Coordinated Transaction Scheduling, developed under Section III.1.10.7.B(c), are activated in the New England and New York wholesale electricity markets, the External Market Monitor will present a second analysis to New England stakeholders. The analysis will be consistent with the analysis described in Section III.1.10.7.B(b) but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section III.1.10.7.B(c) are in place.~~

~~(2) The bid production cost savings associated with the Tie Optimization interchange as developed in Section III.1.10.7.B(d)(1) will reveal the "foregone" bid production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the~~

~~Section III.1.10.7.B(d)(3) formula as the term "b." The different in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section III.1.10.7.B(d)(1), will reveal the "foregone" bid production cost savings of the Tie Optimization interchange rather than the optimal interchange, represented in the Section III.1.10.7.B(d)(3) formula as the term "a."~~

~~(3) Using the above calculations, the External Market Monitor will compute the following ratio:~~

~~b/a~~

~~If the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.~~

~~(4) If the ratio b/a is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.~~

~~(5) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.~~

~~(6) If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the External Market Monitor, the ISO will determine whether a superior alternative has been proposed. If the ISO and the New York Independent System Operator both determine a superior alternative has been proposed, the ISO will prepare tariff amendments to be filed with the Commission to implement the superior alternative, and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments and will not pursue the balance of the actions required by this Section III.1.10.7.B.~~

~~(7) If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing. Tie Optimization was described for stakeholders in the *Design Basis Document* for NE/NY Inter-~~

~~Regional Interchange Scheduling presented at a NEPOOL Participants Committee meeting on June 10, 2011.~~

~~(e) The Compliance Filing~~

~~The ISO will develop tariff language to implement the inter-regional interchange scheduling practice known as Tie Optimization through a compliance filing with the Commission and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments.~~

III.1.10.8 ISO Responsibilities.

(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to the price of priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may ~~at any time, consistent with the provisions in ISO New England Manual M-11,~~ request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(~~c~~b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual-fuel Generator Assets), and the quantity and price pairs of its Blocks may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

~~III.1.12 Dynamic Scheduling.~~

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

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

~~(b) An entity that owns or controls a generating Resource outside of the New England Control Area may electrically include all or part of the generating Resource's output into the New England Control Area through dynamic scheduling of the output to load inside the New England Control Area. Such output shall be available for economic dispatch by the ISO.~~

~~(c) An entity requesting dynamic scheduling shall be responsible for arranging for the provision of signal processing and communication from the generating unit and other participating Control Area and complying with any other procedures established by the ISO regarding dynamic scheduling as set forth in the ISO New England Manuals. Allocation of costs associated with dynamic scheduling shall be determined and filed with the Commission following the first request.~~

~~(d) An entity requesting dynamic scheduling shall be responsible for reserving amounts of appropriate transmission service necessary to deliver the range of the dynamic transfer and any ancillary services.~~

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area.

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a) **Day-Ahead Energy Market Obligations** – For each Market Participant for each settlement interval, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

(i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.

(ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

(iv) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for unmetered load and any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by Generator Assets~~, External Resources,~~ and External Transaction purchases at that Location.

III.3.2.6 Emergency Energy.

(a) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are not following ~~ISO~~ Dispatch Instructions; Self-Scheduled Resources (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts not following ~~ISO~~ Dispatch Instructions; and Self-Scheduled Resources (other than Continuous Storage Generator Assets) not following their Day-Ahead Self-Scheduled amounts other than those following ~~ISO~~ Dispatch Instructions;~~, including External Resources,~~ in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues attributable to the sale of Emergency Energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are following ~~ISO~~ Dispatch Instructions; and Self-Scheduled Generator Assets (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts following ~~ISO~~ Dispatch Instructions;~~, including External Resources,~~ in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency

Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load ~~or in such other manner as may be described in ISO New England Manual M-28 (Market Rule 1 Accounting)~~. Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

provided, however, that the portion of a resource having no Capacity Supply Obligation is not subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures.

III.13.6.1.2. Import Capacity Resources with Capacity Supply Obligations.

III.13.6.1.2.1. Energy Market Offer Requirements.

A Market Participant with an Import Capacity Resource must offer one or more External Transactions to import energy in the Day-Ahead Energy Market and Real-Time Energy Market for every hour of each Operating Day at the same external interface that, in total, equal the resource's Capacity Supply Obligation, except that:

(i) the offer requirement does not apply to any hour in which any External Resource associated with an Import Capacity Resource is on an outage;
(ii) the Day-Ahead Energy Market offer requirement does not apply to any hour in which the import transfer capability of the external interface is 0 MW, and;
(iii) the Real-Time Energy Market offer requirement does not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which Coordinated Transaction Scheduling is implemented.

Each External Transaction submitted in the Day-Ahead Energy Market must reference the associated Import Capacity Resource.

Each External Transaction submitted in the Real-Time Energy Market in accordance with Section III.1.10.7 must reference the associated Import Capacity Resource.

In all cases an Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource.

~~The Real-Time Energy Market offer requirements in this Section III.13.6.1.2.1 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.~~

~~A Market Participant must offer energy associated with an Import Capacity Resource with a Capacity Supply Obligation into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions for every hour of each Operating Day at the same external interface totaling an amount (MW) equal to the Capacity Supply Obligation unless the Import Capacity Resource is associated with an External Resource that is on an outage. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with this requirement may be subject to sanctions pursuant to Appendix B for failing to deliver the External Transaction or External Transactions in the energy market as described in the ISO New England System Rules.~~

~~(a) Submittal of External Transactions to the Day-Ahead Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource requires submittal of matching energy transactions to the Real-Time Energy Market; the External Transactions submitted to the Real-Time Energy Market must match the External Transactions submitted to the Day-Ahead Energy Market, subject to the right to submit different prices into the Real-Time Energy Market.~~

~~(b) External Transactions submitted to the Real-Time Energy Market in support of a Capacity Supply Obligation for an Import Capacity Resource must be submitted prior to the offer submission deadline for the Day-Ahead Energy Market the day before the Operating Day for which they are intended to be scheduled.~~

~~(c) A Market Participant submitting a priced External Transaction supporting an Import Capacity Resource with a Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must link the transaction to the associated transmission reservation and NERC E-Tag no later than one hour before the operating hour in order to be eligible for scheduling in the Real-Time Energy Market.~~

III.13.6.1.2.2. Additional Requirements for ~~Certain~~ Import Capacity Resources.

A Market Participant with an Import Capacity Resource that is associated with an External Resource must:

(i) comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the External Resource's native Control Area, and;

(ii) notify the ISO of all outages impacting the Capacity Supply Obligation of the Import Capacity Resource in accordance with the outage notification requirements in ISO New England Operating Procedure No. 5.

~~The additional requirements for Import Capacity Resources in this Section III.13.6.1.2.2 do not apply to Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1.~~

~~(a) information submittal requirements for External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals;~~

~~(b) resource backed Import Capacity Resources shall be subject to the outage requirements as detailed in the ISO New England Manuals and ISO New England Operating Procedures. Control Area backed Import Capacity Resources are not subject to such outage requirements;~~

~~(c) resource backed Import Capacity Resources are subject to the voluntary and mandatory re-scheduling of maintenance procedures outlined in the ISO New England Operating Procedures and ISO New England Manuals.~~

~~(d) at the time of submittal, each External Transaction shall reference the associated Import Capacity Resource.~~

~~III.13.6.1.2.3. Additional Requirements for Import Capacity Resources at External Interfaces with Enhanced Scheduling.~~

~~Import Capacity Resources with Capacity Supply Obligations at an external interface for which the enhanced scheduling provisions in Section III.1.10.7.A are implemented are subject to the following additional requirements unless the Import Capacity Resource qualified for participation in the Forward Capacity Market under Section III.13.1.3.5.3.1. In all cases the Import Capacity Resource is subject to the provisions in Section III.13.7 for the entire Capacity Supply Obligation of the Import Capacity Resource. A Market Participant with an Import Capacity Resource that fails to comply with the requirements in this Section III.13.6.1.2.3 may be subject to sanctions pursuant to Appendix B.~~

~~(a) The resource must comply with all information submittal requirements for Day-Ahead Energy Market Coordinated External Transactions associated with resource or Control Area backed Import Capacity Resources as detailed in the ISO New England Manuals.~~

~~(b) Where the Import Capacity Resource is physically located in a Control Area with which the New England Control Area has implemented the enhanced scheduling procedures in Section III.1.10.7.A, the resource must comply with all offer, outage scheduling and operating requirements applicable to capacity resources in the native Control Area.~~

~~(c) The resource must notify the ISO of all outages impacting the Capacity Supply Obligation of the resource in accordance with the outage notification requirements in ISO New England Operating Procedures.~~

~~(d) At the time of submittal, each Coordinated External Transaction submitted to the Day-Ahead Energy Market must reference the associated Import Capacity Resource.~~

III.13.6.1.3. Intermittent Power Resources with Capacity Supply Obligations.

III.13.6.1.3.1. Energy Market Offer Requirements.

(a) Market Participants may submit offers into the Day-Ahead Energy Market for Intermittent Power Resources with a Capacity Supply Obligation. Market Participants are required to submit offers for Intermittent Power Resources with a Capacity Supply Obligation for use in the Real-Time Energy Market consistent with the characteristics of the resource. Day-Ahead projections of output shall be submitted as detailed in the ISO New England Manuals. For purposes of calculating Real-Time NCPC Charges, Intermittent Power Resources shall have a generation deviation of zero.

(b) Notwithstanding the foregoing, an Intermittent Power Resource that is a Settlement Only Resource may not submit Supply Offers into the Day-Ahead Energy Market or Real-Time Energy Market.

III.13.6.1.3.2. [Reserved.]

III.13.6.1.3.3. Additional Requirements for Intermittent Power Resources.

Intermittent Power Resources are subject to the following additional requirements:

ISO New England Manual for

Market Operations

Manual M-11

Revision: ~~55~~
Effective Date: ~~October 4, 2018~~

Prepared by
ISO New England Inc.

External Transactions

3.2.1 External Transaction Submittal Software

External Transactions are submitted through either the ISO-NE ~~Enhanced Energy Scheduler~~External Transaction Tool (~~EES~~NEXTT) ~~application~~ and/or the NYISO Joint Energy Scheduling System (JESS), depending on the energy market and interface as defined in the table below. This includes the requirement to submit certain transactions into both the ~~EES~~ NEXTT and JESS applications.

	DAM, **ISO-NE ~~EES~~ NEXTT**	**RTM,** **ISO-NE ~~EES~~NEXTT**	**RTM,** **NYISO JESS**
Submitted under III.1.10.7	ALL	ALL	not applicable
Submitted under III.1.10.7A	ALL	Wheeling through ISO-NE ~~Import Capacity Resource that is wheeling through NYISO~~	ALL

3.2.2 External Transaction Submission Timelines

External Transactions can be submitted at various times, depending on the type of transaction and the energy market as described below.

	ISO-NE ~~EES~~ NEXTT		**NYISO JESS**
	All DAM **RTM priced**	**RTM not priced**	**RTM**
Earliest submittal	10 days prior to start of transaction	10 days prior to start of transaction	60 days prior to start of transaction
Maximum duration	one calendar month	one calendar month	N/A
Latest submittal	III.1.10.7	III.1.10.9(c)	III.1.10.7A

The following additional changes can be made to a priced Real-Time External Transaction ~~submitted to EES~~:

(1) During the Re-Offer Period, the price can be modified, resulting in the treatment described in Section III.1.10.7(b).

(2) Prior to the deadline in Section III.1.10.9(c) for notifying the ISO of a request to Self-Schedule an External Transaction, the MW value on the priced Real-Time External Transaction can be reduced and the e-Tag ID, OASIS reservation and market options may be modified.

3.2.3 External Transaction Submission Rules

(1) Advance purchase of transmission service on the ISO New England OASIS is not required for purchase, sale or through External Transactions.

(2) Advance purchase of transmission service on non-PTF interfaces is required and will be subject to transmission charges whether or not they are used to support Real-Time External Transactions.

(3) The MW value submitted on the External Transaction must be expressed in whole megawatts (MW) and must be stated in terms of the MW quantity to be received at or delivered to the balancing area boundary.

(4) For a Real-Time External Transaction that requires a transmission reservation, the Market Participant submitting the Real-Time External Transaction must also be the owner of the referenced transmission reservation unless other arrangements are made with ISO-NE.

(5) The ISO will confirm that the total hourly amount of a Real-Time External Transaction referencing an Import Capacity Resource is less than or equal to the Capacity Supply Obligation of the Import Capacity Resource.

~~The ISO will confirm that the Market Participant submitting a Real-Time External Transaction associated with an Import Capacity Resource is the Lead Market Participant of the Import Capacity Resource. Upon request to the ISO, this validation can be removed, which will allow any Market Participant to reference the Import Capacity Resource.~~

3.2.4 Additional Treatment for External Transactions

Sections II.44 and III.1.10.7 contain rules regarding certain types of External Transactions and their treatment in real-time scheduling. Table 3.1 describes certain treatment options that can be associated with a transaction, the conditions under which each can or should be selected, and any additional information that is required.

These options are applicable to transactions submitted to the ISO-NE ~~EES~~ NEXTT application. The only option for a transaction submitted to the NYISO JESS application is Generation Information System.

Option	Description	Comment
Import Resource	Market Participants with an Import Capacity Resource with a Capacity Supply Obligation must use this option to notify ISO that the transaction is backing an Import Capacity Resource. For transactions submitted under Section III.1.10.7A, this information must be included on Day-Ahead Market External Transaction.	Must ~~reference~~ provide the Import Capacity Resource ID
~~Flex Reservation~~	~~Applicable only to Market Participants submitting priced transactions backing Import Capacity Resources over interfaces where advance reservations are required. Checking this flag allows the user to link an OASIS reservation, and e-Tag, up to one hour before the start of the transaction. User must also reference the Import Resource option.~~	~~Must reference the Import Capacity Resource ID~~
Non-Capacity Supply Obligation Export	Market Participants must select this option for transactions to be considered under Section III.1.10.7(i) during system-wide capacity deficient conditions.	Must provide ~~reference~~ the numerical Asset ID
LSCC Export (Capacity Export Through Import Constrained Zone or FCA Cleared Export Transaction)	When this is selected by Market Participants that have bid and cleared appropriately in the FCA and submitted the transaction in accordance with Section III.1.10.7(f) i or ii, Market Participant is requesting that the transaction be considered in local second contingency commitment and will be allocated a share of certain costs as defined in Section III.1.10.7(h). Transactions with this option are considered supported in Real-Time scheduling as defined in Section II.44. Note: Market Participant must also ~~reference~~ select Non-Capacity Supply Obligation Export to be considered under Section III.1.10.7(i)	Must provide ~~reference~~ the numerical Asset ID backing the FCA de-list bid
Unconstrained Export (Same Reserve Zone or Unconstrained Export Transaction)	When this option is selected and the referenced generating Resource meets criteria in Section III.1.10.7(f) iii or iv, the transaction is considered supported in Real-Time scheduling as defined in Section II.44. Note: Market Participant must also ~~reference~~ select Non-Capacity Supply Obligation Export to be considered under Section III.1.10.7(i).	Must ~~reference~~ provide the numerical Asset ID
Excepted Transaction	When this is selected by Market Participants with active items in Section II Attachment G-3 and submitted in accordance with Section II.44(a), special priority is assigned in real-time scheduling.	There are currently no active items in Attachment G-3

Generation Information System	Used to indicate transaction is associated with Generation Information System	Must ~~contain~~ provide an alpha-numeric string ~~comment~~
EET Emergency	When emergency transactions are requested by ISO-NE, allows user to submit priced transactions within the operating day.	~~Does not require a comment~~No additional information required~~provided~~
New Brunswick Security Energy Transactions	When New Brunswick Security Energy Transactions are requested by ISO-NE, allows user to submit priced transactions within the operating day.	No additional information required~~provided~~~~Must contain a comment – "NB" is the suggested value~~
Grandfathered	When this is selected by Market Participants with active items in Attachment H of the Open Access Transmission Tariff and submitted in accordance with Section II.44(a), special priority is assigned in Real-Time scheduling.	Must ~~reference~~ provide MEPCO Grandfathered ~~Transmission Service Agreements (MGTSA); user must also link a valid associated~~ OASIS reservation

Table 3.1: Available Options Associated with External Transactions

3.2.5 Status of External Transactions Submitted to ~~EES~~NEXTT

~~—~~Upon submittal of an External Transaction in ~~EES~~ NEXTT to the Real-Time Energy Market, the ISO ~~logs the request and~~ performs automated ~~validity and manual verification tests~~validation of e-Tag ID data, OASIS data, and any referenced market options for each separate interval. Only Real-Time External Transactions with a status of *APPROVED* will be considered in the scheduling process.

If a Real-Time External Transaction passes the automated validation process, each interval is assigned a status of *APPROVED*. However, if a Real-Time External Transaction with the Unconstrained Export option selected passes the automated validation process, each interval is assigned a status of *ISO REVIEW*. The ISO will perform additional validation of transactions with *ISO REVIEW* status and set the status of each interval to *APPROVED* or *DENIED*.

~~—~~If a Real-Time ~~n~~ External Transaction does not pass the automated ~~verification~~ validation process, the relevant intervals are ~~it is~~ assigned a status of ~~*Pending Action*~~*PENDING ACTION*. It is the responsibility of the customer submitting the External Transaction to correct any issues identified. ~~The Transmission Customer is notified of the validation failure and the Transmission Customer may then take action to resubmit the transaction within the appropriate submission deadlines. Manual administrative action to review transactions in a status of *Pending Action* is not taken by the ISO.~~ Any interval of a Real-Time External Transaction that is not *APPROVED* by the deadline specified in Section III.1.10.9(c) is assigned a status of *DENIED*.

~~Once External Transactions pass the automated verification, they are assigned a status of *Pre-Approved* and the ISO performs manual administrative tests to establish the final status of the transaction.~~

~~Real-Time External Transactions that pass all of the preceding tests will have a status of *Approved*. If the requested Real-Time External Transaction fails any of the preceding tests, the status will be set to *Denied*. The ISO will inform the Market Participant or Transmission Customer that the External Transaction request has been denied and the reason for the denial.~~

3.2.6 Status of External Transactions Submitted to JESS

Information regarding the process of submitting and monitoring External Transactions to the NYISO JESS application can be found on the NYISO website in their JESS User Guide.

ISO NEW ENGLAND OPERATING PROCEDURE NO. 9
SCHEDULING AND DISPATCH OF EXTERNAL TRANSACTIONS

Effective Date: draft~~June 1, 2018~~

REFERENCES:

1. North American Energy Standards Board (NAESB) Wholesale Electricity Quadrant (WEQ) Coordinate Interchange Standards - WEQ-004
2. NAESB Electronic Tagging Functional Specification
3. North American Electric Reliability Corporation (NERC) Reliability Standard - INT-006 - Evaluation of Interchange Transactions
4. Section III of the ISO New England Inc. Transmission, Markets and Services Tariff (Tariff)
5. Section II of the Tariff [ISO Open Access Transmission Tariff (OATT)]
6. ISO New England Manual for Market Operations, Manual M-11
7. ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency (OP-4)

II. ISO ACTIVITIES PRIOR TO RTM EXTERNAL TRANSACTION SCHEDULING

A. External Transaction e-Tag Requirements

1. All External Transactions submitted to ISO for physical implementation in the RTM must have an associated e-Tag that complies with the requirements of the North American Energy Standards Board (NAESB) Electronic Tagging Functional Specification. An e-Tag is required for each External Transaction to be implemented for which ISO is on the s~~S~~cheduling p~~P~~ath as the Sink, Source or i~~I~~ntermediate Balancing Authority (BA).
2. ISO reviews and actively approves or denies an e-Tag based solely on the information provided in the e-Tag within the review time specified by the North American Electric Reliability Corporation (NERC) Reliability Standards INT-006 - Evaluation of Interchange Transactions.
3. An e-Tag denial notification is automatically created when the e-Tag is denied and includes the reason for the denial
4. Prior to the start time indicated in the e-Tag, each e-Tag shall be associated with an External Transaction submitted under Section III.1.10.7 of the Tariff or the e-Tag will be terminated by ISO.
5. Before implementing any External Transaction, whether for an import, export or wheel-through, ISO verifies that a complete, approved e-Tag exists for that External Transaction and that the energy profile on the e-Tag and the External Transaction are consistent.
6. If, due to software issues, any variation exists between the e-Tag and the External Transaction, ISO settlement staff shall utilize the External Transaction scheduled MW.

B. Verification of External Transactions on Non-CTS Interfaces

1. ISO validates each External Transaction submitted under Section III.1.10.7 of the Tariff in order of submission through a combination of automated software checks and manual review.
2. Transmission Service Considerations
   a. ISO verifies that appropriate and adequate advance transmission service arrangements have been obtained from Transmission Providers (TP(s)) within the New England RCA/BAA. Where possible, verification is made through the Open Access Same-Time Information System (OASIS). If transmission service arrangements **cannot** be verified via the OASIS:
      i. ISO may use other means at its disposal to attempt to verify the existence of proper transmission service arrangements.
      ii. ISO may ask the entity submitting the External Transaction to state in writing that proper transmission service arrangements are in place or to provide a copy of the transmission service agreement with the TP.

B. Scheduling of External Transactions on the CTS Enabled interface

1. The CTS Enabled Interface is ordinarily scheduled every 15 minutes.

CTS Enabled Interface PNode	Scheduling Interval
.I.ROSETON 345 1	15 minutes

2. When necessary to ensure or preserve system reliability, or when **not** able to implement schedules as expected due to software or communication issues, ISO and NYISO shall coordinate and determine when to temporarily employ hourly scheduling on the CTS Enabled Interface in accordance with the NYISO/ISO-NE Coordination Agreement.
3. ISO schedules each External Transaction (import, export and wheel-through transaction) in whole MW at the New England BAA boundary.
4. ~~After the submittal deadline on the CTS Enabled Interface in JESS, the ISO evaluates any priced External Transaction with the flag of Import Capacity Resource that was submitted to the ISO External Transaction submittal software and, if required, provides the results of the economic evaluation to NYISO through an adjustment to the e-Tag.~~

C. Sales of Energy Backed by Installed Capacity to External BAAs

1. Non-CTS interfaces: ISO shall review the status of generators referenced in External Transactions with the flag of Non-Capacity Supply Obligation (CSO) Export under either of the following conditions:
   a. Whenever exports are being reduced to address Operating Reserve conditions to determine if the requirements of Section III.1.10.7 (i) of the Tariff are satisfied; or
   b. Whenever scheduling on an associated external interface is constrained to determine if the referenced generator is Self-Scheduled in the RTM and online at a MW level greater than or equal to the External Transaction sale's MW amount.
2. CTS Enabled Interface: ISO shall respond to requests from NYISO to deliver capacity in Real-Time. Upon such a request, ISO shall review the status of the generators with capacity obligations to NYISO to determine if the energy from those generators is available and deliverable.

D. Purchases of External Installed Capacity

1. Non-CTS interfaces: External Transactions with the flag of Import Capacity Resource will be verified by ISO for expected delivery with neighboring BA.
2. CTS Enabled Interface: ISO may request capacity associated with Import Capacity Resources located in NYISO as described in Schedule D of the NYISO/ ISO-NE Coordination Agreement. ISO shall **not** request capacity from NYISO unless forecasts indicate that a net import is needed on the CTS Enabled Interface to maintain the ISO total Operating Reserve requirements.

Optional Flags	Impact of Flag on Real-Time Processes
Excepted Transaction	The priority defined in Section II.44.1.a of the OATT is assigned during general scheduling, reductions for reliability and curtailment
Grandfathered	The priority defined in Section II.44.1.a of the OATT is assigned during general scheduling, reductions for reliability and curtailment
Import Resource	This indicates to ISO which transactions to verify for Real-Time capacity delivery with a neighboring area
Non-CSO Export	The status of referenced ISO-NE generator reviewed if: a. the interface is constrained, and b. exports are being reduced to address reserve capacity conditions
Local Second Contingency Commitment (LSCC) Export	If transaction meets criteria defined in Section III.1.10.7(f) of the Tariff, the priority defined in Section II.44 of the OATT is assigned during general scheduling, reductions for reliability and curtailment
Unconstrained Export	If transaction meets criteria defined in Section III.1.10.7(f) of the Tariff, the priority defined in Section II.44 of the OATT is assigned during general scheduling, reductions for reliability and curtailment
EET Emergency	ISO shall only schedule when in appropriate actions of OP-4
New Brunswick Security Energy Transactions	ISO shall only schedule to preserve minimum flows from New Brunswick [See Section IV and V.D]
~~Flex Reservation~~	~~No impact~~
Generation Information System	No impact

IV. REAL-TIME SCHEDULING RELIABILITY CONSIDERATIONS

This section addresses reliability considerations utilized during the RTM External Transaction scheduling process. These considerations include: a restriction on a specific external interface for reliability, excessive change in system-wide net interchange, approaching or reaching minimum generation conditions, and/or approaching or reaching a deficiency in Operating Reserve. If an External Transaction must be reduced due to any reliability condition, an appropriate description shall be included on the electronic notification of the scheduled MW amount.

A. Ramp Constraints

Implementation of a large External Transaction or implementation of a number of External Transactions at the same time may cause a large change in the

Rev. No.	Date	Reason
Rev 16	06/01/18	Periodic review completed by procedure owner; Globally made editorial changes consistent with current conditions, practices, and management expectations; Changes for PRD: Removed the following references to Demand Response in OP-4 Actions in: Section IV.F, deleted "...up to and including the activation of Real-Time Demand Response..." Section V.E, deleted "...up to and including the activation of Real-Time Demand Response..."
Rev 17	draft	Periodic review completed by procedure owner; Section III.B deleted item (4) and Optional Flag = Flex Reservation. Due to market rule changes these items are no longer relevant;.

ISO new england

memo

To: NEPOOL Reliability Committee

From: Jerry Elliott

Date: July 10, 2019

Subject: Revisions to ISO New England Operating Procedure No. 5

The ISO is requesting a vote on its proposed revisions to OP-5. The proposed revisions establish that, for an Import Capacity Resource backed by one or more resources, a Market Participant must notify the ISO if there is a reduction in capability that impacts the CSO of the Import Capacity Resource.

These proposed revisions are part of several corresponding conforming revisions associated with the Import Capacity Resource transaction requirements and clean-up changes project (WMPP ID #136). This project streamlines the requirements for submitting external transactions associated with Import Capacity Resources. These updates are motivated by the technical project to replace the software platform for submitting external transactions, which is scheduled for implementation by October of this year.

The proposed revisions for the committee's consideration at its July 16, 2019 meeting were presented at the June 18, 2019 meeting, agenda item #5.5 https://www.iso-ne.com/event-details?eventId=137637 [A1].

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

ISO new england

Import Resource Transaction Requirements and Clean Up

Proposed revisions to OP-5 to make outage requests for Import Capacity Resources notification only; minor clarifications, updates, and corrections

Jerry Elliott

(413) 535-4123 | GELLIOTT@ISO-NE.COM

Project Title: Import Resource Transaction Requirements and Clean up

WMPP ID: 136

Proposed Effective Dates: October 23, 2019

- The proposed revisions to OP-5 are conforming changes to align with the revised market rule language for an Import Capacity Resource backed by one or more resources: a Market Participant must notify the ISO if there is a reduction in capability that impacts the CSO of the Import Capacity Resource. No outage request is necessary.
- These proposed revisions are part of several corresponding conforming changes associated with the Import Capacity Resource transaction requirements and clean-up project (WMPP ID #136)
  - This project will streamline the requirements for submitting external transactions associated with Import Capacity Resources
  - These proposed updates are motivated by the technical project to replace the software platform for submitting external transactions (i.e. - Enhanced Energy Scheduling (EES) application)
    - The "Update EES Technical Architecture Project"*
    - Target launch date: October 23, 2019
- There have been no further changes made to OP-5 since the June 18, 2019 Reliability Committee meeting
- The proposed effective date of these revisions is October 23, 2019

* https://www.iso-ne.com/participate/support/customer-readiness-outlook/ees-technical-architecture-project

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Markets Committee May 7-8, 2019	Initial meeting: Topic introduction and review of changes
Markets Committee June 11-12, 2019	Second meeting: Further discussion and review of revisions to governing documents (Market Rule 1, Manual 11, and OP-9)
Reliability Committee June 18, 2019	Discussion of the proposed revisions to OP-5
Markets Committee July 9-10, 2019	Recommended PC support of proposed revisions to Market Rule 1, Manual 11, and OP-9
Reliability Committee **July 16-17, 2019**	Vote on proposed revisions to OP-5
Participants Committee **August 2, 2019**	Vote on proposed revisions to Market Rule 1, Manual 11, OP-9, and OP-5

Questions

Jerry Elliott

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ISO New England Operating Procedure No. 5
Resource Maintenance and Outage Scheduling

Effective Date: draft

Deleted: February 1, 2019

References:

North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) - Data Reporting Instructions

ISO New England Inc. Transmission, Markets, and Services Tariff, Section II, Open Access Transmission Tariff (OATT)

ISO New England Inc. Transmission, Markets and Services Tariff, Section III, ISO New England Market Rule 1 - Standard Market Design (Market Rule 1)

ISO New England Inc. Transmission, Markets, and Services Tariff, Attachment D, ISO New England Information Policy

ISO New England Manual for the Forward Capacity Market (FCM), Manual M-20 (M-20)

ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency (OP-4)

ISO New England Operating Procedure No. 7 - Action in an Emergency (OP-7)

ISO New England Operating Procedure No. 8 - Operating Reserve and Regulation (OP-8)

ISO New England Operating Procedure No.14 - Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources (OP-14)

ISO New England Operating Procedure No. 24 - Protection Outages, Settings and Coordination (OP-24)

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I. INTRODUCTION

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This Operating Procedure (OP) establishes the process for a Market Participant (MP) to request a Planned Outage (PO), Maintenance Outage (MO) or Overrun Planned Outage (OPO) for a generator, Demand Response Resource (DRR), Dispatchable Asset Related Demand (DARD), or Alternative Technology Regulation Resource (ATRR). This OP also establishes the process for ISO New England (ISO) and the relevant Local Control Center (LCC) to evaluate PO and MO requests, and for ISO to approve or deny such requests.

This OP is designed to facilitate the scheduling of POs and MOs/OPOs for an MP's generator, DRR, DARD or ATRR and to allow:

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(1) each MP to incorporate future maintenance in its budget forecasts;

(2) sufficient time for an MP to respond to market signals; and

(3) sufficient time for ISO and the relevant LCC to assess the impact of each generator, DRR and DARD outage request on the reliability of the New England Reliability Coordinator Area/Balancing Authority Area (RCA/BAA)[1] and the New England Transmission System.

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Each MP shall, to the fullest extent practicable, maintain and operate all generators, DRRs, DARDs or ATRRs it owns or controls in accordance with Good Utility Practice. An MP shall not take a generator, DRR, DARD, ATRR or Qualified Generator Reactive Resource out of service for maintenance without ISO approval, unless there is a danger to personnel or a risk of equipment damage (except for generator, DRR, DARD or ATRR outages where a Capacity Supply Obligation (CSO) is not impacted or where there is no CSO). If a generator, DRR, DARD or ATRR is forced out of service due to personnel or equipment risk, the ISO control room generation operator and forecaster shall be notified as soon as possible. ISO shall categorize an outage not approved by ISO as a Forced Outage (FO). An MP shall request a PO, MO or OPO with as much advance notice as possible in order to prevent an FO.

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A. PO, MO, and OPO Requests

An MP shall submit a request for a PO, MO or OPO when:

- the PO, MO, or OPO of the generator impacts the CSO of the associated capacity resource;
- the request is associated with a generator without a CSO that is a Qualified Generator Reactive Resource;
- the PO, MO or OPO of the DRR is for 5 MW or more and results in the associated Active Demand Capacity Resource (ADCR) falling short of its CSO by 5 MW or more (the DRR is the unit that is dispatched in the energy market, but the ADCR has the CSO); or

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[1] Reliability Coordinator Area and Balancing Authority Area are defined in the Glossary of Terms Used in NERC Reliability Standards.

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- a PO, MO or OPO would reduce the ability of a DARD to interrupt without reducing its load by a corresponding amount.

The requirements for PO requests are detailed in Section III.B of this OP. The requirements for MO or OPO requests are detailed in Section III.C of this OP.

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B. DRR

An MP shall submit an outage request for a DRR in accordance with this OP if the DRR's offered Maximum Reduction will be reduced by 5 MW or more, the DRR is associated with an ADCR, and the impact of the DRR's reduced availability will result in the associated ADCR falling short of its CSO by 5 MW or more. When there is more than one DRR associated with an ADCR, the impact from the reduced availability of a DRR on the ADCR's CSO is determined by summing the offered Maximum Reductions of all of the DRRs that are associated with that ADCR. If the sum of the offered Maximum Reductions of all the DRRs associated with the ADCR will fall short of the CSO by 5 MW or more, and if a single DRR's Maximum Reduction will be reduced by 5 MW or more, the MP shall be required to report the outage to ISO. (The Maximum Reduction to be used shall be for the expected peak hour of the Operating Day.)

C. DARD

An MP shall not reduce the ability for a DARD to interrupt to its Nominated Consumption Limit (NCL) without ISO approval unless there is a danger to personnel or a risk of equipment damage. An MP that reduces the ability of a DARD to interrupt due to danger to personnel or a risk of equipment damage shall notify the ISO control room generation operator and forecaster of the reduction as soon as practicable.

D. ATRR

When a PO, MO or OPO would reduce the ability of an ATRR that is modeled in the ISO topology to provide the registered Regulation capability for more than 24 continuous hours, the MP shall submit a request for the PO, MO or OPO.

E. Intermittent Capacity Resources

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The process for submitting and evaluating PO, MO and OPO requests for Intermittent Capacity Resources shall be the same as for generators.

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F. Relay Protection Systems

An MP shall submit a request for any planned or unplanned testing or maintenance outage of a relay protection system that could reduce or impact the normal operation of the New England RCA/BAA or the New England Transmission System in accordance with ISO New England Operating Procedure No. 24 - Protection Outages, Settings and Coordination (OP-24). The scheduling requirements are designed to allow sufficient time for ISO and each relevant LCC to assess the impact on reliability of each protection outage request.

G. Notification of PO or MO When CSO Is Not Impacted/There Is No CSO

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An MP shall notify ISO of each generator PO or MO that does not impact the CSO of the associated capacity resource or that is associated with a generator that does not have a CSO. The MP shall categorize and report each generator outage to ISO in accordance with the NERC Generating Availability Data System (GADS) - Data Reporting Instructions and this OP.

H. ISO Coordination of POs and MOs/OPOs

Whenever possible, ISO shall coordinate any transmission, generator, DRR and DARD POs and MOs/OPOs to reduce Congestion Costs. For an importing area, ISO shall evaluate requested POs, MOs and OPOs for any economic generator, DRR or DARD within the area simultaneously with transmission facilities that significantly support area import capability. For an exporting area, ISO shall coordinate any generator, DRR and DARD outage within the area coincident with the outage of transmission facilities that significantly support area export capabilities.

I. Import Capacity Resources

The MP shall notify the ISO if there is a reduction in capability that impacts the CSO of an Import Capacity Resource backed by one or more resources.

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II. DEFINITIONS

Annual Maintenance Schedule (AMS) is a capacity assessment report provided and updated on a monthly basis, which is distributed on or about the 5th day of the month. This capacity assessment is intended to convey forecasted capacity margins in order to coordinate generation and transmission outages in a reliable manner. Providing this report with two years of forecast capacity margins affords sufficient lead-time to schedule Planned Outages (POs) for the current and future Capacity Commitment Periods.

Locational Operable Capacity Margin (LOCM) is a measure of the long-term projected weekly operable capacity margin on a New England sub-area basis, as described in Appendix 5-A. The sub-area analysis is forecast for up to nineteen (19) months and is performed in addition to the operable capacity margin analysis for the entire New England RCA/BAA.

Long-Term Operable Capacity Margin (LTOCM) is a measure of New England RCA/BAA projected weekly operable capacity margin looking ahead up to twenty-four (24) months based on the assumptions in Appendix 5-A. A positive value of LTOCM indicates a potential surplus of operable capacity over and above the estimated load plus Operating Reserve requirement. The LTOCM formula and its components are defined in Appendix 5-A.

Operable Capacity Margin (OCM) is, collectively, the Long Term Operable Capacity Margin (LTOCM), the Locational Operable Capacity Margin (LOCM), the Short Term Operable Capacity Margin (STOCM), and the Short Term Locational Operable Capacity Margin (STLOCM).

Outage Types:

Forced Outage (FO) is any outage or inability, in whole or in part, of a resource to provide its claimed capability or NCL, or any DRR outage as described in section I.B above, that has not been approved by ISO in the form of a PO or MO. An FO incident preceding a PO or MO shall not eliminate the requirement of the MP to report an FO for the entire actual/estimated period to repair the component(s) associated with the FO. Among other things, an FO may occur by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of Section III of the Tariff and ISO New England Manuals.

Maintenance Outage (MO) (identified as "Short-Term Outage" in the ISO outage software) is an outage that can be deferred beyond the end of the weekend, but requires that the generator, DRR, DARD, or ATRR be removed from service within 14 calendar days of the outage start date. During any particular week, if an MP requests an outage that cannot be deferred beyond the weekend, that outage shall be classified as a Forced Outage. ISO shall attempt to, in accordance with the request, accommodate an MO as soon as possible depending on system conditions, significant increases in Locational Marginal Price (LMP), and Congestion Costs. This outage is coordinated in the MO request processes.

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Characteristically, an MO can occur any time during the year, has a flexible start date, may or may not have a predetermined duration, and is usually much shorter than a PO.

Overrun Planned Outage (OPO) is an overrun of a PO that may be requested up until the Thursday, or the week prior to the scheduled return of a generator, DRR, or DARD, or ATRR to service. An OPO is considered a type of MO throughout this document.

Planned Outage (PO) is an outage that must be requested with a minimum of 15 calendar days prior to start date and is typically scheduled for the purpose of performing annual maintenance or more significant work that is planned and coordinated well in advance.

Owner Test Request is a request that must be submitted to ISO when the MP has owner testing to perform and wants to ensure their generator, DRR, or DARD will be able to operate at a predefined schedule during that testing. If a request for owner testing is not submitted by an MP, transmission outages may be approved that could prevent the desired testing from occurring in the desired period. The MP shall submit and ISO shall evaluate an Owner Test Request in the same manner as an MO request.

Short-Term Locational Operable Capacity Margin (STLOCM) is a measure of the projected daily operable capacity margin looking ahead 2 weeks or less on a New England sub-area basis, as described in Appendix 5-A.

Short-Term Operable Capacity Margin (STOCM) is a measure of New England RCA/BAA projected daily operable capacity margin looking ahead 2 weeks or less based on the assumptions in Appendix 5-A. A positive value of STOCM indicates a potential surplus of operable capacity over and above the estimated load plus Operating Reserve requirement. The STOCM formula and its components are defined in Appendix 5-A.

Sub-Area is a local area within the New England RCA/BAA requiring coordination of generator, DRR or DARD and transmission outages.

NOTE

Capitalized terms used but not defined in this OP shall have the meanings ascribed to them in the Tariff

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III. PROCEDURES

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A. ISO & LCC RESPONSIBILITIES

1. General

a. Evaluation Principles

ISO shall assign each outage request an outage tracking number upon receipt. Each request shall be time and date stamped for prioritization purposes.

ISO and the LCC shall evaluate each generator, DRR, or DARD outage request submitted by a Lead MP for the items listed below. Outages of transmission facilities shall be included as a part of this evaluation. Criteria contained in this Section I.A pertain to each generator/DARD outage that impacts the CSO of the associated capacity resource. ISO and the LCC shall conduct their evaluation as follows:

i. Identify if the proposed Resource outage results in an unacceptable OCM

ii. Identify if the proposed generator, DRR, or DARD outage results in any system or local system reliability impacts

iii. Identify opportunities where the proposed generator, DRR, or DARD outage could be adjusted with respect to a pending transmission outage to reduce or eliminate Congestion Costs.

2. PO Review Moratorium

a. Annual Forward Capacity Market (FCM) Reliability Review

i. During the period when ISO is performing reliability reviews of FCM annual CSO bilateral submissions for the upcoming FCM Capacity Commitment Period; ISO shall time stamp PO requests for outages that fall within June 1 and September 15 of the Capacity Commitment Period to establish review priority and hold until the CSO bilateral reliability review process is completed. The annual CSO bilateral reliability review period begins immediately following the close of the annual CSO bilateral submission period for the applicable Capacity Commitment Period.

ii. During the period when ISO is performing reliability reviews of the results of the third annual reconfiguration auction results for the applicable FCM Capacity Commitment Period, ISO shall time stamp PO requests for outages that fall within June 1 and September 15 of the FCM Capacity Commitment Period to establish review priority and hold until the third annual reconfiguration auction results reliability review is completed.

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b. Monthly FCM Reliability Review

During the period when ISO is performing reliability reviews of FCM monthly CSO bilateral submissions and monthly reconfiguration auction results for the applicable month, ISO shall time stamp each PO request for an outage that falls within the applicable month to establish review priority and hold until the reliability review process is completed.

3. Outage Request Approval Principles

The MP shall request ISO approval to remove a generator, DRR, or DARD from service for a PO or MO in accordance with this OP when that generator, DRR or DARD outage may impact the CSO of the associated capacity resource. When the generator, DRR or DARD outage does not impact the CSO of the associated capacity resource, the MP shall provide notification to ISO in accordance with this OP.

ISO shall approve any PO or MO request to the extent that it would not, in ISO or LCC judgment, cause an unacceptable OCM or violate any NERC, Northeast Power Coordinating Council Inc. (NPCC), or ISO operating criteria, policy or procedure. Once approved, an MP shall not subsequently be required to alter its PO request if unacceptable OCM conditions arise as a result of another generator/DRR/DARD or transmission outage. However, ISO may delay the start of an outage for reliability reasons.

ISO shall prioritize the outage requests for any given time period on a first-come, first-served basis.

ISO may reject an outage request if, in ISO judgment, the requested outage would cause an unacceptable LTOCM or LOCM (as defined in Section III.B.1.b of this OP) or STOCM or STLOCM (as defined in Section III.C.1.b of this OP).

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ISO shall coordinate with the LCCs regarding any outage repositioning. The monthly distribution of the "Annual Maintenance Schedule" (AMS) shall provide the LCCs with information regarding any repositioned outages occurring later in the year. For an MO request, ISO provides the relevant LCC with the outage information. The LCC shall notify ISO if an outage repositioning poses any local system reliability impact within its local area. Additionally, to reduce or eliminate Congestion Costs, the LCCs and ISO shall promote the continuous flow of information between them and the Transmission Owners in an effort to match proposed generator, DRR, or DARD POs or FOs with pending transmission outage work to the extent practicable.

B. PLANNED OUTAGE REQUEST AND EVALUATION PROCESS

Where the PO request affects the CSO of associated capacity resource, or of the associated ADCR as described in Section I.B,or is associated with a generator without a CSO that is a Qualified Generator Reactive Resource, an MP shall request ISO approval to schedule a PO in accordance with this OP. Where the generator PO request does not affect the CSO of the associated capacity resource or is associated

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with a generator that does not have a CSO, the MP shall notify ISO of its PO schedule in accordance with this OP.

1. PO Request Processing

a. ISO and the respective LCC shall respond to MP PO requests on a first come, first served basis for any defined submission period. The respective LCC shall review the PO request and continue the requested PO progression for ISO review if the impact on local reliability within its area is acceptable.

b. ISO shall evaluate the impact of the PO request on the OCM (as defined in Appendix A to this OP) and evaluate if approved transmission outages would interfere with the PO request. A PO shall not be approved if the security analysis considering all approved transmission network element outage identifies a violation(s) of ISO, LCC, NERC or NPCC criteria.

c. If ISO determines that the requested PO is not acceptable, then ISO shall discuss with the LCC alternative dates when the system reliability conditions are projected to be more favorable. The LCC shall work with the Transmission Owner (TO) and the generator, DRR, or DARD MP to reposition the PO. If the MP is not willing or not able to move the PO to a period where capacity and security criteria can be met, the PO request shall be denied.

d. In an effort to reduce Congestion Costs, ISO shall also compare the generator, DRR, or DARD PO request against approved transmission outage schedules to identify cases where the generator, DRR, or DARD PO schedules could be adjusted to meet this objective. If a potential schedule adjustment is identified, ISO shall discuss PO rescheduling with the LCC. The LCC shall coordinate rescheduling with the respective TO and the generator, DRR, or DARD MP. (Throughout this process, ISO shall work with the respective LCC, as needed, to develop alternative PO schedules.)

e. Upon coordination of generator, DRR, or DARD PO and transmission outage schedules, ISO shall perform its final review to confirm that the New England RCA/BAA and LCC reliability requirements are satisfied, coordination actions are in order, and Congestion Costs have been reduced or eliminated. Following this review, ISO shall:

i. Notify the MP if its request is approved as submitted, or approved with modifications in accordance with this OP.

ii. Publish the PO in the next update of the AMS.

iii. If applicable, revise the transmission outage information in the "Transmission Overhaul and Maintenance Schedule" that ISO issues to the LCCs on a monthly basis concurrent with the AMS. (The LCC shall relay any schedule revision information to the TO.)

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2. ISO Reporting

ISO shall publish, to the ISO external website, the current year's AMS initially on or about June 5 and subsequently on or about day 5 of each calendar month. If the published AMS poses any local system reliability impact within its local area, each LCC shall notify ISO's Long Term Outage Coordination staff by electronic media (email) at opamoreq@iso-ne.com within five (5) Business Days. [Local system reliability issues identified at this point should be minimal since each generator, DRR, or DARD PO request is forwarded to the respective LCC(s) for local review and approval following ISO's initial evaluation.]

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ISO shall aggregate approved MP PO requests, and ISO shall provide the projected weekly LTOCM for the New England RCA/BAA for two (2) consecutive calendar years. This process provides the MPs with a planning tool for reviewing their maintenance requirements and timing of their own operable capacity needs with the market signals of the New England RCA/BAA. This process provides ISO with a method for coordinating generator, DRR, or DARD maintenance requirements to avoid OP-4 or OP-7 actions, and as a result, ISO can identify potential capacity deficient periods. Additionally, the process provides ISO and the LCCs with the necessary information to identify situations where generator, DRR, or DARD and transmission outages could potentially be coordinated to reduce Congestion Costs.

3. Resolution of a Reliability Issue

If ISO determines that a reliability issue exists after it has approved a PO that is reflected in the AMS, ISO shall work with the LCC and the MP to reposition a previously-approved generator, DRR, or DARD PO to avoid or eliminate unacceptable forecasted LTOCM, LOCM, or reliability issues that have arisen since that approval was granted.

Where a reliability issue cannot be eliminated through ISO discussions with the affected MP by seventy-five (75) calendar days prior to the start of the reliability issue, ISO shall perform the following steps in order:

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a. Within seventy-five (75) calendar days of the reliability issue, ISO shall notify, in writing, all MPs that have requested a PO during the period where an unacceptable LTOCM or LOCM is projected and request that all MPs either voluntarily reposition their PO request or provide ISO with alternatives for repositioning their PO request. The MPs shall have fifteen (15) Business Days to respond to the ISO request.

b. If the problem is not resolved by the next monthly publication of the AMS, ISO may reject one or all of the PO requests as described in this OP. In making its determination, ISO shall group the requests by time stamp, and then apply an allocation method. The ISO allocation method is used to allocate the capacity available for a PO. ISO shall notify the NEPOOL

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Markets Committee that the problem exists, that voluntary repositioning has not resolved the problem, and that ISO must implement an allocation process.

The allocation process starts with the most recent group of PO requests. The allocation method is based on the ratio of a requesting MP's total generating CSO and DARD NCL compared to the sum of the requesting group total generating CSO and DARD NCL. This ratio is multiplied by the capacity available for maintenance to determine the MP allocation. Previously-approved PO requests shall **not** be subjected to the allocation process. If the MP allocation represents at least ninety percent (90%) of the generating CSO or a DARD NCL to be removed from service, ISO shall approve the PO request. If the MP allocation represents less than ninety percent (90%) of the generator, DRR, or DARD capacity to be removed from service, the generator, DRR, or DARD outage shall be relocated. ISO shall notify the MPs of the result of the allocation process no later than 55 calendar days prior to the start of any PO.

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c. Following ISO imposition of the allocation method and by forty-five (45) calendar days prior to the commencement of a PO, if any MP refuses to relocate its generator, DRR, or DARD PO for any month included in this allocation process, then the ISO shall classify the outage as an FO.

C. MAINTENANCE OUTAGE AND OVERRUN PLANNED OUTAGE REQUEST AND EVALUATION PROCESS

An MP shall request ISO approval to schedule an MO or OPO if:

(i) the MO or OPO impacts the CSO of the associated generator capacity resource,

(ii) the MO or OPO of the DRR is for 5 MW or more and results in the associated ADCR falling short of its CSO by 5 MW or more, or

(iii) the MO or OPO is associated with a generator without a CSO that is a Qualified Generator Reactive Resource.

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If an MO or OPO does not impact the CSO of the associated capacity resource or if the generator does not have a CSO, the MP shall notify ISO of the MO or OPO.

1. Processing of MO and OPO Requests

ISO and the respective LCC shall respond to each MO and OPO request as follows:

a. Response time shall be based on the following table:

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Response Time Table	
Submission of MO Request or OPO for an Outage Start of:	**Response time by ISO**
7 to 14 calendar days in the future	Within 3 Business Days
7 calendar days or less in the future	Within 1 calendar day
Overnight or next day, submitted by 0700*	By 0900
Overnight or next day, submitted/requested 0700-2400	Within current day**

* An OPO is not applicable in this timeframe
** Request shall be evaluated considering Day-Ahead Energy Market and Reserve Adequacy Analysis results

b. If an MO request results in the forecast of any actions of OP-4 or OP-7, ISO shall attempt to relocate the MO request to an acceptable period that reliability issues would not be expected to arise. If a request for an OPO results in any actions of OP-4 or OP-7, ISO shall deny the OPO request.

c. With prospective MO or OPO dates identified (that do not affect system reliability), the ISO shall provide the MO or OPO request information to the respective LCC.

d. The LCC shall notify ISO if the MO or OPO request poses a local transmission reliability problem. If it does, ISO shall work with the LCC and the MP to resolve the issue.

e. In an effort to reduce Congestion Costs, ISO shall compare the generator, DRR, or DARD MO or OPO request against approved transmission outage schedules to identify cases where the generator, DRR, or DARD MO or OPO schedules could be adjusted to meet this objective. If a potential schedule adjustment is identified, ISO shall discuss rescheduling with the LCC. The LCC shall coordinate rescheduling with the respective TO and the MP. (Throughout this process, ISO shall work with the respective LCC, as needed, to develop alternative outage schedules.)

f. ISO, coordinating with the respective LCC, shall proceed as follows depending on whether the case involves:

(1) an importing area,

(2) Generators, DRRs, or DARDs or an exporting area involving a single Lead MP, or

(3) an exporting area involving multiple generators, DRRs, or DARDs involving multiple MPs.

i. Importing area

For an importing area, the simultaneous outage of transmission

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supplying the area along with generators, DRRs, or DARDs within the area can increase Congestion Costs and, in severe cases, jeopardize system reliability. To relieve this, the following actions shall be taken to try to position the transmission and generators, DRRs, or DARDs MOs or OPOs so that they occur at different times.

- The LCC shall contact the MP for the generators, DRRs, or DARDs to determine if there is additional flexibility in the MO or OPO position.
- The LCC shall contact the TO for additional flexibility in the TO's schedule. (Generator, DRR, or DARD outage information may be discussed with the TO, as needed.)
- If needed, the LCC shall continue to alternately contact the TO and the MP until a determination is made on whether or not activities can be positioned to reduce/eliminate Congestion Costs. [Note: If the above actions are not sufficient to relieve congestion, then ISO shall dispatch generators/DRRs/DARDs in accordance with the congestion management process or change the timing of the transmission outage.]

ii. Generator, DRR, or DARD or exporting area involving a single MP

This scenario involves a transmission outage that would restrict the commitment or dispatch of a generator, DRR, or DARD involving a single MP (i.e., a line leaving a generator, DRR, or DARD station). The following actions shall be taken as soon as possible to try to change or create outage positions so that generator, DRR, or DARD and transmission outages occur simultaneously, thereby relieving the potential locked-in generator, DRR, or DARD.

- The LCC shall contact the MP for the generator, DRR, or DARD to determine if there is additional flexibility for the timing of the generator, DRR, or DARD MO or OPO.
- LCC shall contact the TO for additional flexibility in the TO's timing of the outage. (generator, DRR, or DARD MO or OPO outage information may be discussed with the TO, as needed).
- If the transmission outage involves a radial circuit to a generator, DRR, or DARD, this information may be shared with the MP. Additionally, non-radial transmission outage information may be shared with the MP if the transmission outage solely affects that MP.
- If needed, the LCC shall continue to alternately contact the TO and the generator, DRR, or DARD MP until a determination is made on whether or not activities can be scheduled to reduce/eliminate Congestion Costs.

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- The TO may contact the MP directly to facilitate positioning of MOs or OPOs.

iii. Exporting area involving multiple generator, DRRs, or DARDs and multiple MPs

This case involves a transmission outage that would restrict the commitment or dispatch of generators, DRRs, or DARDs within an exporting area with several generators, DRRs, or DARDs involving multiple MPs. The following actions shall be taken to try to change or create outage positions so that generators, DRRs, or DARDs and transmission outages occur simultaneously, thereby relieving the potential locked-in generator, DRR, or DARD.

- The LCC shall contact the applicable MPs, in the order in which MO or OPO requests were received to determine if there is additional flexibility in their generators', DRRs', or DARDs' outage position.
- The LCC shall contact the TO for additional flexibility in its position. (Generator, DRR, or DARD MO or OPO information may be discussed with the TO, as needed.)
- If needed, the LCC shall continue to alternately contact the TO and MPs until a determination is made on whether or not outages may be positioned to reduce/eliminate Congestion Costs.
- If generators, DRRs, or DARDs with MO or OPO requests cannot be repositioned or no MO or OPO requests exist, the LCC shall contact affected MPs to inform them that a transmission outage may result in their generator, DRR, or DARD being restricted and to determine if they desire to coordinate an MO or OPO of their generator, DRR or DARD with the transmission outage.
- If needed, the LCC shall continue to alternately contact the TO and MPs until a determination is made on whether or not outages may be positioned to reduce/eliminate Congestion Costs.

g. Upon agreement among ISO, the relevant LCC, the TO, and the MPs for the generators, DRRs, or DARDs involved, ISO shall:

(1) perform a final analysis to confirm that the New England RCA/BAA-wide and LCC reliability requirements are satisfied and that Congestion Costs have been reduced or eliminated;

(2) notify the MP for the generators, DRRs, or DARDs that the request is either approved as submitted, or approved with modifications in accordance

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with this OP; and

(3) if applicable, update short-term transmission outage information on the ISO external website.

2. MO and OPO Requests ISO Reporting

ISO shall notify the submitter of the MO or OPO request of the decision made by ISO, but shall not have an obligation to notify any other person or entity with an ownership or contractual interest in the resource for which the MO or OPO has been submitted.

D. OUTAGE REQUEST ON NON-CSO RESOURCE ENROLLED IN SCHEDULE 2 CAPACITY COST COMPENSATION PROGRAM

An MP for a Qualified Generator Reactive Resource without a CSO shall submit a PO and MO or OPO request. Such requests shall be subject to ISO and LCC review and approval in accordance with this OP with the following exceptions:

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1. There shall be no OCM evaluation performed.
2. Security analyses shall be limited to voltage studies.

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IV. MARKET PARTICIPANT RESPONSIBILITIES

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1. Information Requirements

a. When submitting a PO, MO or OPO request, an MP shall provide the following information for each request:

i. "Capacity Resource ID", only applicable if outage is associated with an Import Capacity Resource

ii. For generator/DARD/ATRR: "Asset ID" and "Asset Name"

iii. For DRR: "DRR ID" and DRR Name

iv. MW amount of the physical reduction

v. Blackstart status during the outage, for black start capable generators only.

vi. Preferred outage start date and time

vii. Projected outage end date and time

viii. Outage reason and description of work to be accomplished during the outage

ix. Flexibility of the requested outage schedule dates

x. For an MO, whether the outage can be postponed

b. An MP shall submit a generator PO, MO or OPO request that crosses capability period boundaries as two separate outage requests.

- The summer capability period is comprised of the months June through September.
- The winter capability period is comprised of the months of October through May.

2. Information Submittal Process

Each MP shall submit the required information as follows:

a. PO request:

- Submit a PO request for a generator electronically through the ISO outage application software.
  - The timestamp for the PO request shall be the time at which the MP last updates the PO request
- Submit a PO request for a DRR, DARD, ATRR or generator when the

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outage application software is not available by electronic (email) to opamoreq@iso-ne.com using the standard form [Appendix B to this OP - Outage Request Form (OP-5B)].

- The timestamp for the PO request will be the time at which the email is received

b. Request for an MO or OPO

- The MP shall submit an MO or OPO request for a generator electronically through the ISO outage application software.
  - Except that the MP shall not submit an MO into the ISO outage application software after 0900 hours the day before the start of the outage; a request for an MO made after 0900 hours the day before the start of the MO shall be submitted by contacting the ISO generation coordinator or control room forecaster.
  - The timestamp of the MO or OPO request shall be the time at which the MP last updates the MO or OPO request.
- The MP for a DRR, DARD or ATRR shall submit an MO or OPO request to the ISO generation coordinator by telephone at (413) 535-4378 from 0700 hours to 1530 hours or the forecaster by telephone at (413) 535-4340 from 1530 hours to 0700 hours by providing the information required by this OP. A generator may submit an MO or OPO to the ISO in this manner.
  - The timestamp for the MO or OPO request shall be the time at which the phone call is received

c. Notification to ISO

- If the MP is required to notify the ISO of a reduction to an Import Resource or generator, as defined in Sections I.G or I.I of this OP, then the MP shall either:
  - Submit the notification via email using OP-5B
  - Call by telephone the ISO generation coordinator at (413) 535-4378 from 0700 hours to 1530 hours or the ISO forecaster at (413) 535-4340 from 1530 hours to 0700 hours to provide the information required in OP-5B

3. Changes To Previously Submitted Outage Requests

An MP request to modify a previously submitted PO, MO, or OPO, request shall follow the same process as described in Section III of this OP. ISO shall accept a change request that reduces the scope or duration of the PO, MO, or OPO without impacting the time stamp of the PO, MO, or OPO request. ISO shall accept a change request that increases the scope or changes the dates of the PO, MO, or OPO such that a new outage evaluation is required as a new PO, MO, or OPO

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request, which shall be time stamped accordingly.

4. Requesting Implementation Of Outage

Immediately prior to commencing scheduled work, the MP shall obtain ISO control room approval for any generator, or DARD, or ATRR PO and MO request. ISO shall not withhold such approval unless the consequences of granting the approval would result in a risk of the OP-4 action where a Power Watch is declared (Action 4) or higher or OP-7 actions, or other serious reliability risk. ISO shall inform the respective LCC when the generator, DRR, or DARD is offline and out-of-service. For a DRR, a request for implementation of a PO, MO or OPO shall be entered in eMarket as the DRR's bid parameters reflecting the implemented PO, MO or OPO.

5. Notifying FO

If an FO is declared, the MP shall notify the ISO control room generation operator with an appropriate redeclaration for the current Operating Day. The ISO generation coordinator shall be contacted at (413) 535-4378 from 0700 to 1530, or the forecaster by telephone at (413) 535-4340 from 1530 to 0700, for the purpose of providing an expected FO return date, and to provide any necessary redeclaration for any future days for which the bidding deadline has passed. These notifications shall be made as soon as practicable.

6. Notifying ISO Of Return To Service

An MP shall notify ISO of the completion of the PO, MO or OPO by releasing the generator, DRR, DARD, or ATRR to ISO for dispatch. If the MP does not expect to return the generator, DRR, DARD, or ATRR to service on the Operating Day indicated on the PO, MO or OPO request, then the MP shall notify ISO of the expected return date for the generator, DRR, DARD, or ATRR, which may be captured in a new PO, MO or OPO request. For a DRR, the notification of return of service after the PO, MO or OPO shall be entered in eMarket as the DRR's bid parameters reflecting the return of service after the PO, MO or OPO.

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ATTACHMENTS:

OP-5 Appendix A - Operable Capacity Calculations

OP-5 Appendix B - Outage Request Form

OP-5 Appendix C - Retired (09/17/12)

OP-5 Appendix D - Retired (06/01/18)

OP-5 REVISION HISTORY

Document History (This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well revisions made to the ISO New England Procedure subsequent to the RTO Operations Date.)

Rev. No.	Date	Reason
- -	draft	For previous revision history, refer to Rev 10 available through Ask ISO
Rev 11	12/01/10	Reformatted entire document, changed font, minor editorial and format changes, Clarified blackout dates Clarified requirements for Import Capacity Resources Modified submittal process to address outage application software Added language to outage types definition to indicate how they will be referenced in outage application software
Rev 12	03/01/11	Add language for non-CSO resources receiving Schedule 2 compensation
Rev 13	09/17/12	Corrected Market Rule 1 title; Appendix C, retired (09/17/12) exists only as place holder, no future plan to use;
Rev 14	10/08/13	Biennial review by procedure owner; Modified the Table located before Section I.D.1.a. (update for DAM timeline moving)
Rev 15	05/02/14	Updated for inclusion of Alternative Technology Regulation Resource (ATRR) requirements for outages and maintenance.
Rev 15.1	08/31/15	Periodic review performed requiring no changes
Rev 16	01/11/16	Provided clarification to: • Definitions • Current Year and First Future Year reporting • Part III, I, D. - Added guidance to the Response Time Table Part III, II, B. - Added guidance to the Informational Submittal Process
Rev 17	09/09/16	Completion on the biennial review by the procedure owner; Added required corporate document identity to all Footers; Modify the posting of First Future year and Current year AMS into one report updated monthly. Delete First Future Year process.; Added comment to require resources to include outage reason within outage requests. Clarified Planned outage definition; Globally minor editorial changes consistent with current practices and management expectations; Truncated the Revision History per SOP-RTMKTS.0210.0010 Section 5.6;
Rev 18	06/01/18	Completion on the biennial review by the procedure owner; Updated for PRD, and removed RTDR references; Format changes; Minor editorial changes consistent with current practices and management expectations; Appendix D, retired (06/01/18) no longer required after PRD implementation;
Rev 19	02/01/19	Corrected Rev 18 Rev History to document completion of the biennial review; References section deleted OP-3 and added OP-24; Part I.F, replaced OP-3 with OP-24;

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Rev. No.	Date	Reason
Rev 20	draft	Modified language such that outage requests for Import Capacity Resources are for notification purposes only; Adjusted title of generation coordinator and hours when generation coordinator and forecaster should be contacted; Simplified reference to Qualified Generator Reactive Resource;

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EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings as of July 31, 2019

The following activity, as more fully described in the attached litigation report, has occurred since the report dated June 23, 2019 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

	1	Winter Fuel Security (Chapter 3) (EL18-182)	Jul 3	FERC issues supplemental notice of ***Jul 15*** public, staff-led meeting
			Jul 15	FERC holds public meeting; speaker materials posted to eLibrary; webcast available for viewing for 3 months
			Jul 31	NESCOE requests 6-month extension of time, to April 15, 2020, for the submission of New England's energy security market design, and that the FERC issue an order granting the extension by Aug 30, 2019; responses due Aug 5
	2	206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19-002)	Jul 23	TOs request 45-day suspension of procedural schedule and 45-day extension of procedural deadlines
			Jul 29	Chief Judge grants 45-day suspension of procedural schedule; initial hearing and decision dates extended by 45 days

II. Rate, ICR, FCA, Cost Recovery Filings

*	6	FCA14 De-List Bids Filing (ER19-2312)	Jun 28	ISO-NE submits filing describing Permanent and Retirement De-List Bids submitted on or prior to the FCA14 Existing Capacity Retirement Deadline
			Jul 2-19	NEPOOL, Dominion, Eversource, Exelon, National Grid, NESCOE, NRG, intervene
			Jul 17	Public Citizen files a protest asserting filing is deficient for failure to provide a proposed non-disclosure certificate for parties' access to privileged components of this filing
	7	Trans. Rate Incentive Request: UI's Pequonnock Substation Project (ER19-1359)	Jul 15	FERC issues tolling order affording it additional time to consider UI's request for rehearing of the May 14 *UI Pequonnock Rate Incentive Order*
	8	FCA13 Results Filing (ER19-1166)	Jun 28	ISO-NE responds to Jun 6 deficiency letter
			Jul 9 & 18	EMM submits comments on IMM's review and mitigation of Killingly's FCA13 Offer Floor Price
			Jul 19	Capacity Suppliers answer EMM comments
			Jul 25	FERC issues 2nd deficiency letter
			Jul 26	ISO-NE responds to 2nd deficiency letter
	10	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Jul 18	Constellation Mystic Power, CT Parties, ENECOS, MA AG, National Grid, FERC Trial Staff file reply briefs
	11	MPD OATT 2019 Annual Informational Filing (ER15-1429-000)	Jun 26	Emera Maine answers Maine Customer Group's Jun 11 motion to strike a portion of Emera Maine's May 1 filing
	11	MPD OATT 2018 Annual Informational Filing (ER15-1429-010)	Jul 18	Fist settlement conference held
			Jul 19	Settlement Judge Dring schedules second settlement conf. for Sep 11
			Jul 29	Settlement Judge Dring issues status report

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

*	13	Nested Capacity Zone Changes (ER19-2421)	Jul 19 Jul 22-30	ISO-NE and NEPOOL jointly file changes; comment date Aug 8, 2019 Eversource, Exelon, NESCOE intervene
*	13	Monthly (BoPP) FTR Auctions Eff. Date Notice & Conforming MR Changes (ER19-2327)	Jul 1 Jul 8-19	ISO-NE and NEPOOL jointly file (i) notice of effective date of monthly (BoPP) FTR auctions (Sep 17, 2019) and (ii) conforming Market Rule changes DC Energy, Exelon, National Grid, NRG intervene
	13	DAM Offer Cap Changes (ER19-2137)	Jul 1	ConEd, NESCOE, NRG intervene
	14	ISO-NE's Interim Winter Energy Security (Chapter 2B) Proposal (ER19-1428)	Jun 27	EDF, MA AG, NECOS/ENE/Direct, NEPGA, NRG, Vistra, Verso, MPUC, Clean Energy Advocates file protests and comments

IV. OATT Amendments / TOAs / Coordination Agreements

	21	Interconnection Studies Scope and Reasonable Efforts Timelines Changes (ER19-1952)	Jun 26 Jul 11	EDF Renewables, Enel, E.ON intervene and protest the changes; Renewable Energy Systems of America intervenes ISO-NE answers Jun 26 joint protest
	21	ISO-NE *Order 845* Compliance Filing (ER19-1951)	Jun 25-26 Jun 26 Jul 11	EDP Renewables, Enel, EPSA, E.ON, Renewable Energy Systems of America intervene MA AG, AWEA/RENEW/Solar Council, ESA protest *Order 845* filing ISO-NE and PTO AC answer protests and comments filed in response to their May 22 filing

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

*	22	Schedule 22: First Revised Clear River LGIA (ER19-2419)	Jul 18	ISO-NE and National Grid file 1st Rev. LGIA; comment date Aug 8
*	23	Schedule 21-NEP: National Grid/GRS SGIA (ER19-2352)	Jul 3	National Grid files SGIA with Gas Recovery Systems to reflect reduced output of Fall River facility
	23	Schedule 21-UI: LCSA Cancellation - UI/EES5 (Bridgeport Energy) (ER19-1921)	Jul 10	FERC accepts Agreement, eff. Apr 1, 2019
	23	Schedule 21-UI: LCSA - UI/Revere Power (Bridgeport Energy) (ER19-1911)	Jul 10	FERC accepts Agreement, eff. Apr 1, 2019
*	25	Schedule 21-FG&E Annual Informational Filing (ER09-1498)	Jul 29	FG&E submits annual update to its Revenue Requirement recovered through the ISO-NE Tariff and Schedule 21-FG&E for the Jun 1, 2018 – May 31, 2019 period
*	25	Schedule 21-NSTAR Annual Informational Filing (ER09-1243; ER07-549)	Jul 2	NSTAR submits CWIP supplement to May 31 annual informational filing
*	25	Schedule 21-CMP Annual Informational Filing (ER09-938)	Jun 28	CMP files updated formula rates reflecting actual 2018 cost data and estimated 2019 cost data

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	26	FCA13 Fuel Security Reliability Review Info Filing (ER18-2364)	Jul 12	ISO-NE files report assessing the study triggers, study and scenarios used by ISO-NE in its FCA13 fuel security reliability review in comparison to actual conditions experienced during Winter 2018-19
*	26	LFTR Implementation: 43rd Quarterly Status Report (ER07-476)	Jul 15	ISO-NE files its 43rd quarterly report

IX. Membership Filings

*	27	Involuntary Termination: Viridity Energy (ER19-2387)	Jul 11-12	NEPOOL and ISO-NE request the involuntary termination of the NEPOOL Participant and Market Participant status of Viridity Energy, Inc.; comment date Aug 1
*	27	July 2019 Membership Filing (ER19-2292)	Jun 28	*New Members*: Bloom Connecticut Clean Energy; Clearway Power Marketing; Excelerate Energy; *Termination*: Marathon Power; *Name Changes*: North Stonington Solar Center; TrailStone Energy Marketing
	27	June 2019 Membership Filing (ER19-2021)	Jul 9	FERC accepts (i) memberships of Brookfield Renewable Trading and Marketing; Community Eco Power; DWW Solar II; and NS Power Energy Marketing; and (ii) May 1, 2019 terminations of Mint Energy; Power Bidding Strategies; and Utility Expense Reduction

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

	29	NOPR - New Reliability Standard: CIP-012-1 (RM18-20)	Jun 24	ISO/RTO Council, APPA, MERC, Tri-State Gen. and Trans. Assoc., Bonneville Power Administration file comments
*	29	5-Year ERO Performance Assessment Report (RR19-7)	Jul 22 Jul 30	NERC files report; comment date Aug 22 Public Citizen intervenes

XI. Misc. - of Regional Interest

	30	203 Application: Footprint, Hartree Partners / Brookfield (EC19-104)	Jul 10	PJM intervenes
*	30	203 Application: ReEnergy (EC19-102)	Jul 30	FERC authorizes transaction pursuant to which ReEnergy Stratton will no longer be a Related Person to Talen Energy Mktg. *et al.*
	30	203 Application: Empire Generating Co, LLC (EC19-99)	Jul 3 Jul 17 Jul 17-18	Ares submits limited protest requesting add'l information Empire submits responses to Jun 21 deficiency letter; comment date Sep 3 Empire, Black Diamond Capital object to Ares' Jul 3 request
	31	203 Application: Kendall Green Energy (EC19-86)	Jun 28	FERC authorizes transaction in which Veolia will become the sole owner of Kendall Green
	31	203 Application: Convergent Energy and Power / ECP (EC19-85)	Jul 5 Jul 9	ECP acquires Convergent, which becomes a Calpine Related Person ECP files notice of consummation of transaction
	31	203 Application: Emera Maine/ENMAX (EC19-80)	Jun 25	FERC authorizes transaction; closing expected at year's end
*	31	203 Application: Crius (Viridian Energy et al.) / Vistra (EC19-59)	Jul 8 Jul 15	FERC authorizes transaction Transaction consummated (as per Jul 17 notice)
	31	203 Application: FirstLight Restructuring (EC19-44)	Jul 16	Restructuring consummated (as per Jul 29 notice)
*	32	203 Notification: NSTAR/Entergy (EC19-1)	Jun 28	NSTAR filed a notice that, coincident with Pilgrim's retirement, it purchased from Entergy the 345-kV switchyard adjacent to Pilgrim

	32	New England Ratepayers Association Complaint (EL19-10)	Jul 18	Public Citizen moved to intervene out-of-time and submits protest suggesting NERA be required to disclose the identities of its members
	33	PJM MOPR-Related Proceedings (EL18-178; ER18-1314; EL16-49)	Jul 25	FERC denies PJM's Motion for Supplemental Clarification; directs PJM not to run its BRA in Aug 2019 and to wait for an order before doing so
*	36	D&E Agreement: NSTAR/SEMASS (ER19-2326)	Jul 1	NSTAR files D&E Agreement
*	37	2nd Supp. to Stony Brook IA (ER19-2303)	Jun 28	NSTAR files second extension, to Oct 1, 2019, of MMWEC's Stonybrook Interconnection Agreement
	37	RFA Termination: NSTAR/Pilgrim (ER19-2108)	Jul 17	FERC accepts RFA termination notice, eff. Jun 1, 2019
	37	IA Termination: Pilgrim Nuclear Power Station/NSTAR (ER19-2046)	Jul 19	FERC accepts IA termination notice, eff. Jun 1, 2019
	38	D&E Agreement: CL&P/NTE CT (ER19-1994)	Jul 9	FERC accepts Agreement, eff. May 28, 2019
	38	Emera Maine *Order 845* Compliance Filing (ER19-1887)	Jul 15	Emera Maine files responses to Jun 13 letter; comment date Aug 5
*	39	FERC Enforcement Action: Vitol and F. Corteggiano (IN14-4)	Jul 10	FERC issues show cause order directing Vitol and Corteggiano to show cause why (i) they should not be found to have violated FERC's Anti-Manipulation Rule; (ii) why Vitol and Corteggiano should not pay civil penalties in the amount of $6 million and $800, 000, respectively; and (iii) why Vitol should not disgorge $1,227,143 plus interest in unjust profits; comment date Aug 9
			Jul 17	FERC issues updated notice identifying 9 OE staff members who will not be included in the blanket designation of OE Staff as non-decisional
			Jul 18	Vitol and Corteggiano object to the exceptions
			Jul 24	Vitol and Corteggiano ask for 30-day extension of response deadline OE
			Jul 25	Staff opposes the motion for extension of time

XII. Misc. - Administrative & Rulemaking Proceedings

	40	Increasing Market and Planning Efficiency Through Improved Software (AD10-12)	Jun 25-27	FERC holds 10th consecutive tech. conf. on this topic
			Jul 3	Speaker materials posted in eLibrary; comment date Jul 31, 2019
	41	*Order 861*: Refinements to Horizontal Market Power Analysis Requirements (RM19-2)	Jul 18	FERC issues *Order 861*, relieving MBR sellers in RTO/ISO regions with capacity markets subject to FERC-approved RTO/ISO monitoring and mitigation from reqs. to submit indicative screens, eff. Sep 24, 2019
	44	NOPR: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)	Jul 18	FERC issues *Order 860*, eff. Oct 1, 2020
	44	NAESB WEQ v. 003.2 NOPR (RM05-5-027)	Jul 23	7 parties submit comments; NAESB submits report regarding minor errata to v003.2 standards
	45	NOI: FERC's ROE Policy (PL19-4)	Jun 26	More than 60 organizations and 15,000 individuals file initial comments
			Jul 12-26	Nearly 30 organizations file reply comments
	45	NOI: Electric Transmission Incentives Policy (PL19-3)	Jun 26-Jul 25	Comments filed, including by Avangrid, Eversource, Exelon, Invenergy, MMWEC/NHEC, NGrid, NextEra, UCS, NESCOE, Potomac Economics, Southern New England State Agencies, AEE, AWEA, EEI, ESA, NRECA, PIOs, TAPS

XIII. Natural Gas Proceedings

No Activity to Report

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

	53	PennEast Project (18-1128) (DC Cir.)	Jul 30	Oral argument scheduled for Oct 4, 2019
*	53	PG&E Bankruptcy (19-71615) (9th Cir.)	Jun 26-Jul 29	Appearances and corporate disclosure statements filed
			Jul 11	PG&E moves to suspend the briefing schedule pending the Court's decision on whether to authorize direct appeal of a decision by the Bankruptcy Court in the Northern District of California
			Jul 12	Court issues mediation order
*	53	First Energy Solutions Bankruptcy (18-3787) (6th Cir.)	Jun 26	Oral argument held

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: July 31, 2019

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through July 31, 2019. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **RTO Insider Press Policy Complaint (EL18-196)**

As reported in the April 10 Report, the FERC dismissed, on April 10, 2019, *RTO Insider*'s August 31 Complaint.[2] The Complaint had requested that the FERC either (i) find that NEPOOL's press policy "unlawful, unjust and unreasonable, unduly discriminatory and contrary to the public interest, and direct NEPOOL to cease and desist" from implementing its policy; or (ii) "if the [FERC] finds that NEPOOL can sustain such a ban as a "private" entity, [] direct that NEPOOL's special powers, privileges and subsidies be terminated and that an open stakeholder process be used by [ISO-NE]" ("RTO Insider Complaint"). In dismissing the RTO Insider Complaint, the FERC agreed with NEPOOL that the claims asserted by RTO Insider did not relate to matters over which the FERC has jurisdiction, finding that the "rules governing attendance at NEPOOL meetings do not directly affect the filings brought before the Commission in the way that membership rules that allow members to vote do … the challenged NEPOOL policies here concern passive attendance at NEPOOL meetings by non-voting entities and dissemination of written accounts of NEPOOL deliberations. The contested attendance and reporting policies are too attenuated from NEPOOL's voting process to directly affect jurisdictional rates." On May 10, Public Citizen requested rehearing of the *RTO Insider Complaint Order*. On June 7, the FERC issued a tolling order affording it additional time to consider the request for rehearing, which remains pending. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Winter Fuel Security (Chapter 3) (EL18-182)**

As previously reported, the July 2, 2018 *Mystic Waiver Order*[3] (reported on in more detail in ER18-1509 in Section III below) in part instituted this Section 206 proceeding in light of the FERC's preliminarily finding that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record in ER18-1509 that could result in reliability violations as soon as 2022. Accordingly, the *Mystic Waiver Order* directed ISO-NE, in part, to submit permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns (the "Chapter 3 Proposal"). Following an ISO-NE request for an extension of time to file its Chapter 3 Proposal, the FERC issued a notice granting an extension of

[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] *RTO Insider LLC v. New England Power Pool Participants Comm.*, 167 FERC ¶ 61,021 (Apr. 10, 2019) ("*RTO Insider Complaint Order*").

[3] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

time, to and including ***October 15, 2019***, a month earlier than requested, for the filing of that Proposal. The schedule for development and consideration of the Chapter 3 mechanism has been adjusted accordingly.

July 15 Technical Conference. On July 15, the FERC held a public, staff-led meeting in response to the April 22 joint request by ISO-NE, NECPUC and NEPOOL for such a meeting to create a forum for pre-filing discussions without violating the *ex parte* limitations. The technical conference was webcast and will be available for viewing for three 3 months at http://ferc.capitolconnection.org. Speaker materials are posted in the FERC's eLibrary.

NESCOE Request for 6-Month Extension of Time. On July 31, 2019, NESCOE requested a 6-month extension of time, to April 15, 2020, for the submission of New England's energy security market redesign, and that the FERC issue an order granting the extension by August 30, 2019. NESCOE stated that "many key details, analyses, and core consumer protections remain under development or will be deferred to a later date. It has become increasingly clear that additional time is needed to resolve the many outstanding issues surrounding ISO-NE's proposed energy security improvement ("ESI") market redesign, provide a greater understanding of how the design is expected to perform and its impact on reliability and consumer costs, and enable the development of design components to address emerging concerns on fundamental issues, such as the exercise of market power and unjustified consumer costs." NESCOE asserted that the extension of time would "enable a more complete and holistic filing in response to the directives in the July 2018 Order, allow ISO-NE to address core consumer protection elements that are fundamental to state support, and remove barriers to achieving a greater degree of regional coalescence around a proposal". NESCOE emphasized its "understanding that a six-month extension would not hinder the implementation of a long-term market design change for the targeted 2024-2025 period." Responses to NESCOE's request will be due August 5.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19-002)**

Concluding that the contested 2018 Joint Offer of Settlement (the "Settlement"),[4] filed to resolve all issues in the Section 206 proceeding instituted by the FERC on December 28, 2015,[5] lacked sufficient detailed information to enable it to apply any of the approaches available to it to approve a contested settlement,[6] the

[4] As previously reported, the Settling Parties filed the Settlement on Aug. 17, 2018, in ER18-2235. The Settlement proposed changes to Section II.25, Schedules 8 and 9, Attachment F (including the addition of Interim Formula Rate Protocols ("Interim Protocols")), and the Schedule 21s to the ISO-NE OATT. Had they been approved, the changes to Attachment F would have become effective mid-June, 2019, with the remaining changes to be effective January 1, 2020. The Interim Protocols, as well as the changes to Section II.25 and Schedules 8 and 9, were supported by the Participants Committee at its July 24, 2018 meeting.

[5] *ISO New England Inc. Participating Transmission Owners Admin. Comm.*, 153 FERC ¶ 61,343 (Dec. 28, 2015), *reh'g denied,* 154 FERC ¶ 61,230 (Mar. 22, 2016) ("*RNS/LNS Rates and Rate Protocols Order*"). The *RNS/LNS Rates and Rate Protocols Order* found the ISO-NE Tariff unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS"). The FERC also found that the RNS and LNS rates themselves "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because (i) "the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates" and "could result in an over-recovery of costs" due to the "the timing and synchronization of the RNS and LNS rates". The FERC encouraged the parties to make every effort to settle this matter before hearing procedures are commenced. The FERC-established refund date is January 4, 2016.

[6] The FERC outlined in a seminal case the following four alternative approaches for approving contested settlements: (1) where the FERC can render a binding merits decision on each contested issue, (2) where the FERC can approve the settlement based on a finding that the overall settlement *as a package* is just and reasonable, (3) where the FERC can determine that the benefits of the settlement outweigh the nature of the objections and the interests of the contesting party are too attenuated, and (4) where the FERC can approve the settlement as uncontested for the consenting parties, and can sever the contesting parties to allow them to litigate the issues raised. *See Trailblazer Pipeline Co.*, 85 FERC ¶ 61,345, at 62,342-44 (1998).

FERC rejected the Settlement and remanded this proceeding (EL16-19) to Chief Judge Cintron to resume hearing procedures.[7] The *RNS Rate/Rate Protocol Settlement Order* terminated Docket No. ER18-2235.

As previously reported, the Settlement was supported by ***NESCOE*** but opposed by Municipal PTF Owners[8] and FERC Trial Staff. The ***Municipal PTF Owners*** ("Munis") asserted that the Settlement would worsen, rather than improve, the issues of "lack of transparency, clarity and specificity that led the Commission [to] find the existing Attachment F formula unjust and unreasonable", discriminate against load directly connected to PTF and exempted by Section II.12(c) of the ISO-NE Tariff from paying costs associated with service across non-PTF facilities, contravened numerous settled rate principles without explanation or justification,[9] and would have imposed an unacceptable moratorium and burden on parties inclined to challenge Attachment F. ***FERC Trial Staff*** asserted that the Settlement, as filed, was not fair and reasonable nor in the public interest "because it would result in unreasonable rates and contains fundamental defects",[10] and opposed the Settlement terms which would bind non-settling parties to the terms of the Settlement and establish a standard of review for changes to the Settlement. FERC Trial Staff suggested that these defects could be corrected in a comprehensive compliance filing. ***Reply comments*** were submitted by NEPOOL, NESCOE and the MA AG. In its limited comments, ***NEPOOL*** noted that it supported the Interim Protocols and that it had no objection to the Settlement. ***NESCOE*** reiterated its support for the Settlement in its reply comments, urging the FERC to reject any arguments that consumer-interested parties "were not familiar with the issues relating to the Settlement or that they reached a settlement for any reason other than their view that it is in the best interests of consumers."[11] ***MA AG*** urged the FERC to approve the Settlement as submitted, despite the objections of FERC Trial Staff and Municipal PTF Owners, because it complies with the *RNS/LNS Rates and Rate Protocols Order* and represents a carefully negotiated resolution to numerous complex ratemaking and transparency issues.[12]

Hearings. Having rejected the Settlement, the FERC remanded this proceeding to Chief ALJ Cintron to resume hearing procedures. On May 23, Chief Judge Cintron designated Judge David H. Coffman as the Presiding Judge for the purpose of hearings and issuance of an initial decision within Track III procedural time standards.[13] A prehearing conference was held on June 6, 2019. Following that conference, orders establishing a procedural schedule and adopting rules of conduct for the hearing were issued. That schedule was extended by 45 days pursuant to the Chief Judge's July 29 order described below. Hearings are now scheduled to begin April 27, 2020, with an initial decision to be issued by September 21, 2020. Interim deadlines may be adjusted in accordance with the Chief Judge's order. Discovery is on-going.

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[7] *ISO New England Inc. Participating Transmission Owners Admin. Comm., et al.*, 167 FERC ¶ 61,164 (May 22, 2019) ("*RNS Rate/Rate Protocol Settlement Order*"). The Parties were reminded that they could seek further settlement judge procedures as well. *Id.* at fn. 49.

[8] "Municipal PTF Owners" are: Braintree, Chicopee, Middleborough, Norwood, Reading, Taunton, and Wallingford.

[9] The elements of the Settlement that Municipal PTF Owners assert contravene settled rate principles include: provision for a fixed accrual for Post-Employment Benefits Other than Pension ("PBOPs"); continued TO use of net proceeds of debt, rather than gross proceeds of debt, in establishing capital structures under their proposed revenue requirement formula; inappropriate allocation of rental revenues from secondary uses of transmission facilities; the addition of miscellaneous intangible plant (Account 303), and depreciation and amortization of intangibles, to rate base; and the creation of a Regulatory Asset for an unspecified Massachusetts state tax rate change (without explanation).

[10] Included in the "fundamental defects" of the Settlement identified by FERC Trial Staff are that it: (1) enables the TOs to conduct extra-formulaic, ad hoc ratemaking for all externally-sourced inputs every year; (2) enables certain PTOs to over-recover certain plant costs; (3) enables certain PTOs to recover greater than 50% of Construction Work in Progress ("CWIP") in rate base (4) violates prior FERC orders about which customer groups can be made to pay incentive returns; (5) fails to appropriately calculate federal and state income taxes and, in particular, fails to account for excess Accumulated Deferred Income Taxes ("ADIT") created by the Tax Cuts and Jobs Act; (6) does not contain a fixed and stated ROE; and (7) does not contain a fixed and stated PBOPs expense.

[11] Reply Comments of NESCOE, Docket Nos. ER18-2235 and EL16-19, at p. 2 (filed Sep. 28, 2018).

[12] Reply Comments of the Mass. Att'y General in Support of Settlement, Docket Nos. EL16-19 and ER18-2235 (filed Sep. 28, 2018).

[13] Track III time standards require a hearing be convened within 42 weeks and an initial decision issued within 63 weeks.

Procedural Schedule dates extended 45 days. Since the last Report, on July 23, the TOs submitted an unopposed motion to extend the deadlines set "in order to allow the Active Participants to pursue settlement negotiations in the most efficient manner." The TOs proposed to extend each of the deadlines set forth above by 45 days. That request was granted by Chief Judge Cintron on July 29, 2019. Accordingly, hearings are now scheduled to begin April 27, 2020, with an initial decision to be issued by September 21, 2020. Interim deadlines may be adjusted in accordance with the Chief Judge's order.

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

- **Base ROE Complaints I-IV: (EL11-66, EL13-33; EL14-86; EL16-64)**

There are four proceedings pending before the FERC in which consumer representatives seek to reduce the TOs' return on equity ("Base ROE") for regional transmission service.

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[14] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[15] However, the FERC's orders were challenged, and in *Emera Maine,*[16] the DC Circuit Court vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[17] and third (EL14-86)[18] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[19] The *Initial Decision* also lowered the ROE ceilings. Parties to these

[14] The TOs' 11.14% pre-existing Base ROE was established in *Opinion 489*. *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarific.*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom.*, Conn. Dep't of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010) ("*Opinion 489*")).

[15] *Coakley Mass. Att'y Gen. v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,234 (2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014) ("*Opinion 531-A*"), *order on reh'g*, 150 FERC ¶ 61,165 (2015) ("*Opinion 531-B*").

[16] *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).

[17] 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% ROE, and seeks a reduction of the Base ROE to 8.7%.

[18] 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.

[19] *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*").

proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[20] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[21] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under section 206 of the FPA.[22] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[23] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings. The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[24]

At highest level, the new methodology will determine whether (1) an existing ROE is unjust and unreasonable under the first prong of FPA section 206 and (2) if so, what the replacement ROE should be under the second prong of FPA section 206. In determining whether an existing ROE is unjust and under the first prong of Section 206, the FERC stated that it will determine a "composite" zone of reasonableness based on the results of three models: the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), and Expected Earnings models. Within that composite zone, a smaller, "presumptively reasonable" zone will be established. Absent additional evidence to the contrary, if the utility's existing ROE falls within the presumptively reasonable zone, it is not unjust and unreasonable. Changes in capital market conditions since the existing ROE was established may be considered in assessing whether the ROE is unjust and unreasonable.

If the FERC finds an existing ROE unjust and unreasonable, it will then determine the new just and reasonable ROE using an averaging process. For a diverse group of average risk utilities, FERC will average four values: the midpoints of the DCF, CAPM and Expected Earnings models, and the results of the Risk Premium model. For a single utility of average risk, the FERC will average the medians rather than the midpoints. The FERC said that it would continue to use the same proxy group criteria it established in *Opinion 531* to run the ROE models, but it made a significant change to the manner in which it will apply the high-end outlier test.

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and

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[20] 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.

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

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

[23] *Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (Oct. 18, 2018) ("*Order Directing Briefs"* or "*Coakley*").

[24] *Id.* at 19.

unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[25] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[26] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, EEI, Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, FERC Trial Staff. This matter is pending before the FERC.

These matters are now pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA14 De-List Bids Filing (ER19-2312)**

Pursuant to Market Rule 1 § 13.8.1(a), ISO-NE submitted on June 28 a filing describing the Permanent De-List Bids and Retirement De-List Bids that were submitted on or prior to the FCA14 Existing Capacity Retirement Deadline. ISO-NE reported that the Existing Capacity Retirement Deadline for FCA14 was March 15, 2019 and it received 22 Permanent De-List, 11 Retirement De-List Bids, and three substitution auction test prices from 11 Lead Market Participants. The bids were for resources located in the CT, ME, NEMA/Boston, and Western Central MA Load Zones, with 279.256 MWs of aggregate capacity. All but two of the Bids were for resources under 20 MW or that did not meet the affiliation requirements that would have required IMM review, with five (representing 157.321 MWs) requiring substitution auction test price reviews because the Bids were for greater than 3 MWs. The IMM did review the remaining two Bids (from one supplier) for 98.198 MWs of capacity. The IMM's determination regarding those 2 bids is described in the version of the filing that was filed confidentially as required under §13.8.1(a) of Market Rule 1.

ISO-NE reported that, because the FERC's determination on its Chapter 2B Interim Winter Energy Security Proposal described in Section III below (ER19-1428), which creates a new revenue stream for resources participating in the program for the FCA14 Capacity Commitment Period, is still pending, the IMM provided conditional retirement notifications to Participants, with a price under both the current rules, and a price to be used if the Chapter 2B rules are approved by the FERC.

[25] *Id.* at P 59.

[26] For purposes of the motion seeking clarification, "Customers" are CT PURA, MA AG and EMCOS.

Comments on this filing were due on or before July 19. On July 17, Public Citizen (which had already doc-less intervened) protested the filing, asserting that the FERC must order the filing deficient for its failure to provide, and should order ISO-NE to provide, intervenors with a proposed non-disclosure certificate to access the privileged components of this filing. Doc-less interventions were filed by NEPOOL, Dominion, Eversource, Exelon, National Grid, NESCOE, and NRG. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Transmission Rate Incentive Request: UI's Pequonnock Substation Project (ER19-1359)**

Rehearing of the FERC's May 14, 2019 order granting two of the three transmission rate incentives[27] requested by UI in connection with its Pequonnock Substation Project[28] is pending. As previously reported, the FERC granted both the requested Abandoned Plant Incentive[29] and the CWIP Incentive,[30] but denied UI's request for an ROE Incentive Adder.[31] In denying the ROE Incentive Adder request, the FERC agreed with State Parties[32] and found that (i) the smart grid technology that UI plans to use for the Project was not sufficiently novel or innovative to satisfy the required showing under the FERC's 2012 Policy Statement and (ii) its "hardened resilient design" was a conventional design, and did not demonstrate risks and challenges not otherwise accounted for in UI's base ROE or addressed through risk-reducing incentives.[33] The incentives granted were granted under *Order 679*. In response to the procedural arguments challenging Public Citizen's intervention, the FERC found that "good cause exists to grant Public Citizen's motion to intervene, based on Public Citizen's representations".[34] The FERC accepted the Abandoned Plant and CWIP Incentives effective as of May 15, 2019.

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[27] Pursuant to section 219 of the FPA, the FERC, in *Order 679*, set forth processes by which a public utility may seek incentive-based rate treatments to promote capital investment in certain transmission infrastructure. Incentive rate treatment is available to applicants that show that the facilities for which incentives are sought "either ensure reliability or reduce the cost of delivered power by reducing transmission congestion." There is a rebuttable presumption that the showing has been made if: (1) the transmission project results from a fair and open regional planning process that considers and evaluates the project for reliability and/or congestion and is found to be acceptable to the FERC; or (2) a project has received construction approval from an appropriate state commission or state siting authority. The FERC a project-specific demonstration of the nexus between the requested incentives and the risks and challenges of the project. In November 2012, the FERC issued the 2012 Policy Statement providing additional guidance regarding its evaluation of applications for transmission rate incentives under section 219 and *Order 679*.

[28] *United Illuminating Co.*, 167 FERC ¶ 61,126 (May 14, 2019) ("*UI Pequonnock Rate Incentive Order*"). As previously reported, UI's Pequonnock Substation Project will replace the existing Pequonnock substation and will include (1) a new 115-kV/13.8-kV gas insulated substation; (2) the relocation and installation of five existing 115-kV overhead transmission lines including seventeen new galvanized steel monopole structures (ten single circuit, two double circuit, and five "walk down" 11 structures); and 3) the relocation and installation of two 115-kV underground high-pressure gas filled cables and one underground XLPE cable, each ranging in length from about 500 to 730 feet. The Pequonnock Substation Project is approximately a $101.6 million electric transmission investment and is expected to be placed in service on or before Dec. 1, 2022.

[29] 100% recovery of prudently incurred costs in the event the Pequonnock Substation Project is abandoned, in whole or in part, for reasons outside of UI's reasonable control.

[30] Inclusion of 100% of Construction Work in Progress ("CWIP") in rate base.

[31] The ROE Incentive Adder would have been a 50 basis point return on common equity for increased risks and challenges prompted by UI's deployment of smart grid communications-enabled technology and construction and operation of a substation that includes a resilient design. The FERC also declined to grant the ROE Incentive Adder under its section 205 authority (which it has previously held it can do under certain circumstances, such as to promote important public policy goals. *See, e.g., Transource Wisconsin, LLC*, 149 FERC ¶ 61,180, at PP 16, 19 (2014)), finding that UI had not demonstrated that the circumstances under which such action could be taken (e.g. to promote important public policy goals) were present in this case.

[32] "State Parties" are: the MA AG, CT AG, CT DEEP, CT PURA, and the CT OCC.

[33] *UI Pequonnock Rate Incentive Order* at PP 63-64.

[34] Citing prior FERC precedent where the FERC previously allowed Public Citizen to cure a deficient motion to intervene in an answer by stating its members' interest in the proceedings and public interest role. *See Southwest Airlines Co. v. Colonial Pipeline Co.*, 166 FERC ¶ 61,094, at PP 10, 16 (2019).

UI requested rehearing of the *UI Pequonnock Rate Incentive Order o*n June 14, 2019, and focused specifically on the FERC's denial of the request for an ROE Incentive Adder. On July 15, the FERC issued a tolling order affording it additional time to consider UI's request, which remains pending. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCA13 Results Filing (ER19-1166)**

On March 1, ISO-NE filed the results of the thirteenth FCA ("FCA13") held February 4, 2019. ISO-NE reported the following highlights:

- FCA13 Capacity Zones were the Southeastern New England ("SENE") Capacity Zone (the Northeastern Massachusetts ("NEMA")/Boston, Southeastern Massachusetts, and Rhode Island Load Zones), the Northern New England ("NNE") Capacity Zone (the Maine, New Hampshire and Vermont Load Zones) and the Rest-of-Pool Capacity Zone (the Connecticut and Western/Central Massachusetts Load Zones).
- FCA13 commenced with a starting price of $13.050/kW-mo. and concluded for the SENE, NNE and Rest-of-Pool after four rounds.
- Resources will be paid as follows:
  - $3.800/kW-mo. – all Capacity Zones
  - $3.800/kW-mo. – NY AC Ties imports (522 MW) and Highgate (57 MW)
  - $3.800/kW-mo. – Phase I/II HQ Excess external interface (431 MW)
  - $2.681/kW-mo. – New Brunswick imports (184 MW).
- The substitution auction resulted in a single clearing price of $0.000 for all Capacity Zones. No demand bids cleared that were priced below the substitution auction clearing price.
- No resources cleared as Conditional Qualified New Generating Capacity Resources.
- No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource.
- No de-list bids were rejected for reliability reasons.

ISO-NE asked the FERC to accept the FCA13 rates and results, effective June 28, 2019. Comments on this filing were due on or before April 12, 2019.

Protests to the FCA13 Results filing were filed by ***Capacity Suppliers*** (concerned that the IMM failed to properly apply the procedures and standards for setting below-ORTP offer floors, particularly for the Killingly Energy Center ("Killingly")),[35] ***MA AG*** (suggesting the justness and reasonableness of the rates were open to question due to Vineyard Wind's inability to participate in FCA13 under the RTR exemption because the FERC failed to act on Vineyard Wind's Petition for Waiver in ER19-570), ***Vineyard Wind*** (similarly asserting that its preclusion from participation as an RTR caused the results to be not just and reasonable, unduly discriminatory and preferential), and ***Public Citizen*** (suggesting the FCA13 results are unjust and unreasonable because of the FERC's failure to act on the Vineyard Wind waiver request, the FERC's failure to take action in response to the EE M&V Declaratory Order Petition, and the failure of CASPR to deliver lower-priced capacity for New England ratepayers). ***NEGPA*** and ***Calpine*** submitted comments (neither specifically challenging the FCA13 results, but NEPGA asking the FERC find the FCA13 Results Filing deficient in that it did not include testimony from the IMM explaining the impact, if any, ISO-NE's administrative actions had on the competitiveness of the FCA13 results, and Calpine identifying a concern that the results suggest there is a systemic problem with the FCM rules, including the financial assurance requirements applicable to new resources). NEPOOL, Avangrid Renewables, Calpine, Dominion, Dynegy/Vistra, Eversource, Exelon, FirstLight, National Grid, NESCOE, NextEra, PSEG, CT AG, CT OCC, CT DEEP, EPSA, Helix Maine Wind Development, Sierra

[35] "Capacity Suppliers" for purposes of this proceeding are: Great River Hydro, NRG Power Marketing, Cogentrix Energy Power Management, and Vistra Energy Corp.

Club, and Public Citizen filed doc-less interventions. On April 29, ISO-NE and the ISO-NE IMM filed answers to the protests and comments submitted. On May 7, Vineyard Wind answered ISO-NE's April 29 answer. On May 10, Clean Energy Advocates[36] answered Vineyard Wind's May 7 answer and other comments submitted in the proceeding. Answers and additional comments were also subsequently filed by Mitsubishi Hitachi Power Systems Americas ("MHPS") (responding specifically to certain statements made about MHPS's turbine technology in the Niemann Affidavit and corresponding statements in Capacity Suppliers' comments) NEPGA and Capacity Suppliers (each answering ISO-NE and the IMM's answers).

Supplement Regarding Failure to Publish Disaggregated Quantity Information. On May 24, ISO-NE submitted supplemental information for the record. In that submission, ISO-NE indicated that, contrary to its Tariff requirements, the auction software used to conduct FCA13 did not publish the disaggregated quantity of capacity from Demand Capacity Resources by type at the End-of-Round Price for each Capacity Zone ("Disaggregated Quantity Information") during FCA 13.[37] ISO-NE stated that the Disaggregated Quantity Information publication requirement was instituted with the original FCM construct to provide capacity suppliers with active demand resources (i.e., Real-Time Demand Resources ("RTDR") and Real-Time Emergency Generation ("RTEG")) with data to help inform their continued participation in a FCA. With the June 1, 2018 removal of RTDR and RTEG as demand resource types, ISO-NE stated that "there appears to be no rationale for posting" Disaggregated Quantity Information, but acknowledged that the Tariff language had not been removed. ISO-NE hypothesized that "that the omission of the information [during FCA13] had no effect on the auction outcome and that no Market Participant incurred financial harm from the omission of the information." ISO-NE stated that it intends, following discussion with NEPOOL, to make a filing deleting from the Tariff the Disaggregated Quantity Information publication requirement. ISO-NE asked the FERC to accept the FCA13 filing, as supplemented.

June 6, 2019 Deficiency Letter. As previously reported, the FERC issued a first deficiency letter indicating that the filing did not provide sufficient detail to enable the FERC to process the filing. The letter directed ISO-NE to submit specified information regarding Killingly's bid and bid review. ISO-NE's responses to the questions were due on or before July 8, 2019. ISO-NE submitted its responses on June 28. ISO-NE's responses included (i) the confidential data and information upon which ISO-NE's IMM relied in reviewing the Killingly requested offer floor price; (ii) explanations of, and reasoning for, adjustments made by the IMM to Killingly's submitted input and assumption values; and (iii) all other information that the IMM used to support its determination regarding Killingly's offer floor price. Comments on the June 28 responses were due on or before July 19. On July 9, the EMM submitted privileged comments on the IMM's review and mitigation of Killingly's FCA13 Offer Floor Price. On July 18, the EMM submitted redacted comments. Capacity Suppliers responded to the EMM's comments on July 19. This matter is again pending before the FERC.

July 25, 2019 Deficiency Letter. On July 25 the FERC issued a second deficiency letter in this proceeding indicating that the filing was "deficient insofar as it does not include a proposed form of a Non-Disclosure Agreement." ISO-NE was directed to submit that form to the FERC and each entity on the Commission's service list. The ISO submitted that form on July 26, re-setting the 60-day clock for FERC action on this filing.

If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[36] "Clean Energy Advocates" are Sierra Club, CLF and Acadia Center.

[37] Tariff Sections III.13.2.3.3(a), (b) and (c) require (in a non-final round) that the "auctioneer shall publish the quantity of capacity in the Capacity Zone from Demand Capacity Resources by type at the End-of-Round Price".

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

As previously reported, on December 20, 2018, in a 2-1 decision (Commissioner Glick dissenting; Commissioner McIntyre not voting; Commissioner McNamee not participating), which followed an evidentiary proceeding and two rounds of briefing, the FERC conditionally accepted the Cost-of-Service Agreement ("COS Agreement")[38] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE.[39] The COS Agreement will provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. The *Mystic Order* directed Mystic to submit a compliance filing (intended to modify aspects of the COS Agreement that FERC rejected or directed be changed) on or before February 18, 2019, and established a paper hearing to ascertain whether and how the ROE methodology that FERC proposed in *Coakley* should apply in the case. Initial briefs on the ROE issue are due on or before April 19, 2019, and reply briefs are due on or before July 18, 2019.[40] Requests for clarification and/or rehearing of the *Mystic Order* were filed by Constellation Mystic Power, CT Parties, EDF, ENECOS, MA AG, NESCOE, NextEra, and Repsol. On February 6, Constellation answered the other parties' requests for rehearing. CT Parties answered Constellation's request for rehearing on February 8. On February 14, NESCOE answered Constellation's February 6 answer. On February 15, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending.

Mystic's Compliance Filing. On March 1, following a 10-day extension of time granted on February 14, 2019, Mystic submitted its required compliance filing. The compliance filing included the following modifications:

- Modification to Section 2.2 (Termination) which provides ISO-NE will be required to seek FERC authorization to extend the term of the COS Agreement beyond May 31, 2024; deletion of Section 2.2.1 in its entirety;
- Inclusion of a clawback provision;
- Modification to Section 4.4 related to settlement of over- and underperformance credits;
- A clarification that fuel opportunity costs will not be included as part of the Stipulated Variable Costs used to calculate the revenue credits;
- Modifications to information access provisions (§ 6.2) both to allow ISO-NE full access to information and to support verification of third-party sales;
- Modifications to Schedule 3 supporting multiple compensation-related directives (e.g. cost of capital/cost of service, fuel supply charge, settlement of over- and under-performance credits);
- Schedule 3A modifications related to Mystic's true-up process; and
- Non-substantive conforming changes.

In addition, Mystic's compliance filing included for informational purposes changes to the Fuel Supply and Terminal Services Agreements. Comments on Mystic's compliance filing were due on or before March 22, 2019. Protests and comments were filed by CT Parties, ENECOS, MA AG, National Grid, Public Systems (MMWEC/NHEC), and NESCOE. Mystic answered the March 22 protests on April 8. Also, on March 22, Concord, Reading and Wellesley moved for the release from Protective Order a documentary response regarding the net book value of

[38] The COS Agreement, submitted on May 16, 2018, is between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE. The COS Agreement is to provide cost-of-service compensation to Mystic for continued operation of Mystic 8 & 9, which ISO-NE has requested be retained to ensure fuel security for the New England region, for the period of June 1, 2022 to May 31, 2024. The COS Agreement provides for recovery of Mystic's fixed and variable costs of operating Mystic 8 & 9 over the 2-year term of the Agreement, which is based on the pro forma cost-of-service agreement contained in Appendix I to Market Rule 1, modified and updated to address Mystic's unique circumstances, including the value placed on continued sourcing of fuel from the Distrigas liquefied natural gas ("LNG") facility, and on the continued provision of surplus LNG from Distrigas to third parties.

[39] *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Mystic Order*").

[40] *Id.* at PP 31-34.

Mystic 8 and 9 from the 2006 Mystic 8/9 RMR proceeding (ER06-427). Mystic's compliance filing and the pleadings related thereto remain pending before the FERC.

ROE Paper Hearing. The *Mystic Order* established a paper hearing to determine the just and reasonable ROE to be used in setting charges under Mystic's COS Agreement. On April 19, Mystic, Connecticut Parties, ENECOS, MA AG, and FERC Trial Staff filed initial briefs. On July 18, Constellation Mystic Power, CT Parties, ENECOS, MA AG, National Grid, FERC Trial Staff filed reply briefs. The ROE Paper Hearing is now pending before the FERC.

July Mystic COS Agreement Order. Rehearing remains pending of the FERC's July order. As previously reported, the FERC issued an initial order regarding the COS Agreement, accepting the COS Agreement but suspending its effectiveness and setting it for accelerated hearings and settlement discussions.[41] The *Mystic COS Agreement Order* was approved by a 3-2 vote, with dissents by Commissioners Powelson and Glick. Challenges to the *July Mystic COS Agreement Order* were filed by NESCOE, ENECOS, MA AG, and the NH PUC. Constellation answered the NESCOE request for reconsideration on August 21. On September 10, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have questions on this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com); or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **MPD OATT 2019 Annual Informational Filing (ER15-1429-000)**

On May 1, 2019, as corrected by its filing on May 16, 2019, Emera Maine submitted its 2019 annual informational filing setting forth, for the June 1, 2019 to May 31, 2020 rate year, the charges for transmission service under the MPD OATT ("MPD Charges") and an updated transmission real power loss factor. Although this filing and the May 16 correction were not noticed for public comment, it will nevertheless be subject to the process established in the "Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas" and may result in further proceedings (*see, e.g.*, ER15-1429-010 below). On June 11, Maine Customer Group ("MCG") moved to strike a portion of Emera Maine's May 1 filing. Specifically, MCG moved to strike the trueup to actuals portion of Emera's Annual Update filing to the extent that true-up proposes a change in the formula rate from a direct assignment of Maine Public District ("MPD") post- retirement benefits other than pensions ("PBOPs") to an allocation of company-wide PBOPs (which MCG argued would be a retroactive change to Emera Maine's formula rate, otherwise required to effect only prospectively). On June 26, Emera Maine answered MCG's June 11 motion to strike. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **MPD OATT 2018 Annual Informational Filing (ER15-1429-010)**

As previously reported, the FERC granted, in part, on April 30, 2019, the formal challenge filed on December 31, 2018 by the Maine Customer Group[42] (the "2018 Challenge") to Emera Maine's May 15, 2018 annual informational filing[43]and set the remaining issues for hearing and settlement judge procedures.[44] As previously reported, the 2018 Challenge sought certain cost reductions/ exclusions[45] to be effective June 1,

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[41] *Constellation Mystic Power,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July Mystic COS Agreement Order*"), *reh'g requested*.

[42] For purposes of this proceeding, "Maine Customer Group" or "MCG" is the MPUC, MOPA, Houlton Water Co., and Van Buren Light & Power District, and Eastern Maine Electric Cooperative.

[43] The May 15 filing, submitted in accordance with the Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas ("Protocols"), set forth for the June 1, 2018 to May 31, 2019 rate year, the charges for transmission service under the MPD OATT ("MPD Charges"). *See* May 31, 2018 Litigation Report.

[44] *Emera Maine*, 167 FERC ¶ 61,090 (Apr. 30, 2019) ("*2018 Challenge Order*").

[45] The formal challenge sought (i) exclusion of certain regulatory expenses allocated or directly assigned to the MPD transmission customers; (ii) exclusion of costs that would otherwise constitute a double-recovery for amortization of losses incurred as a result of a

2018 following unsuccessful efforts to obtain the relief sought directly from Emera Maine MPD through informal resolution procedures in accordance with the Protocols. In granting in part the 2018 Challenge, the FERC found that Emera Maine's formula rate should be corrected for the current rate year and Emera Maine must submit a compliance filing on or before May 30 that revises its 2018-2019 formula rate charges to correct certain acknowledged errors, exclusion of certain costs for land associated with a project not in service, the exclusion of certain costs for distribution equipment from transmission rates, and the flowback of excess ADIT. As to the remaining issues, addressing Administrative and General ("A&G") expenses, merger-related prior losses, exclusion of costs attributed to Line 6901, and exclusion of land rights cost, the FERC found that the 2018 Annual Update raises issues of material fact that cannot be resolved based on the record and set those issues for hearing and settlement judge procedures. Hearings will be held in abeyance to provide time for settlement judge procedures.

Settlement Judge Procedures. Chief Judge Cintron designated John P. Dring as the Settlement Judge for these proceedings. Judge Dring held a first settlement conference on July 18, 2019 and has scheduled a second settlement conference for September 11, 2019. On July 29, Judge Dring issued a second status report recommending that settlement procedures be continued.

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

- **MPD OATT 2018 Annual Info Compliance Filing (ER15-1429-011)**

On May 16, 2019, Emera Maine submitted a filing in response to the requirements of the *2018 Challenge Order* that revises the MPD 2018-19 formula rate charges to correct three errors raised by Maine Customer Group. Emera Maine stated that it calculated refunds due to wholesale (both network and point-to-point) customers as a result of these corrections and will issue such refunds, with interest, to those customers by May 31, 2019. As for the $46,095 plus interest refund to retail customers, Emera Maine asked for a waiver of the need to issue direct refunds to each of its retail customers and in lieu of such direct refunds, reduced the retail annual transmission revenue requirement for 2019-2020. With respect to excess accumulated deferred income tax ("ADIT") issues, Emera Maine stated that no changes or adjustments were needed to charges levied under the MPD OATT for the June 1, 2018 to May 31, 2019 rate year. On May 22, MCG protested the compliance filing for Emera Maine's failure to provide for flowback to customers of excess ADIT effective June 1, 2018. MCG requested that the FERC order Emera to adjust and re-file its Compliance Filing so as to effectuate what it described as "the Commission's clear mandate that flowback of excess ADIT should be made effective June 1, 2018." On June 7, Emera Maine answered MCG's May 22 protest. MCG submitted a brief reply to that answer on June 14, which Emera Maine answered on June 24. This matter is pending before the FERC.

- **TOs' *Opinion 531-A* Compliance Filing Undo (ER15-414)**

Rehearing remains pending of the FERC's October 6, 2017 order rejecting the TOs' June 5, 2017 filing in this proceeding.[46] As previously reported, the June 5 filing was designed to reinstate TOs' transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[47] decision. In its *Order Rejecting Filing*, the FERC required the TOs to continue collecting their ROEs currently on file, subject to a future FERC order.[48] The FERC explained that it will "order such refunds or surcharges as necessary to

merger; (iii) correction of MPD-acknowledged errors in its Annual Update Filing; (iv) exclusion of certain costs for land associated with a project not in service; (v) exclusion from transmission rates certain costs for distribution equipment; (vi) exclude of costs improperly attributed to line 6901; and (vii) a flowback of excess ADIT resulting from the corporate tax reduction, and a requirement for Emera MPD to include a worksheet in its tariff to track excess/deficient ADIT.

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

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

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

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.[49] On November 6, the TOs requested rehearing of the *Order Rejecting Filing*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider the TOs' request for rehearing of the *Order Rejecting Filing*, which remains pending. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **Nested Capacity Zone Changes (ER19-2421)**

On July 18, ISO-NE and NEPOOL jointly filed changes to (i) accommodate a nested export-constrained Capacity Zone in the FCM and (ii) to clarify the type of data that Market Participants must submit in support of Static De-List Bids and Export Bids ("Nested Capacity Zone Changes"). The Nested Capacity Zone Changes were supported by the Participants Committee at its June 25 Summer Meeting (Agenda Item #4). An October 1, 2019 effective date was requested. Comments on this are due on or before August 8, 2019. Thus far, doc-less interventions have been filed by Eversource, Exelon and NESCOE. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Monthly BoPP FTR Auctions Effective Date Notice and Conforming Market Rule Changes (ER19-2327)**

On July 1, ISO-NE and NEPOOL jointly filed (i) a notice that the effective date for monthly Balance of Planning Period ("BoPP") Financial Transmission Rights ("FTR") Auctions will be September 17, 2019[50] and (ii) supporting Market Rule changes, also to be effective September 17, 2019, that provide that *all* monthly FTR Auctions[51] be conducted using the same network model -- the updated version available as of the auction assumptions posting that occurs no later than 40 days prior to the first day of the prompt–month. The Effective Date notice for BoPP monthly auctions was provided in accordance with the FERC's August 23, 2012 order that permitted monthly BoPP auctions to become effective upon 2 weeks' subsequent notice.[52] The supporting Market Rule changes were supported by the Participants Committee at its November 3, 2017 meeting (Consent Agenda Item # 4). Comments on this filing were due on or before July 22, 2019; none were filed. Doc-less interventions were filed by DC Energy, Exelon, National Grid, and NRG. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **DAM Offer Cap Changes (ER19-2137)**

On June 14, ISO-NE and NEPOOL jointly filed Tariff changes to revise the dispatch treatment of resources whose Supply Offers are price-capped in the Day-Ahead Energy Market ("DAM"), to become effective March 1,

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[49] *Id.* at P 36.

[50] *See ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER12-2122 et al. (Aug. 23, 2012) (unpublished letter order).

[51] (both "prompt-month" and BoPP auctions).

[52] The Market Rule changes that provide for Monthly BoPP FTR auctions were originally accepted in 2011. *See ISO New England Inc., NEPOOL Participants Comm. and Participating Trans. Owners Admin. Comm.*, Docket ER11-3568 (June 30, 2011) (unpublished letter order). Deferral of the effective date of the BoPP changes, to allow for the development of supporting financial assurance changes, was accepted in *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket Nos. ER12-2122 et al. (Aug. 23, 2012) (unpublished letter order). The supporting financial assurance changes were accepted, effective Sep. 17, 2019, in *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER18-2293 (Oct. 23, 2018) (unpublished letter order).

2020. In addition, ISO-NE further proposed to move the effective date for all of the *Order 831* Offer Cap revisions, including those previously accepted, from October 1, 2019 to March 1, 2020. The DAM Offer Cap Changes were supported by the Participants Committee at its May 3 meeting (Consent Agenda Item # 2). Comments on this filing were due on or before July 5, 2019; none were filed. Doc-less interventions were filed by Calpine, ConEd, Eversource, Exelon, National Grid, NESCOE, and NRG. 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).

- **ISO-NE's Interim Winter Energy Security (Chapter 2B) Proposal (ER19-1428)**

On March 25, ISO-NE filed its "Inventoried Energy Program" (a/k/a its "Chapter 2B Proposal") for the Winters of 2023-2024 and 2024-2025 (FCA14 and FCA15 Capacity Commitment Periods). ISO-NE stated that the "program will provide incremental compensation to resources that maintain inventoried energy during cold periods when winter energy security is most stressed" and "fulfills a commitment … to identify an interim solution that could complement efforts currently underway to develop a long-term, market-based solution to the region's energy security challenges." A May 28, 2019 effective date was requested. The changes were not supported by the Participants Committee when considered at its March 13 meeting. The ISO-NE Chapter 2B Proposal received a NEPOOL Vote of 32.67% in favor. Comments on this filing were due on or before April 15, 2019. Doc-less interventions were filed by NEPOOL, Avangrid, Calpine, ConEd, CT DEEP, CT OCC, Dominion, Energy New England ("ENE"), Eversource, Exelon, HQ US, LS Power (through Ocean State Power and Wallingford Energy), MA AG, MA DPU, NESCOE, NRG, Shell, Verso, American Petroleum Institute ("API"), EPSA, NH PUC, RENEW, Public Citizen, and Sierra Club.

On April 8, the IMM submitted comments which it stated were "focused on aspects related to administering the Tariff's mitigation rules in both the energy and capacity markets in light of the expected net revenue streams available to resources that elect to participate in the interim program, and on the timing for calculating the administratively-determined forward and spot prices. The IMM comments included the following suggestions:

- Energy market bids of resources that forego revenues from the interim program by converting inventoried energy into electric power should be subject to adjustment/mitigation to reflect such opportunity costs in their Supply Offers at the spot rate for inventoried energy
- Inclusion of opportunity costs of the interim program into energy market bids of participating energy-secure resources likely will impact the wholesale energy markets and result in (a) preserving energy-secure resources for when they are most valuable; (b) a reduced (or eliminated) need for manual intervention in dispatch to preserve fuel-secure resources until needed (so-called resource posturing which can result in price distortions); and (c) an increase in Day-Ahead and Real-Time energy market prices (i.e., LMPs) that directly reflect the value of the scarce fuel-secure energy.
- To the extent that a Participant expects to accrue positive net revenue from the interim program, a competitive De-List bid and New Supply Offer in the FCA would account for this positive revenue stream in the calculation of the resource's net Going Forward Costs, just like any ancillary service revenue, and result in a lower priced bid or offer to better reflect a competitive price to obtain a CSO.
- Failure to account for interim revenue in FCM mitigation potentially could result in the non-economic retirements of energy-secure resources as a result of higher, non-competitively priced bids.
- ISO-NE should factor into its interim proposal a mechanism for recalculating the forward and/or spot rates for inventoried energy closer to the time of procurement of fuel and delivery of inventoried capacity beginning in December 2023, in order to better ensure consistency with the cost of providing winter energy security.

Comments and protests on the Chapter 2B Proposal Filing were filed by: NEPOOL, Algonquin Gas Transmission, Brookfield, Calpine/Vistra, Exelon, MA AG, MPUC, NECOS/ENE/Direct, NEPGA, NRG, Repsol, Verso, API/NGSA/IPAA, Clean Energy Advocates, NH PUC/NH OCA, V DPS, VT DPU, and Public Citizen. Answers were filed by NEPOOL, ISO-NE and the IMM. On May 14, the MA AG answered ISO-NE's April 20 answer.

May 8 Deficiency Letter & ISO-NE Response (ER19-1428-001). On May 8, the FERC issued a deficiency letter requesting additional information in order to process ISO-NE's Chapter 2B Proposal. ISO-NE submitted its response and additional information in response to the deficiency letter on June 6, 2019. Comments on the ISO-NE responses were due on or before June 27, 2019, and were filed by Clean Energy Advocates, EDF, MA AG, MPUC,NECOS/Direct Energy Business, NEPGA, NRG, Verso, and Vistra.

This matter is again pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Waiver Request: Vineyard Wind FCA13 Participation (ER19-570)**

Vineyard Wind's December 14, 2018 petition for a waiver of the ISO-NE Tariff provisions necessary to allow Vineyard Wind to participate in FCA13 as a Renewable Technology Resource ("RTR") remains pending. As previously reported, Vineyard Wind's request for RTR designation was earlier rejected by ISO-NE on the basis that the resource is to be located in federal waters. Under the CASPR Conforming Changes, Vineyard Wind would not have been precluded from utilizing the RTR exemption. Consistent with the discussion in the CASPR Conforming Changes filing, Vineyard Wind asked that the proration requirement that would be triggered by Vineyard Wind's participation in FCA13 as an RTR be limited for FCA13 to it and any other similarly-situated entities (i.e. new offshore wind resources located in federal waters seeking RTR treatment); there would be no impact on resources currently qualified to use the RTR exemption in FCA13. Comments on Vineyard Wind's request were due on or before January 4, 2019. ISO-NE filed comments not opposing the Waiver Request, but requesting FERC action by January 29, 2019 if the waiver was to be effective for FCA13. NEPGA protested the Waiver Request. Answers to NEPGA's protest were filed by Vineyard Wind and NESCOE. On January 15, the Massachusetts Department of Energy Resources ("MA DOER") intervened out-of-time and submitted comments supporting the Waiver Request. Doc-less interventions were filed by NEPOOL, Avangrid, Dominion, ENE, National Grid, and NextEra.

On January 31, Vineyard Wind requested the immediate issuance of order on its request. Massachusetts Governor Baker submitted a request on February 1 that the FERC grant Vineyard Wind's waiver request that day. Also on February 1, ISO-NE reported at that say's Participants Committee meeting, and confirmed later that evening that, in the absence of a FERC order issued early that afternoon, it would proceed to run the auction without granting Vineyard Wind's MWs treatment under the RTR exemption. Early on February 4, Vineyard Wind submitted an emergency motion for immediate stay of FCA13 or, in the alternative, a requirement that FCA13 be re-run following FERC action. The FERC took no action ahead of FCA13 and FCA13 was run without Vineyard Wind receiving RTR treatment. Following FCA13, answers opposing Vineyard Wind's emergency motion were submitted by ISO-NE and NEPGA. A joint statement addressing the FERC's failure to act was issued by Commissioners LaFleur and Glick (to which Chairman Chatterjee responded via Twitter). The Massachusetts Attorney General filed a statement addressing the FERC's failure to act on February 13. On February 15, ISO-NE submitted a letter that addressed two concerns raised in Commissioner Glick's dissent from the *CASPR Conforming Changes Order.* On February 19, Vineyard Wind answered the NEPGA and ISO-NE protests to its motion to vacate and re-run FCA13 upon FERC approval of the waiver sought.

As noted, this matter remains pending before the FERC, with no activity since the last Report. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Order 841* Compliance Filing (ER19-470)**

On December 3, 2018, ISO-NE and NEPOOL jointly filed changes to Market Rule 1 and the OATT (and the PTO AC joined in the filing of the OATT revisions) in response to the requirements of *Order 841*.[53] For the majority of the revisions, ISO-NE requested a December 3, 2019 effective date; for a limited number of revisions, ISO-NE requested a January 1, 2024 effective date. The *Order 841* compliance changes were supported by the Participants Committee at its November 2, 2018 meeting. Following a request for a 45-day extension of time,[54] comments on this filing were due February 7, 2019. Doc-less interventions were filed by Exelon, LS Power, NESCOE, APPA, EPSA, NRECA, GlidePath Development, Lincoln Clean Energy, and Voith Hydro. Protests and comments were filed by Calpine, EDF Renewables, RENEW Northeast ("RENEW"), AEE, ESA, and Tesla. On February 22, NEPOOL, ISO-NE and NRECA filed answers to the comments and protests. On March 1, Voith Hydro submitted comments regarding advanced pumped storage hydro technology. On March 21, ESA filed an answer to ISO-NE's February 22 answer (requesting that the FERC require the issues with the redeclaration process to be resolved prior to December 3, 2019 implementation deadline).

ISO-NE Response to FERC Request for Additional Information (ER19-470-001). As previously reported, on April 1, 2019, the FERC issued a letter advising that additional information was necessary to process the compliance filing and directing that responses to the questions posed in the letter order be submitted on or before May 1, 2019. ISO-NE filed additional information and Tariff changes in response to that letter order on May 1, 2019. The Tariff changes included in the ISO-NE March 1 response were supported by the Participants Committee at its May 3 meeting (Agenda Item #7). Comments on the ISO-NE responses were due on or before May 22, 2019 and were filed by ***NEPOOL*** (reporting that, while it did not vote on the May 1 responses themselves, it did unanimously support the clarifying changes to the ISO-NE Tariff, and requesting that the FERC approve those changes and allow any additional implementation details to be worked through the Participants Processes) and ***AEE*** (which, reiterating its initial comments, stated that ISO-NE did not demonstrate that its metering and accounting practices will ensure that all energy storage resources ("ESR") can participate in the New England Markets and not be subject to inaccurate charges. AEE also challenged ISO-NE's limitation of ESR aggregations to a single point of interconnection).

This matter is again before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Fuel Security Retention Proposal (ER18-2364)**

Requests for rehearing and/or clarification of the *Fuel Security Retention Proposal Order*[55] remain pending before the FERC. As previously reported, the *Fuel Security Retention Proposal Order* accepted ISO-NE's Proposal[56]

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[53] *See Elec. Storage Participation in Mkts. Operated by Regional Transmission Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*").

[54] The request for an extension of the previously noticed Dec. 24 comment deadline was requested by the Energy Storage Association ("ESA") and by a group comprised of Advanced Energy Economy ("AEE"), American Wind Energy Association ("AWEA"), Solar Energy Industries Association ("SEIA"), Solar RTO Coalition, and The Wind Coalition. The request was supported by the Acadia Center, NRDC, UCS, and the Sierra Club Environmental Law Program ("Public Interest Organizations").

[55] *ISO New England Inc.*, 165 FERC ¶ 61,202 (Dec. 3, 2018), *reh'g requested* ("*Fuel Security Retention Proposal Order*"). In accepting the ISO-NE Proposal, the FERC, among other things: (i) found ISO-NE's trigger and assumptions for the fuel security reliability review for retention of resources be reasonable, but required ISO-NE at the end of each winter to "to submit an informational filing comparing the study assumptions and triggers from the modeling analysis to actual conditions experienced in the winter of 2018/19; (ii) found cost allocation on a regional basis to Real-Time Load Obligation just and reasonable and consistent with precedent regarding the past Winter Reliability Programs; (iii) found that entering retained resources into the FCAs as price takers would be just and reasonable to ensure that they clear and are counted towards resource adequacy so that customers do not pay twice for the resource; and (Iv) found that it was appropriate to include FCAs 13, 14 and 15 in the term. The FERC agreed that it is necessary to implement a longer-term market solution as soon as possible, and required ISO-NE to file its longer-term market solution no later than June 1, 2019. The FERC declined to provide guidance on what the long-term solution(s) should be.

[56] As previously reported, ISO-NE filed, in response to the *Mystic Waiver Order*, "interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns". ISO-NE proposed three sets of provisions to

in all respects, despite the various protests and alternative proposals filed. There was a concurring decision from Commissioner Glick, and a partial dissent from Chairman Chatterjee on the FCA price treatment issue. Challenges to the *Fuel Security Retention Proposal Order* were filed by NEPGA, NRG, Verso, Vistra/Dynegy Marketing & Trade, MPUC, and PIOs.[57] On February 1, 2019, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have further questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Economic Life Determination Revisions (ER18-1770)**

Rehearing of the FERC's November 9 order,[58] accepting the revised Tariff language that changed the determination of economic life under Section III.13.1.2.3.2.1.2.C of the Tariff, remains pending before the FERC. As previously reported, the Economic Life Revisions provide that the economic life of an Existing Capacity Resource is calculated as the evaluation period in which the net present value of the resource's expected future profit is maximized. The Economic Life Revisions were accepted effective as of August 10, 2018, as requested. In accepting the revisions, the FERC found that "it is just and reasonable to consider as part of the Economic Life calculation that a rational resource, in exercising competitive bidding behavior, would seek to exit the market, or retire, before it starts incurring consecutive losses."[59] The FERC found, contrary to NEPGA's assertions, that the "Economic Life Revisions do not represent a violation of the filed rate doctrine or constitute retroactive ratemaking."[60] Further, while the FERC was "mindful of the importance of not disrupting settled expectations based on existing market rules," the FERC concluded "that under these specific facts, the benefits of the proposed Economic Life Revisions outweigh potential disruptions to market participants' settled expectations and harm caused by reliance on the existing FCM rules."[61] On December 10, 2018, NEPGA requested rehearing of the *Economic Life Determination Revisions Order*. On January 8, 2019, the FERC issued a tolling order affording it additional time to consider NEPGA's request for rehearing, which remains pending. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509; EL18-182)**

On July 2, 2018, the FERC issued an order[62] that (i) denied ISO-NE's request for waiver of certain Tariff provisions that would have permitted ISO-NE to retain Mystic 8 & 9 for fuel security purposes (ER18-1509); and (ii) instituted an FPA Section 206 proceeding (EL18-182) (having preliminarily found that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022). The *Mystic Waiver Order* required ISO-NE, on or before August 31, 2018 to either: (a) submit interim Tariff revisions that provide for the filing of a short-term, cost-

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expand its authority on a short-term basis to enter into out-of-market arrangements in order to provide greater assurance of fuel security during winter months in New England (collectively, the "Fuel Security Retention Proposal"). ISO-NE stated that the interim provisions would sunset after FCA15, with a longer-term market solution to be filed by July 1, 2019, as directed in the *Mystic Waiver Order*. In addition, the ISO-NE transmittal letter described (i) the generally-applicable fuel security reliability review standard that will be used to determine whether a retiring generating resource is needed for fuel security reliability reasons; (ii) the proposed cost allocation methodology (Real-Time Load Obligation, though ISO-NE indicated an ability to implement NEPOOL's alternative allocation methodology if determined appropriate by the FERC); and (iii) the proposed treatment in the FCA of a retiring generator needed for fuel security reasons that elects to remain in service. The ISO-NE Fuel Security Changes were considered but not supported by the Participants Committee at its August 24, 2018 meeting. There was, however, super-majority support for (1) the Appendix L Proposal with some important adjustments to make that proposal more responsive to the FERC's guidance in the Mystic Waiver Order and other FERC precedent, and (2) the PP-10 Revisions, also with important adjustments (together, the "NEPOOL Alternative").

[57] "PIOs" for purposes of this proceeding are Sierra Club, NRDC, Sustainable FERC Project, and Acadia Center.

[58] *ISO New England Inc. and New England Power Pool Participants Comm.*, 165 FERC ¶ 61,088 (Nov. 9, 2018) ("*Economic Life Determination Revisions Order*").

[59] *Economic Life Determination Revisions Order* at P 23.

[60] *Id.* at P 24.

[61] *Id.* at P 27.

[62] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

of-service agreement (COS Agreement) to address demonstrated fuel security concerns (and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns "Chapter 3 Proposal"); or (b) show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both of Tariff revisions filings is not necessary.

Addressing the waiver element, the FERC found the waiver request "an inappropriate vehicle for allowing Mystic 8 and 9 to submit a [COS Agreement] in response to the identified fuel security need" and further that the request "would not only suspend tariff provisions but also alter the existing conditions upon which a market participant could enter into a [COS Agreement] (for a transmission constraint that impacts reliability) and allow for an entirely new basis (for fuel security concerns that impact reliability) to enter into such an agreement." The FERC concluded that "[s]uch new processes may not be effectuated by a waiver of the ISO-NE Tariff; they must be filed as proposed tariff provisions under FPA section 205(d)."[63] Even if it were inclined to apply its waiver criteria, the FERC stated that it would still have denied the waiver request as "not sufficiently limited in scope."[64]

Although it denied the waiver request, the FERC was persuaded that the record supported "the conclusion that, due largely to fuel security concerns, the retirement of Mystic 8 and 9 may cause ISO-NE to violate NERC reliability criteria." Finding ISO-NE's methodology and assumptions in the Operational Fuel-Security Analysis ("OFSA") and Mystic Retirement Studies reasonable, the FERC directed the filing of both interim and permanent Tariff revisions to address fuel security concerns (or a filing showing why such revisions are not necessary).[65] The FERC directed ISO-NE to consider the possibility that a resource owner may need to decide, prior to receiving approval of a COS Agreement, whether to unconditionally retire, and provided examples of how to address that possibility.[66] The FERC also directed ISO-NE include with any proposed Tariff revisions a mechanism that addresses how cost-of-service-retained resources would be treated in the FCM[67] and an *ex ante* cost allocation proposal that appropriately identifies beneficiaries and adheres to FERC cost causation precedent.[68]

Requests for Rehearing and or Clarification. The following requests for rehearing and or clarification of the *Mystic Waiver Order* remain pending before the FERC:

- ***NEPGA*** (requesting that the FERC grant clarification that it directed, or on rehearing direct, ISO-NE to adopt a mechanism that prohibits the re-pricing of Fuel Security Resources in the FCA at $0/kW-mo. or at any other uncompetitive offer price);
- ***Connecticut Parties***[69] (requesting that the FERC clarify that (i) the discussion in the *Mystic Waiver Order* of pricing treatment in the FCM for fuel security reliability resources is not a final determination nor is it intended to establish FERC policy; (ii) the FERC did not intend to prejudge whether entering those resources in the FCM as price takers would be just and reasonable; and (iii) that ISO-NE may confirm its submitted position that price taking treatment for these resources would, in fact, be a just and reasonable outcome. Failing such clarification, Connecticut Parties request rehearing, asserting that the record fails to support a determination that resources retained for reliability to address fuel security concerns must be entered into the FCM at a price greater than zero);

[63] *Id.* at P 47.

[64] *Id.* at P 48.

[65] *Id.* at P 55.

[66] *Id.* at PP 56-57.

[67] *Id.* at P 57.

[68] *Id.* at P 58.

[69] "Connecticut Parties" are the Conn. Pub. Utils. Regulatory Authority ("CT PURA") and the Conn. Dept. of Energy and Environ. Protection ("CT DEEP").

- ***ENECOS*** (asserting that the *Mystic Waiver Order* (i) misplaces reliance on ISO-NE "assertions concerning 'fuel security,' which do not in fact establish a basis in evidence or logic for initiating" a Section 206(a) proceeding; (ii) impermissibly relies on extra-record material that the FERC did not actually review and that intervenors were afforded no meaningful opportunity to challenge; and (iii) speculation concerning potential future modifications to the FCM bidding rules as to retiring generation retained for fuel security misunderstands the problem it seeks to address, and prejudices the already truncated opportunities for stakeholder input in this proceeding), ENECOS suggest that the FERC should grant rehearing, vacate its show cause directive, strike its dictum concerning potential treatment of FCM bidding for retiring generation retained for "fuel security," and direct ISO-NE to proceed either in accordance with its Tariff or under FPA Section 205 to address, with appropriate evidentiary support, whatever concerns it believes to exist concerning "fuel security");
- ***MA AG*** (asserting that the decision to institute a Section 206 proceeding was insufficiently supported by sole reliance on highly contested OFSA and Mystic Retirement Studies; and the FERC should reconsider the timeline for the permanent tariff solution and set the deadline for implementation no later than February 2020);
- ***MPUC*** (challenging the Order's (i) adoption of ISO-NE's methodology and assumptions in the OFSA and Mystic Retirement Studies without undertaking any independent analysis; (ii) failure to address arguments and analysis challenging assumptions in the OFSA and Mystic Retirement Studies; (iii) failure to address the MPUC argument that the Mystic Retirement Studies adopted a completely new standard for determining a reliability problem three years in advance; (iv) unreasonably discounting of the ability of Pay-for-Performance to provide sufficient incentives to Market Participants to ensure their performance under stressed system conditions; and (v) failure to direct ISO-NE to undertake a Transmission Security Analysis consistent with the provisions in the Tariff);
- ***New England EDCs***[70] (requesting clarification that (i) the central purpose of ISO-NE's July 1, 2019 filing is to assure that New England adds needed new infrastructure to address the fuel supply shortfalls and associated threats to electric reliability that ISO-NE identified in its OFSA and (ii) that, in developing the July 1, 2019 filing, ISO-NE is to evaluate Tariff revisions (such as those the EDCs described in their request), through which ISO-NE customers would pay for the costs of natural gas pipeline capacity additions via rates under the ISO-NE Tariff);
- ***PIOs***[71] (asserting that (i) the FERC failed to respond to or provide a reasoned explanation for rejecting the arguments submitted by numerous parties that key assumptions underlying and the results of the ISO-NE analyses were flawed; and (ii) the FERC's determination that ISO-NE's analyses were reasonable is not supported by substantial evidence in the record); and
- ***AWEA/NGSA*** (asserting that the FERC erred (i) in finding that ISO-NE's OFSA and subsequent impact analysis of fuel security was reasonable without further examination and (ii) in its preliminary finding that a short-term out-of-market solution to keep Mystic 8 & 9 in operation is needed to address fuel security issues).

On August 13, 2018, CT Parties opposed the NEPGA motion for clarification. On August 14, NEPOOL filed a limited response to Indicated New England EDCs, requesting that the FERC "reject the relief sought in [their motion] to the extent that relief would bypass or predetermine the outcome of the stakeholder process, without prejudice to [them] refiling their proposal, if appropriate, following its full consideration in the stakeholder process." Answers to the Indicated New England EDCs were also filed by the MA AG, NEPGA, NextEra, and CLF/NRDC/Sierra Club/Sustainable FERC Project. On August 29, the Indicated New England EDCs answered the

[70] The "EDCs" are the National Grid companies (Mass. Elec. Co., Nantucket Elec. Co., and Narragansett Elec. Co.) and Eversource Energy Service Co. (on behalf of its electric distribution companies – CL&P, NSTAR and PSNH).

[71] "PIOs" are the Sierra Club, Natural Resources Defense Council ("NRDC"), and Sustainable FERC Project.

August 14/16 answers. On August 27, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CASPR (ER18-619)**

Rehearing of the FERC's order accepting and ISO-NE's Competitive Auctions with Sponsored Policy Resources ("CASPR") revisions,[72] summarized in more detail in prior Reports, remains pending. Those requests were filed by (i) ***NextEra/NRG*** *(which* challenged the RTR Exemption Phase Out); (ii) ***ENECOS***[73] (challenging the FERC's findings with respect to the definition of Sponsored Policy Resource and the allocation of CASPR side payment costs to municipal utilities); (iii) ***Clean Energy Advocates***[74] (which challenged the CASPR construct in its entirety, asserting that state-sponsored resources should not be subject to the MOPR); and (iv) ***Public Citizen*** (which also challenged the CASPR construct in its entirety and the *CASPR Order*'s failure to define "investor confidence"). On April 24, ISO-NE answered Clean Energy Advocates' answer. On May 7, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

Rehearing remains pending of the FERC's October 6, 2017 order accepting updated FCM CONE, Net CONE and ORTP values.[75] In accepting the changes, the FERC disagreed with the challenges to ISO-NE's choice of reference technology (gas-fired simple cycle combustion-turbine) and on-shore wind capacity factor (32%). The changes were accepted effective as of March 15, 2017, as requested. On November 6, 2017, 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.[76] In the *2013/14 Winter Reliability Program Remand Order*, the FERC directed ISO-NE to request from Program participants the basis for their bids, including the process used to formulate the bids, and to file with the FERC a compilation of that information, an IMM analysis of that information, and ISO-NE's recommendation as to the reasonableness of the bids, so that the FERC can further consider the question of

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

[73] The Eastern New England Consumer-Owned Systems ("ENECOS") are: Braintree Electric Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Littleton Electric Light & Water Department, Middleton Electric Light Department, Middleborough Gas & Electric Department, Norwood Light & Broadband Department, Pascoag (Rhode Island) Utility District, Rowley Municipal Lighting Plant, Taunton Municipal Lighting Plant, and Wallingford (Connecticut) Department of Public Utilities. Wellesley Municipal Light Plant, which intervened in this proceeding as one of the ENECOS, did not join in the ENECOS' request for rehearing.

[74] "Clean Energy Advocates" are, collectively, the NRDC, Sierra Club, Sustainable FERC Project, CLF, and RENEW Northeast, Inc.

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

[76] *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).

whether the Bid Results were just and reasonable.[77] ISO-NE submitted its compliance filing on January 23, 2017, reporting the IMM's conclusion that "the auction was not structurally competitive and a 'small proportion' of the total cost of the program may be the result of the exercise of market power" but that the "vast majority of supply was offered at prices that appear reasonable and that, for a number of reasons, it is difficult to assess the impact of market power on cost." Based on the IMM and additional analysis, ISO-NE recommended that "there is insufficient demonstration of market power to warrant modification of program." In February 13 comments, both TransCanada and the MA AG protested ISO-NE's conclusion and recommendation that modification of the program was unwarranted. TransCanada requested that FERC establish a settlement proceeding where Market Participants could "exchange confidential information to determine what the rates should be" and refunds and "such other relief as may be warranted" provided. On February 28, ISO-NE answered the TransCanada and MA AG protests. On March 10, 2017, TransCanada answered ISO-NE's February 28 answer. This matter remains pending before the FERC. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Interconnection Studies Scope and Reasonable Efforts Timelines Changes (ER19-1952)**

On May 22, 2019, ISO-NE, NEPOOL and the PTO AC together filed changes to Schedule 22 of the OATT to: (i) reduce the scope of the Interconnection Feasibility Study ("Feasibility Study") and increase the Reasonable Efforts timeframe for completing that study; and (ii) increase the Reasonable Efforts timeframe for completing the Interconnection System Impact Study ("SIS"). The Filing Parties asked that these changes become effective on the same date that the *Order 845* Changes (*see* ER19-1951 below) become effective. The *Order 845* compliance changes were supported by the Participants Committee at its May 3, 2019 meeting (Consent Agenda Item No. 4).

On May 31, AWEA requested a 21-day extension of time to submit comments in this proceeding (and the ISO-NE Order 845 Compliance Filing proceeding (ER19-1951 just below)). The FERC granted AWEA's request, in part, on June 7. Comments in these proceedings were due June 26, 2019. Doc-less interventions were filed by Avangrid, Calpine, Dominion, EDP, National Grid, and NRG. A joint protest was filed by EDF Renewables, E.ON Climate & Renewables North America ("E.ON") and Enel Green Power North America ("Enel"), who asked the FERC to reject the changes for four reasons: (i) ISO-NE is incapable of meeting the study deadline changes proposed; (ii) the proposed study deadlines do not improve ISO-NE's ability to exercise Reasonable Efforts to meet queue study deadlines; (iii) the extensions proposed will delay and perhaps limit the extent of the informational reports to be required under *Order 845*; and (iv) the changes will not promote the transparency or improve the processing of ISO-NE's interconnection queue. On July 11, ISO-NE answered the joint protest. This matter is 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).

- **ISO-NE *Order 845* Compliance Filing (ER19-1951)**

On May 22, 2019, ISO-NE and the PTO AC ("Filing Parties") jointly filed proposed revisions to the Large Generator Interconnection Procedures ("LGIP") and Agreement ("LGIA") in Schedule 22 of the ISO-NE OATT in response to the requirements of *Order 845* ("ISO/TO Proposal"). The Filing Parties asserted that the ISO/TO Proposal "fully compl[ies] with the requirements in Order Nos. 845 and 845-A, and request that the Commission accept them as proposed herein, without modifications or conditions, effective upon issuance of its order accepting this filing." The ISO/TO Proposal did not include the RENEW Amendment's revisions to the Surplus Interconnection Service provisions supported by the Participants Committee at its May 3 meeting

[77] *2013/14 Winter Reliability Program Remand Order* at P 17.

("NEPOOL Proposal"). The Participants Committee considered but did not support the ISO/TO Proposal (without the RENEW Amendment) at its May 3 meeting.

Comments in these proceedings were due June 26, 2019. Doc-less interventions were filed by Avangrid, Calpine, Dominion, EDP, Eversource, MA AG, National Grid, NRG, and ESA. Comments and protests were filed by the following:

- ***NEPOOL***, which in its protest urged the FERC to accept the ISO/TO Proposal to the extent it is consistent with the NEPOOL Proposal, and reject those provisions for Surplus Interconnection Service that deviate both from the requirements of *Orders 845/845-A* and the NEPOOL Proposal. To the extent necessary or desirable, NEPOOL urged the FERC to direct ISO-NE to engage the NEPOOL stakeholder process to address any implementation concerns regarding Surplus Interconnection Service. NEPOOL went on to suggest that any additional provisions developed regarding such service that are properly considered rates, terms and conditions of service should be filed with the FERC and included in the ISO-NE Tariff. NEPOOL also urged the FERC to reject the PTOs' proposal for recovery of actual costs in the absence of a demonstration that their proposed deviation is consistent with or superior to the *Order 845* requirement for a negotiated and stated amount.
- ***MA AG*** (which urged the FERC to (i) reject the ISO-NE provisions for Surplus Interconnection Service that deviate from the NEPOOL Proposal and the requirements of *Order Nos. 845/845-A* and order ISO-NE to make changes to the ISO Tariff in accordance with the NEPOOL Proposal and (ii) reject the PTO AC amendment that seeks unlimited cost recovery for PTO oversight of the option to build rather than a fixed, negotiated amount as provided in the FERC's *pro forma*).
- ***AWEA/RENEW/Solar Council*** (supporting some of ISO-NE's revisions, but protesting ISO-NE's "unreasonably narrow definition of Surplus Interconnection Service" and ISO-NE's failure to establish an outside-the-queue process for reviewing Surplus Interconnection Service requests").
- ***ESA*** (objecting to ISO-NE's Surplus Interconnection Service proposal).

On July 11, ISO-NE and the PTO AC answered the comments and protests. This matter is 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).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 22: First Revised Clear River LGIA (ER19-2419)**

On July 18, ISO-NE and New England Power Company ("NEP" or "National Grid") filed a first revised LGIA by and among ISO-NE, National Grid and Clear River.[78] The LGIA governs the interconnection of Clear River's project in Burrillville, Rhode Island (the "Clear River Project"). The First Revised LGIA amends Article 4.1 and its Appendices to reflect the removal of the Project's Capacity Network Resource Interconnection Service and the associated transmission upgrades, consistent with ISO-NE's termination of the Project's CSO[79] and Section III.13.3.3.4(c) of the Tariff. The milestone dates in Appendix B have also been revised to align with Clear River's updated Commercial Operation Date of May 31, 2022. Other Appendices were revised to reflect minor editorial or cleanup changes. While the First Revised LGIA need not be on file with the FERC insofar as it is fully executed and now conforming to the Tariff's *pro forma* LGIA, ISO-NE and National Grid filed the LGIA to

[78] The original LGIA was accepted in *ISO New England Inc.*, 162 FERC ¶ 61,058 (Jan. 26, 2018).

[79] *See ISO New England Inc.*, 165 FERC ¶ 61,137 (Nov. 19, 2018).

ensure consistency between their eTariff records (which include the original LGIA) and their Electric Quarterly Reports ("EQRs"). A June 18, 2019 effective date was requested (to coincide with the date the First Revised LGIA was executed). Comments on the LGIA are due on or before August 8, 2019. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP National Grid/GRS SGIA (ER19-2352)**

On July 3, National Grid filed a non-conforming Small Generation Interconnection Agreement ("SGIA") with Gas Recovery Systems, LLC ("GRS") to cover the continued interconnection, albeit at a reduced output level, between National Grid and GRS with respect to GRS' land-fill gas-fueled facility located in Fall River, Massachusetts. The SGIA replaces an existing interconnection agreement, and reflects a planned reduction in the output of the facility due to declining landfill gas available to the facility. Since the SGIA covers an existing, interconnected facility, a new three-party interconnection agreement (that would include ISO-NE) was not required. A July 1, 2019 effective was requested. Comments on this filing were due on or before July 24, 2019; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-UI: LCSA Cancellation - UI/EES5 (Bridgport Energy) (ER19-1921)**

On July 10, the FERC accepted the cancellation of the Localized Costs Sharing Agreement ("LCSA") between UI and Emera Energy Services Subsidiary No. 5 ("EES5") under Schedule 21-UI.[80] The termination filing was made in light of the transfer of Category B Network Load Responsibility for the Bridgeport Energy facility to Revere Power LLC ("Revere Power"), which recently acquired the Bridgeport Energy facility (*see* ER19-1911 below). The termination was accepted, effective as of April 1, 2019, as requested. Unless the July 10 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-UI: LCSA - UI/Revere Power (Bridgeport Energy) (ER19-1911)**

Also on July 10, the FERC accepted the LCSA by and between UI and Revere Power.[81] UI filed the LCSA so that it can recover from Revere Power Bridgeport Energy's Category B Load Ratio Share of the revenue requirement for Bridgeport Energy's Localized Facilities under Schedule 21-UI. The LCSA was accepted effective as of April 1, 2019, as requested. Unless the July 10 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: BHD Excess ADIT Changes (ER19-1470)**

On March 29, 2019, Emera Maine filed additional changes to the Emera Maine, Bangor-Hydro District ("BHD") Formula Rate to ensure that excess ADITs are properly reflected in the calculations of charges under Schedule 21-EM (and thus inure to the benefit of customers). Comments on this filing were due on or before April 19, 2019. On April 19, the MPUC filed comments asserting the proposed changes lack transparency and recommending that this matter be accepted for filing, subject to refund, and set for hearing and settlement procedures. Emera Maine answered those comment on May 6. On May 28, pursuant to the May 24 Joint Offer of Settlement filed in Docket No. ER15-1434-003 (see below), MPUC withdrew its April 19 comments. On May 8, Emera Maine filed corrections to typographical errors in the March 29 filing.

May 10 Deficiency Letter. On May 10, the FERC issued a deficiency letter requesting additional information in order to process Emera Maine's filing. Emera Maine submitted those responses on June 10, 2019. Comments on the deficiency letter responses were due on or before July 1; none were filed. This

[80] *The United Illuminating Co.*, Docket No. ER19-1921 (July 10, 2019) (unpublished letter order).

[81] *The United Illuminating Co.*, Docket No. ER19-1911 (July 10, 2019) (unpublished letter order).

matter is again pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: MPD Excess ADIT Changes (ER19-1400)**

On March 21, 2019, Emera Maine filed additional changes to the Emera Maine MPD Formula Rate to ensure that excess ADITs are properly reflected in the calculations of charges under Schedule 21-EM (and thus inure to the benefit of customers). Comments on this filing were due on or before April 11, 2019. MPUC and Maine Customer Group filed protests on April 11, 2019. Emera Maine answered those protests on April 26.

Deficiency Letter. On May 10, the FERC also issued a deficiency letter in this proceeding requesting additional information in order to process Emera Maine's filing. Emera Maine submitted those responses on June 7, 2019. Comments on the deficiency letter responses were due on or before June 28; none were filed. This matter is again pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-EM: 2018 Annual Update Settlement Agreement (ER15-1434-003)**

On May 24, Emera Maine submitted a joint offer of settlement between itself and the MPUC to resolve certain issues raised by the MPUC in response to Emera Maine's annual charges update filed, as previously reported, on June 15, 2018 (the "Emera 2018 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2018 Annual Update, a majority of which are resolved by the Emera 2018 Annual Update Settlement Agreement. Comments on the Emera 2018 Annual Update Settlement Agreement were due on or before June 14, 2019; none were filed. The Emera 2018 Annual Update Settlement Agreement is pending before the FERC. If you have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-EM: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434-001 *et al.*)**

The MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs Order,*[82]and certified by Settlement Judge Dring[83] to the Commission,[84] remains pending before the FERC. As previously reported, under the Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P-EM of the BHD OATT and $260,000 under the MPD OATT. If

[82] *Emera Maine and BHE Holdings*, 155 FERC ¶ 61,230 (June 2, 2016) ("*MPS Merger-Related Costs Order*"). In the *MPS Merger-Related Costs Order*, the FERC accepted, but established hearing and settlement judge procedures for, filings by Emera Maine seeking authorization to recover certain merger-related costs viewed by the FERC's Office of Enforcement's Division of Audits and Accounting ("DAA") to be subject to the conditions of the orders authorizing Emera Maine's acquisition of, and ultimate merger with, Maine Public Service ("Merger Conditions"). The Merger Conditions imposed a hold harmless requirement, and required a compliance filing demonstrating fulfillment of that requirement, should Emera Maine seek to recover transaction-related costs through any transmission rate. Following an audit of Emera Maine, DAA found that Emera Maine "inappropriately included the costs of four merger-related capital initiatives in its formula rate recovery mechanisms" and "did not properly record certain merger-related expenses incurred to consummate the merger transaction to appropriate non-operating expense accounts as required by [FERC] regulations [and] inappropriately included costs of merger-related activities through its formula rate recovery mechanisms" without first making a compliance filing as required by the merger orders. The *MPS Merger-Related Costs Order* set resolution of the issues of material fact for hearing and settlement judge procedures, consolidating the separate compliance filing dockets.

[83] ALJ John Dring was the settlement judge for these proceedings. There were five settlement conferences -- three in 2016 and two in 2017. With the Settlement pending before the FERC, settlement judge procedures, for now, have not been terminated.

[84] *Emera Maine and BHE Holdings*, 163 FERC ¶ 63,018 (June 11, 2018).

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

- **Schedule 21-FG&E Annual Informational Filing (ER09-1498)**

On July 29, 2019, Fitchburg Gas & Electric ("FG&E") submitted its data and schedules used to calculate its annual transmission revenue requirement for Non-PTF Local Network Transmission Service, Firm Point-to-Point Transmission Service and Non-Firm Point-to-Point Transmission Service as set forth in Schedule 21-FG&E covering the June 1, 2019– May 31, 2020 period. FG&E reported that its annual revenue requirement reflected in FG&E's rates effective June 1, 2019, is $1,367,550. The revenue requirement calculation reflects a federal income tax rate of 21%. No changes to address impacts of the federal income tax on ADIT balances in rates were made and remain subject to the outcome of the NOI in RM18-12 (*see* Section XII below). The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com.

- **Schedule 21-NSTAR Annual Info. Filing: CWIP Supplement (ER09-1243; ER07-549)**

On July 2, 2019, NSTAR supplemented its May 31 annual informational filing with a "CWIP Supplement" in accordance with Section 4.1(i) and (ix) of Schedule 21-NSTAR. The CWIP Supplement was provided primarily on a project-specific basis, and included NSTAR's 2018 long-range construction forecast. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-CMP Annual Info. Filing (ER09-938)**

On June 28, CMP submitted its annual update to the formula rates contained in Schedule 21-CMP. CMP indicated that the informational filing reflected actual cost data for the 2018 calendar year plus estimated cost data for the 2019 calendar year associated with CMP's forecasted transmission plant additions and MPRP CWIP as well as the annual true-up and associated interest. CMP referred to Section 10.2 of Schedule 21-CMP for specific procedures for review and challenges to the informational report. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

- **132nd Agreement (Press Membership Provisions) (ER18-2208)**

As previously reported, the FERC rejected, on January 30, 2019, the changes to the NEPOOL Agreement that would have precluded press reporters from becoming NEPOOL End User Participants or representatives of NEPOOL Participants.[85] In rejecting the changes, the FERC concluded that NEPOOL had not supported that "barring members of the press from exercising the privileges unique to NEPOOL membership—i.e. attending, speaking, and voting at NEPOOL meetings—will meaningfully advance its aim for candid deliberation in light of" NEPOOL's Bylaws and Standard Conditions Waivers & Reminders "currently in place—which this order does not affect—[that] already prohibit reporting on deliberations or attributing statements to other NEPOOL members."[86] The FERC further indicated that the *Press Membership Provisions Order* only addressed NEPOOL's proposed changes to the NEPOOL Agreement, and not the pending RTO Insider Complaint (*see* EL18-196 above) that it addressed (and dismissed) in a separate order.

On February 28, 2019, NEPOOL requested clarification, or in the alternative rehearing, of the *Press Membership Provisions Order* (the "Request"). In the Request, NEPOOL asked the FERC, particularly in light of

[85] *New England Power Pool Participants Comm.*, 166 FERC ¶61,062 (Jan. 29, 2019) ("*Press Membership Provisions Order*"), *reh'g requested*. The rejected changes were identified in the One Hundred Thirty-Second Agreement Amending New England Power Pool Agreement ("132nd Agreement"), which was approved in balloting following the 2018 Summer Meeting.

[86] *Id.* at P 50.

issues that remained pending in EL18-196, to clarify the extent to which the FERC sought to assert jurisdiction over the NEPOOL Agreement, or in the alternative, grant rehearing of the *Press Membership Provisions Order* on the grounds that it reflects an impermissible exercise of the FERC's jurisdiction. On March 4, Public Citizen submitted comments requesting that the FERC require NEPOOL to describe the notice and approval of its members sought in connection with the Request, insinuating that the request was unauthorized. On March 14 and 15, PIOs and RTO Insider responded to NEPOOL's Request, respectively. On March 28, the FERC issued a tolling order affording it additional time to consider NEPOOL's Request, which remains pending.

On May 1, 2019, NEPOOL submitted Michael Kuser's membership for FERC acceptance and that filing was accepted on June 18. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com), Dave Doot (860-275-0102; dtdoot@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

VIII. Regional Reports

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

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

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

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[87] *and 531-B*[88] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

- Central Maine Power
- Emera Maine
- Eversource
- National Grid
- NHT
- NSTAR
- United Illuminating
- VTransco

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

- **FCA13 Fuel Security Reliability Review Info Filing (ER18-2364)**

Pursuant to the *Fuel Security Retention Proposal Order*, ISO-NE filed on July 12, 2019 its informational filing assessing the study triggers, study and scenarios that it used in performing its fuel security reliability review for FCA13 in comparison to the actual conditions experienced during Winter 2018-2019. This filing is for informational purposes only and will not be noticed for public comment or subject to a FERC order.

- **LFTR Implementation: 43rd Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 43rd of its Quarterly Status Reports regarding LFTR implementation on July 15, 2019. ISO-NE again reported its plan to implement monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019 and to renew after that implementation efforts to address the financial assurance issues associated with LFTRs. ISO-NE reported that it has recently renewed discussions with the clearinghouse to refine the third-party clearing approach described previously to try and mitigate some of the regulatory concerns previously identified that are impeding the finalization of specific LFTR

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

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

financial assurance policy requirements and completion of LFTR project implementation. These status reports are not noticed for public comment.

IX. Membership Filings

- **Involuntary Termination: Viridity Energy, Inc. (ER19-2387)**

On July 11, as corrected on July 12, NEPOOL and ISO-NE jointly requested that the FERC accept the involuntary termination of the NEPOOL membership and Market Participant status of Viridity Energy, Inc. (Provisional Member) on the basis of on-going Payment and Financial Assurance Defaults. NEPOOL and ISO-NE requested that the terminations be accepted effective as of September 10, 2019. Comments on this filing are due on or before August 1.

- **July 2019 Membership Filing (ER19-2292)**

On June 28, NEPOOL requested that the FERC accept (i) the July 1, 2019 memberships of Bloom Connecticut Clean Energy Company, LLC [Related Person to Yellow Jack Energy (Supplier Sector)]; Clearway Power Marketing LLC [Related Person to CPV Towantic (Generation Sector)]; and Excelerate Energy Limited Partnership (Gas Industry Participant); (ii) the June 1, 2019 termination of the Participant status of Marathon Power LLC; and (iii) the name changes of North Stonington Solar Center, LLC (f/k/a Pawcatuck Solar Center, LLC); and TrailStone Energy Marketing, LLC (f/k/a TrailStone Power, LLC). This matter is pending before the FERC.

- **June 2019 Membership Filing (ER19-2021)**

On July 9, the FERC accepted (i) the June 1, 2019 memberships of Brookfield Renewable Trading and Marketing LP [Related Person to the Brookfield Companies (Supplier Sector)]; Community Eco Power, LLC (AR Sector, RG Sub-Sector, Large RG Group Seat); DWW Solar II, LLC [Related Person to Deepwater Wind Block Island and Fusion Solar Center, LLC (AR Sector, RG Sub-Sector, Large RG Group Seat)]; and NS Power Energy Marketing, Inc. [Related Person to the Emera Companies (Transmission Sector)]; (ii) the May 1, 2019 termination of the Participant status of Supplier Sector members Mint Energy, LLC; Power Bidding Strategies, LLC; and Utility Expense Reduction. Unless the July 9 order is challenged, this proceeding will be concluded.

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: CIP-003-8 (RD19-5)**

On May 21, 2019, NERC filed for approval a revised Reliability Standard CIP-003-8 (Cyber Security – Security Management Controls) to mitigate the risk of malicious code that could result from third-party transient electronic devices for low impact BES Cyber Systems. NERC requested that the CIP-003 changes become effective on the first day of the first calendar quarter that is on the later of: (1) January 1, 2020; or (2) the first day of the first calendar quarter that is six calendar months after the effective date of the FERC's order approving the CIP-003-8 changes, pursuant to the Implementation Plan included with the changes. Comments on the CIP-003-8 changes were due on or before June 12; none were filed. The CIP-0038 changes are pending before the FERC.

- **Revised Reliability Standards: FAC-008-4; INT-006-5; INT-009-3; PRC-004-6; Retirement of 10 Standards (Standards Efficiency Review II) (RM19-17)**

On June 7, 2019, in connection with the first phase of work under NERC's Standards Efficiency Review,[89] NERC filed for approval (i) the retirement of individual requirements (not needed for reliability) in the following four Reliability Standards:

- FAC-008-4 (Facility Ratings);
- INT-006-5 (Evaluation of Interchange Transactions);
- INT-009-3 (Implementation of Interchange); and
- PRC-004-6 (Protection System Misoperation Identification and Correction).

and (ii) the retirement, in their entirety, of the following 10 Reliability Standards:

- FAC-013-2 (Assessment of Transfer Capability for the Near-term Transmission Planning Horizon);
- INT-004-3.1 (Dynamic Transfers);
- INT-010-2.1 (Interchange Initiation and Modification for Reliability);
- MOD-001-1a (Available Transmission System Capability);
- MOD-004-1 (Capacity Benefit Margin);
- MOD-008-1 (Transmission Readability Margin Calculation Methodology);
- MOD-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators);
- MOD-028-2 (Area Interchange Methodology);
- MOD-029-2a (Rated System Path Methodology); and
- MOD-030-3 (Flowgate Methodology).

As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **Revised Reliability Standards: IRO-002-7; TOP-001-5; VAR-001-6 (Standards Efficiency Review I) (RM19-16)**

Also on June 7, 2019, and in connection with the first phase of work under NERC's Standards Efficiency Review,[90] NERC filed for approval (i) the retirement of individual requirements (not needed for reliability) in the following three Reliability Standards:

- IRO-002-7 (Reliability Coordination – Monitoring and Analysis);
- TOP-001-5 (Transmission Operations); and
- VAR-001-6 (Voltage and Reactive Control).

As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **NOPR - Revised Reliability Standard: TPL-001-5 (RM19-10)**

On June 20, 2019, the FERC issued a NOPR proposing to approve a revised Reliability Standard -- TPL-001-5 (Transmission System Planning Performance Requirements), and associated implementation plan, VRFs and VSLs

[89] The Standards Efficiency Review initiative, which began in 2017, reviewed the body of NERC Reliability Standards to identify those Reliability Standards and requirements that were administrative in nature, duplicative to other standards, or provided no benefit to reliability.

[90] The Standards Efficiency Review initiative, which began in 2017, reviewed the body of NERC Reliability Standards to identify those Reliability Standards and requirements that were administrative in nature, duplicative to other standards, or provided no benefit to reliability.

(together, the "TPL-001 Changes").[91] As previously reported, NERC stated that the TPL-001 Changes improve upon the currently effective standard by enhancing Requirements for the study of Protection System single points of failure. Additionally, the TLP-001 Changes address two FERC directives from *Order 786*: (1) the TPL-001 Changes provide for a more complete consideration of factors for selecting which known outages will be included in Near-Term Transmission Planning Horizon studies, addressing the FERC's concern that the exclusion of known outages of less than six months in TPL-001-4 could result in outages of significant facilities not being studied; and (2) the TPL-001 Changes modify Requirements for Stability analysis to require an entity to assess the impact of the possible unavailability of long lead time equipment, consistent with the entity's spare equipment strategy. In addition, the FERC proposes in the *TPL-001-5 NOPR* to direct NERC to modify the Reliability Standards to require corrective action plans for protection system single points of failure in combination with a three-phase fault if planning studies indicate potential cascading. Comments on the *TPL-001-5 NOPR* are due on or before August 26, 2019.[92]

- **NOPR - New Reliability Standard: CIP-012-1 (RM18-20)**

On April 18, 2019, the FERC issued a NOPR proposing to approve a new Reliability Standard -- CIP-012-1 (Cyber Security – Communications between Control Centers), and associated Glossary definitions, implementation plan, VRFs and VSLs (together, the "Control Center Cyber Security Communication Changes").[93] The *CIP-012-1 NOPR* also proposes to direct NERC develop certain modifications to CIP-012-1 to require protections regarding the availability of communication links and data communicated between bulk electric system control centers and, further, to clarify the types of data that must be protected. When it filed CIP-012-1, NERC stated that the changes modify the Critical Infrastructure Protection ("CIP") Reliability Standards to require Responsible Entities to implement controls to protect communication links and sensitive Bulk Electric System ("BES") data communicated between BES Control Centers. CIP-012-1 requires Responsible Entities to develop a plan to mitigate the risks posed by unauthorized modification (integrity) and unauthorized disclosure (confidentiality) of Real-time Assessment and Real-time monitoring data. The plan must include the following three components: (1) identification of security protection used to meet the security objective; (2) identification of where the Responsible Entity applied the security protection; and (3) identification of the responsibilities of each Responsible Entity for applying the security protection. Comments on the *CIP-012-1 NOPR* were due on or before June 24, 2019.[94] Comments were filed by the ISO/RTO Council, APPA, MERC, Tri-State Generation and Transmission Association, the Bonneville Power Administration ("BPA"), J. Appelbaum, and C. Liu, VA Tech Power and Energy Center. This matter is pending before the FERC.

- **5-Year ERO Performance Assessment Report (RR19-7)**

On July 22, 2019, NERC filed a performance assessment report that (i) identified how NERC and its Regional Entities' activities and achievements during the Assessment Period (2014-2018) build upon the certification criteria of 18 C.F.R. § 39.3(b); (ii) evaluated the effectiveness of each Regional Entity in carrying out its Delegated Authority; and (iii) addressed stakeholder comments on NERC's performance (specific comments attached as directed by the Commission in the 2014 Five Year Order).[95] The submission of the assessment was

[91] *Transmission Planning Rel. Standard TPL-001-5*, 167 FERC ¶ 61,249 (June 20, 2019) ("*TPL-001-5 NOPR*").

[92] The *TPL-001-5 NOPR* was published in the Fed. Reg. on June 27, 2019 (Vol. 84, No. 124) pp. 30,639-30,647.

[93] *Critical Infrastructure Protection Rel. Standard CIP-012-1 – Cyber Security – Communications between Control Centers*, 167 FERC ¶ 61,055 (Apr. 18, 2019) ("*CIP-012-1 NOPR*").

[94] The *CIP-012-1 NOPR* was published in the Fed. Reg. on Apr. 18, 2019 (Vol. 84, No. 79) pp. 17,105-17,112.

[95] *N. Amer. Elec. Reliability Corp.*, 149 FERC ¶ 61,141, at P 70 (2014) ("*2014 Five Year Order*").

made in accordance with FERC regulations and directives.[96] Comments on this Report are due on or before August 22, 2019. Thus far, Public Citizen filed a doc-less intervention.

- **Report of Comparisons of Budgeted to Actual Costs for 2018 for NERC and the Regional Entities (RR19-6)**

On May 30, 2019, NERC filed comparisons of actual to budgeted costs for 2018 for NERC and the eight Regional Entities operating in 2018, including NPCC. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2018 budgets and actual results. Comments on this filing were due on or before June 20, 2019; none were filed. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Footprint, Hartree Partners / Brookfield (EC19-104)**

On June 19, 2019, Hartree Partners, Griffith Energy, Cogen Technologies Linden Venture, East Coast Power Linden Holding, Footprint Power Salem Harbor Development ("Footprint") (together, the "Seller Public Utilities"), and Brookfield Asset Management Inc. ("Brookfield") requested authorization for a transaction following which Hartree, Footprint and Brookfield will become Related Persons. The transaction contemplates Brookfield's acquisition of an approximate 62% interest in Oaktree Capital Group, LLC ("Oaktree"), the owner in turn of indirect, upstream interests of greater than 10% in the Seller Public Utilities. Comments on this application were due on or before July 10; none were filed. PJM filed a doc-less intervention. This matter is pending before the FERC.

- **203 Application: ReEnergy (EC19-102)**

On July 30, 2019, the FERC authorized a transaction in which ReEnergy will redeem all of the ReEnergy membership interests held by its immediate upstream parent, R/C ReEnergy, LLC ("R/C LLC"), in exchange for a cash payment to R/C LLC.[97] Following the redemption, all of ReEnergy's membership interests will be held by its individual owners, all natural persons, each of whom will have a voting interest of 10 percent or more in ReEnergy. Following the consummation, ReEnergy and its subsidiaries, including ReEnergy Stratton, will cease to be Related Persons with Riverstone and its affiliates, including Talen Energy Marketing, Millennium Power Partners and Dartmouth Power Associates. Pursuant to the July 30 order, notice must be filed within 10 days of consummation of the transaction. That notice has not yet been filed.

- **203 Application: Empire Generating Co, LLC (EC19-99)**

On June 4, 2019, as amended on June 17,[98] Empire Generating Co, LLC ("Empire") requested authorization for the disposition of its FERC-jurisdictional facilities by way of a bankruptcy-related upstream change in control. Subject to all required authorizations, including the FERC authorization requested in this proceeding, 100% of the ownership interests in Empire's indirect upstream owner, Empire Gen Holdings, LLC, will be transferred to Empire Acquisition, LLC, which in turn will be owned by certain secured creditors[99] of Empire's current owner, TTK Power, LLC. Comments on the Empire application were due on or before June 25; comments on its amendments, July 8. On July 3, ARES Management Corp., one of Empire's creditors, filed a limited protest requesting that the FERC require Empire to provide additional information concerning the post-Transaction governance of both Empire and

[96] 18 C.F.R. § 39.3(c) (2019); *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006).

[97] *Lyonsdale Biomass, LLC et al.*, 168 FERC ¶ 62,056 (July 30, 2019).

[98] The June 17 amendment reflected additional owners and affiliates (creditors) associated with the Transaction.

[99] Various investment funds and entities managed or controlled by Black Diamond Capital Holdings, L.L.C. (93.0%); Various investment funds and entities under management of MJX Asset Management LLC (6.3%); and HSBC Bank plc (0.7%).

Empire Acquisition. Objections to ARES' request were filed by Empire and Black Diamond Capital Holdings (which following the transaction will indirectly hold a majority of the interests in Empire Acquisition) on July 17 and 18, respectively.

Deficiency Letter. In addition, on June 21, the FERC issued a deficiency letter asking that Empire provide the workpapers used to calculate the total post-transaction generation capacity and a Horizontal Competitive Analysis Screen. Empire responded to the deficiency letter on July 17. Comments on Empire's deficiency letter response are due on or before September 3, 2019.

- **203 Application: Kendall Green Energy (EC19-86)**

On June 28, 2019, the FERC authorized a transaction in which Veolia Energy North America Holdings, Inc. ("Veolia") will become the sole owner of Kendall Green Energy through the acquisition of ISQ Thermal Kendall's remaining 49% share.[100] Pursuant to the June 28 order, notice must be filed within 10 days of consummation of the transaction. That notice has not yet been filed.

- **203 Application: Convergent Energy and Power / ECP (EC19-85)**

On July 9, ECP ControlCo, LLC ("ECP") notified the FERC that it consummated, among other things, its acquisition of 100% of the equity interests in Convergent Energy and Power LP ("Convergent") on July 5, 2019.[101] With the consummation of the transaction, Convergent became a Related Person to the Calpine companies. Reporting on this proceeding has concluded.

- **203 Application: Emera Maine/ENMAX (EC19-80)**

On June 25, the FERC authorized a transaction pursuant to which Emera Maine (though not the Emera Energy Service Companies) will become a wholly-owned, indirect subsidiary of ENMAX Corporation, an Alberta corporation wholly-owned by the City of Calgary, Alberta, Canada ("ENMAX"), rather than Emera Inc.[102] Pursuant to the June 25 order, notice must be filed within 10 days of consummation of the transaction, which is expected to occur at the end of 2019.

- **203 Application: Crius (Viridian Energy et al.) / Vistra (EC19-59)**

On July 8, 2019, the FERC authorized a transaction pursuant to which Vistra Energy Corp. ("Vistra") indirectly acquired 100% of the equity interests in Crius Energy Corp. ("Crius").[103] That transaction was consummated on July 15 and, as a result, a number of NEPOOL Participants indirectly held by Crius[104] became Related Persons to Vistra/Dynegy. Reporting on this proceeding has now concluded.

- **203 Application: FirstLight Restructuring (EC19-44)**

On July 29, 2019, the FirstLight Project Companies[105] notified the FERC that the disposition of jurisdictional facilities that resulted from the transfer of 100% of the electric generating facilities and related assets ("Facilities") of FirstLight Hydro Generating Company ("FirstLight Hydro") to the FirstLight Project Companies ("FirstLight

[100] *Kendall Green Energy LLC*, 167 FERC ¶ 62,203 (June 28, 2019).

[101] The acquisition was authorized in *Convergent Energy and Power LP*, 167 FERC ¶ 62,189 (June 20, 2019).

[102] *Emera Maine*, 167 FERC ¶ 62,194 (June 25, 2019).

[103] *Crius Energy Corp. and Vistra Energy Corp.*, 168 FERC ¶ 61,010 (July 8, 2019).

[104] The NEPOOL Participants indirectly held by Crius pre-consummation and to become Vistra/Dynegy Related Persons post-consummation are: Viridian Energy, Energy Rewards, Everyday Energy, Public Power, Massachusetts Gas and Electric, and Connecticut Gas & Electric.

[105] The "FirstLight Project Companies" are FirstLight CT Housatonic, FirstLight CT Hydro, FirstLight MA Hydro, and Northfield Mountain.

Restructuring"), authorized by the FERC on March 12, 2019,[106] was completed on July 16, 2019. Reporting on this proceeding has now concluded.

- **203 Notification: NSTAR/Entergy (EC19-1)**

On June 28, 2019, NSTAR notified the FERC that, coincident with Pilgrim's retirement and pursuant to NSTAR's right of first refusal, it purchased from Entergy the 345-kV transmission switchyard (including the ground easement within which the switchyard resides) located adjacent to Pilgrim. The $9,997,500 transaction was consummated on May 31, 2019.[107]

- **New England Ratepayers Association Complaint (EL19-10)**

As previously reported, the New England Ratepayers Association ("NERA") filed a complaint on November 2, 2018 seeking declaratory order finding that (i) New Hampshire Senate Bill 365 ("SB 365"),[108] which mandates a purchase price for wholesale sales by seven generators operating in NH, (i) is preempted by the Federal Power Act; (ii) SB 365 violates Section 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA") (because SB 365 does not satisfy the requirement under PURPA and the FERC's implementing regulations[109] that rates set by the states for wholesale sales by QFs may not exceed the purchasing utilities' avoided costs; and (iii) NH is pre-empted from ordering purchases that are contrary to the FERC's order terminating PSNH's mandatory purchase obligation on a service territory-wide basis for QFs with a net capacity in excess of 20 MW. NERA asked the FERC to issue a ruling by February 1, 2019 (the date NH customers may first bear the costs of SB 365). Doc-less interventions were filed by Calpine, Eversource, National Grid, NRG, and the DC Office of People's Counsel. Comments supporting the Petition were filed by: NH OCA, the NH Generator Group,[110] EPSA, and a group of NH customers; a Protest was filed by the State of New Hampshire.[111] The New England Small Hydro Coalition filed comments that, while not taking a position on NERA's preemption argument, disagreed with the premise that underlies NERA's argument as to what constitutes an avoided cost rate in New Hampshire. NH OCA and the NH Generator Group amended/supplemented their December 3 comments. A group of NH Legislators that supported SB 365 filed comments on December 17 urging the FERC to deny the Petition. On December 20, NERA answered the protests and comments.

On January 4, 2019, the NH AG answered NERA's December 20 answer, asserting that NERA's Petition is premature, the evidentiary record before the FERC is inadequate to support the declaratory order sought, and the FERC should dismiss the Petition to allow time for the NHPUC to rule on pending issues before the NHPUC related to the implementation of SB 365. The New Hampshire Generator Group similarly answered NERA's December 20 answer, also asserting that the NERA motion misstated the relevant facts and law. On January 7, PSNH moved to lodge its December 27, 2018 pleading in NHPUC Docket No. DE 18-002 (which

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[106] *FirstLight Hydro Generating Co. et al.*, 166 FERC ¶ 62,112 (Mar. 12, 2019).

[107] This notice filing was made pursuant to changes implemented by *Order 855*, and is the first from New England since the changes implemented by that *Order* became effective Mar. 27, 2019. In *Order 855*, the FERC established (i) $10 million as the threshold for FERC authorization under section 203(a)(1)(B) (required when an entity seeks to merge or consolidate, directly or indirectly, facilities subject to FERC jurisdiction, or any part thereof, with the facilities of any other person, or any part thereof, that are subject to FERC jurisdiction) and (ii) a requirement for a notice filing within 30 days of consummation if the facilities to be acquired have a value in excess of $1 million and authorization was not required under section 203(a)(1)(B). Notice filings will always be filed in the first "EC" docket of the FERC's fiscal year (which runs Oct. 1 through Sep. 30).

[108] SB 365, 2018 N.H. Laws Ch. 379, An Act relative to the use of renewable generation to provide fuel diversity, codified at N.H. Rev. Stat. Chapter 362-H.

[109] 18 C.F.R. §§ 292.304(a); 292.101(b)(6) (2018).

[110] The NH Generator Group is comprised of the following entities: Bridgewater Power Company, L.P., DG Whitefield LLC, Pinetree Power – Tamworth LLC, Pinetree Power, Inc., Springfield Power, LLC, and Wheelabrator Concord Company, L.P.

[111] Although the State of New Hampshire requested and was eventually granted a two-week extension of time to file its comments, that extension was noticed on December 4, 2018, after the initial comment date and the submission of NH's comments.

objected to the request that the NHPUC determine certain IPP PPAs conform with SB 365/RSA Chap 362-H and noted uncertainties to be resolved in connection with any purchases). On January 22, 2019, the NH Generator Group answered the motion to lodge, providing additional material and context.

Since the last Report, Public Citizen moved to intervene out-of-time, and in comments joined by two New Hampshire legislators,[112] accused NERA of being "misleading in its advocacy of what financial interests it represents" and suggested that the FERC should require NERA "to amend its Petition to disclose the identities of the roughly 12 members that finance NERA's operations".

Notwithstanding NERA's request, the FERC has yet to act on this matter. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PJM MOPR-Related Proceedings (EL18-178; ER18-1314; EL16-49)**

On June 29, 2018, the FERC issued an order ("*PJM Order*")[113] regarding out-of-market support affecting the PJM capacity market.[114] Opening with the statement that "the integrity and effectiveness of the capacity market administered by [PJM] have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources," the *PJM Order* determined that the PJM Tariff is currently unjust and unreasonable, rejected PJM's Section 205 Filing, granted in part Calpine's Complaint, and established a paper hearing to resolve the "price-suppressive" effects of out-of-market support for certain resources. Commissioners LaFleur and Glick both dissented, and Commissioner Powelson wrote a separate concurrence.

In the *PJM Order*, the FERC found "that it has become necessary to address the price suppressive impact of resources receiving out-of-market support." The FERC agreed with Calpine and PJM that changes to the PJM Tariff were required, but did not accept the changes proposed in the Calpine Complaint or the PJM Filing, finding that neither had been shown to be just and reasonable, and not unduly discriminatory or preferential. The majority stated that it was unable to determine, based on the record of either proceeding, the just and reasonable rate to replace the rate in PJM's Tariff. The *PJM Order* therefore found the PJM Tariff unjust and unreasonable, granted the Calpine Complaint, in part, and *sua sponte* initiated a new FPA section 206 proceeding (EL18-178), consolidating the record of the two earlier proceedings, and setting for paper hearing the issue of how to address a proposed alternative put forth in the *PJM Order,*[115] which would modify two existing aspects of the PJM Tariff, "or any other proposal that may be presented."

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[112] Public Citizen was joined by Representatives Robert Backus, Chairman of the NH House Committee on Science, Technology and Energy, and Renny Cushing, Chairman of the NH House Criminal Justice and Public Safety Committee.

[113] *Calpine Corp. et al.*, 163 FERC ¶ 61,236 (June 29, 2018) ("*June 29, 2018 Order*"), *clarif. and/or reh'g requested*.

[114] The *PJM Order* addressed two separate, but related proceedings. The first, EL16-49, was initiated by a complaint originally filed by Calpine, joined by additional generation entities ("Calpine Complaint") on March 21, 2016, and later amended on January 9, 2017. The Calpine Complaint argued that PJM's MOPR was unjust and unreasonable because it did not address the impact of existing resources receiving out-of-market payments on the capacity market, and proposed interim tariff revisions that would extend the MOPR to a limited set of existing resources. The Calpine Complaint also requested the FERC to direct PJM to conduct a stakeholder process to develop and submit a long-term solution. The second proceeding was PJM's filing of its proposed revisions to its Tariff, pursuant to section 205 of the FPA in ER18-1314 ("PJM Filing"). The PJM Filing consisted of two alternate proposals designed to address the price impacts of state out-of-market support for certain resources. The first approach, preferred by PJM but not supported by its stakeholders, consisted of a two-stage annual auction, with capacity commitments first determined in stage one of the auction and the clearing price set separately in stage two ("Capacity Repricing"). The second alternative approach, proposed in the event that the FERC determined that Capacity Repricing was unjust and unreasonable, would have revised PJM's MOPR to mitigate capacity offers from both new and existing resources, subject to certain proposed exemptions ("MOPR-Ex").

[115] The proposed alternative approach would (i) modify PJM's MOPR such that it would apply to new and existing resources that receive out-of-market payments, regardless of resource type, but would include few to no exemptions; and (ii) in order to accommodate state policy decisions and allow resources that receive out-of-market support to remain online, establish an option in PJM's Tariff that would allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity

16 requests for clarification and/or rehearing of the *PJM Order* were filed on July 30, 2018. On August 29, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

Paper Hearing; Additional Briefing; PJM's Extended RCO Proposal. Following an August 22 notice of extension of time, interested parties were invited to submit their initial round of testimony, evidence, and/or argument by October 2, 2018. Initial briefs, comments and submissions were filed by over 50 parties. In its October 2 submission, PJM submitted a revised proposal, which includes an expanded MOPR coupled with a "Extended Resource Carve-Out" proposal ("Extended RCO"). The proposed MOPR would apply to all fuel and technology types and to both existing and new resources (a change from the original MOPR, which only applied to new gas-fired units). The Extended RCO would provide a means for states to support particular subsidized generation assets by removing them from certain aspects of the PJM capacity market and not subjecting them to MOPR in PJM's capacity market.

Reply testimony, evidence, and/or argument was due on or before November 6, 2018. Over 60 sets of reply briefs, evidence, etc. were filed. Since that time, a few parties submitted answers and additional comments. On December 6, PJM and Direct Energy/NextEra filed limited answers to reply briefs. In addition, a letter from a group of companies representing competitive new generation built in the PJM region since 2010 ("Generator Letter") urged the FERC to "to consider the broadest ramification of a fundamental change in the regulatory compact and the impact it would have on consumers, investors and even the fundamental American belief that markets drive better outcomes than government."[116] Answers to and comments on PJM's answer were filed by "Clean Energy Entities"[117] and UCS. Responses to the December 6 Generators Letter were filed by APPA, ELCON, LPPC, NRECA, and NRDC. On December 28, PSEG submitted supplemental comments. On January 15, PSEG answered PSEG's supplemental comments. These materials, together with all of the initial briefs and reply briefs, are still pending before the FERC.

The FERC committed in the *PJM Order* to make every effort to issue an order establishing the just and reasonable replacement rate no later than January 4, 2019 (a date which has long since passed). The FERC also established a refund effective date of March 21, 2016, the date of the original Calpine Complaint in EL16-49.

On March 11, 2019, PJM submitted an informational filing notifying the FERC that, given the lack of a final FERC order in this proceeding, it instructed Capacity Market Sellers to follow all relevant pre-auction deadlines under ***both*** the existing capacity market rules as well as PJM's proposed Capacity Reform rules (with revised MOPR rules and the Extended RCO alternative), in connection with the upcoming 2022/2023 Delivery Year Base Residual Auction ("BRA") scheduled to begin on August 14, 2019. PJM urged the FERC to issue an order expeditiously. On April 3, 2019, Joint Consumer Advocates[118] also urged the FERC rule in this matter.

PJM Motion for Supplemental Clarification. On April 10, PJM submitted a Motion for Supplemental Clarification of the *June 29, 2018 Order* setting forth its intention to run the August 2019 BRA under its existing

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market, along with a commensurate amount of load, for some period of time. That option, which is similar in concept to the Fixed Resource Requirement ("FRR") that currently exists in PJM's Tariff, is referred to as the "FRR Alternative." Unlike the existing FRR construct, the FRR Alternative would apply only to resources receiving out-of-market support. Both aspects of the proposed replacement rate, along with a series of questions that need to be addressed, are more fully explained and raised in the *PJM Order*.

[116] Those companies included: Ares Power and Infrastructure Group, Caithness, Calpine, Carroll County and South Field Energy, CPV, J-POWER USA Development Co., Panda Power Funds, and Tenaska Energy.

[117] "Clean Energy Entities" are AWEA, the Solar RTO Coalition, Solar Energy Industries Assoc., AEE, the American Council on Renewable Energy ("ACORE"), and the Mid-Atlantic Renewable Energy Coalition ("MAREC").

[118] "Joint Consumer Advocates" were the NJ Division of Rate Counsel, DE Division of the Public Advocate, the DC Office of the People's Counsel, the PA Office of Consumer Advocate, MD Office of People's Counsel and the IL Citizens Utility Board.

capacity market rules and seeking confirmation that, to the extent the FERC has not established a replacement rate prior to the August 2019 BRA, any replacement rate later established by the FERC would be applied prospectively and would not require PJM to re-run the August 2019 BRA. Answers to the Motion were filed by PJM Entities[119] (requesting the FERC establish a revised commencement date and schedule) and the IL AG (requesting that the FERC require PJM to replace the clearing price setting algorithm ahead of running the BRA and to release generator bidding data 30 days after the BRA). EPSA, Clean Energy Entities and Direct Energy each filed comments supporting the PJM Motion. EPSA protested the PJM Entities' April 25 answer (because it is procedurally defective and would only serve to inject further uncertainty into the market).

On July 25, the FERC denied PJM's Motion and directed PJM not to run the BRA in August 2019.[120] In denying PJM's Motion, the FERC declined to "rule prematurely on the issue of any appropriate remedy prior to rendering a determination on the merits of a replacement rate."[121] In directing PJM not to run the BRA, it "recognize[d] the importance of sending price signals sufficiently in advance of delivery to allow for resource investment decisions. However, we believe that in the circumstances presented here, on balance, delaying the auction until the Commission establishes a replacement rate will provide greater certainty to the market than conducting the auction under the existing rules."[122] Each of Commissioners LaFleur, Glick and McNamee concurred with separate statements, which are well-worth the read.

For further information on this proceeding, please contact Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **PJM Clean MOPR Complaint (EL18-169)**

This proceeding, which could impact potentially impact New England's markets, remains pending. As previously reported, CPV Power Holdings, L.P. ("CPV"), Calpine Corporation ("Calpine"), and Eastern Generation, LLC ("Eastern Generation") (collectively, "PJM MOPR Complainants") filed a complaint on May 31, 2018 requesting that the FERC protect PJM's Reliability Pricing Model ("RPM") market from below-cost offers for resources receiving out-of-market subsidies by requiring PJM to adopt a "Clean MOPR" (i.e. a MOPR applicable to all subsidized resources and without categorical exemptions like those in PJM's MOPR-Ex proposal). PJM MOPR Complainants state that the Complaint offers the FERC a procedural vehicle to require adoption of the "Clean MOPR" that Complainants opine is not otherwise available in pending FERC proceedings (EL16-49 (PJM MOPR Complaint)[123] and ER18-1314 (PJM's pending MOPR changes)). They assert that the "Clean MOPR" is required to effectively address the impacts of state subsidy programs, and is consistent with the FERC's MOPR principles identified in the *CASPR Order*. Comments on the PJM Clean MOPR Complaint were due on or before June 20. PJM's answer, as well as comments and protests from over 25 parties were filed. Given its potential to impact New England, NEPOOL filed a doc-less motion to intervene. More than 30 other parties also intervened. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[119] "PJM Entities are AMP, Dominion, Exelon, EDP Renewables, FirstEnergy and the Talen PJM Companies.

[120] *Calpine et al. v. PJM*, 168 FERC ¶ 61,051 (July 25, 2019).

[121] *Id.* at P 13.

[122] *Id.* at P 14.

[123] The "PJM MOPR Complaint" seeks a FERC order expanding the PJM MOPR in the Base Residual Auction for the 2019/2020 Delivery Year to prevent the artificial suppression of prices in the Reliability Pricing Model ("RPM") market by below-cost offers for existing resources whose continued operation is being subsidized by State-approved out-of-market payments. Complainants in the MOPR Complaint are Calpine, Dynegy, Eastern Generation, Homer City Generation, the NRG Companies, Carroll County Energy, C.P. Crane , the Essential Power PJM Companies, GDF SUEZ Energy Marketing NA, Oregon Clean Energy, and Panda Power Generation Infrastructure Fund.

- ***NYISO MOPR Proceeding (EL13-62)***

As in the PJM MOPR Proceeding, NEPOOL filed limited comments requesting that any FERC action or decision be limited narrowly to the facts and circumstances as presented, and that any changes ordered by the FERC not circumscribe the results of NEPOOL's stakeholder process or predetermine the outcome of that process through dicta or a ruling. The NYISO MOPR Proceeding remains pending before the FERC. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **PJM Retroactive Surcharges (EL08-14)**

In a decision which could impact the resolution of future cases in New England, the FERC reversed its prior position on the issue of ordering refunds in cost allocation and rate design cases, and found that it does in fact have authority under the FPA to order refunds to fix an error, even if refunds will require surcharges on other parties.[124] Although the FERC acknowledged that it had "in the past has referenced a general policy of not ordering refunds in cost allocation and rate design cases", it found that it "has greater discretion with respect to this refund-related issue under sections 309 and 206(b) of the FPA than was indicated by those statements."[125] Summarizing recent court precedent, the FERC concluded that retroactive surcharges were not prohibited in all circumstances, and refunds and surcharges are allowable in situations in which surcharges are necessary if the statutory refund provision of Section 206 of the FPA is to be honored.[126] Going forward, the FERC stated that it will consider whether to require refunds in cost allocation and rate design cases based on the specific facts and equities of each case, even where such refunds must be funded through surcharges on certain parties, to meet its obligation under section 206(b) of the FPA to restore the just and reasonable rate.[127] On July 22, 2019, American Municipal Power ("AMP") requested rehearing of the *PJM Retroactive Surcharges Order*. The AMP request for rehearing is pending, with FERC action required on or before August 21, 2019, or the request will be deemed denied by operation of law.

- **D&E Agreement: NSTAR/SEMASS (ER19-2326)**

On July 1, NSTAR filed an Agreement for Design, Engineering and Construction services ("D&E Agreement") between itself and SEMASS Partnership ("SEMASS") to accommodate NSTAR's activities associated with SEMASS' planned move of its existing South Switchyard (and a subsequent new Point of Change in Ownership). Section 14 of the D&E Agreement contains the parties' agreement to revise the existing two-party Interconnection Agreement, executed in 2017, to reflect the new Point of Change of Ownership once services under the D&E Agreement have been completed, revisions which NSTAR committed to file with the FERC. NSTAR requested that the D&E Agreement become effective as of the date of filing. The D&E Agreement will expire no later than one year from its effective date, unless earlier terminated by the parties. Comments on this filing were due on or before July 22; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[124] *Black Oak Energy, EPIC Merchant Energy, and SESCO Enterprises v. PJM Interconnection*, 167 FERC ¶ 61,250 (June 20, 2019) ("*PJM Retroactive Surcharges Order*").

[125] *Id.* at P 15. FPA section 206(a) authorizes the FERC to fix rates prospectively, after it concludes that a rate is inappropriate, and to order refunds where the previous rate was unfairly high. With respect to the retroactive correction of rates that were too low, FPA section 309 gives the FERC expansive remedial authority to advance remedies not expressly provided by the FPA, as long as they are consistent with the FPA. Reallocation of costs, including through surcharges, has been found to be within the FERC's remedial authority under section 309, read in harmony with section 206 (the cost increase to a subgroup of ratepayers not being a retroactive rate increase because the aggregate rate remains the same, albeit divided differently among the constituent payers).

[126] *Id.* at P 26.

[127] *Id.* at P 27.

- **2nd Supp. to Stony Brook IA (ER19-2303)**

On June 28, NSTAR filed a second extension to the Interconnection Agreement with MMWEC for its Stony Brook Generating Station located in Ludlow, Massachusetts. The extension provides that the IA, originally date August 1, 1979, will remain in effect Agreement for Design, Engineering and Construction services ("D&E Agreement") between itself and SEMASS Partnership ("SEMASS") to accommodate NSTAR's activities associated with SEMASS' planned move of its existing South Switchyard (and a subsequent new Point of Change in Ownership). Section 14 of the D&E Agreement contains the parties' agreement to revise the existing two-party Interconnection Agreement, executed in 2017, to reflect the new Point of Change of Ownership once services under the D&E Agreement have been completed, revisions which NSTAR committed to file with the FERC. NSTAR requested that the D&E Agreement become effective as of the date of filing. The D&E Agreement will expire no later than one year from its effective date, unless earlier terminated by the parties. Comments on this filing were due on or before July 22; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/Vineyard Wind (ER19-2171)**

On June 17, NSTAR filed an Agreement for Design, Engineering and Construction services ("D&E Agreement") between itself and Vineyard Wind, LLC ("Vineyard Wind"). The purpose of the D&E Agreement is to set forth the terms and conditions under which NSTAR will undertake and be reimbursed for certain preliminary design and engineering activities in connection with the interconnection of Vineyard Wind's 832 MW wind farm off the shores of Massachusetts. NSTAR requested that the D&E Agreement become effective as of the date of filing. The D&E Agreement will expire no later than the effective date of the LGIA that will be entered into among NSTAR, Vineyard Wind and ISO-NE, unless earlier terminated by the parties. Comments on this filing were due on or before July 8; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **RFA Termination: NSTAR/Pilgrim (ER19-2108)**

On July 17, the FERC accepted NSTAR's notice of termination of the Related Facilities Agreement between NSTAR, f/k/a Boston Edison Company, and Entergy Nuclear Generation Company ("Entergy") (the "RFA").[128] As previously reported, the RFA terminated June 1, 2019 as a result of the May 31, 2019 11:59 p.m. retirement of the Pilgrim facility from the New England Markets, which terminated Pilgrim's interconnection rights, and the transfer of the ownership of Pilgrim's 345 kV transmission switchyard from Entergy to NSTAR. The termination of the RFA was accepted effective June 1, 2019, as requested. Unless the July 17 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Termination: Pilgrim (ER19-2046)**

On July 19, the FERC accepted, effective June 1, 2019, the notice of termination of the Interconnection and Operation Agreement between NSTAR, f/k/a Boston Edison Company, and Entergy Nuclear Generation Company ("Entergy") (the "IA").[129] As previously reported, the IA terminated June 1, 2019 as a result of the May 31, 2019 11:59 p.m. retirement of the Pilgrim facility from the New England Markets, which terminated Pilgrim's interconnection rights, and the transfer of the ownership of Pilgrim's 345 kV transmission switchyard from Entergy to NSTAR. Unless the July 19 order is challenged, his 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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[128] *NSTAR Elec. Co.,* Docket No. ER19-2108, (July 17, 2019) (unpublished letter order).

[129] *NSTAR Elec. Co.*, Docket No. ER19-2046 (July 19. 2019).

- **Emera Maine/Houlton Water Company NITSA (ER19-2036)**

On June 3, Emera Maine filed a non-conforming Network Integration Transmission Service Agreement ("NITSA") with Houlton Water Company. The NITSA provides for continued provision of network integration transmission service by Emera Maine to Houlton until Houlton's electric system is successfully interconnected with New Brunswick Power, which is expected to happen sometime in late 2019. A June 1, 2019 effective date was requested. Comments on this filing were due on or before June 24; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: CL&P/NTE CT (ER19-1994)**

On July 9, the FERC accepted the Agreement for Design, Engineering and Construction services ("D&E Agreement") between CL&P and NTE Connecticut, LLC ("NTE CT").[130] As previously reported, the purpose of the D&E Agreement is to set forth the terms and conditions under which CL&P will undertake and be reimbursed for certain preliminary design and engineering activities in connection with the interconnection of NTE CT's 692 MW generation facility to CL&P's system in Killingly, CT. The FERC accepted the D&E Agreement effective May 28, 2019, as requested. Unless the July 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).

- ***Emera Maine* Order 845 Compliance Filing (ER19-1887)**

On May 17, 2019, in response to the requirements of *Order 845*, Emera Maine submitted changes to the LGIP and LGIA in its Open Access Transmission Tariff for the Maine Public District (the "MPD OATT"). Emera Maine request a May 20, 2019 effective for the changes. Though no comments were filed, the FERC issued a letter in a number of utility filing proceedings, including this one, requesting additional information related to the provisions for surplus interconnection service be filed within 30 days (or July 15). Emera Maine filed a response to the FERC's letter on July 15. Comments on that filing are due on or before August 5. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Mystic COS Agreement Amendment No. 1 (ER19-1164)**

As previously reported, Constellation Mystic Power, LLC ("Mystic") filed on March 1, 2019 (separately from its contemporaneously-submitted compliance filing (*see* ER18-1639 above)) an amendment to its COS Agreement to provide "reciprocal early termination rights for ISO-NE and Mystic based on the results of ISO-NE's updated fuel security analysis, to be completed in September of 2019". Comments on this filing were due on or before March 22, 2019. Protests were filed by CT Parties, ENECOS, MMWEC/NHEC, and Verso. Doc-less interventions were filed by Avangrid, Environmental Defense Fund, Eversource, MA DPU, National Grid, NESCOE, Repsol, and the New England Local Distribution Companies. On April 8, Mystic answered the March 22 protests. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **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 the Office of Enforcement ("OE") 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. There has been no public update provided since that order.

[130] *The Conn. Light and Power Co.*, Docket No. ER19-1994 (July 9, 2019) (unpublished letter order).

- **FERC Enforcement Action: Show Cause Order – Vitol & F. Corteggiano (IN14-4)**

On July 10, 2019, the FERC issued an order[131] directing Vitol Inc. ("Vitol") and its co-head of FTR trading operations, Frederico Corteggiano, to show cause why (i) they should not be found to have violated, from October 28-November 1, 2013, the FERC's Anti-Manipulation Rule by selling physical power at a loss in CAISO's market in order to eliminate congestion that they expected to cause losses on Vitol's congestion revenue rights ("CRRs");[132] (ii) why Vitol and Corteggiano should not pay civil penalties in the amount of $6 million and $800, 000, respectively; and (iii) why Vitol should not disgorge $1,227,143 plus interest in unjust profits, or a modification to these amounts as warranted. Vitol's and Corteggiano's responses are due on or before August 9, 2019. OE staff will have 30 days from that date to file a reply.

On July 17, the FERC issued an updated notice that identified nine OE staff members who would not be included in the blanket designation of OE Staff as non-decisional. On July 18, Vitol and Corteggiano objected to the exceptions and urged the FERC to "designate as non-decisional all OE staff and all staff involved in the decision to issue the OSC and to bar them from having any *ex parte* communication with the Commission and decisional staff relating to this Docket." On July 24, Vitol and Corteggiano asked for a 30-day extension of time to submit their responses. OE Staff opposed that motion the next day, and the extension request is pending before the FERC.

XII. Misc. - Administrative & Rulemaking Proceedings

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

On January 8, 2018, the FERC initiated a Grid Resilience in RTO/ISOs proceeding (AD18-7)[133] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[134] 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,

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[131] *Vitol Inc. and Federico Corteggiano*, 168 FERC ¶ 61,013 (July 10, 2019).

[132] Enforcement Staff alleges that Vitol and Corteggiano ("Respondents") sold physical power at a loss at the Cragview node in CAISO's day-ahead market from Oct. 28 through Nov. 1, 2013, in order to eliminate congestion costs that they expected would negatively affect Vitol's CRRs. On Vitol's behalf, Corteggiano purchased CRRs sourcing at Cragview in CAISO's annual CRR auction for 2013. In mid-October 2013, CAISO derated the Cascade intertie to "0" in only the export direction, while still allowing imports. During the derate, an unusually high LMP appeared at Cragview due to congestion costs. The congestion costs caused Respondents' CRRs to lose money. CAISO announced that identical derates would occur during the week of October 28 through November 1 and on additional dates later in November and in December. Respondents were able to protect against losses on their CRR positions for November and December by buying counter-flow CRRs in the CRR auctions for those months (i.e., "flattening" the CRR position). However, because the monthly CRR auction for October had closed, it was too late for Respondents to flatten their CRR position for the last week of October. Facing over $1.2 million in potential losses on their CRRs during that week's scheduled partial derate, Respondents imported physical power in the day-ahead market at an offering price of $1/MWh, which prevented a recurrence of the congestion costs that Respondents had observed during the October 18-19 derate. Staff alleges Respondents undertook the import transactions in disregard of market fundamentals and were indifferent to whether they made a profit on them. In fact, Respondents lost money on the imports, but avoided a far larger loss on their CRRs. *Id.* at P 3.

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

[134] 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.

FRS requested rehearing of the January 8 order terminating the DOE NOPR proceeding. The FERC issued a tolling order on March 8, 2018 affording it additional time to consider the FRS request for rehearing, which remains pending.

Grid Resilience Administrative Proceeding (AD18-7). AD18-7 was initiated to evaluate the resilience of the bulk power system in RTO/ISO regions. The FERC directed each RTO/ISO to submit information on certain resilience issues and concerns, and committed to use the information submitted to evaluate whether additional FERC action regarding resilience is appropriate. RTO submissions were due on or before March 9, 2018.

ISO-NE Response. In its response, ISO-NE identified fuel security[135] as the most significant resilience challenge facing the New England region. ISO-NE reported that it has established a process to discuss market-based solutions to address this risk, and indicated that it believed it will need through the second quarter of 2019 to develop a solution and test its robustness through the stakeholder process. In the meantime, ISO-NE indicated that it would continue to independently assess the level of fuel-security risk to reliable system operation and, if circumstances dictate, would take, with FERC approval when required, actions it determines to be necessary to address near-term reliability risks. ISO-NE's response was broken into three parts: (i) an introduction to fuel-security risk; (ii) background on how ISO-NE's work in transmission planning, markets, and operations support the New England bulk power system's resilience; and (iii) answers to the specific questions posed in the January 8 order.

Industry Comments. Following a 30-day extension issued on March 20, 2018, reply comments were due on or before May 9, 2018. NEPOOL's comments, which were approved at the May 4 meeting, were filed May 7, and were among over 100 sets of initial comments filed. A summary of the comments that seemed most relevant to New England and NEPOOL was circulated to the Participants Committee on May 15 and is posted on the NEPOOL website. On May 23, NEPOOL submitted a limited response to four sets of comments, opposing the suggestions made in those pleadings to the extent that the suggestions would not permit full use of the Participant Processes. Supplemental comments and answers were also filed by FirstEnergy, MISO South Regulators, NEI, and EDF. Exelon and American Petroleum Institute filed reply comments. FirstEnergy included in this proceeding its motion for emergency action also filed in ER18-1509 (ISO-NE Waiver Filing: Mystic 8 & 9), which Eversource answered (in both proceedings). Reply comments were filed by APPA and AMP and the Nuclear Energy Institute ("NEI") moved to lodge presentations by the National Infrastructure Advisory Council. On December 6, the Harvard Electricity Law Initiative filed a comment suggesting that, as a matter of law, "Commission McNamee cannot be an impartial adjudicator in these proceedings" and "any proceeding about rates for 'fuel-secure' generators" and should recuse himself. Similarly, on December 18, "Clean Energy Advocates"[136] requested Commissioner McNamee recuse himself from these proceedings. These matters remain pending before the FERC.

FirstEnergy DOE Application for Section 202(c) Order. In a related but separate matter, FirstEnergy Solutions ("FirstEnergy") asked the Department of Energy ("DOE") in late March to issue an emergency order to provide cost recovery to coal and nuclear plants in PJM, saying market conditions there are a "threat to energy security and reliability". FirstEnergy made the appeal under Section 202(c) of the FPA, which allows the DOE to issue emergency orders to keep plants operating, but has previously been exercised only in response to natural disasters. Action on that 2018 request is pending.

- **Increasing Market and Planning Efficiency Through Improved Software (AD10-12)**

From June 25-27, 2019, the FERC held its 10th consecutive technical conference addressing increasing Real-Time and Day-Ahead market efficiency through improved software. FERC Staff facilitated a discussion to explore

[135] 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."

[136] For purposes of these proceedings, "Clean Energy Advocates" are NRDC, Sierra Club and UCS.

research and operational advances with respect to market modeling that appear to have significant promise for potential efficiency improvements. Speaker materials were posted in eLibrary on July 3. The FERC will accept post-conference comments through July 31, 2019.

- **NOPR: Public Util. Trans. ADIT Rate Changes (RM19-5)**

On November 15, 2018, the FERC issued a NOPR ("*ADIT NOPR*") proposing to require all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law").[137] Specifically, for transmission formula rates, the FERC is proposing (i) to require that public utilities deduct excess ADIT from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT; (ii) to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information; (iii) to require all public utilities with transmission stated rates to determine the amount of excess and deferred income tax caused by the 2017 Tax Law's reduction to the federal corporate income tax rate and return or recover this amount to or from customers. As previously reported, comments on the *ADIT NOPR* were due on or before January 22, 2019. Comments were filed by over 14 parties, including Eversource, EEI, and NRECA. The *ADIT NOPR* is pending before the FERC.

- ***Order 861*: Refinements to Horizontal Market Power Analysis Requirements (RM19-2)**

On July 18, the FERC issued its final rule that relieves market-based rate ("MBR") sellers of the obligation, when seeking to obtain or retain MBR authority in any RTO/ISO market with RTO/ISO-administered energy, ancillary services, and capacity markets subject to FERC-approved RTO/ISO monitoring and mitigation, to submit indicative screens ("*Order 861"*).[138] In RTOs and ISOs that lack an RTO/ISO-administered capacity market, MBR sellers will be relieved of the requirement to submit indicative screens if their MBR authority is limited to sales of energy and/or ancillary services. The FERC's regulations will continue to require RTO/ISO sellers to submit indicative screens for authorization to make capacity sales in any RTO/ISO markets that lack an RTO/ISO-administered capacity market subject to FERC-approved RTO/ISO monitoring and mitigation. The *NOPR* also proposes to eliminate the rebuttable presumption that FERC-approved RTO/ISO market monitoring and mitigation is sufficient to address any horizontal market power concerns regarding sales of capacity in RTOs/ISOs that do not have an RTO/ISO-administered capacity market. For those RTOs/ISOs that do not have an RTO/ISO-administered capacity market, FERC-approved RTO/ISO monitoring and mitigation is no longer presumed sufficient to address any horizontal market power concerns for capacity sales where there are indicative screen failures. Order 861 will become effective September 24, 2019.[139] Unless *Order 861* is challenged, with any challenges due on or before August 19, 2019, this proceeding will be concluded.

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

In *Order 841*[140] (*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*.[141] All comments filed in response to the *Storage NOPR* will be incorporated by reference into Docket No. RM18-9 and further comments regarding the proposed distributed energy resource aggregation reforms, including

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[137] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 165 FERC ¶ 61,117 (Nov. 15, 2018).

[138] *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Trans. Org. and Indep. Sys. Op. Mkts.*, Order No. 861, 168 FERC ¶ 61,040 (July 18, 2019).

[139] *Order 861* was published *Fed. Reg.* on July 26, 2019 (Vol. 84, No. 144) pp. 36,374-36,387.

[140] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018), reh'g and/or *clarif. requested* ("*Order 841*").

[141] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

comments regarding the April 10-11 technical conference in AD18-10,[142] were also to be filed in RM18-9. On June 26, 2018, over 50 parties submitted post-technical conference comments in this proceeding, including comments from ISO-NE, Calpine, Direct, Eversource, Icetec, NRG, Utility Services, EEI, EPRI, EPSA, NARUC, NRECA, and SEI. On February 11, 2019, a group of 18 US Senators submitted a letter urging the FERC to adopt a final rule that enable all DERs the opportunity to participate in the RTO/ISO markets and requesting an update no later than March 1, 2019. Reply comments and answers were submitted by the Arkansas PUC, AEE, AEMA, and the Missouri PUC. APPA/NRECA submitted supplemental comments. This matter remains pending before the FERC.

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

Order 845. As previously reported, the FERC issued on April 19, 2018, its final rule,[143] *Order 845*, revising its *pro forma* Large Generator Interconnection Procedures ("LGIP") and *pro forma* LGIA to implement 10 specific reforms designed to improve certainty for interconnection customers,[144] promote more informed interconnection decisions,[145] and enhance the interconnection process.[146] Based on the comments received on its December 15, 2016 NOPR[147] in this proceeding as well as other factors, *Order 845* declined to adopt four proposed reforms related to requiring periodic restudies, self-funding of network upgrades, the posting of congestion and curtailment information, and the modeling of electric storage resources. *Order 845* took no action on two additional issues raised in the NOPR -- cost caps for network upgrades and affected system coordination (which is being addressed in a separate proceeding). *Order 845* became effective July 23, 2018.

Order 845-A. On February 21, 2019, the FERC issued its order on rehearing and clarification of *Order 845* ("*Order 845-A*").[148] The FERC granted rehearing in full or in part of four requests and clarification with respect to seven requests. The FERC ***granted rehearing*** with regard to (a) the option to build reform (requiring that transmission providers explain why they do not consider a specific network upgrade to be a standalone network upgrade; and allowing transmission providers to recover oversight costs related to the interconnection customer's option to build), (b) surplus interconnection service reform (explaining that RTOs/ISOs will not be limited in their arguments for an independent entity variation from the requirements), and (c) when an interconnection customer can propose control technologies in connection with

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[142] On April 10-11, 2018, the FERC held a technical conference to gather additional information to help the FERC determine what action to take on DER aggregation reforms proposed in the *Storage NOPR* and to explore issues related to the potential effects of DERs on the bulk power system. Technical conference materials are posted on the FERC's eLibrary. Interested persons were invited to file post-technical conference comments on the topics concerning the Commission's DER aggregation proposal discussed during the technical conference, including on follow-up questions from FERC Staff related to the panels. Comments related to DER aggregation were to be filed in RM18-9; comments on the potential effects of DERs on the bulk power system, in AD18-10.

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

[144] 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.

[145] 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.

[146] 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.

[147] *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.

[148] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845-A, 166 FERC ¶ 61,137 (Feb. 219, 2019).

interconnection service below generating facility capacity (control technologies may be proposed at any time in the interconnection process that it is permitted to request interconnection service below generating facility capacity). The FERC granted clarification with regard to (w) the option to build provisions (finding *Order 845* applies to all public utility transmission providers, including those that reimburse the interconnection customer for network upgrades, and does not apply to stand alone network upgrades on affected systems), (x) study model and assumption transparency (finding that transmission providers may use the FERC's CEII regulations as a model for evaluating entities that request network model information and assumptions and the phrase "current system conditions" does not require transmission providers to maintain network models that reflect current real-time operating conditions of the transmission provider's system), (y) interconnection study deadlines (transmission providers are not required to post 2017 interconnection study metrics) and (z) transmission providers must provide a detailed explanation of its determination to perform additional studies at the full generating facility capacity for an interconnection customer that has requested service below its full generating facility capacity. All other requests for rehearing and clarification were denied. On March 25, AEP requested rehearing of *Order 845-A*. AWEA answered AEP's rehearing request on May 21, 2019. On April 23, 2019, the FERC issued a tolling order affording it additional time to consider AEP's request, which remains pending.

Effective Date and Compliance Filing Deadline. *Order 845-A* became effective May 20, 2019.[149] The *Order 845* compliance filing deadline was ***May 22, 2019***. Additionally, for each RTO/ISO, "the effective date of the proposed revisions shall be the date established in the Commission's order accepting that RTO's/ISO's compliance filing, which will be no earlier than the issuance date of such an order." ISO-NE's *Order 845* compliance filing was considered but not supported by the Participants Committee at its May 3, 2019 meeting and filed on May 22 (*see* ER19-1951 above).

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).

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

Order 841. On February 15, 2018, the FERC issued *Order 841*, which requires each RTO/ISO to revise its tariff "to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets."[150] Additionally, each RTO/ISO must specify that the sale of electric energy from the RTO/ISO markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale locational marginal price. *Order 841* became effective June 4, 2018. As previously reported, *Order 841* did not adopt the *Storage NOPR's* proposed reforms related to DER aggregations. Instead, *Order 841* instituted a new rulemaking proceeding and technical conference (*see* RM18-9 above) to gather additional information to help the FERC determine what action to take with respect to DER aggregation. Requests for Clarification and/or Rehearing of *Order 841* were filed by CAISO, MISO, PJM, the AES Companies, AMP/APPA/NRECA, California Energy Storage Alliance, EEI, NARUC, PG&E, TAPS, and Xcel Energy Services.

Order 841-A. On May 16, The FERC issued *Order 841-A*[151] in which it denied the requests for rehearing and denied in part but granted in part the requests for clarification of *Order 841*. Specifically, the FERC clarified the following (requesting party in parentheses): (i) *Order 841* does not require an RTO/ISO to create

[149] *Order 845-A* was published in the *Fed. Reg.* on Mar. 6, 2019 (Vol. 84, No. 44) pp. 8,156-8,185.

[150] The participation model must: (1) ensure that a resource using the participation model is eligible to provide all capacity, energy and ancillary services that the resource is technically capable of providing in the markets; (2) ensure that a resource using the participation model can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with existing market rules that govern when a resource can set the wholesale price; (3) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and (4) establish a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW.

[151] *Elec. Storage Participation in Mkts. Operated by Regional Transmission Orgs. and Indep. Sys. Ops.*, Order No. 841, 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841*").

and provide a capacity product that an RTO/ISO market does not otherwise offer (SPP); (ii) *Order 841* allows for flexibility in how RTOs/ISOs account for the physical and operational characteristics of electric storage resources, including State of Charge (PJM); (iii) the FERC will not dismiss as *per se* unreasonable any proposal to establish a non-facility-specific rate for wholesale distribution service to an electric storage resource for its charging (EEI); (iv) that an RTO/ISO could require verification from the host distribution utility that it is unable or unwilling to net wholesale demand from retail settlement before the RTO/ISO ceases to settle an electric storage resource's wholesale demand at the wholesale LMP (CAISO); and, finally, (v) that applicable transmission charges should apply when an electric storage resource is charging to resell energy at a later time. In addition the FERC modified § 35.28(g)(9)(i)(B) of the Commission's regulations to clarify that each RTO/ISO is required to allow resources using the participation model for electric storage resources to participate in the RTO/ISO markets as dispatchable resources, not that such resources are required to be dispatchable to use that participation model. *Order 841-A* was not challenged and is final and unappealable. *Order 841-A* will become effective August 21, 2019.[152] Reporting on this proceeding has now concluded.

- ***Order 860*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

On July 18, 2019, the FERC issued *Order 860*.[153] *Order 860*, issued three years after the FERC's *Data Collection NOPR,*[154] (i) revises the FERC's MBR regulations by establishing a relational database of ownership and affiliate information for MBR Sellers (which, among other uses, will be used to create asset appendices and indicative screens), (ii) reduces the scope of information that must be provided in MBR filings, modifies the information required in, and format of, a MBR Seller's asset appendix, (iii) changes the process and timing of the requirements to advise the FERC of changes in status and affiliate information, and (iv) eliminates the requirement adopted in *Order 816* that MBR Sellers submit corporate organization charts. In addition, the FERC stated that it will <u>*not*</u> adopt the *Data Collection NOPR* proposal to collect Connected Entity data from MBR Sellers and entities trading virtuals or holding FTRs. The FERC will post on its website high-level instructions that describe the mechanics of the relational database submission process and how to prepare filings that incorporate information that is submitted to the relational database. While *Order 860* will become effective October 1, 2020, submitters will have until close of business on February 1, 2021 to make their initial baseline submissions. In the fall of 2020, submitters will be required to obtain FERC generated IDs for reportable entities that do not have CIDs or LEIs, as well as Asset IDs for reportable generation assets without an EIA code so that every ultimate upstream affiliate or other reportable entity has a FERC-assigned company identifiers ("CID"), Legal Entity Identifier,[155] or FERC-generated ID and that all reportable generation assets have an code from the Energy Information Agency (EIA) Form EIA-860 database or a FERC-assigned Asset ID. Unless *Order 860* is challenged, with any challenges due on or before August 19, 2019, this proceeding will be concluded.

- **NOPR: NAESB WEQ Standards v. 003.2 - Incorporation by Reference into FERC Regs (RM05-5-027)**

On May 16, 2019, the FERC issued a NOPR proposing to incorporate by reference, with certain enumerated exceptions, the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB").[156] The Version 003.2 Standards include NAESB's Version

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[152] *Order 841-A* was published in the *Fed. Reg.* on May 23, 2019 (Vol. 84, No. 100) pp. 23,902-23,927.

[153] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 168 FERC ¶ 61,039 (July 18, 2019) ("*Order 860*").

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

[155] An LEI is a unique 20-digit alpha-numeric code assigned to a single entity. They are issued by the Local Operating Units of the Global LEI System.

[156] *Standards for Business Practices and Communication Protocols for Public Utilities*, 167 FERC ¶ 61,127 (May 16, 2019) ("*NAESB WEQ v. 003.2 Standards NOPR*").

003.1 revisions, which remain pending before the FERC following a July 2016 NOPR.[157] The FERC stated that comments already filed on the revisions made by NAESB in the WEQ Version 003.1 Standards will be given full consideration and need not be repeated in response to this NOPR. This NOPR invites comment on the latest revisions and corrections NAESB made in the WEQ Version 003.2 Standards. The FERC plans to act on all of the Version 003 revisions in this proceeding. NAESB's WEQ-023 Modeling Business Practice Standards, which concern technical issues affecting the calculation of Available Transfer Capability for wholesale electric transmission services, will be addressed separately. The WEQ Version 003.2 Standards include modifications and reservations to existing standards and newly developed standards made to support the short-term preemption process (WEQ-001-25) and the merger of like transmission reservations (WEQ-001-24) prescribed in the OASIS Suite of Standards. Other changes were made to support consistency with NERC Standards, to support the use of "market operator" as a separate role within the EIR, a NAESB managed industry tool, and on electronic tags (e-Tags), to revise certain Abbreviations, Acronyms, and Definitions of Terms in WEQ-000, and to make minor corrections. Comments on the *NAESB WEQ v. 003.2 Standards NOPR* were due on or before July 23, 2019[158] and were filed by PJM, SPP, MISO, BPA, Southern Company, NV Energy, and Open Access Technology Inc. Also on July 23, NAESB submitted a report notifying the FERC of a minor correction to the Standards. This matter is pending before the FERC.

- **NOI: FERC's ROE Policy (PL19-4)**

On March 21, 2019, the FERC issued a notice of inquiry seeking information and views to help the Commission explore whether, and if so how, it should modify its policies concerning the determination of the return on equity ("ROE") to be used in designing jurisdictional rates charged by public utilities.[159] The Commission also seeks comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. This NOI follows *Emera Maine*, which reversed *Opinion 531*, and seeks to engage interests beyond those represented in the *Emera Maine* proceeding (see EL11-66 *et al.* in Section I above). Initial comments were due June 26, 2019; reply comments, July 26, 2019.[160] Initial comments were been submitted by more than 60 organizations; nearly 15,000 initial comments were received from individuals. Reply comments were received from nearly 30 organizations. This matter, and its voluminous record, are pending before the FERC.

- **NOI: Electric Transmission Incentives Policy (PL19-3)**

Also on March 21, 2019, the FERC issued a notice of inquiry seeking comment on the scope and implementation of its electric transmission incentives regulations and policy pursuant to section 1241 of the Energy Policy Act of 2005 ("EPAct 2005"), codified in FPA Section 219, which directed the FERC to use transmission incentives to help ensure reliability and reduce the cost of delivered power by reducing transmission congestion.[161] Given the passage of time since Order 679 and the FERC's 2012 Incentives Policy Statement and the "significant developments in how transmission is planned, developed, operated, and maintained," the FERC stated that "it is appropriate to seek comment … on the scope and implementation of the Commission's transmission incentives policy and on how the Commission should evaluate future requests for transmission incentives in a manner consistent with Congress's direction in section 219" and solicited

[157] *Standards for Business Practices and Communication Protocols for Public Utilities*, 156 FERC ¶ 61,055 (July 21, 2016), ("*WEQ v. 003.1 NOPR*").

[158] The *ONAESB WEQ v. 003.2 NOPR* was published in the *Fed. Reg.* on May 24, 2019 (Vol. 84, No. 101) pp. 24,050-24,059.

[159] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207 (Mar. 21, 2019) ("*ROE Policy NOI*").

[160] The *ROE Policy NOI* was published in the *Fed. Reg.* on Mar. 28, 2019 (Vol. 84, No. 61) pp. 11,769-11,777.

[161] *Inquiry Regarding the Commission's Elec. Trans. Incentives Policy*, 166 FERC ¶ 61,208 (Mar. 21, 2019) ("*Electric Transmission Incentives Policy NOI*").

comment on a variety of transmission incentives-related issues. Initial comments were due June 26, 2019[162] and were filed by more than 70 parties, including by Avangrid, Eversource, Exelon, Invenergy, MMWEC/NHEC, NGrid, NextEra, UCS, NESCOE, Potomac Economics, Southern New England State Agencies, AEE, AWEA, EEI, ESA, NRECA, PIOs, R Street Institute, and TAPS.

On May 10, 2019, APPA, EEI and NRECA, in a motion covering both this and the FERC's ROE Policy proceeding, requested an extension of time to file reply comments. With respect to this proceeding, and unlike the ROE Policy proceeding, the FERC granted the motion to extend the reply period. According, reply comments will now be due on or before Aug 26, 2019.

- **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[163] 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,[164] comments were due on or before July 25, 2018. Literally thousands of individual and mass-mailed comments were filed. This matter remains pending before the FERC.

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

On March 15, 2018, the FERC found that an impermissible double recovery results from granting a Master Limited Partnership pipeline ("MLP") both an income tax allowance and an ROE pursuant to the DCF methodology.[165] 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[166] 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*[167] holding. The FERC indicated that it will address the application of *United Airlines* to non-MLP partnership forms as those issues arise in subsequent proceedings. The revised policy statement took effect on March 21, 2018. Requests for rehearing of the March 15 order were filed by the Dominion, Enable Mississippi River Transmission and Enable Gas Transmission, Enbridge and Spectra Energy Partners, EQT Midstream Partners, Kinder Morgan, Master Limited Partnership Association ("MLPA"), NGAA, SPPP, LP, Oil Pipe Lines, Plains Pipeline, Tallgrass Pipelines, and TransCanada. On July 18, the FERC issued its order on rehearing,[168] dismissing the requests for rehearing and clarification and providing guidance regarding the treatment of ADIT where the income tax allowance is eliminated from cost-of-service rates under the FERC's post-

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[162] The *Electric Transmission Incentives Policy NOI* was published in the *Fed. Reg.* on Mar. 28, 2019 (Vol. 84, No. 60) pp. 11,759-11,768.

[163] The NOI was published in the *Fed. Reg.* on Apr. 26, 2018 (Vol. 83, No. 80) pp. 18,020-18,032.

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

[165] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs*, 162 FERC ¶ 61,227 (Mar. 15, 2018), *order on reh'g*, 164 FERC ¶ 61,030 (July 18, 2018).

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

[167] *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.

[168] *Inquiry Regarding the FERC's Policy for Recovery of Income Tax Costs*, 164 FERC ¶ 61,030 (July 18, 2018) ("*Order on Rehearing*").

United Airlines policy. On August 17, the MLPA requested clarification and/or reconsideration of the *Order on Rehearing*, which is pending before the FERC. On September 4, R. Gordon Gooch answered MLPA's August 17 pleading. Petitions for review were filed in the D.C. Circuit by Enable Mississippi River Transmission, LLC and Enable Gas Transmission, LLC, as well as by SFPP, L.P., in September 2018. Those appeals are pending in Case Nos. 18-1252, et al. in the D.C. Circuit.

XIII. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Natural Gas-Related Enforcement Actions**

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

BP (IN13-15). On July 11, 2016, the FERC issued *Opinion 549*[169] 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.[170] 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."[171] Accordingly, the FERC assessed a ***$20.16 million civil penalty*** and required BP to ***disgorge $207,169*** in "unjust profits it received as a result of its manipulation of the Houston Ship Channel Gas Daily index." The $20.16 million civil penalty was at the top of the FERC's Penalty Guidelines range, reflecting increases for having had a prior adjudication within 5 years of the violation, and for BP's violation of a FERC order within 5 years of the scheme. BP's penalty was mitigated because it cooperated during the investigation, but BP received no deduction for its compliance program, or for self-reporting. The *BP Penalties Order* also denied BP's request for rehearing of the order establishing a hearing in this proceeding.[172] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, 2016 BP requested rehearing of the *BP Penalties Order*. On September 8, the FERC issued a tolling order, affording it additional time to consider BP's request for rehearing of the *BP Penalties Order*, which remains pending.

On September 7, 2016, BP submitted a motion for modification of the *BP Penalties Order's* disgorgement directive because it cannot comply with the disgorgement directive as ordered. BP explained that the entity to which disgorgement was to be directed, the Texas Low Income Home Energy Assistance Program ("LIHEAP"), is not set up to receive or disburse amounts received from any person other than the Texas Legislature. In response, on September 12, 2016, the FERC stayed the disgorgement directive (until an order on BP's pending request for rehearing is issued), but indicated that interest will continue to accrue on unpaid monies during the pendency of the stay.[173]

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

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

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

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

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

BP moved, on December 11, 2017, to lodge, to reopen the proceeding, and to dismiss, or in the alternative, for reconsideration based on changes in the law it asserted are dispositive and that have occurred since BP filed its request for rehearing of the *BP Penalties Order*. FERC Staff asked for, and was granted, additional time, to January 25, 2018, to file its Answer to BP's December 11 motion. FERC Staff filed its answer on January 25, 2018, and revised that answer on January 31. On February 9, BP replied to FERC Staff's revised answer. This matter remains pending before the FERC.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[174] 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.[175]

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.

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***Atlantic Bridge Project (CP16-9)***
    - 132,700 Dth/d of firm transportation to new and existing delivery points on the Algonquin system and 106,276 Dth/d of firm transportation service from Beverly, MA to various existing delivery points on the Maritimes & Northeast system.
    - 6.3 miles of replacement pipeline along Algonquin in NY and CT; new 7,700-horsepower compressor station in Weymouth, MA; more horsepower at existing compressor stations in CT and NY.
    - Seven firm shippers: Heritage Gas Limited, Maine Natural Gas Company, NSTAR Gas Company d/b/a Eversource Energy, Exelon Generation Company, LLC (as assignee and asset manager of Summit Natural Gas of Maine), Irving Oil Terminal Operations, Inc., New England NG Supply Limited, and Norwich Public Utilities.
    - Certificate of public convenience and necessity granted Jan. 25, 2017.[176]

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

[175] 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.

[176] 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*").

- Certain facilities,[177] 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.[178] Remaining Project capacity will be available when the remaining Project facilities are placed into service following Director of OEP authorization.
- Algonquin files notice that construction of Salem Pike, Needham, Pine Hills and Plymouth meter and regulating stations began on April 2, 2018. Detailed information regarding construction activities can be found in the weekly construction reports filed in this docket.
- On February 16, 2018, Algonquin filed with the DC Circuit Court of Appeals, pursuant to NGA Section 19(d)(2), a petition for review of the MA DEP's failure to issue, condition, or deny a minor-source air permit for Algonquin's proposed natural gas compressor station in the Town of Weymouth, MA by the July 31, 2016 deadline established by the FERC. Algonquin seeks an order establishing a deadline for the MA DEP to issue, condition, or deny the permit.
- On May 31, the DC Circuit issued a *per curiam* order that holds this case in abeyance pending further order of the court.[179] The court based its order on the parties' representation that they have agreed on a schedule by which to resolve their dispute. The parties were directed to file status reports at 90-day intervals and to file motions to govern future proceedings within 30 days of respondents' final decision to issue, condition, or deny petitioner's permit application.
- Status reports have thus far been filed on August 24 and November 21, 2018, and February 20, and May 21, 2019, each indicating that the case should continue to be held in abeyance. The next status report will be due in late August, 2019.
- On December 26, 2018, the FERC granted Algonquin a two-year extension of time, to January 25, 2021, to complete the Project.[180] In requesting the extension, Algonquin attributed the need for additional time to permitting delays for the Weymouth Compressor Station and ongoing construction of the Horizontal Directional Drill of the Taconic Parkway in New York. Requests for rehearing of the December 26 order were filed by two parties. On February 25, 2019, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

- ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
  - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
  - 650,000 Dth/d of firm capacity from Susquehanna County, PA (Marcellus Shale) through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
  - New 122-mile interstate pipeline.
  - Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
  - Final EIS completed on Oct 24, 2014.
  - Certificates of public convenience and necessity granted Dec 2, 2014.

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[177] 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).

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

[179] *Algonquin Gas Trans. v. Mass. Dept. of Envtl. Protection*, Case No. 18-1045, DC Cir. (May 31, 2018).

[180] *Algonquin Gas Trans., LLC*, Docket No. CP16-9 (Dec. 26, 2018) (unpublished letter order), *reh'g requested*. Absent the extension, and pursuant to the Jan. 25, 2017 Certificate Order, the Project would otherwise have had to have been completed by Jan. 25, 2019.

- 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.
  - 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.[181] 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.[182]
  - On February 12, 2018, Constitution Pipeline requested rehearing of the January 11, 2018 order. FERC denied Constitution's request for rehearing of the January 2018 order.[183] On September 14, 2018, Constitution filed a petition for review in the U.S. Court of Appeals for the D.C. Circuit.[184]
- 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.

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

[182] *Id*. at P 23.

[183] *Constitution Pipeline Co., LLC*, 164 FERC ¶ 61,029 (2018) (September 2018 Waiver Rehearing Order).

[184] Constitution, Petition for Review in U.S. Court of Appeals for the D.C. Circuit, Docket No. CP18-5-000 (filed Sept. 14, 2018).

- Tree felling and site preparation continues, but the long-term status of the pipeline is currently unknown.
- On June 25, 2018, Constitution requested a further 2-year extension of the deadline to complete construction of its project, given the delays caused by the on-going fight over the water quality certification from the NYSDEC. Iroquois made a similar request on August 1, 2018. Constitution's request was opposed by several parties and Constitution answered some of the opposition pleadings. The FERC granted the requested two-year extension of time on November 5, 2018.[185]
- Rehearing of the November 5, 2018 order was requested by Halleran Landowners and a group of intervenors comprised of Catskill Mountainkeeper; Clean Air Council; Delaware-Otsego Audubon Society; Delaware Riverkeeper Network; Riverkeeper, Inc.; and Sierra Club ("Intervenors"). Constitution answered the requests for rehearing on December 21. The FERC issued a tolling order on December 21, affording it additional time to consider the requests for rehearing. This matter is pending before the FERC.

- **Non-New England Pipeline Proceedings**
  The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:
  - **Northern Access Project (CP15-115)**
    - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[186] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit.
    - As previously reported, the August 6, 2018 *Northern Access Certificate Rehearing Order* dismissed or denied the requests for rehearing of the *Northern Access Certificate Order*.[187] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed Motion for Expedited Action" filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[188] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.
    - The FERC authorized the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project") in an order issued February 3,

[185] *Constitution Pipeline Co.*, 165 FERC ¶ 61,081 (Nov. 5, 2018), *reh'g requested*.

[186] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[187] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 164 FERC ¶ 61,084 (Aug. 6, 2018) ("*Northern Access Rehearing & Waiver Determination Order*"), *reh'g denied*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[188] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

2017.[189] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.

- Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[190] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3- year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request remains pending.

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

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

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[191] EL15-23[192]
  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).[193] Finding that "the FERC failed to adequately explain why its rationale [for rejecting price lock-in and capacity carry forward rules] in PJM – which seems to foreclose signing off on a Tariff scheme like ISO-NE's – does not apply even more forcefully to the scheme it accepted in the Orders [appealed from]," the DC Circuit granted the Petitions and remanded the case to

[189] *Nat'l Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017) ("*Northern Access Certificate Order*"), *reh'g denied*, 164 FERC ¶ 61,084 (Aug 6, 2018) ("*Northern Access Certificate Rehearing Order*").

[190] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al.* (2d Cir., Case No. 17-1164).

[191] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[192] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

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

the FERC for further proceedings in which the FERC, in order to accept the changes filed, must provide some analysis and explanation why it changed course. The remand is now pending before the FERC.

Other Federal Court Activity of Interest

- **PG&E Bankruptcy (19-71615) (9th Cir.)**
  Underlying FERC Proceeding: EL19-35, EL19-36[194]
  Petitioner: PG&E

On June 26, PG&E appealed the FERC's orders finding that it has concurrent jurisdiction with the bankruptcy courts to review and address the disposition of wholesale power contracts sought to be rejected through its bankruptcy. On July 11, PG&E moved to suspend the briefing schedule pending the Court's decision on whether to authorize direct appeal of a decision by the Bankruptcy Court in the Northern District of California. In a declaratory judgment, the Bankruptcy Court came to a completely different conclusion than the FERC and held that it has "original and exclusive jurisdiction over . . . [PG&E's] rights to assume or reject executory contracts under 11 U.S.C. § 365" and that the FERC "does not have concurrent jurisdiction, or any jurisdiction, over the determination of whether any rejections of power purchase contracts by [PG&E] should be authorized."[195] Because of the opposite conclusions, PG&E suggested that, should the Ninth Circuit allow the direct appeal of the Bankruptcy Court decision, the two appeals should proceed together. On July 12, the Court issued a mediation order directing counsel for all parties intending to file briefs in this matter to inform the circuit court's mediator by July 26, 2019 of their clients' views on whether the issues on appeal or the underlying dispute might be amenable to settlement presently or in the foreseeable future. Upwards of 60 appearances have thus far been filed on behalf of parties to the proceeding. This matter is pending before the Ninth Circuit.

- **First Energy Solutions Bankruptcy (18-3787) (6th Cir.)**
  Petitioner: FERC

In this proceeding, the FERC is appealing an Ohio bankruptcy court's August 2018 ruling that blocks the FERC from taking any action on FirstEnergy Solutions Corp.'s agreement with Ohio Valley Electric Corp. (a power purchase agreement that it is trying to shed as part of its bankruptcy proceedings). The FERC has asked the Sixth Circuit to vacate the bankruptcy court order, claiming that the ruling usurps its FPA authority over wholesale electricity contracts. Oral argument was held on June 26, 2019. This matter is pending before the Court.

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[196]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel

Pending before the DC Circuit is an appeal of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[197] for the construction and operation of a new 116-mile natural gas pipeline from Luzerne County, Pennsylvania, to Mercer County, New Jersey, along with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities ("PennEast Project"). All briefing is complete and oral argument has been scheduled for October 4, 2019. In separate but related proceedings, the New Jersey Attorney General and several conservation groups have filed actions in federal district court in New Jersey seeking to limit PennEast's use of its NGA eminent domain authority. These matters remain pending.

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[194] *NextEra Energy, Inc. v. PG&E*, 166 FERC ¶ 61,049 (Jan. 25, 2019); *Exelon Corp. v. PG&E*, 166 FERC ¶ 61,053 (Jan. 28, 2019); *Order Denying Rehearing*, 167 FERC ¶ 61,096 (May 1, 2019).

[195] Declaratory Judgment at 1-2, *PG&E v. FERC*, (Bankr. N.D. Cal. June 7, 2019).

[196] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[197] PennEast is a joint venture owned by Red Oak Enterprise Holdings, Inc., a subsidiary of AGL Resources Inc.; NJR Pipeline Company, a subsidiary of New Jersey Resources; SJI Midstream, LLC, a subsidiary of South Jersey Industries; UGI PennEast, LLC, a subsidiary of UGI Energy Services, LLC; and Spectra Energy Partners, LP.

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